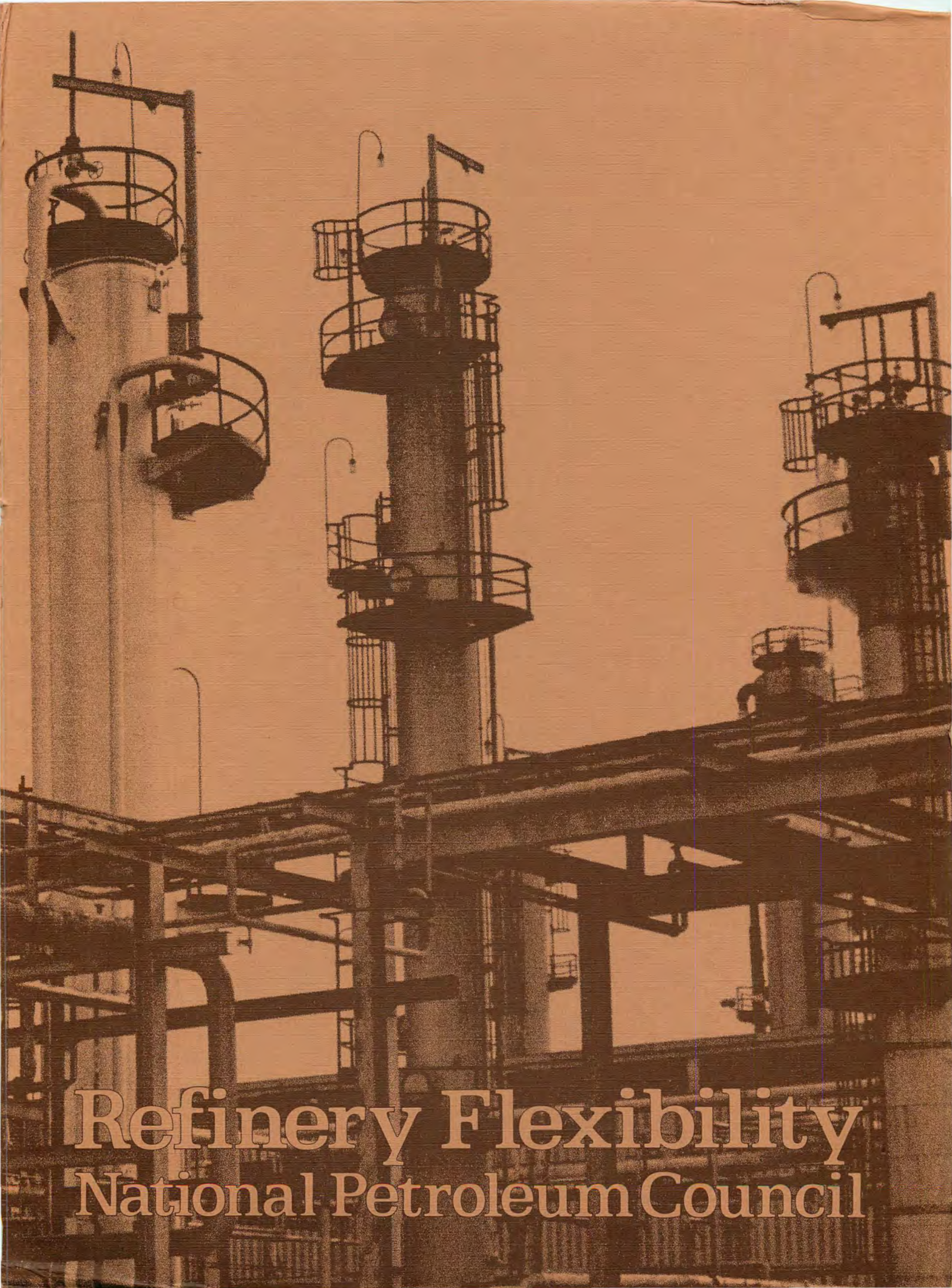
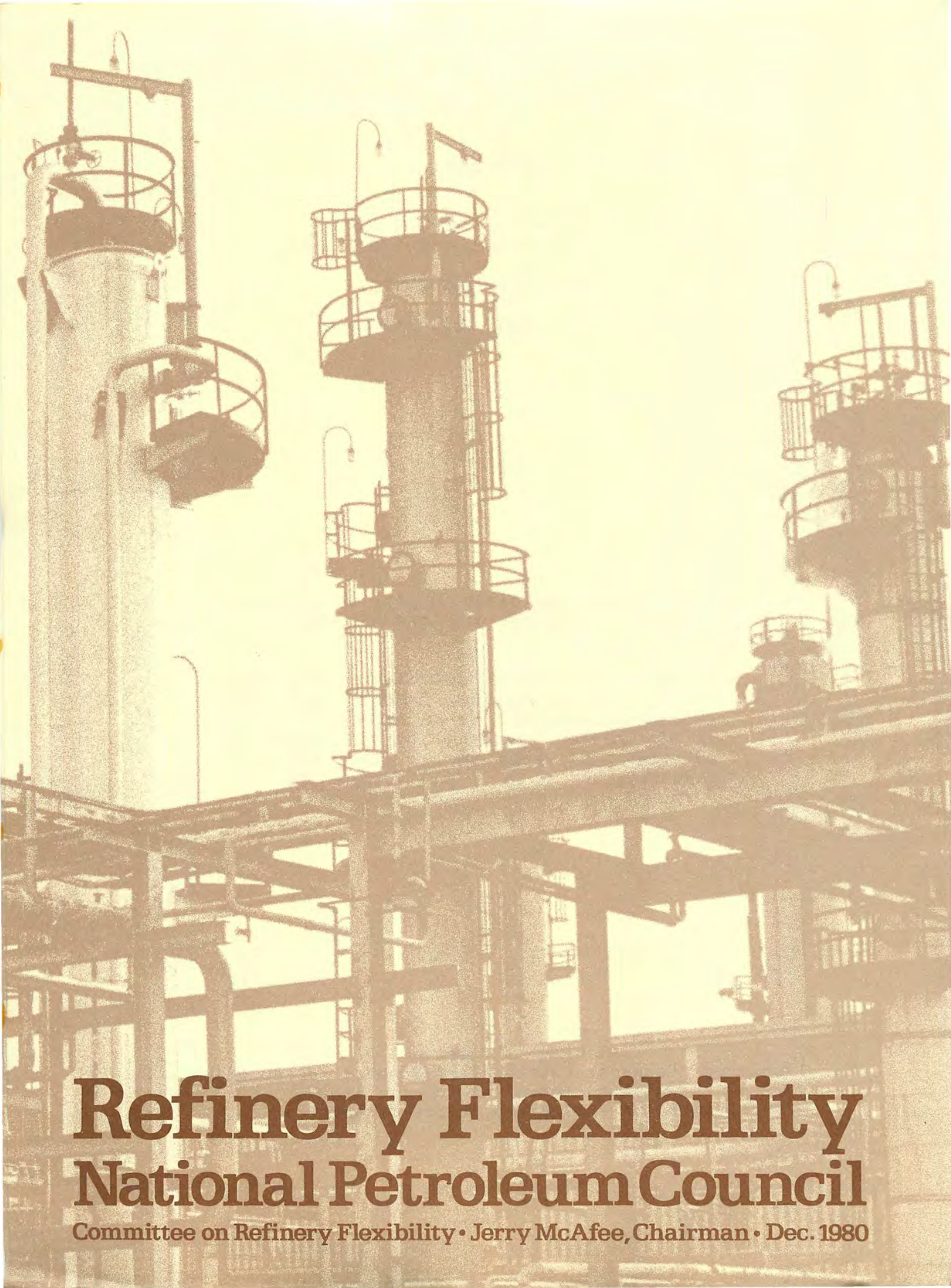


Refinery Flexibility

National Petroleum Council

Cover Photograph: Desulfurizers at the Getty Oil Company's Delaware Refinery



Refinery Flexibility

National Petroleum Council

Committee on Refinery Flexibility • Jerry McAfee, Chairman • Dec. 1980

NATIONAL PETROLEUM COUNCIL

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U.S. DEPARTMENT OF ENERGY

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The National Petroleum Council is a federal advisory committee to the Secretary of Energy.

The sole purpose of the National Petroleum Council is to advise, inform, and make recommendations to the Secretary of Energy on any matter requested by the Secretary relating to petroleum or the petroleum industry.

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INTRODUCTION

On September 18, 1978, the National Petroleum Council (NPC), a federal advisory committee to the Secretary of Energy, was requested by the Secretary to prepare an analysis of the factors which affect the ability of the domestic refining industry to meet demands for essential petroleum products.

In requesting the study, the Secretary of Energy specified that the study should include:

> ...a comprehensive study of the historical trends and present status of the domestic refining industry's sources of crude oil and its capability to process these crudes into marketable petroleum products. The study should analyze factors affecting the future trends in crude availability, refining capability, and the competitive economics of small, medium, and large refinery operations through the year 1990. The study should also examine the industry's flexibility to meet dislocations of supply.

(See Appendix A for the complete text of the Secretary's request letter and a further description of the National Petroleum Council.)

To assist in its response to this request, the NPC established the Committee on Refinery Flexibility, with the following organization:

<u>Committee on Refinery Flexibility</u>

<u>Chairman</u>	<u>Government Cochairman</u>
Jerry McAfee Chairman of the Board Gulf Oil Corporation	R. Dobie Langenkamp[1] Deputy Assistant Secretary Resource Development and Operations Resource Applications U.S. Department of Energy

<u>Coordinating Subcommittee</u>

<u>Chairman</u>	<u>Government Cochairman</u>
Warren B. Davis Chief Economist Gulf Oil Corporation	Frank A. Verrastro Acting Deputy Assistant Secretary for International Energy Resources Office of International Affairs U.S. Department of Energy

[1]Succeeded Alvin L. Alm and C. William Fischer.

Refinery Capability Task Group

Chairman	Government Cochairman
John R. Hall Vice Chairman and Chief Operating Officer Ashland Oil, Inc.	Eugene L. Peer Director, Supply Initiatives Oil and Natural Gas Supply Development U.S. Department of Energy

Oil Supply, Demand and Logistics Task Group

Chairman	Government Cochairman
S. E. Watterson, Jr. Manager, Corporate Planning Standard Oil Company of California	William R. Veno[2] Policy and Evaluation Office of Analytical Services U.S. Department of Energy

(Rosters of all study participants are included in Appendix B.)

INTERIM REPORT

An interim report on this study effort was approved by the NPC in December 1979 and contained the results of the January 1979 NPC Survey of Petroleum Refining Capabilities and the April 1979 NPC Survey of U.S. and World Energy and Oil Supply/Demand Forecasts. The summary of that interim report is reprinted in Appendix C.

The certified public accounting firm of Arthur Young & Company was retained by the NPC to receive and aggregate the survey responses. Arthur Young & Company was instructed to treat all responses in strictest confidence and to release no identified individual company data. The Council wishes to acknowledge the high level of cooperation received from the refiners and other participants and thank them for their time and thoughtful consideration of these questionnaires.

FINAL REPORT

The final report of the Council covers the specific areas noted in the request from the Secretary of Energy and is divided into three principal parts:

Oil Supply and Demand Analyses

Historical petroleum supply/demand data are developed for the 1972-1978 period and surveys of supply/demand projections are reported for the years 1982, 1985, and 1990.

---

[2]Succeeded Robert S. Long.

The first supply/demand survey was conducted in April 1979 and, because the political and economic events which occurred during 1979 were not reflected in its responses, a second survey was conducted in December 1979. For the purposes of this report, the average of the first and second surveys' responses are called the high and medium cases, respectively. A low case was prepared from the second survey's lowest quartile of responses to the 1990 total U.S. demand for petroleum products. The range of supply/demand projections provided by this approach forms a basis for assessing future refining requirements.

Refinery Capability and Flexibility Analyses

In January 1979, the three part NPC Survey of Petroleum Refining Capabilities was distributed to all U.S. refiners requesting:

- Data on each U.S. refinery's operations for 1978, 1980, and 1982, including those facilities in place by January 1979, and facilities firmly committed for installation prior to January 1, 1982

- Crude oil and refinery operating costs for 1978 and refinery assets as of January 1, 1979

- Estimates of the facilities, in addition to those in place by January 1, 1982, which would be required to meet the specifications of three hypothetical cases involving changes in crude oil supply and product demand.

This area of the study assesses the U.S. refining industry's capability to process available crude oils and to meet product demands under a variety of supply/demand scenarios, including emergency disruptions. The 1978 crude oil and product slates and refining process capacity data from the January 1979 NPC survey are used to define the system in place and to verify the analysis procedures used. The study also utilizes a refinery simulation model developed by Bonner & Moore Associates, Inc., to estimate future facility requirements. The analysis uses the crude oil supply and product demand data from the NPC supply/demand surveys.

Competitiveness Analyses

The competitive economics of refining within the United States is analyzed by company and refinery size range, geographic location, and refinery process complexity. For the comparison of foreign and domestic refineries, only the competition for U.S. East Coast markets was analyzed. In this phase of the study, hypothetical refineries were modeled, based on the typical size and complexity of U.S. East Coast and Gulf Coast refineries and foreign export refineries. The analysis compares the incremental economics of these hypothetical refineries when supplying product to the U.S. East Coast.

Throughout the report, various regions of the United States are compared with each other and with foreign regions. The Petroleum Administration for Defense (PAD) districts provide the boundaries of the U.S. regions used in the analyses. Figure 1 shows the five PAD districts.

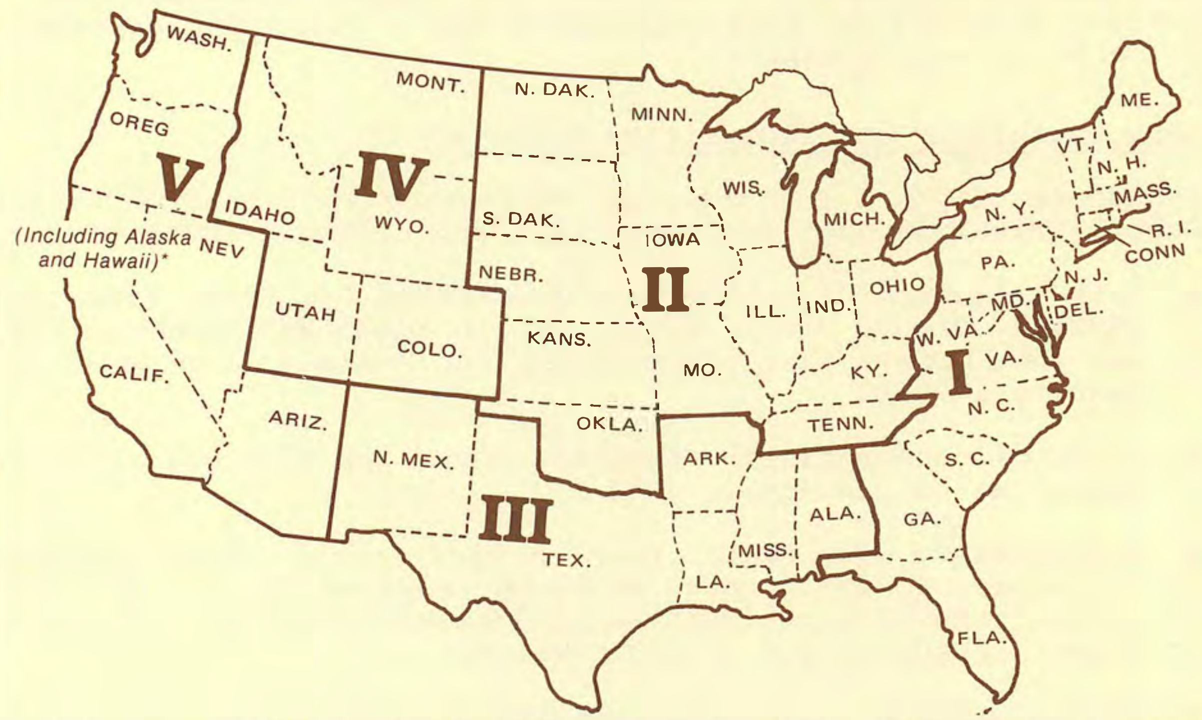

Figure 1. Petroleum Administration for Defense (PAD) Districts.

*Guam is considered a part of PAD V for the purposes of this study.

PERSPECTIVE

The U.S. petroleum refining industry is the largest and most sophisticated in the world. As of January 1, 1979, 174 companies operated 287 refineries in the contiguous 48 states, Alaska, Hawaii, and Guam. The total crude oil processing capacities of these refineries totalled 17.3 million barrels per day, and with the exception of residual fuel oil, U.S. refineries supplied virtually all of the U.S. requirements for refined petroleum products.

Over the past 20 to 30 years the U.S. petroleum refining industry has changed dramatically in its size and complexity. These changes have been the result of U.S. companies keeping pace with the rapid growth of the U.S. economy, increased automobile usage, the introduction and great expansion of jet aircraft usage, and the growing realization of the need to protect the environment. Appendix D provides a historical review of the development of the current U.S. refining industry and explains some of the fundamentals of refining operations in general.

CONCLUSIONS

Based on the data collected and analyses performed during the course of this study of refinery flexibility and competitiveness, the National Petroleum Council respectfully submits the following conclusions for the consideration of the Secretary of Energy:

- Given the economic and political conditions which exist in the summer of 1980, it is concluded that total U.S. demand for refined petroleum products will be constant or slightly declining during the decade of the 1980's. The consensus of forecasters polled by the National Petroleum Council at the end of 1979 is that 1990 product demand will be about 18.9 million barrels per day -- virtually the same as the 1978 level of 18.8 million barrels per day. Within this group of forecasters are several who, on the average, feel that total product demand will decline to about 16.8 million barrels per day by 1990.

- Significant changes in the demand for specific products will occur over the next 10 years. Total motor gasoline demand is expected to decline while the proportion of unleaded gasoline increases from 32 percent in 1978 to 77 percent in 1985 and 89 percent in 1990. Heating oil and residual fuel oil demands also show a steady decline. These declines are projected to be offset by a growth in demand for commercial jet fuel, diesel fuel, liquified gases, and non-energy products such as petrochemical feedstocks, lubricants, metallurgical coke, and asphalt.

- During the 1980's, the decline in domestic petroleum liquids supply is expected to be halted by increased rates of reserve additions and the beginning of synthetics production. From a refining standpoint, however, the average quality of U.S. supply will decline. Domestic supply from all sources was 10.3 million barrels per day in 1978 and is shown to range between 9.5 and 10.4 million barrels per day from 1982 to 1990. Similarly, the requirement for imports was 8.4 million barrels per day in 1978 and is expected to be in the range of 7.5 to 9.0 million barrels per day between 1982 and 1990. While the volumes of supply from domestic and foreign sources are substantially unchanged throughout the period of this study, the average quality of this supply is expected to be higher in sulfur content and residual yield. For example, in 1978, 54 percent of the supply to U.S. refineries was low-sulfur (sweet). By 1990, these more desirable oils will be only 41 to 45 percent of total supply.

- Existing crude oil distillation capacity will be adequate through 1990, but substantial additional downstream processing capacity will be needed. Because of the expected changes in the composition of product demand and petroleum supply, expansion will be required in facilities for upgrading unleaded gasoline (e.g., catalytic reforming), desulfurization (e.g., naphtha and distillate hydrotreating), and residual fuel oil conversion (e.g., coking). Refiners' present plans for expansion of these facilities by 1982 will not be adequate to meet any of the consensus forecast supply/demand cases shown for 1985 or 1990 and may not meet the cases shown for 1982. It is estimated that between 1979 and 1990 $5 billion to $12 billion (1978 dollars) of investment in new downstream process facilities will be required to meet these cases.

- In the event of an import supply interruption in the range of 2 to 5 million barrels per day, there is sufficient flexibility in the U.S. refining system to reflect 75-80 percent of the volume loss in reduced motor gasoline output as opposed to other products such as heating oil. The Council did not attempt to deal with the questions of whether the U.S. economy could function efficiently with a petroleum supply loss of this magnitude or whether it is desirable for gasoline supply to take up to 80 percent of any loss.

- In 1978, small refiners, especially those with capacities less than 30,000 barrels per day, had a competitive advantage over larger refiners through the small refiner bias provisions of the Domestic Crude Oil Allocation Program (entitlements). This advantage was eliminated in June 1979 when the program was modified. The majority of these smaller refineries are low complexity plants with limited gasoline manufacturing capabilities and relatively high yields of heavy fuel oil. These low complexity refineries were placed at a substantial competitive disadvantage as compared to more complex refineries by product market prices in the first quarter of 1980 and may face similar adverse effects from the long-term demand mix and supply quality trends expected in the 1980's.

- Because of U.S. domestic crude oil price controls, U.S. refineries now compete favorably with typical foreign export refineries in U.S. East Coast markets. With the end of domestic crude oil price controls in October 1981, these foreign export refineries will have a competitive advantage over U.S. refineries in these markets.

SUMMARY

PETROLEUM SUPPLY AND DEMAND

Introduction

Petroleum supply/demand projections are necessary for an analysis of future domestic refinery requirements. To reflect the uncertainty of future supply/demand patterns, a range of projections was developed from the averages of the responses of numerous organizations, which regularly prepare energy forecasts, to questionnaires distributed by the National Petroleum Council in April 1979 and again in December 1979 (NPC Surveys of U.S. and World Energy and Oil Supply/Demand Forecasts). The responses from these organizations were based primarily on internal forecasts prepared in the fourth quarters of 1978 and 1979, respectively. During the intervening twelve months, forecasters evaluated the emerging long-term effects of the supply disruptions and crude oil price increases which occurred following the Iranian revolution.

A comparison of the second survey with the first revealed a substantial downward revision of the projected world and U.S. energy and petroleum supply/demand balances. A further review of the data submitted in the second survey revealed a distinct group of forecasts which projected markedly lower future U.S. petroleum demand than the other responses. In order to reflect this point of view, a "low case" was developed from the averages of the lowest quartile of second survey responses (based on 1990 U.S. total demand for petroleum products).

For the purposes of this study, the supply/demand balances of the first survey, second survey, and second survey "low case" are called high case, medium case, and low case, respectively. It is in the context of these three distinct outlooks that future U.S. refining requirements are evaluated. It must be emphasized that no one of the three projections is more or less applicable than the other two. It is recognized, however, that the medium and low cases are generally more reflective and representative of the current (summer 1980) range of forecasts.

As a final step in providing supply/demand outlooks for analysis of future refinery requirements, two crude oil supply quality cases for each of the supply/demand cases (designated crude oil slate A and crude oil slate B) were developed. The two slates are believed to represent a reasonable range of qualities of crude oils available to U.S. refiners through 1990, assuming no major, long-term disruptions in supply sources.

Results

World Petroleum Demand

Between 1960 and 1972 world petroleum demand grew at an average annual rate of 7.6 percent, but in the 1972-1978 period the rate of increase slowed to 3.2 percent per year. In the supply/demand cases utilized in this study, future growth in world petroleum demand slows further to within a range of 1.4 to 2.2 percent per year. The majority of the difference between the three cases is in the demand projections for OECD countries.[1] Figure 2 depicts the trends since 1972 and the projections developed for this study.

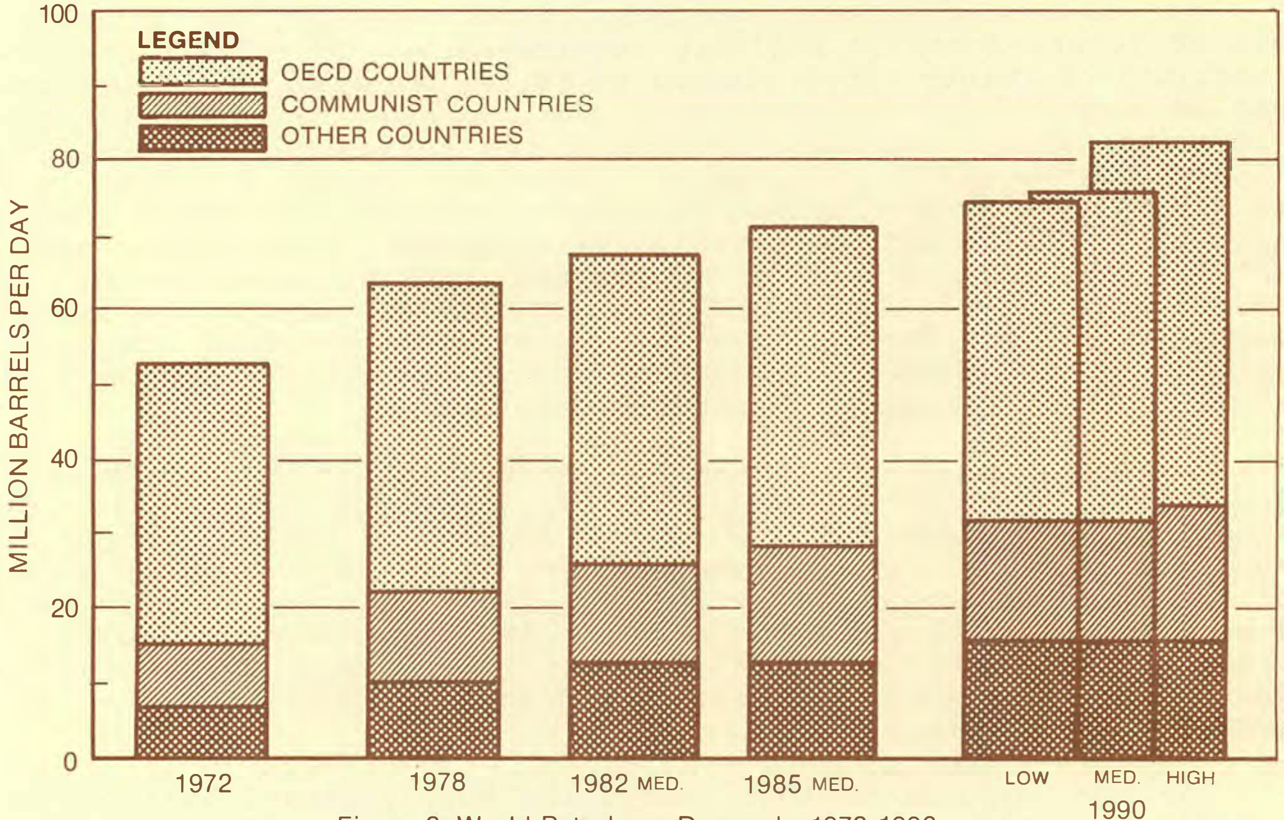

Figure 2. World Petroleum Demand—1972-1990.

NOTE: This figure was plotted from data in Table 3 of Chapter One.

World Petroleum Supply

Figure 3 shows the world petroleum production estimates which correspond to the demand cases in Figure 2. In the medium case, the member countries of OECD and OPEC[2] are both expected to supply 2 million barrels per day (MMB/D) more by 1990 than they did in 1978. The OPEC countries supply most of the incremental production

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[1]Organization for Economic Cooperation and Development. The member countries are: Australia, Austria, Belgium, Canada, Denmark, Finland, France, the Federal Republic of Germany, Greece, Iceland, Ireland, Italy, Japan, Luxembourg, the Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom, and the United States.

[2]Organization of Petroleum Exporting Countries. The member countries are: Algeria, Ecuador, Gabon, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, United Arab Emirates, and Venezuela.

needed in the high case. Other non-Communist countries are expected to produce about 10 MMB/D in 1990 in each case, doubling their 1978 production.

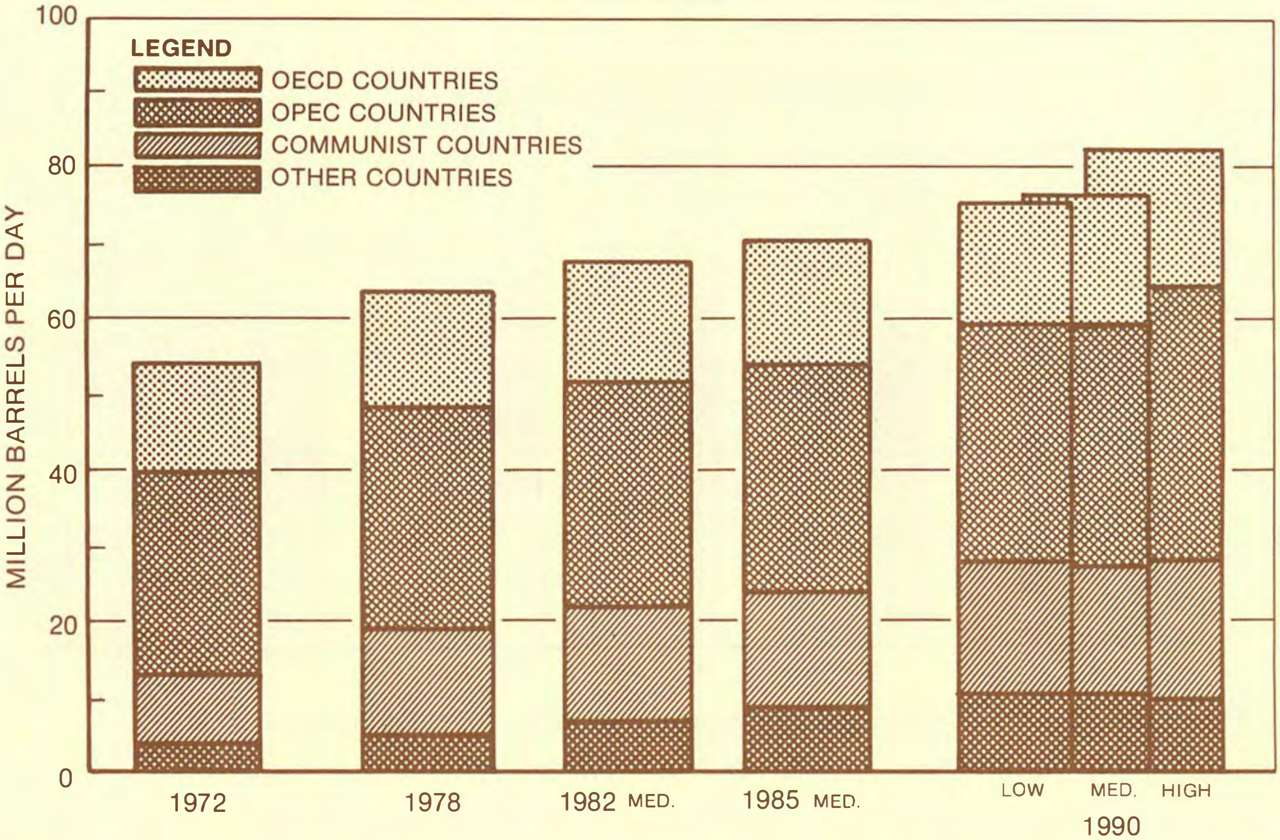

Figure 3. World Petroleum Liquids Production—1972-1990.

NOTE: This figure was plotted from data in Table 6 of Chapter One.

U.S. Petroleum Product Demand

In the high case, U.S. petroleum product demand would grow from 18.8 MMB/D in 1978 to 21.2 MMB/D in 1990 (see Figure 4). In the medium case, however, 1982 demand would be slightly below the level in 1978, and about equal to it in 1985 and 1990. In the low case, total demand drops at a rate of about 0.7 percent per year to 16.8 MMB/D in 1990. While the low case total demand projection for 1990 represents a 21 percent reduction from the high case, up to 53 percent reductions are noted in the demand for specific products.

The most significant downward adjustment in the outlook for future U.S. product demand among the cases occurred in residual fuel oil. The high case projects 1990 residual fuel oil demand at 3.2 MMB/D, an average annual increase of 0.5 percent between 1978 and 1990. The medium and low cases indicate 2-4 percent per year declines over the same period, with 1990 demand projections of 2.3 and 1.5 MMB/D, respectively. In these cases, low-sulfur fuel oil (1.0 wt % maximum) accounted for 96 and 69 percent, respectively, of the decrease from the high case projection of total residual fuel oil demand.

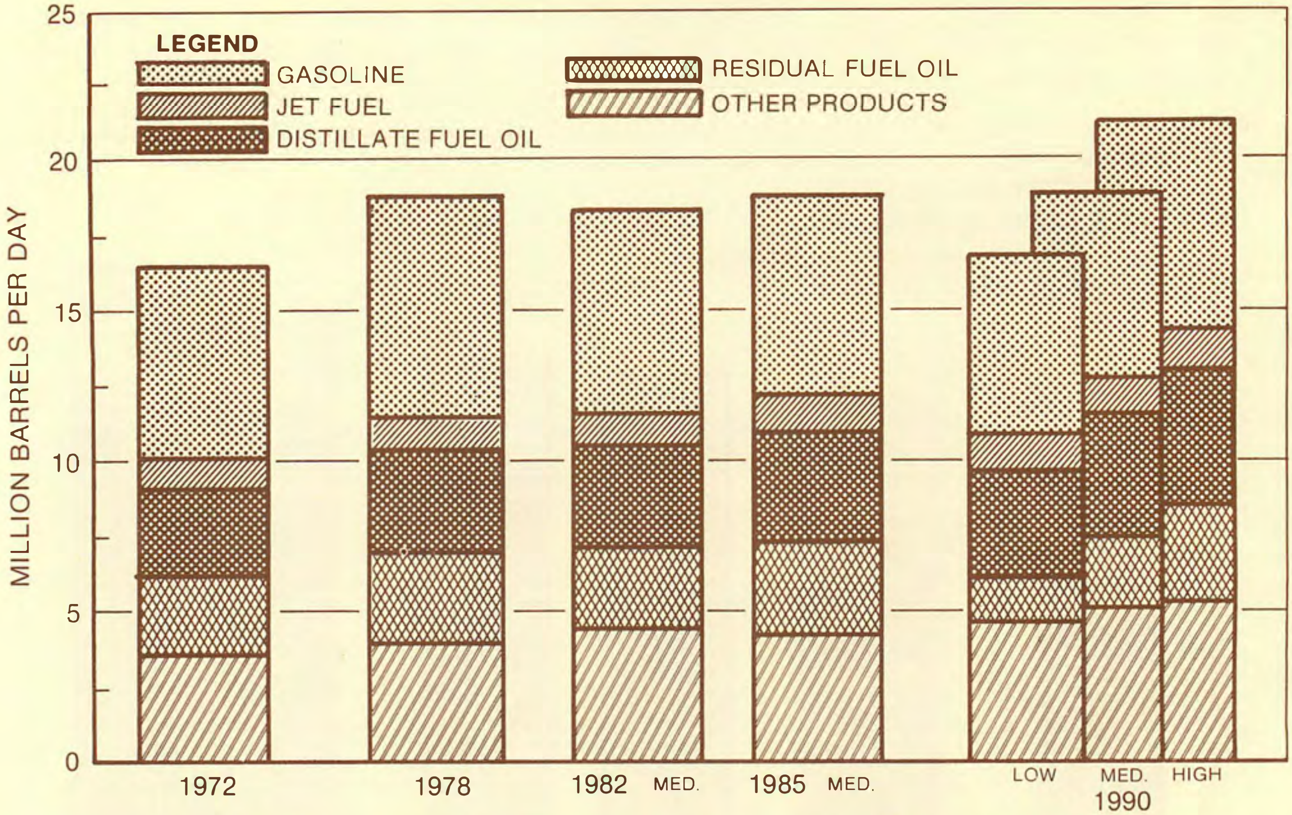

Figure 4. U.S. Petroleum Demand by Principal Products—1972-1990 (Excluding Exports).

NOTE: This figure was plotted from data in Tables 14-16 of Chapter One.

Demand for distillate fuel oils is projected to increase 2.5 percent annually between 1978 and 1990 in the high case, rising from 3.4 to 4.5 MMB/D. The medium case indicates an average annual growth rate of 1.5 percent to 1990, and the low case projects middle distillate demand to be essentially unchanged over the 1978-1990 period. Of the distillate fuel oils, only on-highway diesel demand is expected to increase significantly from 1978 to 1990 in all three projections.

In the high case, motor gasoline demand is projected to decline at an average annual rate of 0.8 percent over the 1978-1990 period, from 7.4 to 6.7 MMB/D. The high case also indicates that unleaded motor gasoline demand would account for about 84 percent of total motor gasoline demand by 1990, compared to only 32 percent in 1978.

In the medium and low cases, demand for motor gasoline is anticipated to decline at an annual rate of about 1.6 to 1.7 percent per year from the 1978 level (a decrease of 1.6 to 1.8 MMB/D over the period). Projected decreases in demand for leaded motor gasoline account for most of the reduction in total motor gasoline demand in the medium and low cases vs. the high case. Unleaded motor gasoline demand accounts for 89 percent and 92 percent of total motor gasoline demand in 1990 in the medium and low cases, respectively.

U.S. Petroleum Supply

U.S. petroleum supply for 1972 and 1978 and the estimates to 1990 are shown in Figure 5. In the medium case, domestic production and imports are expected to remain at about 1978 levels through 1990. In the high case, virtually all the additional supply is from imports. Implicit in the domestic production data is a substantial improvement in annual reserve additions over the period.

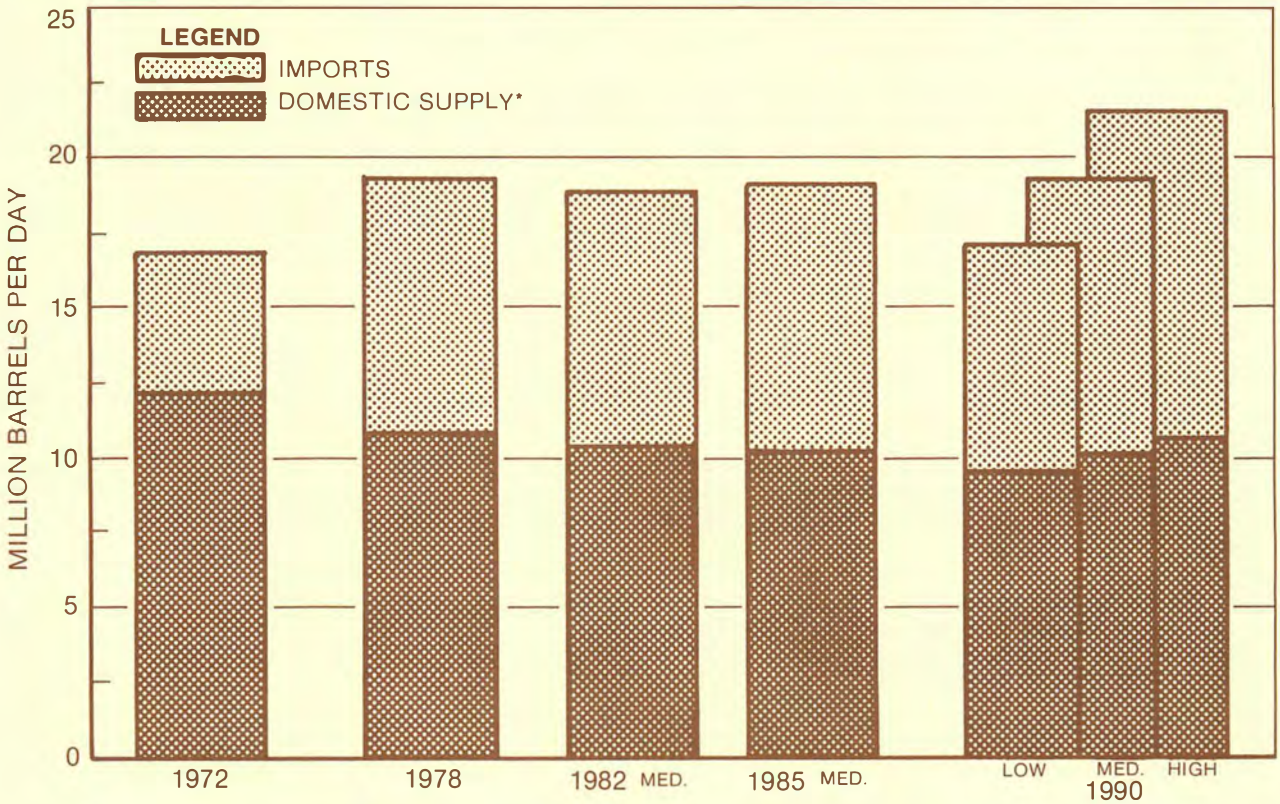

Figure 5. U.S. Petroleum Supply—1972-1990.

*Includes: crude oil, condensate, and natural gas liquids; processing gain; stock change; and synthetic crude oil.
NOTE: This figure was plotted from data in Table 13 of Chapter One.

Crude Oil Quality

Overall, the quality of the crude oils available to U.S. refiners is expected to decline over the study period. To construct a reasonable range of qualities which refiners could expect through 1990, two crude oil quality slates were developed. Crude oil slate A is a continuation of historical trends in crude oil quality wherein the proportion of sweet crude oils (0.5 wt % sulfur or less) available to U.S. refiners declines from 54 percent in 1978 to 45 percent in 1990. In crude oil slate B, adjustments are made in slate A for likely or possible significant future supply developments. The major adjustments include: higher volumes of domestic heavy, high-sulfur and Alaskan North Slope crude oil; synthetic crude oil; and shifts in import qualities as exporting countries move to produce their different crude oils in proportion to their reserves. The net effect of these adjustments is to reduce the 1990 proportion of sweet crude oils from 45 percent in slate A to 41 percent in slate B.

Table 1 summarizes the historical crude oil quality data and the slate A and slate B projections. It is believed that the methodology used in developing slate A tends to overstate the amount of sweet crude oil which will be available to U.S. refiners, while sweet crude oil volumes tend to be understated in slate B.

TABLE 1

Quality Composition of Petroleum Liquids Supply in the United States -- 1969-1990*
(Percentage of Total Petroleum Liquids Supply)†

	Actual		1982§		1985§		1990§	
	1969	1978	Slate A	Slate B	Slate A	Slate B	Slate A	Slate B
Domestic								
Sweet¶	57.0	32.5	27.1	25.7	25.1	22.1	24.3	20.8
Sour	29.0	25.0	25.6	27.1	25.8	28.8	26.8	30.3
Subtotal	86.0	57.5	52.7	52.8	50.9	50.9	51.1	51.1
Foreign								
Sweet¶	7.5	22.0	22.2	20.9	22.7	22.7	20.4	20.4
Sour	6.5	20.5	25.1	26.4	26.4	26.4	28.5	28.5
Subtotal	14.0	42.5	47.3	47.3	49.1	49.1	48.8	48.8
Total								
Sweet¶	64.5	54.5	49.3	46.6	47.8	44.8	44.7	41.2
Sour	35.5	45.5	50.7	53.4	52.2	55.2	55.3	58.8
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

*Condensate and Natural Gas Liquids included in sweet category.
†Percentages may not sum to 100.0 due to rounding.
§Based on the medium case.
¶0.5 wt % sulfur or less.

CAPABILITIES OF THE U.S. REFINING INDUSTRY

Introduction

The capability of the U.S. refining industry to process available crude oil and meet product demand for the 1982-1990 period was analyzed for each of the three supply/demand cases and their two crude oil quality slates. The utilization rates of existing capacity and the needs for additional processing capabilities were determined in the context of these outlooks. Results were aggregated from separate analyses of the capabilities of refineries east of the Rockies (PADs I-IV) and on the West Coast (PAD V).

In addition to these capability analyses, the study examined the impact of short-term supply disruptions and the sensitivities of refinery operations to certain regulatory programs.

Refining industry linear programming (LP) models were used to determine the additional processing capacity needed under each of the supply/demand cases. Process capacities for the 1978-1982 period were obtained from the January 1979 NPC Survey of Petroleum Refining Capabilities and built into the models. In order to reduce over-optimization, each geographic model utilized a three-refinery configuration. Unless otherwise noted, additional capacity requirements summarized below are specifically for the medium supply/demand case (second survey) and crude oil slate B (the higher sulfur, heavier slate).

Results

Future Process Facility Needs

Crude oil distillation and catalytic cracking capacities in 1978 appear more than adequate for the next decade. Capacities for catalytic reforming, naphtha hydrotreating, distillate hydrotreating, and residual fuel oil conversion, however, will require substantial expansion to meet U.S. product needs. Figure 6 shows the requirements for these processes as a percentage of their total U.S. capacity in 1978. In Figure 7, these results are shown in barrels per day of new capacity required and are compared with the planned expansions reported in the January 1979 NPC survey. In the past 18 months, and in response to the changing supply/demand situation, refiners may already have plans underway to build some of the new process facilities indicated in this analysis.

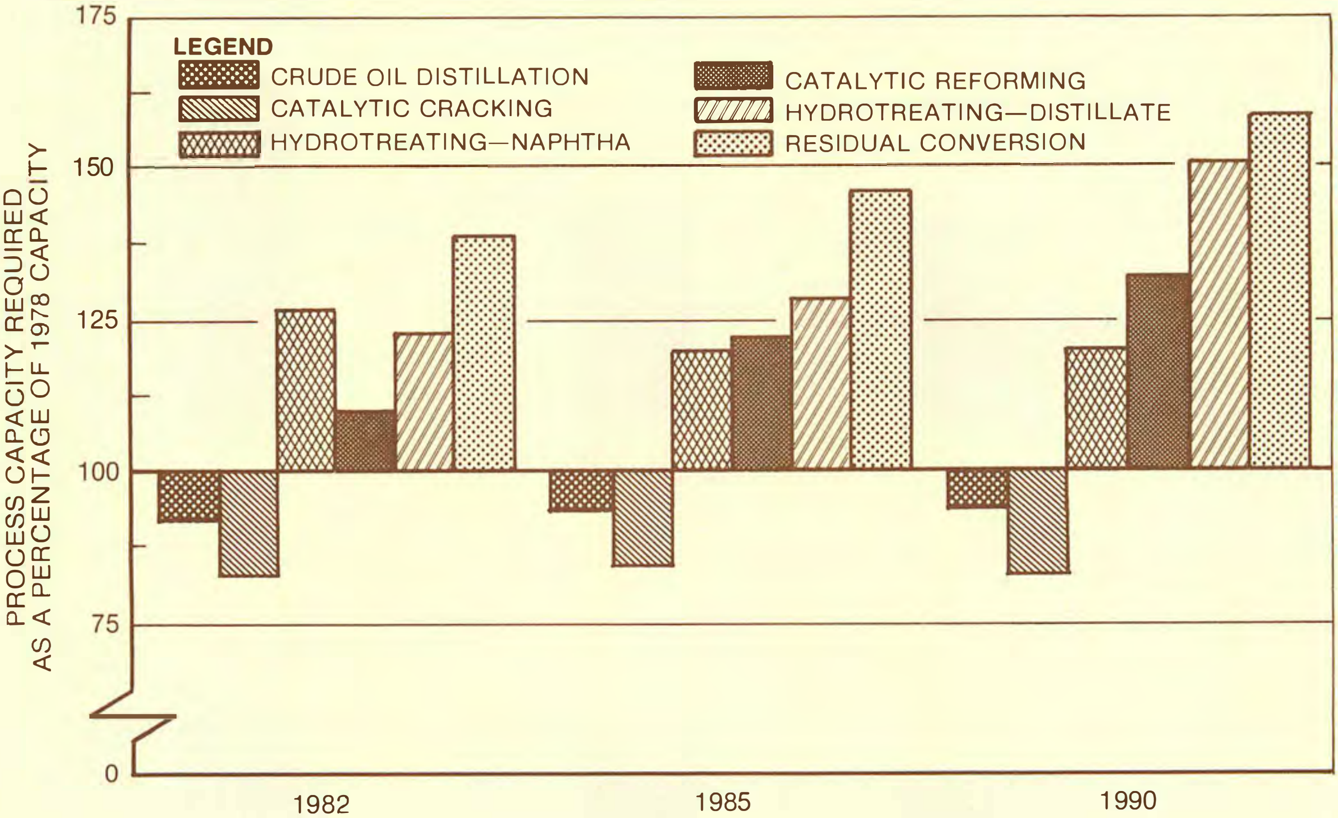

Figure 6. U.S. Refining Industry Changes in Processing Capacity Needed to Meet Future Demand (Based on Medium Supply/Demand Case and Crude Oil Slate B).

NOTE: This figure was plotted from data in Tables 69, 76, and 83 of Chapter Two.

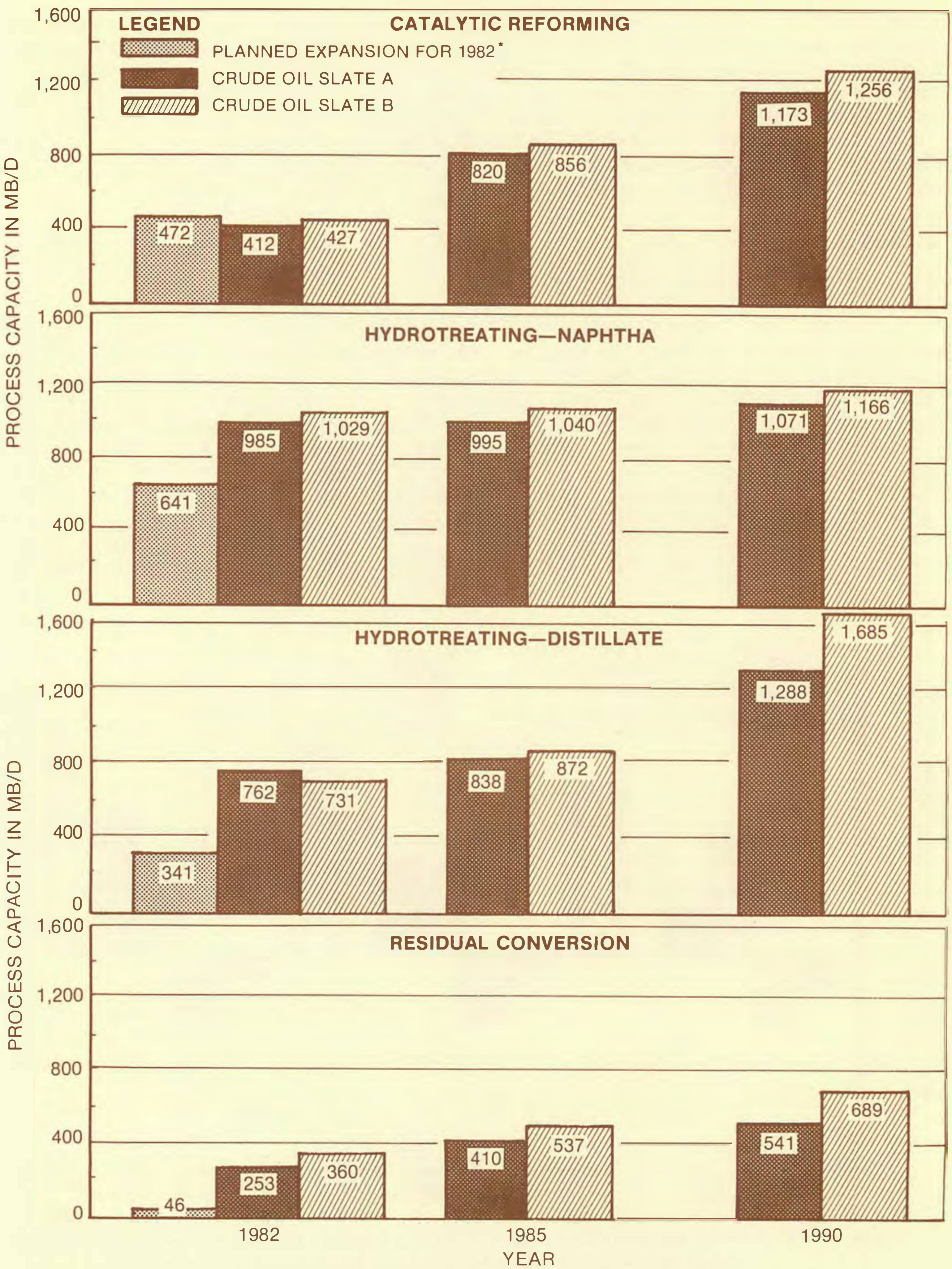

Figure 7. Total U.S. Process Capacity Needed Over 1978 Capacity of Medium Case.

*Based on responses to the January 1979 NPC Survey of Petroleum Refining Capabilities.

NOTE: This figure was plotted from data in Table 59 of Chapter Two.

In all combinations of supply/demand cases and crude oil quality slates examined, significant capacity increases are called for in catalytic reforming, naphtha and distillate hydrotreating, and residual conversion.

In early 1979, refiners were planning to expand naphtha reforming capacity by 472 MB/D prior to 1982. This appears to be adequate in 1982; however, by 1985 the cumulative expansion requirement will be 856 MB/D and by 1990 it will be 1,256 MB/D.

Inadequacies in hydrotreating (both naphtha and distillate) and residual fuel oil conversion (e.g., coking) will become a problem by 1982 unless refiners expand beyond the plans indicated in the January 1979 NPC survey.

The cumulative expansion needed for naphtha hydrotreating will be 1,029 MB/D in 1982 (vs. 641 MB/D reported as being planned in the January 1979 NPC survey) and will increase to 1,166 MB/D in 1990; expansion of hydrotreating facilities needed for distillates (and for catalytic cracker feedstocks) will be 731 MB/D in 1982 (vs. 341 MB/D reported as being planned in the January 1979 NPC survey) and will increase to 1,685 MB/D in 1990.

The cumulative expansion needed for residual fuel oil conversion (coking or equivalent processes) will be 360 MB/D in 1982 (vs. 46 MB/D reported as being planned in the January 1979 NPC survey) and will increase to 689 MB/D by 1990.

The cumulative cost in 1978 dollars for all required new process facilities is estimated to be $1.5 billion by 1982 and $3.8 billion by 1990 for the medium case and crude oil slate B. The cost is probably understated, however, because the optimization of the model concentrates expansion at the larger refineries to achieve economies in construction. In reality, construction will take place in a broad range of refinery sizes where these economies will not be fully available. Further, this investment is only for the required process facilities and does not include any of the very large investment requirements for sustaining existing facilities, improving efficiency, energy conservation, environmental protection, safety, and any facilities outside the refinery. The 1979 NPC Survey of U.S. Petroleum Refining Capabilities asked several questions regarding additional facility requirements under hypothetical supply/demand situations. Appendix F compares the survey's results with those obtained from the model. Based on these two approaches, it is concluded that actual costs for new refinery process capacities between 1979 and 1990 will be in the range of $5-12 billion (constant 1978 dollars).

Impact of Crude Oil Supply Disruptions

Three types of disruptions were considered: a loss of 2,000 MB/D of foreign sweet crude oil, with and without replacement by other types, and a loss of 5,000 MB/D of foreign crude oil of average quality. It was assumed that distillate would be a priority product, and thus, refiners would strive to minimize the loss of its production during the disruption. The specific results reported below are based on 1982 medium supply/demand and crude oil quality slate B.

In the case of a 2,000 MB/D loss of foreign sweet crude oil, 1,593 MB/D or 80 percent of the resulting product loss could be gasoline, while still meeting the criterion of constant distillate supply. This represents 23 percent of total gasoline demand in 1982.

If a higher sulfur crude oil (e.g., Saudi Arabian Light quality) could be obtained to substitute for the lost 2,000 MB/D of foreign sweet crude oil, the shortfall in gasoline supply could be reduced to negligible proportions. However, a relaxation of residual fuel oil sulfur specifications would be required to make the crude oil substitution possible.

With a loss of 5,000 MB/D of foreign crude oil imports of average quality, it is more difficult to take the product shortfall predominantly in gasoline in order to protect the distillate supply. However, attaching a 50 percent higher value to distillate in the models was sufficient to economically maintain nearly all required distillate production, at the expense of gasoline. Under these conditions, 3,711 MB/D, or 75 percent of the total product loss, could be gasoline. The Council did not attempt to deal with the questions of whether the U.S. economy could function efficiently with a petroleum supply loss of this magnitude or whether it is desirable for gasoline supply to take up to 80 percent of any loss.

Regulatory Sensitivities

Refinery construction, operation, product quality, and costs are all affected by numerous laws and regulations (see Appendix D for a list of legislation significantly affecting the U.S. refining industry). While detailed analyses of these effects are not part of this study, two specific areas were examined quantitatively because of their importance to gasoline supply: the elimination of the phasedown of the lead content in leaded gasoline; and the addition of MMT[3] to unleaded gasoline.

The study of the lead phasedown impact was limited to 1982 because of the decreasing fraction of leaded gasoline in the total gasoline pool in later years (36 percent leaded gasoline in 1982 vs. 11 percent in 1990 in the medium case). The total hydrocarbon saving in 1982, made by discontinuing the lead phasedown, was 35 MB/D. This saving is relatively small in 1982 because the calcu-

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[3]Methylcyclopentadienyl manganese tricarbonyl -- a gasoline additive with octane improving qualities similar to lead.

lated optimum lead level for the total U.S. gasoline pool is only 0.2 grams per gallon higher than the phasedown level.[4]

Allowing the addition of 1/16 gram of MMT in unleaded gasoline might save as much as 80 MB/D of hydrocarbons and up to $775 million worth of new processing facilities. These process facility savings include a reduction of 434 MB/D in catalytic reforming capacity.

COMPETITIVE POSITIONS OF VARIOUS SEGMENTS OF THE U.S. REFINING INDUSTRY

Introduction

The relative competitive positions of various segments of the domestic refining industry were analyzed by comparing the total costs of manufacturing, adjusted for value differences in product slates. This comparison is based on data provided by domestic refiners participating in the January 1979 NPC Survey of Petroleum Refining Capabilities, together with supplemental published data regarding values of products and feedstocks other than crude oil. The survey covered actual operations in 1978, a year in which crude oil of suitable quality was generally available to the various categories of refining companies. The data in this section of the report are based on the responses of 186 refineries representing 14.8 MMB/D of refining capacity.

The initial analysis was based on the product market prices, refinery operating costs, and governmental regulations that actually existed for calendar year 1978. Additional analyses were made to examine the implication of changes made by the Department of Energy in mid-1979 to the regulations governing the small refiner bias provisions of the Domestic Crude Oil Allocation Program (entitlements) and the implications of changes in product price patterns experienced in the first quarter of 1980. Updating of other product cost elements (e.g., resurveying crude oil costs and refinery operating expenses) by industry segments was not possible in the time frame of the study.

Crude oil cost for the U.S. refining industry averaged $12.71/bbl in 1978 and represented 75 percent of the total cost of refined products. Since 1978, crude oil costs have more than doubled and

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[4]In this study, the potential hydrocarbon savings attributed to elimination of the lead phasedown were determined in the context of a growing demand for unleaded gasoline. Other studies have reported that the potential overall impact of elimination of lead restrictions, such as might occur in a national emergency, could be considerably larger than the amount noted above. These other studies generally assume essentially no requirement for unleaded gasoline and permit the use of as much as 3 grams of lead per gallon for all grades.

in the first quarter of 1980 averaged $25.93/bbl. These escalations further increased the relative importance of raw material and refinery fuel costs to the competitiveness of every refinery. During this same period, the cost differentials between sweet and sour crude oils increased from $2.00-$3.00/bbl to $7.00-$10.00/bbl in some regions. On the product side, the differential between gasoline prices and residual fuel oil prices went from $0.22 per gallon in 1978 to $0.45 per gallon in the first quarter of 1980. After the first half of 1980, these differentials began to return closer to their historical levels. The relative economics of the various sizes and types of U.S. refineries is very sensitive to changes in these differentials.

The results of these analyses are presented in terms of the advantage or disadvantage of various groups of refiners or refineries, relative to the total U.S. refining industry. These relative positions are not to be confused with overall profitability: a segment of the industry may be shown to have an advantage over other segments but still be in a loss situation or vice versa. Further, the analysis is based on the aggregate position of each segment of the industry which may mask significant differences among individual companies or facilities within any given segment. Finally, the analysis does not include the effects of specific relief granted individual refiners or groups of refineries through the DOE entitlements exceptions and appeals programs. Appendix G details the entitlements calculations used in this report and summarizes the magnitude of the special benefits grants to some companies in 1978.

Results

Company Size[5]

In 1978, the most favorable competitive position was held by the smallest company size range (0-10 MB/D of aggregate refinery capacity), with a product cost advantage relative to the average of all companies of $0.37/bbl of crude oil processed. The costs of refined products for the company size categories studied are compared in Figure 8. The favorable position of the 0-10 MB/D refining companies was significantly influenced by the average net crude oil costs, which were $2.19/bbl below the average for all companies. This crude oil cost advantage was largely due to the small refiner bias, but also reflected other factors such as crude oil quality.

If the 1978 data are adjusted to reflect only the change in the small refiner bias which occurred on June 1, 1979, relative competitive positions shift. For example, in the smallest company size category, 0-10 MB/D, the crude oil cost element of product cost increased significantly, although it is still $1.29/bbl below the

[5]A refining company's size is categorized by the aggregate capacity of all of its refineries.

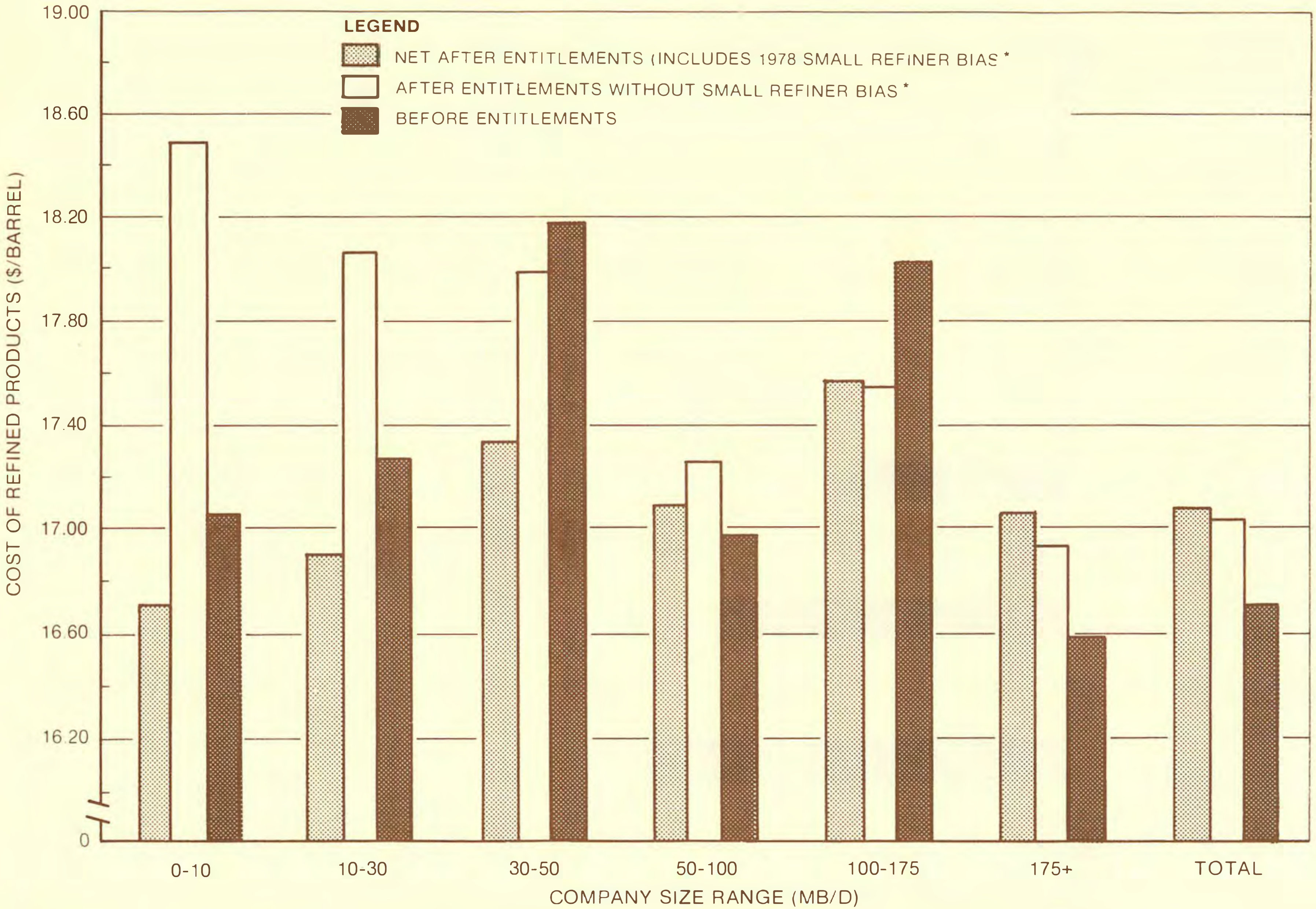

Figure 8. Total 1978 Refined Products Costs in $/Barrel of Crude Oil Processed for Refining Companies—Aggregated by Company Size Range.

*Excludes individual entitlement exceptions granted by DOE.

NOTE: This figure was plotted from data in Table 90 of Chapter Three.

industry average. As shown in Figure 9, the result of this change is to drop the 0-10 MB/D company size range to the poorest competitive position, with product costs $0.53/bbl above the industry average. In this case, companies in the 50-100 MB/D size category became the most competitive, but only by a slight margin of $0.06/bbl.

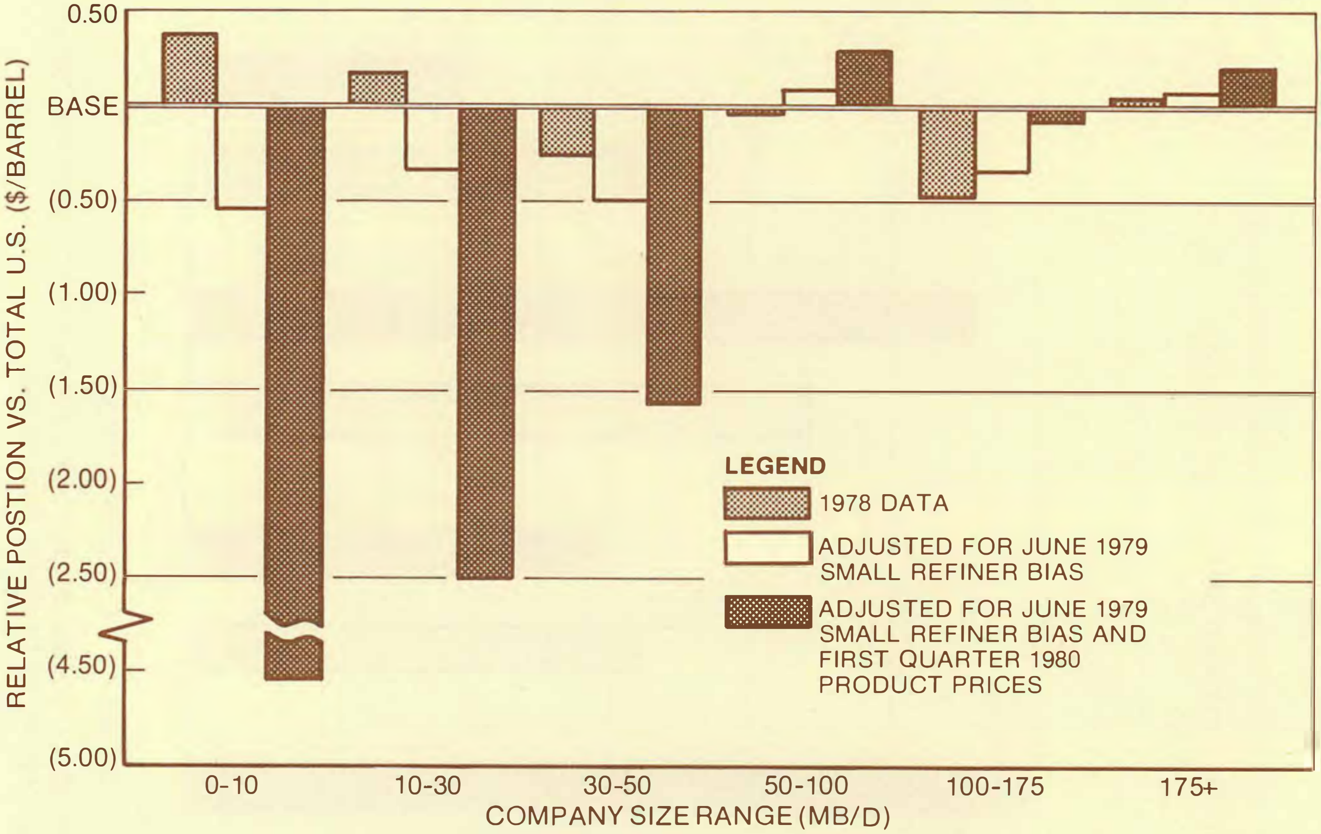

Figure 9. Effect of Changes in the Small Refiner Bias and First Quarter 1980 Product Prices on Refined Product Costs—Aggregated by Company Size Range.

NOTE: This figure was plotted from data in Table 93 of Chapter Three.

When the effects of the bias program changes are combined with first quarter 1980 petroleum product prices, those smaller companies with limited gasoline and other light product yields are placed at a substantial disadvantage. The disadvantage of the average of companies in the smallest company size category (0-10 MB/D) is $4.53/bbl compared to the industry average under these conditions.[6] Plants owned by these companies generally lack product upgrading capabilities to adjust product mix to take advantage of market conditions. The 1980 disadvantage declines rapidly with company size to $1.57/bbl for companies in the 30-50 MB/D category. This comparison has not been adjusted for changes in relative crude oil cost and other factors such as the benefit of

[6]As noted in the section on refinery size, there is a wide diversity of plants in the smaller size categories with a similarly wide diversity of product cost values.

special entitlements which could affect individual refiners' positions.

The analysis of competitiveness by company size is summarized in Table 2.

TABLE 2

Range of Competitive Positions of U.S. Refining Companies*

Basis	Company Size Range	Greatest Advantage (Disadvantage)†
1978 Data	0- 10 MB/D	0.37
	100-175 MB/D	(0.49)
1978 Data Adjusted for June 1979 Small Refiner Bias	50-100 MB/D	(0.06)
	0- 10 MB/D	(0.53)
1978 Data Adjusted for June 1979 Small Refiner Bias and First Quarter 1980 Product Prices	50-100 MB/D	0.29
	0- 10 MB/D	(4.53)

*Comparisons are with the average of all U.S. refining companies. Capital recovery is based on original undepreciated assets.
†In $/bbl of crude oil processed.

Refinery Size

In 1978, refineries with 10-30 MB/D of capacity had the lowest product cost, with a $0.59/bbl advantage over the industry average, and the largest refinery size range, 175+ MB/D, had the highest cost, at $0.06/bbl above the industry average (see Figure 10).

When the 1978 data are adjusted for the June 1979 version of the small refiner bias program, a $0.05 competitive advantage shifts to the 175+ MB/D refinery size category and the 0-10 MB/D category has a $0.72 disadvantage vs. the average.

Further adjusting the 1978 data for first quarter 1980 product prices placed the 0-10 MB/D refineries at a $3.83/bbl disadvantage. The 1980 disadvantage diminishes as size increases, but was still $1.29/bbl for the 30-50 MB/D size category. The advantage of the 175+ MB/D refineries over the average increased by $0.22 when first quarter 1980 product prices were used. The principal cause of this increase is the fact that larger refineries tend to be more complex and to have a greater yield of gasoline and much reduced yields of heavy fuel oil and asphalt.

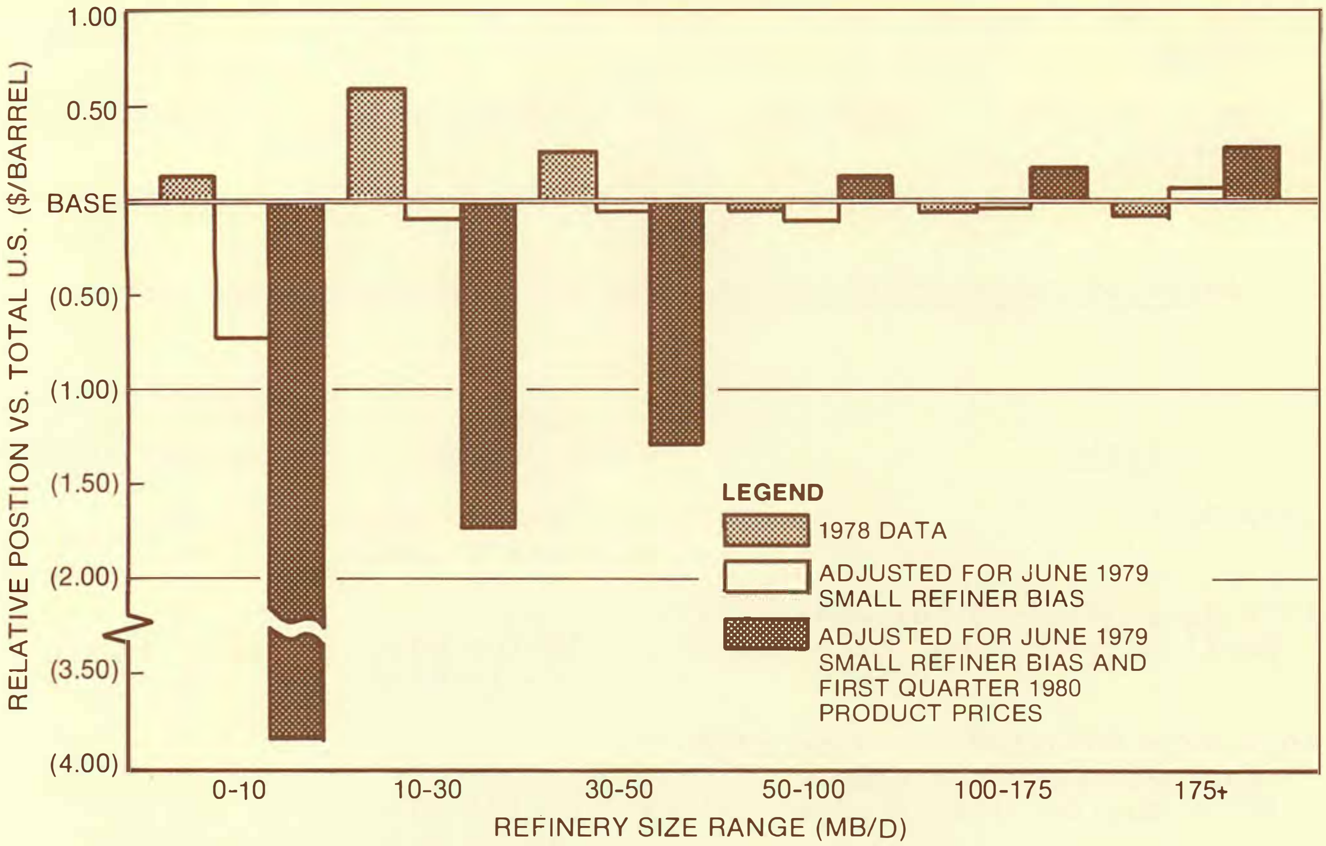

Figure 10. Effect of Changes in the Small Refiner Bias and First Quarter 1980 Product Prices on Refined Product Costs—Aggregated by Refinery Size Range.

NOTE: This figure was plotted from data in Table 98 of Chapter Three.

There are, however, refineries even in the smallest size categories with high yields of gasoline, lubricating oils, and other premium valued products which are small because of location, market, or other factors. The competitive position of these plants can be markedly different from the average of their size category. For example, while the average 0-10 MB/D refinery was at a $3.83 disadvantage in the 1979 bias/first quarter 1980 price case, those plants capable of producing the higher value products had an average disadvantage of $0.41/bbl. Similarly, the average 10-30 MB/D refinery was $1.71 below the average, but the more complex plants were $0.10 below the average.

Refinery Location

In 1978, regional differences in product cost were not large when compared to other factors. As shown in Figure 11, the maximum product cost differential between major areas of the U.S. was $0.30/bbl (PAD IV advantage over PAD II disadvantage). However, throughout the 1978-1980 period, refiners of heavy California crude oil were granted special benefits by the entitlements program, which were not included in the NPC calculation. This provision would have lowered the crude oil cost of some PAD V refiners by a total of $185 million in 1978.

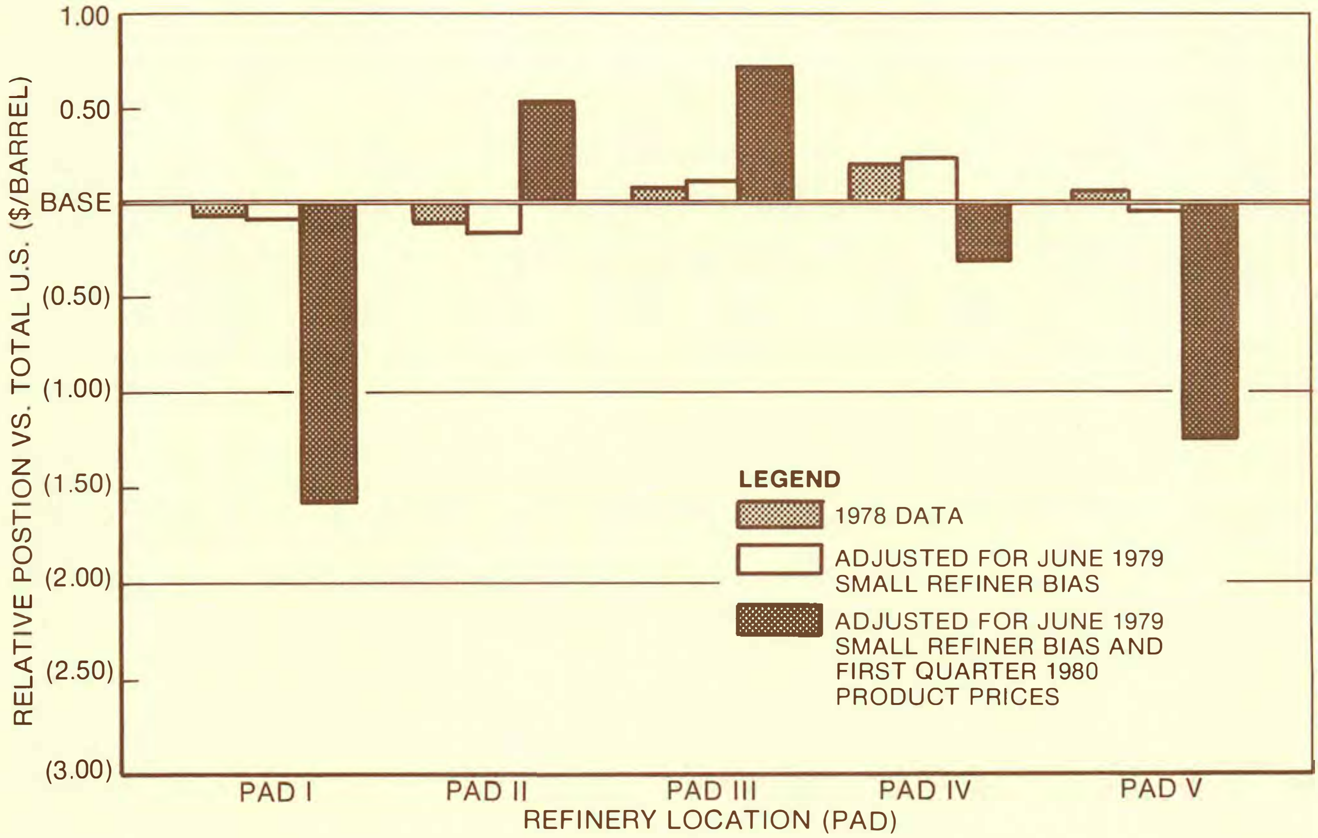

Figure 11. Effect of Changes in the Small Refiner Bias and First Quarter 1980 Product Prices on Refined Product Costs—Aggregated by Refinery Location.

NOTE: This figure was plotted from data in Table 105 of Chapter Three.

Adjusting the 1978 costs for the June 1979 small refiner bias program did not significantly alter the cost differential between PAD districts, but did change the position of individual districts. PAD IV was most affected as it shifted to the position of highest disadvantage, primarily because of the preponderance of smaller refineries in the district.

A variety of factors affected residual fuel oil values around the country in the first quarter of 1980, and were principally accountable for substantial differences in the 1980 regional analysis. PADs I and V show significant disadvantages ($1.56/bbl and $1.22/bbl, respectively), and PADs III and II show advantages of $0.71/bbl and $0.54/bbl, respectively.

Refinery Process Complexity

In this study, refinery complexity is measured by a numerical factor which indicates the capability to produce varied petroleum products. Refineries under 3 complexity are normally capable of manufacturing residual fuel oil, No. 2 fuel oil, diesel fuel, naphtha, and asphalt. Refineries in the 5-7 complexity category produce a wide range of products including unleaded gasoline. Those in the 7-9 category, in addition to the facilities of a 5-7 complexity range refinery, have desulfurization capabilities for manufacturing low-sulfur fuel oils and feedstocks. Refineries in the over-9 categories, in addition to desulfurization and a wide range of product yields, have hydrocracking units which increase unleaded gasoline production.

Higher complexity is incorporated into refineries to achieve the capability to enhance or diversify product slates, improve yields of preferred products, or accommodate lower quality crude oils. Higher complexity generally results in greater capital outlays and increased operating expenses. With some exceptions, as in the case of smaller lubricating oil manufacturing plants or small local markets, high complexity is generally more common to larger refineries.

Under the conditions existing in 1978 (Figure 12) and under those after adjusting for the June 1979 revision to the small refiner bias program, relative competitive advantages of \$0.21/bbl and \$0.27/bbl resided with intermediate process complexity refineries (7-9 factor). These refineries are generally in the 100-175 MB/D range, located near markets, and producers of a full range of products.

First quarter 1980 product prices, featuring high differentials between light and heavy products, increased the advantage of these intermediate complexity refineries to \$0.74/bbl. Conversely, they

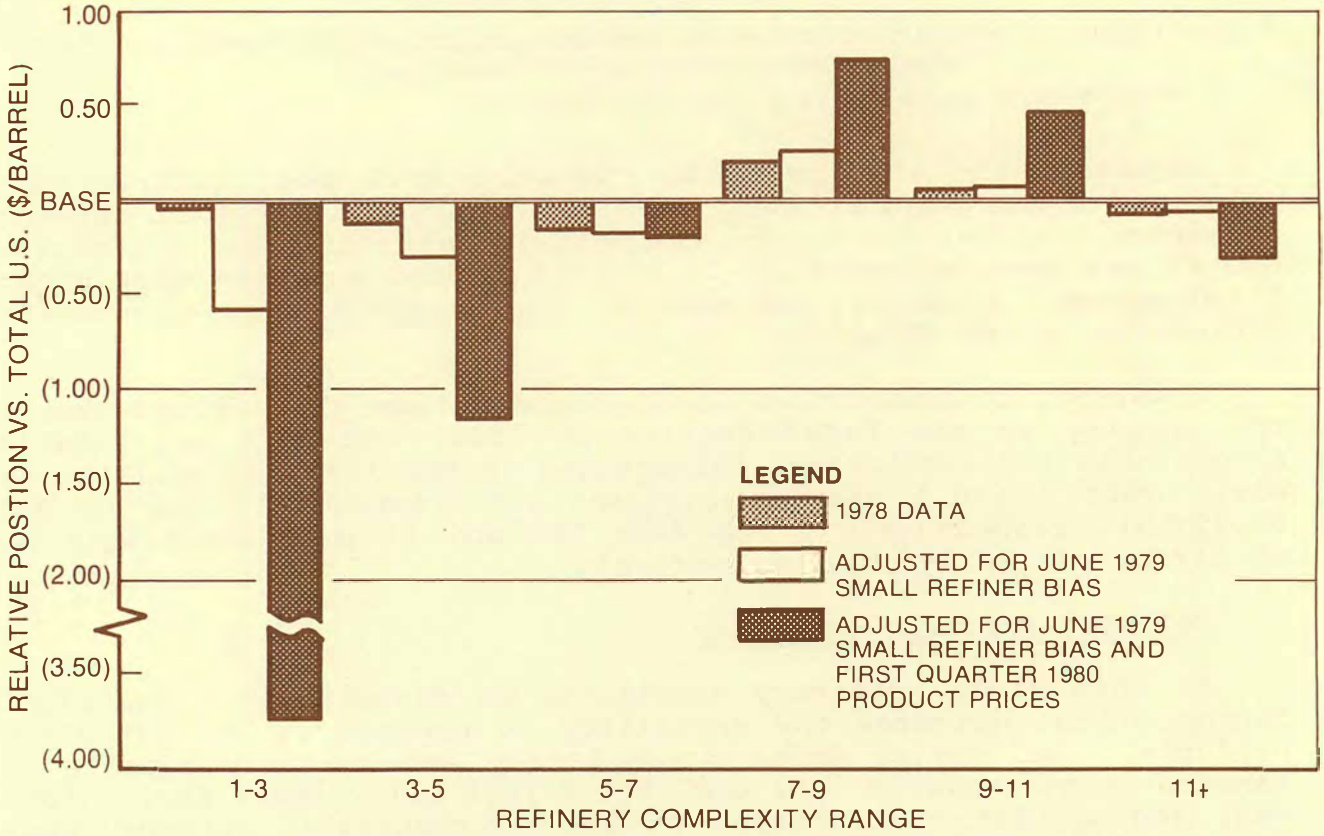

Figure 12. Effect of Changes in the Small Refiner Bias and First Quarter 1980 Product Prices on Refined Product Costs—Aggregated by Process Complexity.

NOTE: This figure was plotted from data in Table 110 of Chapter Three.

placed the low conversion (1-3 complexity factor) refineries with high, heavy fuel oil yields at a substantial disadvantage of \$3.72/bbl relative to the industry average.

1978 COMPETITIVE ECONOMICS OF SUPPLYING INCREMENTAL U.S. EAST COAST PRODUCT DEMAND FROM DOMESTIC REFINERIES AND FOREIGN EXPORT REFINERIES

Introduction

The analysis of the competitive positions of domestic and foreign refineries was conducted in several fundamentally different ways than was the analysis of the competitive position of domestic refineries. First, no comparable survey data were available on foreign export refineries. Second, because of the lack of data, hypothetical refineries were modeled to approximate the typical sizes and complexities of the competing refineries. Third, the domestic analysis was based on average costs for the various segments of the industry while this analysis examined the 70-85 and 85-100 percent capacity utilization increments. This is similar to a marginal cost analysis though it deals with large segments of capacity utilization rather than the last barrel processed. Finally, and most importantly, the analysis was made only of the conditions which existed in 1978. The results of these procedures is an analysis which is broadly useful in understanding the relationships which existed for the year 1978. Extrapolation of these relationships to current or future situations with different market conditions and regulatory factors may be misleading. Competition for product markets in other PAD districts was not studied and may not be similar to that shown for PAD I.

The objective of this phase of the study is to compare the cost of incremental products delivered to the New York Harbor from a typical refinery in PADs I or III with a typical refinery located in the Caribbean, eastern Canada, the Netherlands, or Italy. The foreign offshore areas selected were those which may have the capacity to supply petroleum products to the U.S. East Coast.

Results

The U.S. vs. foreign export refinery competitiveness analysis was conducted for a base case as described above and for two subsidiary cases. Each of these three cases was considered separately for two capacity utilization increments -- 70-85 percent and 85-100 percent. The results compare the average economics of these increments of capacity and are summarized in Figure 13. Since the foreign export refineries were operating at an average of about 65 percent of capacity in 1978, their 70-85 percent increment is compared with the 85-100 percent increment of the U.S. refineries.

1978 Base Case Analysis

The results of this analysis show that the typical foreign export refineries were not competitive with the typical refineries in

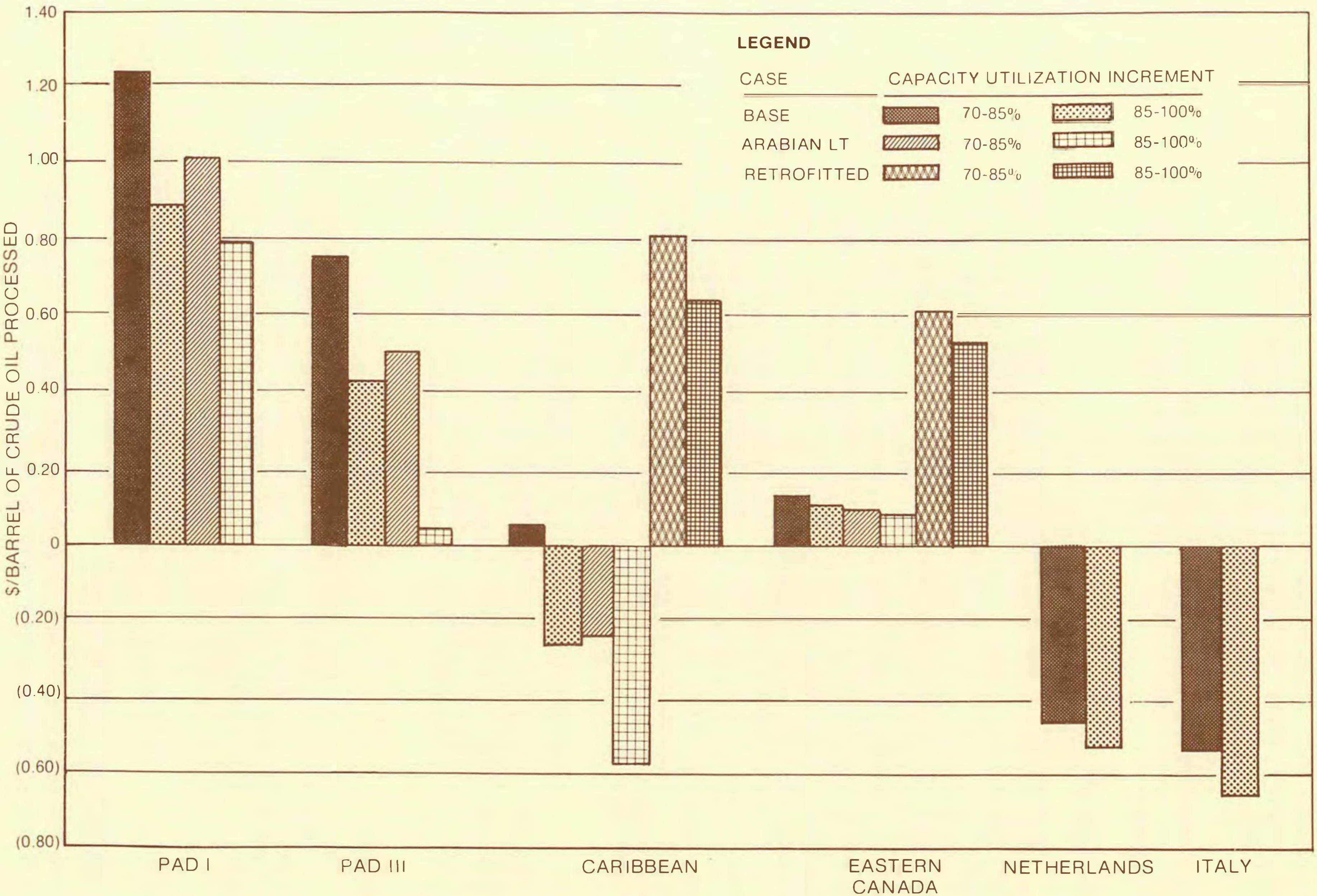

Figure 13. After Tax Gain (Loss) from Incremental Barrel of Crude Oil Processed.

PADs I and III supplying product to the New York Harbor. The PAD I refinery had a competitive advantage of $0.47/bbl over PAD III, $0.84/bbl over the Caribbean, and $1.44/bbl over Italy. There were two primary reasons:

Crude Oil Price Controls. Price controls on domestic crude oil gave U.S. refineries an advantage over foreign export refineries. These controls resulted in an entitlements run credit of $1.61/bbl in 1978 for the U.S. refineries.

Complexity. The foreign export refineries tend to be of lower complexity than U.S. refineries, which limits their capability to produce gasoline and other higher value products. The complexity factors for these typical refineries are summarized below:

Location	Complexity Factor
PAD I	7.22
PAD III	6.12
Caribbean	3.07
Eastern Canada	4.36
The Netherlands	2.94
Italy	2.22

The following are other factors influencing the relative competitive position of the typical refineries:

Transportation. Foreign export refineries have a significantly lower transportation cost than U.S. refineries. This is due to the ability of the foreign export refineries to use very large crude oil tankers and the difference in product transportation costs between foreign and Jones Act, U.S. flag tankers.

Refinery Fuel. Because of environmental regulations, PAD I refineries are required to use higher cost, low-sulfur fuel oil which produces a $0.26 to $0.36 disadvantage per barrel of crude oil processed as compared to the other typical refineries.

Import Fees and Duties. While the domestic refineries suffered a disadvantage of about $0.11/bbl because of crude oil import fees and duties, this was largely offset relative to the offshore refineries by the fees and duties charged on imported products.

Retrofitting Caribbean and Eastern Canada Refineries

Because the 1978 lower competitive position of foreign export refineries is largely due to their lower complexity and resultant lower product mix value, the Caribbean and eastern Canada refineries were hypothetically retrofitted with downstream processing facilities to enable them to produce a product mix comparable to PADs I and III. This retrofitting improved the incremental competitive position for both areas. The Caribbean disadvantage dropped from $0.84/bbl to $0.08/bbl relative to PAD I, and moved into an advantage situation over PAD III of $0.39/bbl. In eastern Canada, the disadvantage decreased from $0.75/bbl to $0.28/bbl relative to PAD I, and became a $0.19/bbl advantage over PAD III.

Incremental Processing of Saudi Arabian Light Crude Oil

In the 1978 base case analysis, each hypothetical refinery was tested when running crude oil of a quality equal to the average mix of incremental crude oils run in its region for each of the capacity utilization increments. As these mixes are different in the various regions, a subsidiary case was prepared which tested each refinery when running an identical incremental barrel. For this case, Saudi Arabian Light crude oil was selected as representative of the quality of crude oil most likely to be available on an incremental basis.

The effect of using incremental Saudi Arabian Light crude oil rather than the typical incremental mix of crude oils is summarized in the following tabulation:

Incremental Advantage (Disadvantage) Relative to PAD I ($/Bbl)

Location	Base Case	Saudi Arabian Light Case
Pad III (85-100 percent increment)	(0.47)	(0.75)
Caribbean (70-85 percent increment)	(0.84)	(1.02)
Eastern Canada (70-85 percent increment)	(0.75)	(0.69)

CHAPTER ONE

AGGREGATED WORLD AND U.S. ENERGY AND PETROLEUM SUPPLY/DEMAND PROJECTIONS

INTRODUCTION

Petroleum supply/demand projections are necessary for the analysis of future domestic refinery requirements. To reflect the uncertainty of future supply/demand patterns, a range of projections was developed. The comprehensive data base used to develop these projections was obtained from the averages of the responses to two surveys (NPC Surveys of U.S. and World Energy and Oil Supply/Demand Forecasts) distributed by the National Petroleum Council in April 1979 and December 1979, respectively, to numerous organizations which regularly prepare such forecasts (for a list of organizations surveyed, see Appendix E). The adjusted averages of the first and second surveys were designated the high and medium supply/demand cases, respectively. In addition, a low case was developed from data submitted in response to the second survey, thus providing three sets of supply/demand projections to the year 1990.

Responses to the first survey were received in the spring and summer of 1979. During the previous several months, however, political turmoil in Iran had resulted in decreased petroleum production in that country, and by January 1, 1979, exports from Iran were greatly reduced. The resulting disruption in world petroleum markets and the reaction in the United States were not recognized or reflected in the first survey results because almost all responses were based on forecasts made in the second half of 1978. Because of these and other economic and political events which occurred in 1979, the first survey results were considered to be high. Accordingly, a second, less detailed, survey was undertaken, based on forecasts prepared in late 1979 or very early 1980.

A comparison of results of the second survey with those of the first survey reveals a substantial downward revision of the projected world and U.S. energy and petroleum supply/demand balances. In further reviewing the data submitted in the second survey, a wide divergence was noted among the respondents; respondents in the lowest quartile submitted forecasts which were markedly lower than the other responses. In order to reflect this point of view, the low case was developed from the averages of the lowest quartile responses (based on 1990 total U.S. demand for petroleum products) from the second survey.

In order to present supply/demand projections which represent both consensuses of the replies received and internally consistent balances, "adjusted average" balances were developed for the arithmetic averages of the first and second surveys and the low case. This chapter summarizes the significant data and findings of the survey results. All data are based on the adjusted average balances for the first and second surveys (high and medium cases) and the low case.

These data were developed for use in the analysis of future U.S. refinery capacity and process hardware requirements to 1990, which is presented in Chapter Two. It is concluded that the three detailed projections developed from respondents' inputs to the two surveys bracket the potential range of U.S. energy supply/demand that may be anticipated by 1990.

It must be emphasized that no one of the three projections is more or less applicable than the other two. It is recognized, however, that the medium and low cases are generally more reflective and representative of the current (summer 1980) range of forecasts.

Appendix E provides a detailed explanation of the methodology and procedures employed to obtain and develop these projections. Appendix E also contains the complete details of the adjusted average balances for all three cases and the tabulations of the high, low, arithmetic average, and standard deviation of each cell of the second survey. Similar range data on the response cells to the first survey were previously published in Appendix H of <u>Refinery Flexibility, An Interim Report</u>.

WORLD PETROLEUM SUPPLY/DEMAND[1]

World Petroleum Consumption

World petroleum consumption is projected to increase from 63.6 MMB/D in 1978 to 82.2 MMB/D in 1990 in the high case, to 76.4 MMB/D in the medium case, and to 75.5 MMB/D in the low case (see Table 3). The political and economic events which began in the fall of 1978 led survey respondents to reduce their 1990 world petroleum consumption projections by almost 6 MMB/D between the high and medium cases, and the 1990 low case projection is almost 7 MMB/D lower than that of the high case.

Although the respondents were not asked to provide explanations for the changes in their first and second survey submissions, the following reasons for the reduction in projected petroleum consumption are suggested. The price of internationally traded petroleum has increased rapidly since mid-1978 (world prices in 1980 are at levels most international petroleum experts did not expect to be reached until 1990). In addition, the willingness of OPEC to increase sustained petroleum production significantly above 1979 producing rates is now being seriously questioned. Hence, the inflation-adjusted prices of internationally-traded petroleum are expected to continue to increase, albeit at lower rates than experienced in the recent past. The projected continued increase in

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[1]The world petroleum supply/demand data reported in the low case are based on the worldwide projections of those respondents who had the lowest total U.S. product demand in 1990. These respondents did not necessarily have the lowest worldwide supply/demand projections.

TABLE 3

World Petroleum Consumption
(MMB/D)

	1972	1978	1982*			1985*			1990*		
			High Case	Medium Case	Low Case	High Case	Medium Case	Low Case	High Case	Medium Case	Low Case
OECD	37.5	41.4	44.0	41.4	40.7	46.1	42.5	41.3	48.1	43.3	42.2
U.S.	16.4	18.8	20.1	18.4	17.8	20.5	18.8	17.4	21.2	18.9	16.8
West Europe	14.1	14.6	15.2	14.6	14.4	16.0	14.8	14.9	16.8	15.3	15.6
Other	7.0	8.0	8.7	8.4	8.5	9.6	8.9	9.0	10.1	9.1	9.8
Non-OECD	7.3	10.0	11.6	12.0	11.8	13.3	13.1	13.5	15.9	15.9	16.1
Subtotal	44.8	51.4	55.6	53.4	52.5	59.4	55.6	54.8	64.0	59.2	58.3
Sino-Soviet	8.0	12.2	14.6	13.9	13.9	16.1	15.4	15.3	18.2	17.2	17.2
Total	52.8	63.6	70.2	67.3	66.4	75.5	71.0	70.1	82.2	76.4	75.5
Difference from High Case											
MMB/D			--	(2.9)	(3.8)	--	(4.5)	(5.4)	--	(5.8)	(6.7)
%			--	(4.1)	(5.4)	--	(6.0)	(7.1)	--	(7.1)	(8.1)

*Projected data derived from the April 1979 and December 1979 NPC Surveys of U.S. and World Energy and Oil Supply/Demand Forecasts.

petroleum prices will affect consuming countries by (1) decreasing their rate of economic growth, (2) accelerating their development of petroleum substitutes, and (3) making conservation measures more economically attractive.

Table 3 also shows that most of the reduction in growth in petroleum consumption is projected to occur within the OECD countries, currently the principal consumers of petroleum. While total world petroleum consumption is projected to increase between 1978 and 1990, in absolute terms in all three projections, the annual rate of growth is projected to decline significantly, averaging only 2.2 percent to 1990 in the high case and 1.5 and 1.4 percent in the medium and the low cases, respectively. These projections may be compared with the 7.6 percent annual growth rate experienced from 1960 to 1972 and the 3.2 percent experienced from 1972 to 1978. Projected annual growth rates also exhibit considerable regional variation, as shown in Table 4.

In all three projections, it is anticipated that the member countries of the OECD will reduce their average annual petroleum consumption growth rate in the 1978-1990 period. These reduced rates of growth are attributed to a combination of projected lower economic growth, increasing energy prices, voluntary and government-mandated conservation measures, and greater availability of non-petroleum energy supplies.

The non-OECD countries, on the other hand, are projected to maintain relatively high annual growth rates in petroleum consumption, although at somewhat lower rates than recently experienced. These growth rates appear realistic for at least two reasons: (1) their capacity for economic growth is significantly higher than that of OECD countries and, thus, their rate of petroleum consumption will also be greater; and (2) those non-OECD countries self-sufficient in petroleum (e.g., OPEC countries and Mexico) will have priority access to lower cost petroleum supplies. According to the survey projections, the Sino-Soviet countries (USSR, East Europe, and China) will also maintain relatively higher rates of growth in petroleum consumption than will the OECD countries.

Understandably, because of differences in individual respondents' assessments of economic growth, energy prices, and petroleum/energy availability, there is considerable variation in projected world petroleum consumption levels in the responses to the two surveys. As shown in Table 5, the variation in the range (high to low) increases over time, and the magnitude of the variance in range and the coefficients of variation are almost twice as large in 1990 as in 1982. Significantly, the degree of variation between the first and second surveys for the years 1982, 1985, and 1990 is quite similar. Regionally, the degree of variation differs widely. Where the coefficients of variation are relatively higher there is likely to be greater uncertainty as to future consumption levels.

TABLE 4

Annual Growth in World Petroleum Consumption*
(Percent)

	Actual		1978-1982			1982-1985		
	1960/ 1972	1972/ 1978	High Case	Medium Case	Low Case	High Case	Medium Case	Low Case
OECD	7.5	1.7	1.5	0	(0.4)	1.6	0.9	0.5
U.S.	4.4	2.3	1.7	(0.5)	(1.4)	0.7	0.7	(0.8)
West Europe	11.3	0.6	1.0	0	(0.3)	1.7	0.5	1.1
Other	11.6	2.3	2.1	1.2	1.5	3.3	1.9	1.9
Non-OECD	7.5	5.4	3.8	4.7	4.1	4.7	3.0	4.6
Subtotal	7.5	2.3	2.0	1.0	0.5	2.2	1.4	1.4
Sino-Soviet	7.8	7.3	4.6	3.3	3.3	3.3	3.5	3.3
Total	7.6	3.2	2.5	1.4	1.1	2.5	1.8	1.8

	1985-1990			1978-1990		
	High Case	Medium Case	Low Case	High Case	Medium Case	Low Case
OECD	0.9	0.4	0.4	1.3	0.4	0.2
U.S.	0.7	0.1	(0.7)	1.0	0	(0.7)
West Europe	1.0	0.7	0.9	1.2	0.4	0.6
Other	1.0	0.4	1.7	2.0	1.1	1.7
Non-OECD	3.6	4.0	3.6	3.9	3.9	4.0
Subtotal	1.5	1.3	1.2	1.8	1.2	1.1
Sino-Soviet	2.5	2.2	2.4	3.4	2.9	2.9
Total	1.7	1.5	1.5	2.2	1.5	1.4

*Projected data derived from the April 1979 and December 1979 NPC Surveys of U.S. and World Energy and Oil Supply/Demand Forecasts.

TABLE 5

Ranges and Coefficients of Variation in NPC Surveys of World Petroleum Consumption Forecasts*

		First NPC Survey (High Case)					
		1982		1985		1990	
	Actual 1978	Range (MMB/D)	C.V.†	Range (MMB/D)	C.V.†	Range (MMB/D)	C.V.†
U.S.	18.8	17.3-20.9	4.8	17.3-21.8	5.1	17.1-23.0	7.3
West Europe	14.6	14.1-16.4	3.7	14.2-17.6	5.1	14.3-19.7	8.4
Japan	5.4	5.4- 6.7	6.4	5.6- 8.6	10.0	5.5- 9.4	13.6
Other OECD	2.6	2.6- 3.3	6.7	2.7- 6.9	31.0	2.4- 8.4	39.5
Non-OECD	10.0	9.7-14.1	9.7	10.3-16.3	11.8	11.4-19.8	15.2
Subtotal	51.4	52.6-59.4	3.5	55.2-64.6	4.6	55.7-72.1	7.0
USSR	8.4	9.1-10.1	3.5	9.6-11.7	6.3	10.1-13.8	10.3
East Europe	2.1	2.3- 3.1	9.3	2.4- 3.4	10.7	2.6- 3.9	14.3
China	1.7	1.9- 2.8	10.5	2.2- 3.8	15.8	2.8- 5.3	22.2
Subtotal	12.2	13.4-15.4	4.0	14.3-18.1	6.5	15.5-21.2	9.7
Total	63.6	66.4-73.3	3.0	69.9-79.9	4.3	74.9-89.1	6.1

	Second NPC Survey (Medium Case)					
	1982		1985		1990	
	Range (MMB/D)	C.V.†	Range (MMB/D)	C.V.†	Range (MMB/D)	C.V.†
U.S.	17.4-19.6	3.3	16.6-20.2	5.1	15.9-20.4	7.3
West Europe	14.1-16.1	3.6	13.3-17.4	5.7	12.9-18.9	8.6
Japan	5.3- 6.5	6.5	5.2- 7.5	9.4	4.8- 8.2	12.4
Other OECD	2.3- 2.9	7.1	2.5- 3.1	7.4	2.4- 3.5	12.9
Non-OECD	11.0-14.1	8.3	11.4-16.0	9.9	14.3-18.5	9.0
Subtotal	51.3-57.7	3.2	51.6-62.8	4.5	52.4-68.1	6.1
USSR	8.9- 9.5	2.4	9.4-10.5	4.0	9.4-11.8	8.1
East Europe	2.3- 2.8	7.2	2.1- 3.0	10.5	2.0- 3.4	15.7
China	2.0- 2.7	9.4	2.4- 3.5	11.7	3.1- 4.7	12.7
Subtotal	12.0-14.6	5.9	12.7-16.7	6.7	13.0-19.3	11.2
Total	64.0-72.3	3.4	66.7-79.2	4.6	71.0-87.1	6.1

*Projected data derived from the April 1979 and December 1979 NPC Surveys of U.S. and World Energy and Oil Supply/Demand Forecasts. Components do not add to totals because some respondents did not provide figures for all components.

†Coefficient of variation (standard deviation as a percentage of the mean).

World Petroleum Liquids (Crude Oil and Natural Gas Liquids) Supply

The geopolitical distribution of the projected future global petroleum liquids production is shown in Table 6. The following discussion focuses upon the reasonableness of the projected petroleum liquids supplies of the Free World from a technical point of view. (Note: the Sino-Soviet group of countries is reviewed separately.)

The production profile developed from the responses to the two supply/demand surveys implies a cumulative world production requirement of 240 to 260 billion barrels between 1979 and 1990, or a drawdown of 49 to 52 percent of current proved reserves. If the recent rate of annual reserve additions (averaging 14 billion barrels per year during the 1972-1978 period) can be maintained, however, the drawdown in proved crude oil reserves would be less than 20 percent by 1990.

Although the world supply of crude oil seems to be adequate, potential trouble spots appear when supply data are examined on a regional basis. Table 7 displays, by region, proved reserves as of January 1, 1979, cumulative production projected by the surveys between 1979 and 1990, the percentage of current proved reserves of crude oil produced during the forecast period, annual crude oil proved reserve additions required for either technical reasons or to keep the reserve drawdown to politically acceptable levels, and annual crude oil reserve additions achieved during the 1972-1978 period.

For the Middle East and Mexico, and possibly Africa, it is reasonable to assume that the physical producing capability either already exists or can be developed to produce at the projected rates implied by the surveys. For the other regions, significant improvements in the rate of new reserve additions will be required if the projected production is to materialize. The United States in particular is in a precarious position. Unless the rate of new reserve additions improves substantially, the production levels implied by the surveys cannot be realized. As to the other OECD countries, the required future new reserve additions may be difficult to achieve; for example, a sharp drop in new field discoveries in the North Sea has recently been experienced.

The production levels projected for the Middle East and Africa are not without risk as well. The future producing rates of these regions, while not generally restricted by physical resource limits, will be governed largely by internal economic and political considerations and decisions. Although international pressure to increase production rates to the level close to the maximum technically sustainable is expected to continue, the stated goal of almost every one of these countries is to limit petroleum exports to volumes consistent and compatible with domestic revenue needs. Thus, the desire of some of the major crude oil exporting countries to limit, if not reduce, future production and export levels conflicts with the projected production rates required to meet future consumption demands, which are increasing over time.

TABLE 6

World Petroleum Liquids* Production†
(MMB/D)

	Actual		1982			1985			1990		
	1972	1978	High Case	Medium Case	Low Case	High Case	Medium Case	Low Case	High Case	Medium Case	Low Case
OECD	14.2	14.7	16.6	15.9	15.5	16.9	16.0	15.9	17.4	16.8	15.4
U.S.§	11.6	10.8	10.5	10.3	10.1	10.3	10.1	9.8	10.3	9.9	9.0
Canada	1.8	1.6	1.7	1.7	1.7	1.8	1.6	1.7	1.8	1.8	1.7
West Europe	0.4	1.8	3.8	3.3	3.1	4.2	3.8	3.8	4.6	4.5	4.0
Other	0.4	0.5	0.6	0.6	0.6	0.6	0.5	0.6	0.7	0.6	0.7
OPEC	27.4	30.1	33.1	30.2	29.3	35.1	30.8	30.4	36.7	32.5	31.9
Venezuela	3.3	2.2	2.3	2.3	2.2	2.3	2.2	2.2	2.3	2.2	2.2
Indonesia	1.1	1.6	1.7	1.7	1.6	1.7	1.7	1.7	1.6	1.6	1.6
Algeria	1.1	1.2	1.4	1.2	1.3	1.3	1.1	1.3	1.3	1.1	1.3
Libya	2.2	2.0	2.3	2.1	2.1	2.3	2.1	2.1	2.2	2.2	2.0
Nigeria	1.8	1.9	2.3	2.2	2.2	2.3	2.2	2.2	2.2	2.2	2.2
Iran	5.0	5.2	4.3	3.2	3.1	4.6	3.3	3.3	4.6	3.6	3.4
Kuwait	3.1	1.9	2.1	1.9	1.7	2.2	1.9	1.8	2.3	2.1	1.9
Saudi Arabia	5.8	8.3	9.6	9.1	8.7	10.5	9.4	8.9	11.7	10.2	9.9
Iraq	1.5	2.6	3.5	3.1	3.1	4.0	3.5	3.5	4.4	3.8	3.9
United Arab Emirates	1.2	1.8	2.1	2.0	1.9	2.4	2.0	2.0	2.6	2.2	2.1
Other	1.3	1.4	1.5	1.4	1.4	1.5	1.4	1.4	1.5	1.3	1.4
Non-OPEC	3.4	4.7	7.0	6.8	7.1	8.0	8.0	8.5	9.7	10.1	10.4
Mexico	0.6	1.3	2.6	2.6	2.6	3.1	3.1	3.3	4.2	4.2	4.1
Other	2.8	3.4	4.4	4.2	4.5	4.9	4.9	5.2	5.5	5.9	6.3
Subtotal	45.0	49.5	56.7	52.9	51.9	60.0	54.8	54.8	63.8	59.4	57.7
Sino-Soviet	9.0	14.0	15.6	14.8	14.5	16.6	15.6	15.5	18.5	17.3	17.7
Total	54.0	63.5	72.3	67.7	66.4	76.6	70.4	70.3	82.3	76.7	75.4

*Crude oil and natural gas liquids.

†Projected data derived from the April 1979 and December 1979 NPC Surveys of U.S. and World Energy and Oil Supply/Demand Forecasts.

§Includes 0.5 MMB/D processing gain.

TABLE 7

Required Annual Crude Oil Reserve Additions -- 1979-1990*
(Billions of Barrels)

	United States	Other OECD	Mexico	Other Latin America	Africa	Middle East	Asia
Proved Reserves as of 1/1/79†	27.8	24.7	28.4	26.3	56.3	311.3	13.6
Cumulative Production (1979-1990)							
High Case	37	27	13	18	33	115	13
Medium Case	36	25	13	18	32	102	13
Percentage of Current Reserves Produced by 1990							
High Case	132	110	46	70	58	37	93
Medium Case	129	101	46	70	57	33	93
Required Annual Reserve Additions							
High Case	2.7	2.4	1.3	1.6	1.3	5.8	1.1
Medium Case	2.6	2.2	1.3	1.6	1.2	4.6	1.1
Average Annual Reserve Additions (1972-1978)§	1.7	2.1	3.9	1.2	2.6	1.8	0.6

*Projected data derived from the April 1979 and December 1979 NPC Surveys of U.S. and World Energy and Oil Supply/Demand Forecasts.

†World Oil, August 15, 1979.

§Based on World Oil reserve estimates.

As shown in Table 8, both supply/demand surveys indicate that the Sino-Soviet countries will continue as a group to be net crude oil exporters, although at declining rates. However, and perhaps more significantly, both surveys project that the USSR and East European countries will become net importers of crude oil sometime between 1985 and 1990. It must be emphasized that widely divergent views exist among Western petroleum experts as to future Sino-Soviet petroleum supply and development. Some predict that the USSR and East European countries will be net crude oil exporters through the 1980's and into the early 1990's, while others believe that they will become net importers as early as 1982. The single most dependent variable in the Sino-Soviet balance is the future rate of USSR crude oil development and production, although the future rate of crude oil development and production in China is also a factor.

The range of data received in both supply/demand surveys on future global petroleum liquids supplies is summarized in Table 9. The range of total supply data closely matches that observed in total world petroleum consumption. The range in supply component data, although affected by overall variation to some extent, is believed to reflect different assessments of future crude oil discovery and development rates and economic/political decisions relative to production rates.

U.S. ENERGY CONSUMPTION

Figure 14 and Table 10 present the U.S. energy consumption data resulting from the first and second supply/demand surveys. Real Gross National Product (GNP) assumptions underlying the energy projections are also shown.

During the 1978-1990 period, U.S. energy consumption is expected to experience a 2.3 percent annual rate of growth in the high case, a 1.5 percent rate in the medium case, and a 1.0 percent rate in the low case. Comparable real GNP growth for the three cases is 3.2, 2.6, and 2.3 percent per year, respectively.

Also shown in Figure 14 is the total energy consumption per dollar of real GNP. In the long term, the decline rates are similar in the three projections. In the high case, the 1978 to 1990 decline was 0.9 percent per year; in the medium case, this rate was increased to 1.1 percent per year; and in the low case, it became 1.2 percent per year. The three cases project the energy/economic activities shown in Table 11.

U.S. energy consumption for the three cases is compared by type of energy in Figure 15. In all three cases, oil and gas combined constitute a declining share of the projected total U.S. energy consumption. In 1978, oil and gas comprised 74 percent of the total energy consumed. In the high case, that percentage declined to 62 percent by 1990; in the medium case, the 1990 share was only 61 percent; and in the low case it was 60 percent. The combined

TABLE 8

Sino-Soviet Petroleum Supply/Demand -- 1978-1990*
(MMB/D -- Average All Respondents)

	Actual	1982			1985			1990		
	1978	High Case	Medium Case	Low Case	High Case	Medium Case	Low Case	High Case	Medium Case	Low Case
USSR										
Production	11.7	12.4	11.7	12.0	12.7	12.1	12.3	13.6	12.6	13.0
Demand	8.4	9.5	9.2	8.9	10.2	9.9	9.7	11.2	10.5	10.4
Net Exports (Imports)	3.3	2.9	2.5	3.1	2.5	2.2	2.6	2.4	2.1	2.6
East Europe										
Production	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Demand	2.1	2.6	2.4	2.7	2.9	2.5	2.4	3.2	2.8	2.7
Net Exports (Imports)	(1.7)	(2.2)	(2.0)	(2.3)	(2.5)	(2.1)	(2.0)	(2.8)	(2.4)	(2.3)
USSR/East Europe										
Net Exports (Imports)	1.6	0.7	0.5	0.8	0	0.1	0.6	(0.4)	(0.3)	0.3
China										
Production	1.9	2.8	2.7	2.1	3.5	3.2	2.8	4.5	4.3	4.3
Demand	1.7	2.5	2.3	2.3	3.0	3.0	3.2	3.8	3.8	4.1
Net Exports (Imports)	0.2	0.3	0.4	(0.2)	0.5	0.2	(0.4)	0.7	0.5	0.2
Sino-Soviet										
Net Exports (Imports)	1.8	1.0	0.9	0.6	0.5	0.3	0.2	0.3	0.2	0.5

*Projected data derived from the April 1979 and December 1979 NPC Surveys of U.S. and World Energy and Oil Supply/Demand Forecasts.

TABLE 9

Ranges and Coefficients of Variation in NPC Surveys of
World Petroleum Supply Forecasts*

		First NPC Survey (High Case)						Second NPC Survey (Medium Case)					
		1982		1985		1990		1982		1985		1990	
	Actual 1978	Range (MMB/D)	C.V.†	Range (MMB/D)	C.V.†	Range (MMB/D)	C.V.†	Range (MMB/D)	C.V.†	Range (MMB/D)	C.V.†	Range (MMB/D)	C.V.†
OECD	14.7	14.9-18.4	5.1	15.1-18.9	5.8	16.0-19.9	6.8	14.6-16.7	3.7	14.2-18.5	6.0	13.2-19.0	9.2
U.S.§	10.8	10.0-11.4	4.4	9.3-11.8	7.2	8.1-12.8	11.3	10.0-11.0	3.0	8.7-11.0	5.6	7.1-11.8	11.1
Canada	1.6	1.5- 2.1	8.2	1.5- 2.1	10.1	1.6- 2.3	12.3	1.5- 1.9	6.6	1.4- 2.0	10.6	1.3- 2.3	15.1
West Europe	1.8	3.2- 4.2	8.6	3.5- 5.1	9.8	3.8- 5.7	11.0	2.3- 4.1	13.7	3.3- 5.0	10.7	3.3- 5.3	12.0
Other	0.5	0.4- 1.1	28.6	0.4- 1.0	29.0	0.4- 1.5	43.0	0.4- 0.8	20.3	0.2- 1.0	31.8	0.2- 1.2	38.4
OPEC		31.2-38.8	6.8	31.6-41.2	8.3	31.3-44.2	10.8	28.0-34.1	5.9	27.2-37.6	7.2	27.2-41.2	9.1
Venezuela	2.2	2.2- 2.4	3.2	1.9- 2.6	6.1	1.8- 2.5	9.2	2.0- 2.7	7.5	1.8- 2.7	10.0	1.5- 2.6	13.4
Indonesia	1.6	1.4- 2.0	9.6	1.4- 2.3	13.6	0.9- 2.2	20.1	1.6- 1.9	6.6	1.5- 2.0	7.5	1.3- 2.0	10.0
Algeria	1.2	1.0- 1.9	20.3	0.9- 2.1	25.8	0.7- 2.3	29.5	1.0- 1.5	12.0	0.9- 1.5	14.8	0.7- 1.4	19.4
Libya	2.0	2.0- 2.7	7.9	2.0- 2.6	8.4	1.5- 2.7	14.5	1.8- 2.6	11.2	1.9- 2.8	12.6	1.7- 3.0	16.6
Nigeria	1.9	1.8- 2.7	9.8	1.6- 2.6	10.4	1.4- 2.9	14.6	2.0- 2.6	8.1	1.9- 2.7	8.2	1.8- 2.5	2.5
Iran	5.2	3.3- 6.6	19.8	3.6- 6.8	19.0	3.7- 6.0	15.6	2.2- 4.8	19.4	2.2- 5.3	21.4	3.0- 5.2	19.4
Kuwait	1.9	1.9- 2.7	9.0	1.8- 2.9	11.3	2.0- 2.9	11.9	1.6- 2.5	13.6	1.6- 2.5	13.7	1.8- 3.0	14.0
Saudi Arabia	8.3	8.9-12.8	11.1	7.6-14.3	15.8	7.8-15.5	19.3	8.5-10.0	5.3	8.1-11.6	10.4	9.0-13.4	13.1
Iraq	2.6	2.8- 4.1	10.4	3.2- 4.7	10.8	3.5- 5.1	11.7	2.7- 4.0	10.8	3.2- 4.7	10.9	3.1- 4.9	13.6
United Arab Emirates	1.8	1.9- 2.4	7.8	1.9- 3.2	13.7	1.8- 3.7	19.4	1.7- 2.5	11.6	1.6- 3.2	18.3	1.7- 3.7	22.6
Other	1.4	1.1- 2.0	NA	1.1- 2.3	NA	0.8- 2.2	NA	1.2- 1.6	NA	0.9- 1.8	NA	0.8- 2.0	NA
Non-OPEC	4.7	5.8- 9.2	12.3	6.6- 9.9	10.4	7.6-12.4	12.7	5.8- 8.6	10.8	6.6-10.0	9.2	7.3-13.7	15.3
Mexico	1.3	2.2- 3.3	13.5	2.5- 4.2	14.5	3.5- 6.4	17.4	2.2- 3.3	11.3	2.6- 3.9	11.5	3.4- 6.1	15.7
Other	3.4	3.2- 5.4	NA	3.2- 6.3	NA	3.1- 8.4	NA	3.1- 5.6	NA	3.1- 6.6	NA	3.4- 8.1	NA
Sino-Soviet	14.0	15.0-16.3	3.0	14.6-18.2	6.1	15.0-22.0	9.8	13.6-16.0	5.6	14.4-17.6	6.5	14.7-20.0	10.3
Total	63.5	67.7-81.3	5.6	71.4-83.5	5.1	74.8-90.7	6.2	64.8-73.5	3.4	58.2-79.9	6.7	71.5-87.5	5.6

*Projected data derived from the April 1979 and December 1979 NPC Surveys of U.S. and World Energy and Oil Supply/Demand Forecasts. Components do not add to totals because some respondents did not provide figures for all components.

†Coefficient of variation (standard deviation as a percentage of the mean).

§Includes 0.5 MMB/D processing gain.

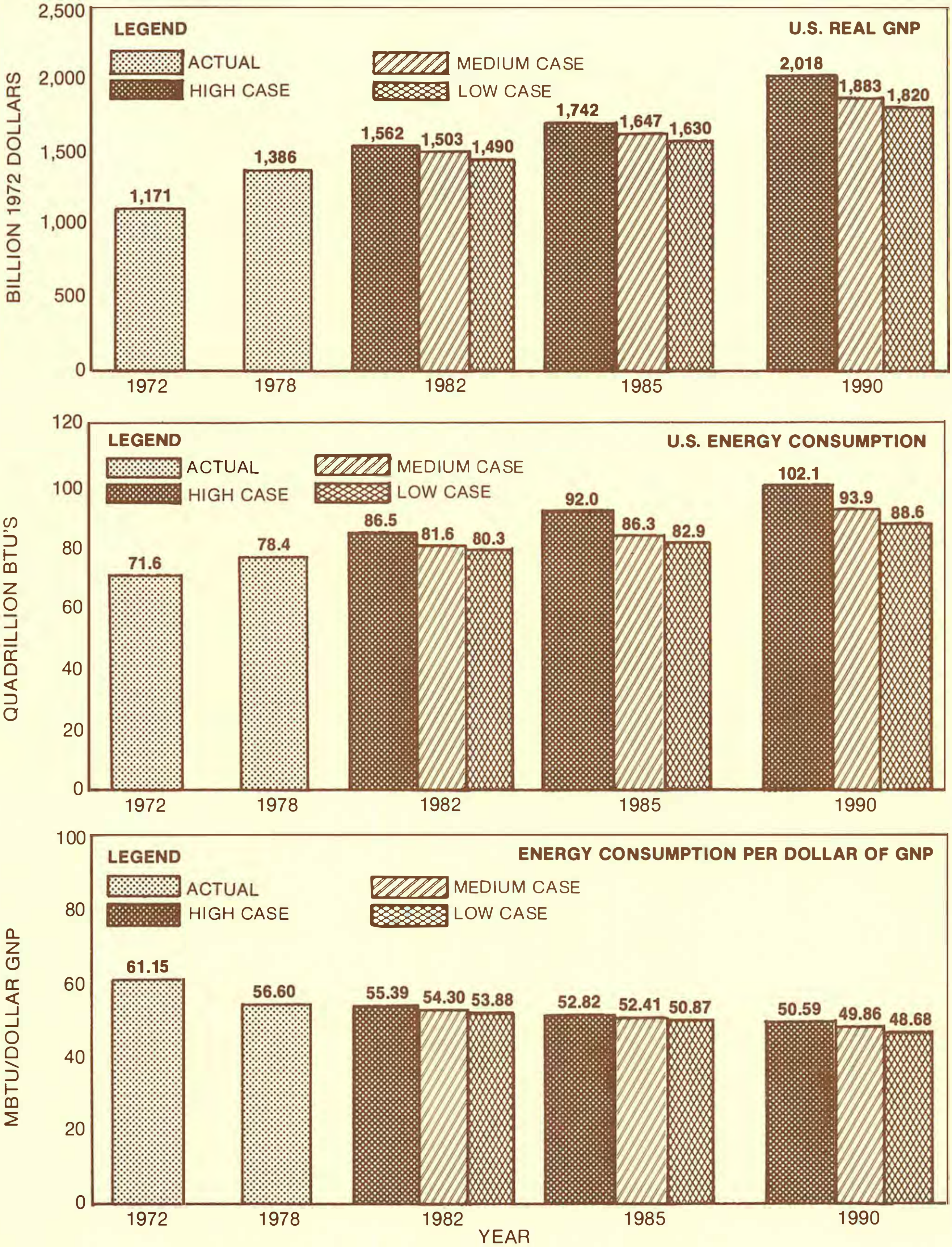

Figure 14. U.S. GNP and Energy Consumption Projections to 1990.

NOTE: Projected data derived from the April 1979 and December 1979 NPC Surveys of U.S. and World Energy and Oil Supply/Demand Forecasts.

TABLE 10

U.S. Energy Consumption and Gross National Product*

	Total Energy (Quadrillion Btu's)			GNP (Billion 1972 Dollars)		
	High Case	Medium Case	Low Case	High Case	Medium Case	Low Case
Actual 1978		78.44			1,386	
1982	86.52	81.62	80.28	1,562	1,503	1,490
1985	92.01	86.32	82.92	1,742	1,647	1,630
1990	102.09	93.89	88.59	2,018	1,883	1,820
	Annual Average Percent Change					
1978-1982	2.5	1.0	0.6	3.0	2.0	1.8
1982-1985	2.1	1.9	1.1	3.7	3.1	3.0
1985-1990	2.1	1.7	1.3	3.0	2.7	2.2
1978-1990	2.3	1.5	1.0	3.2	2.6	2.3

*Projected data derived from the April 1979 and December 1979 NPC Surveys of U.S. and World Energy and Oil Supply/Demand Forecasts.

TABLE 11

Comparison of Energy/Economic Activity -- 1978-1990*

	Actual 1978	Decline, High to Medium Case		Decline, High to Low Case	
	Units	Units	% of High Case	Units	% of High Case
Real GNP (Billion 1972 Dollars)	1,386	135	6.7	198	9.8
Energy Consumption (Quadrillion Btu's)	78.4	8.2	8.0	13.5	13.2
Energy/GNP (Thousand Btu's per Dollar)	56.6	0.7	1.4	1.9	3.8

*Projected data derived from the April 1979 and December 1979 NPC Surveys of U.S. and World Energy and Oil Supply/Demand Forecasts.

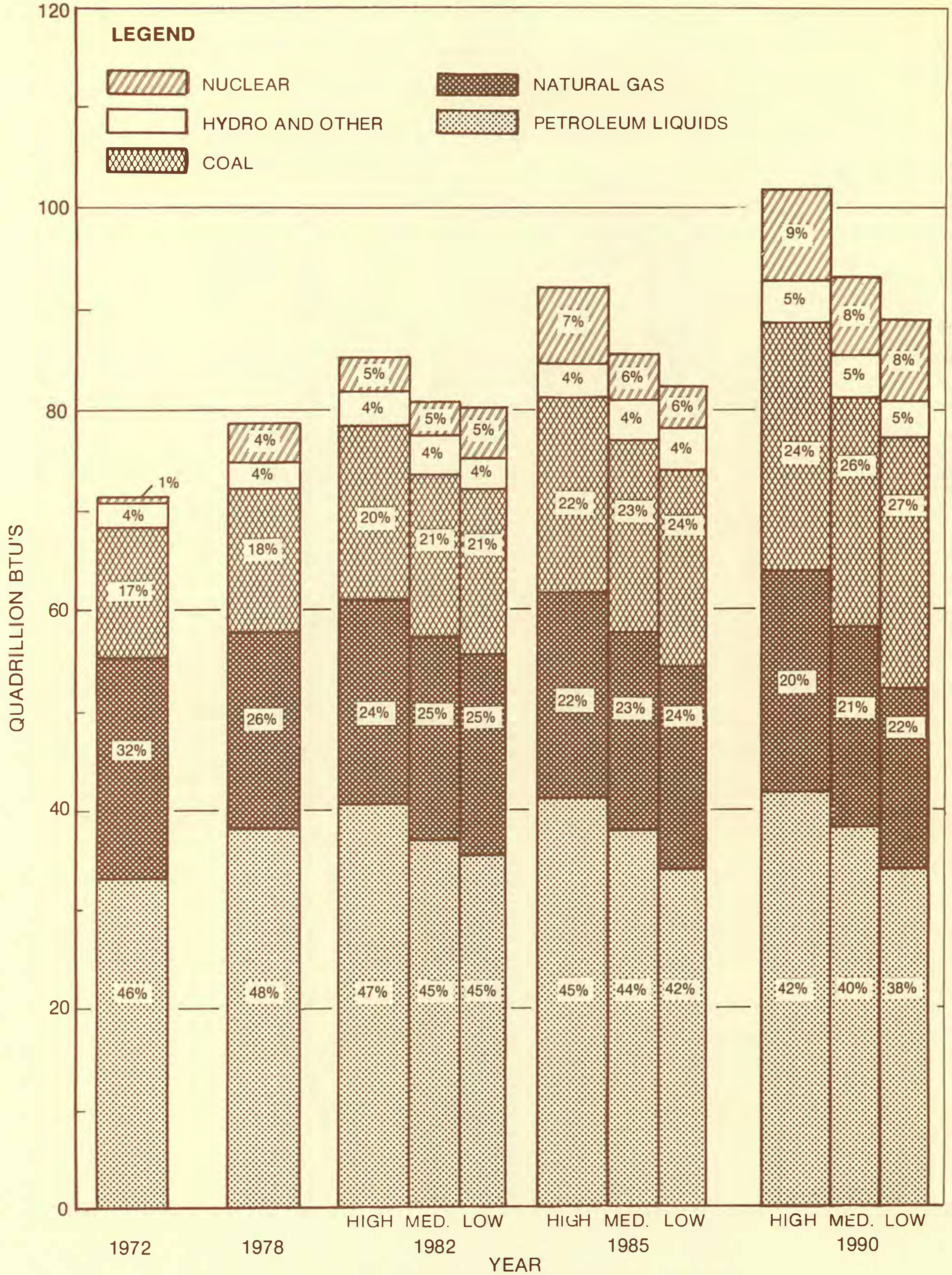

Figure 15. U.S. Energy Consumption by Type of Energy.

NOTE: Projected data derived from the April 1979 and December 1979 NPC Surveys of U.S. and World Energy and Oil Supply/Demand Forecasts; percentages are share of total consumption in year shown.

shares of coal and nuclear energy were expected to increase from the 1978 level of 22 percent, to almost 34 percent in the high and medium cases, and to 35 percent in the low case. However, between the high and medium cases there was a marked reduction in the respondents' expectations for nuclear energy (shown in Table 12).

In the high case, U.S. petroleum consumption (shown in Figure 16) is expected to increase only about 1 percent per year between 1978 and 1990. In the medium case no growth is anticipated, and the low case indicates a decline of 1 percent per year. By 1990, U.S. petroleum consumption is projected to be almost 5 quadrillion Btu's lower in the medium case than in the high case, and the low case responses average about 9 quadrillion Btu's lower than those of the high case.

U.S. PETROLEUM SUPPLY

Figure 17 compares the supply projections of domestic liquids production (crude oil and condensate and natural gas liquids) and petroleum imports to 1990 which correspond to the demand projections developed from the supply/demand surveys. The details of the U.S. petroleum supply projections of the three cases are presented in Table 13.

In the high case, conventional liquids production is projected to decline from 10.3 MMB/D in 1978 to 9.8 MMB/D in 1990. The medium case anticipates a slightly sharper decline, to 9.4 MMB/D by 1990, and the low case an even sharper decline, to 8.5 MMB/D. Synthetic crude oil production is projected to increase from zero in 1978 to 0.3 MMB/D in the high case, and to 0.5 MMB/D in the medium and low case projections.

Total U.S. imports (crude and unfinished oils, and finished products and NGL) are projected to increase in the high case from 8.4 MMB/D in 1978 to 10.9 MMB/D in 1990. The medium case indicates that total U.S. imports will grow to 8.9 MMB/D by 1985 and hold virtually constant at 8.8 MMB/D to 1990. The low case projects a decline in total U.S. imports to 7.5 MMB/D by 1990.

U.S. PETROLEUM DEMAND

The medium and low case projections of total U.S. domestic petroleum demand are compared with those of the high case in Figure 18. The more conservative thinking of respondents following the Iranian revolution is illustrated by this comparison. The high case projects total U.S. domestic petroleum demand at 21.2 MMB/D in 1990, an annual growth rate of 1 percent between 1978 and 1990. The medium case projects 1990 domestic petroleum demand at 18.9 MMB/D, essentially unchanged from 1978, and 2.3 MMB/D (11 percent) lower than the high case. The low case projection of domestic petroleum demand in 1990 is even more pessimistic at 16.8 MMB/D, 4.4 MMB/D (21 percent) lower than the high case.

TABLE 12

Comparison of U.S. Energy Consumption Projections to 1990*

	Actual 1978 (Quad. Btu's)	High Case (Quad. Btu's)	1990 Energy Consumption: Decline, High to Medium Case — Quad. Btu's	Decline, High to Medium Case — % of High Case	Decline, High to Low Case — Quad. Btu's	Decline, High to Low Case — % of High Case
Petroleum	38.01	42.64	4.81	11.3	8.96	21.0
Natural Gas	20.04	20.49	0.72	3.5	0.90	4.4
Coal	14.07	25.15	0.82	3.3	0.97	3.9
Nuclear	2.98	9.17	1.72	18.8	2.15	23.4
Hydro and Other	3.34	4.64	0.13	2.8	0.52	11.2
Total	78.44	102.09	8.20	8.0	13.50	13.2

*Projected data derived from the April 1979 and December 1979 NPC Surveys of U.S. and World Energy and Oil Supply/Demand Forecasts.

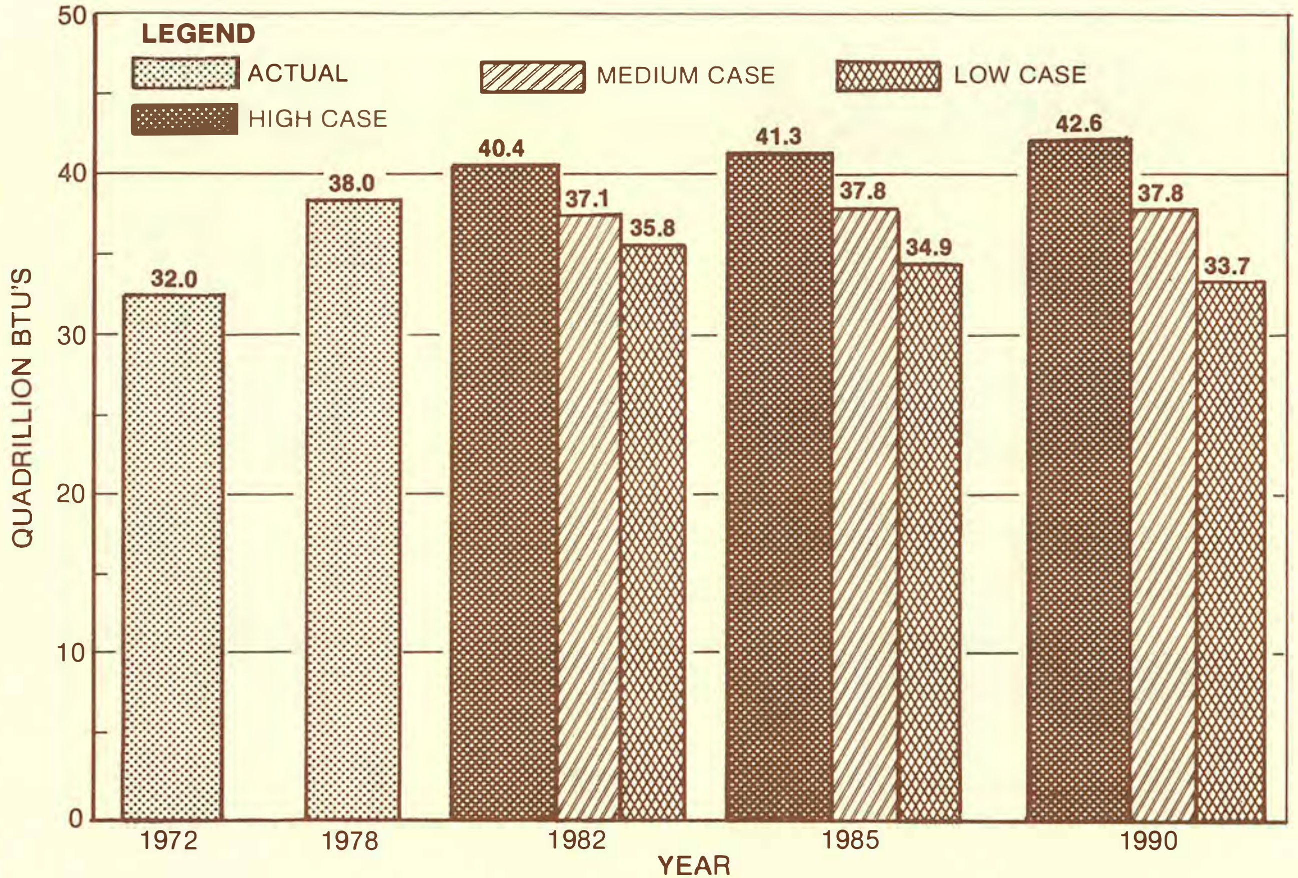

Figure 16. U.S. Petroleum Consumption.

NOTE: Projected data derived from the April 1979 and December 1979 NPC Surveys of U.S. and World Energy and Oil Supply/Demand Forecasts.

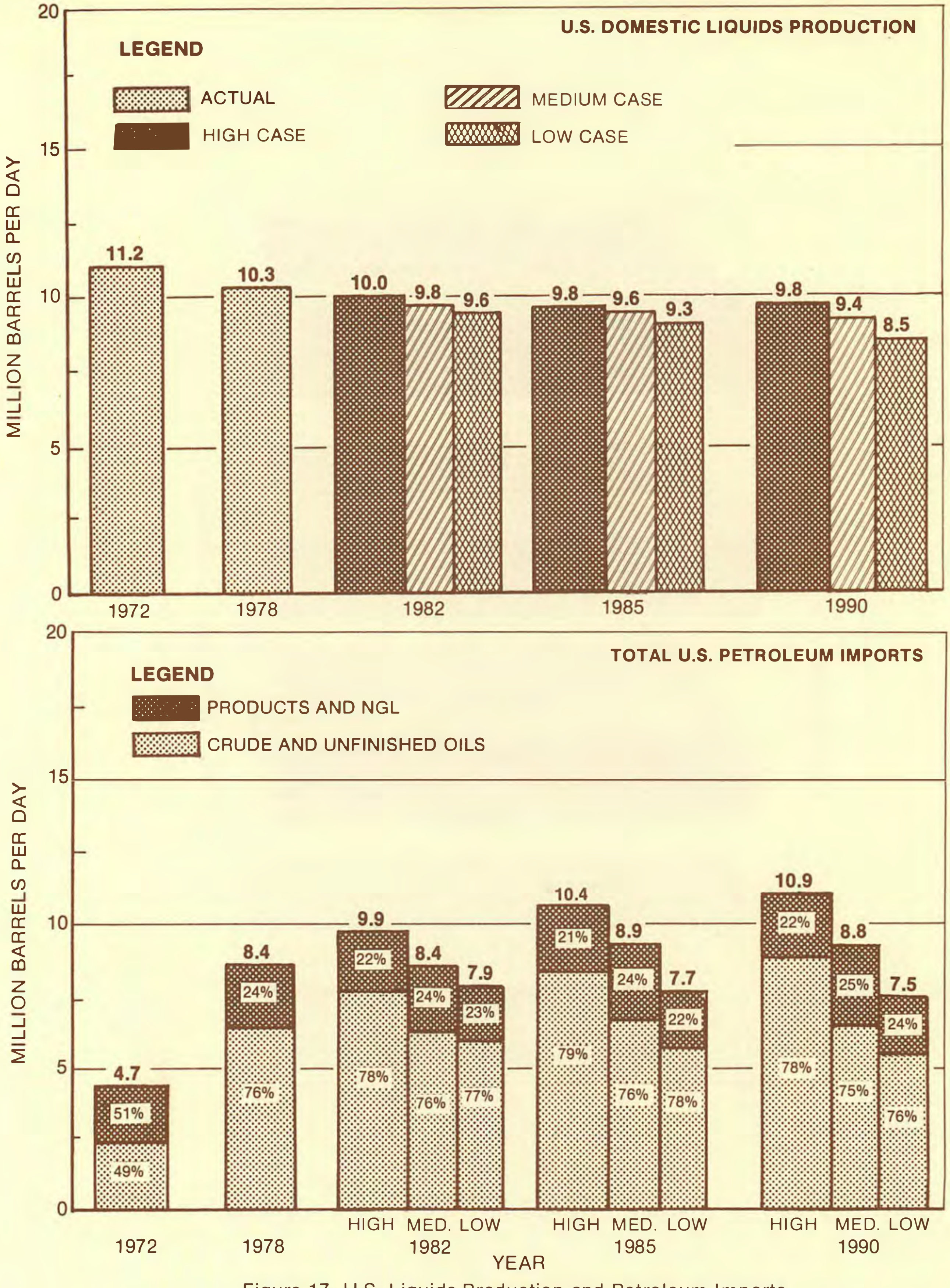

Figure 17. U.S. Liquids Production and Petroleum Imports.

NOTE: Projected data derived from the April 1979 and December 1979 NPC Surveys of U.S. and World Energy and Oil Supply/Demand Forecasts; percentages are share of total imports for years shown.

TABLE 13

U.S. Petroleum Supply*
(MMB/D)

	Actual		High Case			Medium Case			Low Case		
	1972	1978	1982	1985	1990	1982	1985	1990	1982	1985	1990
Domestic Production											
Crude Oil and Condensate	9.4	8.7	8.5	8.4	8.5	8.3	8.2	8.0	8.3	8.0	7.5
NGL	1.7	1.6	1.5	1.4	1.3	1.5	1.4	1.3	1.4	1.2	1.0
Syncrude Production	0.0	0.0	†	†	0.3	†	0.1	0.5	0.0	0.1	0.5
Subtotal	11.2	10.3	10.0	9.8	10.3	9.8	9.7	9.9	9.6	9.4	9.0
Imports											
Crude and Unfinished Oils	2.3	6.4	7.7	8.2	8.5	6.4	6.8	6.6	6.1	6.0	5.7
Products and NGL	2.4	2.0	2.2	2.3	2.4	2.0	2.2	2.2	1.8	1.7	1.8
Subtotal	4.7	8.4	9.9	10.4	10.9	8.4	8.9	8.8	7.9	7.7	7.5
Processing Gain and Stock Change	0.7	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Total Petroleum Supply	16.8	19.2	20.5	20.8	21.5	18.8	19.1	19.2	18.0	17.6	17.0

*Projected data derived from the April 1979 and December 1979 NPC Surveys of U.S. and World Energy and Oil Supply/Demand Forecasts. Columns may not add due to rounding.

†Less than 0.1 MMB/D.

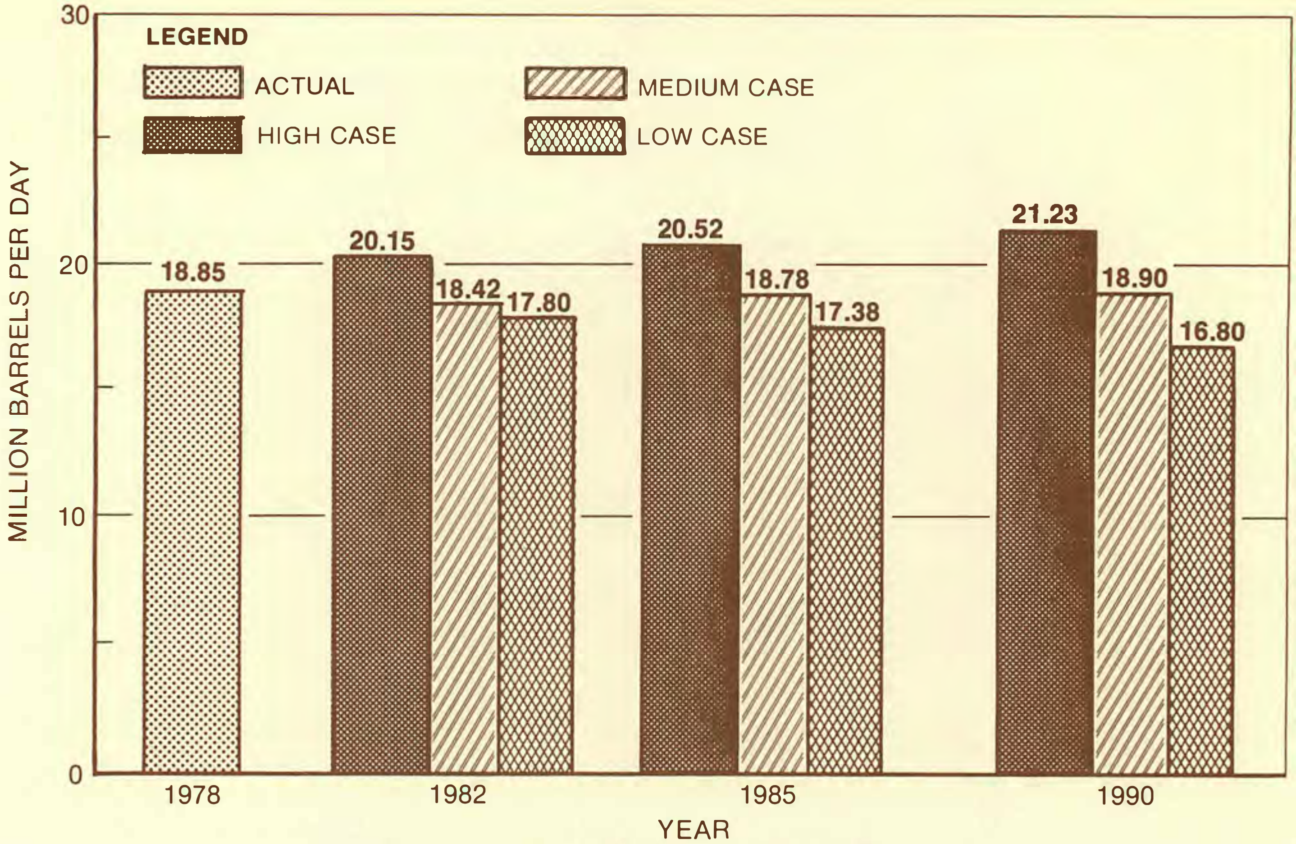

Figure 18. U.S. Domestic Petroleum Demand.

NOTE: Projected data derived from the April 1979 and December 1979 NPC Surveys of U.S. World Energy and Oil Supply/Demand Forecasts.

The most significant downward adjustment in the outlook for future U.S. product demand among the cases occurs in residual fuel oil. The high case projects 1990 residual fuel oil demand at 3.2 MMB/D, an average annual increase of 0.5 percent between 1978 and 1990. The medium and low case projections indicate a decline of over 2 percent and almost 4 percent per year, respectively, over the same period, with 1990 demand down from the high case by 0.9 and 1.8 MMB/D, to 2.3 and 1.5 MMB/D, respectively. Low-sulfur fuel oil (1.0 wt % maximum) accounts for 96 and 69 percent, respectively, of the decrease from the high case in total residual fuel oil demand. Also, the high case indicates that low-sulfur fuel oil, which accounted for 52 percent of total residual fuel oil demand in 1978, would account for 60 percent of total residual fuel oil demand by 1990. In contrast, as shown in Figure 19, the medium case and low cases indicate that low-sulfur fuel oil will account for only 47 and 50 percent, respectively, of total residual fuel oil demand by 1990.

Demand for middle distillates (kerosine and heating oil No. 1, kerosine-type jet fuel, and distillate fuels) is projected to increase 2.4 percent annually between 1978 and 1990 in the high case -- rising from 4.7 to 6.2 MMB/D. The medium case and the low cases

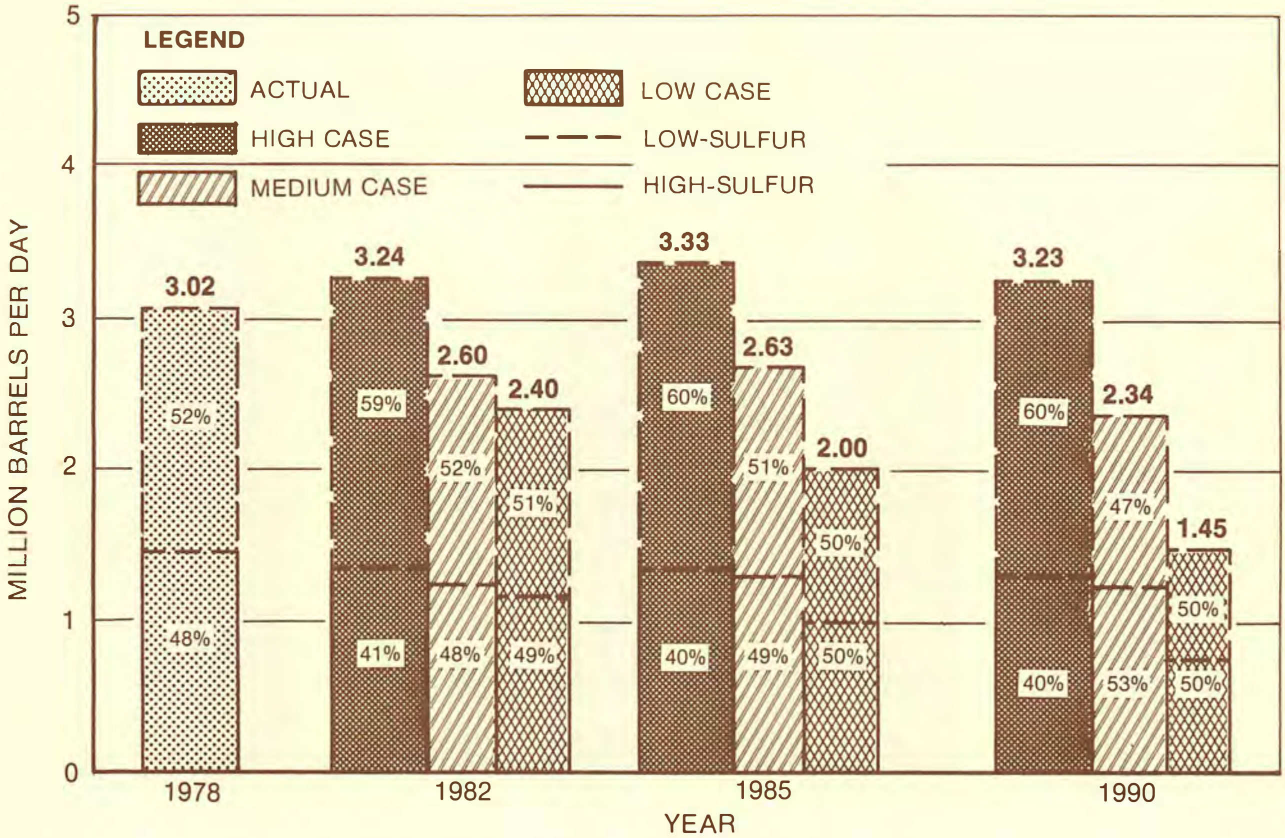

Figure 19. U.S. Residual Fuel Oil Demand.

NOTE: Low sulfur—max. 1.0 wt %; high sulfur—over 1.0 wt %.

NOTE: Projected data derived from the April 1979 and December 1979 NPC Surveys of U.S. and World Energy and Oil Supply/Demand Forecasts.

substantially reduce the demand outlook for middle distillates vs. the high case. The medium case indicates an average annual growth rate of only 1.5 percent, to 5.6 MMB/D in 1990, and the low case projects middle distillate demand to remain essentially constant over the 1978-1990 period. As shown in Figure 20, only on-highway diesel demand is expected to increase significantly from 1978 to 1990 in the three projections, accounting for 30, 31, and 24 percent, respectively, of total middle distillate demand in 1990, compared with only 8 percent in 1978.

The high case projects an annual decline in motor gasoline demand of 0.8 percent over the 1978-1990 period, from 7.4 to 6.7 MMB/D. This decrease of about 0.7 MMB/D represents almost 30 percent of the overall decline in total domestic petroleum demand during the same period. The high case also indicates that unleaded motor gasoline demand will account for 72 and 84 percent of total motor gasoline demand in 1985 and 1990, compared to only 32 percent in 1978.

As shown in Figure 21, motor gasoline demand is projected at about the same levels in the medium and low cases; by 1990, a decline of 1.6 percent per year from the 1978 level, from 7.4 to 6.0 MMB/D (a decrease of about 1.4 MMB/D over the period), is

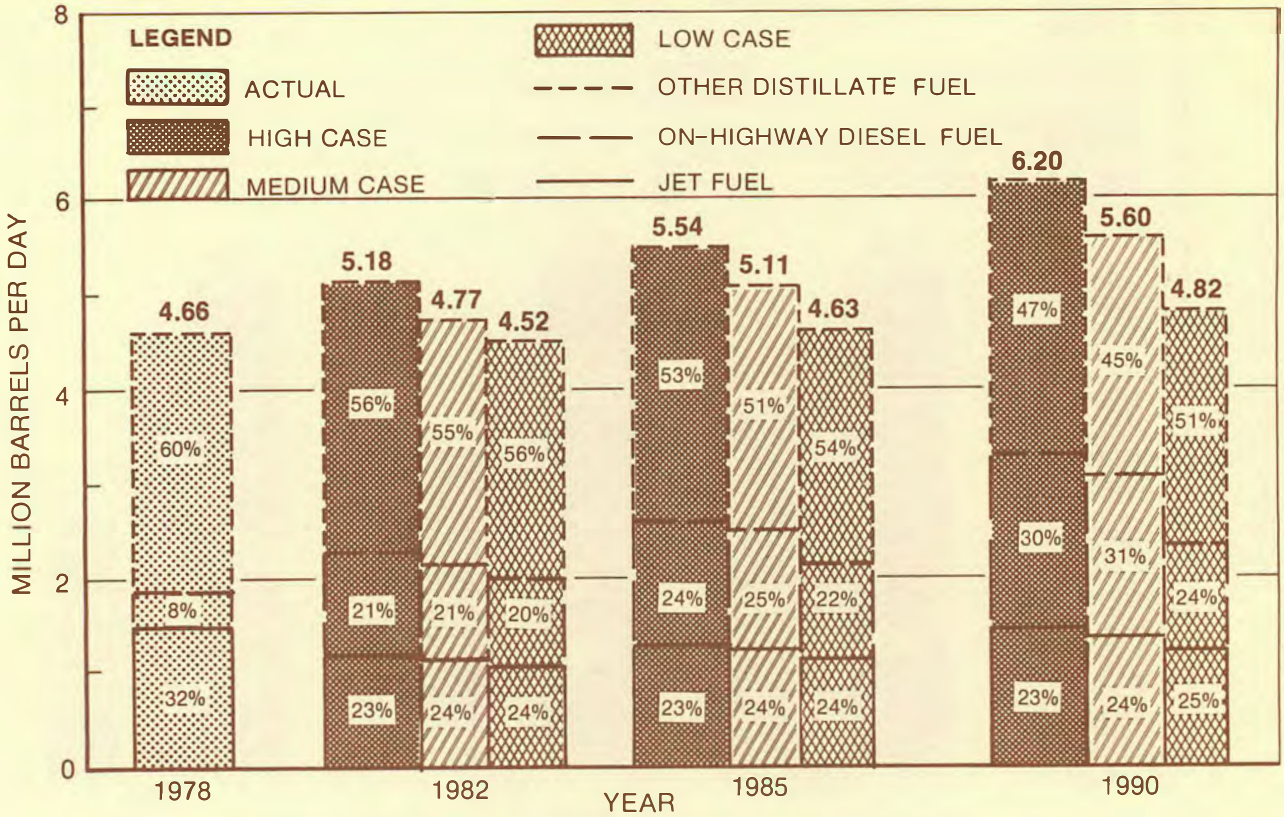

Figure 20. U.S. Middle Distillate Fuel Demand.

NOTE: Projected data derived from the April 1979 and December 1979 NPC Surveys of U.S. and World Energy and Oil Supply/Demand Forecasts.

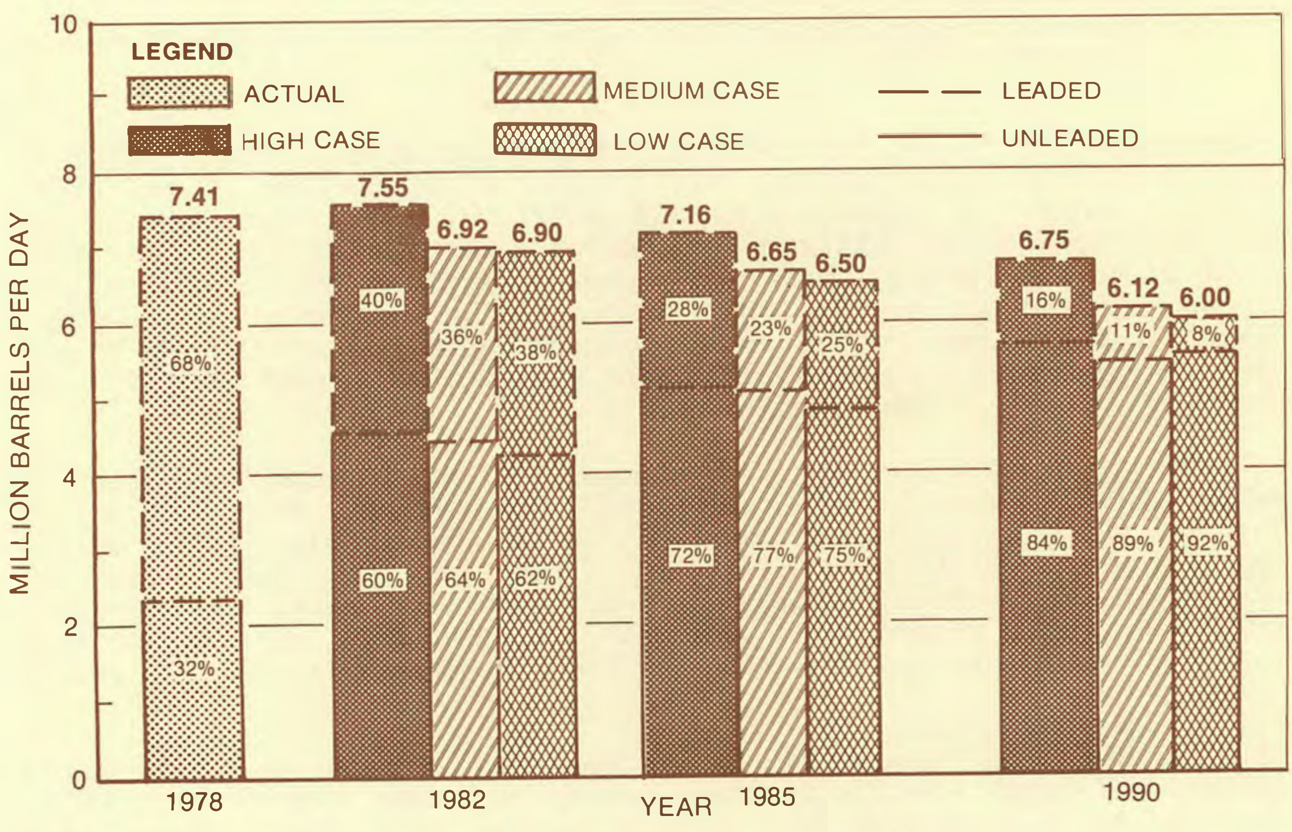

Figure 21. U.S. Motor Gasoline Demand.

NOTE: Projected data derived from the April 1979 and December 1979 NPC Surveys of U.S. and World Energy and Oil Supply/Demand Forecasts.

expected. The 1990 motor gasoline demand projected by the medium and low cases is about 0.75 MMB/D lower than the high case projection. An anticipated decrease in demand for leaded motor gasoline accounts for most of the reduction in total motor gasoline demand in the medium and low cases vs. the high case. Unleaded motor gasoline demand accounts for 89 percent and 92 percent of total motor gasoline demand in 1990 in the medium case and the low case, respectively.

Complete details of total U.S. petroleum demand for the years 1978, 1982, 1985, and 1990 as developed from the three projections are shown in Tables 14-19.

REGIONAL PETROLEUM SUPPLY/DEMAND

The first petroleum supply/demand survey requested detailed regional supply/demand balances for each of the five PAD districts as well as for the total United States for the years 1980, 1982, 1985, and 1990 (see Figure 1 for a map of the PAD districts). Most respondents to the survey were unable to provide the requested PAD district details. They were, however, able to provide information for PADs I-IV (the area east of the Rockies) and PAD V (U.S. West Coast and Alaska and Hawaii). The second supply/demand survey requested detailed balances for PADs I-IV in aggregate and PAD V, in addition to the total United States, for the years 1982, 1985, and 1990. With the assistance and cooperation of the Department of Energy, the total U.S. supply/demand data from the low case were apportioned to PADs I-IV and V for the years 1985 and 1990 only.

Regional Petroleum Supply

Total petroleum supply for PADs I-IV increases in the high case by about 2.2 MMB/D between 1978 and 1990, from 16.46 to 18.57 MMB/D (see Figure 22). The medium case indicates that total petroleum supply would virtually flatten over the same period, while the low case projects a decline in total petroleum supply to 14.47 MMB/D by 1990, a decrease of slightly over 1.8 MMB/D.

Table 20 summarizes the major elements of the projection of the petroleum supply of PADs I-IV by percentage share in 1978 and 1990. As shown in the table, the percentage contribution of indigenous liquids production to the petroleum supply of PADs I-IV declines in each of the three cases between 1978 and 1990, while the share of crude oil and unfinished oil imports and crude oil receipts from PAD V increases.

The net petroleum supply of PADs I-IV (total petroleum supply less crude oil and petroleum product exports, shipments to PAD V, and crude oil losses) corresponds very closely to total petroleum supply in each of the three cases over the 1978-1990 period, as shown in Table 21. This table provides supplementary information to that shown in Figure 22.

Total petroleum supply in PAD V is projected to increase between 1978 and 1990 in all three projections (see Figure 23).

TABLE 14

Domestic Demand for Products -- Total U.S.
(MB/D)

	Actual*	High Case Projection†		
	1978	1982	1985	1990
Motor Gasoline: Leaded - Premium	934	154	22	0
- Non-premium	4,106	2,868	1,950	1,089
Subtotal	5,040	3,022	1,972	1,089
Unleaded - Premium	185	1,342	1,883	2,235
- Non-premium	2,187	3,189	3,302	3,429
Subtotal	2,372	4,531	5,185	5,664
Total Motor Gasoline	7,412	7,553	7,157	6,753
Aviation Gasoline	39	43	45	49
Jet Fuel: Naphtha Type	199	184	171	140
Kerosine Type	858	1,001	1,102	1,298
Total Jet Fuel	1,057	1,185	1,273	1,438
Special Naphtha	103	103	104	113
Kerosine & Heating Oil #1	215	233	215	212
Distillate Fuel Oil: #2 Oil	1,385	1,292	1,280	1,218
#4 Oil	61	67	70	74
Diesel - On-Highway	797	1,088	1,352	1,822
- Off-Highway	191	206	221	251
Other Distillate	958	1,109	1,126	1,180
Total Distillate Fuel Oil	3,392	3,762	4,049	4,545
Residual Fuel Oil: 0 - 0.5%S	862	1,071	1,138	1,049
0.51 - 1.0%S	716	840	876	898
1.1 - 2.0%S	641	651	654	644
2.0%S +	804	679	660	634
Total Residual Fuel Oil	3,023	3,241	3,328	3,225
Liquified Gases: Ethane	433	403	402	390
Propane	778	941	1,018	1,124
Butane	167	170	193	210
Propane/Butane Mix	35	23	24	27
Total Liquified Gases	1,413	1,537	1,637	1,751
Petrochemical Feedstocks: Still Gas	55	58	51	47
400 EP Naphtha	205	272	319	436
Other	335	439	554	771
Total Petrochemical Feedstocks	595	769	924	1,254
Lubricants	172	180	190	210
Waxes	17	20	21	24
Coke	256	277	284	305
Asphalt & Road Oil	479	488	508	544
Still Gas for Fuel	548	581	582	600
Miscellaneous Products	128	176	204	207
Total Domestic Demand for Products	18,847	20,148	20,521	21,230

*Total U.S. per Petroleum Statement, Annual, Final Summary, November 7, 1979.

†Projected data derived from the April 1979 NPC Survey of U.S. and World Energy and Oil Supply/Demand Forecasts. Components may not add to subtotals due to independent rounding.

TABLE 15

Domestic Demand for Products -- Total U.S.
(MB/D)

	Actual*	Medium Case Projection†		
	1978	1982	1985	1990
Motor Gasoline: Leaded - Premium	934	679	158	59
- Non-premium	4,106	1,832	1,386	624
Subtotal	5,040	2,511	1,544	683
Unleaded - Premium	185	282	1,454	1,807
- Non-premium	2,187	4,126	3,653	3,634
Subtotal	2,372	4,408	5,107	5,441
Total Motor Gasoline	7,412	6,919	6,651	6,124
Aviation Gasoline	39	43	46	51
Jet Fuel: Naphtha Type	199	185	171	124
Kerosine Type	858	946	1,034	1,203
Total Jet Fuel	1,057	1,131	1,205	1,327
Special Naphtha	103	102	110	120
Kerosine & Heating Oil #1	215	208	206	203
Distillate Fuel Oil: #2 Oil	1,385	1,218	1,178	1,082
#4 Oil	61	72	85	93
Diesel - On-Highway	797	1,009	1,303	1,732
- Off-Highway	191	198	216	256
Other Distillate	958	934	913	909
Total Distillate Fuel Oil	3,392	3,431	3,695	4,072
Residual Fuel Oil: 0 - 0.5%S	862	762	833	695
0.51 - 1.0%S	716	596	498	408
1.1 - 2.0%S	641	527	720	756
2.0%S +	804	715	575	485
Total Residual Fuel Oil	3,023	2,600	2,626	2,344
Liquified Gases: Ethane	433	438	391	374
Propane	778	897	1,030	1,134
Butane	167	193	211	237
Propane/Butane Mix	35	42	48	48
Total Liquified Gases	1,413	1,570	1,680	1,793
Petrochemical Feedstocks: Still Gas	55	52	71	69
400 EP Naphtha	205	245	303	393
Other	335	471	495	622
Total Petrochemical Feedstocks	595	768	869	1,084
Lubricants	172	182	192	212
Waxes	17	19	21	23
Coke	256	267	274	289
Asphalt & Road Oil	479	489	510	539
Still Gas for Fuel	548	535	540	558
Miscellaneous Products	128	154	156	158
Total Domestic Demand for Products	18,847	18,418	18,781	18,897

*Total U.S. per Petroleum Statement, Annual, Final Summary, November 7, 1979.

†Projected data derived from the December 1979 NPC Survey of U.S. and World Energy and Oil Supply/Demand Forecasts. Components may not add to subtotals due to independent rounding.

TABLE 16

Domestic Demand for Products -- Total U.S.
(MB/D)

	Actual* 1978	Low Case Projection† 1982	1985	1990
Motor Gasoline: Leaded - Premium	934	500	0	0
- Non-premium	4,106	2,100	1,600	500
Subtotal	5,040	2,600	1,600	500
Unleaded - Premium	185	300	1,700	2,000
- Non-premium	2,187	4,000	3,200	3,500
Subtotal	2,372	4,300	4,900	5,500
Total Motor Gasoline	7,412	6,900	6,500	6,000
Aviation Gasoline	39	45	40	55
Jet Fuel: Naphtha Type	199	195	200	215
Kerosine Type	858	885	900	985
Total Jet Fuel	1,057	1,080	1,100	1,200
Special Naphtha	103	95	100	115
Kerosine & Heating Oil #1	215	176	163	155
Distillate Fuel Oil: #2 Oil	1,385	1,190	1,120	1,040
#4 Oil	61	60	65	65
Diesel - On-Highway	797	890	1,000	1,150
- Off-Highway	191	200	215	230
Other Distillate	958	924	962	975
Total Distillate Fuel Oil	3,392	3,264	3,362	3,460
Residual Fuel Oil: 0 - 0.5%S	862	720	555	410
0.51 - 1.0%S	716	515	440	310
1.1 - 2.0%S	641	430	380	250
2.0%S +	804	735	625	480
Total Residual Fuel Oil	3,023	2,400	2,000	1,450
Liquified Gases: Ethane	433	440	420	415
Propane	778	890	1,030	1,065
Butane	167	130	145	175
Propane/Butane Mix	35	40	50	45
Total Liquified Gases	1,413	1,500	1,645	1,700
Petrochemical Feedstocks: Still Gas	55	50	55	55
400 EP Naphtha	205	265	280	340
Other	335	435	465	555
Total Petrochemical Feedstocks	595	750	800	950
Lubricants	172	175	180	190
Waxes	17	20	20	20
Coke	256	250	265	260
Asphalt & Road Oil	479	490	530	550
Still Gas for Fuel	548	510	520	500
Miscellaneous Products	128	140	150	190
Total Domestic Demand for Products	18,847	17,795	17,375	16,795

*Total U.S. per Petroleum Statement, Annual, Final Summary, November 7, 1979.
†Projected data derived from the December 1979 NPC Survey of U.S. and World Energy and Oil Supply/Demand Forecasts. Components may not add to subtotals due to independent rounding.

TABLE 17

U.S. Motor Gasoline Octane Levels -- 1978-1990*

$\frac{(R+M)}{2}$

	Actual	Projection*		
	1978	1982	1985	1990
High Case				
Leaded Premium	94.2	94	95	95
Leaded Non-premium	89.5	89	89	89
Unleaded Premium	88.6	92	92	92
Unleaded Non-premium		87	87	87
Medium Case				
Leaded Premium	94.2	94	95	95
Leaded Non-premium	89.5	89	89	89
Unleaded Premium	88.6	92	92	92
Unleaded Non-premium		87	87	87
Low Case				
Leaded Premium	94.2	94	0	0
Leaded Non-premium	89.5	89	89	89
Unleaded Premium	88.6	93	94	94
Unleaded Non-premium		87	87	87

*Projected octane levels are not available disaggregated by PAD district.

TABLE 18

Amount of Liquified Petroleum Gases
Consumed for Chemical Uses in the United States
(MB/D)

	Actual	Projection		
	1978	1982	1985	1990
High Case				
Ethane	433	389	370	337
Propane	85	176	216	259
Butane	136	104	105	109
Propane/Butane Mix	11	3	4	5
Total	665	672	695	710
Medium Case				
Ethane	433	437	381	332
Propane	85	136	213	304
Butane	136	150	170	190
Propane/Butane Mix	11	10	11	12
Total	665	733	775	838
Low Case				
Ethane	433	430	410	355
Propane	85	145	210	265
Butane	136	105	120	145
Propane/Butane Mix	11	11	11	11
Total	665	691	751	776

TABLE 19

Total U.S. BTX* Demand -- 1978-1990
(MB/D)

	Actual 1978	Projection 1982	1985	1990
High Case				
Other Petrochemical Feedstocks	335	439	554	771
BTX	180	192	197	205
Medium Case				
Other Petrochemical Feedstocks	335	471	495	622
BTX	180	212	218	225
Low Case				
Other Petrochemical Feedstocks	335	435	465	555
BTX	180	185	190	195

*BTX - Benzene, Toluene, and Xylene.

TABLE 20

Total Petroleum Supply -- PADs I-IV
(Percentages)

	1978	1990* High Case	Medium Case	Low Case
Liquids Production (Including Syncrude)	49.3	37.3	41.4	41.8
Imports				
Crude and Unfinished Oils	35.1	43.3	38.4	37.8
NGL and Finished Products	11.3	12.3	12.8	11.9
Subtotal Imports	46.4	55.6	51.2	49.7
Receipts from PAD V (Principally Crude Oil)	1.9	4.7	4.7	5.5
Processing Gain	2.4	2.4	2.7	3.0
Total	100.0	100.0	100.0	100.0

*Projected data derived from the April 1979 and December 1979 NPC Surveys of U.S. and World Energy and Oil Supply/Demand Forecasts.

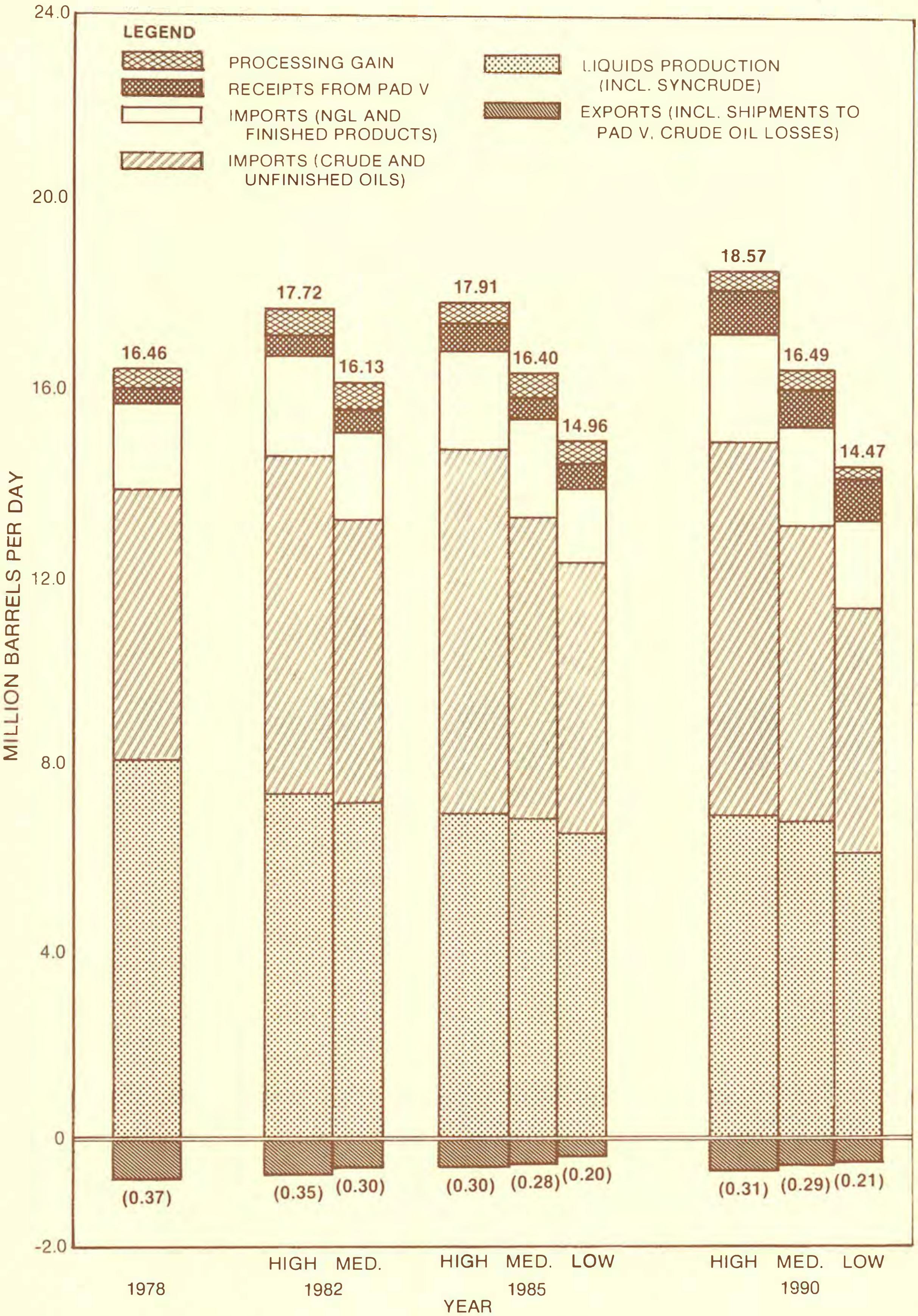

Figure 22. Regional Petroleum Supply—PADs I-IV.

NOTE: Projected data derived from the April 1979 and December 1979 NPC Surveys of U.S. and World Energy and Oil Supply/Demand Forecasts.

TABLE 21

Regional Petroleum Supply — PADs I-IV*
(MB/D)

	1978	1982 High Case	1982 Medium Case	1985 High Case	1985 Medium Case	1985 Low Case	1990 High Case	1990 Medium Case	1990 Low Case
Crude Oil Runs	12,321	13,374	12,210	13,782	12,459	11,843	14,309	12,589	11,654
Liquid Production									
Crude Oil and Lease Condensate	6,523	5,928	5,634	5,591	5,366	5,290	5,447	4,986	4,570
NGL	1,586	1,465	1,470	1,360	1,402	1,230	1,234	1,305	971
Subtotal	8,109	7,393	7,104	6,951	6,768	6,520	6,681	6,291	5,541
Syncrude	--	4	3	46	110	75	253	541	500
Total	8,109	7,397	7,107	6,997	6,878	6,595	6,934	6,832	6,041
Imports									
Crude and Unfinished Oils	5,781	7,240	6,112	7,710	6,464	5,750	8,050	6,338	5,475
NGL and Finished Products	1,857	2,102	1,954	2,138	2,086	1,630	2,267	2,103	1,721
Total	7,638	9,342	8,066	9,848	8,550	7,380	10,317	8,441	7,196
Receipts from PAD V									
Crude Oil, NGL, and Unfinished Oil	301	476	459	583	504	530	821	755	784
Finished Products	15	27	24	32	19	16	45	22	18
Total	316	503	483	615	523	546	866	777	802
Processing Gain	393	479	475	448	449	435	455	442	430
Total Supply	16,456	17,721	16,131	17,908	16,400	14,956	18,572	16,492	14,469
Less: Crude Oil and Product Exports	199	203	183	154	161	95	166	178	115
Crude Oil, NGL, and Unfinished Oil Shipments to PAD V	4	10	1	3	1	1	3	1	1
Finished Product Shipments to PAD V	155	132	103	120	103	90	124	99	85
Crude Losses	14	7	15	20	17	11	21	16	11
Total	372	352	302	297	282	197	314	294	212
Net Supply	16,084	17,369	15,829	17,611	16,118	14,759	18,258	16,198	14,257
Memo: Local Demand	16,215	17,319	15,793	17,596	16,080	14,806	18,240	16,180	14,249

*Projected data derived from the April 1979 and December 1979 NPC Surveys of U.S. and World Energy and Oil Supply/Demand Forecasts.

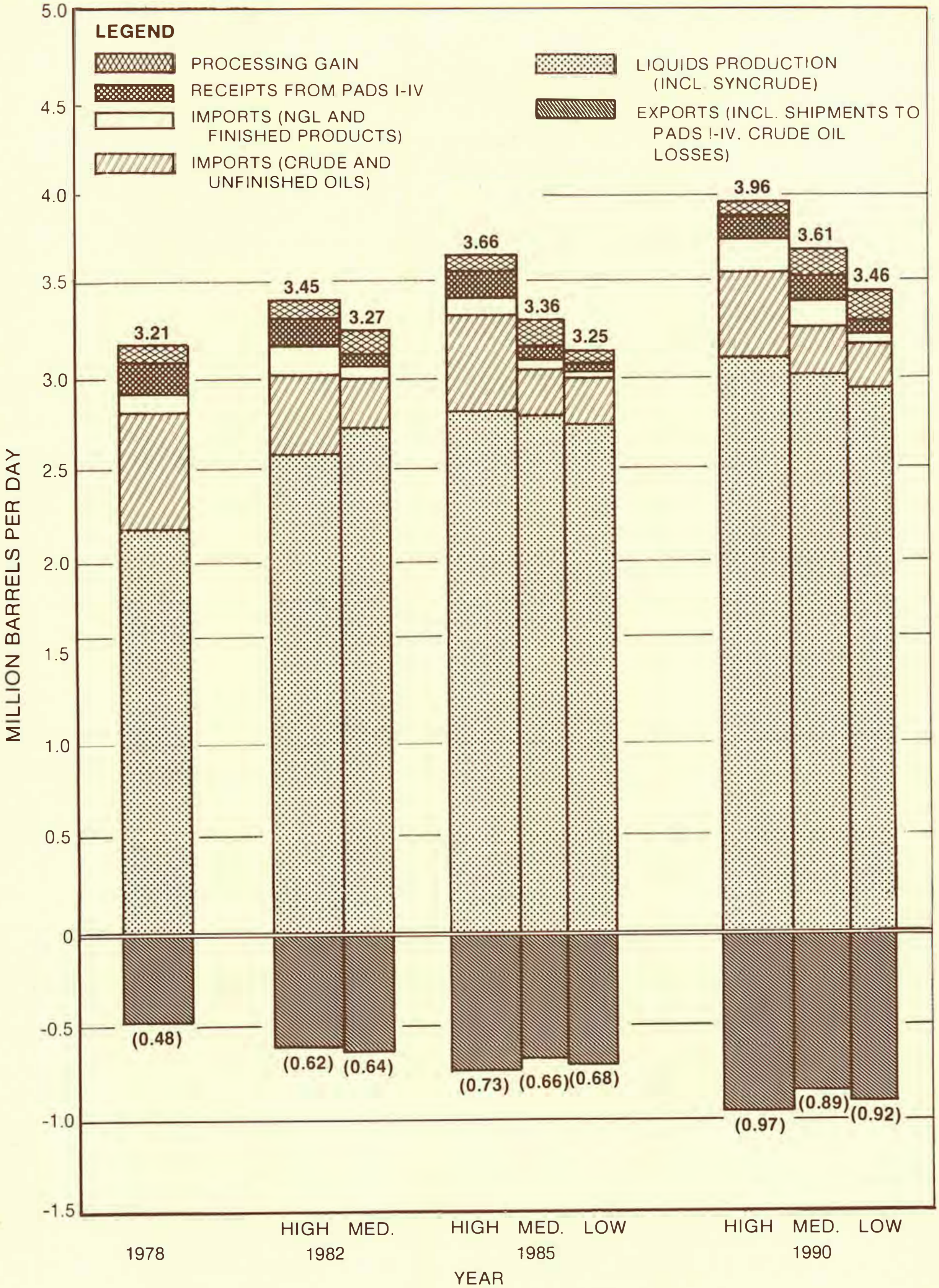

Figure 23. Regional Petroleum Supply—PAD V.

NOTE: Projected data derived from the April 1979 and December 1979 NPC Surveys of U.S. and World Energy and Oil Supply/Demand Forecasts.

The high case projects an increase of 0.75 MMB/D between 1978 and 1990, from 3.21 to 3.96 MMB/D. The medium case results indicate an increase of 0.4 MMB/D, to 3.61 MMB/D, and the low case indicates a modest increase of 0.25 MMB/D, to 3.46 MMB/D by 1990.

As shown in Table 22, the percentage of indigenous liquids production in the total petroleum supply of PAD V increases markedly between 1978 and 1990, as imports and receipts from PADs I-IV decline. The increase in the percentage contribution of PAD V liquids production is more pronounced in the medium and low case projections.

TABLE 22

Total Petroleum Supply -- PAD V
(Percentages)

		1990*		
	1978	High Case	Medium Case	Low Case
Liquids Production (Including Syncrude)	69.2	79.4	85.0	85.9
Imports	22.6	14.8	9.5	9.4
Receipts from PADs I-IV	5.0	3.2	2.8	2.5
Processing Gain	3.2	2.6	2.7	2.2
Total	100.0	100.0	100.0	100.0

*Projected data derived from the April 1979 and December 1979 NPC Surveys of U.S. and World Energy and Oil Supply/Demand Forecasts.

Additional data on the total petroleum supply of PAD V are presented in Table 23. The PAD V net petroleum supply is significantly and increasingly affected over the forecast period by the increase in shipments of petroleum from PAD V to PADs I-IV.

Regional Refinery Crude Oil Runs

The high case indicates that the refinery crude oil runs of PADs I-IV would increase about 2.0 MMB/D between 1978 and 1990, from 12.32 to 14.31 MMB/D (see Figure 24). The medium case projects that PADs I-IV crude oil runs would increase only slightly, to 12.59 MMB/D by 1990, remaining relatively level in the interim period. The low case shows crude oil runs in PADs I-IV declining to 11.65 MMB/D in 1990, a decrease of 0.67 MMB/D from 1978.

The high and medium cases project an increase in PAD V crude oil runs from 1978 to 1990 of 0.34 MMB/D and 0.2 MMB/D, respectively. Also, as shown in Figure 25, the low case projection

TABLE 23

Regional Petroleum Supply -- PAD V*
(MB/D)

	1978	1982 High Case	1982 Medium Case	1985 High Case	1985 Medium Case	1985 Low Case	1990 High Case	1990 Medium Case	1990 Low Case
Crude Oil Runs	2,334	2,530	2,448	2,631	2,509	2,390	2,670	2,533	2,375
Liquids Production									
Crude Oil and Lease Condensate	2,185	2,617	2,700	2,789	2,788	2,735	3,081	3,046	2,955
NGL	34	35	14	43	18	15	63	17	14
Subtotal	2,219	2,652	2,714	2,832	2,806	2,750	3,144	3,063	2,969
Syncrude	--	--	--	--	--	--	--	5	5
Total	2,219	2,652	2,714	2,832	2,806	2,750	3,144	3,068	2,974
Imports									
Crude and Unfinished Oils	602	426	311	471	292	270	442	261	250
NGL and Finished Products	123	122	65	127	78	70	146	81	74
Total	725	548	376	598	370	340	588	342	324
Receipts from PADs I-IV									
Crude Oil, NGL, and Unfinished Oil	4	10	1	3	1	1	3	1	1
Finished Products	155	132	103	120	103	90	124	99	85
Total	159	142	104	123	104	91	127	100	86
Processing Gain	103	106	71	109	84	80	102	99	80
Total Supply	3,206	3,448	3,265	3,662	3,364	3,261	3,961	3,609	3,464
Less: Crude Oil and Product Exports	163	109	151	107	133	130	93	110	110
Crude Oil, NGL, and Unfinished Oil Shipments to PADs I-IV	301	476	459	583	504	530	821	756	784
Finished Product Shipments to PADs I-IV	15	27	24	32	19	16	45	22	18
Crude Oil Losses	1	6	2	10	4	4	8	5	5
Total	480	618	636	732	660	680	967	893	917
Net Supply	2,726	2,830	2,629	2,930	2,704	2,581	2,994	2,716	2,547
Memo: Local Demand	2,631	2,829	2,626	2,925	2,702	2,569	2,991	2,717	2,546

*Projected data derived from the April 1979 and December 1979 NPC Surveys of U.S. and World Energy and Oil Supply/Demand Forecasts.

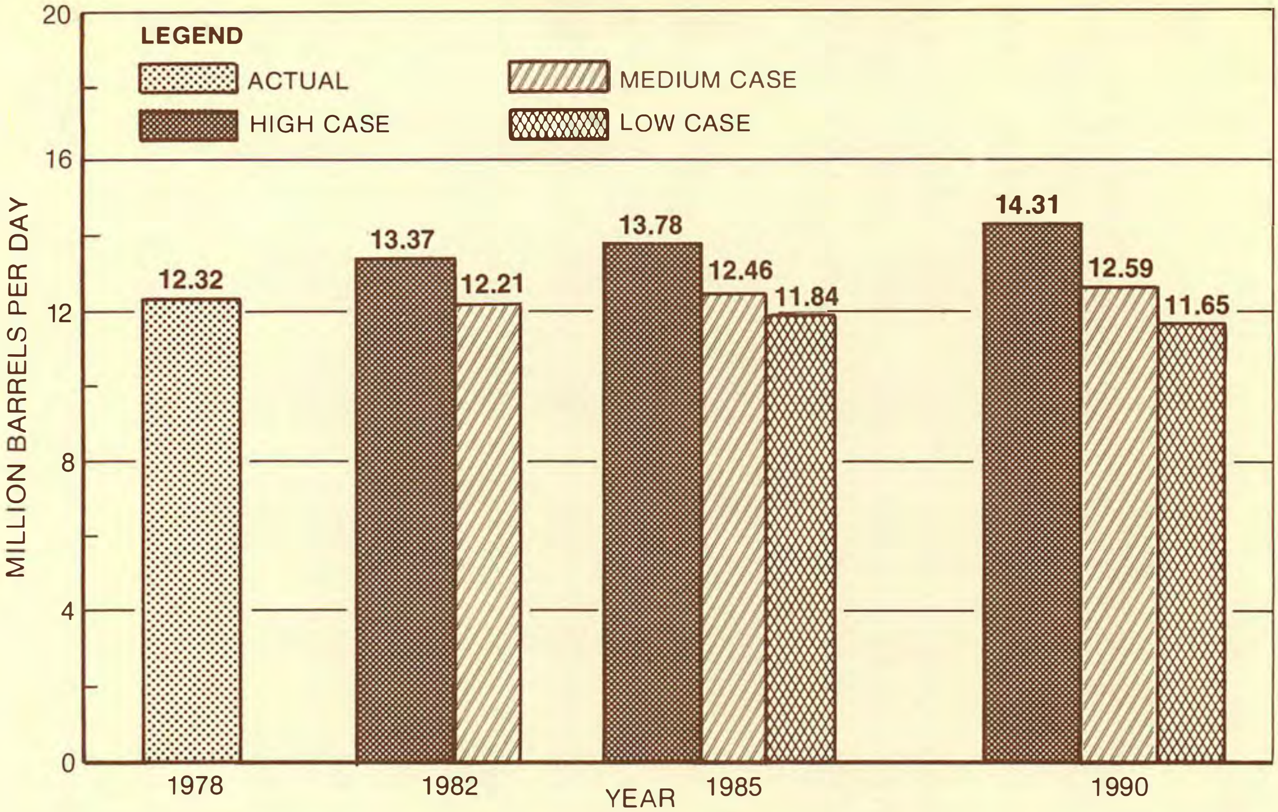

Figure 24. Regional Crude Oil Runs—PADs I-IV.

NOTE: Projected data derived from the April 1979 and December 1979 NPC Surveys of U.S. and World Energy and Oil Supply/Demand Forecasts.

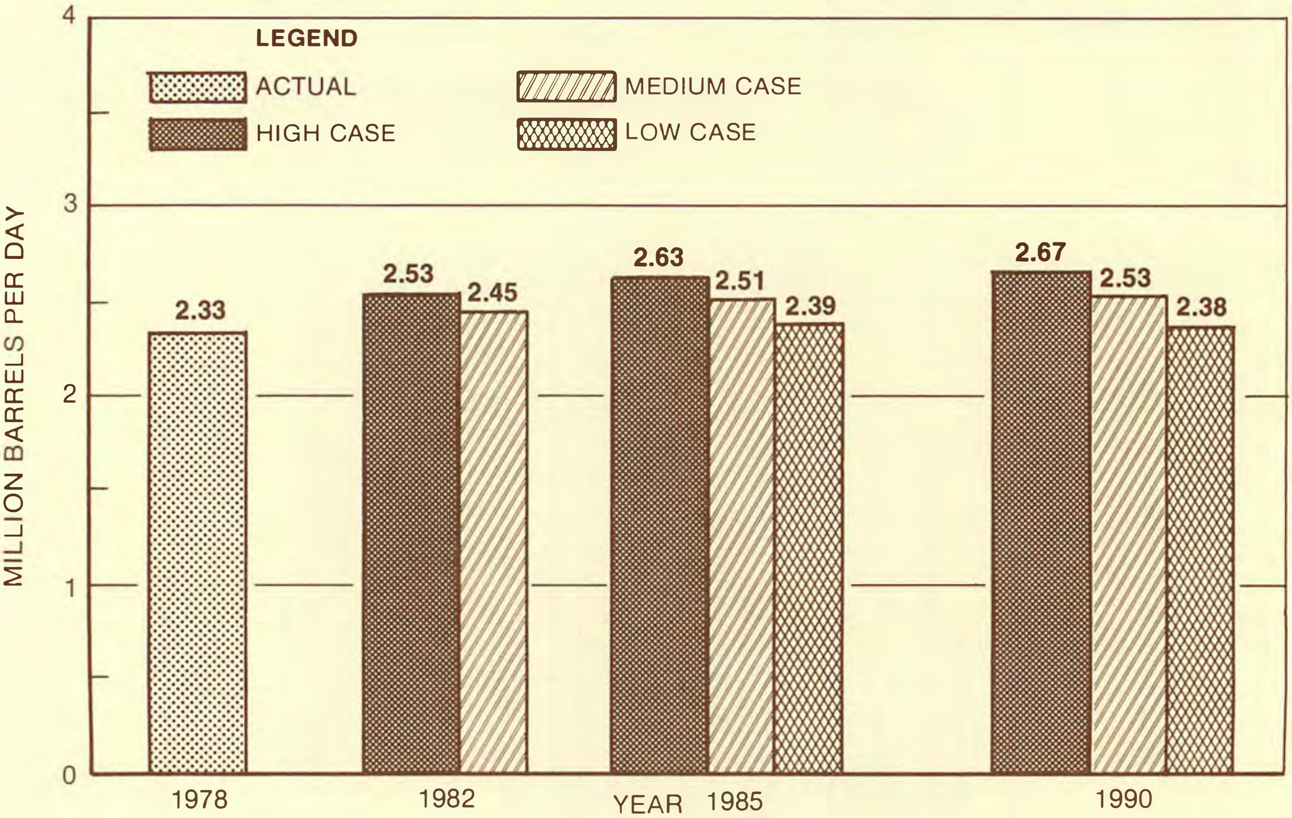

Figure 25. Regional Crude Oil Runs—PAD V.

NOTE: Projected data derived from the April 1979 and December 1979 NPC Surveys of U.S. and World Energy and Oil Supply/Demand Forecasts.

indicates that PAD V refinery crude oil runs will increase only slightly by 1990, approximately 50 MB/D.

Regional Petroleum Product Demand

The high, medium, and low case petroleum demand for PADs I-IV and PAD V are presented in Figure 26.

The high case projects that product demand in PADs I-IV will increase from 16.2 MMB/D in 1978 to 18.2 MMB/D by 1990, an average annual increase of about 1 percent. Product demand in PAD V is projected to increase from 2.6 to 3.0 MMB/D over the same period, also an average annual increase of about 1 percent.

The medium case indicates no growth in PADs I-IV product demand to 1990, and only a very modest growth in PAD V (0.3 percent per year), to 2.7 MMB/D in 1990, compared to 2.6 MMB/D in 1978.

The low case projects PADs I-IV product demand to decline to 14.3 MMB/D in 1990, a decrease of almost 2.0 MMB/D (12 percent) from 1978. PAD V product demand is indicated to decline only slightly over the same period, down from 2.63 MMB/D to 2.55 MMB/D.

In both the high and medium cases, the regional share of total U.S. petroleum demand remains constant over the 1978-1990 period, about 86 percent for the area east of the Rockies and 14 percent for the West Coast and Alaska and Hawaii. The low case projects the regional shares at 85 and 15 percent, respectively, in 1985 and 1990.

Table 24 summarizes PADs I-IV product demand changes between 1978 and 1990 for the three cases and also compares the medium and low case projections for PADs I-IV with those of the high case. Table 25 summarizes the same projections for PAD V.

Complete details of domestic product demand in PADs I-IV and PAD V for the years 1978, 1982, 1985, and 1990 as developed from high and medium cases are shown in Tables 26-33. Also presented are the low case projections for 1985 and 1990.

CRUDE OIL TYPES AND QUALITIES[2]

To determine potential future U.S. refining capacity and process hardware requirements it is necessary to consider not only the availability and demand for crude oil, but also the types and qualities of crude oil available to be run in U.S. refineries to meet projected product demand requirements.

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[2]Field condensate is classified as sweet crude oil for the purposes of this study.

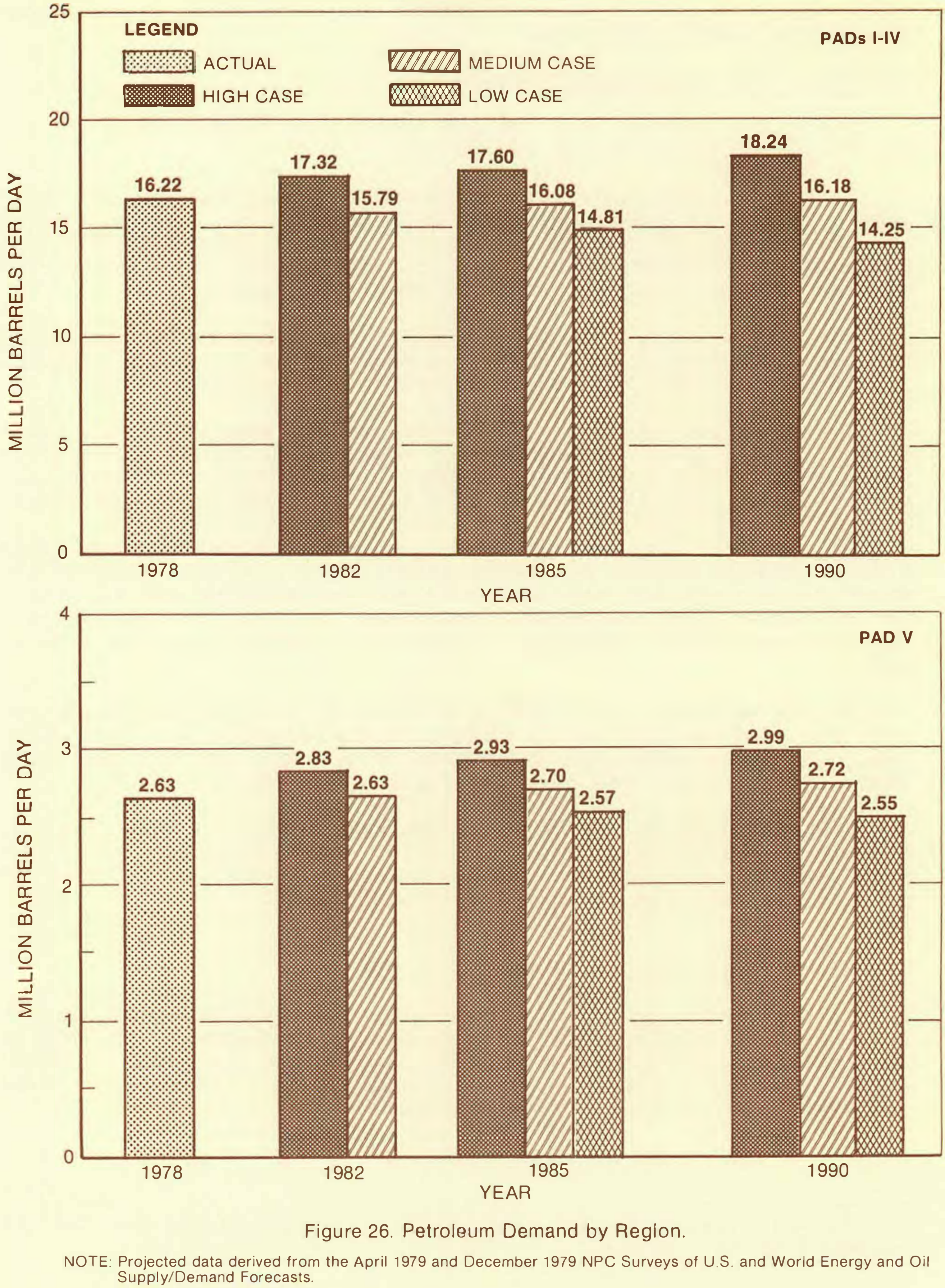

Figure 26. Petroleum Demand by Region.

NOTE: Projected data derived from the April 1979 and December 1979 NPC Surveys of U.S. and World Energy and Oil Supply/Demand Forecasts.

TABLE 24

Local Product Demand -- PADs I-IV*
(MMB/D)

	1978	1990			Increase (Decrease) 1990/1978			Difference From High Case (1990)	
		High Case	Medium Case	Low Case	High Case	Medium Case	Low Case	Medium Case	Low Case
Motor Gasoline									
Leaded	4.25	0.93	0.60	0.41	(3.32)	(3.65)	(3.84)	(0.33)	(0.52)
Unleaded	2.03	4.75	4.54	4.62	2.72	2.51	2.59	(0.21)	(0.13)
Total	6.28	5.68	5.14	5.03	(0.60)	(1.14)	(1.25)	(0.54)	(0.65)
Middle Distillates									
Jet Fuel (Kerosine)	0.61	0.90	0.84	0.63	0.29	0.23	0.02	(0.06)	(0.27)
Diesel-On Highway	0.68	1.56	1.44	0.89	0.88	0.76	0.21	(0.12)	(0.67)
No. 2 Fuel Oil	1.34	1.18	1.04	1.00	(0.16)	(0.30)	(0.34)	(0.14)	(0.18)
Other Distillates	1.22	1.51	1.32	1.28	0.29	0.10	0.06	(0.19)	(0.23)
Total	3.85	5.15	4.64	3.80	1.30	0.79	(0.05)	(0.51)	(1.35)
Residual Fuel Oil									
<1.0% Sulfur	1.21	1.56	0.88	0.53	0.35	(0.33)	(0.68)	(0.68)	(1.03)
>1.0% Sulfur	1.33	1.12	1.01	0.59	(0.21)	(0.32)	(0.74)	(0.11)	(0.53)
Total	2.54	2.68	1.89	1.12	0.14	(0.65)	(1.42)	(0.79)	(1.56)
LPG	1.36	1.68	1.72	1.60	0.32	0.36	0.24	0.04	(0.08)
Petrochemical Feedstocks	0.59	1.20	1.05	0.92	0.61	0.46	0.33	(0.15)	(0.28)
All Other Products	1.60	1.85	1.74	1.78	0.25	0.14	0.18	(0.11)	(0.07)
Total Local Product Demand	16.22	18.24	16.18	14.25	2.02	(0.04)	(1.97)	(2.06)	(3.99)

*Projected data derived from the April 1979 and December 1979 NPC Surveys of U.S. and World Energy and Oil Supply/Demand Forecasts.

TABLE 25

Local Product Demand -- PAD V*
(MMB/D)

	1978	1990			Increase (Decrease) 1990/1978			Difference From High Case (1990)	
		High Case	Medium Case	Low Case	High Case	Medium Case	Low Case	Medium Case	Low Case
Motor Gasoline									
Leaded	0.78	0.15	0.08	0.10	(0.63)	(0.70)	(0.68)	(0.07)	(0.05)
Unleaded	0.35	0.92	0.91	0.88	0.57	0.56	0.53	(0.01)	(0.04)
Total	1.13	1.07	0.99	0.98	(0.06)	(0.14)	(0.15)	(0.08)	(0.09)
Middle Distillates									
Jet Fuel (Kerosine)	0.25	0.40	0.36	0.36	0.15	0.11	0.11	(0.04)	(0.04)
Diesel-On Highway	0.12	0.26	0.29	0.26	0.14	0.17	0.14	0.03	--
Other Distillates	0.24	0.25	0.19	0.18	0.01	(0.05)	(0.06)	(0.06)	(0.07)
Total	0.61	0.91	0.84	0.80	0.30	0.23	0.19	(0.07)	(0.11)
Residual Fuel Oil									
<1.0% Sulfur	0.27	0.39	0.22	0.19	0.12	(0.05)	(0.08)	(0.15)	(0.20)
>1.0% Sulfur	0.22	0.16	0.23	0.14	(0.06)	0.01	(0.08)	0.06	(0.02)
Total	0.49	0.55	0.45	0.33	0.06	(0.04)	(0.16)	(0.09)	(0.22)
All Other Products	0.40	0.46	0.44	0.44	0.06	0.04	0.04	(0.02)	(0.02)
Total Local Product Demand	2.63	2.99	2.72	2.55	0.36	0.09	(0.08)	(0.26)	(0.44)

*Projected data derived from the April 1979 and December 1979 NPC Surveys of U.S. and World Energy and Oil Supply/Demand Forecasts.

TABLE 26

Domestic Demand for Products -- PADs I-IV
(MB/D)

	Actual*	High Case Projection†		
	1978	1982	1985	1990
Motor Gasoline: Leaded - Premium	656	117	13	0
- Non-premium	3,600	2,480	1,683	939
Subtotal	4,256	2,597	1,696	939
Unleaded - Premium	0	1,135	1,559	1,813
- Non-premium	2,026	2,672	2,785	2,932
Subtotal	2,026	3,807	4,344	4,745
Total Motor Gasoline	6,283	6,404	6,040	5,684
Aviation Gasoline	30	33	34	38
Jet Fuel: Naphtha Type	143	132	122	104
Kerosine Type	613	707	775	898
Total Jet Fuel	756	839	897	1,002
Special Naphtha	88	92	93	100
Kerosine & Heating Oil #1	194	213	192	188
Distillate Fuel Oil: #2 Oil	1,344	1,247	1,235	1,178
#4 Oil	58	63	67	71
Diesel - On-Highway	679	929	1,155	1,560
- Off-Highway	165	180	194	220
Other Distillate	801	969	987	1,031
Total Distillate Fuel Oil	3,047	3,388	3,638	4,060
Residual Fuel Oil: 0 - 0.5%S	641	688	727	703
0.51 - 1.0%S	672	803	836	854
1.1 - 2.0%S	426	518	524	513
2.0%S +	796	650	631	609
Total Residual Fuel Oil	2,535	2,659	2,718	2,679
Liquified Gases: Ethane	432	401	400	388
Propane	729	888	960	1,062
Butane	162	165	187	202
Propane/Butane Mix	31	19	21	24
Total Liquified Gases	1,355	1,473	1,568	1,676
Petrochemical Feedstocks: Still Gas	53	56	48	45
400 EP Naphtha	201	268	309	419
Other	331	427	534	738
Total Petrochemical Feedstocks	586	751	891	1,202
Lubricants	153	164	172	190
Waxes	14	16	17	20
Coke	215	228	234	250
Asphalt & Road Oil	401	419	436	467
Still Gas for Fuel	444	477	475	490
Miscellaneous Products	117	163	191	194
Total Domestic Demand for Products	16,216	17,319	17,596	18,240

*Total U.S. per Petroleum Statement, Annual, Final Summary, November 7, 1979. Detail for U.S. PAD districts per PAD District Supply/Disposition, Annual, December 29, 1979, adjusted to conform with Total U.S. Petroleum Statement, Annual, Final Summary figures.

†Projected data derived from the April 1979 NPC Survey of U.S. and World Energy and Oil Supply/Demand Forecasts. Components may not add to subtotals due to independent rounding.

TABLE 27

Domestic Demand for Products -- PADs I-IV*
(MB/D)

	Actual*	Medium Case Projection†		
	1978	1982	1985	1990
Motor Gasoline: Leaded - Premium	656	644	152	59
- Non-premium	3,600	1,468	1,172	543
Subtotal	4,256	2,112	1,324	602
Unleaded - Premium	0	88	1,135	1,391
- Non-premium	2,026	3,641	3,142	3,145
Subtotal	2,026	3,729	4,277	4,536
Total Motor Gasoline	6,283	5,841	5,601	5,138
Aviation Gasoline	30	34	36	40
Jet Fuel: Naphtha Type	143	137	122	107
Kerosine Type	613	672	735	838
Total Jet Fuel	756	809	857	945
Special Naphtha	88	87	92	99
Kerosine & Heating Oil #1	194	188	185	181
Distillate Fuel Oil: #2 Oil	1,344	1,172	1,135	1,043
#4 Oil	58	69	83	90
Diesel - On-Highway	679	811	1,065	1,440
- Off-Highway	165	173	189	224
Other Distillate	801	840	828	826
Total Distillate Fuel Oil	3,047	3,065	3,300	3,623
Residual Fuel Oil: 0 - 0.5%S	641	547	563	496
0.51 - 1.0%S	672	566	473	388
1.1 - 2.0%S	426	305	518	538
2.0%S +	796	695	555	470
Total Residual Fuel Oil	2,535	2,113	2,109	1,892
Liquified Gases: Ethane	432	436	389	372
Propane	729	845	976	1,074
Butane	162	188	204	229
Propane/Butane Mix	31	39	45	45
Total Liquified Gases	1,355	1,508	1,614	1,720
Petrochemical Feedstocks: Still Gas	53	51	69	67
400 EP Naphtha	201	242	299	380
Other	331	461	485	599
Total Petrochemical Feedstocks	586	754	853	1,046
Lubricants	153	164	171	189
Waxes	14	17	18	20
Coke	215	218	223	237
Asphalt & Road Oil	401	420	437	460
Still Gas for Fuel	444	440	447	450
Miscellaneous Products	117	135	137	140
Total Domestic Demand for Products	16,216	15,793	16,080	16,180

*Total U.S. per Petroleum Statement, Annual, Final Summary, November 7, 1979. Detail for U.S. PAD districts per PAD District Supply/Disposition, Annual, December 29, 1979, adjusted to conform with Total U.S. Petroleum Statement, Annual, Final Summary figures.

†Projected data derived from the December 1979 NPC Survey of U.S. and World Energy and Oil Supply/Demand Forecasts. Components may not add to subtotals due to independent rounding.

TABLE 28

Domestic Demand for Products -- PADs I-IV
(MB/D)

	Actual* 1978	Low Case Projection† 1982	1985	1990
Motor Gasoline: Leaded - Premium	656	NOT	0	0
- Non-premium	3,600	AVAILABLE	1,365	405
Subtotal	4,256		1,365	405
Unleaded - Premium	0		1,340	1,580
- Non-premium	2,026		2,785	3,040
Subtotal	2,026		4,125	4,620
Total Motor Gasoline	6,283		5,490	5,025
Aviation Gasoline	30		30	45
Jet Fuel: Naphtha Type	143		150	184
Kerosine Type	613		600	626
Total Jet Fuel	756		750	810
Special Náphtha	88		82	95
Kerosine & Heating Oil #1	194		143	135
Distillate Fuel Oil: #2 Oil	1,344		1,080	1,003
#4 Oil	58		63	63
Diesel - On-Highway	679		795	890
- Off-Highway	165		189	200
Other Distillate	801		872	885
Total Distillate Fuel Oil	3,047		2,999	3,041
Residual Fuel Oil: 0 - 0.5%S	641		310	245
0.51 - 1.0%S	672		412	289
1.1 - 2.0%S	426		214	120
2.0%S +	796		602	462
Total Residual Fuel Oil	2,535		1,538	1,116
Liquified Gases: Ethane	432		418	412
Propane	729		1,084	999
Butane	162		139	167
Propane/Butane Mix	31		47	42
Total Liquified Gases	1,355		1,688	1,620
Petrochemical Feedstocks: Still Gas	53		54	53
400 EP Naphtha	201		275	329
Other	331		455	533
Total Petrochemical Feedstocks	586		784	915
Lubricants	153		160	169
Waxes	14		17	17
Coke	215		215	210
Asphalt & Road Oil	401		455	470
Still Gas for Fuel	444		430	406
Miscellaneous Products	117		133	175
Total Domestic Demand for Products	16,216		14,806	14,249

*Total U.S. per Petroleum Statement, Annual, Final Summary, November 7, 1979. Detail for U.S. PAD districts per PAD District Supply/Disposition, Annual, December 29, 1979, adjusted to conform with Total U.S. Petroleum Statement, Annual, Final Summary figures.

†Projected data derived from the December 1979 NPC Survey of U.S. and World Energy and Oil Supply/Demand Forecasts. Components may not add to subtotals due to independent rounding.

TABLE 29

Domestic Demand for Products -- PAD V
(MB/D)

	Actual*	High Case Projection†		
	1978	1982	1985	1990
Motor Gasoline: Leaded - Premium	278	38	8	0
- Non-premium	506	388	267	150
Subtotal	784	426	275	150
Unleaded - Premium	184	206	323	422
- Non-premium	161	517	518	497
Subtotal	345	723	841	919
Total Motor Gasoline	1,129	1,149	1,116	1,069
Aviation Gasoline	9	10	11	11
Jet Fuel: Naphtha Type	56	52	49	36
Kerosine Type	245	294	327	400
Total Jet Fuel	301	346	376	436
Special Naphtha	15	11	12	13
Kerosine & Heating Oil #1	21	20	23	24
Distillate Fuel Oil: #2 Oil	41	45	44	41
#4 Oil	3	3	3	3
Diesel - On-Highway	118	161	197	262
- Off-Highway	26	26	27	31
Other Distillate	157	140	140	148
Total Distillate Fuel Oil	345	375	411	485
Residual Fuel Oil: 0 - 0.5%S	221	382	411	346
0.51 - 1.0%S	44	37	40	44
1.1 - 2.0%S	215	133	130	131
2.0%S +	8	29	28	25
Total Residual Fuel Oil	488	581	609	546
Liquified Gases: Ethane	1	2	2	2
Propane	49	54	56	62
Butane	5	5	7	8
Propane/Butane Mix	3	3	3	3
Total Liquified Gases	58	64	68	75
Petrochemical Feedstocks: Still Gas	2	2	2	2
400 EP Naphtha	3	5	10	17
Other	4	11	21	33
Total Petrochemical Feedstocks	9	18	33	52
Lubricants	19	17	18	20
Waxes	3	4	4	5
Coke	41	49	51	55
Asphalt & Road Oil	78	69	72	76
Still Gas for Fuel	104	104	108	110
Miscellaneous Products	11	12	13	14
Total Domestic Demand for Products	2,631	2,829	2,925	2,991

*Total U.S. per Petroleum Statement, Annual, Final Summary, November 7, 1979. Detail for U.S. PAD districts per PAD District Supply/Disposition, Annual, December 29, 1979, adjusted to conform with Total U.S. Petroleum Statement, Annual, Final Summary figures.

†Projected data derived from the April 1979 NPC Survey of U.S. and World Energy and Oil Supply/Demand Forecasts. Components may not add to subtotals due to independent rounding.

TABLE 30

Domestic Demand for Products -- PAD V
(MB/D)

	Actual*	Medium Case Projection†		
	1978	1982	1985	1990
Motor Gasoline: Leaded - Premium	278	35	7	0
- Non-premium	506	364	212	81
Subtotal	784	399	219	81
Unleaded - Premium	184	193	319	416
- Non-premium	161	486	511	489
Subtotal	345	679	830	905
Total Motor Gasoline	1,129	1,078	1,049	986
Aviation Gasoline	9	9	10	10
Jet Fuel: Naphtha Type	56	48	49	17
Kerosine Type	245	274	299	364
Total Jet Fuel	301	322	348	381
Special Naphtha	15	15	18	21
Kerosine & Heating Oil #1	21	20	21	22
Distillate Fuel Oil: #2 Oil	41	46	43	39
#4 Oil	3	3	2	3
Diesel - On-Highway	118	198	237	292
- Off-Highway	26	25	26	32
Other Distillate	157	95	86	84
Total Distillate Fuel Oil	345	367	394	450
Residual Fuel Oil: 0 - 0.5%S	221	214	270	200
0.51 - 1.0%S	44	30	25	20
1.1 - 2.0%S	215	223	202	218
2.0%S +	8	20	20	15
Total Residual Fuel Oil	488	487	517	453
Liquified Gases: Ethane	1	2	2	2
Propane	49	52	54	61
Butane	5	5	7	8
Propane/Butane Mix	3	3	3	3
Total Liquified Gases	58	62	66	74
Petrochemical Feedstocks: Still Gas	2	2	1	2
400 EP Naphtha	3	3	5	12
Other	4	9	10	24
Total Petrochemical Feedstocks	9	14	16	38
Lubricants	19	18	21	23
Waxes	3	3	3	3
Coke	41	48	51	52
Asphalt & Road Oil	78	69	74	79
Still Gas for Fuel	104	95	94	108
Miscellaneous Products	11	19	20	17
Total Domestic Demand for Products	2,631	2,626	2,702	2,717

*Total U.S. per Petroleum Statement, Annual, Final Summary, November 7, 1979. Detail for U.S. PAD districts per PAD District Supply/Disposition, Annual, December 29, 1979, adjusted to conform with Total U.S. Petroleum Statement, Annual, Final Summary figures.

†Projected data derived from the December 1979 NPC Survey of U.S. and World Energy and Oil Supply/Demand Forecasts. Components may not add to subtotals due to independent rounding.

TABLE 31

Domestic Demand for Products -- PAD V
(MB/D)

	Actual*	Low Case Projection†		
	1978	1982	1985	1990
Motor Gasoline: Leaded - Premium	278	NOT	0	0
- Non-premium	506	AVAILABLE	235	95
Subtotal	784		235	95
Unleaded - Premium	184		360	420
- Non-premium	161		415	460
Subtotal	345		775	880
Total Motor Gasoline	1,129		1,010	975
Aviation Gasoline	9		10	10
Jet Fuel: Naphtha Type	56		50	31
Kerosine Type	245		300	359
Total Jet Fuel	301		350	390
Special Naphtha	15		18	20
Kerosine & Heating Oil #1	21		20	20
Distillate Fuel Oil: #2 Oil	41		40	37
#4 Oil	3		2	2
Diesel - On-Highway	118		205	260
- Off-Highway	26		26	30
Other Distillate	157		90	90
Total Distillate Fuel Oil	345		363	419
Residual Fuel Oil: 0 - 0.5%S	221		245	165
0.51 - 1.0%S	44		28	21
1.1 - 2.0%S	215		166	130
2.0%S +	8		23	18
Total Residual Fuel Oil	488		462	334
Liquified Gases: Ethane	1		2	3
Propane	49		54	66
Butane	5		6	8
Propane/Butane Mix	3		3	3
Total Liquified Gases	58		65	80
Petrochemical Feedstocks: Still Gas	2		1	2
400 EP Naphtha	3		5	11
Other	4		10	22
Total Petrochemical Feedstocks	9		16	35
Lubricants	19		20	21
Waxes	3		3	3
Coke	41		50	50
Asphalt & Road Oil	78		75	80
Still Gas for Fuel	104		90	94
Miscellaneous Products	11		17	15
Total Domestic Demand for Products	2,631		2,569	2,546

*Total U.S. per Petroleum Statement, Annual, Final Summary, November 7, 1979. Detail for U.S. PAD districts per PAD District Supply/Disposition, Annual, December 29, 1979, adjusted to conform with Total U.S. Petroleum Statement, Annual, Final Summary figures.

†Projected data derived from the December 1979 NPC Survey of U.S. and World Energy and Oil Supply/Demand Forecasts. Components may not add to subtotals due to independent rounding.

TABLE 32

Regional Demand for Liquified Petroleum Gases for Chemical Uses
(MB/D)

	PADs I-IV				PAD V			
	Actual	Projection			Actual	Projection		
	1978	1982	1985	1990	1978	1982	1985	1990
High Case								
Ethane	432	387	369	336	1	2	2	1
Propane	81	168	208	248	4	8	9	11
Butane	133	102	103	107	3	1	2	2
Propane/Butane Mix	10	3	3	4	1	1	1	1
Total	656	660	683	695	9	12	14	15
Medium Case								
Ethane	432	435	379	331	1	2	2	1
Propane	81	129	203	291	4	7	10	13
Butane	133	148	168	188	3	2	2	2
Propane/Butane Mix	10	9	10	11	1	1	1	1
Total	656	721	760	821	9	12	15	17
Low Case								
Ethane	432	NA	408	354	1	NA	2	1
Propane	81	NA	200	263	4	NA	10	12
Butane	133	NA	118	143	3	NA	2	2
Propane/Butane Mix	10	NA	10	10	1	NA	1	1
Total	656	NA	736	770	9	NA	15	16

TABLE 33

PADs I-IV and PAD V BTX* Demand -- 1978-1990
(MB/D)

	Actual 1978		Projection 1982		Projection 1985		Projection 1990	
	PADs I-IV	PAD V	PADs I-IV	PAD V	PADs I-IV	PAD V	PADs I-IV	PAD V
High Case								
Other Petrochemical Feedstocks	331	4	427	11	534	21	738	33
BTX	178	1	186	6	187	10	189	16
Medium Case								
Other Petrochemical Feedstocks	331	4	461	9	485	10	599	24
BTX	178	1	207	5	211	7	214	11
Low Case								
Other Petrochemical Feedstocks	331	4	NA	NA	455	10	533	22
BTX	178	1	NA	NA	184	6	185	11

*BTX - Benzene, toluene, and xylene.

It is difficult, if not impossible, to precisely quantify the types and qualities of crude oil which will be run in U.S. refineries in the future. The following factors contribute to this difficulty:

- The large number of different crude oils (both domestic and foreign) accessible to and used by U.S. refiners, and the uncertainty of their availability over the long term
- The uncertain size and availability of recently discovered and developing crude oil reserves
- The lack of data on the volume and crude oil types and qualities of oil yet to be discovered and developed in the period before 1990.

In view of this difficulty and uncertainty it was determined that the presentation of a potential range of crude oil types and qualities available to U.S. refineries would contribute to the analysis of future refining hardware requirements in a more meaningful way than would an attempt to develop a precise quantification of future crude oil types and qualities.

It was important at the outset to define the crude oil types and qualities which would be most useful to the analysis and which could be developed with reasonable accuracy from available information sources. The five crude oil types and qualities used in the analysis follow:[3]

- Sweet Crude Oil -- Under 0.5 wt % sulfur
- Medium-Sulfur -- Between 0.5 and 1.0 wt % sulfur
  - Light Medium -- 15 percent or less residuum assay @ 1050°F
  - Heavy Medium -- Greater than 15 percent residuum assay @ 1050°F
- High-Sulfur -- In excess of 1.0 wt % sulfur
  - Light High -- 15 percent or less residuum assay @ 1050°F
  - Heavy High -- Greater than 15 percent residuum assay @ 1050°F.

<u>Analysis of Recent Trends in Sweet vs. Sour Crude Oil Runs in U.S. Refineries: 1969-1978</u>

The following information sources were utilized in this analysis:

- U.S. Department of Energy report dated December 1977, entitled <u>Trends in Desulfurization Capabilities, Processing Technologies, and the Availability of Crude Oils</u>
- National Petroleum Refiners Association reports dated May 17, 1973, and March 15, 1978, entitled <u>Capability of U.S. Refineries to Process Sweet/Sour Crude Oil</u>
- National Petroleum Council report dated December 1979, entitled <u>Refinery Flexibility, An Interim Report</u>, Volumes I & II. <u>(Specifically, Appendix C, Crude Oil</u> and Other Feedstock Slates.)

Figure 27 illustrates the proportion of domestic and foreign sweet/sour crude oil available to and run in U.S. refineries during the 1969-1978 period. From 1969 to 1978, sweet crude oils available to U.S. refineries increased from about 6.9 MMB/D to 8.2 MMB/D, and sour crude oils available to U.S. refineries increased from 3.8 MMB/D to 6.9 MMB/D. During this same period, the proportion of sweet crude oils to total available crude oils decreased from 64.5 percent to 54.5 percent, while, conversely, the proportion of sour crude oils increased from 35.5 percent to 45.5 percent. In 1969, foreign crude oil imports totalled only about 1.5 MMB/D (53.3 percent sweet and 46.7 percent sour) vs. 9.2 MMB/D (66.3 percent sweet and 33.7 percent sour) from domestic sources.

[3]These categories are the same as those used in the January 1979 NPC Survey of U.S. Petroleum Refining Capabilities.

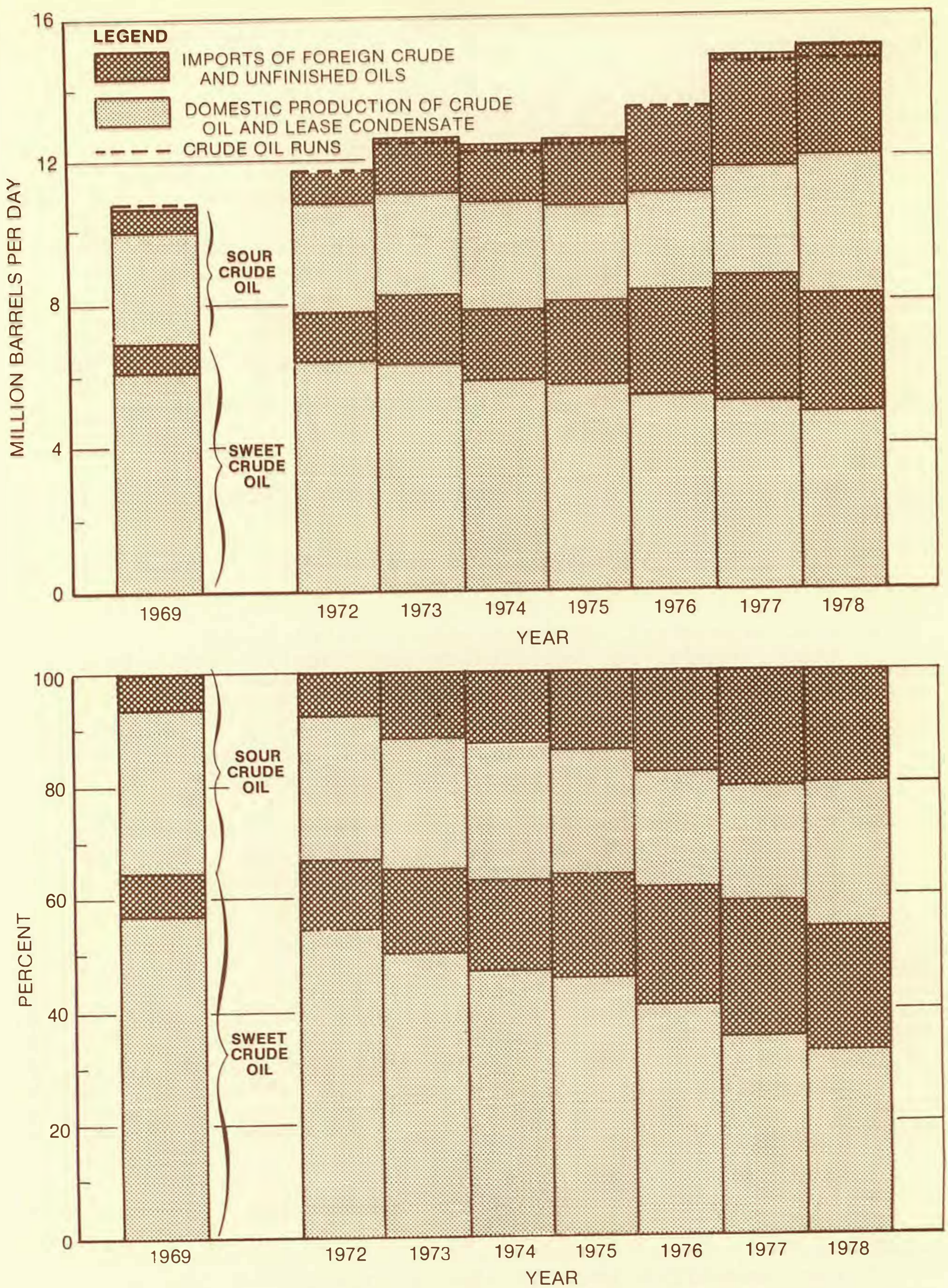

Figure 27. Sweet/Sour Crude Oil Runs in U.S. Refineries—1969-1978.

By 1978, foreign crude oil imports had increased to 6.4 MMB/D (51.6 percent sweet and 48.4 percent sour) compared to 8.7 MMB/D (56.3 percent sweet and 43.7 percent sour) from domestic sources. Thus, the percentage of foreign crude oil imports to total crude oil processed by U.S. refiners increased from about 14 percent in 1969 to 42.5 percent in 1978. Table 34 summarizes the amounts of sweet/sour crude oil available to U.S. refineries in 1969 and 1978 from both domestic and foreign sources.

TABLE 34

Sweet/Sour Crude Oils Available to U.S. Refiners -- 1969 and 1978

	1969		1978	
	MMB/D	%	MMB/D	%
Domestic				
Sweet	6.1	57.0	4.9	32.5
Sour	3.1	29.0	3.8	25.0
Subtotal	9.2	86.0	8.7	57.5
Foreign				
Sweet	0.8	7.5	3.3	22.0
Sour	0.7	6.5	3.1	20.5
Subtotal	1.5	14.0	6.4	42.5
Total				
Sweet	6.9	64.5	8.2	54.5
Sour	3.8	35.5	6.9	45.5
Total	10.7	100.0	15.1	100.0

Figure 28 presents the proportions of domestic and foreign sweet/sour crude oils available to PADs I-IV refineries from 1969 to 1978. During the 1969-1978 period, total sweet crude oils run by PADs I-IV refineries increased from 6.5 MMB/D to 7.6 MMB/D, and total sour crude oils run increased from 2.6 MMB/D to 4.7 MMB/D. The percentage of sweet crude oils to total crude oils available to PADs I-IV refineries declined from about 71.5 percent to 62.0 percent over this period, as the proportion of sour crude oil increased from 28.5 percent to 38.0 percent. In 1969, domestic crude oil runs totalled 8.0 MMB/D (73.8 percent sweet and 26.2 percent sour) while foreign crude oil imports accounted for only 1.1 MMB/D (54.5 percent sweet and 45.5 percent sour) of PADs I-IV total crude oil runs. By 1978, foreign crude oil imports had increased to 5.8 MMB/D (about 50/50 sweet/sour) while domestic crude oil runs declined to 6.5 MMB/D (72.3 percent sweet and 27.7 percent sour). Thus, the percentage of foreign crude oil imports of total crude oil available to PADs I-IV refineries increased from about 12 percent in 1969 to 47 percent in 1978. Table 35 summarizes the changes in the types of crude oils run in PADs I-IV refineries from domestic and foreign sources from 1969 to 1978.

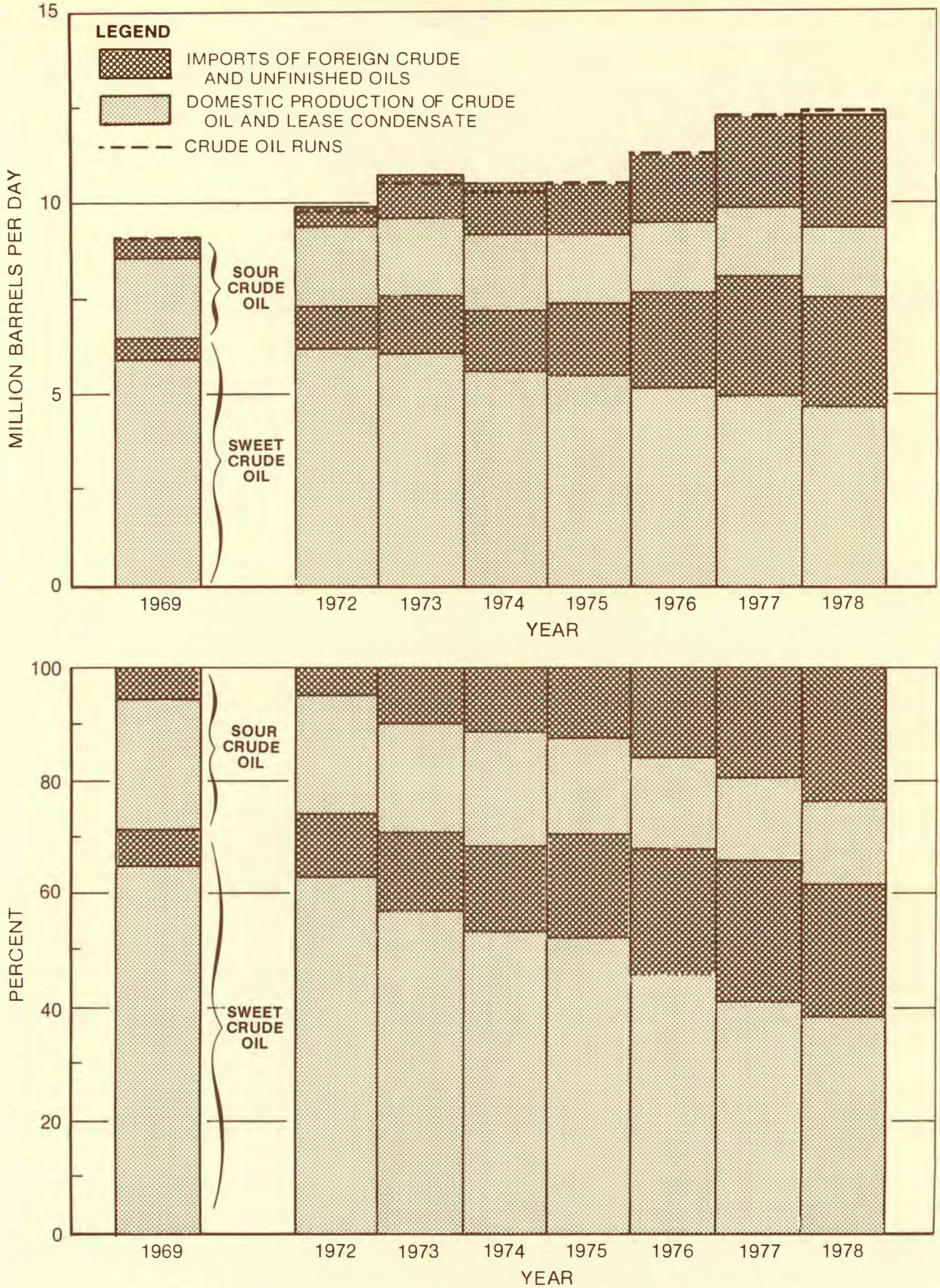

Figure 28. Sweet/Sour Crude Oil Runs in PADs I-IV Refineries—1969-1978.

TABLE 35

Sweet/Sour Crude Oil Runs in PADs I-IV -- 1969 and 1978

	1969		1978	
	MMB/D	%	MMB/D	%
Domestic				
Sweet	5.9	65.0	4.7	38.5
Sour	2.1	23.0	1.8	14.5
Subtotal	8.0	88.0	6.5	53.0
Foreign				
Sweet	0.6	6.5	2.9	23.5
Sour	0.5	5.5	2.9	23.5
Subtotal	1.1	12.0	5.8	47.0
Total				
Sweet	6.5	71.5	7.6	62.0
Sour	2.6	28.5	4.7	38.0
Total	9.1	100.0	12.3	100.0

Figure 29 illustrates the proportions of sweet/sour crude oils available to PAD V refineries from domestic and foreign sources in 1969 and 1978. Total crude oil available to PAD V refineries (after allowing for shipments to PADs I-IV) totalled 1.6 MMB/D in 1969, increasing to 2.8 MMB/D in 1978. Of these amounts, domestic sour crude oil accounted for 1.0 MMB/D in 1969 (62.5 percent of total crude oil runs), doubling to 2.0 MMB/D in 1978 (71.5 percent of total crude oil runs) with the introduction of Alaskan North Slope crude oil into U.S. supplies during that year. Foreign sour crude oil imports remained relatively level over the period at 0.2 MMB/D. Thus, total sour crude oil available to PAD V refineries accounted for about 75 percent of total crude oil runs in 1969, increasing to 78.5 percent in 1978. Table 36 summarizes the changes in the types of crude oils run in PAD V refineries from domestic and foreign sources from 1969 to 1978.

Projections of Crude Oil Availability by Type and Quality

1978, 1980, and 1982

The following data are drawn from the results of the January 1979 NPC Survey of Petroleum Refining Capabilities, which sought specific information on the crude oil types and qualities run or expected to be run in the years 1978, 1980, and 1982.

The NPC survey results for the year 1978 were compared with the National Petroleum Refiners Association report, Capability of U.S. Refineries to Process Sweet/Sour Crude Oil, dated March 15, 1978.

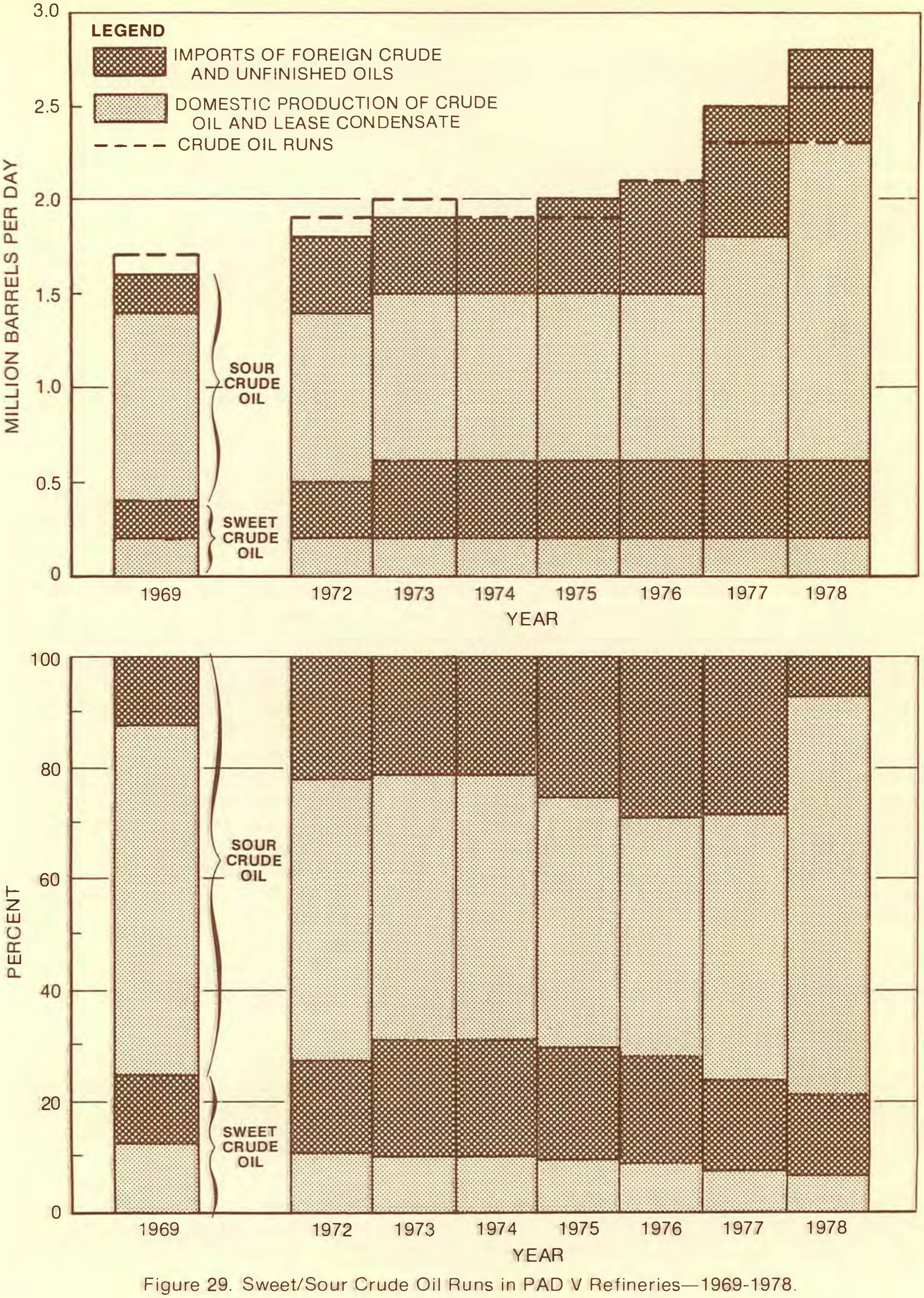

Figure 29. Sweet/Sour Crude Oil Runs in PAD V Refineries—1969-1978.

TABLE 36

Sweet/Sour Crude Oil Runs in PAD V -- 1969 and 1978

	1969		1978	
	MMB/D	%	MMB/D	%
Domestic				
Sweet	0.2	12.5	0.2	7.0
Sour	1.0	62.5	2.0	71.5
Subtotal	1.2	75.0	2.2	78.5
Foreign				
Sweet	0.2	12.5	0.4	14.5
Sour	0.2	12.5	0.2	7.0
Subtotal	0.4	25.0	0.6	21.5
Total				
Sweet	0.4	25.0	0.6	21.5
Sour	1.2	75.0	2.2	78.5
Total	1.6	100.0	2.8	100.0

The results of this comparison are briefly summarized in Table 37. While the comparison served to confirm substantially the sweet/sour crude oil mix reported for 1978, differences in crude oil type and quality definitions between the two surveys rendered the comparison impractical for confirming specific sour crude oil type and quality data obtained from the NPC survey.

Although there are some relatively minor differences in total petroleum supply levels between the two independent surveys, the percentage relationships are very close. Such small differences as do exist in percentage relationships between the two surveys may be due in part to the difference in distribution dates. It was concluded that the comparison essentially confirms the results of both independent surveys and, therefore, the results of the NPC survey for 1978 are considered reasonable.

Table 38 summarizes the results of the NPC survey for the years 1978, 1980, and 1982, and divides the total sour crude oil volumes into the medium- and high-sulfur and light and heavy crude oil categories as previously defined.

1985 and 1990

In order to provide a range of future crude oil supply qualities available to U.S. refineries in 1985 and 1990 (assuming no major long-term or permanent supply disruptions), two crude oil quality supply slates were developed.

Crude oil slate A reflects a projection of the historical trend of U.S. crude oil quality supply (domestic and foreign) for the

TABLE 37

Comparison of NPRA and NPC Survey Data* on 1978 Sweet/Sour Crude Oil Mix†

	NPC Survey						NPRA Survey					
	PADs I-IV		PAD V		Total U.S.		PADs I-IV		PAD V		Total U.S.	
	MMB/D	%	MMB/D	%	MMB/D	%	MMB/D	%	MMB/D	%	MMB/D	%
Domestic												
Sweet	4.52§	36.7	0.25	10.7	4.76§	32.5	4.67	37.3	0.16	6.5	4.83	32.2
Sour	2.14	17.4	1.53	65.2	3.67	25.0	2.34	18.7	1.49	60.0	3.83	25.5
Subtotal	6.66	54.0	1.77	75.9	8.43	57.5	7.00	55.9	1.66	66.9	8.66	57.7
Foreign												
Sweet	2.71	22.0	0.50	21.5	3.21	21.9	2.71	21.6	0.55	22.2	3.26	21.7
Sour	2.96	24.0	0.06	2.6	3.02	20.6	2.82	22.5	0.27	10.9	3.09	20.6
Subtotal	5.67	46.0	0.56	24.1	6.23	42.5	5.53	44.1	0.82	33.1	6.35	42.3
Total												
Sweet	7.23	58.7	0.75	32.2	7.97	54.4	7.39	59.0	0.71	28.6	8.10	54.0
Sour	5.10	41.4	1.59	67.8	6.69	45.6	5.16	41.2	1.76	71.4	6.92	46.0
Total	12.32	100.0	2.33	100.0	14.66	100.0	12.53	100.0	2.48	100.0	15.01	100.0

*National Petroleum Refiners Association report, entitled Capability of U.S. Refineries to Process Sweet/Sour Crude Oil, March 15, 1978; National Petroleum Council Survey of Petroleum Refining Capabilities, January 1979.

†Components may not sum to totals due to rounding.

§Includes field condensate.

TABLE 38

January 1979 National Petroleum Council Survey Results*
Crude Oil Types and Qualities -- 1978, 1980, and 1982
(MB/D)

	1978						1980						1982					
	PADs I-IV		PAD V		Total U.S.		PADs I-IV		PAD V		Total U.S.		PADs I-IV		PAD V		Total U.S.	
	MB/D	%	MB/D	%	MB/D	%	MB/D	%	MB/D	%	MB/D	%	MB/D	%	MB/D	%	MB/D	%
Sweet Crude Oil	7,139	57.9	744	31.9	7,883	53.8	7,338	55.4	666	25.5	8,004	50.5	7,404	53.0	687	24.9	8,091	48.3
Medium-Sulfur Crude Oil																		
Light Medium-Sulfur	698	5.7	136	5.8	834	5.7	657	5.0	181	6.9	838	5.3	718	5.1	219	7.9	937	5.6
Heavy Medium-Sulfur	342	2.8	822	35.2	1,164	7.9	382	2.9	1,000	38.3	1,382	8.7	446	3.2	1,016	36.9	1,462	8.7
High-Sulfur Crude Oil																		
Light High-Sulfur	2,438	19.8	53	2.3	2,491	17.0	3,151	23.8	41	1.6	3,192	20.1	3,531	25.3	41	1.5	3,572	21.3
Heavy High-Sulfur	1,617	13.1	579	24.8	2,196	15.0	1,611	12.2	720	27.6	2,331	14.7	1,766	12.6	802	29.1	2,568	15.3
Subtotal	12,234	99.3	2,334	100.0	14,568	99.4	13,139	99.1	2,608	100.0	15,747	99.3	13,865	99.2	2,765	100.0	16,630	99.3
Field Condensate	87	0.7	(Nil)	--	87	0.6	115	0.9	(Nil)	--	115	0.7	110	0.8	(Nil)	--	110	0.7
Total	12,321	100.0	2,334	100.0	14,655	100.0	13,254	100.0	2,608	100.3	15,862	100.0	13,975	100.0	2,765	100.0	16,740	100.0
Memo: Other Feedstocks†	1,179		195		1,374		1,136		184		1,320		1,067		177		1,244	

*National Petroleum Council Survey of Petroleum Refining Capabilities, January 1979.
†Includes field natural gasoline, butanes, and other blendstocks and feedstocks.

five crude oil types defined earlier for PADs I-IV and PAD V separately. The percentage of the five crude oil types was held constant in the 1985 and 1990 projections, except that the likely continued decline in PADs I-IV sweet crude oil production was recognized. This decline is due to the requirement for sizeable amounts of "new" oil to meet projected product demands and refinery crude oil run levels, while neither the source nor the quality of the "new" oil can be predicted. Table 39 summarizes the percentage proportion of the five crude oil types developed for PADs I-IV and PAD V in crude oil slate A for the years 1985 and 1990.

TABLE 39

Percentages* of Crude Oil Types and Qualities
Available to U.S. Refineries -- Slate A

	PADs I-IV		PAD V
	1985	1990	1985 & 1990
Sweet Crude Oil	51.0	49.0	24.5
Medium-Sulfur Crude Oil			
Light Medium-Sulfur	5.0	5.0	8.0
Heavy Medium-Sulfur	3.5	3.5	37.0
High-Sulfur Crude Oil			
Light High-Sulfur	26.0	27.0	1.5
Heavy High-Sulfur	13.5	14.5	29.0
Field Condensate	1.0	1.0	Nil
Total	100.0	100.0	100.0

*These percentages have been rounded and vary slightly from the specific percentages used in the detailed tables presented in the following section. The specific percentages recognize the different refinery crude oil run levels and varying domestic/foreign crude oil mix inherent in the three cases.

Crude oil slate B adjusted the historical trend as developed in crude oil slate A for likely or significant possible crude oil quality supply developments to 1990. The major adjustments included allowances for higher volumes of domestic heavy, high-sulfur crude oil and Alaskan North Slope crude oil than projected by the supply/demand surveys, introduction of syncrude from shale and coal into U.S. crude oil supplies, and larger volumes of heavier and higher sulfur foreign crude oil supplies as major foreign crude oil producers move to produce their different crude oil types and qualities in proportion to their reserves. Table 40 summarizes the

TABLE 40

Percentages* of Crude Oil Types and Qualities
Available to U.S. Refineries -- Slate B

	PADs I-IV		PAD V	
	1985	1990	1985	1990
Sweet Crude Oil	48.0	44.0	21	19
Medium-Sulfur Crude Oil				
Light Medium-Sulfur	4.0	3.5	9	9
Heavy Medium-Sulfur	4.5	4.0	35	35
High-Sulfur Crude Oil				
Light High-Sulfur	28.0	32.5	2	2
Heavy High-Sulfur	14.5	15.0	33	35
Field Condensate	1.0	1.0	Nil	Nil
Total	100.0	100.0	100.0	100.0

*These percentages have been rounded and vary slightly from the specific percentages used in the detailed tables presented in the following section. The specific percentages recognize the different refinery crude oil run levels and varying domestic/foreign crude oil mix inherent in the three cases.

percentage proportion of the five crude oil types plus field condensate developed for PADs I-IV and PAD V in crude oil slate B for the years 1985 and 1990.

Data on the crude oil runs and crude oil types and qualities for PADs I-IV, PAD V, and the total United States to 1990 are shown in Tables 41-52.[4] It should be emphasized that the crude oil quality data were developed for use in determining future U.S. refinery capacity and process hardware requirements to 1990, which are presented in Chapter Two. The two crude oil quality slates delineated above are believed to present a reasonable range of future crude oil supply qualities available to U.S. refineries to 1990, assuming no major long-term or permanent supply disruption. The methodology followed to develop crude oil slate A may tend to overstate somewhat the proportion of sweet crude oil in the total U.S. crude oil supply by 1990, and conversely, crude oil slate B may tend to understate somewhat the proportion of sweet crude oil available to U.S. refiners by 1990. It is believed that the actual future supply lies within the range presented.

[4]The 1982 low case is presented for total U.S. only (Table 50).

TABLE 41

Actual Refinery Crude Oil Runs and Crude Oil Supply Quality -- 1978*

	PADs I-IV		PAD V		Total U.S.	
	MB/D	%	MB/D	%	MB/D	%
Refinery Crude Oil Runs	12,321	--	2,334	--	14,655	--
Crude Oil Supply						
Domestic						
Sweet Crude Oil	4,426	66.5	245	13.8	4,671	55.4
Medium-Sulfur Crude Oil						
Light Medium-Sulfur	286	4.3	125	7.0	411	4.9
Heavy Medium-Sulfur	144	2.2	810	45.7	954	11.3
High-Sulfur Crude Oil						
Light High-Sulfur	852	12.8	24	1.4	876	10.5
Heavy High-Sulfur	858	12.9	569	32.1	1,427	16.9
Field Condensate	87	1.3	--	--	87	1.0
Total Domestic	6,653	100.0	1,773	100.0	8,426	100.0
Foreign						
Sweet Crude Oil	2,713	47.9	499	89.1	3,212	51.6
Medium-Sulfur Crude Oil						
Light Medium-Sulfur	412	7.3	11	1.9	423	6.8
Heavy Medium-Sulfur	198	3.4	12	2.0	210	3.4
High-Sulfur Crude Oil						
Light High-Sulfur	1,586	28.0	29	5.2	1,615	25.9
Heavy High-Sulfur	759	13.4	10	1.8	769	12.3
Field Condensate	--	--	--	--	--	--
Total Foreign	5,668	100.0	561	100.0	6,229	100.0
Domestic and Foreign						
Sweet Crude Oil	7,139	57.8	744	31.9	7,883	53.8
Medium-Sulfur Crude Oil						
Light Medium-Sulfur	698	5.7	136	5.8	834	5.7
Heavy Medium-Sulfur	342	2.8	822	35.2	1,164	7.9
High-Sulfur Crude Oil						
Light High-Sulfur	2,438	19.9	53	2.3	2,491	17.0
Heavy High-Sulfur	1,617	13.1	579	24.8	2,196	15.0
Field Condensate	87	0.7	--	--	87	0.6
Total Crude Oil Supply	12,321	100.0	2,334	100.0	14,655	100.0

*Data derived from the January 1979 NPC Survey of Petroleum Refining Capabilities.

TABLE 42

Projected Refinery Crude Oil Runs and Crude Oil Supply Quality
High Case -- 1982*

	PADs I-IV				PAD V				Total U.S.			
	Slate A		Slate B		Slate A		Slate B		Slate A		Slate B	
	MB/D	%	MB/D	%	MB/D	%	MB/D	%	MB/D	%	MB/D	%
Refinery Crude Oil Runs	13,374	--	13,374	--	2,530	--	2,530	--	15,904	--	15,904	--
Crude Oil Supply												
Domestic												
Sweet Crude Oil	3,860	61.4	3,665	58.3	323	15.3	282	13.4	4,183	49.9	3,947	47.1
Medium-Sulfur Crude Oil												
Light Medium-Sulfur	225	3.6	225	3.6	169	8.1	191	9.1	394	4.7	416	4.9
Heavy Medium-Sulfur	151	2.4	213	3.4	902	43.0	880	41.9	1,053	12.5	1,093	13.0
High-Sulfur Crude Oil												
Light High-Sulfur	1,113	17.7	1,173	18.7	23	1.1	23	1.1	1,136	13.6	1,196	14.3
Heavy High-Sulfur	801	12.8	874	13.9	683	32.5	724	34.5	1,484	17.7	1,598	19.1
Field Condensate	134	2.1	134	2.1	--	--	--	--	134	1.6	134	1.6
Total Domestic	6,284	100.0	6,284	100.0	2,100	100.0	2,100	100.0	8,384	100.0	8,384	100.0
Foreign												
Sweet Crude Oil	3,228	45.5	3,022	42.6	310	72.1	300	70.1	3,538	47.1	3,322	44.2
Medium-Sulfur Crude Oil												
Light Medium-Sulfur	444	6.3	444	6.3	33	7.7	37	8.7	477	6.3	481	6.4
Heavy Medium-Sulfur	250	3.5	322	4.5	34	7.9	30	6.9	284	3.8	352	4.7
High-Sulfur Crude Oil												
Light High-Sulfur	2,230	31.5	2,304	32.5	28	6.5	28	6.5	2,258	30.0	2,332	31.0
Heavy High-Sulfur	938	13.2	998	14.1	25	5.8	35	7.8	963	12.8	1,033	13.7
Field Condensate	--	--	--	--	--	--	--	--	--	--	--	--
Total Foreign	7,090	100.0	7,090	100.0	430	100.0	430	100.0	7,520	100.0	7,520	100.0

*Projected data derived from the April 1979 NPC Survey of U.S. and World Energy and Oil Supply/Demand Forecasts.

TABLE 43

Projected Refinery Crude Oil Runs and Crude Oil Supply Quality
High Case -- 1985*

	PADs I-IV				PAD V				Total U.S.			
	Slate A		Slate B		Slate A		Slate B		Slate A		Slate B	
	MB/D	%	MB/D	%	MB/D	%	MB/D	%	MB/D	%	MB/D	%
Refinery Crude Oil Runs	13,782	--	13,782	--	2,631	--	2,631	--	16,413	--	16,413	--
Crude Oil Supply												
Domestic												
Sweet Crude Oil	3,683	59.4	3,220	52.0	305	14.1	274	12.7	3,988	47.7	3,494	41.8
Medium-Sulfur Crude Oil												
Light Medium-Sulfur	221	3.6	119	1.9	171	7.9	195	9.0	392	4.7	314	3.8
Heavy Medium-Sulfur	178	2.9	300	4.8	931	43.2	885	41.0	1,109	13.3	1,185	14.2
High-Sulfur Crude Oil												
Light High-Sulfur	1,160	18.7	1,465	23.6	18	0.8	20	0.9	1,178	14.1	1,485	17.8
Heavy High-Sulfur	822	13.2	960	15.5	732	34.0	783	36.3	1,554	18.6	1,743	20.8
Field Condensate	138	2.2	138	2.2	--	--	--	--	138	1.6	138	1.6
Total Domestic	6,202	100.0	6,202	100.0	2,157	100.0	2,157	100.0	8,359	100.0	8,359	100.0
Foreign												
Sweet Crude Oil	3,346	44.1	3,395	44.8	340	71.7	330	69.6	3,686	45.7	3,725	46.3
Medium-Sulfur Crude Oil												
Light Medium-Sulfur	468	6.2	432	5.7	39	8.2	42	8.9	507	6.3	474	5.9
Heavy Medium-Sulfur	304	4.0	320	4.2	42	8.9	36	7.6	346	4.3	356	4.4
High-Sulfur Crude Oil												
Light High-Sulfur	2,423	32.0	2,394	31.6	22	4.6	25	5.3	2,445	30.4	2,419	30.0
Heavy High-Sulfur	1,039	13.7	1,039	13.7	31	6.5	41	8.6	1,070	13.3	1,080	13.4
Field Condensate	--	--	--	--	--	--	--	--	--	--	--	--
Total Foreign	7,580	100.0	7,580	100.0	474	100.0	474	100.0	8,054	100.0	8,054	100.0
Domestic and Foreign												
Sweet Crude Oil	7,029	51.0	6,615	48.0	645	24.5	604	23.0	7,674	46.8	7,219	44.0
Medium-Sulfur Crude Oil												
Light Medium-Sulfur	689	5.0	551	4.0	210	8.0	237	9.0	899	5.5	788	4.8
Heavy Medium-Sulfur	482	3.5	620	4.5	973	37.0	921	35.0	1,455	8.8	1,541	9.4
High-Sulfur Crude Oil												
Light High-Sulfur	3,583	26.0	3,859	28.0	40	1.5	45	1.7	3,623	22.1	3,904	23.8
Heavy High-Sulfur	1,861	13.5	1,999	14.5	763	29.0	824	31.3	2,624	16.0	2,823	17.2
Field Condensate	138	1.0	138	1.0	--	--	--	--	138	0.8	138	0.8
Total Crude Oil Supply	13,782	100.0	13,782	100.0	2,631	100.0	2,631	100.0	16,413	100.0	16,413	100.0

*Projected data derived from the April 1979 NPC Survey of U.S. and World Energy and Oil Supply/Demand Forecasts.

TABLE 44

Projected Refinery Crude Oil Runs and Crude Oil Supply Quality
High Case -- 1990*

	PADs I-IV				PAD V				Total U.S.			
	Slate A		Slate B		Slate A		Slate B		Slate A		Slate B	
	MB/D	%	MB/D	%	MB/D	%	MB/D	%	MB/D	%	MB/D	%
Refinery Crude Oil Runs	14,309	--	14,309	--	2,670	--	2,670	--	16,979	--	16,979	--
Crude Oil Supply												
Domestic												
Sweet Crude Oil	3,695	57.4	3,174	49.3	294	13.1	221	9.9	3,989	46.0	3,395	39.1
Medium-Sulfur Crude Oil												
Light Medium-Sulfur	231	3.6	135	2.1	205	9.2	233	10.4	436	5.0	368	4.2
Heavy Medium-Sulfur	185	2.9	219	3.4	978	43.6	874	39.0	1,163	13.4	1,093	12.6
High-Sulfur Crude Oil												
Light High-Sulfur	1,268	19.7	1,719	25.3	18	0.8	23	1.0	1,286	14.8	1,742	20.1
Heavy High-Sulfur	917	14.2	1,049	14.9	748	33.3	892	39.7	1,665	19.2	1,941	22.4
Field Condensate	143	2.2	143	2.2	--	--	--	--	143	1.6	143	1.6
Total Domestic	6,439	100.0	6,439	100.0	2,243	100.0	2,243	100.0	8,682	100.0	8,682	100.0
Foreign												
Sweet Crude Oil	3,317	42.2	3,123	39.7	360	84.3	340	79.6	3,677	44.3	3,463	41.7
Medium-Sulfur Crude Oil												
Light Medium-Sulfur	484	6.1	366	4.7	9	2.1	7	1.6	493	5.9	373	4.6
Heavy Medium-Sulfur	316	4.0	353	4.5	10	2.3	7	1.6	326	3.9	360	4.3
High-Sulfur Crude Oil												
Light High-Sulfur	2,592	32.9	2,931	37.2	22	5.2	30	7.0	2,614	31.5	2,961	35.7
Heavy High-Sulfur	1,161	14.8	1,097	13.9	26	6.1	43	10.0	1,187	14.4	1,140	13.7
Field Condensate	--	--	--	--	--	--	--	--	--	--	--	--
Total Foreign	7,870	100.0	7,870	100.0	427	100.0	427	100.0	8,297	100.0	8,297	100.0
Domestic and Foreign												
Sweet Crude Oil	7,012	49.0	6,297	44.0	654	24.5	561	21.0	7,666	45.2	6,858	40.4
Medium-Sulfur Crude Oil												
Light Medium-Sulfur	715	5.0	501	3.5	214	8.0	240	9.0	929	5.5	741	4.4
Heavy Medium-Sulfur	501	3.5	572	4.0	988	37.0	881	33.0	1,489	8.8	1,453	8.6
High-Sulfur Crude Oil												
Light High-Sulfur	3,860	27.0	4,650	32.5	40	1.5	53	2.0	3,900	23.0	4,703	27.7
Heavy High-Sulfur	2,078	14.5	2,146	15.0	774	29.0	935	35.0	2,852	16.7	3,081	18.1
Field Condensate	143	1.0	143	1.0	--	--	--	--	143	0.8	143	0.8
Total Crude Oil Supply	14,309	100.0	14,309	100.0	2,670	100.0	2,670	100.0	16,979	100.0	16,979	100.0

*Projected data derived from the April 1979 NPC Survey of U.S. and World Energy and Oil Supply/Demand Forecasts.

TABLE 45

Projected Refinery Crude Oil Runs and Crude Oil Supply Quality
Medium Case -- 1982*

	PADs I-IV				PAD V				Total U.S.			
	Slate A		Slate B		Slate A		Slate B		Slate A		Slate B	
	MB/D	%	MB/D	%	MB/D	%	MB/D	%	MB/D	%	MB/D	%
Refinery Crude Oil Runs	12,210	--	12,210	--	2,448	--	2,448	--	14,658	--	14,658	--
Crude Oil Supply												
Domestic												
Sweet Crude Oil	3,748	61.4	3,565	58.4	372	17.3	327	15.2	4,120	49.8	3,892	47.1
Medium-Sulfur Crude Oil												
Light Medium-Sulfur	220	3.6	220	3.6	184	8.5	206	9.6	404	4.9	426	5.2
Heavy Medium-Sulfur	145	2.4	207	3.4	894	41.5	873	40.5	1,039	12.6	1,080	13.1
High-Sulfur Crude Oil												
Light High-Sulfur	1,080	17.7	1,141	18.7	35	1.6	35	1.6	1,115	13.5	1,176	14.2
Heavy High-Sulfur	790	12.9	850	13.9	669	31.1	713	33.1	1,459	17.7	1,563	18.9
Field Condensate	122	2.0	122	2.0	--	--	--	--	122	1.5	122	1.5
Total Domestic	6,105	100.0	6,105	100.0	2,154	100.0	2,154	100.0	8,259	100.0	8,259	100.0
Foreign												
Sweet Crude Oil	2,723	44.7	2,540	41.6	240	81.6	236	80.2	2,963	46.3	2,776	43.4
Medium-Sulfur Crude Oil												
Light Medium-Sulfur	391	6.4	391	6.4	12	4.1	14	4.8	403	6.3	405	6.3
Heavy Medium-Sulfur	221	3.6	281	4.6	12	4.1	9	3.1	233	3.6	290	4.5
High-Sulfur Crude Oil												
Light High-Sulfur	1,973	32.3	2,034	33.3	14	4.8	14	4.8	1,987	31.1	2,048	32.0
Heavy High-Sulfur	797	13.0	859	14.1	16	5.4	21	7.1	813	12.7	880	13.8
Field Condensate	--	--	--	--	--	--	--	--	--	--	--	--
Total Foreign	6,105	100.0	6,105	100.0	294	100.0	294	100.0	6,399	100.0	6,399	100.0
Domestic and Foreign												
Sweet Crude Oil	6,471	53.0	6,105	50.0	612	25.0	563	23.0	7,083	48.3	6,668	45.5
Medium-Sulfur Crude Oil												
Light Medium-Sulfur	611	5.0	611	5.0	196	8.0	220	9.0	807	5.5	831	5.7
Heavy Medium-Sulfur	366	3.0	488	4.0	906	37.0	882	36.0	1,272	8.7	1,370	9.3
High-Sulfur Crude Oil												
Light High-Sulfur	3,053	25.0	3,175	26.0	49	2.0	49	2.0	3,102	21.2	3,224	22.0
Heavy High-Sulfur	1,587	13.0	1,709	14.0	685	28.0	734	30.0	2,272	15.5	2,443	16.7
Field Condensate	122	1.0	122	1.0	--	--	--	--	122	0.8	122	0.8
Total Crude Oil Supply	12,210	100.0	12,210	100.0	2,448	100.0	2,448	100.0	14,658	100.0	14,658	100.0

*Projected data derived from the December 1979 NPC Survey of U.S. and World Energy and Oil Supply/Demand Forecasts.

TABLE 46

Projected Refinery Crude Oil Runs and Crude Oil Supply Quality
Medium Case -- 1985*

	PADs I-IV				PAD V				Total U.S.			
	Slate A		Slate B		Slate A		Slate B		Slate A		Slate B	
	MB/D	%	MB/D	%	MB/D	%	MB/D	%	MB/D	%	MB/D	%
Refinery Crude Oil Runs	12,459	--	12,459	--	2,509	--	2,509	--	14,968	--	14,968	--
Crude Oil Supply												
Domestic												
Sweet Crude Oil	3,550	59.4	3,377	56.5	390	17.4	306	13.7	3,940	48.0	3,683	44.8
Medium-Sulfur Crude Oil												
Light Medium-Sulfur	212	3.5	154	2.6	190	8.5	210	9.4	402	4.9	364	4.5
Heavy Medium-Sulfur	171	2.9	232	3.9	917	41.1	879	39.4	1,088	13.3	1,111	13.5
High-Sulfur Crude Oil												
Light High-Sulfur	1,119	18.7	1,240	20.7	26	1.2	30	1.3	1,145	13.9	1,270	15.5
Heavy High-Sulfur	803	13.4	852	14.2	710	31.8	808	36.2	1,513	18.4	1,660	20.2
Field Condensate	125	2.1	125	2.1	--	--	--	--	125	1.5	125	1.5
Total Domestic	5,980	100.0	5,980	100.0	2,233	100.0	2,333	100.0	8,213	100.0	8,213	100.0
Foreign												
Sweet Crude Oil	2,804	43.3	2,603	40.2	225	81.5	221	80.0	3,029	44.8	2,824	41.8
Medium-Sulfur Crude Oil												
Light Medium-Sulfur	411	6.3	344	5.3	11	4.0	14	5.2	422	6.2	358	5.3
Heavy Medium-Sulfur	265	4.1	329	5.1	11	4.0	5	1.9	276	4.1	334	4.9
High-Sulfur Crude Oil												
Light High-Sulfur	2,120	32.7	2,249	34.7	12	4.4	13	4.6	2,132	31.6	2,262	33.5
Heavy High-Sulfur	879	13.6	954	14.7	17	6.1	23	8.3	896	13.3	977	14.5
Field Condensate	--	--	--	--	--	--	--	--	--	--	--	--
Total Foreign	6,479	100.0	6,479	100.0	276	100.0	276	100.0	6,755	100.0	6,755	100.0
Domestic and Foreign												
Sweet Crude Oil	6,354	51.0	5,980	48.0	615	24.5	527	21.0	6,969	46.6	6,507	43.5
Medium-Sulfur Crude Oil												
Light Medium-Sulfur	623	5.0	498	4.0	201	8.0	224	9.0	824	5.5	722	4.8
Heavy Medium-Sulfur	436	3.5	561	4.5	928	37.0	884	35.2	1,364	9.1	1,445	9.7
High-Sulfur Crude Oil												
Light High-Sulfur	3,239	26.0	3,489	28.0	38	1.5	43	1.7	3,277	21.9	3,532	23.6
Heavy High-Sulfur	1,682	13.5	1,806	14.5	727	29.0	831	33.1	2,409	16.1	2,637	17.6
Field Condensate	125	1.0	125	1.0	--	--	--	--	125	0.8	125	0.8
Total Crude Oil Supply	12,459	100.0	12,459	100.0	2,509	100.0	2,509	100.0	14,968	100.0	14,968	100.0

*Projected data derived from the December 1979 NPC Survey of U.S. and World Energy and Oil Supply/Demand Forecasts.

TABLE 47

Projected Refinery Crude Oil Runs and Crude Oil Supply Quality
Medium Case -- 1990*

	PADs I-IV				PAD V				Total U.S.			
	Slate A		Slate B		Slate A		Slate B		Slate A		Slate B	
	MB/D	%	MB/D	%	MB/D	%	MB/D	%	MB/D	%	MB/D	%
Refinery Crude Oil Runs	12,589	--	12,589	--	2,533	--	2,533	--	15,122	--	15,122	--
Crude Oil Supply												
Domestic												
Sweet Crude Oil	3,617	57.5	3,304	52.5	417	18.3	288	12.6	4,034	47.1	3,592	41.9
Medium-Sulfur Crude Oil												
Light Medium-Sulfur	225	3.6	131	2.1	191	8.4	215	9.4	416	4.8	346	4.0
Heavy Medium-Sulfur	181	2.9	213	3.4	926	40.6	881	38.7	1,107	12.9	1,094	12.7
High-Sulfur Crude Oil												
Light High-Sulfur	1,261	20.0	1,587	25.2	26	1.1	39	1.7	1,287	15.0	1,626	19.0
Heavy High-Sulfur	885	14.0	934	14.8	719	31.6	856	37.6	1,604	18.7	1,790	20.9
Field Condensate	126	2.0	126	2.0	--	--	--	--	126	1.5	126	1.5
Total Domestic	6,295	100.0	6,295	100.0	2,279	100.0	2,279	100.0	8,574	100.0	8,574	100.0
Foreign												
Sweet Crude Oil	2,553	40.6	2,235	35.5	204	80.3	194	76.4	2,757	42.1	2,429	37.1
Medium-Sulfur Crude Oil												
Light Medium-Sulfur	404	6.4	310	4.9	12	4.7	13	5.1	416	6.4	323	14.9
Heavy Medium-Sulfur	260	4.1	291	4.6	11	4.3	5	2.0	271	4.1	296	4.5
High-Sulfur Crude Oil												
Light High-Sulfur	2,162	34.4	2,504	39.8	12	4.7	12	4.7	2,174	33.2	2,516	38.4
Heavy High-Sulfur	915	14.5	954	15.2	15	6.0	30	11.8	930	14.2	984	15.1
Field Condensate	--	--	--	--	--	--	--	--	--	--	--	--
Total Foreign	6,294	100.0	6,294	100.0	254	100.0	254	100.0	6,548	100.0	6,548	100.0
Domestic and Foreign												
Sweet Crude Oil	6,170	49.0	5,539	44.0	621	24.5	482	19.0	6,791	44.9	6,021	40.1
Medium-Sulfur Crude Oil												
Light Medium-Sulfur	629	5.0	441	3.5	203	8.0	228	9.0	832	5.5	669	4.4
Heavy Medium-Sulfur	441	3.5	504	4.0	937	37.0	886	35.0	1,378	9.1	1,390	8.9
High-Sulfur Crude Oil												
Light High-Sulfur	3,423	27.2	4,091	32.5	38	1.5	51	2.0	3,461	22.9	4,142	27.4
Heavy High-Sulfur	1,800	14.3	1,888	15.0	734	29.0	886	35.0	2,534	16.8	2,774	18.4
Field Condensate	126	1.0	126	1.0	--	--	--	--	126	0.8	126	0.8
Total Crude Oil Supply	12,589	100.0	12,589	100.0	2,533	100.0	2,533	100.0	15,122	100.0	15,122	100.0

*Projected data derived from the December 1979 NPC Survey of U.S. and World Energy and Oil Supply/Demand Forecasts.

TABLE 48

Projected Refinery Crude Oil Runs and Crude Oil Supply Quality
Low Case -- 1985*

	PADs I-IV				PAD V				Total U.S.			
	Slate A		Slate B		Slate A		Slate B		Slate A		Slate B	
	MB/D	%	MB/D	%	MB/D	%	MB/D	%	MB/D	%	MB/D	%
Refinery Crude Oil Runs	11,843	--	11,843	--	2,390	--	2,390	--	14,233	--	14,233	--
Crude Oil Supply												
Domestic												
Sweet Crude Oil	3,529	58.5	3,349	55.6	376	17.6	295	13.8	3,905	47.8	3,644	44.6
Medium-Sulfur Crude Oil												
Light Medium-Sulfur	215	3.6	168	2.8	185	8.6	200	9.4	400	4.9	368	4.5
Heavy Medium-Sulfur	210	3.5	261	4.4	877	41.0	842	39.3	1,087	13.3	1,103	13.5
High-Sulfur Crude Oil												
Light High-Sulfur	1,119	18.6	1,244	20.6	25	1.2	30	1.4	1,144	14.0	1,274	15.6
Heavy High-Sulfur	843	14.0	894	14.8	677	31.6	773	36.1	1,520	18.6	1,667	20.4
Field Condensate	114	1.8	114	1.8	--	--	--	--	114	1.4	114	1.4
Total Domestic	6,030	100.0	6,030	100.0	2,140	100.0	2,140	100.0	8,170	100.0	8,170	100.0
Foreign												
Sweet Crude Oil	2,464	42.4	2,286	39.3	204	81.6	200	80.0	2,668	44.0	2,486	41.0
Medium-Sulfur Crude Oil												
Light Medium-Sulfur	354	6.1	296	5.1	10	4.0	13	5.2	364	6.0	309	5.1
Heavy Medium-Sulfur	233	4.0	286	4.9	10	4.0	5	2.0	243	4.0	291	4.8
High-Sulfur Crude Oil												
Light High-Sulfur	1,953	33.6	2,068	35.6	11	4.4	12	4.8	1,964	32.4	2,080	34.3
Heavy High-Sulfur	809	13.9	877	15.1	15	6.0	20	8.0	824	13.6	897	14.8
Field Condensate	--	--	--	--	--	--	--	--	--	--	--	--
Total Foreign	5,813	100.0	5,813	100.0	250	100.0	250	100.0	6,063	100.0	6,063	100.0
Domestic and Foreign												
Sweet Crude Oil	5,993	50.6	5,635	47.6	580	24.3	495	20.7	6,573	46.2	6,130	43.1
Medium-Sulfur Crude Oil												
Light Medium-Sulfur	569	4.8	464	3.9	195	8.2	213	8.9	764	5.4	677	4.8
Heavy Medium-Sulfur	443	3.7	547	4.6	887	37.1	847	35.4	1,330	9.3	1,394	9.8
High-Sulfur Crude Oil												
Light High-Sulfur	3,072	25.9	3,312	27.9	36	1.5	42	1.8	3,108	21.8	3,354	23.5
Heavy High-Sulfur	1,652	14.0	1,771	15.0	692	28.9	793	33.2	2,344	16.5	2,564	18.0
Field Condensate	114	1.0	114	1.0	--	--	--	--	114	0.8	114	0.8
Total Crude Oil Supply	11,843	100.0	11,843	100.0	2,390	100.0	2,390	100.0	14,233	100.0	14,233	100.0

*Projected data derived from the December 1979 NPC Survey of U.S. and World Energy and Oil Supply/Demand Forecasts.

TABLE 49

Projected Refinery Crude Oil Runs and Crude Oil Supply Quality

Low Case -- 1990*

	PADs I-IV				PAD V				Total U.S.			
	Slate A		Slate B		Slate A		Slate B		Slate A		Slate B	
	MB/D	%	MB/D	%	MB/D	%	MB/D	%	MB/D	%	MB/D	%
Refinery Crude Oil Runs	11,654	--	11,654	--	2,375	--	2,375	--	14,029	--	14,029	--
Crude Oil Supply												
Domestic												
Sweet Crude Oil	3,383	57.4	3,085	52.4	389	18.2	269	12.6	3,772	47.0	3,354	41.8
Medium-Sulfur Crude Oil												
Light Medium-Sulfur	187	3.2	111	1.9	190	8.9	210	9.8	377	4.7	321	4.0
Heavy Medium-Sulfur	172	2.9	197	3.3	863	40.4	822	38.5	1,035	12.9	1,019	12.7
High-Sulfur Crude Oil												
Light High-Sulfur	1,186	20.2	1,490	25.3	26	1.2	35	1.6	1,212	15.1	1,525	19.0
Heavy High-Sulfur	850	14.4	895	15.2	667	31.1	799	37.5	1,517	18.9	1,694	21.1
Field Condensate	112	1.9	112	1.9	--	--	--	--	112	1.4	112	1.4
Total Domestic	5,890	100.0	5,890	100.0	2,135	100.0	2,135	100.0	8,025	100.0	8,025	100.0
Foreign												
Sweet Crude Oil	2,330	40.4	2,039	35.4	192	80.0	182	75.8	2,522	42.0	2,221	37.0
Medium-Sulfur Crude Oil												
Light Medium-Sulfur	379	6.6	288	5.0	11	4.6	12	5.0	390	6.5	300	5.0
Heavy Medium-Sulfur	230	4.0	265	4.6	10	4.2	5	2.1	240	4.0	270	4.5
High-Sulfur Crude Oil												
Light High-Sulfur	1,988	34.5	2,288	39.7	11	4.6	12	5.0	1,999	33.3	2,300	38.3
Heavy High-Sulfur	837	14.5	884	15.3	16	6.6	29	12.1	853	14.2	913	15.2
Field Condensate	--	--	--	--	--	--	--	--	--	--	--	--
Total Foreign	5,764	100.0	5,764	100.0	240	100.0	240	100.0	6,004	100.0	6,004	100.0
Domestic and Foreign												
Sweet Crude Oil	5,713	49.0	5,124	44.0	581	24.5	451	19.0	6,294	44.9	5,575	39.7
Medium-Sulfur Crude Oil												
Light Medium-Sulfur	566	4.9	399	3.4	201	8.5	222	9.3	767	5.5	621	4.4
Heavy Medium-Sulfur	402	3.4	462	4.0	873	36.7	827	34.8	1,275	9.1	1,289	9.2
High-Sulfur Crude Oil												
Light High-Sulfur	3,174	27.2	3,778	32.4	37	1.5	47	2.0	3,211	22.8	3,825	27.3
Heavy High-Sulfur	1,687	14.5	1,779	15.2	683	28.8	828	34.9	2,370	16.9	2,607	18.6
Field Condensate	112	1.0	112	1.0	--	--	--	--	112	0.8	112	0.8
Total Crude Oil Supply	11,654	100.0	11,654	100.0	2,375	100.0	2,375	100.0	14,029	100.0	14,029	100.0

*Projected data derived from the December 1979 NPC Survey of U.S. and World Energy and Oil Supply/Demand Forecasts.

TABLE 50

Projected Total U.S. Refinery Crude Oil Runs and Crude Oil Supply Quality
High Case -- 1982, 1985, and 1990*

	1982				1985				1990			
	Slate A		Slate B		Slate A		Slate B		Slate A		Slate B	
	MB/D	%	MB/D	%	MB/D	%	MB/D	%	MB/D	%	MB/D	%
Refinery Crude Oil Runs	15,904	--	15,904	--	16,413	--	16,413	--	16,979	--	16,979	--
Crude Oil Supply												
Domestic												
Sweet Crude Oil	4,183	49.9	3,947	47.1	3,988	47.7	3,494	41.8	3,989	46.0	3,395	39.1
Medium-Sulfur Crude Oil												
Light Medium-Sulfur	394	4.7	416	4.9	392	4.7	314	3.8	436	5.0	368	4.2
Heavy Medium-Sulfur	1,053	12.5	1,093	13.0	1,109	13.3	1,185	14.2	1,163	13.4	1,093	12.6
High-Sulfur Crude Oil												
Light High-Sulfur	1,136	13.6	1,196	14.3	1,178	14.1	1,485	17.8	1,286	14.8	1,742	20.1
Heavy High-Sulfur	1,484	17.7	1,598	19.1	1,554	18.6	1,743	20.8	1,665	19.2	1,941	22.4
Field Condensate	134	1.6	134	1.6	138	1.6	138	1.6	143	1.6	143	1.6
Total Domestic	8,384	100.0	8,384	100.0	8,359	100.0	8,359	100.0	8,682	100.0	8,682	100.0
Foreign												
Sweet Crude Oil	3,538	47.1	3,322	44.2	3,686	45.7	3,725	46.3	3,677	44.3	3,463	41.7
Medium-Sulfur Crude Oil												
Light Medium-Sulfur	477	6.3	481	6.4	507	6.3	474	5.9	493	5.9	373	4.6
Heavy Medium-Sulfur	284	3.8	352	4.7	346	4.3	356	4.4	326	3.9	360	4.3
High-Sulfur Crude Oil												
Light High-Sulfur	2,258	30.0	2,332	31.0	2,445	30.4	2,419	30.0	2,614	31.5	2,961	35.7
Heavy High-Sulfur	963	12.8	1,033	13.7	1,070	13.3	1,080	13.4	1,187	14.4	1,140	13.7
Field Condensate	--	--	--	--	--	--	--	--	--	--	--	--
Total Foreign	7,520	100.0	7,520	100.0	8,054	100.0	8,054	100.0	8,297	100.0	8,297	100.0
Domestic and Foreign												
Sweet Crude Oil	7,721	48.5	7,269	45.7	7,674	46.8	7,219	44.0	7,666	45.2	6,858	40.4
Medium-Sulfur Crude Oil												
Light Medium-Sulfur	871	5.5	897	5.6	899	5.5	788	4.8	929	5.5	741	4.4
Heavy Medium-Sulfur	1,337	8.5	1,445	9.1	1,455	8.8	1,541	9.4	1,489	8.8	1,453	8.6
High-Sulfur Crude Oil												
Light High-Sulfur	3,394	21.3	3,528	22.2	3,623	22.1	3,904	23.8	3,900	23.0	4,703	27.7
Heavy High-Sulfur	2,447	15.4	2,631	16.6	2,624	16.0	2,823	17.2	2,852	16.7	3,081	18.1
Field Condensate	134	0.8	134	0.8	138	0.8	138	0.8	143	0.8	143	0.8
Total Crude Oil Supply	15,904	100.0	15,904	100.0	16,413	100.0	16,413	100.0	16,979	100.0	16,979	100.0

*Projected data derived from the April 1979 NPC Survey of U.S. and World Energy and Oil Supply/Demand Forecasts.

TABLE 51

Projected Total U.S. Refinery Crude Oil Runs and Crude Oil Supply Quality
Medium Case -- 1982, 1985, and 1990*

	1982				1985				1990			
	Slate A		Slate B		Slate A		Slate B		Slate A		Slate B	
	MB/D	%	MB/D	%	MB/D	%	MB/D	%	MB/D	%	MB/D	%
Refinery Crude Oil Runs	14,658	--	14,658	--	14,968	--	14,968	--	15,122	--	15,122	--
Crude Oil Supply												
Domestic												
Sweet Crude Oil	4,120	49.8	3,892	47.1	3,940	48.0	3,683	44.8	4,034	47.1	3,592	41.9
Medium-Sulfur Crude Oil												
Light Medium-Sulfur	404	4.9	426	5.2	402	4.9	364	4.5	416	4.8	346	4.0
Heavy Medium-Sulfur	1,039	12.6	1,080	13.1	1,088	13.3	1,111	13.5	1,107	12.9	1,094	12.7
High-Sulfur Crude Oil												
Light High-Sulfur	1,115	13.5	1,176	14.2	1,145	13.9	1,270	15.5	1,287	15.0	1,626	19.0
Heavy High-Sulfur	1,459	17.7	1,563	18.9	1,513	18.4	1,660	20.2	1,604	18.7	1,790	20.9
Field Condensate	122	1.5	122	1.5	125	1.5	125	1.5	126	1.5	126	1.5
Total Domestic	8,259	100.0	8,259	100.0	8,213	100.0	8,213	100.0	8,574	100.0	8,574	100.0
Foreign												
Sweet Crude Oil	2,963	46.3	2,776	43.4	3,029	44.8	2,824	41.8	2,757	42.1	2,429	37.1
Medium-Sulfur Crude Oil												
Light Medium-Sulfur	403	6.3	405	6.3	422	6.2	358	5.3	416	6.4	323	14.9
Heavy Medium-Sulfur	233	3.6	290	4.5	276	4.1	334	4.9	271	4.1	296	4.5
High-Sulfur Crude Oil												
Light High-Sulfur	1,987	31.1	2,048	32.0	2,132	31.6	2,262	33.5	2,174	33.2	2,516	38.4
Heavy High-Sulfur	813	12.7	880	13.8	896	13.3	977	14.5	930	14.2	984	15.1
Field Condensate	--	--	--	--	--	--	--	--	--	--	--	--
Total Foreign	6,399	100.0	6,399	100.0	6,755	100.0	6,755	100.0	6,548	100.0	6,548	100.0
Domestic and Foreign												
Sweet Crude Oil	7,083	48.3	6,668	45.5	6,969	46.6	6,507	43.5	6,791	44.9	6,021	40.1
Medium-Sulfur Crude Oil												
Light Medium-Sulfur	807	5.5	831	5.7	824	5.5	722	4.8	832	5.5	669	4.4
Heavy Medium-Sulfur	1,272	8.7	1,370	9.3	1,364	9.1	1,445	9.7	1,378	9.1	1,390	8.9
High-Sulfur Crude Oil												
Light High-Sulfur	3,102	21.2	3,224	22.0	3,277	21.9	3,532	23.6	3,461	22.9	4,142	27.4
Heavy High-Sulfur	2,272	15.5	2,443	16.7	2,409	16.1	2,637	17.6	2,534	16.8	2,774	18.4
Field Condensate	122	0.8	122	0.8	125	0.8	125	0.8	126	0.8	126	0.8
Total Crude Oil Supply	14,658	100.0	14,658	100.0	14,968	100.0	14,968	100.0	15,122	100.0	15,122	100.0

*Projected data derived from the December 1979 NPC Survey of U.S. and World Energy and Oil Supply/Demand Forecasts.

TABLE 52

Projected Total U.S. Refinery Crude Oil Runs and Crude Oil Supply Quality
Low Case -- 1982, 1985, and 1990*

	1982				1985				1990			
	Slate A		Slate B		Slate A		Slate B		Slate A		Slate B	
	MB/D	%	MB/D	%	MB/D	%	MB/D	%	MB/D	%	MB/D	%
Refinery Crude Oil Runs	14,365	--	14,365	--	14,233	--	14,233	--	14,029	--	14,029	--
Crude Oil Supply												
Domestic												
Sweet Crude Oil	4,122	49.9	3,890	47.1	3,905	47.8	3,644	44.6	3,772	47.0	3,354	41.8
Medium-Sulfur Crude Oil												
Light Medium-Sulfur	405	4.9	438	5.3	400	4.9	368	4.5	377	4.7	321	4.0
Heavy Medium-Sulfur	1,041	12.6	1,082	13.1	1,087	13.3	1,103	13.5	1,035	12.9	1,019	12.7
High-Sulfur Crude Oil												
Light High-Sulfur	1,115	13.5	1,173	14.2	1,144	14.0	1,274	15.6	1,212	15.1	1,525	19.0
Heavy High-Sulfur	1,462	17.7	1,562	18.9	1,520	18.6	1,667	20.4	1,517	18.9	1,694	21.1
Field Condensate	115	1.4	115	1.4	114	1.4	114	1.4	112	1.4	112	1.4
Total Domestic	8,260	100.0	8,260	100.0	8,170	100.0	8,170	100.0	8,025	100.0	8,025	100.0
Foreign												
Sweet Crude Oil	2,808	46.0	2,631	43.1	2,668	44.0	2,486	41.0	2,522	42.0	2,221	37.0
Medium-Sulfur Crude Oil												
Light Medium-Sulfur	385	6.3	391	6.4	364	6.0	309	5.1	390	6.5	300	5.0
Heavy Medium-Sulfur	214	3.5	269	4.4	243	4.0	291	4.8	240	4.0	270	4.5
High-Sulfur Crude Oil												
Light High-Sulfur	1,917	31.4	1,972	32.3	1,964	32.4	2,080	34.3	1,999	33.3	2,300	38.3
Heavy High-Sulfur	781	12.8	842	13.8	824	13.6	897	14.8	853	14.2	913	15.2
Field Condensate	--	--	--	--	--	--	--	--	--	--	--	--
Total Foreign	6,105	100.0	6,105	100.0	6,063	100.0	6,063	100.0	6,004	100.0	6,004	100.0
Domestic and Foreign												
Sweet Crude Oil	6,930	48.2	6,521	45.4	6,573	46.2	6,130	43.1	6,294	44.9	5,575	39.7
Medium-Sulfur Crude Oil												
Light Medium-Sulfur	790	5.5	829	5.8	764	5.4	677	4.8	767	5.5	621	4.4
Heavy Medium-Sulfur	1,255	8.7	1,351	9.4	1,330	9.3	1,394	9.8	1,275	9.1	1,289	9.2
High-Sulfur Crude Oil												
Light High-Sulfur	3,032	21.2	3,145	21.9	3,108	21.8	3,354	23.5	3,211	22.8	3,825	27.3
Heavy High-Sulfur	2,243	15.6	2,404	16.7	2,344	16.5	2,564	18.0	2,370	16.9	2,607	18.6
Field Condensate	115	0.8	115	0.8	114	0.8	114	0.8	112	0.8	112	0.8
Total Crude Oil Supply	14,365	100.0	14,365	100.0	14,233	100.0	14,233	100.0	14,029	100.0	14,029	100.0

*Projected data derived from the December 1979 NPC Survey of U.S. and World Energy and Oil Supply/Demand Forecasts.

CHAPTER TWO

U.S. DOMESTIC REFINING INDUSTRY CAPABILITY TO PROCESS AVAILABLE CRUDE OIL TO MEET FUTURE PRODUCT DEMAND

INTRODUCTION

The objective of this chapter is to analyze the capability of the U.S. domestic refining industry to meet requirements under a variety of scenarios of crude oil availability and product demand, so as to determine possible facility requirements and associated installation costs for the 1982-1990 period. In addition, this chapter covers the effects of crude oil supply disruptions and certain federal regulatory programs.

Crude oil supply and product demand projections were obtained from responses to the two supply/demand surveys which were discussed in Chapter One. From these surveys, three supply/demand cases were developed for each of three years -- 1982, 1985, and 1990. In addition, two crude oil supply quality slates (designated crude oil slate A and crude oil slate B) were developed for each of the three supply/demand cases in each of the three years.

The principal "variable" on the crude oil supply side of the supply/demand equation is the type and availability of crude oil. Declining supplies of sweet crude oil from both domestic and foreign sources require that the proportion of low-sulfur crude oil be decreased. Possibly of greater importance is the increasing percentage of heavy crude oil. These ranges in estimated composition are bracketed in this study by crude oil slates A and B, the latter reflecting the greatest change toward heavy, high-sulfur crude oil. The crude oil import disruption is bracketed within a minimum to maximum range of 2 to 5 MMB/D. On the product demand side, the principal concern originated with unleaded gasoline and low-sulfur fuel oil; however, because of the changing product mix requirements, various levels of demand for major products are examined to determine their effects on facility requirements.

The impact upon process capability of gasoline lead additive regulation is examined in this chapter. The use of MMT[1] in unleaded gasoline is also covered.

In general, the December 1979 NPC report, entitled Refinery Flexibility, An Interim Report, provided a picture of the domestic industry as it existed in 1978. This chapter deals with how the industry might adapt to meet projected future requirements. Areas of inadequacy as to facility flexibility, product mix, and geographic balance are identified. The magnitude and cost of required process capacity additions are also developed.

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[1]Methylcyclopentadienyl manganese tricarbonyl -- a gasoline additive with octane improving qualities similar to lead.

METHODOLOGY

The approach taken in this study was to use the Bonner & Moore Associates, Inc., Refinery and Petrochemical Modeling System to build a composite LP model of the refining industry. Two separate models were developed, one for PADs I-IV and one for PAD V. This separation recognizes the processing differences between the two regions and the fact that there is limited interregional movement of product. In order to reduce over-optimization, each geographic model utilized a three-refinery configuration; however, results are reported on an aggregated basis. Only limited inter-refinery transfer of feedstocks was allowed. This is more realistic than a single-refinery representation which implies unlimited access to all downstream capacity. For example, a simple refinery without catalytic (cat) cracking usually routes the cat feedstock portion of the crude oil to residual fuel oil, unless it can be sold to another refinery.

The industry refineries with their corresponding capacities were divided into three classes of complexity. The first type was essentially a hydroskimming operation with topping units and may include naphtha reforming capability and distillate desulfurization; the second added catalytic cracking and alkylation; the third added hydrocracking and bottoms processing (primarily coking). For reasons of confidentiality, the process capacity information in the January 1979 NPC Survey of Petroleum Refining Capabilities was reported only in aggregates according to PAD location, refinery size, and complexity index. This breakdown was insufficient by itself to provide the processing capacity detail by the refinery classes within the models. Also, the NPC survey did not receive a 100 percent response. Industry data from the Oil & Gas Journal's March 26, 1979, Annual Refining Survey augmented the NPC data in development of the capacities for the model. The final breakdown of the U.S. crude oil capacity according to the model classification was 9 percent in the first type of refinery, 29 percent in the second, and 62 percent in the third.

Availability of process capacity and unit performance were affected by necessary downtime for unit maintenance, both scheduled and unscheduled; shipment irregularities; equipment or catalyst deterioration; and other uncontrollable factors. To represent the loss of capacity from scheduled downtime, a 5 percent discount was applied to the crude oil distillation stream day capacity rating, and a 10 percent discount to other processes. A second discount of 7 percent, applied uniformly, represented the other types of losses as well as the fact that the model reflected modern technology, whereas the actual industry processing capacity was of varying vintage and efficiency. The net result was termed "effective capacity," which was the basis used in the models.

In attempting to validate the model, using 1978 actual production data from the January 1979 NPC survey, various approaches were tried, including a single-refinery model, three-refinery model, demand-driven model, price-driven model, etc. A three-refinery model, essentially demand driven, was found to be most appropriate.

The model runs for determining future process capacity requirements were demand driven, except for LPG, coke, sulfur, and residual fuel oil, which were allowed to vary within limits. To the extent that optimization with price was involved, actual 1978 prices were used. These data were derived from public sources, particularly from DOE Energy Information Administration publications and Platt's 1978 Oil Price Handbook and Oilmanac, 55th edition. In the supply disruption cases, assumed national priorities were reflected by changing relative product demand and prices. For cases wherein the model indicated that additional processing capacity was needed, optimizing runs with capital charges for new or debottlenecked capacity were made. This procedure selected the most economic way of meeting the refining requirements. Construction costs were based on 1978 Gulf Coast data adjusted for regional differences, ranging up to 15 percent. Debottlenecking costs were assumed to be applicable to expansion up to 20 percent of original capacity, new unit costs to expansion of 60 percent or greater, and interpolated costs to the intermediate range. The new units were sized to suit the typical refinery in each complexity category. Debottlenecking costs were assumed to be 70 percent of new unit costs.

The 1978 crude oil supply, from Chapter One, was allocated by refinery class within the PAD districts from data derived from the Oil and Gas Journal and the Department of Energy. Alaskan North Slope crude oil surplus to the West Coast's needs was considered available to PADs I-IV. For the model validation, using 1978 data, the quantity of incremental crude oil was allowed to vary to satisfy the material balance. For this reason, the 1978 crude oil input data in this chapter may vary slightly from that shown in Chapter One. The incremental crude oils, assumed to be available, were of a quality similar to Saudi Arabian Light crude oil for PADs I-IV and Alaskan North Slope crude oil for PAD V. Crude oil properties were obtained from industry assay data and the crude oils were then classified according to the five NPC quality category definitions as listed in Chapter One. In the studies of future situations, crude oil supply variations were postulated in terms of varying proportions of the NPC-defined categories.

The categories of crude oil were allocated to each of the three refineries in the models according to 1978 data from the January 1979 NPC Survey of Petroleum Refining Capabilities, augmented by 1978 refinery data from the Oil & Gas Journal. The foreign crude oil allocation was derived from data in the Petroleum Import Data Book 1978, John G. Yeager and Associates, Inc. For future years, the distribution of crude oil categories across refinery classes was assumed to remain in proportion to the 1978 distribution.

As in previous attempts by others to model the refining industry, this study encountered difficulties and uncertainties. Oversimplification to keep the model to a manageable size is inherent in a simulation of an entire industry. Data inadequacies also impose practical limits. For example, utilization rates of downstream capacity indicated by the model validation runs could not be confirmed by actual 1978 experience, because such data were not part of the January 1979 NPC survey. In this and other instances qualitative judgments had to be applied as to the reasonableness of results. Appendix F compares the models' output with responses received in the January 1979 NPC survey to questions regarding facility requests under several hypothetical supply/demand situations. Considering the difficulties in matching the model to observed 1978 operations, predictions of future situations cannot be precise. Therefore, in viewing the results of the various study cases, the differences among cases should be recognized as being more meaningful than the absolute values.

EXPANDED DISCUSSION

Future Process Facility Needs

As explained above, a refining industry model was used to test the industry's capability to meet future changes in crude oil supply composition, product demand, product specifications, and increases in the proportion of unleaded gasoline in the total pool. Although the model starts with the 1978 effective capacities (Table 53), it is allowed to employ additional capacity provided by construction if needed.

The needs for new facilities were determined on a cumulative basis as of three points in time -- 1982, 1985, and 1990. The product demand variations and the range of crude oil supply compositions that were studied are the same as those discussed in Chapter One. The model selects the least-cost route to meet the requirements, considering process yields, operating costs, and construction costs. Of these factors, process yield is the most important in facility selection, because of the overriding requirement to meet product demand and process the available crude oil types. The specific construction cost data were those contained in the Bonner & Moore Associates, Inc., Refinery and Petrochemical Modeling System. These data were compared against other sources and found to be in reasonable agreement. However, the data represent calendar year 1978 costs of construction; future changes in the relative costs of the various kinds of process units could affect the ultimate choices.

In general, the model chose to expand capacity only when process utilization exceeded the 1978 effective capacity. However, there were instances in which a process area was expanded to take advantage of new technology (e.g., low pressure naphtha reforming) or to maintain balanced crude oil running among the three refinery classes, even though some existing capacity was idled.

Tables 54 through 62 show the model-indicated expansions of process capacity for the various combinations of forecast product demand and crude oil supply composition. In these tables the capacities are expressed in terms of full stream day rating, and the expansion shown for any given year is the cumulative increase to that point in time from 1978. For comparison with the model-indicated expansions, the 1982 expansion plans drawn from the

TABLE 53

Effective Capacity* for 1978 Process Facilities
(Capacities in MB/D)

Process Facility	Refinery Location PADs I-IV	PAD V	Total U.S.
Crude Oil Distillation	13,137	2,831	15,968
Catalytic Reforming	2,588	535	3,123
Catalytic Cracking	3,617	524	4,141
Alkylation	662	103	765
Polymerization	39	2	41
Isomerization†	90	10	100
Hydrotreating			
Naphtha§	2,630	522	3,152
Distillate¶	2,265	390	2,655
Visbreaking/Thermal Cracking	167	94	261
Hydrorefining			
Gas Oil**	368	281	649
Residual Oil††	78	38	116
Coking (Feed Rate)	648	334	982
Hydrogen Manufacturing (MMSCF/D)	575	603	1,178

*The effective capacities as used in the study are derived from actual stream day capacity as follows:

Crude Oil Distillation Units

Effective Capacity = Actual Capacity x 95 percent x 93 percent

All Other Process Units

Effective Capacity = Actual Capacity x 90 percent x 93 percent

†C_4 through C_6 naphtha isomerization.

§Primarily reformer feedstock treating.

¶Catalytic cracker feedstocks and light distillate products treating.

**Primarily hydrocracking to lighter products.

††Hydrotreating residual oil.

January 1979 NPC Survey of Petroleum Refining Capabilities[2] are also shown. Facility needs are shown separately for PADs I-IV and PAD V refineries, as well as for the total United States. The corresponding cost estimates of the construction program are in constant 1978 dollars. It should be noted that construction costs have been increasing at an annual rate of 8 percent per year since 1976. The costs are undoubtedly low because the model optimized approach tends to place the new or expanded facilities preferentially at the larger refineries, which leads to larger units and lower per-barrel costs than might actually occur. Also, the estimates do not include any of the very large investment requirements for sustaining existing facilities, improving efficiency, energy conservation, environmental protection and safety, and any facilities outside the refinery.

[2]Survey data are presented in Chapter Three of Refinery Flexibility, an Interim Report, published by the National Petroleum Council in December 1979.

TABLE 54

PADs I-IV

Process Capacity Needed Over 1978 Capacity -- High Case*

(MB/SD)

Process Facility	Planned 1982†	Crude Oil Slate A Cumulative Expansion 1982	1985	1990	Crude Oil Slate B Cumulative Expansion 1982	1985	1990
Crude Oil Distillation	937	514	890	1,446	516	938	1,395
Vacuum Distillation	352	206	356	578	207	375	558
Catalytic Reforming	406	706	706	1,053	700	700	953
Catalytic Cracking	382	0	0	0	0	0	0
Alkylation	48	239	260	295	291	291	415
Isomerization	22	0	0	0	0	0	0
Polymerization	8	0	0	0	0	0	0
Hydrotreating							
Naphtha	604	1,266	1,266	1,266	1,310	1,310	1,310
Distillate	260	1,421	1,561	1,723	1,350	1,502	1,560
Hydrorefining							
Gas Oil	3	15	15	46	2	2	7
Residual Oil	0	0	0	0	0	0	0
Residual Conversion	37	175	175	300	248	248	349
Estimated Cost§	--	2,686	2,906	3,910	2,775	2,957	3,769

*Data derived from the April 1979 NPC Survey of U.S. and World Energy and Oil Supply/Demand Forecasts.

†Based on response to the January 1979 NPC Survey of Petroleum Refining Capabilities.

§Estimated cost based on 1978 construction costs. Cost is in millions of dollars.

TABLE 55

PAD V
Process Capacity Needed Over 1978 Capacity -- High Case*
(MB/SD)

Process Facility	Planned 1982†	Crude Oil Slate A Cumulative Expansion 1982	1985	1990	Crude Oil Slate B Cumulative Expansion 1982	1985	1990
Crude Oil Distillation	156	0	5	8	0	1	1
Vacuum Distillation	56	0	2	3	0	0	0
Catalytic Reforming	66	66	153	552	49	152	504
Catalytic Cracking	25	24	27	33	105	105	105
Alkylation	0	16	16	16	14	14	14
Isomerization	0	1	1	1	1	1	1
Polymerization	0	0	0	0	0	0	0
Hydrotreating							
Naphtha	37	33	53	104	30	58	87
Distillate	81	779	872	887	705	808	893
Hydrorefining							
Gas Oil	18	0	0	30	0	0	23
Residual Oil	0	0	0	0	0	0	0
Residual Conversion	9	112	139	179	83	112	188
Estimated Cost§	--	811	1,078	1,644	814	1,061	1,802

*Data derived from the April 1979 NPC Survey of U.S. and World Energy and Oil Supply/Demand Forecasts.

†Based on response to the January 1979 NPC Survey of Petroleum Refining Capabilities.

§Estimated cost based on 1978 construction costs. Cost is in millions of dollars.

TABLE 56

Total U.S.
Process Capacity Needed Over 1978 Capacity -- High Case*
(MB/SD)

Process Facility	Planned 1982†	Crude Oil Slate A Cumulative Expansion 1982	1985	1990	Crude Oil Slate B Cumulative Expansion 1982	1985	1990
Crude Oil Distillation	1,093	514	895	1,454	516	939	1,396
Vacuum Distillation	408	206	358	581	207	375	558
Catalytic Reforming	472	772	859	1,605	749	852	1,457
Catalytic Cracking	407	24	27	33	105	105	105
Alkylation	48	255	276	311	305	305	429
Isomerization	22	1	1	1	1	1	1
Polymerization	8	0	0	0	0	0	0
Hydrotreating							
Naphtha	641	1,299	1,319	1,370	1,340	1,368	1,397
Distillate	341	2,200	2,433	2,610	2,055	2,310	2,453
Hydrorefining							
Gas Oil	21	15	15	76	2	2	30
Residual Oil	0	0	0	0	0	0	0
Residual Conversion	46	287	314	479	331	360	537
Estimated Cost§	--	3,497	3,984	5,554	3,589	4,018	5,571

*Data derived from the April 1979 NPC Survey of U.S. and World Energy and Oil Supply/Demand Forecasts.

†Based on response to the January 1979 NPC Survey of Petroleum Refining Capabilities.

§Estimated cost based on 1978 construction costs. Cost is in millions of dollars.

TABLE 57

PADs I-IV
Process Capacity Needed Over 1978 Capacity -- Medium Case*
(MB/SD)

Process Facility	Planned 1982†	Crude Oil Slate A Cumulative Expansion 1982	1985	1990	Crude Oil Slate B Cumulative Expansion 1982	1985	1990
Crude Oil Distillation	937	0	0	0	0	0	99
Vacuum Distillation	352	0	0	0	0	0	40
Catalytic Reforming	406	379	678	843	391	695	876
Catalytic Cracking	382	0	0	0	0	0	0
Alkylation	48	5	23	26	7	25	25
Isomerization	22	0	0	0	0	0	0
Polymerization	8	0	0	0	0	0	0
Hydrotreating							
Naphtha	604	971	971	980	1,029	1,029	1,029
Distillate	260	746	783	865	704	756	886
Hydrorefining							
Gas Oil	3	74	74	113	68	68	80
Residual Oil	0	0	0	0	0	0	0
Residual Conversion	37	213	301	422	274	363	464
Estimated Cost§	--	1,327	1,855	2,352	1,244	1,937	2,369

*Data derived from the December 1979 NPC Survey of U.S. and World Energy and Oil Supply/Demand Forecasts.

†Based on response to the January 1979 NPC Survey of Petroleum Refining Capabilities.

§Estimated cost based on 1978 construction costs. Cost is in millions of dollars.

TABLE 58

PAD V

Process Capacity Needed Over 1978 Capacity -- Medium Case*

(MB/SD)

Process Facility	Planned 1982†	Crude Oil Slate A Cumulative Expansion			Crude Oil Slate B Cumulative Expansion		
		1982	1985	1990	1982	1985	1990
Crude Oil Distillation	156	0	0	0	0	0	0
Vacuum Distillation	56	0	0	0	0	0	0
Catalytic Reforming	66	33	142	330	36	161	380
Catalytic Cracking	25	17	17	17	23	23	23
Alkylation	0	0	5	5	0	0	0
Isomerization	0	2	2	2	0	0	0
Polymerization	0	0	0	0	0	0	0
Hydrotreating							
Naphtha	37	14	24	91	0	11	137
Distillate	81	16	55	423	27	116	799
Hydrorefining							
Gas Oil	18	0	0	25	0	0	0
Residual Oil	0	0	0	0	0	0	0
Residual Conversion	9	40	109	119	86	174	225
Estimated Cost†	--	163	487	1,045	231	620	1,465

*Data derived from the December 1979 NPC Survey of U.S. and World Energy and Oil Supply/Demand Forecasts.

†Based on response to the January 1979 NPC Survey of Petroleum Refining Capabilities.

§Estimated cost based on 1978 construction costs. Cost is in millions of dollars.

TABLE 59

Total U.S.
Process Capacity Needed Over 1978 Capacity -- Medium Case*
(MB/SD)

Process Facility	Planned 1982†	Crude Oil Slate A Cumulative Expansion 1982	1985	1990	Crude Oil Slate B Cumulative Expansion 1982	1985	1990
Crude Oil Distillation	1,093	0	0	0	0	0	99
Vacuum Distillation	408	0	0	0	0	0	40
Catalytic Reforming	472	412	820	1,173	427	856	1,256
Catalytic Cracking	407	17	17	17	23	23	23
Alkylation	48	5	28	31	7	25	25
Isomerization	22	2	2	2	0	0	0
Polymerization	8	0	0	0	0	0	0
Hydrotreating							
Naphtha	641	985	995	1,071	1,029	1,040	1,166
Distillate	341	762	838	1,288	731	872	1,685
Hydrorefining							
Gas Oil	21	74	74	138	68	68	80
Residual Oil	0	0	0	0	0	0	0
Residual Conversion	46	253	410	541	360	537	689
Estimated Cost§	--	1,490	2,342	3,397	1,475	2,557	3,834

*Data derived from the December 1979 NPC Survey of U.S. and World Energy and Oil Supply/Demand Forecasts.

†Based on response to the January 1979 NPC Survey of Petroleum Refining Capabilities.

§Estimated cost based on 1978 construction costs. Cost is in millions of dollars.

TABLE 60

PADs I-IV

Process Capacity Needed Over 1978 Capacity -- Low Case*

(MB/SD)

Process Facility	Planned 1982†	Crude Oil Slate A Cumulative Expansion 1982	1985	1990	Crude Oil Slate B Cumulative Expansion 1982	1985	1990
Crude Oil Distillation	937	--	0	0	--	0	0
Vacuum Distillation	352	--	0	0	--	0	0
Catalytic Reforming	406	--	556	869	--	554	881
Catalytic Cracking	382	--	0	0	--	0	0
Alkylation	48	--	18	18	--	22	23
Isomerization	22	--	0	0	--	0	0
Polymerization	8	--	0	0	--	0	0
Hydrotreating							
Naphtha	604	--	562	570	--	584	588
Distillate	260	--	626	675	--	524	633
Hydrorefining							
Gas Oil	3	--	27	104	--	29	100
Residual Oil	0	--	0	0	--	0	0
Residual Conversion	37	--	302	352	--	340	434
Estimated Cost§	--	--	1,375	2,029	--	1,404	2,144

*Data derived from the December 1979 NPC Survey of U.S. and World Energy and Oil Supply/Demand Forecasts.

†Based on response to the January 1979 NPC Survey of Petroleum Refining Capabilities.

§Estimated cost based on 1978 construction costs. Cost is in millions of dollars.

TABLE 61

PAD V
Process Capacity Needed Over 1978 Capacity -- Low Case*
(MB/SD)

Process Facility	Planned 1982†	Crude Oil Slate A Cumulative Expansion 1982	1985	1990	Crude Oil Slate B Cumulative Expansion 1982	1985	1990
Crude Oil Distillation	156	--	0	0	--	0	0
Vacuum Distillation	56	--	0	0	--	0	0
Catalytic Reforming	66	--	114	306	--	134	298
Catalytic Cracking	25	--	24	24	--	15	18
Alkylation	0	--	2	2	--	0	0
Isomerization	0	--	3	3	--	3	3
Polymerization	0	--	0	0	--	0	0
Hydrotreating							
Naphtha	37	--	38	93	--	37	85
Distillate	81	--	41	558	--	38	720
Hydrorefining							
Gas Oil	18	--	6	23	--	4	30
Residual Oil	0	--	0	0	--	0	0
Residual Conversion	9	--	92	144	--	98	205
Estimated Cost§	--	--	424	1,133	--	403	1,262

*Data derived from the December 1979 NPC Survey of U.S. and World Energy and Oil Supply/Demand Forecasts.

†Based on response to the January 1979 NPC Survey of Petroleum Refining Capabilities.

§Estimated cost based on 1978 construction costs. Cost is in millions of dollars.

TABLE 62

Total U.S.
Process Capacity Needed Over 1978 Capacity -- Low Case*
(MB/SD)

Process Facility	Planned 1982†	Crude Oil Slate A Cumulative Expansion 1982	1985	1990	Crude Oil Slate B Cumulative Expansion 1982	1985	1990
Crude Oil Distillation	1,093	--	0	0	--	0	0
Vacuum Distillation	408	--	0	0	--	0	0
Catalytic Reforming	472	--	670	1,175	--	688	1,179
Catalytic Cracking	407	--	24	24	--	15	18
Alkylation	48	--	20	20	--	22	23
Isomerization	22	--	3	3	--	3	3
Polymerization	8	--	0	0	--	0	0
Hydrotreating							
Naphtha	641	--	600	663	--	621	673
Distillate	341	--	667	1,233	--	562	1,353
Hydrorefining							
Gas Oil	21	--	33	127	--	33	130
Residual Oil	0	--	0	0	--	0	0
Residual Conversion	46	--	394	496	--	438	639
Estimated Cost§	--	--	1,799	3,162	--	1,807	3,406

*Data derived from the December 1979 NPC Survey of U.S. and World Energy and Oil Supply/Demand Forecasts.

†Based on response to the January 1979 NPC Survey of Petroleum Refining Capabilities.

§Estimated cost based on 1978 construction costs. Cost is in millions of dollars.

This study found that no expansion of crude oil distillation capacity per se is required except in the high case, which needs a 6.9 percent increase in 1990 over 1978 actual capacity for PADs I-IV. In the medium case, no increase in crude oil distillation would be required, although the model, for economic reasons, chooses to expand the high complexity refineries a modest amount and slack off operations at the simpler refineries. In light of the refiners' expansion plans indicated by the January 1979 NPC survey, crude oil distillation capacity should not be a bottleneck under any foreseeable circumstances.

All the scenarios, however, call for significant capacity increases in catalytic reforming, hydrotreating, and residual conversion (e.g., coking) (Figures 30, 31, and 32). The high case also calls for expansion of alkylation capacity. In view of the refiners' plans for expansion of downstream facilities indicated by the January 1979 NPC survey, the expectation is that naphtha reforming capacity will be adequate in 1982, but that residual conversion and hydrotreating will remain bottlenecks unless refiners expand beyond their earlier plans. The apparent inadequacy is traceable in part to the more optimistic outlook for crude oil quality that individual refiners held at the time of the January 1979 NPC survey.

As shown in Table 59, U.S. refiners will need to add $3.8 billion (1978 dollars) of process modifications by 1990 to meet the forecast medium product demand and process crude oil slate B. The principal refinery changes are a 34 percent increase (1,256 MB/SD) in catalytic reforming and an associated 31 percent increase (1,170 MB/SD) in naphtha hydrotreating; a 63 percent increase (1,685 MB/SD) in distillate hydrotreating; and a 58 percent increase (689 MB/SD) in residual conversion. Roughly two-thirds of this construction program needs to be in place by 1985.

Tables 63 through 83 show the refining input/output balances and process utilization for the various cases. Forecast demands for the major products are exactly met. The deviations allowed on residual fuel oil and LPG can be translated into adjustments of imports of those products. Total product demand is fulfilled by refinery output combined with product imports and LPG from natural gas processing plants. Refinery output equals refinery input plus volume gain in processing. The tabulated demands reflect aviation gasoline as part of leaded premium gasoline, and the item "other special and petrochemical" includes special naphthas and petrochemical feedstocks, both distillate and naphtha types (exclusive of BTX aromatics, shown separately).

If product demand and crude oil supply availabilities in 1982 materialize as forecast, but refiners' expansions are limited to just those reported in the January 1979 NPC survey, the industry may not be capable of fulfilling all product requirements. Table 84 illustrates this for the high case and crude oil slate B, the combination that taxes refinery capability most severely. In this instance the model shows the industry falling short of meeting demands for light products by 521 MB/D. Although for this illustration it is assumed that the distillate production would carry a

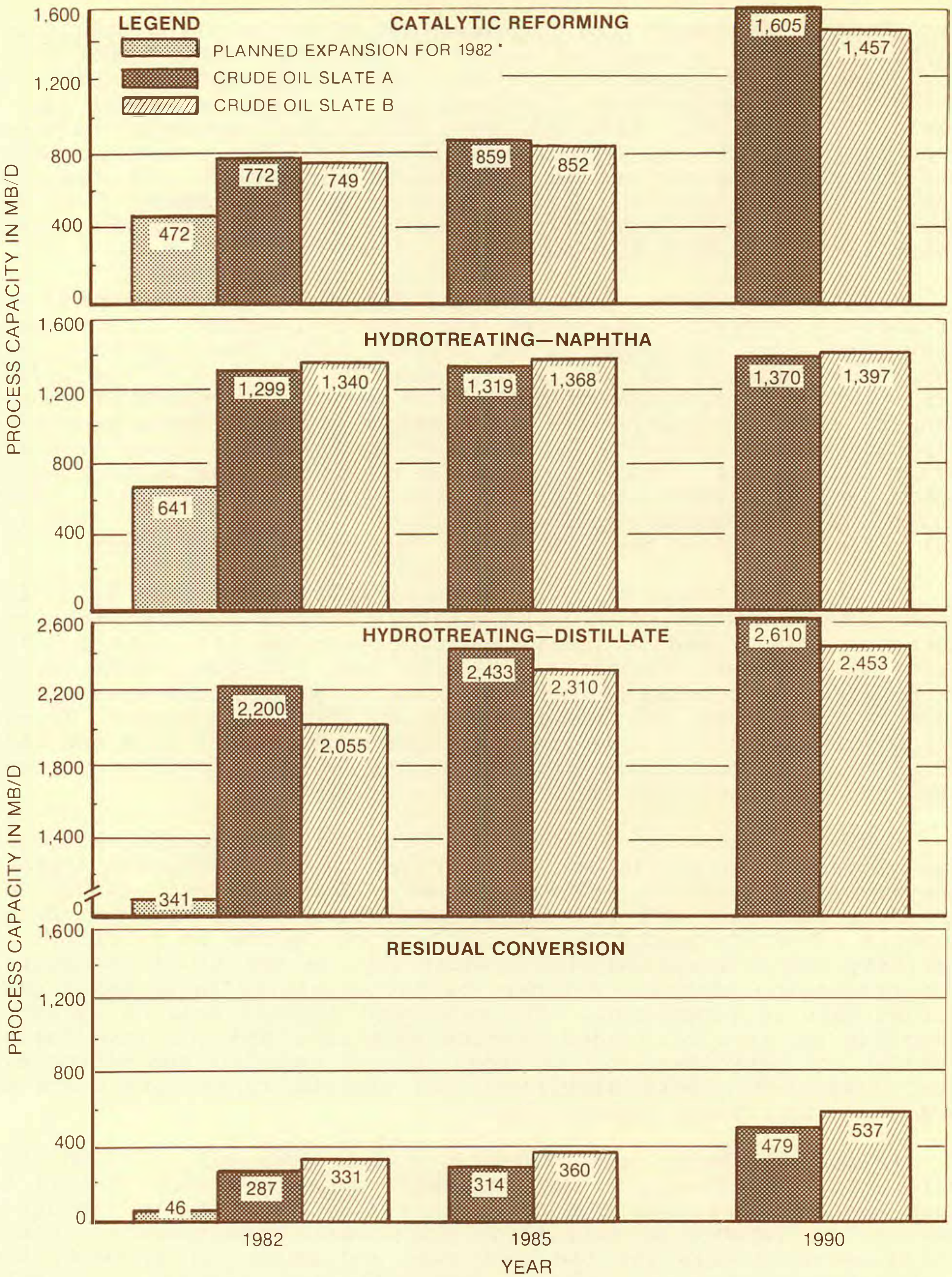

Figure 30. Total U.S. Process Capacity Needed Over 1978 Capacity for the High Case.

*Based on responses to the January 1979 NPC Survey of Petroleum Refining Capabilities.

NOTE: This figure was plotted from data in Table 56 of Chapter Two.

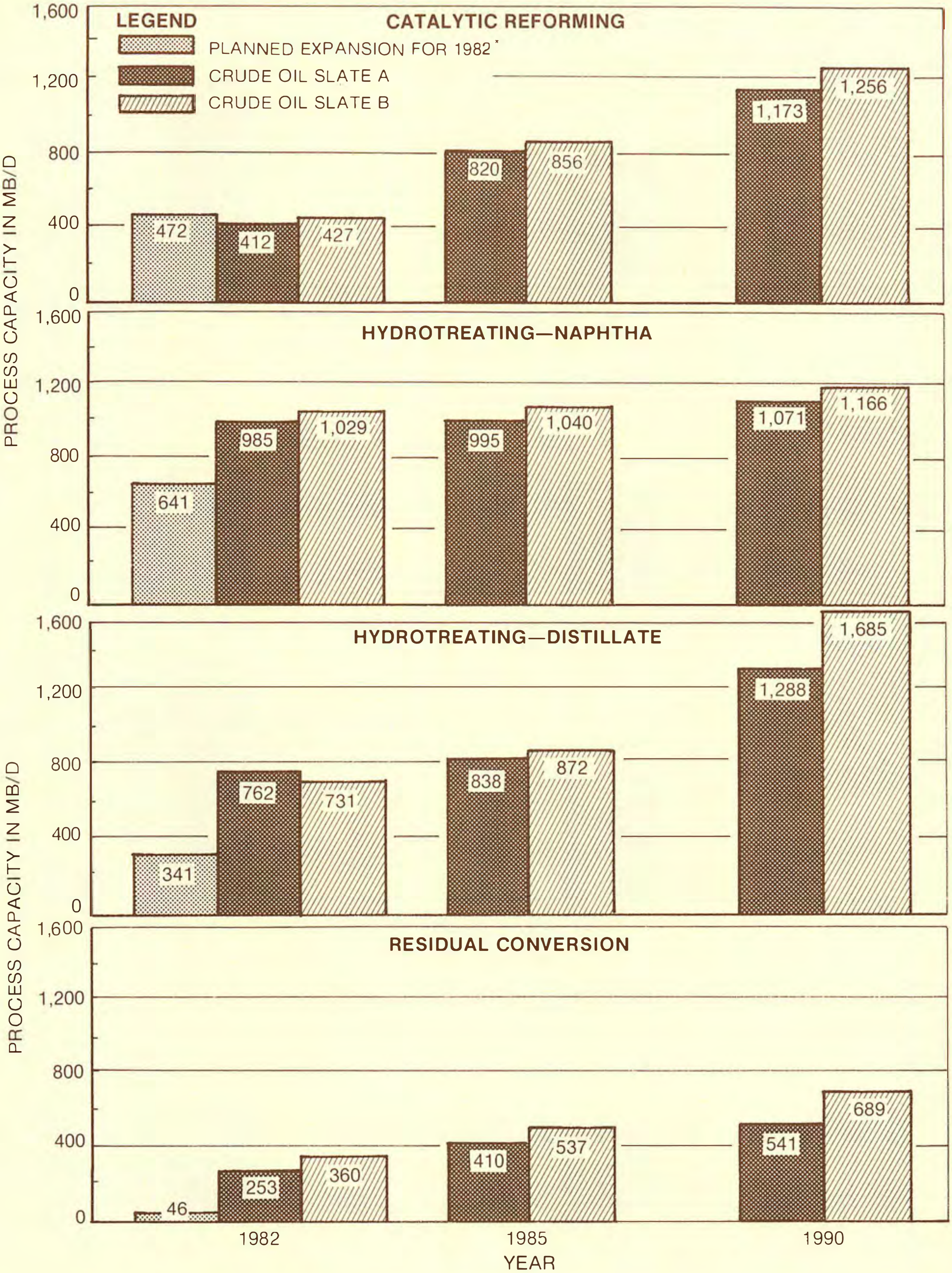

Figure 31. Total U.S. Process Capacity Needed Over 1978 Capacity for the Medium Case.

*Based on responses to the January 1979 NPC Survey of Petroleum Refining Capabilities.
NOTE: This figure was plotted from data in Table 59 of Chapter Two.

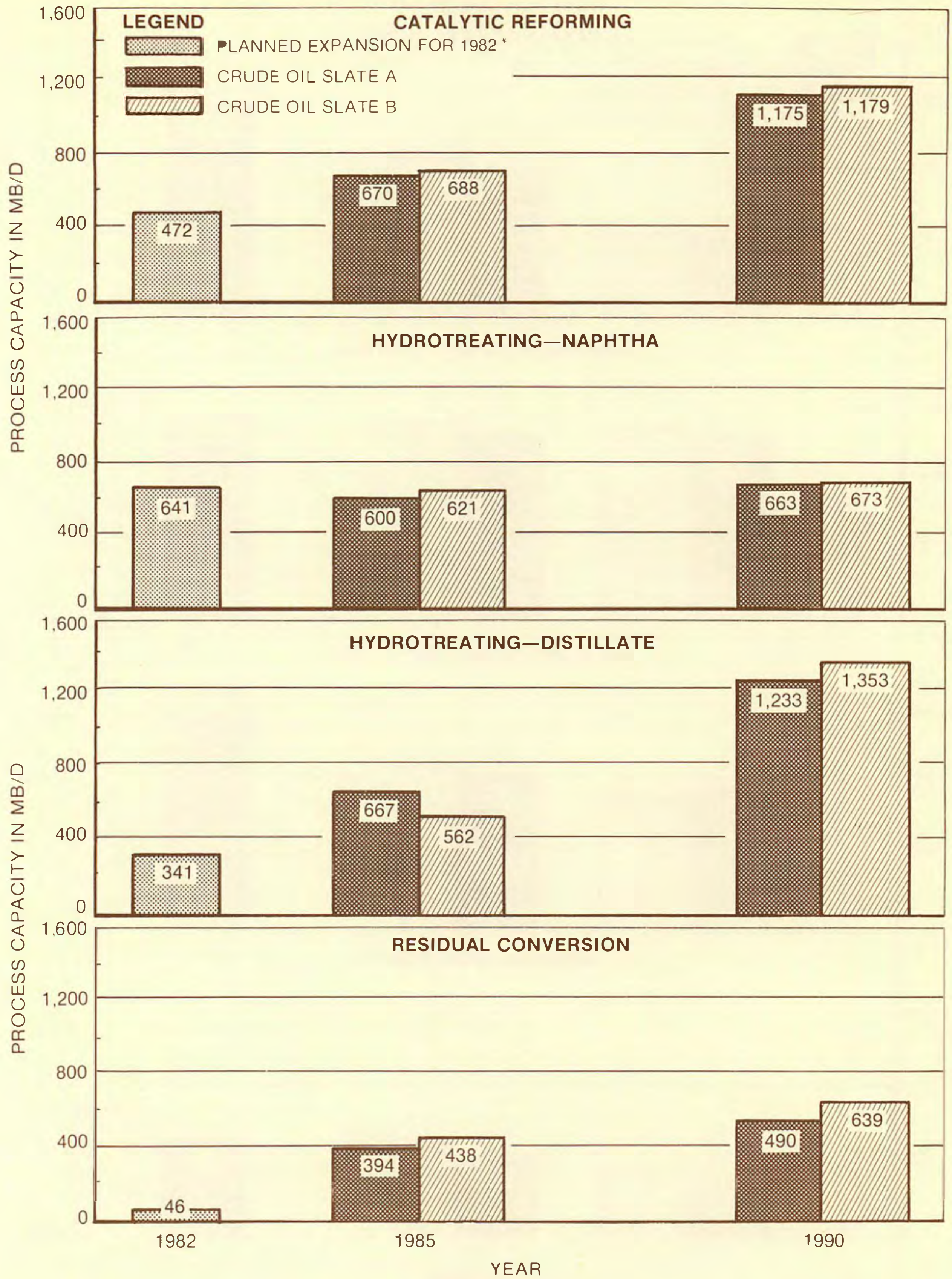

Figure 32. Total U.S. Process Capacity Needed Over 1978 Capacity for the Low Case.

*Based on responses to the January 1979 NPC Survey of Petroleum Refining Capabilities.

NOTE: This figure was plotted from data in Table 62 of Chapter Two.

higher priority than gasoline, industry flexibility exists to vary the composition of this shortfall between gasoline and distillates depending on the relative values placed thereon.

Impact of Crude Oil Supply Disruption

The impact upon major products (i.e., motor gasoline, distillate, and residual fuel oil) of various disruptions in foreign crude oil supply has also been examined. The crude oil losses were superimposed on the medium case in 1982 (Table 85) and 1985 (Table 86) with the base crude oil volumes being those in crude oil slate B. The types of disruptions considered were a 2,000 MB/D shortfall of foreign sweet crude oil, with and without replacement by other types, and a 5,000 MB/D shortfall of foreign average crude oil. As a point of reference, 2,000 MB/D of crude oil represents 13.8 percent of the total projected 1982 crude oil runs in the U.S. and 13.4 percent of the 1985 total, whereas 5,000 MB/D represents 34.4 percent of the 1982 total and 33.6 percent of the 1985 total.

The results shown indicate the net impact on an average daily basis apart from the use of either industry or government crude oil or product reserve stocks. These reserves would offer somewhat of a buffer for the consumer depending upon the length of any disruption of crude oil supply.

In the disruption cases an attempt was made to test refinery flexibility by decreasing production of gasoline only, while maintaining production of the other major products to the extent feasible. If it was necessary to short other products, the allocation of the shortfall, by product, was set by economics. The remaining motor gasoline produced was required to be in the same proportion, by grade, as in the base case. Because the disruptions are unpredictable in their timing, and presumably, too infrequent to justify refinery modifications, the process capacities are the same as in the respective base case.

In the case of a 2,000 MB/D loss of foreign sweet crude oil in 1982 it was feasible to allow about 80 percent of the major product shortfall to show up as motor gasoline. This represents a 23 percent shortfall in the 1982 total projected motor gasoline pool. The upper section of Table 85 shows this case. It was assumed that the 2,000 MB/D loss of foreign sweet crude oil would be allocated between PADs I-IV and PAD V in proportion to their normal dependence on such crude oil. PAD V, being less dependent on foreign supply sources, suffers relatively little on this basis.

If this crude oil reduction of 2,000 MB/D is allowed to be made up with the foreign light, high-sulfur crude oil assumed to be available, the total product shortfall is negligible with lower gasoline production offset by higher volumes of distillate and residual fuel oil. This is shown in the center section of Table 85. Also, if higher than normal values were placed on gasoline relative to distillate, refineries could undoubtedly rebalance production between the two. It is noteworthy, however, that the average sulfur level of residual fuel oil has to rise in order to make

TABLE 63

PADs I-IV
Industry Input -- 1982
(MB/D)

	Estimated	Projected 1982					
		Crude Oil Slate A			Crude Oil Slate B		
	1978	High	Medium	Low	High	Medium	Low
Refinery Inputs - Crude Oil							
Domestic							
Sweet	4,426	3,860	3,748	--	3,665	3,565	--
Light Medium-Sulfur	286	225	220	--	225	220	--
Heavy Medium-Sulfur	144	151	145	--	213	207	--
Light High-Sulfur	852	1,113	1,080	--	1,173	1,141	--
Heavy High-Sulfur	858	801	790	--	874	850	--
Total Domestic Crude	6,566	6,150	5,983	--	6,150	5,983	--
Foreign							
Sweet	2,713	3,228	2,723	--	3,022	2,540	--
Light Medium-Sulfur	412	444	391	--	444	391	--
Heavy Medium-Sulfur	198	250	221	--	322	281	--
Light High-Sulfur	1,363	2,230	1,973	--	2,304	2,034	--
Heavy High-Sulfur	758	938	797	--	998	859	--
Total Foreign Crude	5,444	7,090	6,105	--	7,090	6,105	--
Total Crude Oil	12,010	13,240	12,088	--	13,240	12,088	--
Refinery Inputs - Other							
Domestic Condensate	87	134	122	--	134	122	--
Natural Gasoline	350	350	350	--	350	350	--
Butanes	260	807	597	--	831	608	--
Outside Fuel				--			--
and Plant Liquid Fuel	277	298	298	--	298	298	--
Total Other Inputs	974	1,589	1,367	--	1,613	1,378	--
Total Refinery Inputs	12,984	14,829	13,455	--	14,853	13,466	--

TABLE 64

PADs I-IV

Industry Outputs -- 1982

(MB/D)

	Estimated 1978	Projected 1982					
		Crude Oil Slate A			Crude Oil Slate B		
		High	Medium	Low	High	Medium	Low
Product Demands							
Liquified Petroleum Gases	1,355	1,473	1,508	--	1,473	1,508	--
Motor Gasoline							--
Regular Unleaded	2,026	2,672	3,641	--	2,672	3,641	--
Regular Leaded	3,600	2,480	1,468	--	2,480	1,468	--
Premium Unleaded	0	1,135	88	--	1,135	88	--
Premium Leaded	686	150	678	--	150	678	--
Total Gasoline	6,312	6,437	5,875	--	6,437	5,875	--
Jet Fuel							
Naphtha	143	132	137	--	132	137	--
Kerosine	613	707	672	--	707	672	--
Total Jet Fuel	756	839	809	--	839	809	--
Kerosine and No. 1 Fuel Oil	194	213	188	--	213	188	--
Diesel Fuel	844	1,109	984	--	1,109	984	--
No. 2 Distillate	2,145	2,216	2,012	--	2,216	2,012	--
Heavy Fuel Oil							
0 to 0.5 wt % Sulfur	641	688	547	--	688	547	--
0.5 to 1.0 wt % Sulfur	672	803	566	--	803	566	--
1.0 to 2.0 wt % Sulfur	426	518	305	--	518	305	--
2.0+ wt % Sulfur	796	650	695	--	650	695	--
Total Heavy Fuel Oil	2,535	2,659	2,113	--	2,659	2,113	--
No. 4 Fuel Oil	58	63	69	--	63	69	--
Asphalt	401	419	420	--	419	420	--
Lubricants	153	164	164	--	164	164	--
Other Special and Petrochemical	559	764	718	--	764	718	--
Aromatics	178	186	207	--	186	207	--
Wax	14	16	17	--	16	17	--
Sulfur (Long Tons)*	7	7	6	--	7	7	--
Coker Coke (Short Tons)†	27	34	35	--	38	38	--
Still Gas to Fuel (FOE)	254	395	309	--	400	310	--
Total Product Demands (MB/D)	15,907	16,563	14,954	--	16,587	14,973	--
Indicated Surplus (Deficit)							
LPG (Gas Plants & Imports)	(1,094)	(843)	(926)	--	(830)	(914)	--
Fuel Oils (Imports)	(1,876)§	(1,534)	(1,244)	--	(1,534)	(1,258)	--
Refinery Output	12,876	14,759	13,407	--	14,796	13,424	--
Volume Percent -- Refinery Output/Input	99.2	99.5	99.6	--	99.6	99.7	--

*Sulfur - 1 long ton = 3.2 bbl.

†Coke - 1 short ton = 4.72 bbl.

§All product imports in 1978.

TABLE 65

PAD V
Industry Input — 1982
(MB/D)

	Estimated 1978	Projected 1982 Crude Oil Slate A High	Crude Oil Slate A Medium	Crude Oil Slate A Low	Crude Oil Slate B High	Crude Oil Slate B Medium	Crude Oil Slate B Low
Refinery Inputs - Crude Oil							
Domestic							
Sweet	245	328	378	--	286	332	--
Light Medium-Sulfur	125	172	187	--	194	209	--
Heavy Medium-Sulfur	739	939	887	--	917	872	--
Light High-Sulfur	0	0	0	--	0	0	--
Heavy High-Sulfur	569	693	679	--	735	724	--
Total Domestic Crude	1,678	2,132	2,131	--	2,132	2,137	--
Foreign							
Sweet	499	315	244	--	305	240	--
Light Medium-Sulfur	11	33	12	--	38	14	--
Heavy Medium-Sulfur	0	0	0	--	0	0	--
Light High-Sulfur	41	63	26	--	59	23	--
Heavy High-Sulfur	10	25	16	--	35	21	--
Total Foreign Crude	561	436	298	--	437	298	--
Total Crude Oil	2,239	2,568	2,429	--	2,569	2,435	--
Refinery Inputs - Other							
Domestic Condensate	0	0	0	--	0	0	--
Natural Gasoline	195	195	195	--	195	195	--
Butanes	15	93	12	--	105	13	--
Outside Fuel and Plant Liquid Fuel	44	44	44	--	44	44	--
Total Other Inputs	254	332	251	--	344	252	--
Total Refinery Inputs	2,493	2,900	2,680	--	2,913	2,687	--

TABLE 66

PAD V
Industry Outputs -- 1982
(MB/D)

	Estimated 1978	Projected 1982 Crude Oil Slate A High	Crude Oil Slate A Medium	Crude Oil Slate A Low	Crude Oil Slate B High	Crude Oil Slate B Medium	Crude Oil Slate B Low
Product Demands							
Liquified Petroleum Gases	60	66	64	--	66	64	--
Motor Gasoline							
Regular Unleaded	161	517	486	--	517	486	--
Regular Leaded	506	388	364	--	388	364	--
Premium Unleaded	184	206	193	--	206	193	--
Premium Leaded	287	48	44	--	48	44	--
Total Gasoline	1,138	1,159	1,087	--	1,159	1,087	--
Jet Fuel							
Naphtha	56	52	48	--	52	48	--
Kerosine	245	294	274	--	294	274	--
Total Jet Fuel	301	346	322	--	346	322	--
Kerosine and No. 1 Fuel Oil	21	20	20	--	20	20	--
Diesel Fuel	144	187	223	--	187	223	--
No. 2 Distillate	198	185	141	--	185	141	--
Heavy Fuel Oil							
0 to 0.5 wt % Sulfur	221	382	214	--	382	214	--
0.5 to 1.0 wt % Sulfur	44	37	30	--	37	30	--
1.0 to 2.0 wt % Sulfur	215	133	223	--	133	223	--
2.0+ wt % Sulfur	8	29	20	--	29	20	--
Total Heavy Fuel Oil	488	581	487	--	581	487	--
No. 4 Fuel Oil	3	3	3	--	3	3	--
Asphalt	78	69	69	--	69	69	--
Lubricants	19	17	18	--	17	18	--
Other Special and Petrochemical	32	28	37	--	28	37	--
Aromatics	1	11	9	--	11	9	--
Wax	3	4	3	--	4	3	--
Sulfur (Long Tons)*	1	2	2	--	2	2	--
Coker Coke (Short Tons)†	16	23	19	--	21	21	--
Still Gas to Fuel (FOE)	114	150	119	--	150	121	--
Total Product Demands (MB/D)	2,678	2,941	2,698	--	2,932	2,707	--
Indicated Surplus (Deficit)							
LPG (Gas Plants & Imports)	0	0	0	--	0	0	--
Fuel Oils (Imports)	(146)§	(16)	0	--	(2)	0	--
Refinery Output	2,532	2,925	2,698	--	2,930	2,707	--
Volume Percent -- Refinery Output/Input	101.5	100.9	100.7	--	100.6	100.7	--

*Sulfur - 1 long ton = 3.2 bbl.
†Coke - 1 short ton = 4.72 bbl.
§All product imports in 1978.

TABLE 67

Total U.S.
Industry Input -- 1982
(MB/D)

	Estimated	Projected 1982					
		Crude Oil Slate A			Crude Oil Slate B		
	1978	High	Medium	Low	High	Medium	Low
Refinery Inputs - Crude Oil							
Domestic							
Sweet	4,671	4,188	4,126	--	3,951	3,897	--
Light Medium-Sulfur	411	397	407	--	419	429	--
Heavy Medium-Sulfur	883	1,090	1,032	--	1,130	1,079	--
Light High-Sulfur	852	1,113	1,080	--	1,173	1,141	--
Heavy High-Sulfur	1,427	1,494	1,469	--	1,609	1,574	--
Total Domestic Crude	8,244	8,282	8,114	--	8,282	8,120	--
Foreign							
Sweet	3,212	3,543	2,967	--	3,327	2,780	--
Light Medium-Sulfur	423	477	403	--	482	405	--
Heavy Medium-Sulfur	198	250	221	--	322	281	--
Light High-Sulfur	1,404	2,293	1,999	--	2,363	2,057	--
Heavy High-Sulfur	768	963	813	--	1,033	880	--
Total Foreign Crude	6,005	7,526	6,403	--	7,527	6,403	--
Total Crude Oil	14,249	15,808	14,517	--	15,809	14,523	--
Refinery Inputs - Other							
Domestic Condensate	87	134	122	--	134	122	--
Natural Gasoline	545	545	545	--	545	545	--
Butanes	275	900	609	--	936	621	--
Outside Fuel and Plant Liquid Fuel	321	342	342	--	342	342	--
Total Other Inputs	1,228	1,921	1,618	--	1,957	1,630	--
Total Refinery Inputs	15,477	17,729	16,135	--	17,766	16,153	--

TABLE 68

Total U.S.
Industry Outputs -- 1982
(MB/D)

	Estimated	Projected 1982					
		Crude Oil Slate A			Crude Oil Slate B		
	1978	High	Medium	Low	High	Medium	Low
Product Demands							
Liquified Petroleum Gases	1,415	1,539	1,572	--	1,539	1,572	--
Motor Gasoline							
Regular Unleaded	2,187	3,189	4,127	--	3,189	4,127	--
Regular Leaded	4,106	2,868	1,832	--	2,868	1,832	--
Premium Unleaded	184	1,341	281	--	1,341	281	--
Premium Leaded	973	198	722	--	198	722	--
Total Gasoline	7,450	7,596	6,962	--	7,596	6,962	--
Jet Fuel							
Naphtha	199	184	185	--	184	185	--
Kerosine	858	1,001	946	--	1,001	946	--
Total Jet Fuel	1,057	1,185	1,131	--	1,185	1,131	--
Kerosine and No. 1 Fuel Oil	215	233	208	--	233	208	--
Diesel Fuel	988	1,296	1,207	--	1,296	1,207	--
No. 2 Distillate	2,343	2,401	2,153	--	2,401	2,153	--
Heavy Fuel Oil							
0 to 0.5 wt % Sulfur	862	1,070	761	--	1,070	761	--
0.5 to 1.0 wt % Sulfur	716	840	596	--	840	596	--
1.0 to 2.0 wt % Sulfur	641	651	528	--	651	528	--
2.0+ wt % Sulfur	804	679	715	--	679	715	--
Total Heavy Fuel Oil	3,023	3,240	2,600	--	3,240	2,600	--
No. 4 Fuel Oil	61	66	72	--	66	72	--
Asphalt	479	488	489	--	488	489	--
Lubricants	172	181	182	--	181	182	--
Other Special and Petrochemical	591	792	755	--	792	755	--
Aromatics	179	197	216	--	197	216	--
Wax	17	20	20	--	20	20	--
Sulfur (Long Tons)*	8	9	8	--	9	9	--
Coker Coke (Short Tons)†	43	57	54	--	59	59	--
Still Gas to Fuel (FOE)	368	545	428	--	550	431	--
Total Product Demands (MB/D)	18,585	19,504	17,652	--	19,519	17,680	--
Indicated Surplus (Deficit)							
LPG (Gas Plants & Imports)	(1,094)	(843)	(926)	--	(830)	(914)	--
Fuel Oils (Imports)	(2,083)§	(1,550)	(1,134)	--	(1,536)	(1,148)	--
Refinery Output	15,408	17,634	16,215	--	17,726	16,241	--
Volume Percent -- Refinery Output/Input	99.6	99.7	100.5	--	99.8	100.5	--

*Sulfur - 1 long ton = 3.2 bbl.
†Coke - 1 short ton = 4.72 bbl.
§All product imports in 1978.

TABLE 69

PADs I-IV

Industry Input -- 1985

(MB/D)

	Estimated 1978	Projected 1985 Crude Oil Slate A High	Medium	Low	Crude Oil Slate B High	Medium	Low
Refinery Inputs - Crude Oil							
Domestic							
Sweet	4,426	3,683	3,550	3,529	3,220	3,377	3,349
Light Medium-Sulfur	286	221	212	215	119	154	108
Heavy Medium-Sulfur	144	178	171	210	300	232	261
Light High-Sulfur	852	1,160	1,119	1,119	1,465	1,240	1,244
Heavy High-Sulfur	858	822	803	843	960	852	894
Total Domestic Crude	6,566	6,064	5,855	5,916	6,064	5,855	5,856
Foreign							
Sweet	2,713	3,346	2,804	2,464	3,395	2,603	2,286
Light Medium-Sulfur	412	468	411	354	432	344	296
Heavy Medium-Sulfur	198	304	265	233	320	329	286
Light High-Sulfur	1,363	2,423	2,120	1,953	2,394	2,249	2,068
Heavy High-Sulfur	758	1,039	879	809	1,039	954	877
Total Foreign Crude	5,444	7,580	6,479	5,813	7,580	6,479	5,813
Total Crude Oil	12,010	13,644	12,334	11,729	13,644	12,334	11,669
Refinery Inputs - Other							
Domestic Condensate	87	138	125	114	138	125	114
Natural Gasoline	350	350	350	350	350	350	350
Butanes	260	763	560	536	789	559	537
Outside Fuel and Plant Liquid Fuel	277	298	298	298	298	298	298
Total Other Inputs	974	1,549	1,333	1,298	1,575	1,332	1,299
Total Refinery Inputs	12,984	15,193	13,667	13,027	15,219	13,666	12,968

TABLE 70

PADs I-IV
Industry Outputs -- 1985
(MB/D)

	Estimated	Projected 1985					
		Crude Oil Slate A			Crude Oil Slate B		
	1978	High	Medium	Low	High	Medium	Low
Product Demands							
Liquified Petroleum Gases	1,355	1,568	1,614	1,580	1,568	1,614	1,580
Motor Gasoline							
Regular Unleaded	2,026	2,785	3,142	2,785	2,785	3,142	2,785
Regular Leaded	3,600	1,683	1,172	1,365	1,683	1,172	1,365
Premium Unleaded	0	1,593	1,171	1,370	1,593	1,171	1,370
Premium Leaded	686	13	152	0	13	152	0
Total Gasoline	6,312	6,074	5,637	5,520	6,074	5,637	5,520
Jet Fuel							
Naphtha	143	122	122	150	122	122	150
Kerosine	613	775	735	600	775	735	600
Total Jet Fuel	756	897	857	750	897	857	750
Kerosine and No. 1 Fuel Oil	194	192	185	143	192	185	143
Diesel Fuel	844	1,349	1,254	984	1,349	1,254	984
No. 2 Distillate	2,145	2,222	1,963	1,952	2,222	1,963	1,952
Heavy Fuel Oil							
0 to 0.5 wt % Sulfur	641	727	563	310	727	563	310
0.5 to 1.0 wt % Sulfur	672	836	473	412	836	473	412
1.0 to 2.0 wt % Sulfur	426	524	518	214	524	518	214
2.0+ wt % Sulfur	796	631	555	602	631	555	602
Total Heavy Fuel Oil	2,535	2,718	2,109	1,538	2,718	2,109	1,538
No. 4 Fuel Oil	58	67	83	63	67	83	63
Asphalt	401	436	437	455	436	437	455
Lubricants	153	172	171	160	172	171	160
Other Special and Petrochemical	559	940	802	761	940	802	761
Aromatics	178	187	211	184	187	211	184
Wax	14	17	18	17	17	18	17
Sulfur (Long Tons)*	7	7	7	6	7	7	7
Coker Coke (Short Tons)†	27	33	38	38	36	41	40
Still Gas to Fuel (FOE)	254	414	331	307	419	333	308
Total Product Demands (MB/D)	15,907	16,860	15,318	14,016	16,879	15,334	14,030
Indicated Surplus (Deficit)							
LPG (Gas Plants & Imports)	(1,094)	(895)	(965)	(945)	(897)	(946)	(942)
Fuel Oils (Imports)	(1,937)§	(1,440)	(1,288)	(691)	(1,440)	(1,304)	(761)
Refinery Output	12,876	15,096	13,621	12,977	15,113	13,640	12,924
Volume Percent -- Refinery Output/Input	99.2	99.4	99.7	99.6	99.3	99.8	99.7

*Sulfur - 1 long ton = 3.2 bbl.
†Coke - 1 short ton = 4.72 bbl.
§All product imports in 1978.

TABLE 71

PAD V
Industry Input -- 1985
(MB/D)

		Projected 1985					
	Estimated	Crude Oil Slate A			Crude Oil Slate B		
	1978	High	Medium	Low	High	Medium	Low
Refinery Inputs - Crude Oil							
Domestic							
Sweet	245	310	396	382	278	311	299
Light Medium-Sulfur	125	174	193	188	198	213	203
Heavy Medium-Sulfur	739	963	951	894	919	923	862
Light High-Sulfur	0	0	0	0	0	0	0
Heavy High-Sulfur	569	743	721	687	795	820	785
Total Domestic Crude	1,678	2,190	2,261	2,151	2,190	2,267	2,149
Foreign							
Sweet	499	345	228	207	335	224	203
Light Medium-Sulfur	11	40	11	10	43	14	13
Heavy Medium-Sulfur	0	0	0	0	0	0	0
Light High-Sulfur	41	65	23	21	62	18	17
Heavy High-Sulfur	10	31	17	15	42	23	20
Total Foreign Crude	561	481	279	253	482	279	253
Total Crude Oil	2,239	2,671	2,540	2,404	2,672	2,546	2,402
Refinery Inputs - Other							
Domestic Condensate	0	0	0	0	0	0	0
Natural Gasoline	195	195	195	195	195	195	195
Butanes	15	103	13	12	103	16	11
Outside Fuel and Plant Liquid Fuel	44	44	44	44	44	44	44
Total Other Inputs	254	342	252	251	342	255	250
Total Refinery Inputs	2,493	3,013	2,792	2,655	3,014	2,801	2,652

TABLE 72

PAD V
Industry Outputs -- 1985
(MB/D)

	Estimated 1978	Projected 1985: Crude Oil Slate A: High	Medium	Low	Crude Oil Slate B: High	Medium	Low
Product Demands							
Liquified Petroleum Gases	60	70	67	66	70	67	66
Motor Gasoline							
Regular Unleaded	161	518	511	415	518	511	415
Regular Leaded	506	267	212	235	267	212	235
Premium Unleaded	184	323	319	360	323	319	360
Premium Leaded	287	19	17	10	19	17	10
Total Gasoline	1,138	1,127	1,059	1,020	1,127	1,059	1,020
Jet Fuel							
Naphtha	56	49	49	50	49	49	50
Kerosine	245	327	299	300	327	299	300
Total Jet Fuel	301	376	348	350	376	348	350
Kerosine and No. 1 Fuel Oil	21	23	21	20	23	21	20
Diesel Fuel	144	224	263	231	224	263	231
No. 2 Distillate	198	184	129	130	184	129	130
Heavy Fuel Oil							
0 to 0.5 wt % Sulfur	221	411	270	245	411	270	245
0.5 to 1.0 wt % Sulfur	44	40	25	28	40	25	28
1.0 to 2.0 wt % Sulfur	215	130	202	166	130	202	166
2.0+ wt % Sulfur	8	28	20	23	28	20	23
Total Heavy Fuel Oil	488	609	517	462	609	517	462
No. 4 Fuel Oil	3	3	2	2	3	2	2
Asphalt	78	72	74	75	72	74	75
Lubricants	19	18	21	20	18	21	20
Other Special and Petrochemical	32	35	43	40	35	43	40
Aromatics	1	21	10	10	21	10	10
Wax	3	4	3	3	4	3	3
Sulfur (Long Tons)*	1	2	2	2	2	2	2
Coker Coke (Short Tons)†	16	24	23	22	23	25	22
Still Gas to Fuel (FOE)	114	177	151	143	182	151	147
Total Product Demands (MB/D)	2,678	3,063	2,823	2,682	3,063	2,832	2,686
Indicated Surplus (Deficit)							
LPG (Gas Plants & Imports)	0	0	0	0	0	0	0
Fuel Oils (Imports)	(146)§	(21)	0	0	(16)	0	0
Refinery Output	2,532	3,042	2,823	2,682	3,047	2,832	2,686
Volume Percent -- Refinery Output/Input	101.5	101.0	101.1	101.0	101.1	101.1	101.3

*Sulfur - 1 long ton = 3.2 bbl.
†Coke - 1 short ton = 4.72 bbl.
§All product imports in 1978.

TABLE 73

Total U.S.
Industry Input -- 1985
(MB/D)

	Estimated	Projected 1985					
		Crude Oil Slate A			Crude Oil Slate B		
	1978	High	Medium	Low	High	Medium	Low
Refinery Inputs - Crude Oil							
Domestic							
Sweet	4,671	3,993	3,946	3,911	3,498	3,688	3,648
Light Medium-Sulfur	411	395	405	403	317	367	311
Heavy Medium-Sulfur	883	1,141	1,122	1,104	1,219	1,155	1,123
Light High-Sulfur	852	1,160	1,119	1,119	1,465	1,240	1,244
Heavy High-Sulfur	1,427	1,565	1,524	1,530	1,755	1,672	1,679
Total Domestic Crude	8,244	8,254	8,116	8,067	8,254	8,122	8,005
Foreign							
Sweet	3,212	3,691	3,032	2,671	3,730	2,827	2,489
Light Medium-Sulfur	423	508	422	364	475	358	309
Heavy Medium-Sulfur	198	304	265	233	320	329	286
Light High-Sulfur	1,404	2,488	2,143	1,974	2,456	2,267	2,085
Heavy High-Sulfur	768	1,070	896	824	1,081	977	897
Total Foreign Crude	6,005	8,061	6,758	6,066	8,062	6,758	6,066
Total Crude Oil	14,249	16,315	14,874	14,133	16,316	14,880	14,071
Refinery Inputs - Other							
Domestic Condensate	87	138	125	114	138	125	114
Natural Gasoline	545	545	545	545	545	545	545
Butanes	275	866	573	548	892	575	548
Outside Fuel and Plant Liquid Fuel	321	342	342	342	342	342	342
Total Other Inputs	1,228	1,891	1,585	1,549	1,917	1,587	1,549
Total Refinery Inputs	15,477	18,206	16,459	15,682	18,233	16,467	15,620

TABLE 74

Total U.S.
Industry Outputs -- 1985
(MB/D)

	Estimated	Projected 1985					
		Crude Oil Slate A			Crude Oil Slate B		
	1978	High	Medium	Low	High	Medium	Low
Product Demands							
Liquified Petroleum Gases	1,415	1,638	1,681	1,646	1,638	1,681	1,646
Motor Gasoline							
Regular Unleaded	2,187	3,303	3,653	3,200	3,303	3,653	3,200
Regular Leaded	4,106	1,950	1,384	1,600	1,950	1,384	1,600
Premium Unleaded	184	1,916	1,490	1,730	1,916	1,490	1,730
Premium Leaded	973	32	169	10	32	169	10
Total Gasoline	7,450	7,201	6,696	6,540	7,201	6,696	6,540
Jet Fuel							
Naphtha	199	171	171	200	171	171	200
Kerosine	858	1,102	1,034	900	1,102	1,034	900
Total Jet Fuel	1,057	1,273	1,205	1,100	1,273	1,205	1,100
Kerosine and No. 1 Fuel Oil	215	215	206	163	215	206	163
Diesel Fuel	988	1,573	1,517	1,215	1,573	1,517	1,215
No. 2 Distillate	2,343	2,406	2,092	2,082	2,406	2,092	2,082
Heavy Fuel Oil							
0 to 0.5 wt % Sulfur	862	1,138	833	555	1,138	833	555
0.5 to 1.0 wt % Sulfur	716	876	498	440	876	498	440
1.0 to 2.0 wt % Sulfur	641	654	720	380	654	720	380
2.0+ wt % Sulfur	804	659	575	625	659	575	625
Total Heavy Fuel Oil	3,023	3,327	2,626	2,000	3,327	2,626	2,000
No. 4 Fuel Oil	61	70	85	65	70	85	65
Asphalt	479	508	511	530	508	511	530
Lubricants	172	190	192	180	190	192	180
Other Special and Petrochemical	591	975	845	801	975	845	801
Aromatics	179	208	221	194	208	221	194
Wax	17	21	21	20	21	21	20
Sulfur (Long Tons)*	8	9	9	8	9	9	9
Coker Coke (Short Tons)†	43	57	61	60	59	66	62
Still Gas to Fuel (FOE)	368	591	482	450	601	484	455
Total Product Demands (MB/D)	18,585	19,923	18,141	16,698	19,942	18,166	16,716
Indicated Surplus (Deficit)							
LPG (Gas Plants & Imports)	(1,094)	(895)	(965)	(945)	(897)	(946)	(942)
Fuel Oils (Imports)	(2,083)§	(1,461)	(1,288)	(691)	(1,456)	(1,304)	(761)
Refinery Output	15,408	18,138	16,444	15,659	18,160	16,472	15,610
Volume Percent -- Refinery Output/Input	99.6	99.6	99.9	99.9	99.6	100.0	99.9

*Sulfur - 1 long ton = 3.2 bbl.
†Coke - 1 short ton = 4.72 bbl.
§All product imports in 1978.

TABLE 75

PADs I-IV
Industry Input -- 1990
(MB/D)

	Estimated	Projected 1990					
		Crude Oil Slate A			Crude Oil Slate B		
	1978	High	Medium	Low	High	Medium	Low
Refinery Inputs - Crude Oil							
Domestic							
Sweet	4,426	3,695	3,617	3,383	3,174	3,304	3,085
Light Medium-Sulfur	286	231	225	187	135	131	111
Heavy Medium-Sulfur	144	185	181	172	219	213	197
Light High-Sulfur	852	1,268	1,261	1,186	1,719	1,587	1,490
Heavy High-Sulfur	858	917	885	850	1,049	934	895
Total Domestic Crude	6,566	6,296	6,169	5,778	6,296	6,169	5,778
Foreign							
Sweet	2,713	3,317	2,553	2,320	3,123	2,235	2,039
Light Medium-Sulfur	412	484	404	379	366	310	288
Heavy Medium-Sulfur	198	316	260	230	353	291	265
Light High-Sulfur	1,363	2,592	2,162	1,988	2,931	2,504	2,288
Heavy High-Sulfur	758	1,161	915	837	1,097	954	884
Total Foreign Crude	5,444	7,870	6,294	5,754	7,870	6,294	5,764
Total Crude Oil	12,010	14,166	12,463	11,532	14,166	12,463	11,542
Refinery Inputs - Other							
Domestic Condensate	87	143	126	112	143	126	112
Natural Gasoline	350	350	350	350	350	350	350
Butanes	260	749	536	491	839	533	485
Outside Fuel							
and Plant Liquid Fuel	277	298	298	298	298	298	298
Total Other Inputs	974	1,540	1,310	1,251	1,630	1,307	1,245
Total Refinery Inputs	12,984	15,706	13,773	12,783	15,796	13,770	12,787

TABLE 76

PADs I-IV
Industry Outputs -- 1990
(MB/D)

	Estimated 1978	Projected 1990 Crude Oil Slate A High	Medium	Low	Crude Oil Slate B High	Medium	Low
Product Demands							
Liquified Petroleum Gases	1,355	1,676	1,720	1,620	1,676	1,720	1,620
Motor Gasoline							
Regular Unleaded	2,026	2,932	3,145	3,040	2,932	3,145	3,040
Regular Leaded	3,600	939	543	405	939	543	405
Premium Unleaded	0	1,851	1,431	1,625	1,851	1,431	1,625
Premium Leaded	686	0	59	0	0	59	0
Total Gasoline	6,312	5,722	5,178	5,070	5,722	5,178	5,070
Naphtha	143	104	107	184	104	107	184
Kerosine	613	898	838	626	898	838	626
Total Jet Fuel	776	1,002	945	810	1,002	945	810
Kerosine and No. 1 Fuel Oil	194	188	181	135	188	181	135
Diesel Fuel	844	1,780	1,664	1,090	1,780	1,664	1,090
No. 2 Distillate	2,145	2,209	1,869	1,888	2,209	1,869	1,888
Heavy Fuel Oil							
0 to 0.5 wt % Sulfur	641	703	496	245	703	496	245
0.5 to 1.0 wt % Sulfur	672	854	388	289	854	388	289
1.0 to 2.0 wt % Sulfur	426	513	538	120	513	538	120
2.0+ wt % Sulfur	796	609	470	462	609	470	462
Total Heavy Fuel Oil	2,535	2,679	1,892	1,116	2,679	1,892	1,116
No. 4 Fuel Oil	58	71	90	63	71	90	63
Asphalt	401	467	460	470	467	460	470
Lubricants	153	190	189	169	190	189	169
Other Special and Petrochemical	559	1,261	1,004	947	1,261	1,004	947
Aromatics	178	190	214	185	190	214	185
Wax	14	20	20	17	20	20	17
Sulfur (Long Tons)*	7	8	7	7	8	8	7
Coker Coke (Short Tons)†	27	40	42	39	43	45	43
Still Gas to Fuel (FOE)	254	462	364	336	475	367	337
Total Product Demands (MB/D)	15,907	17,577	15,480	13,533	17,604	15,500	13,553
Indicated Surplus (Deficit)							
LPG (Gas Plants & Imports)	(1,094)	(959)	(1,062)	(980)	(971)	(1,057)	(975)
Fuel Oils (Imports)	(1,937)§	(1,528)	(1,200)	(389)	(1,483)	(1,223)	(406)
Refinery Output	12,876	15,644	13,749	12,753	15,704	13,751	12,761
Volume Percent -- Refinery Output/Input	99.2	99.6	99.8	99.8	99.4	99.9	99.8

*Sulfur - 1 long ton = 3.2 bbl.
†Coke - 1 short ton = 4.72 bbl.
§All product imports in 1978.

TABLE 77

PAD V
Industry Input -- 1990
(MB/D)

	Estimated 1978	Projected 1990 Crude Oil Slate A High	Medium	Low	Crude Oil Slate B High	Medium	Low
Refinery Inputs - Crude Oil							
Domestic							
Sweet	245	298	423	395	224	292	273
Light Medium-Sulfur	125	208	194	193	237	218	213
Heavy Medium-Sulfur	739	1,011	966	903	911	934	870
Light High-Sulfur	0	0	0	0	0	0	0
Heavy High-Sulfur	569	759	730	677	906	869	811
Total Domestic Crude	1,678	2,276	2,313	2,168	2,278	2,313	2,167
Foreign							
Sweet	499	365	207	195	345	197	185
Light Medium-Sulfur	11	9	12	11	7	13	12
Heavy Medium-Sulfur	0	0	0	0	0	0	0
Light High-Sulfur	41	32	23	21	37	17	17
Heavy High-Sulfur	10	26	15	16	44	30	29
Total Foreign Crude	561	432	257	243	433	257	243
Total Crude Oil	2,239	2,708	2,570	2,411	2,711	2,570	2,410
Refinery Inputs - Other							
Domestic Condensate	0	0	0	0	0	0	0
Natural Gasoline	195	195	191	188	195	195	193
Butanes	15	128	23	24	128	32	31
Outside Fuel and Plant Liquid Fuel	44	44	44	44	44	44	44
Total Other Inputs	254	367	258	256	367	271	268
Total Refinery Inputs	2,493	3,075	2,828	2,667	3,078	2,841	2,678

TABLE 78

PAD V
Industry Outputs -- 1990
(MB/D)

	Estimated	Projected 1990					
		Crude Oil Slate A			Crude Oil Slate B		
	1978	High	Medium	Low	High	Medium	Low
Product Demands							
Liquified Petroleum Gases	60	75	76	82	75	76	82
Motor Gasoline							
Regular Unleaded	161	497	489	460	497	489	460
Regular Leaded	506	150	81	95	150	81	95
Premium Unleaded	184	422	416	420	422	416	420
Premium Leaded	287	11	10	10	11	10	10
Total Gasoline	1,138	1,080	996	985	1,080	996	985
Jet Fuel							
Naphtha	56	36	17	31	36	17	31
Kerosine	245	400	364	359	400	364	359
Total Jet Fuel	301	436	381	390	436	381	390
Kerosine and No. 1 Fuel Oil	21	24	22	20	24	22	20
Diesel Fuel	144	293	324	290	293	324	290
No. 2 Distillate	198	189	123	127	189	123	127
Heavy Fuel Oil							
0 to 0.5 wt % Sulfur	221	346	200	165	346	200	165
0.5 to 1.0 wt % Sulfur	44	44	20	21	44	20	21
1.0 to 2.0 wt % Sulfur	215	131	218	130	131	218	130
2.0+ wt % Sulfur	8	25	15	18	25	15	18
Total Heavy Fuel Oil	488	546	453	334	546	453	334
No. 4 Fuel Oil	3	3	3	2	3	3	2
Asphalt	78	76	79	80	76	79	80
Lubricants	19	20	23	21	20	23	21
Other Special and Petrochemical	32	44	50	46	44	50	46
Aromatics	1	17	24	22	17	24	22
Wax	3	5	3	3	5	3	3
Sulfur (Long Tons)*	1	2	2	2	3	2	2
Coker Coke (Short Tons)†	16	26	23	24	26	26	27
Still Gas to Fuel (FOE)	114	213	194	193	212	201	201
Total Product Demands (MB/D)	2,678	3,150	2,866	2,715	3,153	2,887	2,737
Indicated Surplus (Deficit)							
LPG (Gas Plants & Imports)	0	0	0	0	0	0	0
Fuel Oils (Imports)	(146)§	0	0	0	0	0	0
Refinery Output	2,532	3,150	2,866	2,715	3,153	2,887	2,737
Volume Percent -- Refinery Output/Input	101.5	102.4	101.3	101.8	102.4	101.6	102.2

*Sulfur - 1 long ton = 3.2 bbl.
†Coke - 1 short ton = 4.72 bbl.
§All product imports in 1978.

TABLE 79

Total U.S.
Industry Input -- 1990
(MB/D)

	Estimated	Projected 1990					
		Crude Oil Slate A			Crude Oil Slate B		
	1978	High	Medium	Low	High	Medium	Low
Refinery Inputs - Crude Oil							
Domestic							
Sweet	4,671	3,993	4,040	3,778	3,398	3,596	3,358
Light Medium-Sulfur	411	439	419	380	372	349	324
Heavy Medium-Sulfur	883	1,196	1,147	1,075	1,130	1,147	1,067
Light High-Sulfur	852	1,268	1,261	1,186	1,719	1,587	1,490
Heavy High-Sulfur	1,427	1,676	1,615	1,527	1,955	1,803	1,706
Total Domestic Crude	8,244	8,572	8,482	7,946	8,574	8,482	7,945
Foreign							
Sweet	3,212	3,682	2,760	2,515	3,468	2,432	2,224
Light Medium-Sulfur	423	493	416	390	373	323	300
Heavy Medium-Sulfur	198	316	260	230	353	291	265
Light High-Sulfur	1,404	2,624	2,185	2,009	2,968	2,521	2,305
Heavy High-Sulfur	768	1,187	930	853	1,141	984	913
Total Foreign Crude	6,005	8,302	6,551	5,997	8,303	6,551	6,007
Total Crude Oil	14,249	16,874	15,033	13,943	16,877	15,033	13,952
Refinery Inputs - Other							
Domestic Condensate	87	143	126	112	143	126	112
Natural Gasoline	545	545	541	538	545	545	543
Butanes	275	877	559	515	967	565	516
Outside Fuel and Plant Liquid Fuel	321	342	342	342	342	342	342
Total Other Inputs	1,228	1,907	1,568	1,507	1,997	1,578	1,513
Total Refinery Inputs	15,477	18,781	16,601	15,450	18,874	16,611	15,465

TABLE 80

Total U.S.
Industry Outputs -- 1990
(MB/D)

	Estimated	Projected 1990					
		Crude Oil Slate A			Crude Oil Slate B		
	1978	High	Medium	Low	High	Medium	Low
Product Demands							
Liquified Petroleum Gases	1,415	1,751	1,796	1,702	1,751	1,796	1,751
Motor Gasoline							
Regular Unleaded	2,187	3,429	3,634	3,500	3,429	3,634	3,500
Regular Leaded	4,106	1,089	624	500	1,089	624	500
Premium Unleaded	184	2,273	1,847	2,045	2,273	1,847	2,045
Premium Leaded	973	11	69	10	11	69	10
Total Gasoline	7,450	6,802	6,174	6,055	6,802	6,174	6,055
Jet Fuel							
Naphtha	199	140	124	215	140	124	215
Kerosine	858	1,298	1,202	985	1,298	1,202	985
Total Jet Fuel	1,057	1,438	1,326	1,200	1,438	1,326	1,200
Kerosine and No. 1 Fuel Oil	215	212	203	155	212	203	155
Diesel Fuel	988	2,073	1,988	1,380	2,073	1,988	1,380
No. 2 Distillate	2,343	2,250	1,908	1,925	2,250	1,908	1,925
Heavy Fuel Oil							
0 to 0.5 wt % Sulfur	862	1,049	696	410	1,049	696	410
0.5 to 1.0 wt % Sulfur	716	898	408	310	898	408	310
1.0 to 2.0 wt % Sulfur	641	644	756	350	644	756	350
2.0+ wt % Sulfur	804	634	485	480	634	485	480
Total Heavy Fuel Oil	3,023	3,225	2,345	1,550	3,225	2,345	1,550
No. 4 Fuel Oil	61	74	93	65	74	93	65
Asphalt	479	543	539	550	543	539	550
Lubricants	172	210	212	190	210	212	190
Other Special and Petrochemical	591	1,305	1,054	993	1,305	1,054	993
Aromatics	179	207	238	207	207	238	207
Wax	17	25	23	20	25	23	20
Sulfur (Long Tons)*	8	10	9	9	11	10	9
Coker Coke (Short Tons)†	43	66	65	63	69	71	70
Still Gas to Fuel (FOE)	368	675	558	529	687	568	538
Total Product Demands (MB/D)	18,585	20,727	18,346	16,248	20,757	18,387	16,290
Indicated Surplus (Deficit)							
LPG (Gas Plants & Imports)	(1,094)	(959)	(1,062)	(980)	(971)	(1,057)	(975)
Fuel Oils (Imports)	(2,083)§	(1,528)	(1,200)	(389)	(1,483)	(1,223)	(406)
Refinery Output	15,408	18,794	16,615	15,468	18,857	16,638	15,498
Volume Percent -- Refinery Output/Input	99.6	100.1	100.1	100.1	99.9	100.2	100.2

*Sulfur - 1 long ton = 3.2 bbl.
†Coke - 1 short ton = 4.72 bbl.
§All product imports in 1978.

TABLE 81

Utilization of Process Equipment -- 1982
(Percentage of 1978 Capacity)

	Estimated	Projected 1982					
		Crude Oil Slate A			Crude Oil Slate B		
	1978	High	Medium	Low	High	Medium	Low
PADs I-IV							
Crude Oil Distillation	91	101	93	--	101	93	--
Catalytic Reforming	99	123	112	--	123	112	--
Catalytic Cracking	86	92	80	--	92	80	--
Residual Conversion	100	123	127	--	132	135	--
Hydrotreating							
Naphtha	100	141	131	--	142	133	--
Distillate	86	153	128	--	150	126	--
Hydrorefining							
Gas Oil	100	103	117	--	101	116	--
Residual Oil	100	100	100	--	100	100	--
Alkylation	93	133	103	--	139	103	--
Polymerization	5	5	5	--	5	5	--
Isomerization	50	71	71	--	71	71	--
PAD V							
Crude Oil Distillation	79	89	85	--	89	85	--
Catalytic Reforming	87	113	106	--	109	106	--
Catalytic Cracking	100	105	103	--	120	104	--
Residual Conversion	100	134	112	--	125	122	--
Hydrotreating							
Naphtha	86	102	91	--	98	91	--
Distillate	100	298	104	--	281	106	--
Hydrorefining							
Gas Oil	64	68	79	--	67	81	--
Residual Oil	5	5	5	--	5	5	--
Alkylation	80	107	80	--	114	80	--
Polymerization	6	6	6	--	6	6	--
Isomerization	5	13	24	--	10	15	--
Total U.S.							
Crude Oil Distillation	89	99	92	--	99	92	--
Catalytic Reforming	97	121	110	--	120	110	--
Catalytic Cracking	88	94	83	--	96	83	--
Residual Conversion	100	127	121	--	130	139	--
Hydrotreating							
Naphtha	98	135	124	--	135	126	--
Distillate	88	174	124	--	169	123	--
Hydrorefining							
Gas Oil	84	88	101	--	86	100	--
Residual Oil	69	69	69	--	69	69	--
Alkylation	91	129	100	--	136	99	--
Polymerization	5	5	5	--	5	5	--
Isomerization	46	65	66	--	65	65	--

TABLE 82

Utilization of Process Equipment -- 1985
(Percentage of 1978 Capacity)

	Estimated	Crude Oil Slate A			Crude Oil Slate B		
	1978	High	Medium	Low	High	Medium	Low
PADs I-IV							
Crude Oil Distillation	91	103	94	90	104	94	89
Catalytic Reforming	99	122	122	118	121	122	118
Catalytic Cracking	86	92	81	81	92	82	82
Residual Conversion	100	115	139	139	122	147	144
Hydrotreating							
Naphtha	100	127	123	118	127	124	119
Distillate	86	158	129	123	155	128	120
Hydrorefining							
Gas Oil	100	100	106	106	100	106	106
Residual Oil	100	100	100	100	100	100	100
Alkylation	93	131	106	105	137	106	105
Polymerization	5	5	5	5	5	5	5
Isomerization	50	71	71	71	71	71	71
PAD V							
Crude Oil Distillation	79	93	88	84	93	89	84
Catalytic Reforming	87	129	127	121	128	125	121
Catalytic Cracking	100	105	100	105	108	100	103
Residual Conversion	100	142	133	128	134	144	129
Hydrotreating							
Naphtha	86	106	100	100	103	102	94
Distillate	100	324	114	111	307	125	110
Hydrorefining							
Gas Oil	64	79	87	85	85	90	94
Residual Oil	5	5	5	5	5	5	5
Alkylation	80	102	74	69	98	80	69
Polymerization	6	6	6	6	6	6	6
Isomerization	5	11	16	36	11	12	34
Total U.S.							
Crude Oil Distillation	89	101	93	89	102	93	88
Catalytic Reforming	97	123	123	119	122	122	119
Catalytic Cracking	88	94	83	84	94	84	85
Residual Conversion	100	124	137	135	126	146	139
Hydrotreating							
Naphtha	98	124	119	115	123	120	115
Distillate	88	182	127	121	177	128	119
Hydrorefining							
Gas Oil	84	91	98	97	94	96	102
Residual Oil	69	69	69	69	69	69	69
Alkylation	91	127	102	100	132	103	100
Polymerization	5	5	5	5	5	5	5
Isomerization	46	65	66	68	65	65	64

TABLE 83

Utilization of Process Equipment -- 1990
(Percentage of 1978 Capacity)

	Estimated	Crude Oil Slate A			Crude Oil Slate B		
	1978	High	Medium	Low	High	Medium	Low
PADs I-IV							
Crude Oil Distillation	91	108	95	89	108	95	89
Catalytic Reforming	99	134	128	128	130	129	129
Catalytic Cracking	86	96	80	80	85	79	82
Residual Conversion	100	140	155	145	145	160	156
Hydrotreating							
Naphtha	100	124	116	114	125	119	116
Distillate	86	154	132	124	153	129	120
Hydrorefining							
Gas Oil	100	110	116	124	102	118	123
Residual Oil	100	100	100	100	100	100	100
Alkylation	93	127	104	104	146	104	105
Polymerization	5	5	5	5	5	5	5
Isomerization	50	71	71	71	71	71	71
PAD V							
Crude Oil Distillation	79	94	90	84	94	90	84
Catalytic Reforming	87	203	162	157	194	160	156
Catalytic Cracking	100	90	100	105	101	100	103
Residual Conversion	100	154	136	143	156	157	161
Hydrotreating							
Naphtha	86	111	112	110	110	122	109
Distillate	100	327	209	243	329	272	285
Hydrorefining							
Gas Oil	64	107	105	108	105	97	111
Residual Oil	5	5	5	5	5	5	5
Alkylation	80	82	57	59	93	61	63
Polymerization	6	6	6	6	6	6	6
Isomerization	5	10	13	5	10	26	5
Total U.S.							
Crude Oil Distillation	89	106	94	88	106	94	88
Catalytic Reforming	97	146	134	133	141	132	134
Catalytic Cracking	88	95	83	83	87	83	85
Residual Conversion	100	145	149	144	146	159	158
Hydrotreating							
Naphtha	98	122	115	113	123	120	115
Distillate	88	179	143	141	179	151	144
Hydrorefining							
Gas Oil	84	109	111	117	103	106	118
Residual Oil	69	69	69	69	69	69	69
Alkylation	91	121	98	98	139	98	99
Polymerization	5	5	5	5	5	5	5
Isomerization	46	65	65	64	65	67	64

TABLE 84

Product Shortfall in 1982 if Refinery Expansions are Limited to 1978 Construction Plans*
(High Case and Crude Oil Slate B)

	MB/D Shortfall†		
Products	PADs I-IV	PAD V	Total U.S.
LPG	(1)	0	(1)
Butanes	(194)	(94)	(288)
Gasoline	388	133	521
Distillates	0	0	0
Residual Fuel	(190)	(70)	(260)
Coke (M Tons/D)	6	4	10
Fuel Gas (Plant)	47	30	77

*Data from NPC December 1979 Refinery Flexibility, An Interim Report, Volume I, Table 7, page 39.

†Shortfall vs. optimized case per Tables 64, 66, and 68. Numbers in parentheses denote gains. Distillate supply protected at expense of gasoline.

possible the processing of the higher sulfur crude oil slate. In PADs I-IV, the residual sulfur level increases from 1.61 wt % to 2.00 wt %, and in PAD V, it increased from 0.99 wt % to 1.03 wt %. This indicates that some relaxation of environmental restrictions may be necessary in an emergency.

The lower section of Table 85 shows the impact of a 5,000 MB/D loss of foreign average crude oil. In the case of this more severe disruption it is assumed that the government would allocate all available crude oil, including domestic, among the PAD districts in proportion to normal refinery runs, rather than to historical consumption of foreign crude oil. This requires PAD V to transfer about 800 MB/D of crude oil (e.g., Alaskan North Slope) to the other PAD districts. With a crude oil loss as large as 5,000 MB/D, the flexibility to take the bulk of the shortfall in motor gasoline is strained. As the table demonstrates, however, the gasoline portion can approach 80 percent if sufficient value is attached to protecting distillate supply. This can be done, for example, by raising the relative price of distillate by 50 percent.

Table 86 deals with the disruptions in 1985. The upper section shows the impact of a 2,000 MB/D loss of foreign sweet crude oil. As in the 1982 results, the bulk of the reduction appears as motor gasoline, a 32 percent reduction in the total projected gasoline demand. Although the case of substituting higher sulfur crude oil was not run, results similar to those for calendar year 1982 can be expected. The case of a 5,000 MB/D loss of foreign average crude oil in 1985 is shown in the lower section.

TABLE 85

Crude Oil Disruption Impact on the Medium Case and Crude Oil Slate B -- 1982

	2,000 MB/D Loss		
	PADs I-IV	PAD V	Total U.S.
Crude Oil Shortfall			
Foreign Sweet*	1,830	170	2,000
Product Shortfall			
Motor Gasoline	1,480	113	1,593
Distillates	227	0	227
Residual Fuel Oil	60	0	60
Others†	98	75	173
Total Products	1,865	188	2,053

	2,000 MB/D Substitution§		
	PADs I-IV	PAD V	Total U.S.
Crude Oil Shortfall			
Foreign Sweet*	1,830	170	2,000
Arabian Light§	(1,830)	(170)	(2,000)
Product Shortfall¶			
Motor Gasoline	362	3	365
Distillates	(294)	0	(294)
Residual Fuel Oil**	(47)	0	(47)
Others†	(9)	(6)	(15)

	5,000 MB/D Loss		
	PADs I-IV	PAD V	Total U.S.
Crude Oil Shortfall			
Foreign Average††	5,000	--	5,000
Foreign Sour	(58)	58	--
Alaskan North Slope	(763)	763	--
Total Shortfall	4,179	821	5,000
Product Shortfall if Prices Unchanged			
Motor Gasoline	1,660	543	2,203
Distillates	2,080	154	2,234
Residual Fuel Oil	65	32	97
Others†	198	71	269
Product Shortfall if Distillate Price up 50%			
Motor Gasoline	3,362	543	3,905
Distillates	522	154	706
Residual Fuel Oil	65	32	97
Others†	58	71	129

*Sweet Crude Oil -- under 0.5 wt % sulfur.

†Includes adjustments for plant fuel, butane purchases, and changes in other products.

§Crude oil substituted for the foreign sweet crude oil shortfall.

¶Figures shown in parenthesis for Product Shortfall are a gain rather than a loss.

**Average sulfur level was 1.61 wt % before substitution and 2.00 wt % after for PADs I-IV; for PAD V average sulfur level was 0.99 wt % before substitution and 1.03 wt % after.

††Average Crude Oil -- the percentage of each crude oil is the same as in the imported crude oil supply before disruption.

TABLE 86

Crude Oil Disruption Impact on the Medium Case and Crude Oil Slate B -- 1985

	2,000 MB/D Loss		
	PADs I-IV	PAD V	Total U.S.
Crude Oil Shortfall			
Foreign Sweet*	1,843	157	2,000
Product Shortfall			
Motor Gasoline	1,686	137	1,823
Distillates	61	0	61
Residual Fuel Oil	10	0	10
Others†	113	26	139
Total Products	1,870	163	2,033

	5,000 MB/D Loss		
	PADs I-IV	PAD V	Total U.S.
Crude Oil Shortfall			
Foreign Average§	5,000	--	5,000
Foreign Sour	(55)	55	--
Alaskan North Slope	(783)	783	--
Total Shortfall	4,162	838	5,000
Product Shortfall if Prices Unchanged			
Motor Gasoline	1,568	467	2,035
Distillates	2,129	264	2,393
Residual Fuel Oil	112	0	112
Others†	221	99	320
Product Shortfall if Distillate Price up 50%			
Motor Gasoline	3,130	576	3,706
Distillates	634	124	758
Residual Fuel Oil	174	0	174
Others†	106	145	251

*Sweet Crude Oil -- under 0.5 wt % sulfur.

†Includes adjustments for plant fuel and butane purchases, as well as other products.

§Average Crude Oil -- the percentage of each crude oil is the same as in the imported crude oil supply before disruption.

Regulatory Sensitivities

As discussed above, the changes in products and crude oils expected during the 1980's will necessitate additional processing facilities. The nature of these facilities, the physical and economic feasibility of installation, as well as the required lead time for construction, will be influenced by government regulations. Examples of such regulatory areas are:

- Motor fuel additives
- Sulfur content of products
- Refinery air emissions, water effluent quality, and hazardous waste disposal
- Product price controls (Department of Energy and the Council on Wage and Price Stability).

In this study the only regulatory areas covered quantitatively dealt with lead and MMT additives in motor gasoline. The impact of the lead phasedown regulation was limited to 1982 because the decreasing fraction of leaded gasoline in the motor gasoline pool will gradually make this restriction less constraining. Table 87 shows the hydrocarbon savings that could be realized by eliminating the 0.5 grams per gallon (gm/gal) pool lead level restriction (this will be an average of 0.6 gm/gal after exceptions are granted for certain refiners, permitting higher levels). The elimination of this regulation could result in a hydrocarbon saving of 35 MB/D, based on optimum lead usage, 0.8 gm/gal. If the addition of 3.0 gm/gal in the leaded grades were economical the total gasoline pool would be at 1.09 gm/gal lead and process requirements would decrease by 0.7 clear octane ([R+M]/2). The hydrocarbon savings would then be about 70 percent greater than the calculated optimum case.

TABLE 87

Impact of Deregulation of Gasoline Lead Additive -- 1982
(Medium Case and Crude Oil Slate B)

	PADs I-IV	PAD V	Total U.S.
Pool Lead Level (gm/gal)*			
Phasedown Case	0.60	0.61	--
Calculated Optimum	0.75	0.95	--
Hydrocarbon Savings (MB/D)			
Crude Oil Savings	18	15	33
Butane Savings	0	2	2
Total Savings	18	17	35

*Grams per gallon for the total gasoline pool.

By 1985, the leaded gasoline fraction will decline further, thus at the same regulated pool lead level of 0.6 gm/gal there could be 2.6 grams of lead per gallon of gasoline. Even allowing maximum lead usage of 3.0 gm/gal would decrease process octane requirements by only 0.1 octane number, and therefore yield very small hydrocarbon savings. Conversely, relaxing restrictions in 1980-1981 would be of much greater benefit than in 1982, because of a higher fraction of leaded gasoline in the total pool.

The effects of allowing the use of MMT in unleaded gasoline were considered for all three time periods, because the removal of the ban will be of continuing benefit. The use of MMT at a level of 1/16 gm/gal in unleaded gasoline was assumed, and does not necessarily represent an economic optimum. The incentive consists of the hydrocarbon and facility investment savings shown in Table 88. The maximum savings range up to 80 MB/D for hydrocarbons in 1985, 434 MB/D of new catalytic reforming capacity (which is the major process unit saving) in 1985, and up to $775 million of corresponding investment in 1990. Depending on the cost of MMT, however, optimum usage may well be lower than 1/16 gm/gal, in which case the potential savings would also be lower.

Survey respondents indicated that if the current DOE and COWPS pricing regulations were not judged to be just temporary, refiners might be reluctant to make substantial investments to increase their ability to process the less expensive but lower quality crude oils which are projected to become an increasing part of the supply. Current regulations, wherein much of the raw material savings needed to obtain an acceptable return on the investment must be passed through in lower product prices, make such investments uneconomical or only marginally attractive.

Environmental regulations were cited as obstacles to modifications of certain refineries to process more high-sulfur crude oil, although most respondents to the January 1979 NPC survey thought they could obtain the necessary permits. In any event, the timetable for construction of new facilities is affected by the permitting process. Respondents to the survey estimated lead times averaging 43 months overall for authorization, permitting, design, engineering, procurement, and construction.

Above all, the respondents noted that stability of government policy and regulations, especially those affecting capital formation, is necessary for sound investment planning and a viable domestic refining industry.

TABLE 88

Effect of MMT in Unleaded Gasoline at 1/16 Gram/Gallon
(Medium Case and Crude Oil Slate B)

	1982			1985			1990		
	PADs I-IV	PAD V	Total U.S.	PADs I-IV	PAD V	Total U.S.	PADs I-IV	PAD V	Total U.S.
Crude Oil Savings (MB/D)	38	19	57	34	13	47	31	1	32
Butane Savings (MB/D)	17	0	17	14	19	33	21	4	25
Total Hydrocarbon Savings	55	19	74	48	32	80	52	5	57
Capacity Expansion Savings (MB/SD)									
Crude Oil Distillation	0	0	0	0	0	0	78	0	78
Reforming	223	36	259	320	114	434	265	134	399
Residual Conversion	16	(4)	12	21	(7)	14	9	(5)	4
Catalytic Cracking	0	23	23	0	23	23	0	18	18
Hydrotreating									
Naphtha	305	0	305	131	5	136	47	19	66
Distillate	24	18	42	(15)	38	23	26	38	64
Hydrorefining									
Gas Oil	(14)	0	(14)	(2)	0	(2)	52	0	52
Residual Oil	0	0	0	0	0	0	0	0	0
Alkylation	7	0	7	25	8	33	12	0	12
Hydrogen Manufacturing (MMSCF/SD)	0	0	0	0	0	0	0	2	2
Estimated Investment Cost Savings*	301	97	398	325	240	565	535	240	775

*Cost is in millions of 1978 dollars.

CHAPTER THREE

COMPETITIVE POSITION OF VARIOUS SEGMENTS OF THE U.S. REFINING INDUSTRY

INTRODUCTION

An analysis of the competitive economics within the domestic refining industry is a principal element in the comprehensive study of refinery capability. Specifically, this chapter investigates the effects of size, location, and refinery process complexity upon competitive positions.

The competitive position of any refinery or segment of the refining industry is largely determined by the total cost of producing similar petroleum products relative to its competitors. All other factors being the same, the lower this cost of production, the better the competitive position. The analysis which is presented in this chapter relies upon this concept of competitiveness.

Of course, other considerations, such as product logistical advantages or disadvantages, product quality, service, reputation for reliability and fairness, and marketing and management skills, are also quite important in determining the overall competitive position of any refinery or refining company. However, such factors are difficult to quantify and are not subject to aggregation. Individual refineries were not examined in respect to these factors in which they may differ significantly from the average of an aggregation.

Within a given capacity size range there are great variations in process complexity between plants. Consequently the competitive position between individual refineries of similar size may differ greatly.

Competitiveness must also be viewed as a dynamic concept: individual companies respond to changes in their perceived environments with differing business strategies, investment decisions, and productivity improvement efforts.

Quantifiable cost factors which influence refineries' competitive positions and are considered in this chapter are crude oil and other feedstock costs, operating expenses (fuel and purchased utilities, depreciation, maintenance, etc.), and capital costs. In addition, the analysis provides for adjustments to reflect varying product yield structures and inputs of feedstock other than crude oil.

It would be inappropriate to attempt to calculate actual earnings for an industry segment solely on the basis of information generated by or available to this study of competitive positions. Computation of earnings requires certain data which were not necessary for the competitive analysis of the various segments of the industry, which employs the criteria of relative cost of manufacturing similar products adjusted for product value of the different product mixes. For example, due to marketing judgments and other factors, pricing patterns for individual products may have differed significantly between various company size ranges or other industry segments. Actual product revenue information reflecting such pricing differences would be needed to complement previously provided raw material and operating cost data if one were to attempt computation of earnings by company or refinery aggregations.

METHODOLOGY

The January 1979 NPC Survey of Petroleum Refining Capabilities provides much of the basic economic data required for this chapter with respect to the cost of crude oil and operating expenses experienced by various segments of the refining industry in 1978. It is the principal data source supporting this competitive analysis of domestic refineries. The results of the survey were published by the NPC as an interim report in December 1979 (Refinery Flexibility, An Interim Report). The interim report shows aggregated cost data on 15,445 MB/D or 89 percent of the total 1978 estimated refining capacity in the 50 states and Guam. Responses to some or all elements of this part of the survey were received from 203 refineries. The survey, in Part I, asked refiners for their actual 1978 product yields. Part I had a slightly higher response rate, with 246 refineries reporting on a total capacity of 16,876 MB/D.

For the purposes of this analysis of competitive position, complete Part I and Part II data were required from each refinery. In some cases, a refiner supplied complete data on either Part I or Part II, but not both. The number of refineries that replied to both Parts I and II was 186 and their aggregate capacity was 14,811 MB/D. The cost data shown in Tables 89-111 are for this smaller group of refiners. All tables after Table 111 are from the interim report and show all of the cost data received in the survey. The minor differences between the two groups of tables are due to the different sample sizes.

As noted, the January 1979 NPC survey is the source of information for refined product yields and throughputs of feedstocks other than crude oil. Since the mix of other feedstocks and of products varies among refineries, reasonable adjustment for these factors must be made before costs of manufactured products can be compared in a meaningful manner. Prices for other feedstocks and for products were not reported in the NPC survey and were therefore obtained from public sources, particularly from DOE Energy Information Administration publications and Platt's 1978 Oil Price Handbook and Oilmanac, 55th edition.

A "value" of product per barrel of crude oil refined for each refinery was computed by summation of the results of multiplying product percentage yields by the monthly weighted average product prices derived from the aforementioned public sources for the PAD district in which the refinery was located. Then product value adjustments were determined as the difference between the "values" of product per barrel of crude oil for the several company and refinery categories and the weighted average "value" of product per barrel of crude oil for all domestic refineries. These product value adjustments to the total product cost are appropriate reflections of varying product mixes for the refineries.

It should be emphasized that the actual product revenue experienced by the refineries participating in the survey may have differed from the "value" of products computed as described above. This is due to the fact that actual product prices for a refinery may have differed from the average product prices obtained from the public sources. Consequently, the "value" of products determined as set forth above cannot be used in determining bottom line earning of any industry segment.

The "other feedstock" adjustment is the result of multiplying the percentage input of that feedstock for the individual refinery by the unit cost of that feedstock appropriate for the geographic region (PAD district) in which the refinery is located.

Inasmuch as refineries differ considerably in the amount of capitalization per barrel of crude oil processed, further adjustment was made for the cost of capital employed, based upon capital asset information supplied by refineries participating in the NPC survey. The cost of capital was assumed to be 20 percent of gross original undepreciated investments per year before tax for the use of refinery facility assets. One of the sensitivity studies of this competitive analysis employed cost of capital computed on the basis of current replacement investment. To obtain greater consistency, the replacement investments for each refinery size range and complexity were derived by a regression analysis of replacement cost data provided by refiners participating in the survey.

One of the factors determining the net crude oil and product costs to U.S. refineries in 1978 was the U.S. Department of Energy's crude oil entitlements program and its small refiner bias provisions. The effects of the entitlements program were included in the calculations; however, the benefits of special entitlements provisions (exceptions and appeals relief, entitlements for California crude oil, adjustments for residual fuel oil marketed on the East Coast, and naphtha imported into Puerto Rico) were not distributed to the recipients. The effect of the exclusion of these benefits is to overstate net crude oil costs for specific refiners and the categories in which they fall, leading in turn to a relatively small overstatement of industry-wide crude oil costs. See Appendix G for a discussion of the entitlements calculation and the estimated impact of these special programs.

The competitive positions of the various aggregations were assessed by comparing the "cost of refined products" computed in accordance with the following format:

	$/Bbl of Crude Oil
Crude Oil Cost	xx.xx
Other Feestock Cost	x.xx
Total Input Cost	xx.xx
Operating Expense	
Fuel and Purchased Utilities	x.xx
Depreciation	x.xx
Maintenance and Other Expenses	x.xx
Total Operating Expense	x.xx
Cost of Capital Employed	x.xx
Product Value Adjustments[1]	x.xx
Total Product Costs	xx.xx
Relative Advantage (Disadvantage) vs. Average	x.xx

The certified public accounting firm of Arthur Young & Company performed the above calculations and aggregated the resulting data under instruction to treat all individual refinery data in strictest confidence and to release no identifiable company data.

Based on data provided by the January 1979 NPC Survey of Petroleum Refining Capabilities and the product prices developed from DOE data and Platt's publication, the cost of refined products was calculated by (1) company size, (2) refinery size, (3) refinery location (PAD district), and (4) refinery complexity. The average product costs for refineries within various subsegments were calculated and compared with the costs for other subsegments and average costs for each category for U.S. refineries.

Since early 1979, when the survey data were submitted, there have been a number of changes in the values associated with factors determining the relative economic positions of refineries. One of the most significant changes and one that lends itself to quantification without further survey is the revision to the small refiner bias provisions of the DOE's entitlements program which reduced the supplemental entitlements received by refining companies of less than 175 MB/D system capacity. Arthur Young & Company further computed and reported, on an aggregated basis, the cost of refined products for the hypothetical situation that this change has been in effect for all of calendar year 1978.

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[1]The product value adjustments were determined to be the difference between "value" of product per barrel of crude oil refined for the several company and refinery categories and the weighted average "value" of product per barrel of crude oil for all domestic refineries.

Further considering the implication of changes since 1978, product value adjustments based upon major product prices published during the first quarter of 1980 were determined, and the cost of refined products was recomputed as though this change had been in effect for calendar year 1978. Heavy fuel oil prices were depressed relative to lighter products in the first quarter of 1980. No other adjustments were made to reflect changes in operations, crude oil prices, or operating cost, which could be offsetting or aggravating factors to some extent.

EXPANDED DISCUSSION

Cost of Refined Products

Data showing relative competitive positions, as determined by the costs of refined products for 1978, are summarized in Tables 89, 95, 102, and 107 for companies aggregated by size and for refineries aggregated by size, location (PAD district), and process complexity.

Determination of the sensitivity of competitive positions to (1) the revision to the small refiner bias provisions of the entitlements program as of June 1, 1979, and (2) wholesale product price patterns during the first quarter of 1980 are summarized in Tables 93, 98, 105, and 110. These competitive position data are displayed for two bases of computing cost of capital; the primary basis was original undepreciated assets and the secondary basis provided a sensitivity analysis using replacement investment. Each of the elements of product cost (crude oil and other feedstock costs, operating expenses, and cost of capital employed) are discussed in some detail later in this chapter.

Company Size Aggregations

Companies in the two smaller size categories, 0-10 MB/D and 10-30 MB/D, were in more favorable competitive positions than were larger companies under 1978 conditions. Refining companies of 10 MB/D or less in capacity appear on the average to have been able to manufacture products at costs of $0.37/bbl of crude oil less than the average, while refiners in the 100-175 MB/D size category had the highest product cost in 1978 at $0.49/bbl of crude oil above the average. Companies of greater than 175 MB/D capacity, the industry segment with the greatest fraction of the nation's capacity, incurred slightly lower costs ($0.02/bbl) than the average (Table 89).

The favorable competitive position of the 0-10 MB/D refiners was significantly influenced by their average net crude oil costs, which were $2.19/bbl below the average for all companies. This crude oil cost advantage was largely due to the small refiner bias but also reflects crude oil quality (i.e., higher sulfur content and lower API gravity) and other factors. Crude oil costs for aggregations of companies having less than 50 MB/D capacity ranged

TABLE 89

1978 Competitive Positions of Refining Companies
Aggregated by Company Size Range
(All Figures Other Than Company Size and Complexity are $/Barrel of Crude Oil and Field Condensate)

	Company Size Range (MB/D)						
	0-10	10-30	30-50	50-100	100-175	175+	All
Weight Average Complexity	1.50	2.88	4.78	5.68	7.21	7.72	7.27
Crude Oil Cost*	10.54	11.55	12.25	13.00	12.92	12.78	12.73
Other Feedstock Cost†	1.56	0.91	0.88	1.36	0.93	1.23	1.20
Total Input Cost	12.10	12.46	13.13	14.36	13.85	14.01	13.93
Operating Expenses							
Fuel and Purchased Utilities	0.42	0.70	0.72	0.84	0.85	1.13	1.07
Depreciation	0.11	0.19	0.21	0.13	0.17	0.20	0.19
Maintenance and Other Expenses	0.85	0.98	0.96	1.04	0.85	1.03	1.02
Subtotal, Operating Expenses	1.38	1.87	1.89	2.01	1.87	2.36	2.28
Cost of Capital Employed	0.38	0.70	0.68	0.67	0.92	0.90	0.87
Product Value Adjustment	2.85	1.87	1.64	0.05	0.93	(0.21)	0
Total Product Cost	16.71	16.90	17.34	17.09	17.57	17.06	17.08
Relative Company Advantage (Disadvantage) vs. Average	0.37	0.18	(0.26)	(0.01)	(0.49)	0.02	Base
Number of Companies	21	25	11	11	5	18	91
Number of Refineries	22	31	11	19	8	95	186
Crude Charge Capacity (MB/D)	167	551	424	765	670	12,234	14,811

*Crude oil expense includes crude oil and field condensate after entitlements including small refiner bias and excluding the benefits of all other special entitlements programs.

†Other feedstock acquisition expense is the estimated cost of other hydrocarbon feedstock purchased for processing or blending.

from \$10.54/bbl to \$12.25/bbl net after entitlements, while company aggregations of greater than 50 MB/D experienced net after entitlement costs of \$12.78/bbl to \$13.00/bbl. The average crude oil cost for all companies was \$12.73/bbl (Table 89).

The net after entitlements crude oil and associated refined product costs mentioned above include the effects of the small refiner bias provisions of the entitlements program. In the absence of the small refiner bias provisions, the range of the cost of refined products for company size categories would have been from \$16.93 to \$18.48/bbl of crude oil. Under that hypothetical situation, the companies in the 175+ MB/D size category would have occupied the most competitive position, while those in the 0-10 MB/D size range would have been in the least competitive position (Table 90).

To document the impact of certain regulatory programs as they existed in 1978, Table 90 and Figure 33 present the relative competitive positions of companies under several scenarios regarding crude oil cost. In Scenario A, net after entitlements crude oil costs reflect the program as actually administered in 1978 to the extent that small refiner benefits are included. The next two scenarios are hypothetical: Scenario B is after entitlements but without the small refiner bias, and Scenario C is before entitlements. In these scenarios, the competitive advantage is shown to have resided in 1978 with the smaller companies when the crude oil cost bases were net after entitlements (Scenario A). Without the small refiner bias (Scenario B), there would have been a dramatic shift, with the smaller companies at a pronounced disadvantage. The cost of products from the 0-10 MB/D company size category would have been \$1.44/bbl higher than the average. There is not a distinguishable pattern for the hypothetical situation before entitlements in 1978; the refineries having greater than 175 MB/D of capacity would have had the lowest cost products and companies in the 30-50 MB/D size range had the highest cost products. The difference shown in costs before and after entitlements is due to the procedure used for the entitlements calculations (see Appendix G).

In mid-1979, the small refiner bias provisions of the entitlements program were substantially modified, reducing the benefits to all companies in the program with greatest impact on those with capacities of 50 MB/D or less. For the 0-10 MB/D company category, the reduction amounted to \$0.90/bbl. This fourth crude oil cost basis scenario (Scenario D) is presented in Table 90 and Figure 34; the 1978 data have been adjusted to reflect only the change in the small refiner bias program as administered after June 1, 1979.

In the smallest company size category, 0-10 MB/D, the crude oil cost element of product cost increased by \$0.90/bbl, but was still \$1.29/bbl below the industry average (Table 93). Because of the crude oil cost shift, however, the revision of the small refiner bias program dropped the 0-10 MB/D company size range to the poorest competitive position, with product costs \$0.53/bbl above the industry average. In this context, the 50-100 MB/D company size range became the most competitive, with product costs \$0.06/bbl below the average.

TABLE 90

Competitive Positions of Refining Companies Under Various Crude Oil Cost Scenarios
Aggregated by Company Size Range

	Company Size Range (MB/D)						
Basis of Crude Oil Cost*	0-10	10-30	30-50	50-100	100-175	175+	Average
I. Total 1978 Refined Products Costs in $/Barrel of Crude Oil Processed							
A. Net After Entitlements†	16.71	16.90	17.34	17.09	17.57	17.06	17.08
B. After Entitlements Without Small Refiner Bias	18.48	18.06	17.99	17.26	17.55	16.93	17.04
C. Before Entitlements	17.06	17.27	18.18	16.98	18.03	16.59	16.71
D. Net After Entitlements† Adjusted for June 1979 Small Refiner Bias	17.61	17.41	17.58	17.02	17.42	17.04	17.08
II. Relative Company Advantage (Disadvantage) vs. Average in Refined Products Costs in $/Barrel of Crude Oil Processed							
A. Net After Entitlements†	0.37	0.18	(0.26)	(0.01)	(0.49)	0.02	Base
B. After Entitlements Without Small Refiner Bias	(1.44)	(1.02)	(0.95)	(0.22)	(0.51)	0.11	Base
C. Before Entitlements	(0.35)	(0.56)	(1.47)	(0.27)	(1.32)	0.12	Base
D. Net After Entitlements† Adjusted for June 1979 Small Refiner Bias	(0.53)	(0.33)	(0.50)	0.06	(0.34)	0.04	Base

*All entitlements calculations exclude the benefits of special entitlements programs except the small refiner bias, which is included where noted.

†Includes small refiner bias.

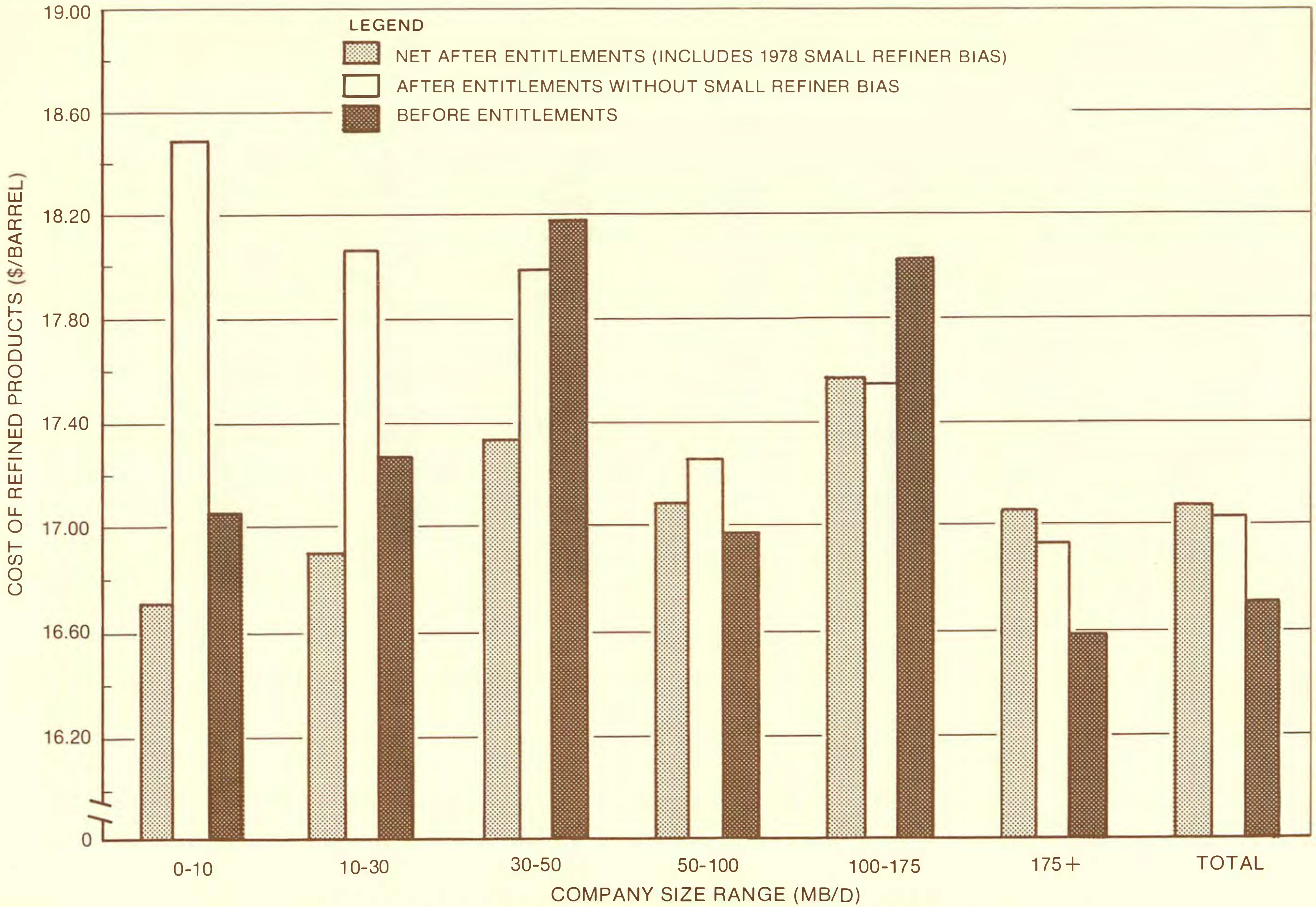

Figure 33. Total 1978 Refined Products Costs in $/Barrel of Crude Oil Processed for Refining Companies—Aggregated by Company Size Range.

NOTE: This figure was plotted from data in Table 90.

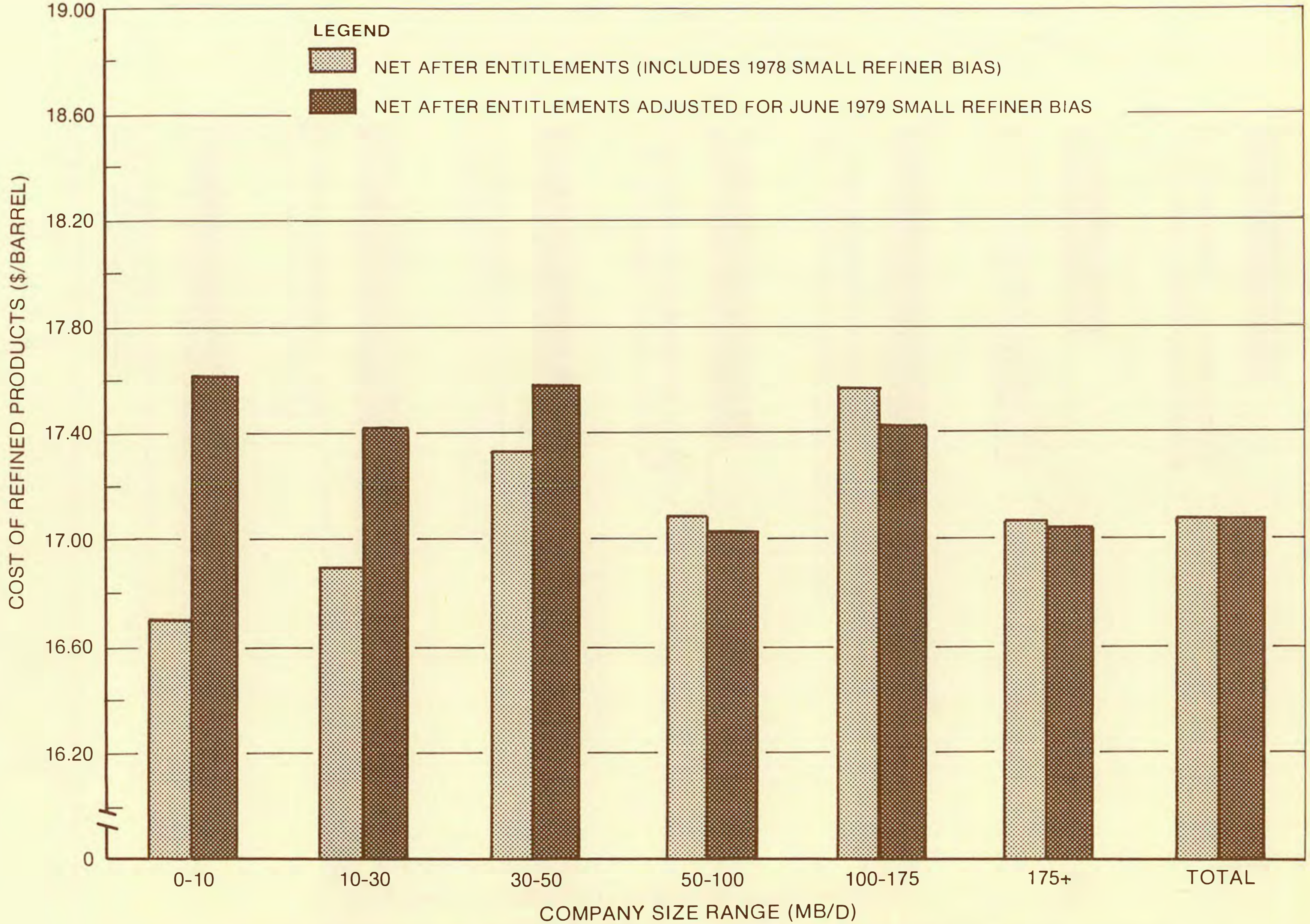

Figure 34. Effect of the Change in the Small Refiner Bias on Refined Products Costs in $/Barrel of Crude Oil Processed for Refineries—Aggregated by Company Size Range.

NOTE: This figure was plotted from data in Table 90.

Operating costs and cost of capital employed increased with company size, from a low of $1.76/bbl to a high of $3.26/bbl of crude oil (Table 89). Increasing complexity with increasing company size significantly influenced this trend (Table 107).

Enhanced product mix value is realized as one result of the greater capital outlay and operating costs incurred by the larger companies. Table 91 shows greater yields of higher value products as company size increases, up to at least the 50-100 MB/D size range.

The enhancement of product slate with company size generally more than offset the added costs associated with that of upgrading for companies of 100 MB/D capacity or less. This may be illustrated by considering the sum of the net adjustments for product value and for other feedstocks added to operating expenses and capital costs, as in the following tabulation:

Company Size Range (MB/D)	0-10	10-30	30-50	50-100	100-175	175+
Average Complexity	1.50	2.88	3.98	5.61	7.21	7.72
Net Product & Feedstock Adjustment ($/Bbl)	4.41	2.78	2.52	1.41	1.81	1.02
Plus Operating Expense and Cost of Capital ($/Bbl)	1.76	2.57	2.57	2.68	2.79	3.27
Total	6.17	5.35	5.09	4.09	4.60	4.29

Among the factors influencing competitive positions which have changed markedly since 1978 and which may be approximately quantified are published major product prices. There was a much wider spread in the first quarter of 1980 than in 1978 between the prices of lighter products such as gasoline or distillate and the heavier petroleum fractions such as heavy fuel oil (Table 92).

As a sensitivity analysis, the impact of computing product value adjustments was determined as though these 1980 product prices had been in effect in 1978. As would be expected, the companies with smaller, less complex refineries and greater yields of heavier products are placed at a pronounced disadvantage in such circumstances.

Under the combined effects of adjustments to the 1978 data for the June 1, 1979, small refiner bias revision and the first quarter 1980 product markets, the smallest company size range, 0-10 MB/D, is at an average disadvantage of $4.53/bbl compared to the industry average. Plants owned by these companies generally lack conversion capabilities to adjust product mix to take advantage of market conditions. This comparison is exclusive of any adjustment for changes in relative crude oil cost and other factors. The 1980 disadvantage declines rapidly with company size to $1.57/bbl for companies in the 30-50 MB/D category.

TABLE 91

1978 Product and Other Feedstock Slates

Aggregated by Company Size Range

(Vol. % of Total Input)

	Company Size Range (MB/D)						
	0-10	10-30	30-50	50-100	100-175	175+	Average
Product Yields							
LPG	0.2	0.8	1.5	1.8	1.2	2.0	1.9
Motor Gasoline	14.7	26.6	29.0	48.4	48.2	46.7	45.1
Jet Fuels	7.7	6.0	8.3	4.3	-	6.7	6.3
Middle Distillate	16.2	22.6	25.2	24.0	27.1	19.4	20.2
Heavy Fuel Oils	34.0	25.7	18.5	10.8	7.8	8.8	10.1
Asphalt	9.4	5.7	5.0	2.3	3.7	2.5	2.8
Finished Lubricants	3.5	*	-	*	-	1.3	1.2
BTX	-	*	*	*	*	0.8	0.7
Feedstocks Sold to Others	5.2	3.1	2.5	1.9	5.0	3.9	3.8
Other Saleable	3.9	*	*	*	*	3.7	3.5
Refinery Fuel Produced	1.0	3.2	3.5	4.5	5.3	5.7	5.4
Total (Except Sulfur, Wax, and Coke)	95.9	99.6	99.8	101.3	99.8	101.5	101.2
Other Feedstocks							
Natural Gasoline	4.4	1.9	2.4	1.7	1.7	2.3	2.2
Butanes	-	1.0	1.5	2.9	2.1	1.7	1.7
Other Feedstocks	*	*	2.2	3.6	2.1	3.6	3.4
Other Blendstocks	2.8	1.3	*	0.6	*	1.3	1.2
Total	*	*	*	8.8	*	8.9	8.5

*Data withheld to protect confidentiality.

TABLE 92

New York Harbor Product Prices
(¢/Gallon)

	Calendar 1978	First Quarter 1980
Refinery Products		
LPG	23.2-27.2	40
Motor Gasoline	40.1-43.5	86.5
Jet Fuel-Naphtha	40.7-42.8	80
Jet Fuel-Kerosine	36.7-40.8	78
Kerosine, No. 1 Heating Oil	37.5-41.6	79
Diesel	34.3-38.4	77
Distillate No. 2	34.2-38.3	76.5
Heavy Fuel Oil	20.0-31.6	42
Asphalt	35.0	45
Finished Lubricants	70.0-75.0	120
BTX	61.3	125
Feedstock Other Than Crude Oil		
Butanes	23.2-27.2	60
Natural Gasoline	33.3-37.3	75

Table 93 presents data detailing the impact of this change in product prices when coupled with the aforementioned 1979 modification of the small refiner bias. This table also shows the capital cost element of product cost computed on two bases; the primary basis reflects a 20 percent per year charge upon original undepreciated assets and the secondary basis employs current replacement investment. The competitive ranking of company size ranges is quite sensitive to the basis used for the capital cost computation. The position of the smaller companies with lower investment levels is enhanced if the comparison is on a current replacement cost basis. The analysis of competitiveness by company size is recapped in Table 94.

Refinery Aggregations

Refinery Size. Similar to the trend noted with respect to company size, this study shows, as presented in Table 95, that refineries of lower crude oil capacities had an economic advantage in the 1978 environment. The cost of refined products generally increased with refinery size, from a low of $16.49/bbl of crude oil for refineries of 10-30 MB/D capacity to a high of $17.14/bbl of crude oil for refineries of greater than 175 MB/D capacity. The weighted average product costs of all refineries was $17.08/bbl of crude oil.

TABLE 93

Implications of Changes Since 1978 in Competitive Factors and Varying Bases for Computing Cost of Capital for Refining Companies Aggregated by Size Range
(All Figures Other Than Company Size and Complexity are $/Barrel of Crude Oil and Field Condensate)

	Company Size Range (MB/D)						
	0-10	10-30	30-50	50-100	100-175	175+	Average
Weight Average Complexity	1.50	2.88	3.98	5.61	7.21	7.72	7.27
1. 1978 Data							
A. Capital Cost Based Upon Original Undepreciated Assets							
Crude Oil Expense	10.54	11.55	12.25	13.00	12.92	12.78	12.73
Cost of Capital Employed	0.38	0.70	0.68	0.67	0.92	0.90	0.87
Other Costs	5.79	4.65	4.41	3.42	3.73	3.38	3.48
Total Product Cost	16.71	16.90	17.34	17.09	17.57	17.06	17.08
Relative Company Advantage (Disadvantage) vs. Average	0.37	0.18	(0.26)	(0.01)	(0.49)	0.02	Base
B. Capital Cost Based Upon Replacement Investment							
Crude Oil Expense	10.54	11.55	12.25	13.00	12.92	12.78	12.73
Cost of Capital Employed	1.06	2.13	2.14	2.40	2.42	2.52	2.47
Other Costs	5.79	4.65	4.41	3.42	3.73	3.38	3.48
Total Product Cost	17.39	18.33	18.80	18.82	19.07	18.68	18.68
Relative Company Advantage (Disadvantage) vs. Average	1.29	0.35	(0.12)	(0.14)	(0.39)	0.00	Base
2. 1978 Data Adjusted for June 1979 Small Refiner Bias							
A. Capital Cost Based Upon Original Undepreciated Assets							
Crude Oil Expense	11.44	12.06	12.49	12.93	12.77	12.76	12.73
Cost of Capital Employed	0.38	0.70	0.68	0.67	0.92	0.90	0.87
Other Costs	5.79	4.65	4.41	3.42	3.73	3.38	3.48
Total Product Cost	17.61	17.41	17.58	17.02	17.42	17.04	17.08
Relative Company Advantage (Disadvantage) vs. Average	(0.53)	(0.33)	(0.50)	0.06	(0.34)	0.04	Base
B. Capital Cost Based Upon Replacement Investment							
Crude Oil Expense	11.44	12.06	12.49	12.93	12.77	12.76	12.73
Cost of Capital Employed	1.06	2.13	2.14	2.40	2.42	2.52	2.47
Other Costs	5.79	4.65	4.41	3.42	3.73	3.38	3.48
Total Product Cost	18.29	18.84	19.04	18.75	18.92	18.66	18.68
Relative Company Advantage (Disadvantage) vs. Average	0.39	(0.16)	(0.36)	(0.07)	(0.24)	0.02	Base
3. 1978 Data Adjusted for June 1979 Small Refiner Bias and First Quarter 1980 Product Prices							
A. Capital Cost Based Upon Original Undepreciated Assets							
Crude Oil Expense	11.44	12.06	12.49	12.93	12.77	12.76	12.73
Cost of Capital Employed	0.38	0.70	0.68	0.67	0.92	0.90	0.87
Other Costs	11.33	8.36	7.02	4.73	4.99	4.76	5.02
Total Product Cost	23.15	21.12	20.19	18.33	18.68	18.42	18.62
Relative Company Advantage (Disadvantage) vs. Average	(4.53)	(2.50)	(1.57)	0.29	(0.06)	0.20	Base
B. Capital Cost Based Upon Replacement Investment							
Crude Oil Expense	11.44	12.06	12.49	12.93	12.77	12.76	12.73
Cost of Capital Employed	1.06	2.13	2.14	2.40	2.42	2.52	2.47
Other Costs	11.33	8.36	7.02	4.73	4.99	4.76	5.02
Total Product Cost	23.83	23.55	22.65	20.06	20.18	20.04	20.22
Relative Company Advantage (Disadvantage) vs. Average	(3.61)	(3.33)	(2.43)	0.16	0.04	0.18	Base

TABLE 94

Highest and Lowest Product Mix Cost
Aggregated by Company Size Range
($/Bbl Crude Oil Throughput)

	Company Size Range	Advantage (Disadvantage) vs. Average
1978 Data		
Capital Cost Based Upon:		
Original Undepreciated Assets	0- 10 MB/D	0.37
	100-175 MB/D	(0.49)
Replacement Investment	0- 10 MB/D	1.29
	100-175 MB/D	(0.39)
1978 Data Adjusted for June 1979 Small Refiner Bias		
Capital Cost Based Upon:		
Original Undepreciated Assets	50-100 MB/D	0.06
	0- 10 MB/D	(0.53)
Replacement Investment	0- 10 MB/D	0.39
	30- 50 MB/D	(0.36)
1978 Data Adjusted for June 1979 Small Refiner Bias and First Quarter 1980 Product Prices		
Capital Cost Based Upon:		
Original Undepreciated Assets	50-100 MB/D	0.29
	0- 10 MB/D	(4.53)
Replacement Investment	175+ MB/D	0.18
	0- 10 MB/D	(3.61)

The cost of crude oil is again the major factor influencing the trend of product cost by refinery size, ranging from a low of $11.03/bbl for plants of under 10 MB/D capacity to a high of $12.87/bbl for refineries having more than 175 MB/D capacity (Table 95). In computing crude oil costs for all refinery aggregations (as differentiated from company aggregations), entitlements were calculated on a hypothetical basis as though each refinery, regardless of size, were a separate company. The spread between the

TABLE 95

Competitive Positions of Refineries
Aggregated by Refinery Size Range
(All Figures Other Than Refinery Size and Complexity Are $/Barrel of Crude Oil and Field Condensate)

	Refinery Size Range (MB/D)						
	0-10	10-30	30-50	50-100	100-175	175+	All
Weight Average Complexity	2.34	3.33	5.39	7.83	8.46	7.59	7.27
Crude Oil Cost*	11.03	11.55	12.41	12.85	12.75	12.87	12.73
Other Feedstock Cost†	1.59	0.93	0.86	1.37	1.30	1.19	1.20
Subtotal Input Cost	12.62	12.48	13.27	14.22	14.05	14.06	13.93
Operating Expenses							
Fuel and Purchased Utilities	0.85	0.80	0.88	1.11	1.29	1.05	1.07
Depreciation	0.20	0.16	0.15	0.16	0.22	0.21	0.19
Maintenance and Other Expenses	1.29	0.93	0.94	1.07	1.10	0.98	1.02
Subtotal, Operating Expenses	2.34	1.89	1.97	2.34	2.61	2.24	2.28
Cost of Capital Employed	0.78	0.62	0.69	0.81	1.01	0.89	0.87
Product Value Adjustment	1.22	1.50	0.90	(0.26)	(0.55)	(0.05)	0
Total Product Cost	16.96	16.49	16.83	17.11	17.12	17.14	17.08
Relative Refinery Size Advantage (Disadvantage) vs. Average	0.12	0.59	0.25	(0.03)	(0.04)	(0.06)	Base
Number of Refineries	31	45	30	33	24	23	186
Number of Companies	27	36	24	21	16	11	91
Crude Charge Capacity (MB/D)	209	931	1,317	2,307	3,084	6,962	14,811

*Crude oil expense includes crude oil and field condensate after entitlements including small refiner bias program and excluding the benefits of all other special entitlement programs.

†Other feedstock acquisition expense is the estimated cost of other hydrocarbon feedstocks purchased for blending or processing.

highest and lowest crude oil cost aggregations was slightly less on a refinery size basis than on a company size basis. One factor contributing to this effect is a reduced range of variances with respect to percentages of price-controlled (upper and lower tier) crude oils refined by the several refinery size aggregations as compared to company size aggregations. This reflects the fact that some smaller refineries are owned by larger companies.

Table 96 and Figures 35 and 36 show the relative competitive position for refinery size aggregations under the same scenarios regarding crude oil cost as previously shown for companies; i.e., Scenario A -- net after entitlements, Scenario B -- with entitlements but excluding small refiner bias, Scenario C -- before entitlements, and Scenario D -- net after entitlements, adjusted for the June 1979 small refiner bias. In the absence of any entitlements, the 30-50 MB/D refineries would have had the competitive advantage by having lower crude oil cost than larger refineries and better product mix than smaller refineries. Had the entitlements program not included a small refiner bias, the advantage in competitive position would have shifted to the 175+ MB/D refineries. Those refineries of less than 10 MB/D capacity enjoyed a substantial competitive advantage under actual 1978 conditions, with crude oil costs net after entitlements including the small refiner bias. The implication of the modification of the small refiner bias as of June 1, 1979, was to compress the range of product cost for refineries of greater than 10 MB/D capacity. However, due to a lower product mix value, companies of less than 10 MB/D capacity were not competitive under these circumstances. Table 97 shows greater yields of higher valued products as refinery size increases after the 10-30 MB/D size range.

Table 98 reveals the competitive impact upon refineries by size range comparing capital cost based on original undepreciated assets and capital cost based upon replacement investments between 1978 data and 1978 data adjusted for the June 1979 small refiner bias and for first quarter 1980 product prices.

Operating expenses and cost of capital employed also generally increase with refinery size (Table 95). This is not contrary to economies of scale, but rather reflects the fact that larger refineries tend to be more complex in order to efficiently process crude oil to a higher value product mix or to be capable of handling a less attractive crude oil slate. Later in this chapter an extensive discussion of operating expenses and asset costs is presented, which addresses the separate effects of refinery size and complexity. That analysis does show economies of scale up to the 50 MB/D refinery size range; above this level, some economies of scale may exist but are not apparent from these data.

Refineries in the 100-175 MB/D size range show the greatest advantage in competitive position with respect to the product mix value adjustment. The product slate for this size range also shows the greatest percentage yield of gasoline (51 percent) and the lowest yield of lower value residual fuel oil (7 percent). The least advantageous product mix value adjustment resided with the 10-30

TABLE 96

Competitive Positions of Refineries Under Various Crude Oil Cost Scenarios
Aggregated by Refinery Size Range

Basis of Crude Oil Cost*	Refinery Size Range (MB/D) 0-10	10-30	30-50	50-100	100-175	175+	Average
I. Total 1978 Refined Products Costs in $/Barrel of Crude Oil Processed							
A. Net After Entitlements†	16.96	16.49	16.83	17.11	17.12	17.14	17.08
B. After Entitlements Without Small Refiner Bias	18.64	17.57	17.23	17.13	17.00	16.91	17.08
C. Before Entitlements	17.65	16.80	16.07	16.79	17.23	16.61	16.75
D. Net After Entitlements† Adjusted for June 1979 Small Refiner Bias	17.80	17.16	17.11	17.17	17.09	17.03	17.08
II. Relative Refinery Size Advantage (Disadvantage) vs. Average in Refined Products Costs in $/Barrel of Crude Oil Processed							
A. Net After Entitlements†	0.12	0.59	0.25	(0.03)	(0.04)	(0.06)	Base
B. After Entitlements Without Small Refiner Bias	(1.56)	(0.49)	(0.15)	(0.05)	0.08	0.17	Base
C. Before Entitlements	(0.90)	0.05	0.68	(0.04)	(0.48)	0.14	Base
D. Net After Entitlements† Adjusted for June 1979 Small Refiner Bias	(0.72)	(0.08)	(0.03)	(0.09)	(0.01)	0.05	Base

*All entitlements calculations exclude the benefits of special entitlements programs except the small refiner bias, which is included where noted.

†Includes small refiner bias.

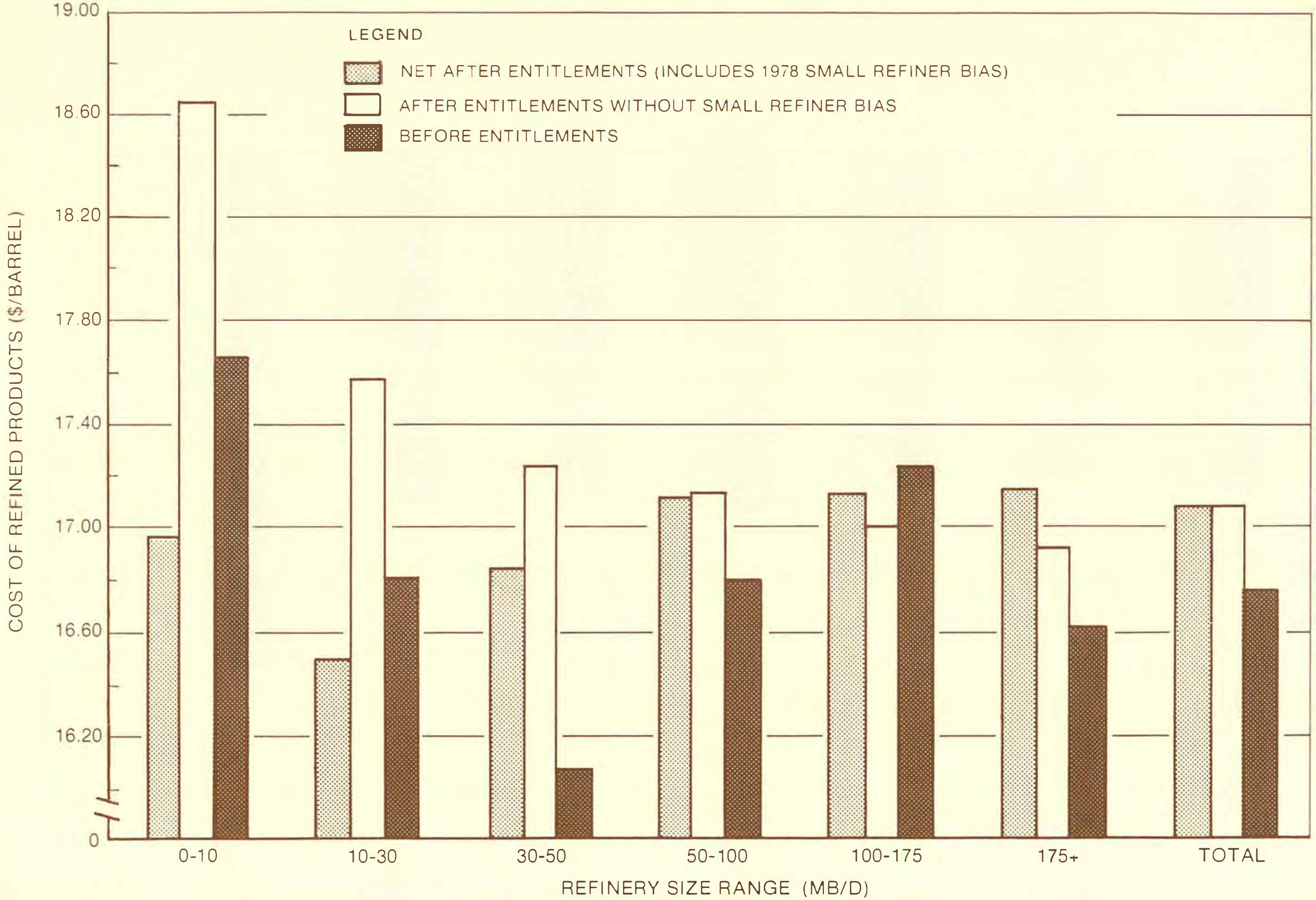

Figure 35. 1978 Refined Products Costs in $/Barrel of Crude Oil Processed for Refineries—Aggregated by Refinery Size Range.

NOTE: This figure was plotted from data in Table 96

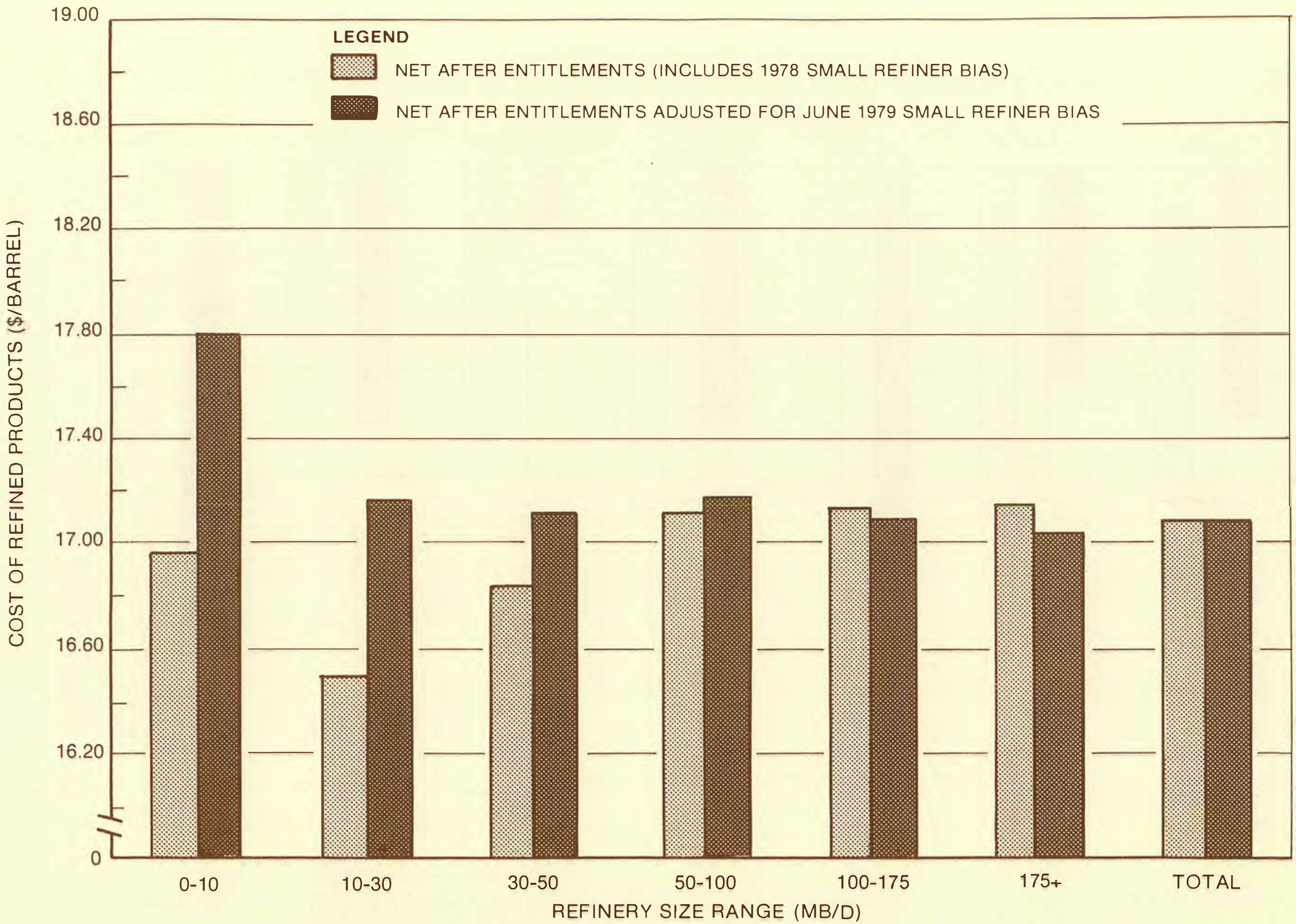

Figure 36. Effect of the Change in the Small Refiner Bias on Refined Products Costs in $/Barrel of Crude Oil Processed for Refineries—Aggregated by Refinery Size Range.

NOTE: This figure was plotted from data in Table 96.

TABLE 97

1978 Product and Other Feedstock Slates
Aggregated by Refinery Size Range
(Vol. % of Total Input)

	Refinery Size Range (MB/D)						
	0-10	10-30	30-50	50-100	100-175	175+	Average
Product Yields							
LPG	0.7	1.7	1.3	3.7	1.6	1.4	1.9
Motor Gasoline	18.2	33.7	42.0	48.9	50.5	44.1	45.1
Jet Fuels	7.3	5.0	6.7	4.1	5.8	7.6	6.3
Middle Distillate	18.7	21.9	22.6	22.0	20.9	18.4	20.2
Heavy Fuel Oils	25.2	18.2	11.5	7.7	6.8	10.9	10.1
Asphalt	8.7	7.0	4.6	1.9	2.5	2.2	2.8
Finished Lubricants	6.4	*	*	0.6	1.0	1.7	1.2
BTX	-	*	*	0.5	0.8	0.9	0.7
Feedstocks Sold to Others	5.1	3.0	2.0	3.1	1.7	5.6	3.8
Other Saleable	3.3	5.4	4.3	3.2	3.4	3.4	3.5
Refinery Fuel Produced	2.1	3.8	5.0	5.6	6.5	5.3	5.4
Total (Except Sulfur, Wax and Coke)	95.9	100.1	100.7	101.3	101.6	101.5	101.2
Other Feedstocks							
Butanes	-	1.3	1.9	2.2	1.7	1.7	1.7
Natural Gasoline	4.2	2.4	1.5	5.6	0.4	1.7	2.2
Other Feedstocks	0.9	2.4	2.2	4.4	3.9	3.2	3.4
Other Blendstocks	3.2	0.6	0.2	*	*	1.2	1.2
Total	8.3	6.7	5.8	*	*	7.8	8.5

*Data withheld to protect confidentiality.

TABLE 98

Implications of Changes Since 1978 in Competitive Factors and Varying Bases for Computing Cost of Capital for Refineries Aggregated by Size Range

(All Figures Other Than Crude Oil Throughput and Complexity are $/Barrel of Crude Oil and Field Condensate)

	Refinery Size Range (MB/D)						
	0-10	10-30	30-50	50-100	100-175	175+	Average
Weight Average Complexity	2.34	3.33	5.19	7.03	8.23	7.49	7.27
1. 1978 Data							
A. Capital Cost Based Upon Original Undepreciated Assets							
Crude Oil Expense	11.03	11.55	12.41	12.85	12.75	12.87	12.73
Cost of Capital Employed	0.78	0.62	0.69	0.81	1.01	0.89	0.87
Other Costs	5.15	4.32	3.73	3.45	3.36	3.38	3.48
Total Product Cost	16.96	16.49	16.83	17.11	17.12	17.14	17.08
Relative Refinery Size Advantage (Disadvantage) vs. Average	0.12	0.59	0.25	(0.03)	(0.04)	(0.06)	Base
B. Capital Cost Based Upon Replacement Investment							
Crude Oil Expense	11.03	11.55	12.41	12.85	12.75	12.87	12.73
Cost of Capital Employed	1.60	2.30	2.33	2.48	2.60	2.49	2.47
Other Costs	5.15	4.32	3.73	3.45	3.36	3.38	3.48
Total Product Cost	17.78	18.17	18.47	18.78	18.71	18.74	18.68
Relative Refinery Size Advantage (Disadvantage) vs. Average	0.90	0.51	0.21	(0.10)	(0.03)	(0.06)	Base
2. 1978 Data Adjusted for June 1979 Small Refiner Bias							
A. Capital Cost Based Upon Original Undepreciated Assets							
Crude Oil Expense	11.87	12.22	12.69	12.91	12.72	12.76	12.73
Cost of Capital Employed	0.78	0.62	0.69	0.81	1.01	0.89	0.87
Other Costs	5.15	4.32	3.73	3.45	3.36	3.38	3.48
Total Product Cost	17.80	17.16	17.11	17.17	17.09	17.03	17.08
Relative Refinery Size Advantage (Disadvantage) vs. Average	(0.72)	(0.08)	(0.03)	(0.09)	(0.01)	0.05	Base
B. Capital Cost Based Upon Replacement Investment							
Crude Oil Expense	11.87	12.22	12.69	12.91	12.72	12.76	12.73
Cost of Capital Employed	1.60	2.30	2.33	2.48	2.60	2.49	2.47
Other Costs	5.15	4.32	3.73	3.45	3.36	3.38	3.48
Total Product Cost	18.62	18.84	18.75	18.84	18.68	18.63	18.68
Relative Refinery Size Advantage (Disadvantage) vs. Average	0.06	(0.16)	(0.07)	(0.16)	(0.01)	0.05	Base
3. 1978 Data Adjusted for June 1979 Small Refiner Bias and First Quarter 1980 Product Prices							
A. Capital Cost Based Upon Original Undepreciated Assets							
Crude Oil Expense	11.87	12.22	12.69	12.91	12.72	12.76	12.73
Cost of Capital Employed	0.78	0.62	0.69	0.81	1.01	0.89	0.87
Other Costs	9.80	7.49	5.53	4.78	4.74	4.70	5.02
Total Product Cost	22.45	20.33	19.91	18.50	18.47	18.35	18.62
Relative Refinery Size Advantage (Disadvantage) vs. Average	(3.83)	(1.71)	(1.29)	0.12	0.15	0.27	Base
B. Capital Cost Based Upon Replacement Investment							
Crude Oil Expense	11.87	12.22	12.69	12.91	12.72	12.76	12.73
Cost of Capital Employed	1.60	2.30	2.33	2.48	2.60	2.49	2.47
Other Costs	9.80	7.49	5.53	4.78	4.74	4.70	5.02
Total Product Cost	23.27	22.01	20.55	20.17	20.06	19.95	20.22
Relative Refinery Size Advantage (Disadvantage) vs. Average	(3.05)	(1.79)	(0.33)	0.01	0.13	0.02	Base

MB/D size range, which had only 34 percent gasoline and a relatively high 18 percent heavy fuel oil yield without the benefit of specialties such as lubricants and petrochemicals. Yield structures are discussed in greater detail later in this chapter.

Adjusting the 1978 data for the first quarter 1980 product market price structure (and the June 1979 small refiner bias change) places the smallest size range refineries, 0-10 MB/D, at a disadvantage of $3.83/bbl. The 1980 disadvantage for smaller company size diminishes to $1.29/bbl for the 30-50 MB/D size category based on undepreciated assets.

Tables 99 and 100 show the advantage (disadvantage) for complexity factors[2] of 1-3 and over 3 for the 0-10 and 10-30 MB/D size range refineries. The average disadvantage of $3.83/bbl for the 0-10 MB/D refineries in the June 1979 small refiner bias/first quarter 1980 product price case was $4.42/bbl for the 1-3 complexity refineries and $0.41/bbl for those over 3. This difference was due to the value of the product mix. Plants in the 1-3 complexity range produced 3.8 percent lubes and 34.8 percent transportation fuels, those over 3 produced 17.7 percent lubes and 45.9 percent transportation fuels. This trend was similiar for the 10-30 MB/D refineries; the average disadvantage was $1.71/bbl, but the 1-3 complexity plants were $3.75/bbl above the average while the over 3 were $0.10/bbl below the average of all domestic refineries. To recap the competitiveness by refinery size range, Table 101 is presented.

Larger refineries tend to be more complex and to have a greater yield of gasoline and much reduced yields of heavy fuel oil and asphalt. Therefore, their relative competitive positions were significantly enhanced by the first quarter 1980 product market price structure.

Refinery Location. Segmentation of the domestic refining industry competitive positions on a geographic basis (such as by PAD district) reflects local crude oil availability and product supply logistics. Some operating costs, such as purchased fuel and manpower, vary geographically. Comparison of competitive positions between PAD districts (Table 102) is useful particularly where there is substantial movement of products from one PAD district to another, as is the case between PADs I and III. It is also useful for comparing the competitiveness of domestic vs. foreign export refineries (see Chapter Four). PAD I is the principle U.S. market for foreign export refineries in competition with product movements from PAD III.

The relative cost of refined products between the several PAD districts ranged from a low of $16.88/bbl of crude oil in PAD IV to a high of $17.18/bbl in PAD II. PAD IV was favored by product yield structure, product prices, and crude oil costs below the average. PAD I refineries experienced fairly high crude oil cost and the most unfavorable product mix value adjustments (Table 102).

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[2]See discussion of complexity factors in Appendix D.

TABLE 99

1978 Competitive Positions of Small Refineries by Size and Complexity, Adjusted for June 1979 Small Refiner Bias and First Quarter 1980 Product Prices (All Figures Other Than Refinery Size, Complexity, and Yield Percentages are $/Barrel of Crude Oil and Field Condensate)

	0-10 MB/D Refineries			10-30 MB/D Refineries		
	1-3 Complexity	3+ Complexity	All	1-3 Complexity	3+ Complexity	All
Weight Average Complexity	1.36	5.69	2.34	1.44	5.33	3.33
Lube Yield (%)	3.8	17.7	6.6	0	0.8	0.4
Transportation Fuel Yield (%)*	34.8	45.9	37.0	28.6	64.4	47.7
Crude Oil Cost†	11.53	12.94	11.87	11.79	12.60	12.22
Other Feedstock Cost§	3.48	3.63	3.51	1.44	2.65	2.10
Subtotal Input Cost	15.01	16.57	15.38	13.23	15.25	14.32
Operating Expenses						
Fuel and Purchased Utilities	0.56	1.76	0.85	0.46	1.10	0.80
Depreciation	0.15	0.36	0.20	0.14	0.18	0.16
Maintenance and Other Expenses	1.07	1.98	1.29	0.72	1.12	0.93
Subtotal, Operating Expenses	1.78	4.10	2.34	1.32	2.40	1.89
Cost of Capital Employed¶	0.53	1.56	0.78	0.53	0.70	0.62
Product Value Adjustment	5.72	(3.20)	3.95	7.29	0.37	3.50
Total Product Cost	23.04	19.03	22.45	22.37	18.72	20.33
Relative Refinery Size Advantage (Disadvantage) vs. Average	(4.42)	(0.41)	(3.83)	(3.75)	(0.10)	(1.71)
Number of Refineries	24	7	31	24	21	45
Crude Oil Charge Capacity (MB/D)	162	47	209	480	451	931

*Transporation fuels are motor gasoline, jet fuels, and diesel.

†Crude oil expense includes crude oil and field condensate after entitlements including small refiner bias and excluding the benefits of all other special entitlements programs. [Note: These crude oil costs are estimates. They are based upon a tabulation which (1) was subdivided at a 2.5 complexity level (rather than 3.0); and (2) had 8 percent more crude oil charge capacity than the data set used to compile the remainder of this table. Estimates of crude oil cost had to be used, because this table was requested after the original data base had been destroyed.]

§Other feedstock acquisition expense is the estimated cost of other hydrocarbon feedstocks purchased for blending or processing.

¶Based on original undepreciated assets.

TABLE 100

Implications of Changes Since 1978 in Competitive Factors and Varying Bases for Computing Cost of Capital for Small Refineries Aggregated by Size and Complexity
(All Figures Other Than Crude Oil Throughput, Complexity, and Yield Percentage are $/Barrel of Crude Oil and Field Condensate)

	0-10 MB/D Refineries			10-30 MB/D Refineries		
	1-3 Complexity	3+ Complexity	All	1-3 Complexity	3+ Complexity	All
Weight Average Complexity	1.36	5.69	2.34	1.44	5.33	3.33
Lube Yield (%)	3.8	17.7	6.6	0	0.8	0.4
Transportation Fuel Yield (%)*	34.8	45.9	37.0	28.6	64.4	47.7
1. 1978 Data						
Crude Oil Expense†	10.75	11.91	11.03	11.07	11.97	11.55
Cost of Capital§	0.53	1.56	0.78	0.53	0.70	0.62
Other Costs	5.32	3.96	5.15	5.00	3.74	4.32
Total Product Cost	16.60	17.43	16.96	16.60	16.41	16.49
Relative Refinery Advantage (Disadvantage) vs. Average	0.48	(0.35)	0.12	0.48	0.67	0.59
2. 1978 Data Adjusted for June 1979 Small Refiner Bias						
Crude Oil Expense†	11.53	12.94	11.87	11.79	12.60	12.22
Cost of Capital§	0.53	1.56	0.78	0.53	0.70	0.62
Other Costs	5.32	3.96	5.15	5.00	3.74	4.32
Total Product Cost	17.38	18.46	17.80	17.32	17.04	17.16
Relative Refinery Advantage (Disadvantage) vs. Average	(0.38)	(1.38)	(0.72)	(0.24)	0.04	(0.08)
3. 1978 Data Adjusted for June 1979 Small Refiner Bias and First Quarter 1980 Product Prices						
Crude Oil Expense†						
Cost of Capital§	11.53	12.94	11.87	11.79	12.60	12.22
Other Costs	0.53	1.56	0.78	0.53	0.70	0.62
Total Product Cost	10.98	4.53	9.80	10.05	5.42	7.49
Relative Refinery	23.04	19.03	22.45	22.37	18.72	20.33
Advantage (Disadvantage) vs. Average						
	(4.42)	(0.41)	(3.83)	(3.75)	(0.10)	(1.71)

*Transportation fuels are motor gasoline, jet fuels, and diesel.

†Crude oil expense includes crude oil and field condensate after entitlements including small refiner bias and exluding the benefits of all other special entitlement programs. [Note: These crude oil costs are estimates. They are based upon a tabulation which (1) was subdivided at a 2.5 complexity level (rather than 3.0); and (2) had 8 percent more crude charge oil capacity than the data set used to compile the remainder of this table. Estimates of crude oil cost had to be used, because this table was requested after the original data base had been destroyed.]

§Based on original undepreciated assets.

TABLE 101

Highest and Lowest Product Mix Cost
Aggregated by Refinery Size Range
($/Bbl Crude Oil Throughput)

	Refinery Size Range	Advantage (Disadvantage) vs. Average
1978 Data		
Capital Cost Based Upon:		
Original Undepreciated Assets	10- 30 MB/D	0.59
	175+ MB/D	(0.06)
Replacement Investment	0- 10 MB/D	0.90
	50-100 MB/D	(0.10)
1978 Data Adjusted for June 1979 Small Refiner Bias		
Capital Cost Based Upon:		
Original Undepreciated Assets	175+ MB/D	0.05
	0- 10 MB/D	(0.72)
Replacement Investment	0- 10 MB/D	0.06
	10- 30 & 50-100 MB/D	(0.16)
1978 Data Adjusted for June 1979 Small Refiner Bias and First Quarter 1980 Product Prices		
Capital Cost Based Upon:		
Original Undepreciated Assets	175+ MB/D	0.27
	0- 10 MB/D	(3.83)
Replacement Investment	100-175 MB/D	0.13
	0- 10 MB/D	(3.05)

With respect to PADs I and III, the cost of refined products is \$17.14 and \$17.01/bbl of crude oil, respectively. This is a differential of \$0.13/bbl, or \$0.003 per gallon. Comparing only these two areas, PAD III refineries have advantages with respect to crude oil cost, operating expense, and cost of capital employed, while PAD I has a product mix value advantage. Considering that tanker transportation costs from the Gulf Coast to the East Coast are on the order of \$0.03 per gallon, the PAD I refineries should have been in a relatively favorable position in 1978 to compete with

TABLE 102

Competitive Positions of Refineries
Aggregated by Refinery Location
(All Figures Other Than Refinery Location and Complexity are $/Barrel of Crude Oil and Field Condensate)

	Refinery Location					
	PAD I	PAD II	PAD III	PAD IV	PAD V	Average
Weight Average Complexity	7.08	7.16	7.41	5.24	7.63	7.27
Crude Oil Cost*	12.94	13.02	12.78	12.46	11.82	12.73
Other Feedstock Cost†	1.26	0.90	1.35	0.76	1.35	1.20
Subtotal Input Cost	14.20	13.92	14.13	13.22	13.17	13.93
Operating Expenses						
Fuel and Purchased Utilities	1.12	1.11	0.97	0.94	1.29	1.07
Depreciation	0.19	0.16	0.20	0.19	0.24	0.19
Maintenance and Other Expenses	1.20	0.94	0.96	1.12	1.14	1.02
Subtotal, Operating Expenses	2.51	2.21	2.13	2.25	2.67	2.28
Cost of Capital Employed	0.93	0.83	0.83	0.72	1.03	0.87
Product Value Adjustment	(0.50)	0.22	(0.08)	0.69	0.15	0
Total Product Cost	17.14	17.18	17.01	16.88	17.02	17.08
Relative PAD Advantage (Disadvantage) vs. Average	(0.06)	(0.10)	0.07	0.20	0.06	Base
Number of Refineries	26	50	58	18	34	186
Number of Companies	17	30	46	14	24	91
Crude Charge Capacity (MB/D)	1,857	3,688	6,517	503	2,246	14,811

*Crude oil expense includes crude oil and field condensate after entitlements including small refiner bias and excluding the benefits of all other special entitlements programs.

†Other feedstock acquisition expense is the estimated cost of other hydrocarbon feedstocks purchased for processing or blending.

product from PAD III, notwithstanding the fact that PAD III refineries enjoyed advantages in crude oil and operating costs.

Table 103 and Figures 37 and 38 present computed competitive positions under the four crude oil cost scenarios previously defined in discussions of other aggregations of the industry. The small refiner bias provisions of the entitlements program had somewhat limited impact upon the competitive order of PAD districts: they served to reduce the cost of refined products in PAD IV and increase it in PAD III relative to the other districts. Without any entitlements program, PADs II, III, and IV, with substantial throughputs of price-controlled domestic oils, would have experienced a much more favorable cost of refined products.

PAD IV refineries average 19 MB/D of capacity, well below the national average of 61 MB/D. Consequently, the June 1, 1979, change in the small refiner bias provisions of the entitlements program most adversely affected that area, shifting it from the most advantageous to the least advantageous position. However, the June 1979 small refiner bias provisions did not significantly alter the position among refineries in competing PAD districts. PAD III product costs improved relative to PAD I, but only to $0.18/bbl.

Table 104 shows the product mix for PADs I through V. The total percentage yields showed little variation (101.1 percent to 101.7 percent). Table 105 presents a comparison, between 1978 data and 1978 data adjusted for the June 1979 small refiner bias, of the impact of capital cost based on original undepreciated assets and capital costs based on replacement investments. A comparison is also made assuming that first quarter 1980 product prices were in effect along with the June 1979 small refiner bias revision. From Tables 104 and 105, it may be observed that PADs II and III particularly benefited from the shift in product prices between 1978 and early 1980, while PAD I and PAD V were especially disadvantaged. The analysis of competitiveness by refinery location (PAD district) is recapped in Table 106.

Refinery Process Complexity. Higher complexity, as previously observed, is incorporated into refineries to achieve the capability to enhance or diversify product slate, improve yield of preferred products, or accommodate lower quality crude oils. Higher complexity generally results in greater capital outlay and increased operating expenses. With some exceptions, as in the case of smaller lubricating plants, high complexity is generally more common to larger ranges of refinery size.

As developed in Table 107, those refineries in the relatively high complexity ranges (7-9 and 9-11) had the more advantageous competitive position under conditions existing in 1978. It is interesting to note that the advantage for these refineries was largely due to a favorable product mix which more than compensated for added operating expenses and capital costs. The crude oil cost advantage reported for the less complex refineries is considered to be more the result of regulatory programs (e.g., small refiner bias) than of complexity.

TABLE 103

Competitive Positions of Refineries Under Various Crude Oil Cost Scenarios
Aggregated by Refinery Location

	Refinery Location					
Basis of Crude Oil Cost*	PAD I	PAD II	PAD III	PAD IV	PAD V	Average
I. Total 1978 Refined Products Costs in $/Barrel of Crude Oil Processed						
A. Net After Entitlements†	17.14	17.18	17.01	16.88	17.02	17.08
B. After Entitlements Without Small Refiner Bias	17.08	17.21	16.93	17.45	17.07	17.08
C. Before Entitlements	18.18	16.63	16.35	15.53	17.03	16.75
D. Net After Entitlements† Adjusted for June 1979 Small Refiner Bias	17.15	17.22	16.97	17.30	17.11	17.08
II. Relative PAD Advantage (Disadvantage) vs. Average in Refined Products Costs in $/Barrel of Crude Oil Processed						
A. Net After Entitlements†	(0.06)	(0.10)	0.07	0.20	0.06	Base
B. After Entitlements Without Small Refiner Bias	0.00	(0.13)	0.15	(0.37)	0.01	Base
C. Before Entitlements	(1.43)	0.12	0.40	1.22	(0.28)	Base
D. Net After Entitlements† Adjusted for June 1979 Small Refiner Bias	(0.07)	(0.14)	0.11	(0.22)	(0.03)	Base

*All entitlements calculations exclude the benefits of special entitlements programs except the small refiner bias, which is included where noted.

†Includes small refiner bias.

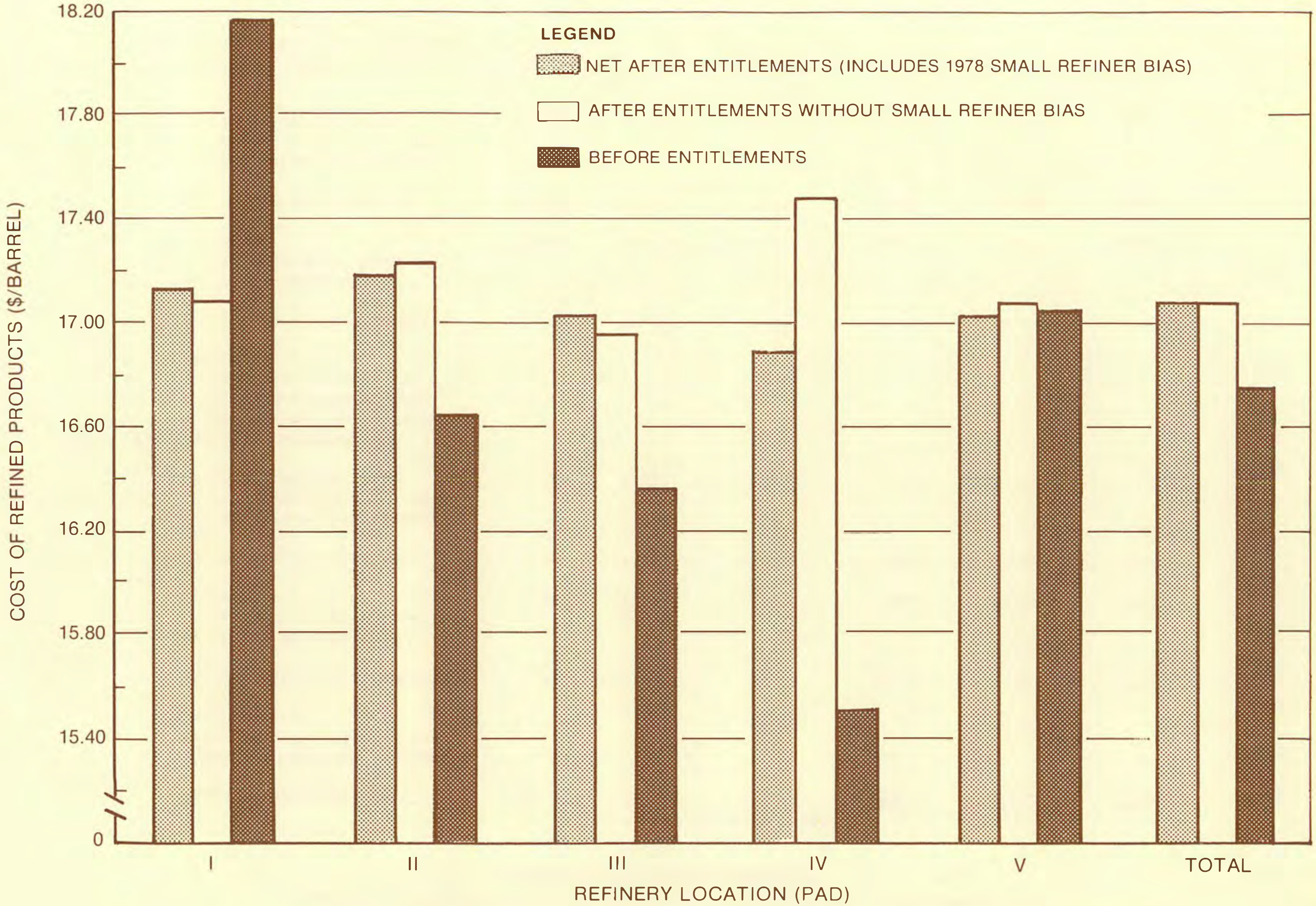

Figure 37. 1978 Refined Products Costs in $/Barrel of Crude Oil Processed for Refineries—
Aggregated by Refinery Location.

NOTE: This figure was plotted from data in Table 103.

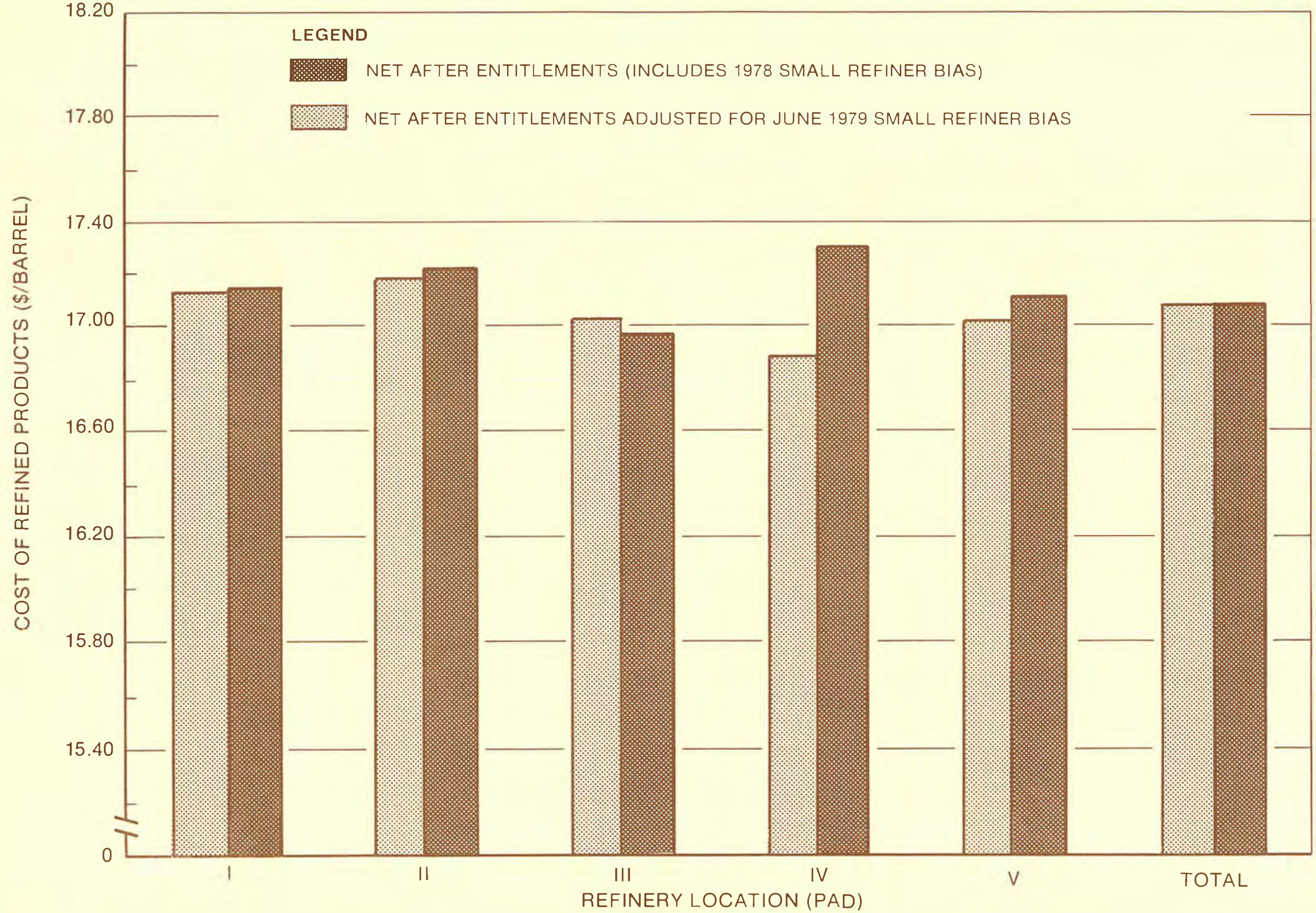

Figure 38. Effect of the Change in the Small Refiner Bias on Refiner Products Costs in $/Barrel of Crude Oil Processed for Refineries—Aggregated by Refinery Location.

NOTE: This figure was plotted from data in Table 103.

TABLE 104

1978 Product and Other Feedstock Slates
Aggregated by Refinery Location
(Vol. % of Total Input)

	Refinery Location					
	PAD I	PAD II	PAD III	PAD IV	PAD V	Average
Product Yields						
LPG	1.7	1.5	2.3	1.1	1.7	1.9
Motor Gasoline	42.4	53.3	42.5	48.1	41.1	45.1
Jet Fuels	3.5	4.4	6.7	5.0	10.5	6.3
Middle Distillate	24.6	22.5	20.2	24.0	13.0	20.2
Heavy Fuel Oils	11.6	4.8	9.9	4.8	19.3	10.1
Asphalt	5.0	4.1	1.5	5.7	2.4	2.8
Finished Lubricants	1.9	0.8	1.6	0.3	0.5	1.2
BTX	*	0.5	1.2	-	*	0.7
Feedstocks Sold to Others	1.4	1.1	6.8	3.6	1.5	3.8
Other Saleable	*	1.9	4.2	1.5	*	3.5
Refinery Fuel Produced	6.4	6.4	4.4	6.4	5.8	5.4
Total (Except Sulfur, Wax, and Coke)	101.7	101.3	101.1	100.4	101.3	101.2
Other Feedstocks						
Butanes	0.7	2.9	1.7	2.1	0.8	1.7
Natural Gasoline	-	1.4	4.0	0.8	0.4	2.2
Other Feedstocks	5.4	1.6	3.7	1.5	4.4	3.4
Other Blendstocks	1.2	0.7	1.2	0.7	2.2	1.2
Total	7.3	6.6	10.6	5.1	7.8	8.5

*Data withheld to protect confidentiality.

TABLE 105

Implications of Changes Since 1978 in Competitive Factors and Varying Bases for Computing Cost of Capital for Refineries Aggregated by Refinery Location
(All Figures Other Than Complexity are $/Barrel of Crude Oil and Field Condensate)

	Refinery Location					
	PAD I	PAD II	PAD III	PAD IV	PAD V	Average
Weight Average Complexity	7.08	7.16	7.41	5.24	7.63	7.27
1. 1978 Data						
A. Capital Cost Based Upon Original Gross Assets						
Crude Oil Expense	12.94	13.02	12.78	12.46	11.82	12.73
Cost of Capital Employed	0.93	0.83	0.83	0.72	1.03	0.87
Other Costs	3.27	3.33	3.40	3.70	4.17	3.48
Total Product Cost	17.14	17.18	17.01	16.88	17.02	17.08
Relative Location (PAD) Advantage (Disadvantage) vs. Average	(0.06)	(0.10)	0.07	0.20	0.06	Base
B. Capital Cost Based Upon Replacement Investment						
Crude Oil Expense	12.94	13.02	12.78	12.46	11.82	12.73
Cost of Capital Employed	2.42	2.51	2.49	2.55	2.41	2.47
Other Costs	3.27	3.33	3.40	3.70	4.17	3.48
Total Product Cost	18.63	18.86	18.67	18.71	18.40	18.68
Relative Location (PAD) Advantage (Disadvantage) vs. Average	0.05	(0.18)	0.01	(0.03)	0.28	Base
2. 1978 Data Adjusted for June 1979 Small Refiner Bias						
A. Capital Cost Based Upon Original Gross Assets						
Crude Oil Expense	12.95	13.06	12.74	12.88	11.91	12.73
Cost of Capital Employed	0.93	0.83	0.83	0.72	1.03	0.87
Other Costs	3.27	3.33	3.40	3.70	4.17	3.48
Total Product Cost	17.15	17.22	16.97	17.30	17.11	17.08
Relative Location (PAD) Advantage (Disadvantage) vs. Average	(0.07)	(0.14)	0.11	(0.22)	(0.03)	Base
B. Capital Cost Based Upon Replacement Investment						
Crude Oil Expense	12.95	13.06	12.74	12.88	11.91	12.73
Cost of Capital Employed	2.42	2.51	2.49	2.55	2.41	2.47
Other Costs	3.27	3.33	3.40	3.70	4.17	3.48
Total Product Cost	18.64	18.90	18.63	19.13	18.49	18.68
Relative Location (PAD) Advantage (Disadvantage) vs. Average	0.04	(0.22)	0.05	(0.45)	0.19	Base
3. 1978 Data Adjusted for June 1979 Small Refiner Bias and First Quarter 1980 Product Prices						
A. Capital Cost Based Upon Original Gross Assets						
Crude Oil Expense	12.95	13.06	12.74	12.88	11.91	12.73
Cost of Capital Employed	0.93	0.83	0.83	0.72	1.03	0.87
Other Costs	6.32	4.21	4.36	5.34	6.92	5.04
Total Product Cost	20.20	18.10	17.93	18.94	19.86	18.64
Relative Location (PAD) Advantage (Disadvantage) vs. Average	(1.56)	0.54	0.71	(0.30)	(1.22)	Base
B. Capital Cost Based Upon Replacement Investment						
Crude Oil Expense	12.95	13.06	12.74	12.88	11.91	12.73
Cost of Capital Employed	2.42	2.51	2.49	2.55	2.41	2.47
Other Costs	6.32	4.21	4.36	5.34	6.92	5.04
Total Product Cost	21.69	19.78	19.59	20.77	21.24	20.24
Relative Location (PAD) Advantage (Disadvantage) vs. Average	(1.45)	0.46	0.65	(0.53)	(1.00)	Base

TABLE 106

Highest and Lowest Product Mix Cost
Aggregated by Refinery Location
($/Bbl Crude Oil Throughput)

	Refinery Location	Advantage (Disadvantage) vs. Average
1978 Data		
Capital Cost Based Upon:		
Original Undepreciated Investment	PAD IV	0.20
	PAD II	(0.10)
Replacement Investment	PAD V	0.28
	PAD II	(0.18)
1978 Data Adjusted for June 1979 Small Refiner Bias		
Capital Cost Based Upon:		
Original Undepreciated Investment	PAD III	0.11
	PAD IV	(0.22)
Replacement Investment	PAD V	0.19
	PAD IV	(0.45)
1978 Data Adjusted for June 1979 Small Refiner Bias and First Quarter 1980 Product Prices		
Capital Cost Based Upon:		
Original Undepreciated Investment	PAD III	0.71
	PAD I	(1.56)
Replacement Investment	PAD III	0.65
	PAD I	(1.45)

Table 108 and Figures 39 and 40 display computed competitive positions under the four crude oil cost scenarios previously discussed. Low complexity refineries, which generally tend to be small, were most adversely affected by the small refiner bias revision made in June 1, 1979. After this date, refineries in the 7-9 complexity range attained still further advantage in their competitive positions as measured by the cost of refined product.

TABLE 107

Competitive Positions of Refineries
Aggregated by Complexity Factor
(All Figures Other Than Complexity are $/Barrel of Crude Oil and Field Condensate)

	Complexity Factor 1-3	3-5	5-7	7-9	9-11	11+	Average
Weight Average Complexity	1.62	4.29	6.20	7.80	10.04	12.96	7.27
Crude Oil Cost*	11.46	12.59	12.90	12.80	12.70	12.46	12.73
Other Feedstock Cost†	0.71	1.12	0.76	1.46	1.95	1.43	1.20
Subtotal Input Cost	12.17	13.71	13.66	14.26	14.65	13.89	13.93
Operating Expenses							
Fuel and Purchased Utilities	0.51	0.76	0.92	1.17	1.33	1.55	1.07
Depreciation	0.15	0.18	0.17	.20	0.21	0.27	0.19
Maintenance and Other Expenses	0.83	0.72	1.07	1.02	1.02	1.22	1.02
Subtotal, Operating Expenses	1.49	1.66	2.16	2.39	2.56	3.04	2.28
Cost of Capital Employed	0.56	0.76	0.82	0.88	1.10	1.03	0.87
Product Value Adjustment	2.91	1.06	0.57	(0.66)	(1.28)	(0.81)	0
Total Product Cost	17.13	17.19	17.21	16.87	17.03	17.15	17.08
Relative Refinery Complexity Advantage (Disadvantage) vs. Average	(0.05)	(0.11)	(0.12)	0.21	0.05	(0.07)	Base
Number of Refineries	53	29	45	36	13	10	186
Number of Companies	48	21	25	20	12	9	91
Crude Charge Capacity (MB/D)	894	1,170	4,790	5,285	1,487	1,185	14,811

*Crude oil expense includes crude oil and field condensate after entitlements including small refiner bias and excluding the benefits of all other special entitlements programs.

†Other feedstocks acquisition expense is the estimated cost of other hydrocarbon feedstocks purchased for processing or blending.

TABLE 108

Competitive Positions of Refineries by Size Under Various Crude Oil Cost Scenarios
Aggregated by Complexity Factor

Basis of Crude Oil Cost*	Complexity Factor 1-3	3-5	5-7	7-9	9-11	11+	Average
I. Total 1978 Refined Products Costs in $/Barrel of Crude Oil Processed							
A. Net After Entitlements†	17.13	17.19	17.21	16.87	17.03	17.15	17.08
B. After Entitlements Without Small Refiner Bias	18.13	17.53	17.17	16.73	16.93	17.08	17.08
C. Before Entitlements	17.69	17.08	16.88	16.58	16.37	17.23	16.75
D. Net After Entitlements† Adjusted for June 1979 Small Refiner Bias	17.66	17.38	17.22	16.81	17.02	17.12	17.08
II. Relative Refinery Complexity Advantage (Disadvantage) vs. Average in Refined Products Costs in $/Barrel of Crude Oil Processed							
A. Net After Entitlements†	(0.05)	(0.11)	(0.13)	0.21	0.05	(0.07)	Base
B. After Entitlements Without Small Refiner Bias	(1.05)	(0.48)	(0.09)	0.35	0.15	0.00	Base
C. Before Entitlements	(0.94)	(0.33)	(0.13)	0.17	0.38	(0.48)	Base
D. Net After Entitlements† Adjusted for June 1979 Small Refiner Bias	(0.58)	(0.30)	(0.14)	0.37	0.06	(0.04)	Base

*All entitlements calculations exclude the benefits of special entitlements programs except the small refiner bias, which is included where noted.

†Includes small refiner bias.

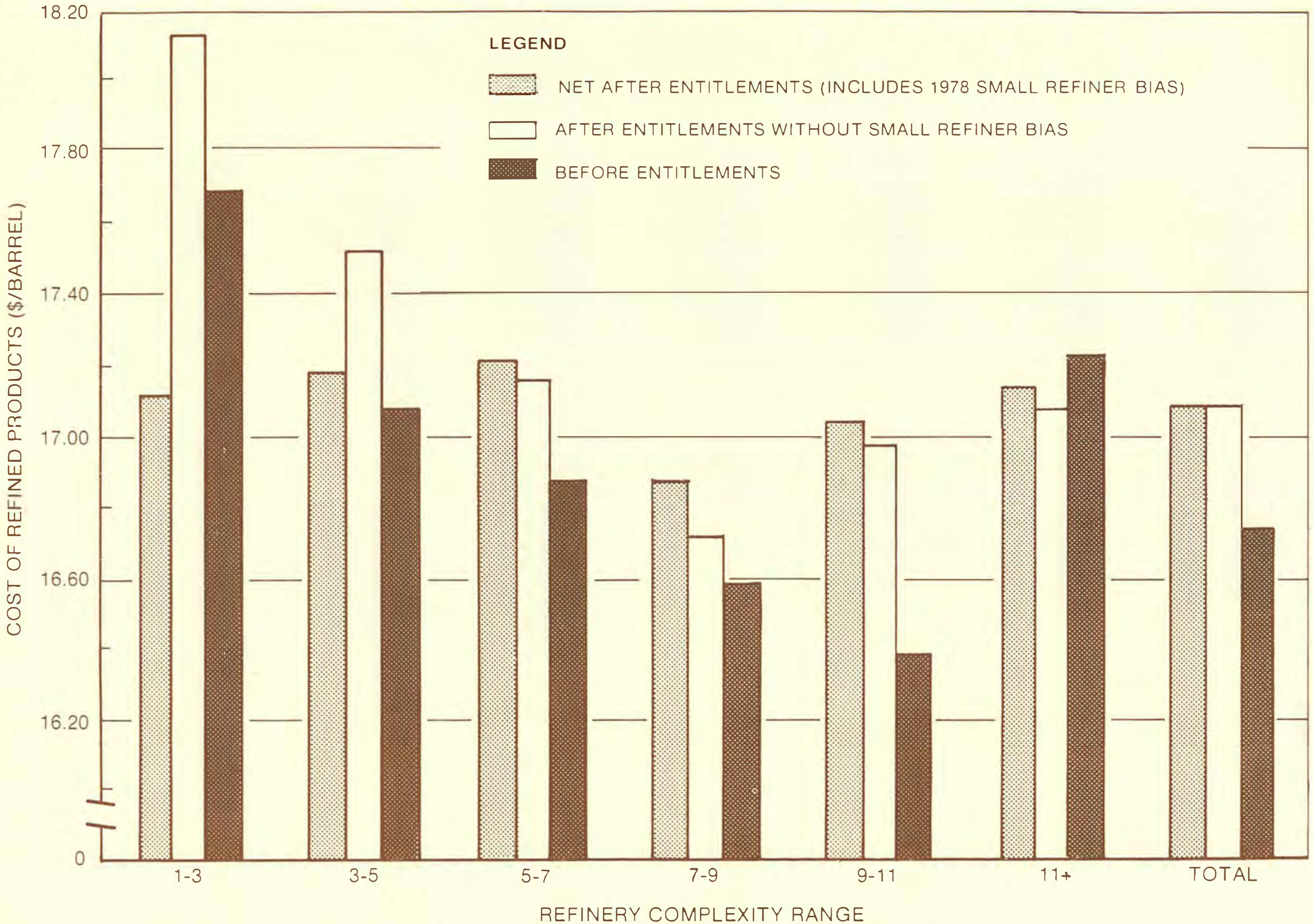

Figure 39. 1978 Refined Products Costs in S/Barrel of Crude Oil Processed for Refineries—Aggregated by Complexity.

NOTE: This figure was plotted from data in Table 108.

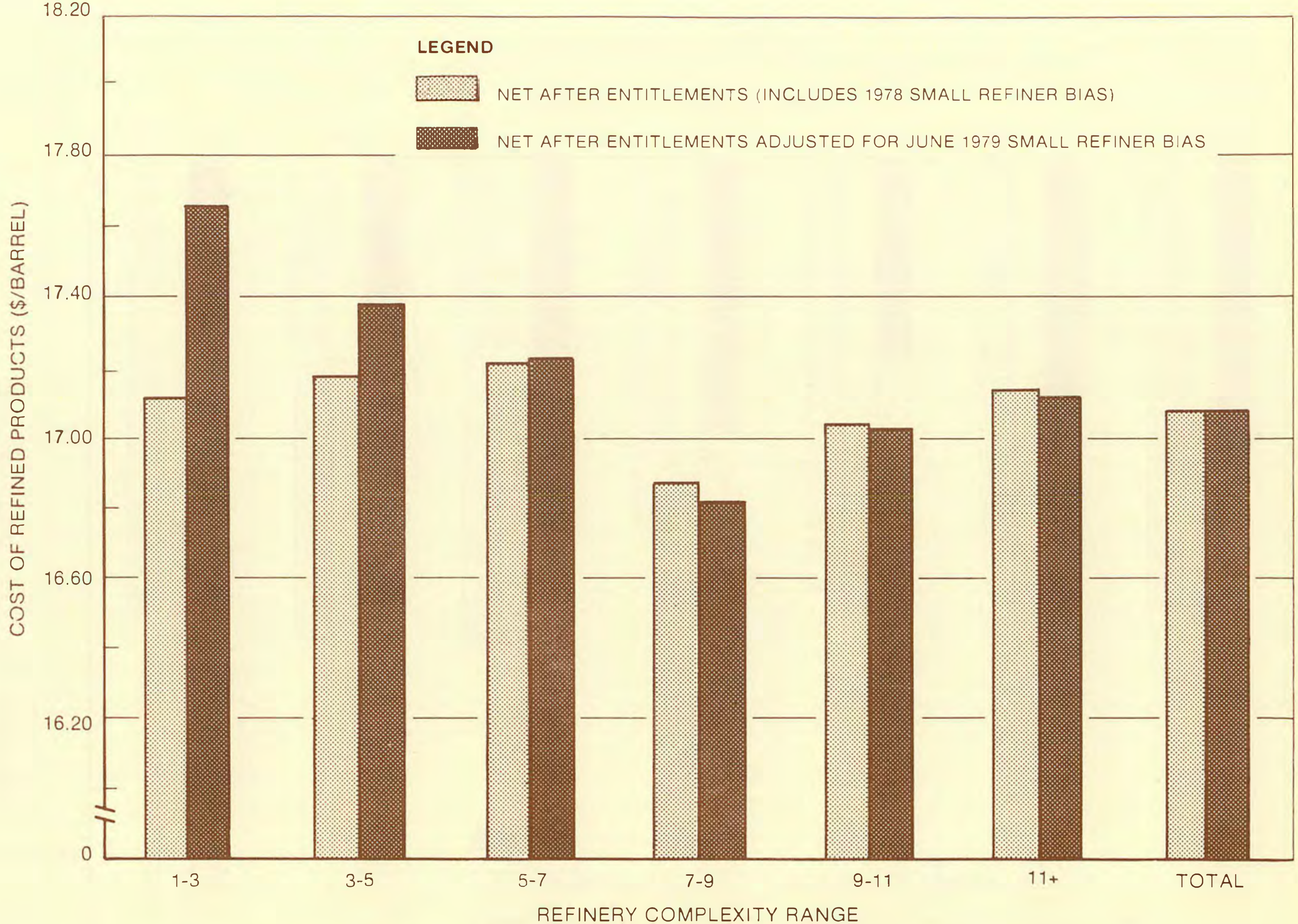

Figure 40. Effect of the Change in the Small Refiner Bias on Refined Products Costs in $/Barrel of Crude Oil Processed for Refineries—Aggregated by Complexity.

NOTE: This figure was plotted from data in Table 108.

Table 109 illustrates that the refineries in the 1-3 complexity range have a lower yield percentage and a low percentage of higher value products. Table 110 compares the data based on undepreciated assets and capital cost based on replacement costs with 1978 data and with 1978 data adjusted for the June 1979 small refiner bias and first quarter 1980 product prices.

First quarter 1980 product prices, featuring high differentials between light and heavy products, place the low complexity (low conversion) refineries with high heavy oil yields at a substantial disadvantage. For example, the least complex refinery category experienced a $3.72/bbl disadvantage relative to the industry average. Table 111 summarizes the analysis of competitiveness as a function of complexity.

Product Value and Other Feedstock Adjustments

The relative competitiveness of a company or refinery is influenced significantly by the value of the mix of products which it derives from crude oil processed. High complexity refineries yield large percentages of higher value fuel products such as motor gasoline, jet fuels, distillate, and specialties such as petrochemical intermediates and lube oils, while the least complex plants are oriented toward lower price residual products. In order to achieve high conversion and enhancement of product mix, the high complexity refineries incur greater capital costs and higher expenses of operation. Consequently, the mix of products must be considered in conjunction with several cost factors when studying competitive positions. Similarly, such studies must give the proper weight to the cost of supplemental feedstocks other than whole crude oil.

Finished product prices and supplemental feedstock values vary between PAD districts, reflecting local demand for the individual products, transportation and logistic considerations, regulatory constraints, etc. Table 112 lists product values based primarily upon published reports for terminals in principal cities in the several PAD districts. Platt's 1978 Oil Price Handbook and Oilmanac, 55th edition, showing annual high and low averages for 1978, was the principal data source for product prices. The main supplemental source was the Department of Energy's Energy Information Administration which provided annual average wholesale prices aggregated by company size. The DOE does not have similar information for the PAD districts. For certain specialty products, such as benzene, toluene, xylene, coke, and asphalt, other publications were consulted.

It is recognized that individual companies and refineries experience product realizations differing to some extent from those of other firms and plants in the same areas. However, the concept of competitiveness employed in this study focuses attention upon the cost of manufacturing product rather than upon individual company price realizations. It is believed that the use of these regional prices derived from public sources for principal products should give meaningful product differentials for determining product mix and supplemental feedstock adjustments to product cost in the PAD districts.

TABLE 109

1978 Product and Other Feedstock Slates
Aggregated by Complexity Factor
(Vol. % of Total Input)

	Complexity Factor						
	1-3	3-5	5-7	7-9	9-11	11+	Average
Product Yields							
LPG	0.9	1.1	1.6	2.6	1.1	2.2	1.9
Motor Gasoline	15.9	38.3	44.9	48.9	49.9	53.2	45.1
Jet Fuels	9.8	3.3	7.0	6.5	6.9	2.6	6.3
Middle Distillate	21.2	25.3	22.1	18.7	16.0	19.2	20.2
Heavy Fuel Oils	31.4	14.6	9.8	7.2	9.0	4.9	10.1
Asphalt	6.9	4.5	3.5	1.9	*	*	2.8
Finished Lubricants	1.0	*	1.6	1.4	*	-	1.2
BTX	-	*	0.1	0.7	1.7	*	0.7
Feedstocks Sold to Others	4.0	3.7	2.9	4.0	4.9	4.8	3.8
Other Saleable	5.6	5.1	2.6	3.8	3.7	3.2	3.5
Refinery Fuel Produced	1.8	4.0	5.3	5.8	5.9	7.8	5.4
Total (Except Sulfur, Wax, and Coke)	98.5	100.7	101.3	101.4	102.1	101.7	101.2
Other Feedstocks							
Butanes	0.2	1.2	1.5	2.4	2.0	1.3	1.7
Natural Gasoline	1.8	1.5	1.4	3.4	1.7	1.9	2.2
Other Feedstocks	1.8	2.5	1.8	4.2	6.8	3.9	3.4
Other Blendstocks	1.0	1.9	0.6	*	*	2.0	1.2
Total	4.8	7.1	5.3	*	*	9.1	8.5

*Data withheld to protect confidentiality.

TABLE 110

Implications of Changes Since 1978 in Competitive Factors and Varying Bases for Computing Cost of Capital for Refineries Aggregated by Complexity Factor
(All Figures are $/Barrel of Crude Oil and Field Condensate)

	Complexity Factor						
	1-3	3-5	5-7	7-9	9-11	11+	Average
Weight Average Complexity	1.62	4.29	6.05	7.80	10.04	12.96	7.27
1. 1978 Data							
A. Capital Cost Based Upon Original Gross Assets							
Crude Oil Expense	11.46	12.59	12.90	12.80	12.70	12.46	12.73
Cost of Capital Employed	0.56	0.76	0.82	0.88	1.10	1.03	0.87
Other Costs	5.11	3.84	3.49	3.19	3.23	3.66	3.48
Total Product Cost	17.13	17.19	17.21	16.87	17.03	17.15	17.08
Relative Refinery Complexity Advantage (Disadvantage) vs. Average	(0.05)	(0.11)	(0.13)	0.21	0.05	(0.07)	Base
B. Capital Cost Based Upon Replacement Investment							
Crude Oil Expense	11.46	12.59	12.90	12.80	12.70	12.46	12.73
Cost of Capital Employed	1.22	2.20	2.37	2.56	2.81	3.13	2.47
Other Costs	5.11	3.84	3.49	3.19	3.23	3.66	3.48
Total Product Cost	17.79	18.63	18.76	18.55	18.74	19.25	18.68
Relative Refinery Complexity Advantage (Disadvantage) vs. Average	0.89	0.05	(0.08)	0.13	(0.06)	(0.57)	Base
2. 1978 Data Adjusted for June 1979 Small Refiner Bias							
A. Capital Cost Based Upon Original Gross Assets							
Crude Oil Expense	11.99	12.78	12.91	12.74	12.69	12.43	12.73
Cost of Capital Employed	0.56	0.76	0.82	0.88	1.10	1.03	0.87
Other Costs	5.11	3.84	3.49	3.19	3.23	3.66	3.48
Total Product Cost	17.66	17.38	17.22	16.81	17.02	17.12	17.08
Relative Refinery Complexity Advantage (Disadvantage) vs. Average	(0.58)	(0.30)	(0.14)	0.27	0.06	(0.04)	Base
B. Capital Cost Based Upon Replacement Investment							
Crude Oil Expense	11.99	12.78	12.91	12.74	12.69	12.43	12.73
Cost of Capital Employed	1.22	2.20	2.37	2.56	2.81	3.13	2.47
Other Costs	5.11	3.84	3.49	3.19	3.23	3.66	3.48
Total Product Cost	18.32	18.82	18.77	18.49	18.73	19.22	18.68
Relative Refinery Complexity Advantage (Disadvantage) vs. Average	0.36	(0.14)	(0.09)	0.19	0.05	(0.54)	Base
3. 1978 Data Adjusted for June 1979 Small Refiner Bias and First Quarter 1980 Product Prices							
A. Capital Cost Based Upon Original Gross Assets							
Crude Oil Expense	11.99	12.78	12.91	12.74	12.69	12.43	12.73
Cost of Capital Employed	0.56	0.76	0.82	0.88	1.10	1.03	0.87
Other Costs	9.79	6.23	5.10	4.26	4.35	4.46	5.02
Total Product Cost	22.34	19.77	18.83	17.88	18.14	18.92	18.62
Relative Refinery Complexity Advantage (Disadvantage) vs. Average	(3.72)	(1.15)	(0.19)	0.74	0.48	(0.30)	Base
B. Capital Cost Based Upon Replacement Investment							
Crude Oil Expense	11.99	12.78	12.91	12.74	12.69	12.43	12.73
Cost of Capital Employed	1.22	2.20	2.37	2.56	2.81	3.13	2.47
Other Costs	9.79	6.23	5.10	4.26	4.35	4.46	5.02
Total Product Cost	23.00	21.21	20.38	19.56	19.85	20.02	20.22
Relative Refinery Complexity Advantage (Disadvantage) vs. Average	(2.78)	(0.99)	0.16	0.66	0.37	0.20	Base

TABLE 111

Highest and Lowest Product Mix Cost
Aggregated by Complexity Factor
($/Bbl Crude Oil Throughput)

	Complexity Factor	Advantage (Disadvantage) vs. Average
1978 Data		
Capital Costs Based Upon:		
Original Undepreciated Assets	7-9	0.21
	5-7	(0.13)
Replacement Investment	1-3	0.89
	11+	(0.57)
1978 Data Adjusted for June 1979 Small Refiner Bias		
Capital Costs Based Upon:		
Original Undepreciated Assets	7-9	0.27
	1-3	(0.58)
Replacement Investment	1-3	0.36
	11+	(0.54)
1978 Data Adjusted for June 1979 Small Refiner Bias and First Quarter 1980 Product Prices		
Capital Costs Based Upon:		
Original Undepreciatd Assets	7-9	0.74
	1-3	(3.72)
Replacement Investment	7-9	0.66
	1-3	(2.78)

Tables 91, 97, 104, and 109 summarize the yields of principal products and throughputs of other feedstocks as percentages of total inputs for the aggregations for companies by size and for refineries by size, location, and complexity.

Company Size

Generally, as company size increases the product slates set forth in Table 91 show greater yields of higher value products and an associated favorable product mix value. This is reflective of the typical trend toward higher complexity, more fully integrated

TABLE 112

1978 Prices for Products and "Other Feedstocks"
(¢/Gallon)

	Refinery Location					
	PAD I	PAD II	PAD III	PAD IV	PAD V	Basis
Products						
LPG	27.2	23.7	23.7	23.7	23.2	Platt's ex PAD IV
Motor Gasoline	41.6	40.1	40.7	41.9	43.9	Platt's and DOE†
Jet Fuel						
Naphtha	39.5	41.4	39.3	41.4	41.6	Defense Fuel Supply Center
Kerosine	40.8	38.8	38.1	39.2	36.7	0.8 ¢/gal. under No. 1 Heating Oil (DOE)
Kerosine/No. 1 Heating Oil	41.6	39.6	38.9	40.0	37.5	3.3 ¢/gal. above No. 2 Distillate (DOE)
Diesel	38.4	36.4	35.7	36.8	34.3	Platt's and DOE
Distillate, No. 2	38.3	36.3	35.6	36.7	34.2	Platt's and DOE
H.F.O. (No. 4, 5, and 6)	31.6	26.0	26.5	20.0	21.7	Platt's
Asphalt	35.0	35.0	35.0	35.0	35.0	$82/Ton
Lube Base Stocks	71.8	70.0	70.0	71.0	75.0	Platt's
Waxes*	64.6	63.0	63.0	63.9	67.5	0.9 x lube base stock prices
BTX	61.3	61.3	61.3	61.3	61.3	1/3 Bz. @ 72 ¢/gal., 2/3 TX @ 56 ¢/gal.
Other Specialties and Petrochem Int.	48.3	45.1	45.8	47.3	48.5	5 ¢/gal. above avg. gasoline
Feedstocks Sold to Others	39.3	35.3	36.2	37.7	38.8	3 ¢/gal. under regular gasoline
Sulfur*	29.5	29.5	29.5	29.5	29.5	
Coke*	18.8	18.8	18.8	18.8	18.8	$40/Ton
Miscellaneous	37.2	37.2	37.2	37.2	37.2	Weighted Average Product Price
Blendstocks Sold to Others	39.3	35.3	36.2	37.7	38.8	3 ¢/gal. under regular gasoline
Refinery Fuel	31.2	29.3	26.8	24.9	30.7	NPC Survey Part II $/MMBtu
Other Raw Materials						
Butanes	27.2	23.7	23.7	23.7	23.2	Equal to LPG price
Natural Gasoline	37.3	33.3	34.2	35.7	36.8	5 ¢/gal. under regular gasoline
Other Feedstocks	39.3	35.3	36.2	37.7	38.8	3 ¢/gal. under regular gasoline
Other Blendstocks	39.3	35.3	36.2	37.7	38.8	3 ¢/gal. under regular gasoline

*Conversion Factors
Sulfur - 1.0 ST .0032 Mbbl liquid equivalent.
Coke - 1.0 LT .0049 Mbbl liquid equivalent.
Waxes - 1.0 ST .0068 Mbbl liquid equivalent.
†10% premium leaded, 35% unleaded.

refineries with increasing company size. Below 50 MB/D company capacity, the average refinery size is 15.8 MB/D and complexity is 3.4, while above 50 MB/D company capacity, the average refinery size is 113.7 MB/D and complexity is 7.5.

The yield of the highest value fuel product, gasoline, varies markedly between company size categories, ranging from a low of 15 percent for the 0-10 MB/D capacity category to 46 to 48 percent for companies of greater than 50 MB/D capacity. Typically, refineries owned by smaller companies do not have as much capacity for converting heavier stocks to gasoline as refineries owned by the larger companies. Consequently, these plants display a higher yield of the heavier products which command lower market prices.

The yields of lube oils and BTX[3] should be noted inasmuch as these products command relatively high prices. While these products are more abundantly produced by the larger refineries, a number of the companies under 10 MB/D capacity also benefit from upgrading of crude oil fractions to manufacture lubestocks.

Refinery Size

Product yield structures follow roughly the same trend as for company size; that is, larger refineries generally manufacture more gasoline, specialties, and other light products of higher market value than do the smaller plants. Consequently, the overall trend is for the larger refineries to enjoy a product value advantage. The product value adjustments range from a \$0.55/bbl of crude oil advantage for the 100-175 MB/D refinery size range to a \$1.50/bbl disadvantage for the 10-30 MB/D size range (Table 95).

Principal exceptions to this generalization are for refineries of less than 10 MB/D capacity and for those of greater than 175 MB/D capacity. As previously observed, some of the former size category enjoy an advantage over some larger plant sizes due to lubricant production. With respect to the latter, these large refineries, as a group, are not as complex as those refineries in the 100-175 MB/D class and hence do not have as high a value for product mix.

Refinery Location

Computed adjustments for product value range from a favorable value of \$0.50/bbl for PAD I to an unfavorable \$0.69/bbl for PAD IV refineries (Table 102). PAD III refineries also show a favorable adjustment while those in PADs II, IV, and V have a product value below the average for U.S. refineries.

The greatest significance from a competitive analysis standpoint relative to interregional product value appertains to PADs I and III. The expense of product transportation from the Gulf Coast to the East Coast is reflected in the respective product mix value

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[3]Benzene, toluene, and xylene.

for these two areas. The product value for the other PAD districts is considered to be more reflective of local market demand and prices rather than major competitive forces connected with interregional product movements.

Refinery Complexity

Refinery complexity greatly affects product slate and product mix value. The 1-3 complexity refinery category has an unfavorable product value of $2.91/bbl of crude oil while refineries in the 9-11 complexity range have a favorable product value of $1.28/bbl. This is a substantial range, amounting to $4.19/bbl (Table 107).

There is a corresponding marked difference in the product slates for the refineries representing the extremes in refinery complexity mentioned above. Those plants in the 1-3 complexity category manufactured 15.9 percent gasoline and 31.4 percent jet fuel and middle distillate. This contrasts significantly with the yields from the refineries of 9-11 complexity which produced 49.9 percent gasoline and 16.0 percent jet fuel and middle distillate (Table 109).

Implication of Other Changes in Economic Factors Since 1978 on Competitiveness

In 1978, crude oil cost for the industry averaged $12.73/bbl; this represented 75 percent of the total cost of refined products. Since then, crude oil costs have escalated rapidly, in some instances to over $40.00/bbl. This obviously increases the relative importance of raw material and energy costs. The effectiveness of crude oil acquisition and energy conservation programs will be the key to competitiveness for every refiner. Fuel and utility costs, for example, could easily approach 70 percent of total refinery operating cost (other than crude oil and other feedstocks) as U.S. energy costs approach world parity values. Rapidly rising energy costs as well as new special investment tax credits provide large incentives for new investment in energy saving equipment, assuming such incentives are not negated by federal price guidelines. Surveys by the American Petroleum Institute (API) show that refiners have reduced energy consumption by 19 percent since 1972, but substantial further improvement is expected by 1985. Refiners that fail to match industry performance in energy conservation could lose their competitive position to more energy-efficient companies.

The December 1979 NPC Survey of U.S. and World Energy and Oil Supply/Demand Forecasts (medium case) shows that total demand is expected to remain essentially constant through 1990. Considerable change in product mix is projected, however. Total motor gasoline demand is expected to decline while the proportion of unleaded gasoline increases from 32 percent in 1978 to 77 percent by 1985, and 89 percent by 1990. Heating oil and residual fuel oil demand also show a steady decline. These declines are projected to be offset by a growth in demand for commercial jet fuel, diesel fuel, liquified petroleum gases, and non-energy products such as petrochemical feedstocks, lubricants, metallurgical coke, and asphalt.

Refiners must adapt their product mix to these changes in consumer demand. Companies with high conversion refineries will need to cope with falling demand for their prime product -- motor gasoline. Products with growth potential, such as jet fuel, diesel, and chemical feedstocks, generally require less processing than gasoline. Also, declining demand for residual fuel oil indicates that refiners must prepare for the time when residual fuel oil will be in limited demand as fuel for stationary power plants. Upgrading residual fuel oil to more valuable products will require large investments in processing facilities and larger refiners may have some benefit of economies of scale. Small refiners may choose to sell their residual products as feedstocks rather than make the major investments for conversion facilities.

In summary, it is difficult to predict how changing circumstances will affect the future relative competitiveness of various segments of the refining industry. For any segment there appear to be favorable as well as unfavorable trends. All refiners can respond to perceived changes in their environment with a wide range of manufacturing and marketing strategies and investment alternatives. The decisions made by the individual refining companies will determine their fundamental efficiency and relative competitive position in the future.

Elements of Crude Oil Refinery Operating Costs and Assets

Quantifiable cost factors which influence refineries' competitive positions and are considered in this study are crude oil, operating expenses (fuel and purchased utilities, depreciation, maintenance, etc.), and capital costs. Source data for these cost elements as received in the January 1979 NPC Survey of Petroleum Refining Capabilities and reported in the interim report, are discussed in this section. As noted earlier, the competitive sections of this chapter are based on a 186 refinery, 14,811 MB/D sample for which complete data were available. The following sections include cost and other data for all respondents to the survey.

Crude Oil Costs

Petroleum refining is increasingly raw material cost intensive. For the 1978 period upon which the data base for this study was developed, the cost of crude oil represented approximately 75 percent of the total cost of refined products for the domestic industry.

Refiners have had widely varying crude oil costs during recent years. In addition to quality and location differentials, costs of crude oil from domestic and foreign sources have been heavily impacted by governmental regulations establishing price control tiers, entitlements programs, regulatory exceptions, etc. As a result of these factors, the relative competitive positions of the several company and refinery aggregations considered in this study have to be largely determined by the crude oil source and classifications and by refiner size.

The December 1979 NPC report, Refinery Flexibility, An Interim Report, provided gross crude oil cost data before entitlements for lower tier, upper tier, and exempt (including imports) crude oil runs in most refineries in the United States. This section presents the collected information and analyzes it with respect to the company and refinery aggregations considered in this study. Tables 113, 114, 115, and 116 present crude oil cost and quality data for refineries by company size and refinery location, size, and complexity.

The net cost of crude oil to refineries was affected in 1978 by various federal programs administered on a company basis rather than on an individual refinery basis. U.S. Department of Energy entitlements program factors for 1978 (domestic oil supply ratio [DOSR], deemed old oil ratio [DOOR], etc.) were applied to the aggregated data supplied by the respondent refineries to determine the effects of the entitlements program and its small refiner bias provisions on crude oil costs by company size. Table 113 and Figure 41 display the crude oil costs on three bases, aggregated by company size range: (1) before entitlements, (2) after entitlements without small refiner bias, and (3) after entitlements with small refiner bias.

Under the DOE entitlements program and its small refiner bias provisions as administered in 1978, net crude oil cost ranged from $10.53/bbl for companies with a capacity of less than 10 MB/D to a maximum of $12.99/bbl for companies having system capacities in the range of 50-100 MB/D. Generally, smaller companies experienced lower net crude oil costs (Table 113). Although the DOE program contributed to the observed differences, crude oil price control classifications (upper tier, lower tier, exempt) and crude oil quality (sulfur and API gravity) also significantly affected net crude oil cost. For example, some small companies' crude oil costs tended to be relatively low due to their processing less expensive, heavy, high-sulfur crude oils for the manufacture of asphalt.

The effect of the entitlements program exclusive of the small refiner bias also reduced the maximum spread for net crude oil cost between companies of different size ranges to $0.86/bbl. Without the entitlements program this spread would have been as much as $2.52/bbl of crude oil. With both entitlements and the small refiner bias, this maximum differential became $2.46/bbl. In all of these instances, the companies in the smaller size categories display lower crude oil costs (Table 113).

The calculation of net crude oil costs (after entitlements with small refiner bias) for individual refineries is, by definition, hypothetical, because the small refiner bias program was administered in 1978 on a company basis. The method used treats each refinery as if it were a separate company for the purposes of the bias calculation. This includes a number of refineries in the small refiner bias credit range that did not qualify for the bias provisions when in the company size range, thus increasing the quantity of entitlements in the small refiner bias pool. This larger "credit" pool is offset by higher crude oil costs for those refineries with capacities greater than 175 MB/D.

TABLE 113

1978 Crude Oil Costs and Quality
Aggregated by Company Size Range

	Company Size Range (MB/D)							DOE
	0-10	10-30	30-50	50-100	100-175	175+	All	1978 Data*
Weight Average Complexity	1.49	3.01	4.78	5.68	7.21	7.71	7.24	
1978 Throughput (MB/D)								
Lower Tier	38	116	43	122	41	2,353	2,713	3,034
Upper Tier	50	122	80	178	77	2,057	2,565	2,931
Exempt	36	219	190	345	257	6,599	7,646	9,747
Total	124	457	314	644	375	11,010	12,924	15,712
Volume Percent								
Lower Tier	30.7	25.4	13.8	18.9	10.9	21.4	21.0	19.3
Upper Tier	40.3	26.7	25.6	27.6	20.6	18.7	19.8	18.7
Exempt	29.0	47.9	60.0	53.6	68.5	59.9	59.2	62.0
Cost ($/barrel)								
Lower Tier	5.95	6.16	5.89	6.02	6.20	5.98	5.99	5.90
Upper Tier	12.71	12.38	12.65	13.22	12.86	12.63	12.67	12.61
Exempt	13.49	14.61	14.86	15.12	14.71	14.48	14.52	14.39
Average Before Entitlements	10.88	11.87	13.06	12.88	13.40	12.31	12.36	12.42
After Entitlements (without small refiner bias)	12.30	12.66	12.87	13.16	12.92	12.65	12.69	
After Entitlements (with small refiner bias)†	10.53	11.50	12.22	12.99	12.94	12.78	12.71	
API Gravity								
Lower Tier	27.7	30.3	31.8	34.5	35.4	35.4	34.8	
Upper Tier	36.6	32.6	43.9	38.0	36.6	36.0	36.3	
Exempt	25.6	34.4	36.9	36.7	35.1	34.1	34.4	
Average	30.7	32.8	38.0	36.6	35.5	34.7	34.8	
Wt % Sulfur								
Lower Tier	0.73	1.11	0.81	1.13	0.94	0.75	0.80	
Upper Tier	0.47	1.01	0.60	0.58	1.05	0.78	0.77	
Exempt	1.27	0.71	0.80	0.46	0.92	0.89	0.86	
Average	0.79	0.90	0.75	0.62	0.95	0.84	0.83	
Owner Production, plus Royalty Owners' Share (percent)	11.2	9.0	11.4	9.2	7.9	44.5	37.7	
Respondents' Crude Charge Capacity (MB/D)	174	631	424	765	670	12,782	15,445	
Respondents' Number of Refineries	29	38	11	19	8	98	203	
Respondents' Number of Companies	28	30	11	11	5	18	103	
Non-Respondents								
Crude Charge Capacity (MB/D)	174	380	88	140	247	840	1,869	
Number of Refineries	40	22	5	2	2	13	84	
Number of Companies	12	8	3	1	2	4	30	

*Data from Department of Energy for U.S Refineries, Virgin Islands, Puerto Rico, Guam, Free Trade Zone, and Strategic Petroleum Reserve.

†Based on company size as actually administered.

TABLE 114

1978 Crude Oil Costs and Quality
Aggregated by Refinery Location

	Refinery Location						DOE
	PAD I	PAD II	PAD III	PAD IV	PAD V	All	1978 Data*
Weight Average Complexity	7.08	7.14	7.38	5.16	7.52	7.24	
1978 Throughput (MB/D)							
Lower Tier	104	736	1,309	159	405	2,713	3,034
Upper Tier	108	728	1,286	166	277	2,565	2,981
Exempt	1,436	1,675	2,959	106	1,470	7,646	9,747
Total	1,647	3,139	5,554	432	2,152	12,924	15,712
Volume Percent							
Lower Tier	6.3	23.5	23.6	36.8	18.8	21.0	19.3
Upper Tier	6.6	23.2	23.1	38.4	12.9	19.8	18.7
Exempt	87.2	53.4	53.3	24.5	68.3	59.2	62.0
Cost ($/barrel)							
Lower Tier	6.30	6.15	5.97	6.19	5.61	5.99	5.90
Upper Tier	13.03	12.96	12.64	13.01	11.68	12.67	12.61
Exempt	14.63	15.02	14.59	15.38	13.66	14.52	14.39
Average Before Entitlements	14.00	12.46	12.11	11.08	11.89	12.36	12.42
After Entitlements (without small refiner bias)†	12.90	13.04	12.69	13.00	11.93	12.69	
After Entitlements (with small refiner bias)§	12.96	13.01	12.77	12.43	11.88	12.69	
Own Production, plus Royalty Owners' Share, percentage	16.8	32.1	42.2	41.8	51.7	37.7	
Crude Charge Capacity (MB/D)	1,857	3,718	6,549	516	2,806	15,445	
Percentage of Total Capacity¶	99.3	88.4	86.6	87.5	91.0	89.2	
Number of Refineries	26	53	65	20	39	203	

*Data from Department of Energy for refineries in the United States, Virgin Islands, Puerto Rico, Guam, Free Trade Zone, and Strategic Petroleum Reserve.

†Excludes the benefits of all special entitlements programs.

§Excludes the benefits of all other special entitlements programs; Entitlements calculated on the hypothetical basis that each refinery, regardless of size, was treated as a separate company.

¶Percentage of capacity of respondents who provided cost and quality data to the January 1979 NPC Survey of Petroleum Refining Capabilities.

TABLE 115

1978 Crude Oil Costs and Quality

Aggregated by Refinery Size Range and Complexity Factor

	Refinery Size Range (MB/D)/Complexity Factor													DOE
	0-10			10-30			30-50			50-100	100-175	175+		1978
	<2.5	>2.5	All	<2.5	>2.5	All	<2.5	>2.5	All	All	All	All	All	Data*
Weight Average Complexity	1.31	5.18	2.21	1.41	5.29	3.45	1.31	5.91	5.38	7.78	8.46	7.57	7.24	
1978 Throughput (MB/D)														
Lower Tier	41	5	46	69	121	190	14	301	315	471	361	1,331	2,713	3,034
Upper Tier	50	15	65	76	120	196	24	305	329	430	345	1,200	2,565	2,981
Exempt	42	25	67	177	184	361	74	363	437	1,309	1,652	3,819	7,646	9,747
Total	133	45	178	321	426	747	112	969	1,081	2,210	2,358	6,350	12,924	15,712
Volume Percent														
Lower Tier	30.8	11.1	25.8	21.5	28.4	25.4	12.5	31.1	29.1	21.3	15.3	21.0	21.0	19.3
Upper Tier	37.6	33.3	36.5	23.7	28.2	26.2	21.4	31.5	30.4	19.5	14.6	18.9	19.9	18.7
Exempt	31.6	55.6	37.6	55.1	43.2	48.3	66.1	37.5	40.4	59.2	70.1	60.1	59.2	62.0
Cost ($/barrel)														
Lower Tier	5.88	5.74	5.87	5.67	6.28	6.06	5.92	5.95	5.95	6.08	6.04	5.95	5.99	5.90
Upper Tier	12.64	13.20	12.77	11.96	12.91	12.54	12.91	12.84	12.85	12.83	12.54	12.62	12.67	12.61
Exempt	13.95	15.67	14.60	14.03	14.83	14.44	14.18	14.90	14.78	14.74	14.42	14.47	14.52	12.39
Average Before Entitlements	10.96	13.78	11.68	11.76	11.85	11.81	12.88	11.47	11.62	12.52	12.86	12.34	12.36	12.42
After Entitlements (without small refiner bias)†	11.91	13.55	12.67	12.17	12.91	12.59	12.54	12.81	12.78	12.86	12.63	12.64	12.69	§
After Entitlements (with small refiner bias)¶	10.70	11.86	10.99	11.00	11.90	11.51	11.94	12.43	12.38	12.84	12.75	12.85	12.69	
Own Production plus Royalty Owners' Share (percent)	12.4	11.8	12.2	22.1	28.1	25.5	0.0	36.1	32.1	30.8	31.4	49.6	37.7	
Crude Charge Capacity (MB/D)	188	57	245	470	520	990	156	1,196	1,352	2,407	3,084	7,367	15,445	
Percentage of Total Capacity**			55.3			69.0			93.0	79.9	85.6	100	89.2	
Number of Refineries	32	9	41	24	25	49	4	27	31	34	24	24	203	

*Data from Department of Energy for refineries in the United States, Virgin Islands, Puerto Rico, Free Trade Zone, Guam, and Strategic Petroleum Reserve.

†Excludes the benefits of all special entitlements programs.

§These figures should be the same; difference due to the fact that not all U.S. refineries responded to the survey and methodology used for computations.

¶Excludes the benefits of all other special entitlements programs; Entitlements calculated on the hypothetical basis that each refinery, regardless of size, was treated as a separate company.

**Percentage of capacity of respondents who provided cost and quality data to the January 1979 NPC Survey of Petroleum Refining Capabilities.

TABLE 116

1978 Crude Oil Costs and Quality
Aggregated by Complexity Factor

	Complexity Factor 1-3	3-5	5-7	7-9	9-11	11+	All	DOE 1978 Data*
Weight Average Complexity	1.60	4.37	6.11	7.80	10.04	13.28	7.24	
1978 Throughput (MB/D)								
Lower Tier	153	196	865	1,025	303	172	2,713	3,034
Upper Tier	185	280	894	819	227	160	2,565	2,931
Exempt	376	469	2,495	2,845	724	737	7,646	9,747
Total	714	945	4,254	4,689	1,254	1,069	12,924	15,712
Volume Percent								
Lower Tier	21.4	20.7	20.3	21.9	24.2	16.1	21.0	19.5
Upper Tier	25.9	29.6	21.0	17.5	18.1	15.0	19.9	18.7
Exempt	52.7	49.6	58.7	60.7	57.7	68.9	59.2	62.0
Cost ($/barrel)								
Lower Tier	5.81	6.28	6.04	5.98	5.81	5.93	5.99	5.90
Upper Tier	12.51	12.84	12.79	12.63	12.42	12.45	12.67	12.61
Exempt	14.21	14.78	14.68	14.49	14.53	14.08	14.52	14.39
Average Before Entitlements	11.97	12.44	12.53	12.31	12.04	12.53	12.36	12.42
After Entitlements (without small refiner bias)†	12.41	12.89	12.82	12.66	12.60	12.38	12.69	
After Entitlements (with small refiner bias)§	11.41	12.55	12.86	12.80	12.70	12.45	12.69	
Owner Production, plus Royalty Owners' Share (percent)	12.4	26.8	42.3	43.1	33.9	34.1	37.7	
Crude Charge Capacity (MB/D)	988	1,186	5,215	5,285	1,487	1,285	15,445	
Percentage of Total Capacity¶	75.5	81.3	96.9	88.7	100	100	91.5	
Number of Refineries	66	30	47	36	13	11	203	

*Data from Department of Energy for refineries in the United States, Virgin Islands, Puerto Rico, Free Trade Zone, Guam, and Strategic Petroleum Reserve.

†Excludes the benefits of all special entitlements programs.

§Excludes the benefits of all other special entitlements programs; Entitlements calculated on the hypothetical basis that each refinery, regardless of size, was treated as a separate company.

¶Percentage of capacity of respondents who provided cost and quality data to the January 1979 NPC Survey of Petroleum Refining Capabilities.

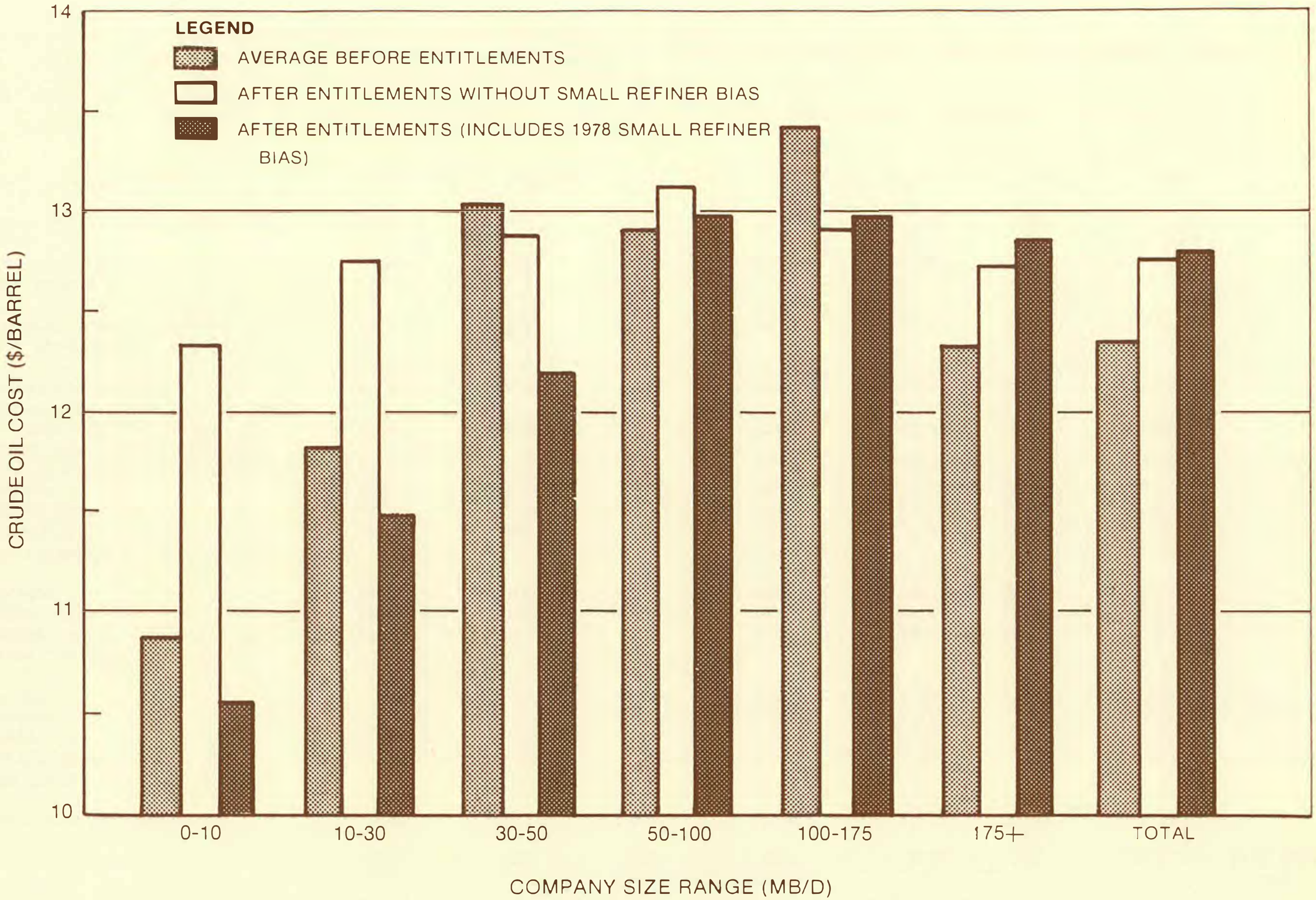

Figure 41. 1978 Crude Oil Costs—Aggregated by Company Size Range.

NOTE: This figure was plotted from data in Table 113

The calculation of crude oil costs for individual refineries on an "after entitlements without small refiner bias" basis uses factors adapted from the entitlements factors applied in calculating crude oil costs on a company size basis (see Appendix G).

It may be observed from Tables 115 and 116 that the refineries benefiting most significantly from the bias program are those with a complexity factor of less than 3. This is because the refineries of less than 3 complexity include no refineries of greater than 100 MB/D capacity, and 80 percent of the capacity in this complexity category was in refineries of less than 30 MB/D.

With respect to refinery location, Table 114 indicates that PAD I experienced the greatest reduction ($1.04/bbl) in crude oil costs. This area refined relatively small quantities of lower tier crude oil (6.3 percent) and a larger percentage of exempt oil (87.2 percent), and experienced a reduction in crude oil costs due to the entitlements program.

Crude Oil Classifications

With respect to refinery location, as reported in Table 114, the eastern and western regions of the country (PADs I and V) refined high percentages of exempt crude oils, perhaps reflecting historical dependence on imported supply and the influx of Alaskan North Slope crude oil in PAD V. PAD IV utilized the lowest percentage of exempt crude oil, indicative of local crude oil production meeting a greater portion of the demand for refiners in the area.

Variations in cost within the several crude oil classifications were relatively moderate with the exception of costs in PAD V, where the cost of each classification of crude oil was below the national average, possibly reflecting a lower quality. Refiners of heavy California crude oil were granted special benefits by the entitlements program, which were not included in the NPC calculation. As noted in Appendix G, this provision would have lowered the crude oil cost of some PAD V refiners by a total of $185 million in 1978.

Refineries with capacities greater than 100 MB/D processed crude oil slates of lower API gravities and higher sulfur content than the respondents' average. This was particularly evident for refineries in the 100-175 MB/D size range; a preponderance of high complexity refineries, including many with desulfurization and residual processing capabilities, fall within this size range.

Operating Costs

Summaries of 1978 operating costs aggregated by company size and refinery location, size, and complexity are presented in Tables 117, 118, 119, and 120. It should be noted that the capacity of refineries in the Hawaiian Trade Zone, Alaska, and Guam is aggregated in the PAD V figures. As with the crude oil cost data in Tables 113-116, these operating cost figures are based on a different sample from that used earlier in this chapter.

TABLE 117

1978 Operating Costs
Aggregated by Company Size

	Company Size (MB/D)						
	0-10	10-30	30-50	50-100	100-175	175+	Average
Weight Average Complexity	1.49	3.01	4.78	5.68	7.21	7.71	7.24
Fuel and Purchased Utilities							
MMBtu/barrel	0.255	0.389	0.404	0.550	0.505	0.576	0.559
$/MMBtu	1.739	1.958	1.875	1.621	1.675	1.946	1.919
$/barrel	0.412	0.712	0.695	0.844	0.850	1.133	1.080
Depreciation ($/barrel)	0.123	0.183	0.159	0.161	0.172	0.187	0.184
Maintenance and Other Operating Costs ($/barrel)	0.818	0.971	0.812	1.075	0.847	1.035	1.022
Total ($/barrel Throughput)	1.353	1.866	1.666	2.080	1.869	2.355	2.286
Crude Charge Capacity (MB/D)	173	615	424	765	670	12,782	15,428
Number of Refineries	27	37	11	19	8	98	200
Number of Companies	26	29	11	11	5	18	100

TABLE 118

1978 Operating Costs
Aggregated by Refinery Location

	Refinery Location					
	PAD I	PAD II	PAD III	PAD IV	PAD V	Average
Weight Average Complexity	7.08	7.14	7.38	5.16	7.52	7.24
Fuel and Purchased Utilities						
MMBtu/barrel	0.538	0.557	0.544	0.579	0.616	0.559
$/MMBtu	2.094	1.972	1.802	1.672	2.061	1.919
$/barrel	1.120	1.112	0.975	0.952	1.301	1.080
Depreciation ($/barrel)	0.194	0.158	0.168	0.185	0.253	0.184
Maintenance and Other Operating Costs ($/barrel)	1.194	0.946	0.956	1.123	1.153	1.022
Total ($/barrel Throughput)	2.508	2.216	2.099	2.260	2.707	2.286
Crude Charge Capacity (MB/D)	1,857	3,718	6,548	515	2,790	15,428
Percentage of Total Capacity*	99.3	89.9	89.5	91.3	93.3	91.4
Number of Refineries	26	53	64	19	38	200

*Percentage of capacity of respondents who provided operating cost data to the January 1979 NPC Survey of Petroleum Refining Capabilities.

TABLE 119

1978 Operating Costs
Aggregated by Refinery Size Range and Complexity Factor

	Refinery Size Range (MB/D)/Complexity Factor												
	0-10			10-30			30-50			50-100	100-175	175+	
	<2.5	>2.5	All	<2.5	>2.5	All	<2.5	>2.5	All	All	All	All	Average
Weight Average Complexity	1.31	5.18	2.21	1.41	5.29	3.45	1.31	5.91	5.38	7.78	8.46	7.57	7.24
Fuel and Purchased Utilities													
MMBtu/barrel	0.294	0.845	0.440	0.234	0.582	0.429	0.202	0.542	0.515	0.590	0.614	0.554	0.559
$/MMBtu	1.779	1.912	1.814	2.133	1.814	1.957	1.362	1.752	1.721	1.957	2.066	1.882	1.919
$/barrel	0.518	1.668	0.823	0.506	1.051	0.807	0.253	0.932	0.878	1.141	1.289	1.052	1.080
Depreciation ($/barrel)	0.146	0.346	0.201	0.130	0.174	0.155	0.145	0.155	0.154	0.167	0.221	0.183	0.184
Maintenance and Other Operating Costs ($/barrel)	0.920	1.970	1.188	0.666	1.132	0.931	0.378	0.990	0.927	1.094	1.102	0.989	1.022
Total ($/barrel Throughput)	1.584	3.984	2.212	1.302	2.357	1.893	0.776	2.077	1.959	2.402	2.612	2.224	2.286
Crude Charge Capacity (MB/D)	187	57	243	470	505	975	156	1,196	1,352	2,407	3.084	7,367	15,428
Percentage of Total Capacity*			54.9			68.0			93.0	79.9	85.5	100	91.4
Number of Refineries	30	9	39	24	24	48	4	27	31	34	24	24	200

*Percentage of capacity of respondents who provided operating cost data to the January 1979 NPC Survey of Petroleum Refining Capabilities.

TABLE 120

1978 Operating Costs
Aggregated by Complexity Factor

	Complexity Factor						
	1-3	3-5	5-7	7-9	9-11	11+	Average
Weight Average Complexity	1.60	4.37	6.11	7.80	10.04	13.28	7.24
Fuel and Purchased Utilities							
MMBtu/barrel	0.267	0.423	0.518	0.581	0.690	0.777	0.559
$/MMBtu	1.965	1.838	1.805	2.011	1.887	2.048	1.919
$/barrel	0.524	0.761	0.931	1.175	1.330	1.585	1.080
Depreciation ($/barrel)	0.157	0.180	0.177	0.167	0.210	0.272	0.184
Maintenance and Other Operating Costs ($/barrel)	0.805	0.772	1.070	1.015	1.018	1.273	1.022
Total ($/barrel Throughput)	1.486	1.713	2.178	2.357	2.558	3.130	2.286
Crude Charge Capacity (MB/D)	986	1,170	5,215	5,285	1,487	1,285	15,428
Percentage of Total Capacity*	75.4	80.2	96.9	88.7	100	100	91.4
Number of Refineries	64	29	47	36	13	11	200

*Percentage of capacity of respondents who provided operating cost data to the January 1979 NPC Survey of Petroleum Refining Capabilities.

In general, total 1978 operating costs (fuel, purchased utilities, depreciation, maintenance, etc.) increased with company size. The principal factor appears to be the average higher complexity of refineries operated by larger companies. Total operating costs ranged from $1.35/bbl for companies of less than 10 MB/D capacity to $2.35/bbl for companies of greater than 175 MB/D capacity. This represents approximately 9.4 to 16.7 percent of total costs of refined products for the domestic industry by company size (Table 117). In 1978, total operating costs averaged $2.29/bbl of crude oil processed. Of this total, nearly half ($1.08/bbl) was for fuel and purchased utilities (Table 117). This cost will increase because of the increase in fuel prices.

Complexity of operation has a substantial effect upon total operating costs and appears to mask many of the effects of refinery size; i.e., large refineries or companies were expected to have lower unit costs. Table 120 presents survey results for the operating cost categories as aggregated by complexity factor alone, disregarding refinery size or location. Total operating costs for the highest complexity range (greater than 11), representing 8 percent of aggregate respondent capacity, were reported to be $3.13/bbl, twice that of refineries with a complexity factor of less than 3.

Refineries in the 10-30 and 30-50 MB/D ranges had the lowest average total operating costs, apparently reflecting lower complexity than the larger refineries.

Table 118 shows that PAD III refineries reported the lowest range of total operating costs, at $2.10/bbl, while PAD V reported the highest costs, at $2.71/bbl. Each of the categories of operating costs (fuel and purchased utilities, depreciation, maintenance, etc.) were higher in PAD V than in PAD III. Differing unit costs of energy ($/MMBtu) are also a substantial factor in the variation of operating costs among PAD districts. Figure 42 illustrates the relationship between complexity and total operating costs in dollars per barrel.

Fuel and Purchased Utilities

The amount of fuel and purchased utilities required to operate a refinery differs greatly between plants and depends to a large extent upon refinery complexity as well as the efficiency of energy utilization. Those refineries in the 1-3 complexity range (6 percent of respondent capacity) had fuel and purchased utility consumption averaging about 0.27 MMBtu/bbl, less than half of that for the U.S. average. The highest energy consumption, 0.78 MMBtu/bbl, was reported by those refineries having a complexity of greater than 11, representing about 8 percent of respondent capacity. It is interesting to note that the energy consumption of those refineries of greater than 11 complexity is nearly three times that of those of less than 3 complexity (Table 120).

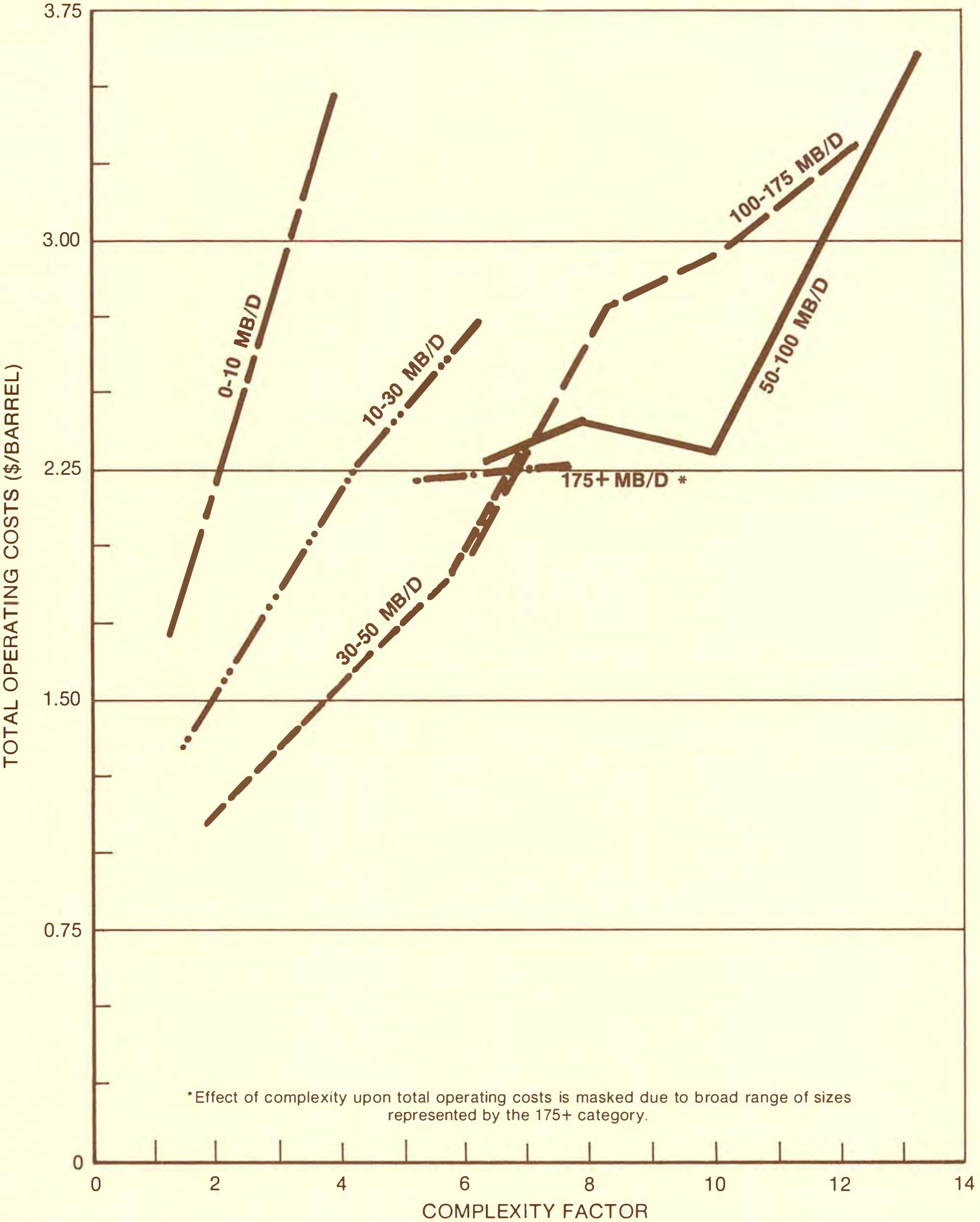

Figure 42. 1978 Total Operating Costs as a Function of Complexity—Aggregated by Refinery Size Range.

The unit cost of energy, on a dollar-per-million-Btu basis, is not a function of complexity; it ranges from $1.81/MMBtu to $2.05/MMBtu (Table 121) within the various complexities, while the U.S. average is $1.92/MMBtu. Purchased electricity costs may be understated as refineries were instructed to value purchased utilities in terms of fuel equivalent at local incremental fuel costs.

The fraction of total cost incurred by the cost of fuel and purchased utilities varies significantly with complexity. For those refineries of less than 3 complexity, the cost of fuel and purchased utilities amounts to about 35 percent of total expenses, as compared with about 50 percent for the highest complexity range studied.

With respect to refinery size, those refineries of less than 50 MB/D capacity consume less fuel and purchased utilities per barrel than the national average. Many of the least complex refineries

TABLE 121

1978 Unit Energy Costs
Aggregated by Refinery Size
and Complexity Factor

Refinery Size (MB/D)	Complexity Factor	Weight Average Complexity	Unit Energy Cost ($/MMBtu)
0-10	1-3	1.37	1.81
	3-5	3.94	1.74
10-30	1-3	1.48	2.11
	3-5	4.26	2.05
	5-7	6.23	1.77
30-50	3-5	4.41	1.72
	5-7	5.74	1.78
	7-9	7.35	1.78
50-100	5-7	6.27	1.92
	7-9	7.93	2.17
	9-11	10.01	1.53
	11+	13.08	1.99
100-175	5-7	6.11	1.84
	9-11	10.02	2.20
	11+	12.32	2.03
175+	5-7	6.09	1.76
	7-9	7.70	1.96

are in this size range. Thus, the generally lower energy consumption of the smaller refineries is probably due primarily to lower complexity. A few of the more energy-intensive refineries also appear among those of less than 10 MB/D capacity; these appear to be the lubricating oil refineries in PAD I.

Refineries in the 100-175 MB/D range are also relatively energy intensive. Survey data indicate that this size range has a large concentration of high complexity refineries. These interrelationships are more clearly displayed in Figure 43, which presents energy consumption (fuel and purchased utilities) in MMBtu/bbl as a function of both refinery complexity and refinery size range. Figure 44 illustrates the cost of fuel in dollars per barrel. It appears that, for refineries with capacities of up to 50 MB/D, energy consumption decreases with size at a given complexity. Above that size range, there is no clear relationship between energy consumption and refinery size; rather, energy requirements are dependent on complexity.

The unit cost of energy by refinery size category ranges from $1.72/MMBtu to $2.07/MMBtu. This appears to be due more to refinery location (Table 118) than to refinery size (Table 119). It is not clear from the survey results why these variations occur, but there were apparently fuel oil and gas market price variations between PAD districts. Survey respondents were instructed to value internally produced refinery fuel based upon local incremental purchase/sale fuel prices.

Consumption of fuel and purchased utilities per barrel of crude oil refined differs between PAD districts and ranges from 3.8 percent below the national average in PAD I to 10.2 percent above that average in PAD V. The fact that energy consumption is highest in PAD V reflects that there are a significant number of energy-intensive refineries of greater complexity.

Table 118 shows that PAD IV had the lowest unit energy cost, at $1.67/MMBtu. The energy cost reported for the east and west regions (PADs I and V) were considerably higher, at $2.09/MMBtu and $2.06/MMBtu, respectively.

Energy consumption cost as a function of company size (Table 117) relates to the more fundamental factors of complexity and refinery size. Companies of less than 10 MB/D total capacity reported energy costs of $0.41/bbl of crude oil, while the average was $1.08/bbl, and refiners having system capacities of greater than 175 MB/D experienced energy costs of $1.13/bbl. The greater average complexity of refineries owned by larger companies contributes to higher energy consumption by these companies.

Depreciation

Principal variations in depreciation charge can be traced to investment differences due to complexity, size, and vintage of refining facilities. The only significant relationship between geography and depreciation is the $0.25/bbl figure shown for PAD V

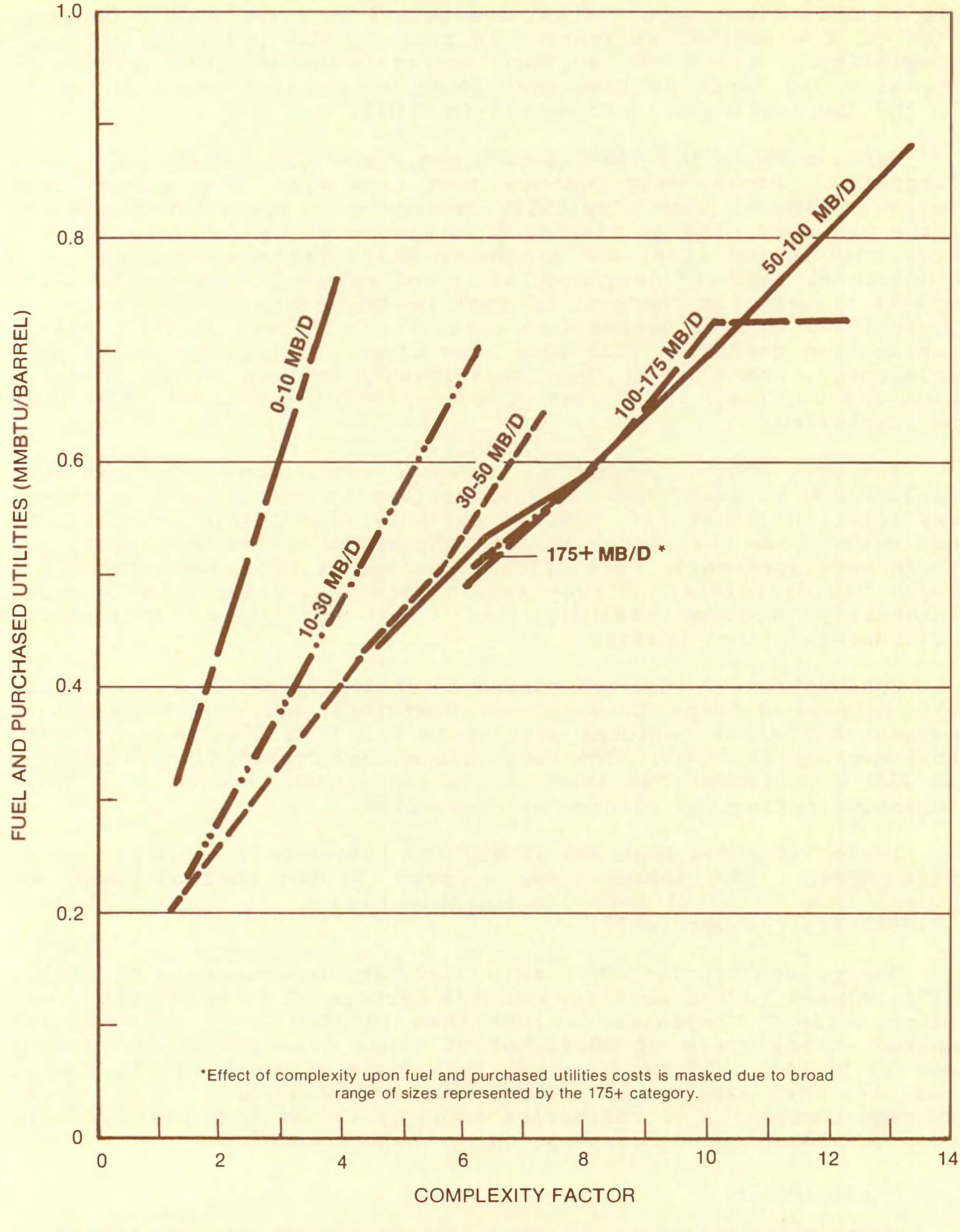

Figure 43. 1978 Fuel and Purchased Utilities Consumption as a Function of Complexity—Aggregated by Refinery Size Range.

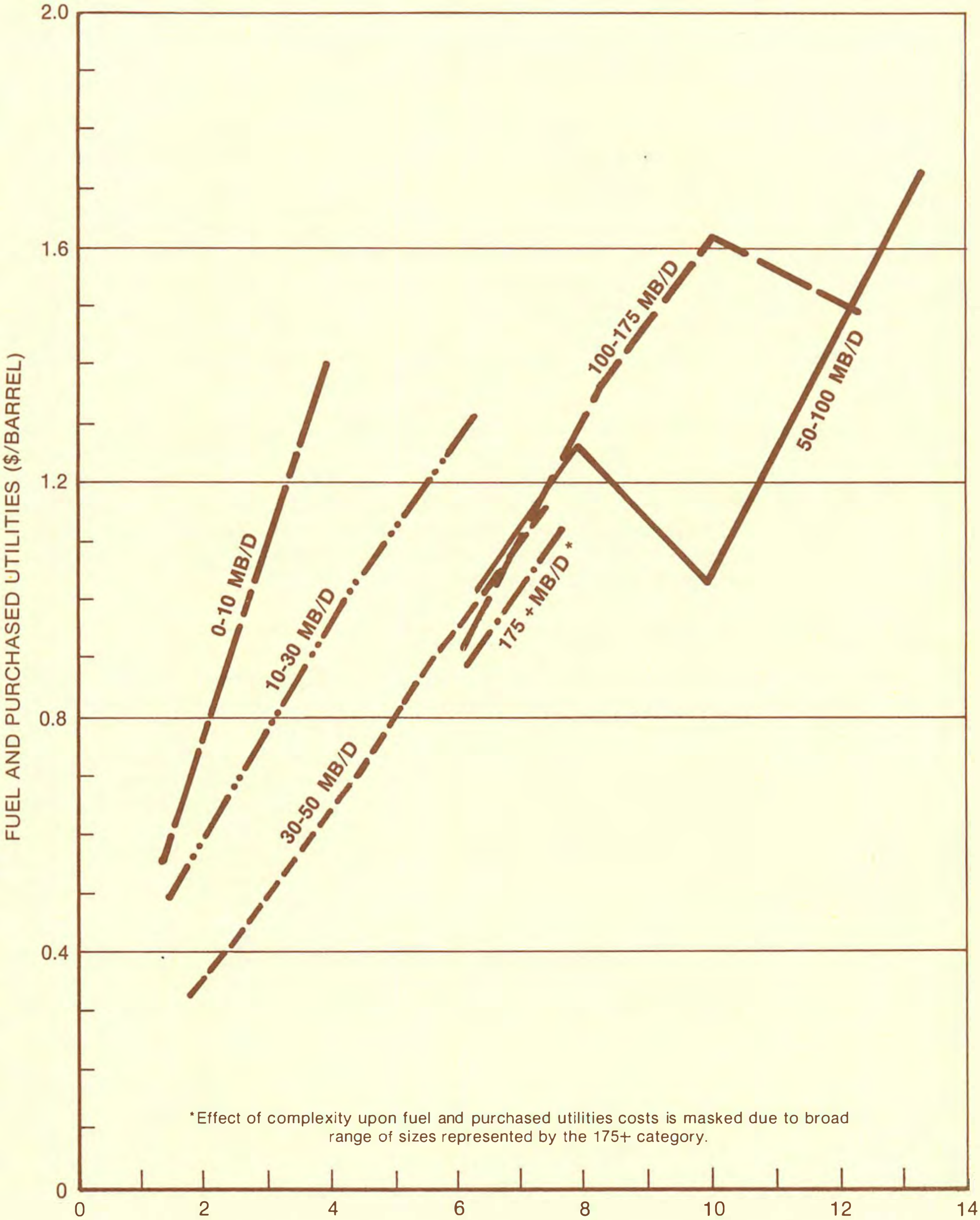

Figure 44. Refinery Fuel and Purchased Utilities Costs as a Function of Complexity—Aggregated by Refinery Size Range.

(Table 118). That district's response includes eight refineries (897 MB/D crude oil charge capacity and complexity in the 7-9 range or higher) with an average depreciation cost of $0.35/bbl, which increased the PAD V average significantly.

As would be expected, depreciation charges generally increase with complexity, ranging from $0.16/bbl for refineries of less than 3 complexity to $0.27/bbl for those of greater than 11 complexity (Table 120). Those refineries in the 7-9 complexity range show the greatest deviation from the trend of increased depreciation with increased complexity. It appears from a comparison of replacement capital cost data to original gross fixed assets that the refineries in this complexity range were initially installed at an earlier date. If this is the case, it is not surprising that their depreciation schedules are relatively lower than adjacent complexity ranges.

With respect to refinery size (Table 119), depreciation charges ranged from $0.15 to $0.22/bbl of crude oil. The highest depreciation charges were reported for those higher complexity refineries of less than 10 MB/D capacity and for those over 100 MB/D capacity. The lowest depreciation charges reported were for low complexity refineries in the 10-30 MB/D size category. Figure 45 illustrates depreciation in dollars per barrel vs. complexity.

Maintenance and Other Operating Costs

Costs for maintenance and other operating expense items (payroll, catalysts, administration, etc.) ranged from $0.77/bbl to $0.81/bbl for refineries of less than 5 complexity to $1.27/bbl for those in the 11+ category (Table 120); the costs of the latter were over one and a half times as great as the costs of the former. For the least complex refinery category, these costs constitute about 54 percent of total operating costs, while for refineries with a complexity of greater than 11, these costs were about 41 percent of total expenses.

Examination of these maintenance and other costs by refinery size category (Table 119) shows the lowest costs for those refineries in the 10-30 MB/D and 30-50 MB/D ranges. Figure 46 illustrates maintenance and other operating costs in dollars per barrel vs. complexity.

There is no pattern to maintenance and other operating costs with respect to company size; the lowest cost was reported to be $0.82/bbl for the 0-10 MB/D capacity range and the highest was $1.07/bbl for the 50-100 MB/D range.

Original Undepreciated Assets and Replacement Costs

The original construction costs of a refinery (original undepreciated assets) varied by both company size and complexity. Table 122 shows the variations in refining construction costs by company size. The per-barrel costs of refineries increase with

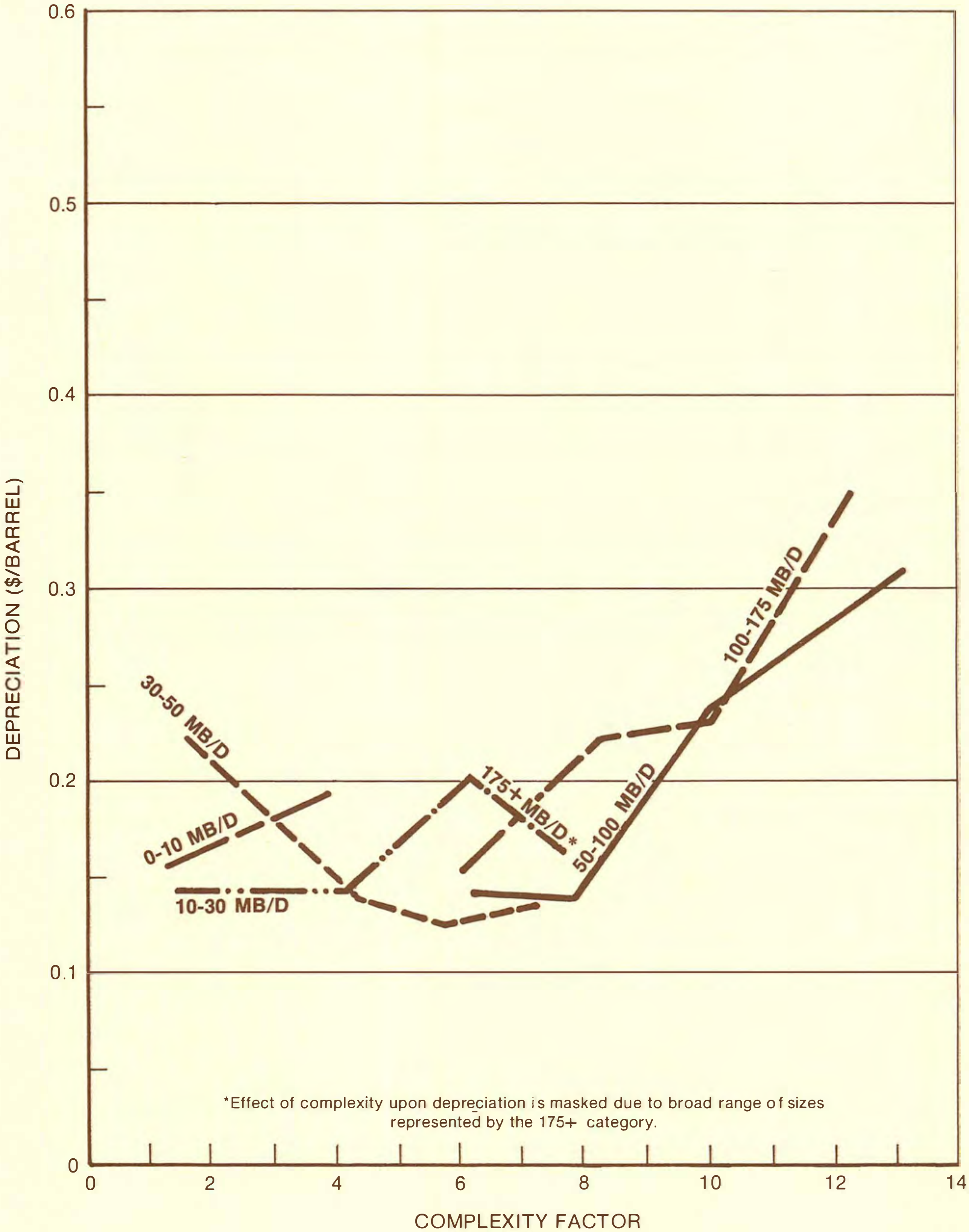

Figure 45. 1978 Depreciation as a Function of Complexity—Aggregated by Refinery Size Range.

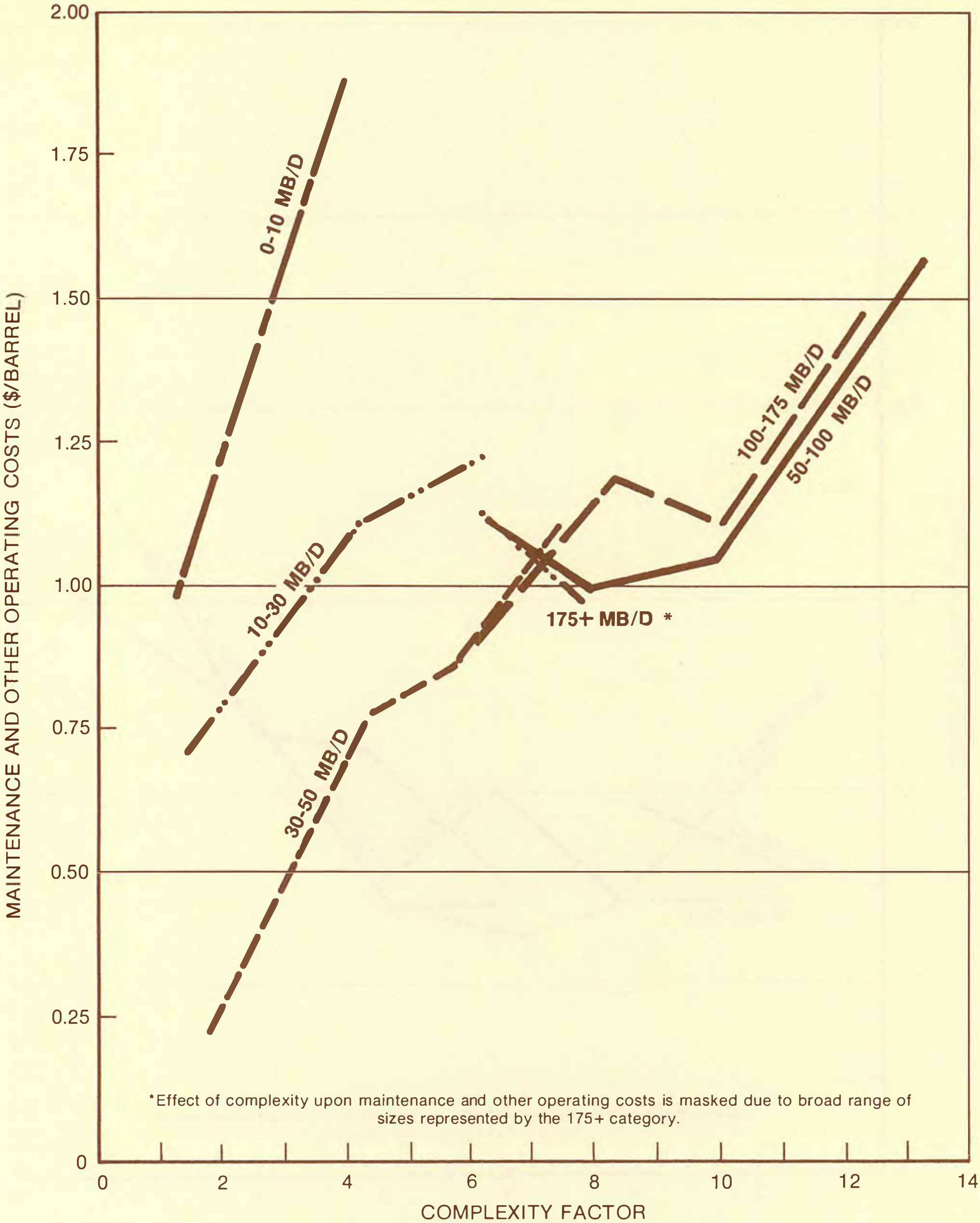

Figure 46. 1978 Maintenance and Other Operating Costs as a Function of Complexity—Aggregated by Refinery Size Range.

TABLE 122

January 1, 1979, Refinery Assets
Aggregated by Company Size

	Company Size (MB/D)						
	0-10	10-30	30-50	50-100	100-175	175+	All
Weight Average Complexity	1.49	3.01	4.78	5.68	7.21	7.72	7.24
Gross Fixed Assets							
MM$	82	544	359	786	790	18,304	20,865
$/barrel/day	498	862	923	1,027	1,178	1,432	1,354
Replacement Costs*							
MM$	200	1,320	961	2,394	2,189	45,980	53,045
$/barrel/day	1,173	2,224	2,725	3,130	3,267	3,937	3,727
Ratio Replacement Costs to Gross Fixed Assets†	2.36	2.58	2.95	3.05	2.77	2.75	2.75
Number of Refineries	25	38	10	19	8	98	198
Number of Companies	24	30	10	11	5	18	98
Crude Charge Capacity (MB/D)	165	631	389	765	670	12,782	15,401

*Replacement cost data were submitted for 186 refineries, having 14,330 MB/D of crude charge capacity.

†Ratio derived from $/barrel data.

company size. While this may appear contrary to the expected effect of economy of scale, complexity apparently overrides the effect of size. Another factor in lower construction costs may be the result of some refineries being of earlier vintage.

The average original construction cost of a refinery (original undepreciated assets) was reported to have been $1,354 per daily barrel of crude oil charge capacity. Table 123 indicates refinery construction cost by refinery location. PADs I and V had the highest asset value at $1,507/bbl and $1,530/bbl, respectively, and PAD IV the lowest at $1,089/bbl.

The effect of refinery size on original undepreciatd assets was masked by the greater impact of refinery complexity. In smaller refinery size categories, the data indicate a decrease in per-barrel investment with increasing size at a given complexity. The effect of size alone diminished in the larger (50 MB/D) refinery size category.

Table 124 indicates the relationship between refinery size and capital assets and includes a breakout by two complexity factor ranges on some of the smaller refinery size categories. The effect of complexity factor is much more pronounced than size. For example, in the 0-10 MB/D refinery size category, the original construction cost is almost five times greater for refineries with a complexity factor of over 2.5 than for those with complexity factors under 2.5. The significant effect of complexity is also evident in the variation of refinery costs with size. As shown in Table 124, per-barrel original undepreciated assets and replacement costs generally increase with increasing refinery size, contrary to the "economies of scale" effect; this is because complexity also increases with refinery size, masking any "scale" effect. Many of the larger refineries also have multiple processing trains which diminish the effect of size on investments. Figures 47 and 48 illustrate original undepreciated assets and replacement costs in dollars per barrel vs. complexity. Table 125 also indicates that the original cost generally increased with the complexity factor of the refinery, ranging from $715/bbl to $1,800/bbl.

This chapter addressed crude oil costs, operating costs, combined crude oil and operating costs, and refinery assets on both a company basis (aggregated by size range) and a refinery basis (aggregated by complexity, location, and size range). Tables 126, 127, and 128 provide demographic data on respondents to the survey for selected operating costs within the U.S. refining industry.

TABLE 123

January 1, 1979, Refinery Assets
Aggregated by Refinery Location

	Refinery Location					
	PAD I	PAD II	PAD III	PAD IV	PAD V	All
Weight Average Complexity	7.08	7.14	7.38	5.16	7.52	7.24
Gross Fixed Assets						
MM$	2,799	4,722	8,546	562	4,236	20,865
$/barrel/day	1,507	1,271	1,305	1,089	1,530	1,354
Replacement Costs*						
MM$	7,471	12,846	19,074	1,887	11,767	53,045
$/barrel/day	4,224	3,659	3,254	3,658	4,572	3,727
Ratio Replacement Costs to Gross Fixed Assets	2.80	2.88	2.49	3.36	2.99	2.75
Number of Refineries	26	52	63	20	37	198
Crude Charge Capacity (MB/D)	1,857	3,713	6,548	516	2,767	15,401
Percentage of Total Capacity†	99.3	88.2	86.6	86.6	89.8	88.9

*Replacement cost data were submitted for 186 refineries, having 14,330 MB/D of crude charge capacity.

†Percentage of capacity of respondents who provided refinery asset data to the January 1979 NPC Survey of Petroleum Refining Capabilities.

TABLE 124

January 1, 1979, Refinery Assets
Aggregated by Refinery Size Range and Complexity Factor

	Refinery Size Range (MB/D)/Complexity Factor												
	0-10			10-30			30-50			50-100	100-175	175+	
	<2.5	>2.5	All	<2.5	>2.5	All	<2.5	>2.5	All	All	All	All	All
Weight Average Complexity	1.31	5.18	2.21	1.41	5.29	3.46	1.31	5.91	5.38	7.78	8.46	7.57	7.24
Gross Fixed Assets													
MM$	95	134	229	299	531	829	112	1,214	1,326	3,368	4,515	10,596	20,865
$/barrel/day	530	2,356	972	635	1,020	837	925	1,014	1,006	1,399	1,464	1,438	1,354
Replacement Costs													
MM$	253	353	607	750	1,474	2,224	*	*	4,053	7,398	13,553	25,211	53,045
$/barrel/day	1,378	6,207	2,521	1,671	3,151	2,426	*	*	3,291	3,729	4,602	3,646	3,727
Ratio Replacement Cost to Gross Fixed Assets	2.60	2.63	2.59	2.63	3.09	2.90	-	-	3.27	2.67	3.14	2.54	2.75
Number of Refineries	28	9	37	24	25	49	3	27	30	34	24	24	198
Crude Charge Capacity (MB/D)	179	57	236	470	520	990	121	1,196	1,317	2,407	3,084	7,367	15,401
Percentage of Total Capacity†			53.3			69.0			90.6	65.3	85.5	100	91.2

*Data withheld to protect confidentiality.

†Percentage of capacity of respondents who provided operating cost data to the January 1979 NPC Survey of Petroleum Refining Capabilities.

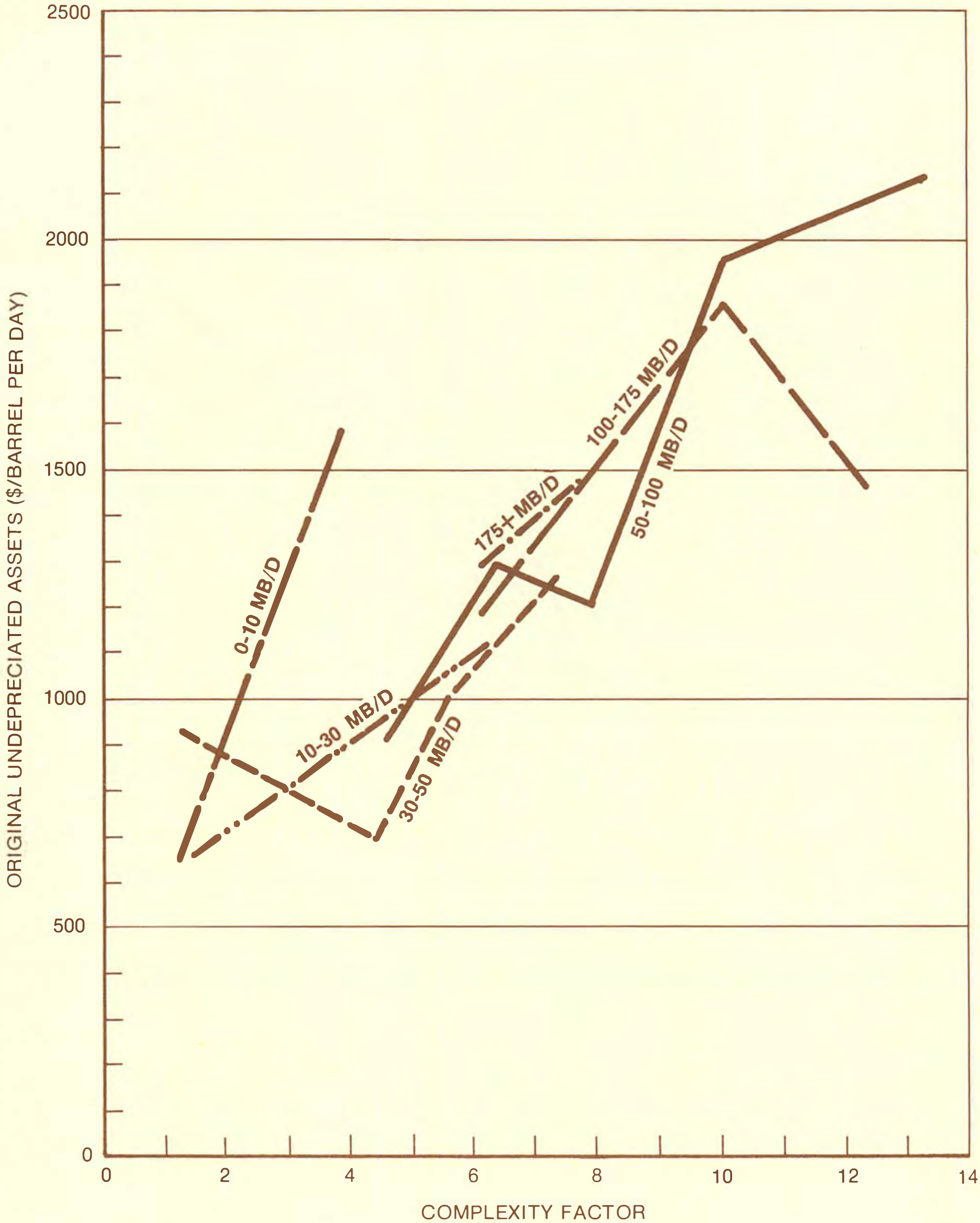

Figure 47. 1978 Original Undepreciated Assets as a Function of Complexity—Aggregated by Refinery Size Range.

Figure 48. 1978 Replacement Costs as a Function of Complexity—
Aggregated by Refinery Size Range.

TABLE 125

January 1, 1979, Refinery Assets
Aggregated by Complexity Factor

	Complexity Factor 1-3	3-5	5-7	7-9	9-11	11+	All
Weight Average Complexity	1.60	4.37	6.11	7.80	10.04	13.28	7.24
Gross Fixed Assets							
MM$	675	1,300	6,611	7,507	2,679	2,092	20,865
$/barrel/day	715	1,096	1,267	1,420	1,800	1,628	1,354
Replacement Costs*							
MM$	1,521	2,267	15,370	21,623	6,329	4,936	53,045
$/barrel/day	1,706	2,792	3,475	4,188	4,522	4,166	3,727
Ratio Replacement Cost to Gross Fixed Assets	2.25	2.50	2.30	2.88	2.36	2.36	2.54
Number of Refineries	61	30	47	36	13	11	198
Crude Charge Capacity (MB/D)	943	1,186	5,215	5,285	1,487	1,285	15,401
Percentage of Total Capacity†	72.1	81.3	96.9	88.7	100.0	100.0	91.2

*Replacement cost data were submitted for 186 refineries, having 14,330 MB/D of crude charge capacity.

†Percentage of capacity of respondents who provided refinery asset data to the January 1979 NPC Survey of Petroleum Refining Capabilities.

TABLE 126

January 1, 1979, Refining Capacity Distribution
by Process Complexity and Refinery Size Range
for Respondents to the NPC Survey of Petroleum Refining Capabilities
(Figures Shown are Aggregate Capacity (MB/D) with
Number of Reporting Refineries in Parentheses)

Refinery Size Range (MB/D)	Weight Average Complexity	Complexity Factor: Under 3	3-5	5-7	7-9	9-11	11+	Total
Weight Average Complexity		1.60	4.37	6.11	7.80	10.04	13.28	7.24
0- 10	2.21	198 (34)	32 (5)	0	*	0	*	245 (41)
10- 30	3.45	503 (26)	236 (11)	193 (10)	*	*	0	990 (49)
30- 50	5.38	*	428 (10)	356 (8)	217 (5)	*	*	1,352 (31)
50-100	7.78	*	*	927 (14)	691 (10)	234 (3)	316 (4)	2,407 (34)
100-175	8.46	0	*	1,071 (8)	*	688 (6)	510 (4)	3,084 (24)
175+	7.57	0	*	2,668 (7)	3,603 (13)	*	*	7,367 (24)
Total	7.24	988 (66)	1,186 (30)	5,215 (47)	5,285 (36)	1,487 (13)	1,285 (11)	15,445 (203)

*Data withheld to protect confidentiality.

TABLE 127

January 1, 1979, Refining Capacity Distribution
by Process Complexity and Refinery Location
for Respondents to the NPC Survey of Petroleum Refining Capabilities
(Figures Shown are Aggregate Capacity (MB/D) with
Number of Reporting Refineries in Parentheses)

Refinery Location	Weight Average Complexity	Complexity Factor: Under 3	3-5	5-7	7-9	9-11	11+	Total
		1.60	4.37	6.11	7.80	10.04	13.28	7.24
PAD I	7.08	111 (9)	*	826 (6)	*	*	*	1,857 (26)
PAD II	7.14	83 (10)	331 (8)	1,345 (18)	1,497 (12)	*	*	3,718 (53)
PAD III	7.38	304 (24)	575 (9)	2,172 (12)	2,268 (12)	660 (4)	570 (4)	6,549 (65)
PAD IV	5.16	102 (5)	*	182 (6)	*	*	0	516 (20)
PAD V	7.52	387 (18)	107 (3)	690 (5)	815 (5)	358 (4)	449 (4)	2,806 (39)
Total	7.24	988 (66)	1,186 (30)	5,215 (47)	5,285 (36)	1,487 (13)	1,285 (11)	15,445 (203)

*Data withheld to protect confidentiality.

TABLE 128

January 1, 1979, Refinery Capacity Distribution
by Refinery Size Range and Location for Respondents
to the NPC Survey of Petroleum Refining Capabilities
(Figures Shown are Aggregate Capacity (MB/D) with
Number of Reporting Refineries in Parentheses)

Refinery Size Range (MB/D)	Weight Average Complexity	Refinery Location: PAD I	PAD II	PAD III	PAD IV	PAD V	Total
	7.24 (weight average complexity)	7.08	7.14	7.38	5.16	7.52	7.24
0- 10	2.21	45 (7)	43 (8)	86 (15)	27 (5)	45 (6)	245 (41)
10- 30	3.45	98 (6)	197 (10)	348 (16)	131 (7)	216 (10)	990 (49)
30- 50	5.38	†	460 (10)	276 (7)	*	*	1,352 (31)
50-100	7.78	*	810 (12)	659 (9)	*	*	2,407 (34)
100-175	8.46	644 (4)	1,170 (9)	484 (4)	0	787 (7)	3,084 (24)
175+	7.57	*	1,038 (4)	4,697 (14)	0	*	7,367 (24)
Total	7.24	1,857 (26)	3,718 (53)	6,549 (65)	516 (20)	2,806 (39)	15,445 (203)

*Data withheld to protect confidentiality.
†Reclassified to protect confidentiality.

CHAPTER FOUR

COMPETITIVE ECONOMICS OF SUPPLYING INCREMENTAL U.S. EAST COAST PRODUCT DEMAND FROM DOMESTIC REFINERIES AND FOREIGN EXPORT REFINERIES

INTRODUCTION

The objective of this chapter is to compare the competitive position of U.S. domestic and foreign export refineries in the 1978 economic environment. Because PAD I receives the majority of product imports, this study was based on the cost of incremental products delivered to New York Harbor from a typical refinery in PADs I or III and a typical refinery located in the Caribbean, eastern Canada, the Netherlands, or Italy. The foreign export refineries selected were those which had the capacity to supply petroleum products to PAD I. Competition for product markets in other PAD districts was not studied and may not be similar to that shown for PAD I.

The relative competitive position of any refinery in the United States relative to foreign export refineries is largely determined by crude oil price, cost of processing, and cost of transportation for similar petroleum products. All other factors being the same, the lower the cost for processing and transportation and the higher the delivered product value, the better the competitive position. The base analysis considers these factors as they existed in 1978. Two additional cases were constructed to test the effects of product slate and crude oil charge. To equalize the product slates produced by foreign export refineries with typical refineries in PADs I and III, an analysis was included for comparison purposes only, which hypothetically retrofitted Caribbean and eastern Canadian refineries with additional downstream facilities yielding an upgraded product mix. Additionally, to exclude the effect of crude oil selection, a special case was developed for PADs I and III, the Caribbean, and eastern Canada, using only Saudi Arabian Light crude oil as incremental charge stock.

Other considerations in determining competitive positions, such as capital and fixed costs, product quality, and industry marketing and management, are not subject to aggregation, and are not available from NPC survey data. Competitiveness should be viewed as a dynamic concept, because individual companies respond to changes in their perceived environments with different business strategies, investment decisions, and productivity improvement efforts.

Factors considered in this study which influence refineries' individual competitive positions include: "typical" refinery processing units for each area; crude oil slates at 1978 official prices; crude oil and product transportation at 1978 rates; product prices generally based on Platt's New York Terminal average high and low prices; 1978 incremental tax rates for each area; the quality of refinery fuel used as determined by local environmental regulations; incremental processing costs; U.S. import fees and duties; and the entitlements program.

It has been assumed that all incremental products from these refineries (excluding butanes and lighter hydrocarbons, sulfur, and coke) were sold in the U.S. East Coast market with the exception of naphtha, which was marketed on the U.S. Gulf Coast. This was necessary in order to keep the data on a comparable basis. It is recognized that each refiner would prefer to sell the incremental product into its highest net-back market. However, this may not be possible without upsetting the local price structure. This is especially true of No. 6 fuel oil and naphtha, which may have greater net-backs in the local (or non-U.S.) area. Therefore, the economics presented may tend to overstate the disadvantage of foreign refineries.

It cannot be overemphasized that these data are applicable to the conditions that existed in calendar year 1978 and are comparable only on the basis of increments of capacity. The analysis is of the average economics for the 70-85 percent increment of refinery capacity utilization and the 85-100 percent increment. This study is not a marginal analysis of the costs associated with the last barrel processed. Further, it does not attempt to assess the absolute profitability of those refineries considered. Changes in crude oil costs and availability, product demand and prices, and government policies and regulations would have a major impact on the relative competitiveness between refineries. Factors such as environmental regulations, working conditions (regulated by OSHA), and the omission of the cost of implementing these regulations significantly affect the relative profitability of individual refineries. None of these regulations, with the exception of the cost of refinery fuel sulfur limits, were used in determining the regulatory costs included in the analysis. Examples of these are the cost for installation of sulfur recovery, water treating, and particulate facilities, as well as the operating costs for such facilities. Also not included in this analysis are the foreign government subsidies allowed for foreign refineries, such as price controls on refinery fuels. Costs such as those listed above were not available for this study.

METHODOLOGY

The relative incremental profitability of U.S. vs. foreign export refineries was analyzed by comparing the profitability of processing incremental foreign crude oils. To serve as a basis for comparison, typical refinery configurations and yields were developed from a refinery simulation model for refineries located in the Caribbean, eastern Canada, the Netherlands, and Italy, and for U.S. refineries located in PADs I and III.

The typical refineries in PADs I and III were drawn from the average configuration of refineries in the 100-175 MB/D range in each district as reported in the January 1979 NPC Survey of Petroleum Refining Capabilities; foreign export refinery configurations were based on the average refinery size and configuration of large export refineries as reported in the Oil & Gas Journal, March 24, 1979. Each refinery was examined at crude oil charge levels of 70 percent, 85 percent, and 100 percent of capacity. The analysis was based on the incremental results; i.e., the average of the 70-85 percent increment and the 85-100 percent increment.

The crude oil slates for the refineries were based on the Pace Company entitled Competitive Economics of United States and Foreign Refining.[1] Incremental changes in crude oil runs were made for all areas by changing the volume of foreign crude oil only. PAD III was the only area processing both domestic and foreign crude oil.

The domestic crude oil prices were based on the average 1978 posted prices for lower tier, upper tier, and stripper crude oil with entitlements adjustment which were allocated according to the national fraction of crude oil in each price tier. The foreign crude oil prices were based on the 1978 average official foreign government prices.

The product slates were the results of a simulation model for each refinery. The net-back of each product in each refinery center was used by the model to optimize the value of product slates. Imported gasoline and distillate from all foreign export refineries met U.S. product specifications.

The rates for transportation of foreign crude oil and products were spot rates based on Shipping Statistics and Economics by H. P. Drewry, Ltd., 1978. The U.S.-flag product tanker transportation rates used were the 1978 average of those reported by Dietz, Inc.

All major products were to be sold at the New York Harbor terminal price, with the exception of naphtha, which was deemed to be sold on the Gulf Coast. The weighted average of the monthly low and high prices for 1978 was used. Such averaging is not necessarily reflective of actual volume/price transactions which occured in 1978. The prices for other fuel oils higher in sulfur content were calculated using price differentials taken from the Pace Company's study of foreign refinery competitiveness. Unleaded gasoline was assumed to be priced at 2.8 cents per gallon above regular grade, which was the national average price differential as determined by the U.S. Department of Energy.

Federal and local incremental tax rates for 1978 were used to determine the income tax liability for the typical refinery in each area. The data have been presented on both before- and after-tax bases in order that either comparison of competitive position can be made.

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[1]A report entitled Competitive Economics of United States and Foreign Refining, prepared by the Pace Company Consultants and Engineers, Inc., was released to the Department of Energy in December 1979. This report included fixed costs in developing the economics between the regions. To compare the Pace Company report with this NPC study would require that the latter be adjusted for fixed costs. This comparison is illustrated in Appendix H.

Data were not available for all refinery operation environmental costs. The analysis was limited to the required use of low-sulfur fuel oil in PAD I, the use of conventional gas in PAD III, and the use of high-sulfur fuel oil in the Caribbean, eastern Canada, the Netherlands, and Italy.

Among the factors determining the net crude oil and product costs to U.S. refineries in 1978 were the U.S. Department of Energy's crude oil entitlements program and the residual fuel oil reverse entitlements. The analysis did not attempt to adjust entitlements for shifting crude oil runs from U.S. to foreign export refineries. However, if it were assumed that 500 MB/D of crude oil runs were shifted, the entitlements crude oil run credit of $1.61/bbl would change by about $0.05/bbl.

Depreciation, maintenance, and other fixed operating expenses of the existing refineries were taken from NPC survey data (January 1979 Survey of Petroleum Refining Capabilities) on all refineries greater than 50 MB/D correlated as a function of complexity factor. The added fixed costs, including depreciation, for the special retrofit cases of added downstream processing capacity in the Caribbean and eastern Canadian refineries were considered to be 27 percent per year of the estimated added capital investment.

The 1978 import fees and duties were used for crude oil and products. The total rate schedule for duties was used, but the fees for crude oil and residual fuel oil were reduced from the scheduled rates for fees because duties net out fees and a large percentage of crude oil and residual fuel oil was fee-free.

The relative incremental advantage (disadvantage) was used to compare the competitive position between a typical refinery in PAD I with one in each of the following areas: PAD III, the Caribbean, eastern Canada, the Netherlands, and Italy. The comparison was based on the summation of the differences in each cost item between PAD I and each of the areas under consideration. These cost items were: crude oil, crude oil and product transportation, crude oil and product fees and duties, plant fuels, other variables, delivered product value, entitlements benefits, and taxes.

EXPANDED DISCUSSION

Factors Affecting the Incremental Advantage (Disadvantage)

The following factors had the greatest impact on the competitive relationship between a typical refinery in PAD I and those in PAD III, the Caribbean, eastern Canada, the Netherlands, and Italy (see Table 129).

Crude Oil Slate

The crude oil slates were based on the Pace Company Consultants and Engineers, Inc., report entitled Competitive Economics of United States and Foreign Refining, dated December 1979. The

TABLE 129

Estimated 1978 Relative Incremental Advantage (Disadvantage)*
(All Cost Figures in U.S. $/Bbl of Crude Oil Charge)

	PAD I	PAD III	Caribbean	E. Canada	Netherlands	Italy
Base: PAD I, 85-100% Increment						
		85-100% Incremental Advantage (Disadvantage) Relative to Base				
Due to:						
Crude Oil Cost (FOB)	Base	(0.66)	0.13	0.09	(0.04)	(0.04)
Crude Oil Transportation	Base	0.20	0.53	0.55	0.39	0.44
Crude Oil Fees and Duties	Base	--	0.11	0.11	0.11	0.11
Delivered Product Value	Base	(0.12)	(1.97)	(1.47)	(1.76)	(1.70)
Product Transportation	Base	(0.63)	(0.06)	0.11	(0.65)	(0.76)
Product Fees and Duties	Base	--	(0.10)	(0.10)	(0.11)	(0.13)
Fuel Cost	Base	0.26	0.35	0.34	0.36	0.35
Other Variable Costs		0.04	0.05	0.07	0.08	0.08
Subtotal (Pre-Entitlements and Taxes)	Base	(0.91)	(0.96)	(0.30)	(1.62)	(1.65)
Entitlements -- Crude Oil Throughput	Base	--	(1.61)	(1.61)	(1.61)	(1.61)
Entitlements -- Residual Produced	Base	(0.03)	0.10	0.10	0.10	0.10
Entitlements -- Residual Imports	Base	--	0.36	0.25	0.32	0.31
Total Advantage (Disadvantage) (Without Taxes)	Base	(0.94)	(2.11)	(1.56)	(2.81)	(2.85)
Taxes	Base	0.47	0.97	0.78	1.38	1.32
Total Advantage (Disadvantage) (With Taxes)	Base	(0.47)	(1.14)	(0.78)	(1.43)	(1.53)
	70-85% Incremental Advantage (Disadvantage) Relative to Base					
Due to:						
Crude Oil Cost (FOB)	--	(0.66)	0.13	0.09	(0.04)	(0.04)
Crude Oil Transportation	--	0.20	0.53	0.55	0.39	0.44
Crude Oil Fees and Duties	--	--	0.11	0.11	0.11	0.11
Delivered Product Value	0.84	0.91	(1.53)	(1.17)	(1.56)	(1.43)
Product Transportation	0.03	(0.80)	(0.07)	0.12	(0.67)	(0.79)
Product Fees and Duties	--	--	(0.06)	(0.21)	(0.10)	(0.11)
Fuel Cost	(0.14)	0.05	0.31	0.27	0.36	0.32
Other Variable Costs	(0.06)	--	0.05	(0.02)	0.08	0.07
Subtotal (Pre-Entitlements and Taxes)	0.67	(0.30)	(0.53)	(0.26)	(1.43)	(1.43)
Entitlements -- Crude Oil Throughput	--	--	(1.61)	(1.61)	(1.61)	(1.61)
Entitlements -- Residual Produced	0.01	0.04	0.10	0.10	0.10	0.10
Entitlements -- Residual Imports	--	--	0.33	0.25	0.30	0.25
Total Advantage (Disadvantage) (Without Taxes)	0.68	(0.26)	(1.71)	(1.52)	(2.64)	(2.69)
Taxes	(0.34)	0.13	0.87	0.77	1.30	1.25
Total Advantage (Disadvantage) (With Taxes)†	0.34	(0.13)	(0.84)	(0.75)	(1.34)	(1.44)
70-85% Incremental Advantage (Disadvantage) Relative to PAD I (70-85%)	0.00	(0.47)	(1.18)	(1.09)	(1.68)	(1.78)

*Calculated as the differences for all costs and income taxes between PAD I and the respective area from Tables 132, 133, 134, 138, and 139.

†These data should be compared with "Total Advantage (Disadvantage) (With Taxes)" for 85-100 percent increment.

amount of sweet crude oil processed in these refineries ranged from 73 percent in PAD III to 15 percent in the Netherlands and Italy. The requirement for a sweet crude oil in PAD III resulted in a crude oil cost $0.62/bbl higher than in the Netherlands and Italy.

Delivered Product Value

The delivered product value per barrel for the incremental product in PAD I is $0.12 higher than PAD III and $1.97 higher than the Caribbean refinery due to the greater proportion of high value products such as gasoline, distillate, and kerosine. For the 85-100 percent increment of capacity, the yield of these products per barrel of crude oil processed ranged from 73.5 percent of crude oil for PAD I and 70.3 percent for PAD III, to 57.4 percent for eastern Canada and a low of 39.5 percent for the Caribbean. The prices for light product were higher than No. 6 fuel oil (high sulfur), the lowest price product. For example, kerosine was $4.95/ bbl higher, and unleaded gasoline was $6.27/bbl higher.

Transportation Costs

A large portion of the PAD III disadvantage relative to PAD I is a result of the high product transportation cost in Jones Act (domestic) tankers. This product transportation cost disadvantage is about $0.63/bbl of crude oil processed in PAD III. A Netherlands refinery, which can use lower cost foreign flag vessels, can ship products from Europe to the East Coast for about the same cost per barrel of crude oil processed as a PAD III refinery. Both eastern Canadian and Caribbean refineries have a product transportation advantage over PAD III.

Foreign export refineries near the East Coast (the Caribbean and eastern Canada) have an approximate $0.53/bbl of crude oil transportation cost advantage primarily because of assumed access to deepwater ports in which large, low-cost VLCC's can be used.

Fuel Costs

Refineries in PAD I were at a relative disadvantage because environmental regulations require them to use higher cost, low-sulfur fuel oils for refining fuel. The advantages the other areas had over PAD I for the 85-100 percent increment are as follows: PAD III -- $0.26/bbl; the Caribbean -- $0.35/bbl; eastern Canada -- 0.34/bbl; the Netherlands -- $0.36/bbl; Italy -- $0.35/bbl. No other environmental factors were considered, due to a lack of adequate information.

Import Fees and Duties

While the domestic refineries suffered a disadvantage of about $0.11/bbl because of crude oil import fees and duties, this was largely offset relative to the offshore refineries by the fees and duties charged on imported products.

Entitlements

The incremental impact of the entitlements credit was a direct $1.61/bbl advantage to domestic refiners importing foreign crude oil into the United States. Price controls on domestic crude oil kept incremental crude oil costs low to U.S. refineries and product costs low relative to world product prices. This was partially offset by the reverse entitlements penalty for domestic residual fuel production marketed in PAD I and by the entitlements credit given to residual fuel oil importers.

Taxes

Federal and local tax rates for 1978 were used to determine the incremental tax liability for the typical refinery in each area. The tax rates ranged from a high of 50 percent in the United States to a low of 25 percent for the Caribbean refinery.

The data base used to develop this study is shown in Tables 144 through 154 (at the end of this chapter). It was developed as a basis for determing the competitiveness between a representative foreign export refinery located in the Caribbean (Aruba), eastern Canada (St. John, N.B.), the Netherlands (Rotterdam), and Italy (Milazzo) and U.S. refineries in PADs I (Philadelphia) and III (Houston), all serving the New York market. Specifically, the analysis considered refineries typical in size and complexity for each area. The foreign export refineries were assumed to be exporting refineries having the capability to ship product to PAD I.

Estimated 1978 Relative Incremental Advantage (Disadvantage)

For the 85-100 percent increment of capacity using PAD I as a base (Table 129), PAD III had the closest competitive position, at a $0.47/bbl relative disadvantage, and Italy was in the least competitive position, with a $1.53/bbl disadvantage. In general, all foreign export refineries had a competitive disadvantage due to the impact of domestic crude oil price controls on product costs and a disadvantage in product value due to lower refinery complexity. The value of product from a refinery in Italy was $1.70/bbl below that of a PAD I refinery. The relative distance of the foreign export refinery from PAD I is also a factor in competitive position.

For the 70-85 percent increment of capacity, PAD III was the nearest to PAD I, with a $0.47/bbl disadvantage, and Italy was the least competitive, with a $1.78/bbl disadvantage. As in the 85-100 percent increment, crude oil cost, product value, and distance from PAD I were factors in the competitive position (see Table 129).

Since eastern Canadian, Caribbean, and European refineries were operating at an average of about 65 percent in 1978 (DOE publication, Trends in Refinery Capacity and Utilization, to be published in January 1981), the relative advantage (disadvantage) comparisons of these foreign export areas for the 70-85 percent increment should be made with PADs I and III at the 85-100 percent increment to more accurately represent their actual 1978 competitive positions. For example, this would decrease the disadvantage, when comparing the Caribbean with PAD I, from $1.14/bbl to $0.84/bbl.

The following factors contributed to the advantage (disadvantage) of PAD I over the other areas:

- The entitlements crude oil run credit of $1.61/bbl for U.S. refineries contributed significantly to the advantage of PAD I and PAD III refineries. In the absence of the credit, the refineries in PADs I and III would be at a disadvantage when compared to the foreign export refineries, especially those in eastern Canada and the Caribbean.

- The low product mix value caused by lack of incremental downstream capacity for the foreign export refineries was partially offset by the entitlements credit for imported residual oil, which was equivalent to about $0.30/bbl of crude oil charge.

- Foreign export refineries have significantly lower crude oil transportation costs than do U.S. refineries.

- Because of environmental regulations, PAD I refineries are required to use higher cost, low-sulfur fuel oil which produces a $0.26/bbl to $0.36/bbl disadvantage as compared to the other refinery areas.

Estimated 1978 Relative Incremental Advantage (Disadvantage) -- Saudi Arabian Light Crude Oil

In 1978, the official prices of foreign sweet and sour crude oil grades did not necessarily reflect their relative value when considering the attainable product mix of each crude oil grade. The different crude oil mixes used for the incremental crude oil slates have a varying impact on the relative profitability of the U.S. and foreign export refineries. To remove any potential bias resulting from crude oil type selection, the study was extended for PAD I, PAD III, the Caribbean, and eastern Canada to evaluate their processing of a common incremental crude oil, Saudi Arabian Light.

For the 85-100 percent increment using Saudi Arabian Light (Table 130), the Caribbean had a $1.36/bbl disadvantage compared with PAD I. This compares with a $1.14/bbl disadvantage processing their average crude oil mix (Table 129). Eastern Canada had a $0.70/bbl disadvantage, which was an improvement over the $0.78/bbl disadvantage in processing their average crude oil mix.

For PAD III processing of Saudi Arabian Light, the disadvantage increased from $0.47/bbl to $0.75/bbl. This was primarily because a typical PAD III refinery processes a lighter, lower sulfur crude oil mix for which a smaller vacuum distillation capacity is required. Processing the Saudi Arabian Light required that a significant portion of the increment bypass the vacuum distillation units because of limited capacity. This bypass situation greatly reduced incremental product values. The delivered product value was lowered from a $0.12/bbl disadvantage compared to PAD I with the mixed crude oil slate to a $1.63/bbl disadvantage when processing Saudi Arabian Light crude oil in the 85-100 percent increment of capacity.

In the 70-85 percent increment in processing Saudi Arabian Light, the PAD III economics reversed to the same trend as Table 129; i.e., the most competitive position, at a disadvantage of $0.60/bbl vs. $1.34/bbl for the Caribbean and $1.01/bbl for eastern Canada. This was because the Saudi Arabian Light crude oil did not overload the vacuum distillation capacity at this increment. In

TABLE 130

Estimated 1978 Relative Incremental Advantage (Disadvantage) --
Saudi Arabian Light Crude Oil*
(All Cost Figures in U.S. $/Bbl of Crude Oil Charge)

	PAD I	PAD III	Caribbean	E. Canada
Base: PAD I, 85-100% Increment				
		85-100% Incremental Advantage (Disadvantage) Relative to Base		
Due to:				
Crude Oil Cost (FOB)	Base	--	--	--
Crude Oil Transportation	Base	0.01	0.73	0.77
Crude Oil Fees and Duties	Base	--	0.11	0.11
Delivered Product Value	Base	(1.63)	(2.45)	(1.51)
Product Transportation	Base	(0.10)	(0.04)	0.09
Product Fees and Duties	Base	--	(0.07)	(0.05)
Fuel Cost	Base	0.28	0.39	0.37
Other Variable Costs	Base	0.05	0.08	0.12
Subtotal (Pre-Entitlements and Taxes)	Base	(1.39)	(1.25)	(0.10)
Entitlements -- Crude Oil Throughput	Base	--	(1.61)	(1.61)
Entitlements -- Residual Produced	Base	(0.11)	0.09	0.09
Entitlements -- Residual Imports	Base	--	0.43	0.22
Total Advantage (Disadvantage) (Without Taxes)	Base	(1.50)	(2.34)	(1.40)
Taxes	Base	0.75	0.98	0.70
Total Advantage (Disadvantage) (With Taxes)	Base	(0.75)	(1.36)	(0.70)
		70-85% Incremental Advantage (Disadvantage) Relative to Base		
Due to:				
Crude Oil Cost (FOB)	--	--	--	--
Crude Oil Transportation	--	0.01	0.73	0.77
Crude Oil Fees and Duties	--	--	0.11	0.11
Delivered Product Value	0.82	0.11	(1.83)	(1.15)
Product Transportation	0.03	(0.72)	(0.05)	0.12
Product Fees and Duties	--	--	(0.05)	(0.20)
Fuel Cost	(0.15)	0.06	0.34	0.29
Other Variable Costs	(0.06)	(0.01)	(0.01)	(0.02)
Subtotal (Pre-Entitlements and Taxes)	0.64	(0.55)	(0.76)	(0.08)
Entitlements -- Crude Oil Throughput	--	--	(1.61)	(1.61)
Entitlements -- Residual Produced	--	(0.01)	0.09	0.09
Entitlements -- Residual Imports	--	--	0.39	0.22
Total Advantage (Disadvantage) (Without Taxes)	0.64	(0.56)	(1.89)	(1.38)
Taxes	(0.32)	0.28	0.87	0.69
Total Advantage (Disadvantage) (With Taxes)†	0.32	(0.28)	(1.02)	(0.69)
70-85% Incremental Advantage (Disadvantage) Relative to PAD I (70-85%)	0.00	(0.60)	(1.34)	(1.01)

*Calculated as the difference for all costs and income taxes between PAD I and the respective area from Tables 140, 141, 142, and 143.

†These data should be compared with "Total (With Taxes)" for 85-100 percent increment.

this increment, the product mix value changed from a $0.07/bbl disadvantage for PAD I vs. PAD III to a $0.71/bbl advantage when processing incremental Saudi Arabian Light crude oil.

The more logical comparison of the PAD I 85-100 percent increment to the 70-85 percent increment for the Caribbean and eastern Canadian refineries indicates that the Caribbean disadvantage decreases from $1.36/bbl to $1.02/bbl, while the eastern Canadian disadvantage only decreases from $0.70/bbl to $0.69/bbl.

Estimated 1978 Relative Incremental Advantage (Disadvantage) with Retrofitted Downstream Capacity -- Caribbean and Eastern Canada

The typical foreign export refineries covered by this report are not equipped to manufacture high yields of motor gasoline, kerosine, and light distillates which have a higher product value than fuel oil in the New York market. This results in a competitive disadvantage for these refineries when compared with PADs I and III, which have the capability to produce high yields of these higher priced products.

Because the lower competitive position of foreign export refineries is largely due to their lower complexity and resultant lower product mix value, the Caribbean and eastern Canadian refineries were retrofitted with downstream processing facilities to enable them to produce a product mix comparable to PAD I (i.e., by adding fluid catalytic cracking, alkylation, and catalytic reforming). This retrofitting improved the incremental competitive position for the 85-100 percent increment for both areas (Table 131). The Caribbean dropped from a $1.14/bbl disadvantage to a $0.25/bbl disadvantage relative to PAD I; this is an advantage over PAD III of $0.22/bbl. In eastern Canada, the disadvantage decreased from $0.78/bbl to $0.35/bbl relative to PAD I, or a $0.12/bbl advantage over PAD III. It may be observed that the Caribbean retrofitted refinery had considerably greater capacity than the domestic refineries in PADs I and III. The NPC survey data did not support the expectation that operating costs would decrease significantly with size due to economy of scale. This may be because most large refineries in the United States have evolved through growth and in reality are multiple operations.

The capital investments for retrofitting the eastern Canadian and Caribbean refineries with downstream processing capacity up to the complexity level of domestic refineries amounted to some $1,389 and $1,171 per daily barrel of crude oil throughput capacity, respectively. The increase in total fixed costs, including depreciation, for these refineries was $1.08/bbl for eastern Canada and $0.87/bbl for the Caribbean. This substantially offset the gains in product mix value attained by the additional processing capability.

In a comparison with PAD I at the 70-85 percent increment, the Caribbean improved its relative position from a $1.18/bbl disadvantage to a $0.42/bbl disadvantage; however, this increment is more competitive than PAD III by $0.05/bbl. For eastern Canada, the

TABLE 131

Estimated 1978 Relative Incremental Advantage (Disadvantage)* -- With Retrofitted Downstream Capacity†
(All Cost Figures in U.S. $/Bbl of Crude Oil Charge)

	PAD I	PAD III	Caribbean Existing Capacity	Caribbean Retrofitted Downstream	E. Canada Existing Capacity	E. Canada Retrofitted Downstream
Base: PAD I, 85-100% Increment						
		85-100% Incremental Advantage (Disadvantage) Relative to Base				
Due to:						
Crude Oil Cost (FOB)	Base	(0.66)	0.13	0.13	0.09	0.09
Crude Oil Transportation	Base	0.20	0.53	0.53	0.55	0.55
Crude Oil Fees and Duties	Base	--	0.11	0.11	0.11	0.11
Delivered Product Value	Base	(0.12)	(1.97)	(0.12)	(1.47)	0.03
Product Transportation	Base	(0.63)	(0.06)	(0.11)	0.11	0.14
Product Fees and Duties	Base	--	(0.10)	(0.12)	(0.10)	(0.33)
Fuel Cost	Base	0.26	0.35	(0.01)	0.34	0.02
Other Variable Costs	Base	0.04	0.05	0.06	0.07	0.02
Subtotal (Pre-Entitlements and Taxes)	Base	(0.91)	(0.96)	0.47	(0.30)	0.63
Entitlements -- Crude Oil Throughput	Base	--	(1.61)	(1.61)	(1.61)	(1.61)
Entitlements -- Residual Produced	Base	(0.03)	0.10	0.10	0.10	0.10
Entitlements -- Residual Imports	Base	--	0.36	0.12	0.25	0.13
Total Advantage (Disadvantage) (Without Taxes)	Base	(0.94)	(2.11)	(0.92)	(1.56)	(0.75)
Taxes	Base	0.47	0.97	0.67	0.78	0.40
Total Advantage (Disadvantage) (With Taxes)	Base	(0.47)	(1.14)	(0.25)	(0.78)	(0.35)
	70-85% Incremental Advantage (Disadvantage) Relative to Base					
Due to:						
Crude Oil Cost (FOB)	--	(0.66)	0.13	0.13	0.09	0.09
Crude Oil Transportation	--	0.20	0.53	0.53	0.55	0.55
Crude Oil Fees and Duties	--	--	0.11	0.11	0.11	0.11
Delivered Product Value	0.84	0.91	(1.53)	0.62	(1.17)	0.26
Product Transportation	0.03	(0.80)	(0.07)	(0.07)	0.12	0.20
Product Fees and Duties	--	--	(0.06)	(0.36)	(0.21)	(0.38)
Fuel Cost	(0.14)	0.05	0.31	(0.18)	0.27	(0.08)
Other Variable Costs	(0.06)	--	0.05	(0.08)	(0.02)	0.02
Subtotal (Pre-Entitlements and Taxes)	0.67	(0.30)	(0.53)	0.70	(0.26)	0.77
Entitlements -- Crude Oil Throughput	--	--	(1.61)	(1.61)	(1.61)	(1.61)
Entitlements -- Residual Produced	0.01	0.04	0.10	0.10	0.10	0.10
Entitlements -- Residual Imports	--	--	0.33	0.11	0.25	0.14
Total Advantage (Disadvantage) (Without Taxes)	0.68	(0.26)	(1.71)	(0.70)	(1.52)	(0.60)
Taxes	(0.34)	0.13	0.87	0.62	0.77	0.32
Total Advantage (Disadvantage) (With Taxes)	0.34	(0.13)	(0.84)§	(0.08)§	(0.75)§	(0.28)§
70-85% Incremental Advantage (Disadvantage) Relative to PAD I (70-85%)	0.00	(0.47)	(1.18)	(0.42)	(1.09)	(0.62)

*Calculated as the difference for all costs and income taxes between PAD I and the respective area from Tables 132, 133, 135, and 137.

†Added downstream capacity in the Caribbean and eastern Canada. See Table 25 for additional data on the cost of retrofitting.

§These data should be compared with "Total Advantage (Disadvantage) (With Taxes)" for 85-100 percent increment.

competitive position improved from a $1.09/bbl disadvantage to a $0.62/bbl disadvantage. This was a reverse from the 85-100 percent increment in that the retrofit was $0.15/bbl less competitive than PAD III.

A comparison of the 85-100 percent increment in PAD I to the 70-85 percent increments (rather than the 85-100 percent increments) for the retrofitted refineries in eastern Canada and the

Caribbean area is less meaningful. When making this comparison the disadvantage dropped from $0.42/bbl to $0.08/bbl for the Caribbean refinery and $0.62/bbl to $0.28/bbl for the eastern Canadian refinery.

Crude Oil, Product Yield, Variable Costs, and Relative Profitability

Tables 132 through 143 present data for all areas considered in this study which were used to develop Tables 129 through 131. The tables include crude oil charge (crude oil slates) in barrels per day; product yield (product mix) in volume percentage of crude oil charge; and summary costs, values, etc., in dollars per barrel of crude oil charge. The relative gain/loss (after income tax) for the 70-85 percent and 85-100 percent increments is shown under the summary costs, values, etc., in dollars per barrel of crude oil charge. These tables are broken down as follows:

- Tables 132, 133, 134, 136, 138, and 139 present data on existing capacity.

- Tables 135 and 137 present data on retrofitted downstream capacity in the Caribbean and eastern Canada.

- Tables 140 through 143 present data reflecting the processing of incremental Saudi Arabian Light crude oil, for PAD I, PAD III, the Caribbean, and eastern Canada.

Differentials calculated on elements of cost and volume data in Tables 132 through 143 may not be identical to data presented in Tables 129 through 131 due to rounding.

Figure 49 illustrates the relative incremental profitability for the following:

- All areas covered in this study for 70-85 percent and 85-100 percent incremental capacity for each refinery (Tables 132, 133, 134, 135, 138, and 139)

- PADs I and III, the Caribbean, and eastern Canada as a result of retrofitting the latter two areas to meet PAD III product mix (Tables 135 and 137)

- PADs I and III, the Caribbean, and eastern Canada reflecting the processing of incremental Saudi Arabian Light crude oil (Tables 140, 141, 142, and 143).

The following tables present data used for determining the relative competitiveness between U.S. and foreign export refineries:

Table 144. Assumed Refinery Configurations -- 1978

A "typical" refinery was determined for each geographic region under consideration. The configurations of the typical refineries in PADs I and III were based upon the average configuration of

TABLE 132

PAD I Refinery -- Charge, Yield, Variable Costs, and Relative Profitability
(All Cost Figures in U.S. $/Bbl)

		Operating Capacity @			Differential Data	
		70%	85%	100%	70-85%	85-100%
	$/Bbl	Crude Oil Charge (MB/D)				
Saudi Arabian Light	12.70	29.1	35.4	41.7	6.3	6.3
Saudi Arabian Medium	12.32	4.9	6.0	7.1	1.1	1.1
Saudi Arabian Heavy	12.02	7.3	8.8	10.3	1.5	1.5
Saudi Arabian Berri	13.22	3.6	4.4	5.2	0.8	0.8
Iranian Light	12.81	3.2	3.9	4.6	0.7	0.7
Kuwait Export	12.22	10.2	12.4	14.6	2.2	2.2
Venezuelan Tia Juana Medium	12.75	9.0	10.9	12.8	1.9	1.9
Nigerian Forcados	13.71	12.8	15.5	18.2	2.7	2.7
Nigerian Bonny Light	14.03	12.6	15.3	18.0	2.7	2.7
Libyan Es Sider	13.71	11.0	13.3	15.6	2.3	2.3
Total		103.7	125.9	148.1	22.2	22.2
	$/Bbl	Yield (Vol. % of Crude Oil)				
Propane	11.42	3.6	3.4	3.0	2.7	0.7
Naphtha	15.11	1.1	1.3	1.3	2.1	1.2
Gasoline Unleaded (91 RON)	18.08	12.8	19.3	20.0	50.0	23.5
Gasoline Regular (94 RON)	16.91	46.4	38.2	32.5	--	--
Gasoline Premium (99 RON)	18.12	9.5	7.8	6.7	--	--
Kerosine	16.76	13.8	15.3	13.7	22.5	4.5
No. 2 Fuel Oil	16.09	--	--	6.7	--	44.4
No. 6 Fuel Oil (0.3 Wt % Sulfur)	14.53	--	--	--	--	--
No. 6 Fuel Oil (0.5 Wt % Sulfur)	14.17	--	--	--	--	--
No. 6 Fuel Oil (1.0 Wt % Sulfur)	13.53	0.3	0.5	1.3	1.4	5.7
No. 6 Fuel Oil (High-Sulfur)	11.81	8.7	10.5	11.4	18.5	16.4
Refinery Fuel	*	7.5	7.2	6.8	5.6	4.5
By-Products		1.8	1.5	1.3	--	--
Loss (Gain)		(5.5)	(5.0)	(4.7)	(2.8)	(0.9)
Total		100.0	100.0	100.0	100.0	100.0
		Summary Costs, Values, Etc. ($/Bbl of Crude Oil Charge)				
Delivered Product Value		17.10	16.92	16.75	16.56	15.72
Crude Oil Costs						
Crude Oil (FOB)		13.01	13.01	13.01	13.01	13.01
Entitlements Earned		(1.61)	(1.61)	(1.61)	(1.61)	(1.61)
Transportation		1.15	1.15	1.15	1.15	1.15
Fees and Duties		0.11	0.11	0.11	0.11	0.11
Subtotal -- Crude Oil Costs		12.66	12.66	12.66	12.66	12.66
Gross Margin (Product Value less Crude Oil Costs)		4.44	4.26	4.09	4.90	3.06
Other Product Processing Costs						
Transportation		0.44	0.44	0.45	0.46	0.49
Fees and Duties		--	--	--	--	--
Residual Entitlements (Import)		--	--	--	--	--
Residual Entitlements (Reverse Domestic)		0.04	0.05	0.06	0.09	0.10
Refinery Fuel		1.06	0.93	0.88	0.73	0.59
Other Variable		0.26	0.24	0.22	0.16	0.10
Subtotal -- Other Product Processing Costs		1.80	1.66	1.61	1.44	1.28
Relative Profit (Before Income Tax)†		2.64	2.60	2.48	2.46	1.78
Income Tax		1.32	1.30	1.24	1.23	0.89
Relative Profit (After Income Tax)		1.32	1.30	1.24	1.23	0.89

*Valued at average crude oil cost.
†Relative Profit (Before Income Tax) is equal to Gross Margin less Other Product Processing Costs.

TABLE 133

PAD III Refinery -- Charge, Yield, Variable Costs, and Relative Profitability
(All Cost Figures in U.S. $/Bbl)

		Operating Capacity @			Differential Data	
		70%	85%	100%	70-85%	85-100%
	$/Bbl	Crude Oil Charge (MB/D)				
Saudi Arabian Light	12.70	2.3	3.6	4.9	1.3	1.3
Saudi Arabian Medium	12.32	0.4	0.6	0.8	0.2	0.2
Saudi Arabian Heavy	12.02	0.6	0.9	1.2	0.3	0.3
Saudi Arabian Berri	13.22	0.2	0.4	0.6	0.2	0.2
Nigerian Forcados	13.71	8.4	13.0	17.6	4.6	4.6
Nigerian Bonny Light	14.03	8.4	12.9	17.4	4.5	4.5
Libyan Es Sider	13.71	12.1	18.6	25.1	6.5	6.5
West Texas Sour	12.47	21.2	21.2	21.2	--	--
West Texas Semi-Sweet	13.00	7.7	7.7	7.7	--	--
South Louisiana	12.81	17.9	17.9	17.9	--	--
Alaskan North Slope	13.02	2.8	2.8	2.8	--	--
Total		82.0	99.6	117.2	17.6	17.6
	$/Bbl	Yield (Vol. % of Crude Oil)				
Propane	11.42	3.6	3.2	2.8	1.1	0.5
Naphtha	15.11	0.2	0.2	2.3	(0.3)	14.2
Gasoline Unleaded (91 RON)	18.08	19.0	21.4	20.4	32.9	14.5
Gasoline Regular (94 RON)	16.91	44.5	36.6	31.1	--	--
Gasoline Premium (99 RON)	18.12	9.1	7.5	6.4	--	--
Kerosine	16.76	15.9	12.1	10.1	(5.3)	(1.6)
No. 2 Fuel Oil	16.09	2.0	12.3	17.0	60.8	43.2
No. 6 Fuel Oil (0.3 Wt % Sulfur)	14.53	--	--	--	--	--
No. 6 Fuel Oil (0.5 Wt % Sulfur)	14.17	1.1	0.7	2.3	(0.9)	11.3
No. 6 Fuel Oil (1.0 Wt % Sulfur)	13.53	8.0	9.1	10.5	13.9	18.3
No. 6 Fuel Oil (High-Sulfur)	11.81	--	--	--	--	--
Refinery Fuel	*	2.8	2.6	2.4	1.8	1.0
By-Products		(0.6)	(0.9)	(1.0)	(2.5)	(1.2)
Loss (Gain)		(5.6)	(4.8)	(4.3)	(1.5)	(0.2)
Total		100.0	100.0	100.0	100.0	100.0
		Summary Costs, Values, Etc. ($/Bbl of Crude Oil Charge)				
Delivered Product Value		17.52	17.37	17.10	16.63	15.60
Crude Oil Costs						
Crude Oil (FOB)		13.09	13.19	13.26	13.67	13.67
Entitlements Earned		(1.61)	(1.61)	(1.61)	(1.61)	(1.61)
Transportation		0.68	0.73	0.75	0.95	0.95
Fees and Duties		0.04	0.05	0.06	0.11	0.11
Subtotal -- Crude Oil Costs		12.20	12.36	12.46	13.12	13.12
Gross Margin (Product Value less Crude Oil Costs)		5.32	5.01	4.64	3.51	2.48
Other Product Processing Costs						
Transportation		1.17	1.20	1.19	1.29	1.12
Fees and Duties		--	--	--	--	--
Residual Entitlements (Import)		--	--	--	--	--
Residual Entitlements (Reverse Domestic)		0.04	0.04	0.06	0.06	0.13
Refinery Fuel†		0.85	0.79	0.72	0.54	0.33
Other Variable		0.24	0.22	0.19	0.10	0.06
Subtotal -- Other Product Processing Costs		2.30	2.25	2.16	1.99	1.64
Relative Profit (Before Income Tax)§		3.02	2.76	2.48	1.52	0.84
Income Tax		1.51	1.38	1.24	0.76	0.42
Relative Profit (After Income Tax)		1.51	1.38	1.24	0.76	0.42

*Valued at average crude oil cost.

†Refinery fuel required in excess of that produced from processing was assumed purchased at $11.25/bbl of fuel oil equivalent, or $1.80 per thousand cubic feet (1,000 Btu per cubic foot of gas).

§Relative Profit (Before Income Tax) is equal to Gross Margin less Other Product Processing Costs.

TABLE 134

Caribbean Refinery -- Charge, Yield, Variable Costs, and Relative Profitability
(All Cost Figures in U.S. $/Bbl)

	$/Bbl	Operating Capacity @ 70%	85%	100%	Differential Data 70-85%	85-100%
		Crude Oil Charge (MB/D)				
Saudi Arabian Light	12.70	113.7	138.1	162.5	24.4	24.4
Saudi Arabian Medium	12.32	19.3	23.4	27.5	4.1	4.1
Saudi Arabian Heavy	12.02	28.0	34.0	40.0	6.0	6.0
Saudi Arabian Berri	13.22	14.0	17.0	20.0	3.0	3.0
Iranian Light	12.81	12.6	15.3	18.0	2.7	2.7
Kuwait Export	12.22	39.8	48.4	57.0	8.6	8.6
Venezuelan Tia Juana Medium	12.75	35.0	42.5	50.0	7.5	7.5
Nigerian Forcados	13.71	30.8	37.4	44.0	6.6	6.6
Nigerian Bonny Light	14.03	30.5	37.0	43.5	6.5	6.5
Libyan Es Sider	13.71	26.3	31.9	37.5	5.6	5.6
Total		350.0	425.0	500.0	75.0	75.0
	$/Bbl	Yield (Vol. % of Crude Oil)				
Propane	11.42	0.9	0.8	0.8	0.5	0.5
Naphtha	15.11	17.4	18.1	18.5	21.2	20.9
Gasoline Unleaded (91 RON)	18.08	1.9	1.3	1.2	(1.5)	0.4
Gasoline Regular (94 RON)	16.91	0.3	1.1	1.6	4.7	4.3
Caribbean Regular (85 RON)	15.90	8.6	7.1	6.0	--	--
Caribbean Premium (95 RON)	16.45	5.7	4.7	4.0	--	--
Kerosine	16.76	1.7	--	--	(8.1)	
No. 2 Fuel Oil	16.09	31.9	31.2	28.6	28.2	13.9
No. 6 Fuel Oil (0.3 Wt % Sulfur)	14.53	22.5	22.2	18.0	21.1	(5.8)
No. 6 Fuel Oil (0.5 Wt % Sulfur)	14.17	--	--	--	--	--
No. 6 Fuel Oil (1.0 Wt % Sulfur)	13.53	--	2.0	6.6	11.1	33.1
No. 6 Fuel Oil (High-Sulfur)	11.81	5.5	8.1	11.5	20.3	30.6
Refinery Fuel	*	3.8	3.5	3.2	2.0	1.8
By-Products		0.5	0.4	0.4	--	--
Loss (Gain)		(0.7)	(0.5)	(0.4)	0.5	0.3
Total		100.0	100.0	100.0	100.0	100.0
		Summary Costs, Values, Etc. ($/Bbl of Crude Oil Charge)				
Delivered Product Value		15.39	15.18	14.97	14.19	13.75
Crude Oil Costs						
Crude Oil (FOB)		12.88	12.88	12.88	12.88	12.88
Entitlements Earned		--	--	--	--	--
Transportation		0.62	0.62	0.62	0.62	0.62
Fees and Duties		--	--	--	--	--
Subtotal -- Crude Oil Costs		13.50	13.50	13.50	13.50	13.50
Gross Margin (Product Value less Crude Oil Costs)		1.89	1.68	1.47	0.69	0.25
Other Product Processing Costs						
Transportation		0.49	0.50	0.51	0.56	0.55
Fees and Duties		0.09	0.09	0.09	0.06	0.10
Residual Entitlements (Import)		(0.17)	(0.20)	(0.22)	(0.33)	(0.36)
Residual Entitlements (Reverse Domestic)		--	--	--	--	--
Refinery Fuel		0.53	0.48	0.45	0.28	0.24
Other Variable		0.12	0.11	0.10	0.05	0.05
Subtotal -- Other Product Processing Costs		1.06	0.98	0.93	0.62	0.58
Relative Profit (Before Income Tax)†		0.83	0.70	0.54	0.07	(0.33)
Income Tax		0.21	0.18	0.14	0.02	(0.08)
Relative Profit (After Income Tax)		0.62	0.52	0.40	0.05	(0.25)

*Valued at average crude oil cost.
†Relative Profit (Before Income Tax) is equal to Gross Margin less Other Product Processing Costs.

TABLE 135

Caribbean Refinery With Retrofitted Downstream Capacity --
Charge, Yield, Variable Costs, and Relative Profitability
(All Cost Figures in U.S. $/Bbl)

		Operating Capacity @			Differential Data	
		70%	85%	100%	70-85%	85-100%
	$/Bbl	Crude Oil Charge (MB/D)				
Saudi Arabian Light	12.70	113.7	138.1	162.5	24.4	24.4
Saudi Arabian Medium	12.32	19.3	23.4	27.5	4.1	4.1
Saudi Arabian Heavy	12.02	28.0	34.0	40.0	6.0	6.0
Saudi Arabian Berri	13.22	14.0	17.0	20.0	3.0	3.0
Iranian Light	12.81	12.6	15.3	18.0	2.7	2.7
Kuwait Export	12.22	39.8	48.4	57.0	8.6	8.6
Venezuelan Tia Juana Medium	12.75	35.0	42.5	50.0	7.5	7.5
Nigerian Forcados	13.71	30.8	37.4	44.0	6.6	6.6
Nigerian Bonny Light	14.03	30.5	37.0	43.5	6.5	6.5
Libyan Es Sider	13.71	26.3	31.9	37.5	5.6	5.6
Total		350.0	425.0	500.0	75.0	75.0
	$/Bbl	Yield (Vol. % of Crude Oil)				
Propane	11.42	3.1	2.9	2.7	2.3	1.3
Naphtha	15.11	--	--	0.8	--	5.4
Gasoline Unleaded (91 RON)	18.08	35.7	34.1	32.1	26.7	20.5
Gasoline Regular (94 RON)	16.91	12.3	13.8	11.6	21.0	(1.0)
Caribbean Regular (85 RON)	15.90	8.6	7.1	6.0	--	--
Caribbean Premium (95 RON)	16.45	5.7	4.7	4.0	--	--
Kerosine	16.76	13.2	13.9	9.8	17.1	(13.1)
No. 2 Fuel Oil	16.09	9.3	9.7	17.9	11.9	64.1
No. 6 Fuel Oil (0.3 Wt % Sulfur)	14.53	--	--	--	--	--
No. 6 Fuel Oil (0.5 Wt % Sulfur)	14.17	1.8	1.5	1.3	--	--
No. 6 Fuel Oil (1.0 Wt % Sulfur)	13.53	1.7	2.2	2.3	4.3	3.1
No. 6 Fuel Oil (High-Sulfur)	11.81	5.2	6.6	8.1	13.2	16.5
Refinery Fuel	*	6.8	6.6	6.2	5.6	4.3
By-Products		0.5	0.4	0.4	--	--
Loss (Gain)		(3.9)	(3.5)	(3.2)	(2.1)	(1.1)
Total		100.0	100.0	100.0	100.0	100.0
		Summary Costs, Values, Etc. ($/Bbl of Crude Oil Charge)				
Delivered Product Value		17.00	16.88	16.69	16.34	15.60
Crude Oil Costs						
Crude Oil (FOB)		12.88	12.88	12.88	12.88	12.88
Entitlements Earned		--	--	--	--	--
Transportation		0.62	0.62	0.62	0.62	0.62
Fees and Duties		--	--	--	--	--
Subtotal -- Crude Oil Costs		13.50	13.50	13.50	13.50	13.50
Gross Margin (Product Value less Crude Oil Costs)		3.50	3.38	3.19	2.84	2.10
Other Product Processing Costs						
Transportation		0.46	0.49	0.50	0.56	0.60
Fees and Duties		0.34	0.33	0.31	0.36	0.12
Residual Entitlements (Import)		(0.05)	(0.06)	(0.07)	(0.11)	(0.12)
Residual Entitlements (Reverse Domestic)		--	--	--	--	--
Refinery Fuel		0.94	0.91	0.86	0.77	0.60
Other Variable		0.18	0.18	0.16	0.18	0.04
Subtotal -- Other Product Processing Costs		1.87	1.85	1.76	1.76	1.24
Relative Profit (Before Income Tax)†		1.63	1.53	1.43	1.08	0.86
Income Tax		0.41	0.38	0.36	0.27	0.22
Relative Profit (After Income Tax)		1.22	1.15	1.07	0.81	0.64

*Valued at average crude oil cost.
†Relative Profit (Before Income Tax) is equal to Gross Margin less Other Product Processing Costs.

TABLE 136

Eastern Canada Refinery -- Charge, Yield, Variable Costs, and Relative Profitability
(All Cost Figures in U.S. $/Bbl)

		Operating Capacity @			Differential Data	
		70%	85%	100%	70-85%	85-100%
	$/Bbl	Crude Oil Charge (MB/D)				
Saudi Arabian Light	12.70	29.6	35.9	42.2	6.3	6.3
Saudi Arabian Medium	12.32	5.0	6.1	7.2	1.1	1.1
Saudi Arabian Heavy	12.02	7.2	8.8	10.4	1.6	1.6
Saudi Arabian Berri	13.22	3.6	4.4	5.2	0.8	0.8
Iranian Light	12.81	3.3	4.0	4.7	0.7	0.7
Kuwait Export	12.22	10.4	12.6	14.8	2.2	2.2
Canadian	13.11	9.2	11.1	13.0	1.9	1.9
Nigerian Forcados	13.71	8.0	9.7	11.4	1.7	1.7
Nigerian Bonny Light	14.03	7.9	9.6	11.3	1.7	1.7
Libyan Es Sider	13.71	6.8	8.3	9.8	1.5	1.5
Total		91.0	110.5	130.0	19.5	19.5
	$/Bbl	Yield (Vol. % of Crude Oil)				
Propane	11.42	1.8	1.6	1.5	0.9	0.5
Naphtha	15.11	7.8	10.5	12.5	23.4	23.4
Gasoline Unleaded (91 RON)	18.08	5.6	5.0	4.5	1.8	1.8
Gasoline Regular (94 RON)	16.91	27.2	24.0	20.3	8.9	(0.8)
Canadian Regular (94 RON)	16.57	8.1	6.7	5.7	--	--
Canadian Premium (100 RON)	17.86	1.4	1.2	1.0	--	--
Kerosine	16.76	14.2	14.7	12.7	17.3	1.4
No. 2 Fuel Oil	16.09	1.3	2.1	6.5	5.7	31.5
No. 6 Fuel Oil (0.3 Wt % Sulfur)	14.53	--	--	--	--	--
No. 6 Fuel Oil (0.5 Wt % Sulfur)	14.17	8.1	8.1	8.1	8.1	8.0
No. 6 Fuel Oil (1.0 Wt % Sulfur)	13.53	--	--	--	--	--
No. 6 Fuel Oil (High-Sulfur)	11.81	22.2	24.0	25.1	32.1	31.9
Refinery Fuel	*	5.5	4.9	4.5	2.3	1.8
By-Products		--	--	--	--	--
Loss (Gain)		(3.2)	(2.8)	(2.4)	(0.5)	0.5
Total		100.0	100.0	100.0	100.0	100.0
		Summary Costs, Values, Etc. ($/Bbl of Crude Oil Charge)				
Delivered Product Value		15.74	15.52	15.33	14.55	14.25
Crude Oil Costs						
Crude Oil (FOB)		12.92	12.92	12.92	12.92	12.92
Entitlements Earned		--	--	--	--	--
Transportation		0.60	0.60	0.60	0.60	0.60
Fees and Duties		--	--	--	--	--
Subtotal -- Crude Oil Costs		13.52	13.52	13.52	13.52	13.52
Gross Margin (Product Value less Crude Oil Costs)		2.22	2.00	1.81	1.03	0.73
Other Product Processing Costs						
Transportation		0.28	0.30	0.30	0.37	0.38
Fees and Duties		0.28	0.26	0.24	0.21	0.10
Residual Entitlements (Import)		(0.19)	(0.20)	(0.21)	(0.25)	(0.25)
Residual Entitlements (Reverse Domestic)		--	--	--	--	--
Refinery Fuel		0.76	0.68	0.62	0.32	0.25
Other Variable		0.27	0.24	0.21	0.12	0.03
Subtotal -- Other Product Processing Costs		1.40	1.28	1.16	0.77	0.51
Relative Profit (Before Income Tax)†		0.82	0.72	0.65	0.26	0.22
Income Tax		0.39	0.35	0.31	0.12	0.11
Relative Profit (After Income Tax)		0.43	0.37	0.34	0.14	0.11

*Valued at average crude oil cost.
†Relative Profit (Before Income Tax) is equal to Gross Margin less Other Product Processing Costs.

TABLE 137

Eastern Canada Refinery With Retrofitted Downstream Capacity --
Charge, Yield, Variable Costs, and Relative Profitability
(All Cost Figures in U.S. $/Bbl)

		Operating Capacity @			Differential Data	
		70%	85%	100%	70-85%	85-100%
	$/Bbl	Crude Oil Charge (MB/D)				
Saudi Arabian Light	12.70	29.6	35.9	42.2	6.3	6.3
Saudi Arabian Medium	12.32	5.0	6.1	7.2	1.1	1.1
Saudi Arabian Heavy	12.02	7.2	8.8	10.4	1.6	1.6
Saudi Arabian Berri	13.22	3.6	4.4	5.2	0.8	0.8
Iranian Light	12.81	3.3	4.0	4.7	0.7	0.7
Kuwait Export	12.22	10.4	12.6	14.8	2.2	2.2
Canadian	13.11	9.2	11.1	13.0	1.9	1.9
Nigerian Forcados	13.71	8.0	9.7	11.4	1.7	1.7
Nigerian Bonny Light	14.03	7.9	9.6	11.3	1.7	1.7
Libyan Es Sider	13.71	6.8	8.3	9.8	1.5	1.5
Total		91.0	110.5	130.0	19.5	19.5
	$/Bbl	Yield (Vol. % of Crude Oil)				
Propane	11.42	3.9	3.4	3.1	1.3	1.5
Naphtha	15.11	1.6	2.2	4.6	4.8	18.6
Gasoline Unleaded (91 RON)	18.08	45.4	41.2	36.9	21.5	12.9
Gasoline Regular (94 RON)	16.91	20.9	18.1	17.0	5.0	10.6
Canadian Regular (94 RON)	16.57	8.1	6.7	5.7	--	--
Canadian Premium (100 RON)	17.86	1.4	1.2	1.0	--	--
Kerosine	16.76	4.1	10.6	14.0	41.3	32.8
No. 2 Fuel Oil	16.09	--	--	--	--	--
No. 6 Fuel Oil (0.3 Wt % Sulfur)	14.53	--	0.2	--	1.4	(1.4)
No. 6 Fuel Oil (0.5 Wt % Sulfur)	14.17	1.6	0.9	1.1	(2.1)	2.1
No. 6 Fuel Oil (1.0 Wt % Sulfur)	13.53	0.1	1.0	1.1	5.3	1.3
No. 6 Fuel Oil (High-Sulfur)	11.81	11.0	12.3	13.3	18.2	19.3
Refinery Fuel	*	8.5	7.8	7.3	4.8	4.1
By-Products		--	--	--	--	--
Loss (Gain)		(6.6)	(5.6)	(5.1)	(1.5)	(1.8)
Total		100.0	100.0	100.0	100.0	100.0
		Summary Costs, Values, Etc. ($/Bbl of Crude Oil Charge)				
Delivered Product Value		17.44	17.18	16.97	15.98	15.75
Crude Oil Costs						
Crude Oil (FOB)		12.92	12.92	12.92	12.92	12.92
Entitlements Earned		--	--	--	--	--
Transportation		0.60	0.60	0.60	0.60	0.60
Fees and Duties		--	--	--	--	--
Subtotal -- Crude Oil Costs		13.52	13.52	13.52	13.52	13.52
Gross Margin (Product Value less Crude Oil Costs)		3.92	3.66	3.45	2.46	2.23
Other Product Processing Costs						
Transportation		0.25	0.26	0.27	0.29	0.35
Fees and Duties		0.38	0.38	0.38	0.38	0.33
Residual Entitlements (Import)		(0.08)	(0.09)	(0.10)	(0.14)	(0.13)
Residual Entitlements (Reverse Domestic)		--	--	--	--	--
Refinery Fuel		1.17	1.08	1.01	0.67	0.57
Other Variable		0.30	0.26	0.23	0.08	0.08
Subtotal -- Other Product Processing Costs		2.02	1.89	1.79	1.28	1.20
Relative Profit (Before Income Tax)†		1.90	1.77	1.66	1.18	1.03
Income Tax		0.91	0.85	0.80	0.57	0.49
Relative Profit (After Income Tax)		0.99	0.92	0.86	0.61	0.54

*Valued at average crude oil cost.
†Relative Profit (Before Income Tax) is equal to Gross Margin less Other Product Processing Costs.

TABLE 138

Netherlands Refinery -- Charge, Yield, Variable Costs, and Relative Profitability
(All Cost Figures in U.S. $/Bbl)

		Operating Capacity @			Differential Data	
		70%	85%	100%	70-85%	85-100%
	$/Bbl	Crude Oil Charge (MB/D)				
Saudi Arabian Light	12.70	54.6	66.3	78.0	11.7	11.7
Saudi Arabian Medium	12.32	9.2	11.2	13.2	2.0	2.0
Saudi Arabian Heavy	12.02	13.4	16.3	19.2	2.9	2.9
Saudi Arabian Berri	13.22	6.8	8.2	9.6	1.4	1.4
Iranian Heavy	12.41	7.5	9.0	10.5	1.5	1.5
Abu Dhabi Murban	13.26	87.1	105.8	124.5	18.7	18.7
Nigerian Forcados	13.71	11.0	13.4	15.8	2.4	2.4
Nigerian Bonny Light	14.03	10.9	13.3	15.7	2.4	2.4
Libyan Es Sider	13.71	9.5	11.5	13.5	2.0	2.0
Total		210.0	255.0	300.0	45.0	45.0
	$/Bbl	Yield (Vol. % of Crude Oil)				
Propane	11.42	1.4	1.2	1.0	0.2	0.4
Naphtha	15.11	11.8	14.9	17.1	29.7	29.3
Gasoline Unleaded (91 RON)	18.08	5.0	4.1	3.3	--	(1.1)
Gasoline Regular (94 RON)	--	--	--	--	--	--
European Regular (92 RON)	16.39	6.1	5.1	4.3	--	--
European Premium (99 RON)	16.96	12.9	10.6	9.0	--	--
Kerosine	16.76	1.1	1.8	2.8	4.7	8.5
No. 2 Fuel Oil	16.09	33.6	30.4	27.3	15.5	9.4
No. 6 Fuel Oil (0.3 Wt % Sulfur)	14.53	0.4	4.5	7.7	23.9	25.5
No. 6 Fuel Oil (0.5 Wt % Sulfur)	14.17	4.9	2.8	1.3	(6.7)	(7.4)
No. 6 Fuel Oil (1.0 Wt % Sulfur)	13.53	--	--	--	--	--
No. 6 Fuel Oil (High-Sulfur)	11.81	19.6	21.5	23.2	30.5	32.7
Refinery Fuel	*	3.9	3.5	3.2	1.6	1.7
By-Products		--	--	--	--	--
Loss (Gain)		(0.7)	(0.4)	(0.2)	0.6	1.0
Total		100.0	100.0	100.0	10.0	100.0
		Summary Costs, Values, Etc. ($/Bbl of Crude Oil Charge)				
Delivered Product Value		15.26	15.07	14.90	14.16	13.96
Crude Oil Costs						
Crude Oil (FOB)		13.05	13.05	13.05	13.05	13.05
Entitlements Earned		--	--	--	--	--
Transportation		0.76	0.76	0.76	0.76	0.76
Fees and Duties		--	--	--	--	--
Subtotal -- Crude Oil Costs		13.81	13.81	13.81	13.81	13.81
Gross Margin (Product Value less Crude Oil Costs)		1.45	1.26	1.09	0.35	0.15
Other Product Processing Costs						
Transportation		0.90	0.95	0.98	1.16	1.14
Fees and Duties		0.10	0.10	0.10	0.10	0.11
Residual Entitlements (Import)		(0.15)	(0.18)	(0.20)	(0.30)	(0.32)
Residual Entitlements (Reverse		--	--	--	--	--
Domestic)		0.55	0.50	0.46	0.23	0.23
Refinery Fuel		0.11	0.10	0.08	0.02	0.02
Other Variable						
Subtotal -- Other Product Processing Costs		1.51	1.47	1.42	1.21	1.18
Relative Profit (Before Income Tax)†		(0.06)	(0.21)	(0.33)	(0.86)	(1.03)
Income Tax		(0.03)	(0.10)	(0.16)	(0.41)	(0.49)
Relative Profit (After Income Tax)		(0.03)	(0.11)	(0.17)	(0.45)	(0.54)

*Valued at average crude oil cost.
†Relative Profit (Before Income Tax) is equal to Gross Margin less Other Product Processing Costs.

TABLE 139

Italy Refinery -- Charge, Yield, Variable Costs, and Relative Profitability
(All Cost Figures in U.S. $/Bbl)

	$/Bbl	Operating Capacity @ 70%	85%	100%	Differential Data 70-85%	85-100%
		Crude Oil Charge (MB/D)				
Saudi Arabian Light	12.70	63.8	77.4	91.0	13.6	13.6
Saudi Arabian Medium	12.32	10.8	13.1	15.4	2.3	2.3
Saudi Arabian Heavy	12.02	15.6	19.0	22.4	3.4	3.4
Saudi Arabian Berri	13.22	7.8	9.5	11.2	1.7	1.7
Iranian Heavy	12.41	8.7	10.5	12.3	1.8	1.8
Abu Dhabi Murban	13.26	101.6	123.4	145.2	21.8	21.8
Nigerian Forcados	13.71	12.9	15.7	18.5	2.8	2.8
Nigerian Bonny Light	14.03	12.8	15.5	18.2	2.7	2.7
Libyan Es Sider	13.71	11.0	13.4	15.8	2.4	2.4
Total		245.0	297.5	350.0	52.5	52.5
	$/Bbl	Yield (Vol. % of Crude Oil)				
Propane	11.42	0.9	0.8	0.7	0.2	0.2
Naphtha	15.11	20.1	21.5	22.5	28.1	28.3
Gasoline Unleaded (91 RON)	18.08	--	0.2	--	1.1	(1.1)
Gasoline Regular (94 RON)	16.91	0.9	0.9	1.3	1.0	3.1
European Regular (92 RON)	16.39	5.5	4.5	3.8	--	--
European Premium (99 RON)	16.96	11.4	9.4	8.0	--	--
Kerosine	16.76	0.8	1.2	2.6	2.9	10.4
No. 2 Fuel Oil	16.09	34.1	32.3	28.6	24.1	7.4
No. 6 Fuel Oil (0.3 Wt % Sulfur)	14.53	--	--	--	--	--
No. 6 Fuel Oil (0.5 Wt % Sulfur)	14.17	2.1	--	--	(9.6)	--
No. 6 Fuel Oil (1.0 Wt % Sulfur)	13.53	4.5	8.3	9.9	26.3	18.9
No. 6 Fuel Oil (High-Sulfur)	11.81	17.0	18.2	20.2	23.8	31.2
Refinery Fuel	*	3.3	3.1	2.9	1.9	1.7
By-Products		--	--	--	--	--
Loss (Gain)		(0.6)	(0.4)	(0.5)	0.2	(0.1)
Total		100.0	100.0	100.0	100.0	100.0
		Summary Costs, Values, Etc. ($/Bbl of Crude Oil Charge)				
Delivered Product Value		15.14	14.99	14.84	14.29	14.02
Crude Oil Costs						
Crude Oil (FOB)		13.05	13.05	13.05	13.05	13.05
Entitlements Earned		--	--	--	--	--
Transportation		0.71	0.71	0.71	0.71	0.71
Fees and Duties		--	--	--	--	--
Subtotal -- Crude Oil Costs		13.76	13.76	13.76	13.76	13.76
Gross Margin (Product Value less Crude Oil Costs)		1.38	1.23	1.08	0.53	0.26
Other Product Processing Costs						
Transportation		1.07	1.11	1.13	1.28	1.25
Fees and Duties		0.08	0.09	0.09	0.11	0.13
Residual Entitlements (Import)		(0.15)	(0.16)	(0.19)	(0.25)	(0.31)
Residual Entitlements (Reverse Domestic)		--	--	--	--	--
Refinery Fuel		0.47	0.43	0.41	0.27	0.24
Other Variable		0.11	0.09	0.08	0.03	0.02
Subtotal -- Other Product Processing Costs		1.58	1.56	1.52	1.44	1.33
Relative Profit (Before Income Tax)†		(0.20)	(0.33)	(0.44)	(0.91)	(1.07)
Income Tax		(0.08)	(0.13)	(0.18)	(0.36)	(0.43)
Relative Profit (After Income Tax)		(0.12)	(0.20)	(0.26)	(0.55)	(0.64)

*Valued at average crude oil cost.
†Relative Profit (Before Income Tax) is equal to Gross Margin less Other Product Processing Costs.

TABLE 140

PAD I Refinery -- Charge, Yield, Variable Costs, and Relative Profitability
Incremental Crude Oil -- Saudi Arabian Light
(All Cost Figures in U.S. $/Bbl)

		Operating Capacity @			Differential Data	
		70%	85%	100%	70-85%	85-100%
	$/Bbl	Crude Oil Charge (MB/D)				
Saudi Arabian Light	12.70	29.1	51.3	73.5	22.2	22.2
Saudi Arabian Medium	12.32	4.9	4.9	4.9	--	--
Saudi Arabian Heavy	12.02	7.3	7.3	7.3	--	--
Saudi Arabian Berri	13.22	3.6	3.6	3.6	--	--
Iranian Light	12.81	3.2	3.2	3.2	--	--
Kuwait Export	12.22	10.2	10.2	10.2	--	--
Venezuelan Tia Juana Medium	12.75	9.0	9.0	9.0	--	--
Nigerian Forcados	13.71	12.8	12.8	12.8	--	--
Nigerian Bonny Light	14.03	12.6	12.6	12.6	--	--
Libyan Es Sider	13.71	11.0	11.0	11.0	--	--
Total		103.7	125.9	148.1	22.2	22.2
	$/Bbl	Yield (Vol. % of Crude Oil)				
Propane	11.42	3.6	3.5	3.1	2.9	0.8
Naphtha	15.11	1.1	1.7	1.9	4.3	3.3
Gasoline Unleaded (91 RON)	18.08	12.8	18.9	19.2	47.4	20.9
Gasoline Regular (94 RON)	16.91	46.4	38.2	32.5	--	--
Gasoline Premium (99 RON)	18.12	9.5	7.8	6.7	--	--
Kerosine	16.76	13.8	15.3	14.3	22.2	8.9
No. 2 Fuel Oil	16.09	--	--	6.1	--	40.7
No. 6 Fuel Oil (0.3 Wt % Sulfur)	14.53	--	--	--	--	--
No. 6 Fuel Oil (0.5 Wt % Sulfur)	14.17	--	--	--	--	--
No. 6 Fuel Oil (1.0 Wt % Sulfur)	13.53	0.3	--	0.1	(1.4)	0.7
No. 6 Fuel Oil (High-Sulfur)	11.81	8.7	10.9	12.3	21.0	20.3
Refinery Fuel	*	7.5	7.2	6.8	5.8	4.7
By-Products		1.8	1.5	1.3	(0.1)	--
Loss (Gain)		(5.5)	(5.0)	(4.3)	(2.1)	(0.3)
Total		100.0	100.0	100.0	100.0	100.0
		Summary Costs, Values, Etc. ($/Bbl of Crude Oil Charge)				
Delivered Product Value		17.10	16.89	16.69	16.36	15.54
Crude Oil Costs						
Crude Oil (FOB)		13.01	12.95	12.91	12.70	12.70
Entitlements Earned		(1.61)	(1.61)	(1.61)	(1.61)	(1.61)
Transportation		1.15	1.21	1.25	1.46	1.46
Fees and Duties		0.11	0.11	0.11	0.11	0.11
Subtotal -- Crude Oil Costs		12.66	12.66	12.66	12.66	12.66
Gross Margin (Product Value less Crude Oil Costs)		4.44	4.23	4.03	3.70	2.88
Other Product Processing Costs						
Transportation		0.44	0.44	0.45	0.47	0.50
Fees and Duties		--	--	--	--	--
Residual Entitlements (Import)		--	--	--	--	--
Residual Entitlements (Reverse Domestic)		0.04	0.05	0.06	0.09	0.09
Refinery Fuel		1.06	0.94	0.90	0.76	0.61
Other Variable		0.26	0.24	0.22	0.16	0.10
Subtotal -- Other Product Processing Costs		1.80	1.67	1.63	1.48	1.30
Relative Profit (Before Income Tax)†		2.64	2.56	2.40	2.22	1.58
Income Tax		1.32	1.28	1.20	1.11	0.79
Relative Profit (After Income Tax)		1.32	1.28	1.20	1.11	0.79

*Valued at average crude oil cost.
†Relative Profit (Before Income Tax) is equal to Gross Margin less Other Product Processing Costs.

TABLE 141

PAD III Refinery -- Charge, Yield, Variable Cost, and Relative Profitability
Incremental Crude Oil -- Saudi Arabian Light
(All Cost Figures in U.S. $/Bbl)

	$/Bbl	Operating Capacity @ 70%	85%	100%	Differential Data 70-85%	85-100%
		Crude Oil Charge (MB/D)				
Saudi Arabian Light	12.70	2.3	19.9	37.5	17.6	17.6
Saudi Arabian Medium	12.32	0.4	0.4	0.4	--	--
Saudi Arabian Heavy	12.02	0.6	0.6	0.6	--	--
Saudi Arabian Berri	13.22	0.2	0.2	0.2	--	--
Nigerian Forcados	13.71	8.4	8.4	8.4	--	--
Nigerian Bonny Light	14.03	8.4	8.4	8.4	--	--
Libyan Es Sider	13.71	12.1	12.1	12.1	--	--
West Texas Sour	12.47	21.2	21.2	21.2	--	--
West Texas Semi-Sweet	13.00	7.7	7.7	7.7	--	--
South Louisiana	12.81	17.9	17.9	17.9	--	--
Alaskan North Slope	13.02	2.8	2.8	2.8	--	--
Total		82.0	99.6	117.2	17.6	17.6
	$/Bbl	Yield (Vol. % of Crude Oil)				
Propane	11.42	3.6	3.3	2.9	1.4	0.9
Naphtha	15.11	0.2	0.9	3.2	3.9	16.4
Gasoline Unleaded (91 RON)	18.08	19.0	19.7	17.9	23.3	7.6
Gasoline Regular (94 RON)	16.91	44.5	36.6	31.1	--	--
Gasoline Premium (99 RON)	18.12	9.1	7.5	6.4	--	--
Kerosine	16.76	15.9	12.0	10.9	(6.0)	4.5
No. 2 Fuel Oil	16.09	2.0	11.4	13.6	55.3	26.2
No. 6 Fuel Oil (0.3 Wt % Sulfur)	14.53	--	--	--	--	--
No. 6 Fuel Oil (0.5 Wt % Sulfur)	14.17	1.1	0.7	0.6	(1.0)	(0.3)
No. 6 Fuel Oil (1.0 Wt % Sulfur)	13.53	8.0	9.3	10.9	14.9	20.4
No. 6 Fuel Oil (High-Sulfur)	11.81	--	1.3	4.5	7.4	22.4
Refinery Fuel	*	2.8	2.5	2.2	1.0	0.6
By-Products		(0.6)	(0.5)	(0.3)	--	0.4
Loss (Gain)		(5.6)	(4.7)	(3.9)	(0.2)	0.9
Total		100.0	100.0	100.0	100.0	100.0
		Summary Costs, Values, Etc. ($/Bbl of Crude Oil Charge)				
Delivered Product Value		17.52	17.21	16.79	15.65	13.91
Crude Oil Costs						
Crude Oil (FOB)		13.09	13.02	12.97	12.70	12.70
Entitlements Earned		(1.61)	(1.61)	(1.61)	(1.61)	(1.61)
Transportation		0.68	0.82	0.92	1.45	1.45
Fees and Duties		0.04	0.05	0.06	0.11	0.11
Subtotal -- Crude Oil Costs		12.20	12.28	12.34	12.65	12.65
Gross Margin (Product Value less Crude Oil Costs)		5.32	4.93	4.45	3.00	1.26
Other Product Processing Costs						
Transportation		1.17	1.18	1.16	1.22	0.60
Fees and Duties		--	--	--	--	--
Residual Entitlements (Import)		--	--	--	--	--
Residual Entitlements (Reverse Domestic)		0.04	0.05	0.07	0.10	0.20
Refinery Fuel†		0.85	0.80	0.73	0.55	0.33
Other Variable		0.24	0.22	0.19	0.11	0.05
Subtotal -- Other Product Processing Costs		2.30	2.25	2.15	1.98	1.18
Relative Profit (Before Income Tax)§		3.02	2.68	2.30	1.02	0.08
Income Tax		1.51	1.34	1.15	0.51	0.04
Relative Profit (After Income Tax)		1.51	1.34	1.15	0.51	0.04

*Valued at average crude oil cost.

†Refinery fuel required in excess of that produced from processing was assumed purchased at $11.25 per barrel of fuel oil equivalent, or $1.80 per thousand cubic feet (1,000 Btu per cubic foot of gas).

§Relative Profit (Before Income Tax) is equal to Gross Margin less Other Product Processing Costs.

TABLE 142

Caribbean Refinery -- Charge, Yield, Variable Cost, and Relative Profitability
Incremental Crude Oil -- Saudi Arabian Light
(All Cost Figures in U.S. $/Bbl)

	$/Bbl	Operating Capacity @ 70%	85%	100%	Differential Data 70-85%	85-100%
		Crude Oil Charge (MB/D)				
Saudi Arabian Light	12.70	113.7	188.7	263.7	75.0	75.0
Saudi Arabian Medium	12.32	19.3	19.3	19.3	--	--
Saudi Arabian Heavy	12.02	28.0	28.0	28.0	--	--
Saudi Arabian Berri	13.22	14.0	14.0	14.0	--	--
Iranian Light	12.81	12.6	12.6	12.6	--	--
Kuwait Export	12.22	39.8	39.8	39.8	--	--
Canadian	13.11	--	--	--	--	--
Venezuelan Tia Juana Medium	12.75	35.0	35.0	35.0	--	--
Nigerian Forcados	13.71	30.8	30.8	30.8	--	--
Nigerian Bonny Light	14.03	30.5	30.5	30.5	--	--
Libyan Es Sider	13.71	26.3	26.3	26.3	--	--
Total		350.0	425.0	500.0	75.0	75.0
	$/Bbl	Yield (Vol. % of Crude Oil)				
Propane	11.42	0.9	0.8	0.7	0.2	0.2
Naphtha	15.11	17.4	18.5	19.6	23.6	25.8
Gasoline Unleaded (91 RON)	18.08	1.9	1.3	1.1	(1.7)	0.3
Gasoline Regular (94 RON)	16.91	0.3	0.9	0.8	3.7	--
Caribbean Regular (85 RON)	15.90	8.6	7.1	6.0	--	--
Caribbean Premium (95 RON)	16.45	5.7	4.7	4.0	--	--
Kerosine	16.76	1.7	--	--	(8.1)	--
No. 2 Fuel Oil	16.09	31.9	29.3	25.3	17.3	2.7
No. 6 Fuel Oil (0.3 Wt % Sulfur)	14.53	22.5	19.2	12.8	4.0	(23.8)
No. 6 Fuel Oil (0.5 Wt % Sulfur)	14.17	--	--	--	--	--
No. 6 Fuel Oil (1.0 Wt % Sulfur)	13.53	--	6.1	13.5	34.8	54.9
No. 6 Fuel Oil (High-Sulfur)	11.81	5.5	8.8	13.1	23.8	38.0
Refinery Fuel	*	3.8	3.5	3.2	1.9	1.6
By-Products		0.5	0.4	0.4	--	--
Loss (Gain)		(0.7)	(0.6)	(0.5)	0.5	0.3
Total		100.0	100.0	100.0	100.0	100.0
		Summary Costs, Values, Etc. ($/Bbl of Crude Oil Charge)				
Delivered Product Value		15.39	15.10	14.80	13.71	13.09
Crude Oil Costs						
Crude Oil (FOB)		12.88	12.85	12.82	12.70	12.70
Entitlements Earned		--	--	--	--	--
Transportation		0.62	0.64	0.65	0.73	0.73
Fees and Duties		--	--	--	--	--
Subtotal -- Crude Oil Costs		13.50	13.49	13.47	13.43	13.43
Gross Margin (Product Value less Crude Oil Costs)		1.89	1.61	1.33	0.28	(0.34)
Other Product Processing Costs						
Transportation		0.49	0.50	0.51	0.55	0.54
Fees and Duties		0.09	0.09	0.08	0.05	0.07
Residual Entitlements (Import)		(0.17)	(0.21)	(0.24)	(0.39)	(0.43)
Residual Entitlements (Reverse Domestic)		--	--	--	--	--
Refinery Fuel		0.53	0.48	0.44	0.27	0.22
Other Variable		0.12	0.12	0.11	0.11	0.02
Subtotal -- Other Product Processing Costs		1.06	0.98	0.90	0.59	0.42
Relative Profit (Before Income Tax)†		0.83	0.63	0.43	(0.31)	(0.76)
Income Tax		0.21	0.16	0.11	(0.08)	(0.19)
Relative Profit (After Income Tax)		0.62	0.47	0.32	(0.23)	(0.57)

*Valued at average crude oil cost.
†Relative Profit (Before Income Tax) is equal to Gross Margin less Other Product Processing Costs.

TABLE 143

Eastern Canada Refinery -- Charge, Yield, Variable Cost, and Relative Profitability -- Incremental Crude Oil -- Saudi Arabian Light
(All Cost Figures in U.S. $/Bbl)

		Operating Capacity @			Differential Data	
		70%	85%	100%	70-85%	85-100%
	$/Bbl	Crude Oil Charge (MB/D)				
Saudi Arabian Light	12.70	29.6	49.1	68.6	19.5	19.5
Saudi Arabian Medium	12.32	5.0	5.0	5.0	--	--
Saudi Arabian Heavy	12.02	7.2	7.2	7.2	--	--
Saudi Arabian Berri	13.22	3.6	3.6	3.6	--	--
Iranian Light	12.81	3.3	3.3	3.3	--	--
Kuwait Export	12.22	10.4	10.4	10.4	--	--
Canadian	13.11	9.2	9.2	9.2	--	--
Venezuelan Tia Juana Medium	12.75	--	--	--	--	--
Nigerian Forcados	13.71	8.0	8.0	8.0	--	--
Nigerian Bonny Light	14.03	7.9	7.9	7.9	--	--
Libyan Es Sider	13.71	6.8	6.8	6.8	--	--
Total		91.0	110.5	130.0	19.5	19.5
	$/Bbl	Yield (Vol. % of Crude Oil)				
Propane	11.42	1.8	1.6	1.4	0.8	0.3
Naphtha	15.11	7.8	10.8	13.6	24.9	29.6
Gasoline Unleaded (91 RON)	18.08	5.6	4.5	3.8	(0.6)	(0.4)
Gasoline Regular (94 RON)	16.91	27.2	24.2	19.5	10.0	(7.3)
Canadian Regular (94 RON)	16.57	8.1	6.7	5.7	--	--
Canadian Premium (100 RON)	17.86	1.4	1.2	1.0	--	--
Kerosine	16.76	14.2	14.8	12.4	17.7	(1.3)
No. 2 Fuel Oil	16.09	1.3	2.5	8.4	8.2	41.5
No. 6 Fuel Oil (0.3 Wt % Sulfur)	14.53	--	--	--	--	--
No. 6 Fuel Oil (0.5 Wt % Sulfur)	14.17	8.1	6.6	5.6	(0.2)	(0.4)
No. 6 Fuel Oil (1.0 Wt % Sulfur)	13.53	--	--	--	--	--
No. 6 Fuel Oil (High-Sulfur)	11.81	22.2	24.8	26.4	36.9	35.2
Refinery Fuel	*	5.5	4.9	4.4	2.3	1.7
By-Products		--	--	--	--	--
Loss (Gain)		(3.2)	(2.6)	(2.2)	--	1.1
Total		100.0	100.0	100.0	100.0	100.0
		Summary Costs, Values, Etc. ($/Bbl of Crude Oil Charge)				
Delivered Product Value		15.74	15.49	15.27	14.39	14.03
Crude Oil Costs						
Crude Oil (FOB)		12.92	12.88	12.85	12.70	12.70
Entitlements Earned		--	--	--	--	--
Transportation		0.60	0.62	0.63	0.69	0.69
Fees and Duties		--	--	--	--	--
Subtotal -- Crude Oil Costs		13.52	13.50	13.48	13.39	13.39
Gross Margin (Product Value less Crude Oil Costs)		2.22	1.99	1.79	1.00	0.64
Other Product Processing Costs						
Transportation		0.28	0.30	0.32	0.38	0.41
Fees and Duties		0.28	0.26	0.23	0.20	0.05
Residual Entitlements (Import)		(0.19)	(0.20)	(0.20)	(0.22)	(0.22)
Residual Entitlements (Reverse Domestic)		--	--	--	--	--
Refinery Fuel		0.76	0.68	0.61	0.32	0.24
Other Variable		0.27	0.24	0.20	0.12	(0.02)
Subtotal -- Other Product Processing Costs		1.40	1.28	1.16	0.80	0.46
Relative Profit (Before Income Tax)†		0.82	0.71	0.63	0.20	0.18
Income Tax		0.39	0.34	0.30	0.10	0.09
Relative Profit (After Income Tax)		0.43	0.37	0.33	0.10	0.09

*Valued at average crude oil cost.
†Relative Profit (Before Income Tax) is equal to Gross Margin less Other Product Processing Costs.

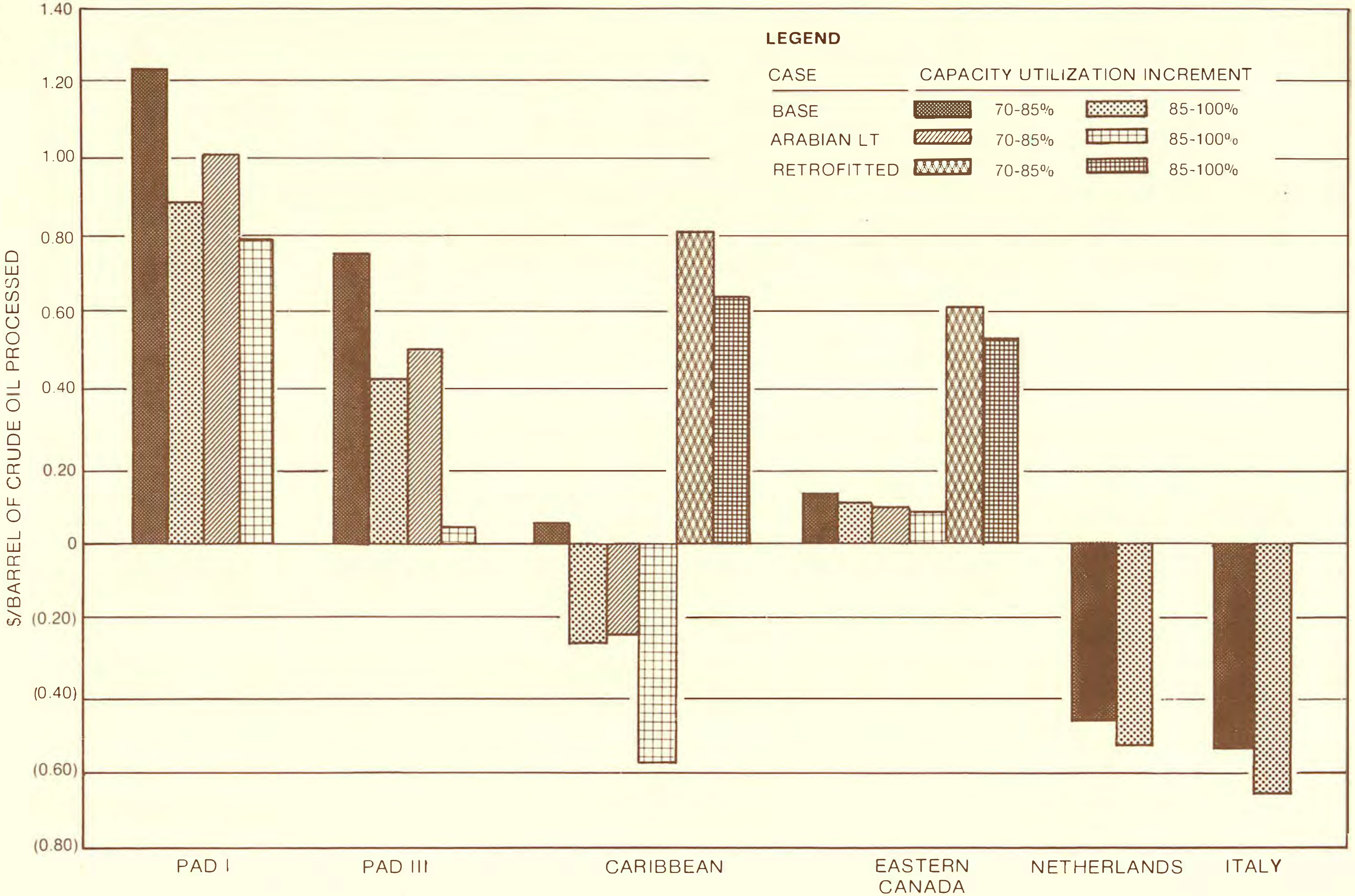

Figure 49. After Tax Gain/Loss from Incremental Barrel of Crude Oil Processed.

TABLE 144

Assumed Refinery Configurations -- 1978

	PAD I	PAD III	Caribbean	E. Canada	Netherlands	Italy
Crude Oil Quality -- Percentage at 100% Capacity*						
Sweet	35	73	25	25	15	15
Sour	65	27	75	75	85	85

	PAD I MB/D	PAD I %	PAD III MB/D	PAD III %	Caribbean MB/D	Caribbean %	E. Canada MB/D	E. Canada %	Netherlands MB/D	Netherlands %	Italy MB/D	Italy %
Processing Units†												
Atmospheric Distillation	161	100	126	100	500	100	130	100	300	100	350	100
Vacuum Distillation	81	50	38	30	150	30	40	31	21	7	68	19
Catalytic Cracking	55	34	39	31	26	5	11	8	17	4	28	8
Thermal Cracking	--	--	3	2	50	10	5	4	30	10	3	1
Reforming	42	26	27	21	16	3	21	16	33	11	19	5
Hydrotreating	100	62	48	38	25	5	38	29	64	21	24	7
Hydrodesulfurization	17	11	6	5	110	22	--	--	32	11	35	10
Alkylation (Capacity as Product)	6	4	7	6	8	2	--	--	2	1	4	1
Coking	7	4	5	4	7	1	--	--	--	--	--	--
Hydrocracking	--	--	--	--	--	--	17	13	--	--	--	--

*See Table 145.
†MB/D and percentage of atmospheric distillation capacity.

refineries in the 100-175 MB/D range in each district as reported in the December 1979 NPC report, Refinery Flexibility, An Interim Report; foreign export refinery configurations were based on the average refinery size and configuration of large export refineries as reported in the Oil & Gas Journal, March 24, 1979. Each refinery was examined at crude oil charge levels of 70 percent, 85 percent, and 100 percent of capacity.

Table 145. Crude Oil Slates Based on 100 Percent Capacity Utilization

The crude oil slates for the study were based on the crude oil slates in the Pace Company Consultants and Engineers, Inc., report entitled Competitive Economics of United States and Foreign Refining, dated December 1979. Incremental changes in crude oil runs were made by reducing all crude oil proportionally, with the exception of the PAD III refinery in which the domestic crude oil volumes were held constant, and imported crude oil volumes varied.

Table 146. 1978 Crude Oil Price and Quality

The domestic crude oil prices were based on the average 1978 posted prices of lower tier, upper tier, and stripper crude oil with entitlements adjustments to which was applied the national fraction of each tier. The foreign crude oil prices were based on the 1978 average official foreign government prices.

Table 147. 1978 Product Pricing

The prices utilized in this study were based on the 1978 averages of low and high from Platt's Oil Price Handbook and Oilmanac, 55th edition, Pages 11, 18, 49, and 50.

All major products were to be sold at the New York Harbor terminal price, with the exception of naphtha, which was to be sold on the Gulf Coast. The simple arithmetic average of the 1978 low and high prices was used for regular gasoline, premium gasoline, kerosine/No. 1 fuel oil, No. 2 fuel oil, and No. 6 fuel oil (maximum 0.3 wt % sulfur). The prices for other fuel oils higher in sulfur content were calculated using price differentials taken from the Pace Company's study of foreign export refinery competitiveness. Unleaded gasoline was assumed to be priced at 2.8 cents per gallon above regular grade, which was the national average price differential as determined by the U.S. Department of Energy. Propane, butanes, sulfur, and coke were assumed sold in local markets at net-backs based on Chapter Three product price data.

Table 148. Crude Oil and Product Transportation Costs

The transportation costs of foreign crude oil were based on 1978 spot rates as averaged in Shipping Statistics and Economics, by H. P. Drewry, Ltd. In all foreign locations it was assumed that VLCC's could be used where applicable. Domestic refineries, because of a lack of VLCC port facilities, transshipped Middle Eastern crude oil but shipped African crude oil directly in smaller

TABLE 145

Crude Oil Slates Based on 100% Capacity Utilization
(Figures in MB/D)

	PAD I	PAD III	Caribbean	E. Canada	Netherlands	Italy
Sweet Crude Oil						
Nigerian Forcados	20.9	19.9	44.0	11.4	15.8	18.5
Nigerian Bonny Light	20.7	19.7	43.5	11.3	15.7	18.2
Libyan Es Sider	17.9	28.5	37.5	9.8	13.5	15.8
West Texas Semi-Sweet	--	8.7	--	--	--	--
South Louisiana	--	20.3	--	--	--	--
Total Sweet	59.5	97.1	125.0	32.5	45.0	52.5
High-Sulfur Crude Oil						
Saudi Arabian Light	47.9	5.6	162.5	42.2	78.0	91.0
Saudi Arabian Medium	8.1	0.9	27.5	7.2	13.2	15.4
Saudi Arabian Heavy	11.8	1.4	40.0	10.4	19.2	22.4
Saudi Arabian Berri	5.9	0.7	20.0	5.2	9.6	11.2
Iranian Light	5.3	--	18.0	4.7	--	--
Iranian Heavy	--	--	--	--	10.5	12.3
Kuwait Export	16.8	--	57.0	14.8	--	--
Venezuelan Tia Juana Medium	14.7	--	50.0	--	--	--
Abu Dhabi Murban	--	--	--	--	124.5	145.2
Canadian	--	--	--	13.0	--	--
West Texas Sour	--	24.1	--	--	--	--
Alaskan North Slope	--	3.2	--	--	--	--
Total High Sulfur	110.5	35.9	375.0	97.5	255.0	297.5
Total Crude Oil	160.0	133.0	500.0	130.0	300.0	350.0
Percent Sweet	35.0	73.0	25.0	25.0	15.0	15.0
Percent High-Sulfur	65.0	27.0	75.0	75.0	85.0	85.0

TABLE 146

1978 Foreign Crude Oil Price and Quality
(All Cost Figures in U.S. $/Bbl FOB)

	FOB Price	°API Gravity	Wt % Sulfur
Saudi Arabian Light	$12.70	33.5	1.82
Saudi Arabian Medium	12.32	30.6	2.43
Saudi Arabian Heavy	12.02	28.2	2.77
Saudi Arabian Berri	13.22	37.9	1.19
Iranian Light	12.81	33.8	1.38
Iranian Heavy	12.49	31.0	1.48
Abu Dhabi Murban	13.26	39.7	0.82
Kuwait Export	12.22	31.4	2.56
Venezuelan Tia Juana Medium	12.75	24.7	1.61
Canadian	13.11	24.7	1.61
Nigerian Forcados	13.71	31.3	0.23
Nigerian Bonny Light	14.03	36.7	0.15
Libyan Es Sider	13.71	37.4	0.44

TABLE 147

1978 Product Pricing
(All Cost Figures in U.S. Dollars)

New York City Refinery and Terminal Price[*]

Unleaded Gasoline[†]	(91 RON)	$0.4305/gallon
Regular Gasoline	(94 RON)	0.4025/gallon
Premium Gasoline	(99 RON)	0.4314/gallon
Kerosine/No. 1 Fuel Oil (0.1 Wt % Sulfur)		0.3990/gallon
No. 2 Fuel Oil (0.2 Wt % Sulfur)		0.3830/gallon
No. 6 Fuel Oil (0.3 Wt % Sulfur)		$14.53/barrel[§]

New Orleans Refinery and Terminal Price[¶]

Regular Gasoline	$0.3897/gallon
Naphtha at 3¢/Gallon Below Regular	0.3597/gallon

Other Prices

LPG and Butanes[†]	$0.272/gallon
Coke (Green)[†]	$40.00/short ton
Sulfur (3.2 Bbl Per Long Ton)[†]	0.295/gallon
Unleaded Gasoline (93 RON) Differential Over Regular[**]	$0.028/gallon

Heavy Fuel Oil Prices	Average Price ($/Bbl)	Vs. 0.3 Wt %[††]
No. 6 Fuel Oil (0.3 Wt % Sulfur, Low Pour)	14.53	Base
No. 6 Fuel Oil (0.5 Wt % Sulfur, Low Pour)	14.17	(0.36)
No. 6 Fuel Oil (1.0 Wt % Sulfur)	13.53	(1.00)
No. 6 Fuel Oil (3.0 Wt % Sulfur, Bunkers)	11.81	(2.72)

[*] 1978 averages low and high, Platt's Oil Price Handbook and Oilmanac, 55th edition, pp. 11, 49, 50.
[†] From Chapter Three.
[§] Offshore refineries given residual entitlement credit of 0.62/barrel.
[¶] Platt's, p. 18.
[**] 1978 national average differential as determined by the U.S. Department of Energy.
[††] "Competitive Economics of United States and Foreign Refining," The Pace Company, November 1979, p. 65.

TABLE 148

Crude Oil and Product Transportation Costs
(All Cost Figures in U.S. $/Bbl)

	Refinery Location					
	PAD I (Philadelphia)	PAD III (Houston)	Caribbean (Aruba)	E. Canada (St. John N.B.)	Netherlands (Rotterdam)	Italy (Milazzo)
Crude Oil						
Saudi Arabian Light	1.46	1.45	0.73	0.69	0.80	0.76
Saudi Arabian Medium	1.47	1.47	0.74	0.70	0.81	0.78
Saudi Arabian Heavy	1.49	1.48	0.75	0.71	0.82	0.79
Saudi Arabian Berri	1.42	1.41	0.71	0.67	0.77	0.74
Iranian Light	1.48	1.47	0.75	0.71	0.82	0.78
Iranian Heavy	1.50	1.49	0.77	0.72	0.83	0.80
Abu Dhabi Murban	1.43	1.42	0.72	0.68	0.78	0.75
Kuwait Export	1.48	1.48	0.75	0.71	0.82	0.78
Nigerian Forcados	0.81	0.91	0.40	0.41	0.55	0.51
Nigerian Bonny Light	0.81	0.91	0.40	0.42	0.54	0.51
Libyan Es Sider	0.70	0.84	0.54	0.48	0.57	0.24
Venezeulan Tia Juana Medium	0.60	--	0.26	--	--	--
Products						
Gasoline	0.45	1.14	0.58	0.29	1.07	1.19
Naphtha	1.12	0.00	0.57	0.69	1.45	1.54
Kerosine	0.49	1.25	0.63	0.31	1.17	1.30
Distillate Fuel	0.53	1.34	0.68	0.34	1.25	1.40
Residual Fuel	0.53	1.33	0.54	0.27	1.00	1.11

tankers. Product transportation costs from foreign refineries were based on estimates in Shipping Statistics and Economics. U.S.-flag product tanker rates were based on the 1978 average of those reported by Dietz, Inc.

Table 149. 1978 Incremental Tax Rates (Percentages)

Federal and local tax rates for 1978 were used to determine the incremental tax liability for the typical refinery in each area.

Table 150. 1978 Environmental Restrictions on Refinery Fuel

Environmental restrictions were limited to the types of fuels authorized for each area covered by the analysis between the U.S. domestic refineries and foreign export refineries. PAD I was limited to 0.5 wt % sulfur in fuel oils; PAD III was considered to have access to the use of natural gas which was competitively priced with higher sulfur fuel oils. The sulfur limits for foreign export refineries was as follows: the Caribbean -- no sulfur limit; eastern Canada -- 3.8 wt % sulfur; the Netherlands -- 2.5 wt % sulfur; and Italy -- 3.5 wt % sulfur.

Table 151. 1978 U.S. Import Fees and Duties

While the domestic refineries suffered a disadvantage of about $0.11/bbl because of crude oil import fees and duties, this was largely offset relative to the foreign export refineries by the fees and duties charged on imported products. The $0.11/bbl for fees and duties breaks down into $0.005/bbl for fees and $0.105/bbl for duties. This is below the official rate of $0.21/bbl for import fees because any duties paid could be credited against fees owed. Also, most crude oil imports were fee-free.

Total import fees for crude oil in 1978 were $12,000,000. As 2.3 billion barrels of crude oil were imported in 1978, this amounted to $0.0052/bbl. Total import fees for products were $4,000,000. As 490 million barrels of product were imported, this amounted to $0.0082/bbl.

Table 152. 1978 Crude Oil and Residual Fuel Oil Entitlements Credits

The incremental impact of the entitlements credit was a direct $1.61/bbl advantage to domestic refineries importing foreign crude oil into the United States. Controls on domestic crude oil prices kept incremental crude oil costs low to U.S. refineries and product costs low relative to world crude oil prices. This was partially offset in the reverse entitlements penalty for domestic residual fuel production ($0.46/bbl marketed in PAD I) and by the entitlements credit given to residual importers ($0.62/bbl imported).

TABLE 149

1978 Incremental Tax Rates
(Percentages)

	Federal/Country	Local/Provincial	Total
United States	46	4	50
Caribbean	25	--	25
E. Canada	36	12	48
Netherlands	48	--	48
Italy	25	15	40

TABLE 150

1978 Environmental Restrictions on Refinery Fuel

	Refinery Fuel Sulfur Limit
PAD I	0.5 wt %
PAD III	Purchased Gas
Caribbean	No Limit
E. Canada	3.8 wt %
Netherlands	2.5 wt %
Italy	3.5 wt %

TABLE 151

1978 U.S. Import Fees and Duties
(All Cost Figures in U.S. $/Bbl)

	Net Fees	Duty	Total
Naphtha	0.005	0.105	0.110
Gasoline	0.005	0.525	0.530
Kerosine/Jet Fuel	0.005	0.525	0.530
No. 2 Distillate	0.005	0.105	0.110
Residual	0.005	0.0525	0.0575
Crude Oil	0.005	0.105	0.110

TABLE 152

1978 Crude Oil and Residual Fuel Oil Entitlements Credits
(All Cost Figures in U.S. $/Bbl)

Crude Oil Run Entitlement Credit	$1.61/Bbl Crude Oil Processed
Residual Fuel Oil Import Credit	0.62/Bbl Residual Oil Imported
Reverse Entitlement	0.46/Bbl Residual Oil Produced

Table 153. Capital Investment for Retrofitted Downstream Capacity

The added capacity for the Caribbean and eastern Canadian refineries was determined by the capacity required to make the complexity impact of downstream process units of these retrofitted refineries equal to that of PAD I. The capital investments were estimated by the use of investment curves developed for this study. These capital costs were assumed equal to construction on the Gulf Coast of the United States.

TABLE 153

Capital Investment for Retrofitted Downstream Capacity

	Current Capacity (MB/D)	New Capacity (MB/D)	Increase (MB/D)	Capital Investment (MM$)
Caribbean				
Atmospheric Distillation	500.0	500.0	0.0	0.0
Vacuum Distillation	150.0	273.5	123.5	40.0
Reforming	16.0	141.8	125.8	120.0
Fluid Catalytic Cracking	26.0	185.7	159.7	196.2
Alkylation	7.5	20.3	12.3	17.3
Naphtha Desulfurization	16.0	141.8	125.8	32.1
Distillate Desulfurization	47.5	97.9	50.4	16.0
Merox Treating	41.4	140.1	98.7	4.8
Sulfur Plant/Tail Gas Cleanup (LT/D)	343.7	443.1	99.4	7.4
Subtotal Onsite Investment				433.8
Offsites @ 35% of Onsites				151.8
Total				585.6
Added Fixed Costs for Retrofitting (Including Depreciation) at 27% Per Year of Capital Investment				$0.866/Bbl
E. Canada				
Atmospheric Distillation	130.0	130.0	0.0	0.0
Vacuum Distillation	40.0	71.1	31.1	19.0
Reforming	21.0	36.9	15.9	23.0
Fluid Catalytic Cracking	11.0	48.3	37.3	61.9
Alkylation	--	5.3	5.3	9.7
Naphtha Desulfurization	21.0	36.9	15.9	12.1
Merox Treating	13.2	33.5	20.3	1.8
Sulfur Plant/Tail Gas Cleanup (LT/D)	47.8	100.2	52.4	6.3
Subtotal Onsite Investment				133.8
Offsites @ 35% of Onsites				46.8
Total				180.6
Added Fixed Costs for Retrofitting (Including Depreciation) at 27% Per Year of Capital Investment				$1.028/Bbl

Table 154. Estimated Average Fixed Costs at 100 Percent Capacity

Fixed costs for existing refinery facilities (i.e., maintenance and other operating costs and depreciation) were developed from Figures 50 and 51. These figures are regression curves, developed by Arthur Young & Company from the NPC's December 1979 report, Refinery Flexibility, An Interim Report. These costs were used for the refineries in PADs I and III, the Caribbean, eastern Canada, the Netherlands, and Italy.

Fixed costs for retrofitting Caribbean and eastern Canadian refineries were assumed to be 27 percent of the added capital investment, including depreciation (shown in Table 153).

Total fixed costs are the sum of the fixed costs for existing facilities and retrofitting costs.

TABLE 154

Estimated Average Fixed Costs at 100% Capacity
(All Cost Figures in U.S. $/Bbl)

Refinery Areas	Capacity (MB/D)	Complexity Factor	Maintenance & Other* ($/Bbl)	Depre-ciation ($/Bbl)	Retro-fitted Costs† ($/Bbl)	Total Fixed Cost§ ($/Bbl)	Advantage (Disadvantage) ($/Bbl)
PAD I	148.1	7.22	0.99	0.16	--	1.15	--
PAD III	117.2	6.12	0.92	0.14	--	1.06	0.09
Caribbean (Existing)	500.0	3.07	0.67	0.08	--	0.75	0.40
Caribbean (Retrofitted Downstream)	500.0	6.96	0.67	0.08	0.87	1.62	(0.47)
E. Canada (Existing)	130.0	4.36	0.78	0.11	--	0.89	0.26
E. Canada (Retrofitted Downstream)	130.0	7.86	0.78	0.11	1.03	1.92	(0.77)
Netherlands	300.0	2.94	0.66	0.08	--	0.74	0.41
Italy	350.0	2.22	0.58	0.06	--	0.64	0.51

*Based on regression curves developed from the 1979 NPC Survey of Petroleum Refining Capabilities.

Maintenance and Other Costs = $\$0.400\ (\text{factor})^{0.457}$
Depreciation = $\$0.035\ (\text{factor})^{0.755}$

†Taken as 27 percent per year on depreciable investment for added facilities (Table 153). Costs for downstream additional facilities.
§Excludes refinery fuel and other variable costs.

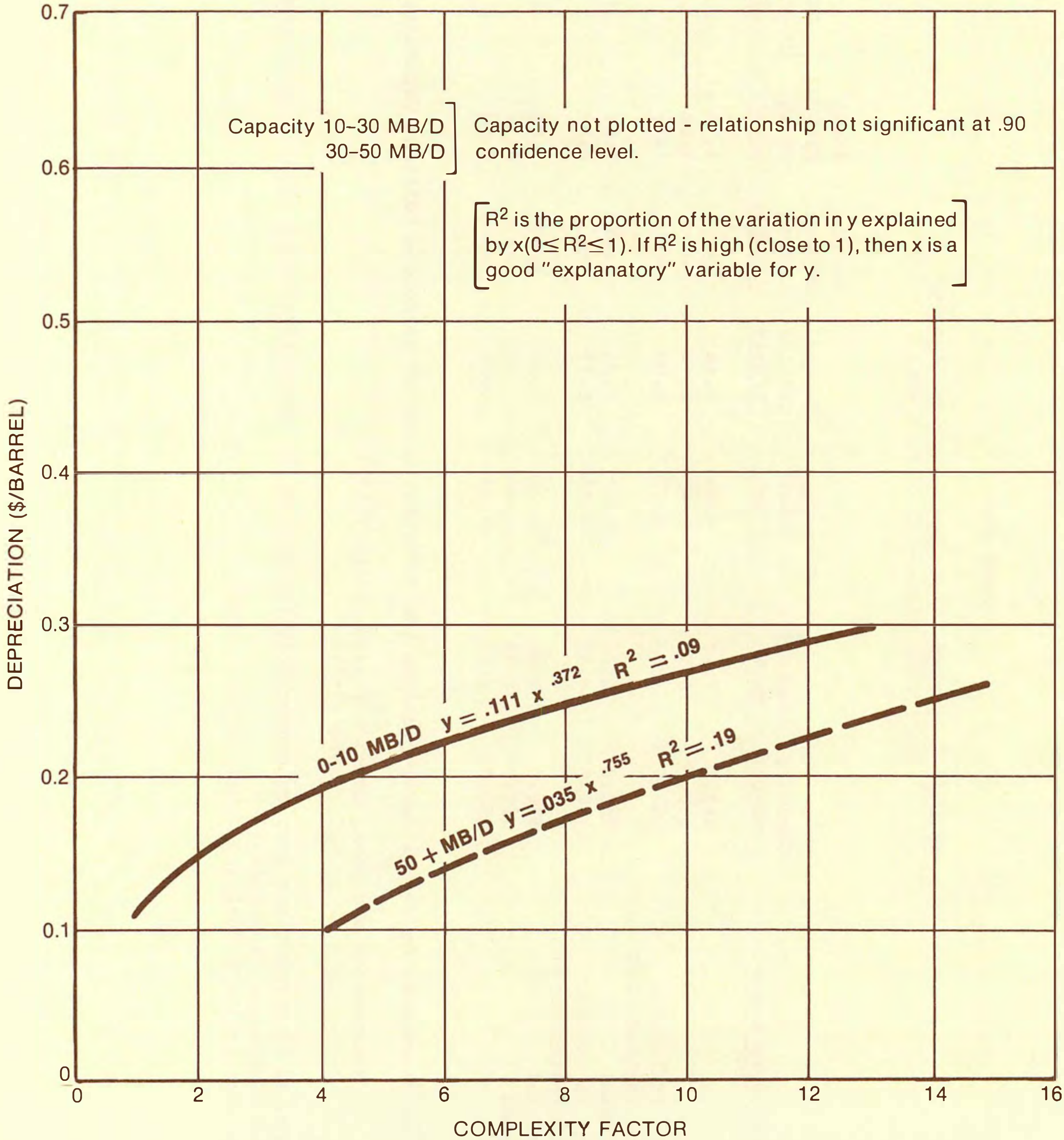

Figure 50. Depreciation as a Function of Complexity.

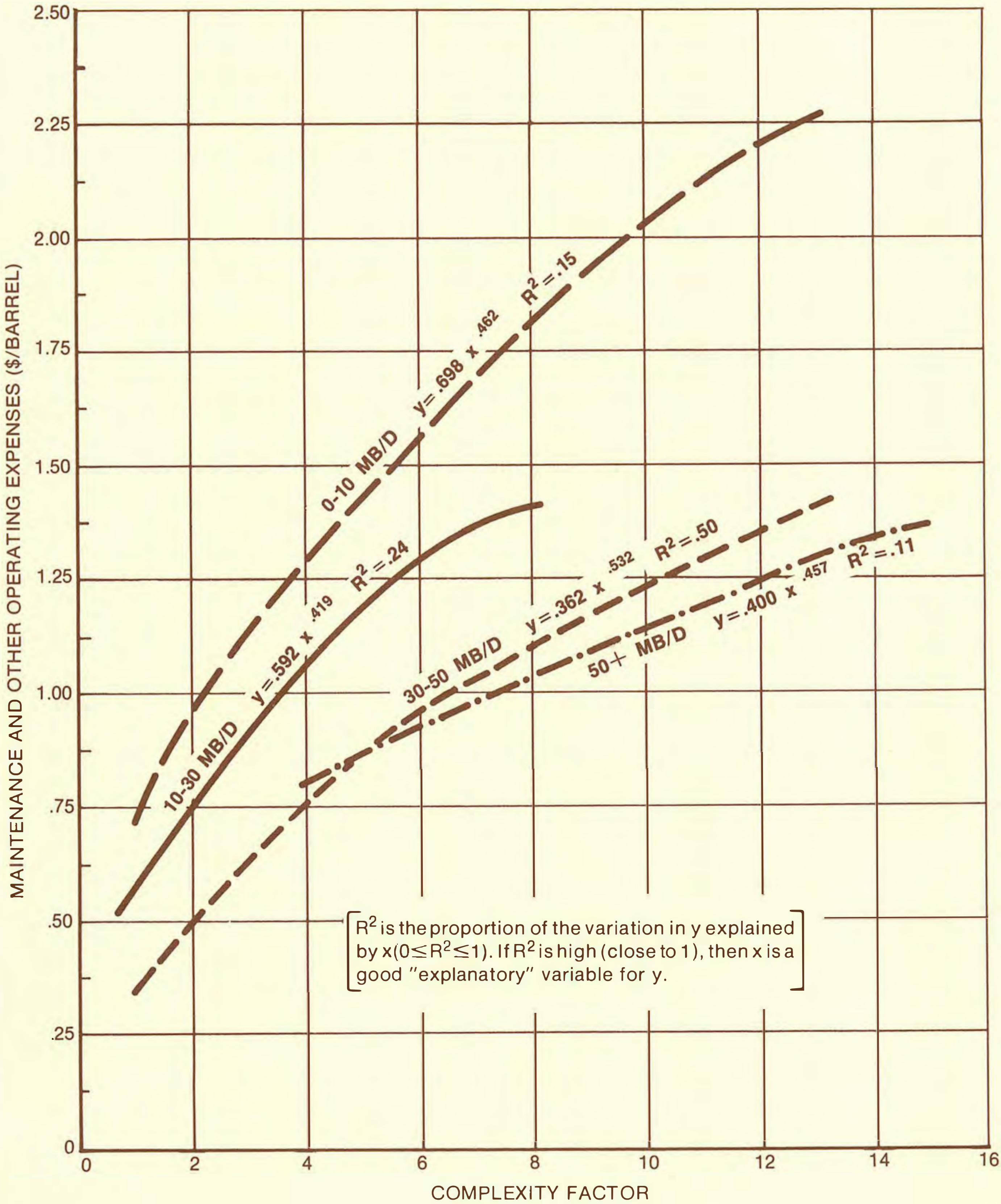

Figure 51. Maintenance and Other Operating Expenses as a Function of Complexity.

APPENDICES

APPENDIX A

Request Letter
and
Description of the
National Petroleum Council

Department of Energy
Washington, D.C. 20585

September 18, 1978

Dear Mr. Chandler:

The National Petroleum Council has prepared numerous studies in the past on the Nation's petroleum refining industry. These studies have outlined the economic, environmental, governmental, and technological factors which affect the ability of the domestic refining industry to respond to demands for essential petroleum products. Since the Council's last such study in 1973, patterns of crude sources for domestic refineries have changed and a re-examination of the situation by the Council is in order.

In my letter of June 20, 1978, I indicated that your study on oil and gas transporation systems should also treat the spatial and transportation relationships between refiners of varying capacities and crude oil sources. After further consideration, however, it appears that the complexities of the refinery capability issue are sufficient to warrant a separate study effort.

I, therefore, request the National Petroleum Council to undertake a comprehensive study of the historical trends and present status of the domestic refining industry's sources of crude oil and its capability to process these crudes into marketable petroleum products. The study should analyze factors affecting the future trends in crude oil availability, refining capability and the competitive economics of small, medium, and large refinery operations through the year 1990. The study should also examine the industry's flexibility to meet dislocations of supply.

For the purpose of this study, I am designating Darius Gaskins, Deputy Assistant Secretary for Policy Analysis, to represent me and to provide the necessary coordination between the Department of Energy and the National Petroleum Council.

Sincerely,

James R. Schlesinger

James R. Schlesinger
Secretary

Mr. Collis P. Chandler, Jr.
Chairman, National Petroleum Council
1625 K Street, N.W.
Washington, DC 20006

DESCRIPTION OF THE NATIONAL PETROLEUM COUNCIL

In May 1946, the President stated in a letter to the Secretary of the Interior that he had been impressed by the contribution made through government/industry cooperation to the success of the World War II petroleum program. He felt that it would be beneficial if this close relationship were to be continued and suggested that the Secretary of the Interior establish an industry organization to advise the Secretary on oil and natural gas matters.

Pursuant to this request, Interior Secretary J. A. Krug established the National Petroleum Council (NPC) on June 18, 1946. In October 1977, the Department of Energy was established and the Council's functions were transferred to the new department.

The purpose of the NPC is solely to advise, inform, and make recommendations to the Secretary of Energy on any matter, requested by him, relating to petroleum or the petroleum industry. The Council is subject to the provisions of the Federal Advisory Committee Act of 1972.

Matters which the Secretary of Energy would like to have considered by the Council are submitted as a request in the form of a letter outlining the nature and scope of the study. The request is then referred to the NPC Agenda Committee, which makes a recommendation to the Council. The Council reserves the right to decide whether or not it will consider any matter referred to it.

Examples of recent major studies undertaken by the NPC at the request of the Department of the Interior and the Department of Energy include:

- <u>Petroleum Resources Under the Ocean Floor</u> (1969, 1971)
  <u>Law of the Sea</u> (1973)
  <u>Ocean Petroleum Resources</u> (1974, 1975)
- <u>Environmental Conservation -- The Oil and Gas Industries</u> (1971, 1972)
- <u>U.S. Energy Outlook</u> (1971, 1972)
- <u>Emergency Preparedness for Interruption of Petroleum Imports into the United States</u> (1973, 1974)
- <u>Petroleum Storage for National Security</u> (1975)
- <u>Potential for Energy Conservation in the United States: 1974-1978</u> (1974)
  <u>Potential for Energy Conservation in the United States: 1979-1985</u> (1975)
- <u>Enhanced Oil Recovery</u> (1976)

- Materials and Manpower Requirements (1979)
- Petroleum Storage & Transportation Capacities (1979)
- Unconventional Gas Sources (1980).

The NPC does not concern itself with trade practices, nor does it engage in any of the usual trade association activities.

Members of the National Petroleum Council are appointed by the Secretary of Energy and represent all segments of petroleum interests. The NPC is headed by a Chairman and a Vice Chairman who are elected by the Council. The Council is supported entirely by voluntary contributions from its members.

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APPENDIX B

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APPENDIX C

Summary
(reprinted from *Refinery Flexibility, An Interim Report*)

SUMMARY*

CURRENT AND PROJECTED REFINERY OPERATIONS AND FACILITIES

This section summarizes the survey data on refinery facilities in place as of January 1, 1979, and those committed for installation by January 1, 1982.[1] Actual 1978 operations and operating plans through 1982 are also summarized. These data are based on surveys submitted to all U.S. refiners in January 1979.

Responses to this part of the survey were received from 246 refineries, representing 97.7 percent of the refining capacity in the 50 states and Guam. This response also represents 86 percent of the 289 refineries owned by the 174 refining companies in the United States. Puerto Rico and the Virgin Islands are not included in the survey results.

Refining Capacity

- As of January 1, 1979, companies responding to the survey had a combined crude oil refining capacity of 16,878 thousand barrels per day (MB/D).[2] Projections for January 1 of 1980 and 1982 show that these same refineries will have aggregate estimated capacities of 17,260 and 17,969 MB/D on the two dates, respectively.

  These projections represent a capacity growth of two percent per year in each of the next three years.

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[1]All data are reported on a calendar day basis (not stream day). Calendar day data include provision for limited shutdowns associated with regularly scheduled maintenance and other equipment-related factors.

[2]All data have been rounded to the nearest thousand barrels per day.

*This is a reprint of the summary of Refinery Flexibility, An Interim Report, Volume I, published in December 1979.

- Modest gains in capacities appear in all PAD districts. The two percent increase in 1979 will be distributed throughout the nation, but PAD III dominates the 1980-1982 increase with an expansion of 516 MB/D.

- With respect to refinery size, the findings indicate that there will be minimal change in the relative percentages of refinery capacity in the various categories during the three-year period beginning January 1, 1979.

Crude Oil Slates

- Responding companies processed 14,655 MB/D of crude oil and condensate in their refineries during 1978. In addition, 1,374 MB/D of other feedstocks were processed, some of which may have been charged to crude distillation units (reduced crude, natural gasoline, naphtha, etc.). Projections of future crude oil refining rates for responding companies show an increase of about 14 percent to 16,740 MB/D of crude oil and condensate in 1982. In addition, 1,244 MB/D of other feedstocks were reported for 1982.

- In 1978, 45.9 percent of the crude oil processed by the reporting refineries was of medium to high sulfur content (greater than 0.5 wt % sulfur). The proportion of above 0.5 wt % sulfur crude oil is projected to increase to 49.2 percent in 1980 and 51.3 percent in 1982. These changes were evident in PADs III and V and for all refinery size categories except 0-10 MB/D.

- In 1978, the total of crude oil processed of greater than 0.5 wt % sulfur was 6,685 MB/D, of which 1,998 MB/D (or 29.9 percent) was medium sulfur crude oil (between 0.5 and 1.0 wt % sulfur) and 4,687 MB/D (or 70.1 percent) was high sulfur crude oil (over 1.0 wt % sulfur).

Substitution of High Sulfur Crude Oil

- Respondents expect to utilize most of their reported capability to process higher sulfur crude oils. Survey results show that between 397 and 968 MB/D of sour crude oil could be substituted for sweet crude oils in 1980 under known environmental restraints, depending upon crude oil type (medium or high sulfur, light or heavy). Reductions in total crude oil throughputs associated with these substitutions amount to 43-169 MB/D. The capability to substitute higher sulfur crude oil is relatively unchanged at 339-957 MB/D in 1982 and is fairly evenly distributed throughout all PAD districts.

Motor Gasoline

- Trends in product yield forecasts show that gasoline volumes are expected to increase from 7,237 MB/D in 1978 to 7,588 MB/D in 1980, and to 7,846 MB/D in 1982. While these volumes increase 609 MB/D (a compounded growth rate of 2.0 percent per year), gasoline yields from crude oil and other feedstocks are projected to decline from 45.1 to 43.6 percent from 1978 to 1982.

- Octane number is a significant factor in the capability of a refinery to produce unleaded gasoline.[3] The reported 1978 capability for blending unleaded gasoline of an octane number of 87 (R+M)/2 was 4,615 MB/D; unleaded gasoline capability drops to 3,195 for 89 (R+M)/2 and to 2,573 MB/D for 90 (R+M)/2. The Department of Energy reported that the

[3]Octane numbers are calculated by either the Research or Motor method. Data in this report are based on the arithmetic average of these two calculations [(R+M)/2].

national average octane number for unleaded gasoline in 1978 was 88.5 (R+M)/2; based upon previously described survey data, the 1978 capability to produce 88.5 (R+M)/2 unleaded gasoline would have been 3,500 MB/D.[4]

- The survey indicates a capability in 1980 to produce 5,927 MB/D of 87 (R+M)/2, 4,018 MB/D of 89 (R+M)/2, or 2,886 MB/D of 90 (R+M)/2 unleaded gasoline. The 1982 capability is approximately 550 MB/D over 1980 estimates for unleaded gasoline.

- The number of refineries capable of producing unleaded gasoline decreases with increased octane number requirements. For example, in 1980, 59 fewer refineries would be capable of producing unleaded gasoline if octane number specifications were increased from 87 to 90 (R+M)/2. However, 40 of these refineries could continue to produce 87 (R+M)/2 octane number unleaded gasoline and the remaining 19 could produce 89 (R+M)/2 unleaded gasoline. The aggregate 1980 capability to manufacture unleaded gasoline would be 5,927 MB/D when maximizing 87 (R+M)/2; 4,335 MB/D when maximizing 89 (R+M)/2; and 3,458 MB/D when maximizing 90 (R+M)/2 grade.

- Consistent with the above 1980 capability, when maximizing unleaded gasoline, the lead content for the remaining leaded gasoline would range from 0.9 to 1.5 grams/gallon, depending upon octane number specifications for the unleaded gasoline and the ratio of unleaded to leaded gasoline volumes. The average lead content of the total gasoline pool (leaded and unleaded gasoline) is maximized at 0.5 grams/gallon in keeping with Environmental Protection Agency (EPA) lead limits.

[4]These data for 1978 were developed in the context of federal lead phasedown standards in effect in 1978.

Other Product Trends

- Significant changes in the percentage yields based on refinery inputs included increases in kerosine-based jet fuel and feedstocks sold to others, with a decrease in gasoline and distillate No. 2 fuel oil. BTX (benzene, toluene, and xylene) projections show an industry-wide gain from 115 to 155 MB/D between 1978 and 1982.

Low Sulfur Heavy Fuel Oil

- Survey results project a 1980 capability, under normal conditions, to produce 397 MB/D of heavy fuel oil of less than 0.3 wt % sulfur content. The capability for low sulfur fuel oil is increased to 771 MB/D if the sulfur specification is raised to 0.7 wt % and increases further to 1,441 MB/D at a sulfur specification of 2.0 wt %. The low sulfur fuel oil capacity is projected to increase by 1982, reflecting hydrotreating capacity additions, notwithstanding increases in high sulfur crude runs.

- If, in the event of a national emergency, it becomes necessary to maximize heavy fuel oil at the expense of light products, while limiting the reduction of distillates and jet fuel volumes to 10 percent, the 1980 yield of low sulfur fuel oil could be increased to 828 MB/D for the 0.3 wt % sulfur grade, 1,520 MB/D for the 0.7 wt % sulfur grade, and 2,483 MB/D for the 2.0 wt % sulfur grade. Gasoline volumes would decrease 553 MB/D as a consequence of maximizing 2.0 wt % sulfur fuel oil.

Process Capabilities

- With respect to refinery size, the survey results show that larger refineries generally have a greater ability to produce unleaded gasoline. Larger refineries tend to have more residual processing facilities such as cokers and resid desulfurization (which, incidentally, produce more blending and feedstocks for unleaded gasoline).

- Featured in process facility trends in the 1979-1982 period are significant gains in the capacity for reforming, isomerization, and catalytic cracking to facilitate unleaded gasoline manufacture. Gains were also registered in hydrotreating to cope with heavier, higher sulfur crude oils. Other process capacities gains appear to be related to increased crude charge capabilities.

CRUDE OIL COSTS, REFINERY OPERATING COSTS AND ASSETS

Part II of the survey addressed 1978 crude oil costs, and refinery operating costs and assets as of January 1, 1979. Refinery fuel, purchased utilities, depreciation, and other operating costs were reported for the year 1978. Also reported were crude oil slates with respect to cost, quality, regulatory classification (lower tier, upper tier, exempt), and percentage of owned production or royalty owners' share for 1978. Original gross fixed assets and replacement costs as of January 1, 1979, were also included.

Respondents to Part II represented an aggregate capacity of 15,445 MB/D or 89 percent of the total capacity reported in Part I. Responses to some or all elements of the survey were received from 203, or about 70 percent of, U.S. refineries. The attrition in the number of refineries reporting was primarily in refineries below 30 MB/D capacity.

The following presentation of refinery cost data, aggregated from the survey, is not a competitive analysis of the domestic refining industry. Product revenue and other factors affecting competitiveness are not included. It would be inappropriate to draw final conclusions regarding the relative economics of any group or class of refineries from the Part II survey data alone. The final report on Refinery Flexibility will contain an analysis of the competitive economics of small, medium, and large refinery operations.

Crude Oil Costs and Quality[5]

- In 1978, the refining companies participating in the survey experienced crude oil costs averaging $12.71 net per barrel after entitlements.

- The respondents' average crude oil costs before entitlements was $12.36 per barrel, or $0.35 per barrel lower than the average net cost after the regulatory effects. Product import entitlements and other exceptions increased after-entitlements crude oil costs to respondents.

- The highest average net crude oil costs after entitlements amounting to $12.99 per barrel ($0.28 per barrel above the survey average), were incurred by companies with refining capacities in the 50-100 MB/D size range.

- Companies of greater than 100 MB/D also experienced net after-entitlements crude oil costs above the $12.71 per barrel respondent average, at $12.94 per barrel for the 100-175 MB/D category and $12.78 per barrel for those companies of greater than 175 MB/D capacity.

- Companies of less than 50 MB/D capacity experienced lower net crude oil costs, ranging from an average of $10.53 per barrel for the 0-10 MB/D size category to $12.22 per barrel for the 30-50 MB/D companies.

[5]The terms "crude costs after entitlements" and "net crude costs" as used herein include the effects of the small refiner bias.

- Companies of less than 50 MB/D crude oil capacity had a net reduction in crude oil cost from the effects of the small refiner bias segment of the entitlements program. With the exception of companies in the 100-175 MB/D size category, companies of greater than 50 MB/D capacity experienced an increase in crude oil cost as a net result of the entitlement program.

- Refineries in PAD V reported lower net crude oil costs than the other PAD districts. PAD V's lower cost is related to crude oil quality. The inland refineries in PAD II incurred the highest net crude oil costs.

- Considering crude cost as a function of individual refinery size, the larger refineries generally experienced higher net crude oil costs. Refineries of less than 50 MB/D capacity had net crude costs below the respondents' average, similar to the results of aggregation by company size.

- Crude costs tend to increase with increased refinery complexity. The larger refineries are generally more complex, and do not receive small refiner bias entitlements. Crude oil quality for the asphalt-oriented refineries in the lower complexity categories is also a factor.

- Most of the larger refining companies (those of greater than 175 MB/D capacity) own domestic production. On average, their production plus associated royalty owners' share is about 45 percent of the crude oil they refine. Other refiners (those of less than 175 MB/D capacity) own production plus associated royalty owners' share which averages less than 12 percent of their refinery throughput.

Operating Costs

- In general, total 1978 operating costs (fuel, purchased utilities, depreciation, maintenance, etc.) increased with company size. The principal factor appears to be the average higher process complexity of refineries operated by larger companies. Total operating costs ranged from $1.35 per barrel for companies of less than 10 MB/D capacity to $2.35 per barrel for companies of greater than 175 MB/D capacity.

- In 1978, total operating costs averaged $2.29 per barrel of crude oil processed. Of this total, nearly half ($1.08 per barrel) was for fuel and purchased utilities.

- PAD V had higher average operating costs than the other PAD districts. This appears to be due primarily to the high complexity and relatively high fuel costs for refineries in this area.

- Below 50 MB/D, per barrel operating expenses generally decreased with increasing refinery size of a given complexity. The impact of refinery size on operating costs diminished for refineries above 50 MB/D in capacity. This may be due to parallel process trains in the larger refineries.

- 1978 operating costs increased steadily with refinery complexity from $1.49 per barrel for the 1-3 complexity category to $3.13 per barrel for refineries in the 11+ complexity category.

Gross Fixed Assets and Replacement Costs

- The January 1, 1979, average per-barrel gross fixed assets for all respondents was $1,354/bbl/day; replacement costs average $3,727/bbl/day.

- Per-barrel gross fixed assets and replacement costs increased with company size. Economies of scale were more than offset by higher assets associated with greater complexity and multiple process trains in the larger company size categories.

- On a geographic basis, PAD V had the highest per-barrel gross fixed assets and replacement costs, $1,530/bbl/day and $4,572/bbl/day, respectively.

- The effect of refinery size on gross fixed assets and replacement costs was masked by the greater impact of refinery complexity. In the smaller refinery size categories, the data indicate a decrease in per-barrel investments with increasing size at a given complexity. The effect of size alone diminished in the larger (50+ MB/D) refinery size categories.

- Gross fixed assets and replacement costs per barrel generally increased with complexity. Reported replacement costs ranged from $1,706/bbl/day for refineries in the 1-3 complexity range to over $4,000/bbl/day for refineries of greater than 7 complexity.

- Comparison of replacement costs with gross fixed assets should be indicative of the vintage of the facilities. On this premise, it would appear that refineries of least complexity were constructed most recently, while those refineries in the 7-9 complexity category (integrated gasoline refineries with some hydrodesulfurization capabilities) are the oldest.

ADDITIONAL FACILITIES TO MEET THREE ALTERNATE SUPPLY/DEMAND CASES

Part III of the survey concerned the new facilities which would be required by refining companies under three hypothetical cases:

- Provide capacity necessary to substitute additional high sulfur crude oil equivalent to at least 20 percent of the total crude oil capacity based on the 1982 projections reported in response to Part I of the survey

- Provide facilities to increase production of specific grades of unleaded gasoline to 90 percent of the projected total 1982 gasoline pool reported in Part I of the survey

- Provide facilities to increase production of low sulfur heavy fuel oil (0.7 wt %) by 25 percent of the total heavy fuel oil projected for 1982 and reported in Part I of the survey.

Respondents to this part of the survey were given the option of reporting on a "system" basis. A company with two or more refineries was not required to modify each of its refineries by its proportional share of the company total. For example, a company might choose to increase the high sulfur crude oil processing capability of Refinery A by 60 percent and not modify refineries B and C.

Responses indicating that new facilities were required to process more high sulfur crude oil were received from companies owning 147 refineries with a total capacity of 15,004 MB/D. This represents about 78.4 percent of total 1982 capacity (19.13 MMB/D) and 50.9 percent of U.S. refineries.

Refineries with a total capacity of 15,207 MB/D, representing about 79.5 percent of total capacity and 54.3 percent of U.S. refineries, completed the unleaded gasoline portion of the survey.

Responses indicating that new facilities were required to produce low sulfur fuel were received from companies owning 148 refineries with a total capacity of 14,027 MB/D. This represents about 73.3 percent of total capacity and 51.2 percent of U.S. refineries.

Increased High Sulfur Crude Oil Processing Capability

- Refineries anticipate processing 6,140 MB/D of light and heavy high sulfur crude oil in 1982, equivalent to 34.2 percent of total projected throughputs. An increase in the capability to process an amount of high sulfur crude oil equivalent to at least 20 percent of capacity would permit the respondents to process an additional 3,000 MB/D of high sulfur crude oils.

- A 30 percent increase in capacity for the desulfurization of naphtha, distillate, and heavy fuel oil, amounting to 2,362 MB/D, would be needed to increase the respondents' capability to process light high sulfur crude oil by at least 20 percent of projected 1982 total crude oil capacity. These and other required facilities, if built, would be placed in 95 refineries with projected combined January 1, 1982 capacities of 10,408 MB/D. Associated "system" capacities were 13,878 MB/D in 133 refineries.

- If the increase in high sulfur crude oil processed is in the heavy grades, 2,518 MB/D of additional desulfurization capacity would be required. In this case, the mix would shift, with a decrease of approximately 100 MB/D in naphtha desulfurization and an increase of 217 MB/D in heavy fuel oil desulfurization capacity. These and other required facilities, if built, would be placed in 98 refineries with a projected January 1, 1982 capacity of 10,842 MB/D. Associated "system" capacities were 14,377 MB/D in 137 refineries.

- Substantial new capacity is also required for sulfur recovery facilities, hydrogen generation, and residual conversion processes if more high sulfur crude oil is to be processed. Total new capacities identified by the respondents for light and heavy high sulfur crude oil processing, respectively, amounted to: 4,527 and 6,277 long tons per day of sulfur recovery; 531 and 788 million standard cubic feet per day of hydrogen generation; and 299 and 488 MB/D of residual conversion (mostly coking).

- Metallurgy is not now adequate to handle the high sulfur crude oil in 44 percent of the refinery capacity where the added facilities might be constructed.

- Respondents estimated lead times averaging 43 months to bring on stream the added facilities required to process additional high sulfur crude oil equivalent to 20 percent of crude oil capacity. This time includes authorization, permitting, design, engineering, procurement, and construction.

- Companies representing 83 percent of total respondent capacity indicated that they believed they could obtain necessary permits for construction and operation of added facilities to refine high sulfur crude.

- In response to the hypothetical question and based on the economic conditions and company plans which existed at the time of the survey, firms representing 73 percent of respondent capacity indicated that the probability of any significant part of the added facilities being constructed was low or impossible.

Increased Unleaded Gasoline Manufacturing Capability

- As reported in Part I, significant new unleaded gasoline manufacturing facilities are committed for completion by January 1, 1982. These facilities will provide the capacity to produce 87 (R+M)/2 unleaded gasoline as 82 percent of the total gasoline pool. If this percentage were required to rise to 90 percent, at least 124 refineries with a 1982 capacity of 12,425 MB/D would have to add some additional facilities. These relatively limited additions would be in capacity for reforming, isomerization, catalytic cracking, and alkylation.

- If 90 percent of the total gasoline pool in 1982 were required to be unleaded and its octane specification were raised to 89 (R+M)/2, companies representing 77.5 percent of capacity would have to build additional facilities. In this case, reforming capacity would increase substantially and total isomerization requirements would be five times that now planned for 1982.

- Companies representing 92 percent of total respondent capacity believed they could obtain necessary permits for construction and operation of the facilities required to increase their unleaded pool to 90 percent of total gasoline production.

- Considering future economic conditions and company plans, firms representing 14 percent of respondent capacity indicated a high probability that a significant part of the added facilities would be constructed and 42 percent indicated a medium probability.

Increased Low Sulfur Heavy Fuel Oil Manufacturing Capability

- In 1982, companies responding to this question plan to produce 1.5 MMB/D of heavy fuel oil. Increasing this output by 25 percent (375 MB/D) and requiring this incremental product to be 0.7 or less wt % sulfur would result in the construction of 769 MB/D of new crude oil distillation capacity.

- Increases in process capabilities which would be required in this case are: 364 MB/D in hydrotreating, 233 MB/D in hydrorefining, 1,351 long tons per day in sulfur recovery, and 210 million standard cubic feet per day in hydrogen generation.

- Based on assessments of future economic conditions and corporate plans at the time of the survey, companies representing 88 percent of respondent capacity indicated a low probability that the facilities required by this hypothetical case would actually be installed.

ENERGY SUPPLY/DEMAND SURVEY

This section summarizes the survey data on energy and oil supply, demand, and logistics for the years 1980, 1982, 1985, and 1990. Summary projections are based upon data from twenty respondents including twelve domestic oil companies, three foreign oil companies, and five non-oil organizations. Unless otherwise noted, data reported are the average of all responses received adjusted to arrive at a balanced and consistent supply/demand matrix.

Responses to the survey were received in the spring and summer of 1979. The individual forecasts which provide the basis for the aggregations were almost all prepared in late 1978 or very early 1979. Because of this, they do not reflect the political and economic events which have occurred in 1979. Because the 1980-1990 data are based on now outdated forecasts and the fact that many respondents would most likely change their forecasts, the final report will contain data which update portions of the survey.

World Oil Supply/Demand

- The respondents expect a significant slowing in the growth of global petroleum consumption. Growth in petroleum consumption is forecast to average 2.3 percent per annum between 1977 and 1990, a very significant reduction from the 7.7 percent rate observed between 1960 and 1972.

- The countries belonging to the Organization for Economic Co-operation and Development (OECD) are considered able to reduce the average annual growth in oil consumption to 1.3 percent over the forecast period.

- Because of respondents' different assessments of future economic growth, energy prices, petroleum availability, etc., there is increasing variability over time in the forecasts received. For example, the spread between $\pm$ 2 standard deviations from average global petroleum consumption increases from 1.5 MMB/D in 1980 to 10 MMB/D in 1990.

- The geo-political distribution of future growth in petroleum production is expected to depart significantly from past trends. The OECD countries' petroleum production is projected to grow at an average annual rate of 1.7 percent between 1977 and 1990, constituting a reversal of the decline in production in recent years. However, significant improvements in the rate of new reserve additions will be required if the forecasted production is to materialize.

- Organization of Petroleum Exporting Countries (OPEC) production will grow at only 1.1 percent annually, a sharp decline from historic growth rates. OPEC's share in global supplies will decline slightly from 50 percent in 1977 to 45 percent in 1990. The low rate of production growth is probably due mostly to internal political and economic considerations rather than to physical resource limits.

- The fastest growth in petroleum production is expected to take place in the non-OPEC developing countries. Production in these countries is forecasted to grow 6.5 percent a year between 1977 and 1990. Their share in global supplies will increase from seven percent to 12 percent.

- A wide range of individual responses was received on the future supply/demand situation in the Sino-Soviet block countries (U.S.S.R., Eastern Europe, and China). The average responses indicate that the Sino-Soviet bloc will remain a net exporter of petroleum. The wide range of individual responses indicates the uncertainty of the future Sino-Soviet petroleum balance.

U.S. Energy Supply/Demand

- U.S. energy consumption is forecasted by respondents to increase 2.3 percent per year over the 1977-1990 period while GNP will grow at a 3.2 percent rate. In the 1977-1990 period, the ratio of total energy to GNP declines from 57.3 to 50.6 thousand BTU's per 1972 dollar of GNP.

- Transportation energy will decline as a percent of the total from 26 percent in 1977 to 22 percent in 1990. Non-energy and conversion losses (primarily electric utilities) will continue to grow substantially faster than the total (from 26 percent in 1977 to 32 percent in 1990).

- The share of oil and gas in total energy consumption is shown declining from almost 75 percent in 1977 to 62 percent in 1990. Coal and nuclear power will increase from 22 percent in 1977 to almost 34 percent in 1990.

- Domestic liquids production (crude, condensate, and natural gas liquids) stay at about 10 MMB/D through 1990, while imports are forecasted to increase from 9.1 MMB/D in 1980 to 10.9 MMB/D in 1990.

- Domestic gas production will continue to decline during the 13 year forecast period, but at a diminishing rate. Total gas supplies are forecasted to remain flat at about 19.4 trillion cubic feet per year, as increasing imports offset the production decline.

- Coal production is forecasted to be 40 percent greater in 1985 and 80 percent greater in 1990 than in 1977. The average of the responses received indicates that nuclear output will triple over the 1977-1990 period.

U.S. Petroleum Product Demand

- Respondents expect a considerable slowing of domestic petroleum demand growth during 1977-90 from the historical 1972-77 trend of 2.4 percent annually, with growth during the 1980's to average slightly less than 1 percent per annum. Survey results show demand increasing from 18.4 MMB/D in 1977, to 19.5 by 1980, and to 21.3 MMB/D by 1990.

- The survey shows that motor gasoline requirements are projected to peak in the early 1980's, primarily reflecting improvements in automotive fuel economy. New car miles per gallon, on average, are projected to rise from 15 in 1977 to 26 by 1990. As a result, the miles per gallon of the entire passenger car population is forecasted to improve by nearly 50 percent during the 1980's to 22 mpg.

- Survey respondents expect unleaded gasoline to account for more than 80 percent of total gasoline demand by 1990. Of this quantity, about 40 percent is anticipated to be premium unleaded with an octane level of 92 (R+M)/2.

- According to survey respondents, middle distillate demand (kerosine, jet fuel, distillate fuel) growth will average about 2.4 percent annually during 1977-90. Of this total, the survey data indicate that on-highway diesel requirements will increase sharply (7.4 percent annually 1977-90) reflecting the growing use of diesel powered passenger cars.

- Survey responses show residual fuel demand increasing throughout the early to mid-1980's and then declining modestly by 1990. These results track electric utility liquids consumption -- the single largest end-use market for residual fuel oil.

- By 1990, respondents expect low sulfur fuel oil (less than 1.0 wt % sulfur) to account for nearly 60 percent of total residual fuel demand. In contrast, low sulfur demand was slightly less than 54 percent in 1977.

- Substantial differences exist among individual survey responses on future demands for kerosine, liquefied gases, petrochemical feedstocks, and miscellaneous products. For these products the standard deviation is more than 20 percent of the mean forecast value for 1990.

- Over the forecast period 1977-90, the survey indicates a moderate increase in the proportion of light-end products consumed, despite the projected peaking of gasoline requirements during the mid-1980's. This is opposite to the trend during 1972-77, when residual fuel demand increased, on average, four percent annually.

Regional Oil Supply/Demand

- Total product demand increases in both PADs I-IV and PAD V will be modest over the next decade, averaging less than one percent annually in both areas. Demand in PADs I-IV will grow from 16.8 MMB/D in 1980 to 18.2 MMB/D in 1990; PAD V demands will build from 2.7 to 3.0 MMB/D over the same period.

- The survey data show a halt in the trend of PAD V total demand growing faster than PADs I-IV. However, the survey indicates that 1990 gasoline demand in PAD V will remain essentially unchanged from 1977 levels, whereas demand in PADs I-IV will decline five to six percent during the same period.

- Changes in PAD crude runs will mirror product demands and remain at a runs/demand ratio of 0.78 in PADs I-IV and 0.90 in PAD V in the 1980-90 time period.

- The production of petroleum liquids in PADs I-IV is expected to decline further, at a 1.5 percent annual rate, from 7.8 MMB/D in 1980 to 6.7 MMB/D in 1990. Forecasters estimate that only half of that loss will be offset by with PAD V production rising from 2.5 to 3.1 MMB/D in the same period.

- Respondents anticipate imports of foreign oils into PADs I-IV to continue upward, reaching 10.3 MMB/D in 1990 from a

1980 level of 8.6 MMB/D -- a 2.0 percent annual increase -- with included product imports remaining near constant at a two MMB/D level. Foreign shipments into PAD V drop sharply from 1977 to 1980, but hold at about 600 MB/D from 1980 through 1990.

- PAD V receipts from PADs I-IV are expected to hold through the decade at the 130 MB/D level and will be 97 percent products. PADs I-IV reliance on PAD V will move toward 870 MB/D (95 percent crude oil) by 1990, doubling 1980 receipts at an annual rate of near 7.5 percent. However, a wide range of opinions were expressed.

APPENDIX D

History and Fundamentals of Refining Operations

BASIC REFINING PROCESSES[1]

The history of petroleum refining has been one of evolution. Petroleum refining technologies have risen to meet the demands of the marketplace, the new developments of each period being based largely on the scientific advances of the previous one.

Following the development of the first commercial oil well by Col. Edwin Drake in 1859 in Pennsylvania, a number of refineries were constructed in Pennsylvania and New York, where more commercial wells were struck. During these early days of the refining industry, roughly extending from the 1860's until 1920, operations were generally limited to heat distillation of crude oil.

Although equipment design and distillation techniques have advanced markedly over the years, crude oil distillation remains today what it was in the early years -- the separation of crude oil into discrete fractions having differing characteristics. These various fractions, or cuts, may be sold directly or may be further "refined" in other process units. The total products manufactured by a refinery for distribution are termed "the product slate."

Those components which "boil" and are recovered as an overhead stream, or as sidecuts, are referred to as "distillates" and are further categorized by other physical properties. The bottom product from the crude oil distillation column contains materials which are too heavy to boil under the atmospheric pressure conditions of the crude oil unit. This bottom product has many names -- "asphalt," "atmospheric resid," "residual oil," "topped crude," and "No. 6 fuel oil," among them.

Initially, kerosine and light distillates were considered the prime products. Gasoline had essentially only nuisance value until the early 20th century, when the advent of the automobile and its internal combustion engine resulted in increased demand for gasoline. However, the quantities required were in approximate balance with the amount contained in the quantity of crude oil processed to meet the demand for the heavier distillates. Simultaneously, a growing market was developing for lubricating oils of better quality.

During World War I, military requirements necessitated rapid advancement in application and refinement of existing internal combustion engine technology. In the immediately subsequent post-war

[1]Adapted with permission from a paper presented by R. M. DeVierman and A. P. Krueding, UOP Process Division, before a joint Federal Energy Administration/National Petroleum Refiners Association Symposium, Arlington, VA, September 4, 1974.

years, "spin-off" from wartime technology led to design and production improvements in automotive manufacture which made automobile ownership generally more common.

During this period, the typical U.S. refinery was still a small and simple operation. In 1918 there were 267 refineries with a total capacity of 1.2 MMB/D, or less than 4,500 MB/D per refinery (see Figure D-1).

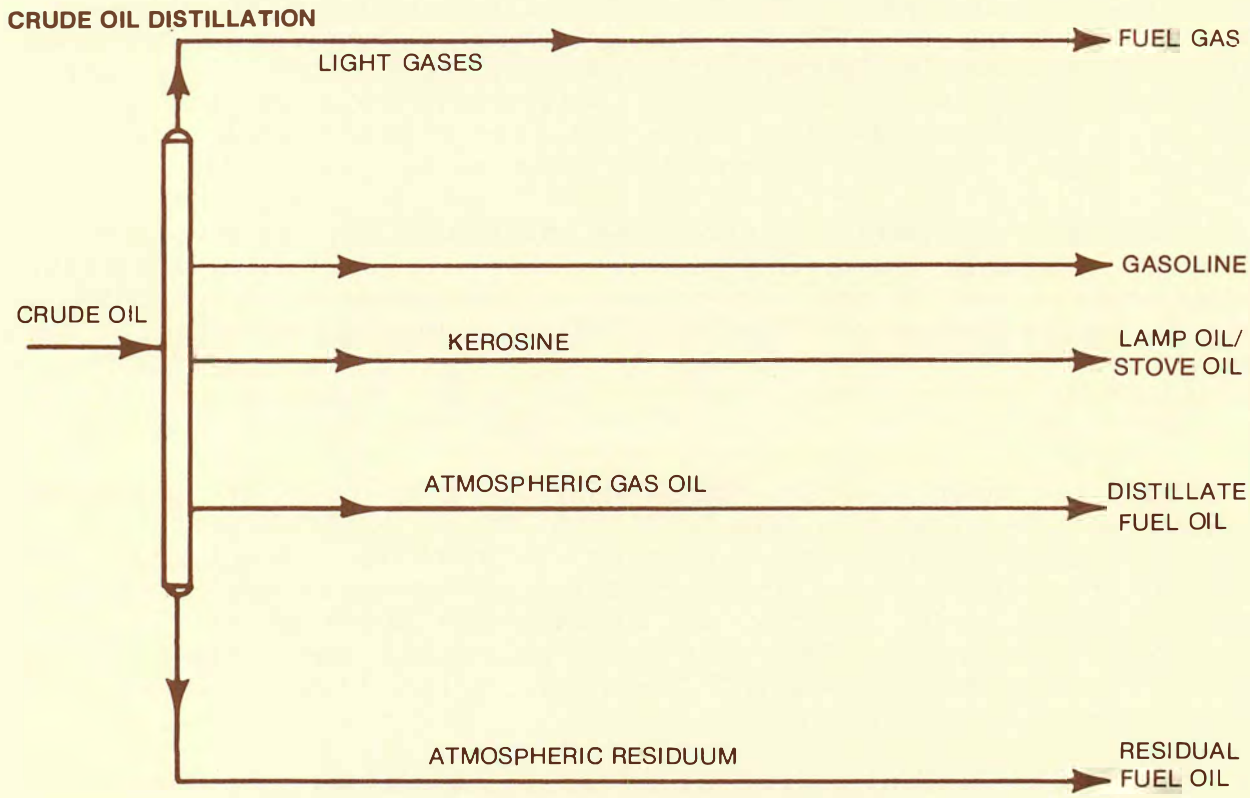


Figure D-1. U.S. Petroleum Refinery (circa 1915).

Within a short time, petroleum refiners were faced with the problem of shifting their product slate toward production of more, higher quality gasoline from a given barrel of crude oil than had previously been recovered by simple distillation processes. The conversion of heavier fractions to gasoline became necessary.

In the early 1920's, with the commercialization of the thermal cracking process, refiners found a satisfactory economic solution which was complemented by a substantial increase in domestic crude oil production (see Figure D-2). Thermal cracking is a severe form of thermal processing. It reduces the amount of heavy fuel oil produced by cracking, or fracturing, the molecules using the heaviest components present in crude oil to produce lighter, generally more valuable materials, such as gasoline and light fuel oils.

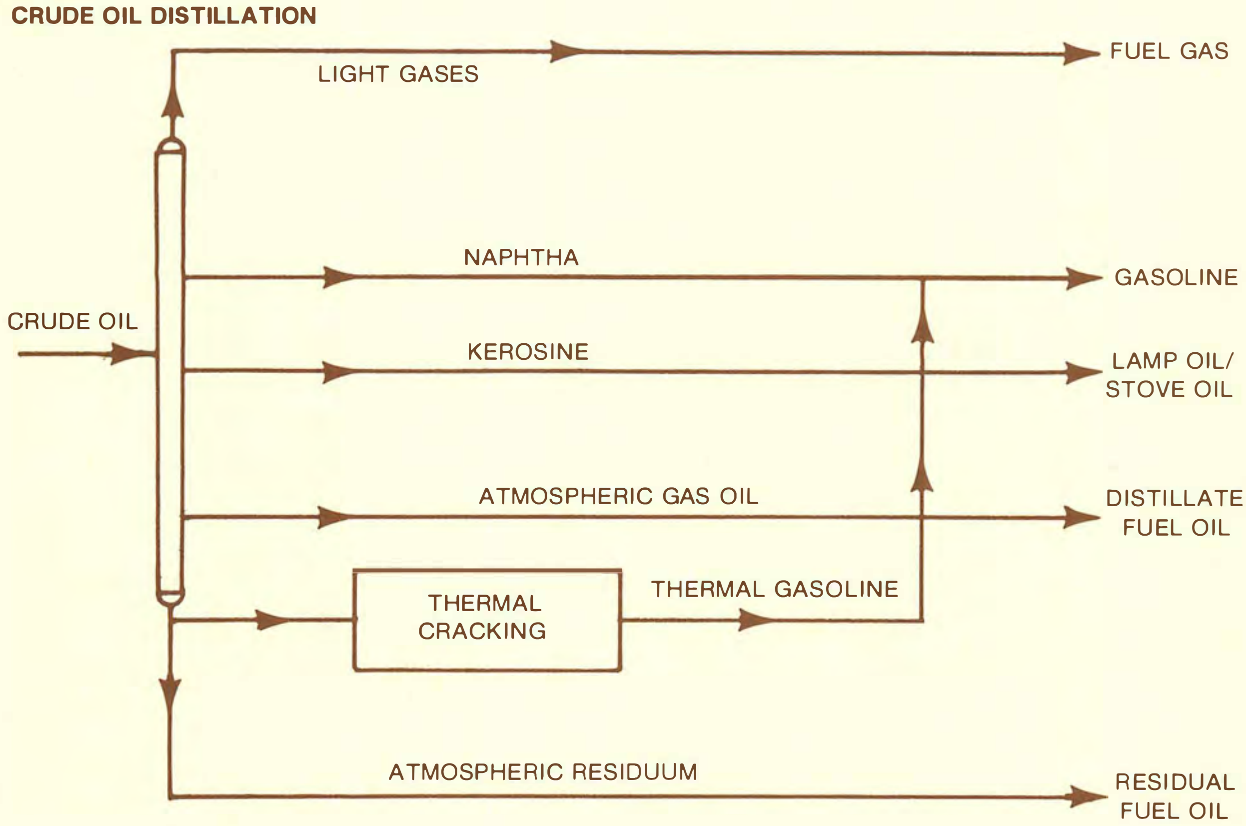


Figure D-2. U.S. Petroleum Refinery (circa 1920's).

Acceptance of the new processing technique was immediate. From the standpoint of the automotive industry, the successful commercialization of the cracking process came none too soon. Apart from the problem of gasoline availability, gasoline quality had become troublesome. Engine knock had been identified as a severe fuel problem; gasoline from crude oil distillation units burned too fast and unevenly, affecting the efficiency of engine performance. Cracked gasoline was found to be of superior quality, as measured by the "octane rating," and demand for what was then considered to be a "premium" fuel from thermal crackers soared. The thermal cracking process became a mainstay of the early refinery.

During the late 1920's and early 1930's, consumer demand required that the refining industry continue to shift from production of heavy distillates and fuel oils toward that of more higher quality gasoline (see Figure D-3).

A by-product of the previously commercialized thermal cracking process was a gaseous material, rich in a type of hydrocarbon known as "olefins." Olefins are typically produced in operations where a deficiency in hydrogen exists. They are reactive materials and can be made to form heavier, liquid materials. In the early days of thermal cracking, this olefin-rich gaseous co-product was used as a fuel gas or, in some cases, burned as a waste product.

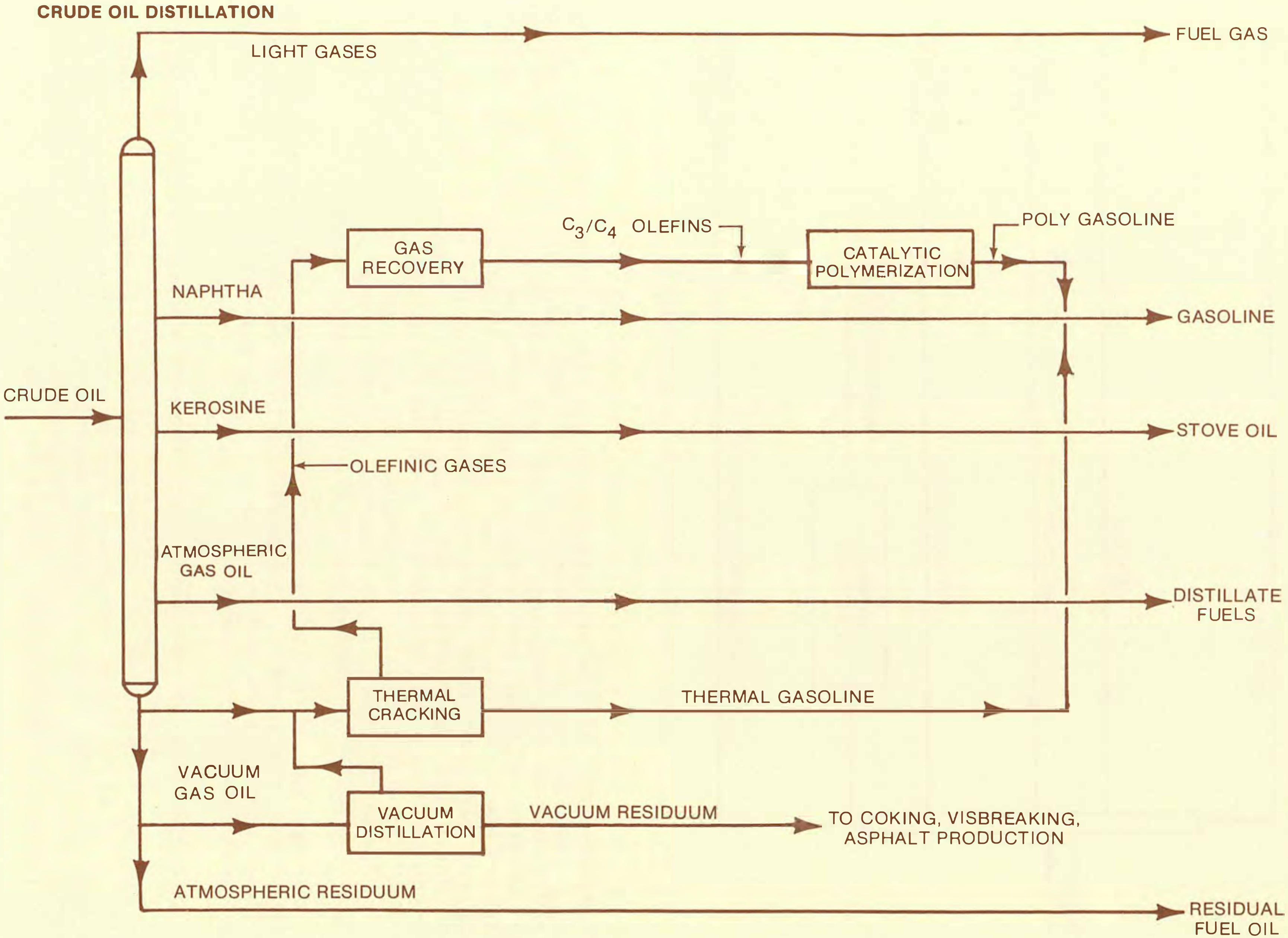


Figure D-3. U.S. Petroleum Refinery (circa 1930's).

To make economic use of these light thermal olefins, the catalytic condensation or polymerization process was developed. This processing technique utilizes a catalyst to provide the proper processing conditions under which light olefins will react selectively to yield a high octane gasoline. The overall efficiency of the operation was improved by "concentrating" the light olefins in a gas recovery plant prior to processing in the polymerization unit. This process was later applied to produce gasoline from suitable olefins recovered from other types of operations.

The yield of residual oil was reduced through application of improvements in vacuum distillation techniques and equipment design. As mentioned previously, the bottom product from the crude oil distillation column contains materials which will not distill at atmospheric pressure. When the atmospheric resid was fractionated under a vacuum, a distillate, referred to as vacuum gas oil, was recovered, which could be directed to thermal cracking to produce additional gasoline.

The refiner was able to cut more deeply into the crude oil and further reduce heavy fuel oil yields by applying the visbreaking and coking processes to the vacuum residuum, or pitch. Visbreaking is a mild form of thermal cracking which was, and still is, used primarily to improve certain of the fuel oil characteristics of residua.

Coking is a more severe type of thermal processing. In the coking unit, atmospheric or vacuum residuum is subjected to time-temperature conditions which, through a series of complex reactions, result in production of gas, gasoline, distillates, and petroleum coke.

The number of refineries in the United States peaked in 1940, with 461 in operation; their total capacity was 4.2 MMB/D, an average of 9.1 MB/D per refinery.

During the early years of World War II, the U.S. government brought together the refining technologies to expedite the contribution of the petroleum industry to the war effort, particularly in the manufacture of badly needed high octane aviation fuel. Working in close collaboration, petroleum industry scientists and engineers immediately directed their broad knowledge and talents to the war effort. From the industry's laboratories and engineering departments came technology for the process of alkylation, isomerization, fixed bed cracking, thermofor catalytic cracking, and the most important of the heavy distillate conversion processes -- fluid catalytic cracking (FCC) (see Figure D-4).

Fluid catalytic cracking converts virgin atmospheric and vacuum gas oils and heavy stocks derived from other refinery operations into high-octane "cat" gasoline and light fuel oils called "cycle stocks." Olefin-rich light gases, which can be directed to polymerization or alkylation operations to produce gasoline, are co-products. With proper design and selection of operating conditions

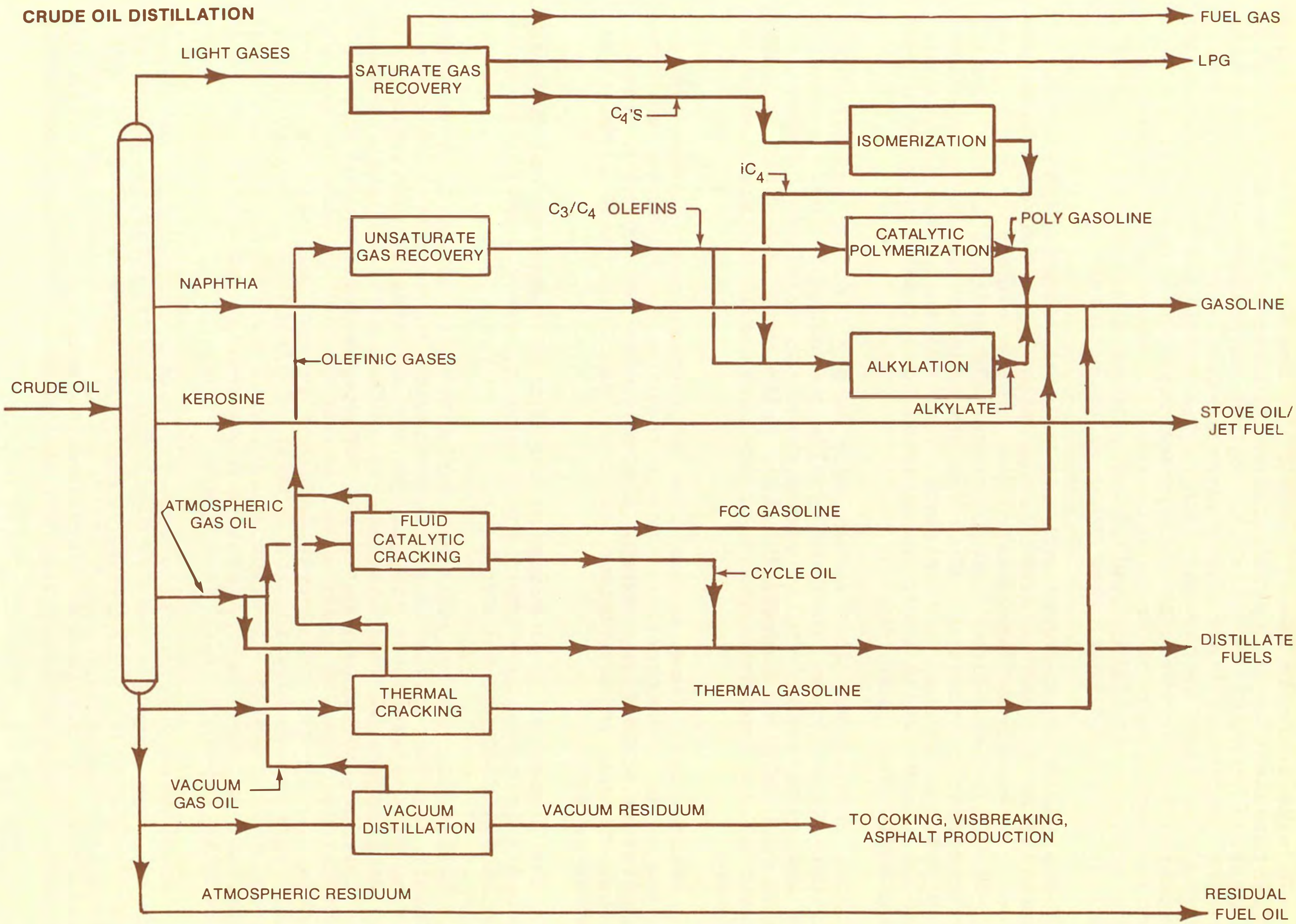


Figure D-4. U.S. Petroleum Refinery (circa 1940's).

and catalysts, yields and qualities of specific FCC products may be varied. Typically, yields of liquid products will exceed 75 to 80 volume percent of the FCC feed. The cracking reaction is accomplished in the presence of a catalyst at controlled conditions of temperature, pressure, and time. The term "fluid catalytic cracking" derives from the use of a catalyst consisting of small particles which, when aerated with a vapor, behave as a fluid. This fluidized catalyst will flow and is circulated within the system.

The alkylation process for motor fuel production catalytically combines light olefins, primarily mixtures of propylene and butylenes, with isobutane (a paraffinic hydrocarbon) to produce a fuel that is one of the highest quality components of a gasoline pool. The alkylate product has excellent antiknock properties and lead response. It is clean burning, has high unleaded and leaded Research and Motor octane ratings, and has an excellent "performance" rating, as well. The alkylation reaction takes place in the presence of a catalyst, hydrofluoric acid or sulfuric acid, under conditions selected to maximize alkylate yield and quality.

When considered together, the FCC and alkylation processes are of major importance in the manufacture of quality gasoline. The overall gasoline yield of the two processes -- the "cat" gasoline plus the alkylate produced from the FCC olefins -- will typically exceed 90 volume percent of the FCC feed. Allowing for the blending of butane into the gasoline to meet volatility requirements, the overall yield approaches 100 volume percent. In other words, for each barrel of feedstock processed in the FCC unit, approximately one barrel of gasoline can be recovered from the combined FCC-alky operation. There is, of course, an additional yield of fuel oil from the FCC unit.

Isobutane is consumed in the alkylation process. The isomerization process was developed and added to the refinery components in order to produce isobutane from normal butane and, thus, supplement the isobutane recovered from the crude itself and from other processes.

After World War II, the availability of catalytically cracked gasolines and alkylate for motor fuel blending made refinery naphtha, with its low octane number, increasingly unattractive as a gasoline component. In the late 1940's, a radically different process was developed that utilized a catalyst containing platinum in petroleum refining for the first time. This process, known as catalytic reforming, revolutionized the art of converting low grade naphthas into high-octane motor fuels.

Catalytic reforming is the octane generator and determinant in the gasoline-oriented refinery. The gasoline-range materials recovered from other operations, such as FCC, alkylation, hydrocracking, and polymerization, are of relatively fixed octane quality. The catalytic reforming process is capable of efficiently yielding gasoline products ranging in octane number from the low 80's to over 100 Research clear (unleaded). Unfortunately, as operating severity is increased to raise the octane number, gasoline yield decreases. On the basis of gasoline produced per unit of feedstock, typical yields can range from over 90 volume percent to 70 volume percent, respectively, for low to high octane operations. This process is also the major source of the hydrogen required for many of the operations employed in today's modern refineries.

Since processing over a platinum catalyst produces aromatics, such as benzene, toluene, and xylene, catalytic reforming quickly established itself as a processing base for development of an aromatic based petrochemical industry.

With continuing emphasis on producing greater quantities of higher octane gasolines, it became necessary to upgrade other materials which were formerly used directly as gasoline components, such as thermal naphthas derived from thermal cracking, visbreaking, and coking operations, as well as refinery naphthas having more than modest amounts of sulfur and nitrogen. The contaminants present in these materials, however, were detrimental (poisonous) to the platinum-based catalyst used in the reforming process. Treatment of such stocks prior to catalytic reforming became a necessity.

With the development of the hydrotreating process in the mid-1950's an efficient answer to this problem was provided. The process utilized hydrogen produced in the catalytic reformer itself, to catalytically remove sulfur, nitrogen, and other reformer catalyst poisons. The yield of treated product from a hydrotreater generally approaches 100 volume percent. As catalytic reforming severity increased over the years, more active catalysts were developed and greater care was exercised to provide clean feedstocks for these operations. Thus, it became routine practice to hydrotreat reformer feeds for elimination of contaminants (see Figure D-5).

In the latter part of the 1950's, improvements in the design and reliability of sulfuric and hydrofluoric alkylation process units resulted in the beginning of the phasing out of the catalytic polymerization process as a route to gasoline production. Polymerization technology, however, retained its importance as a refining tool in the production of a variety of compounds used in the petrochemical industry.

The use of chemical treating processes for odor improvement of gasoline and distillate, or for reduction of the sulfur content of light hydrocarbon streams, became widespread.

With the development of catalytic processing during the war years and early 1950's, thermal based operations became relegated to a position of lesser importance. Most thermal processing now is being used in the area of visbreaking and coking. The refining industry had passed from the thermal to the catalytic era.

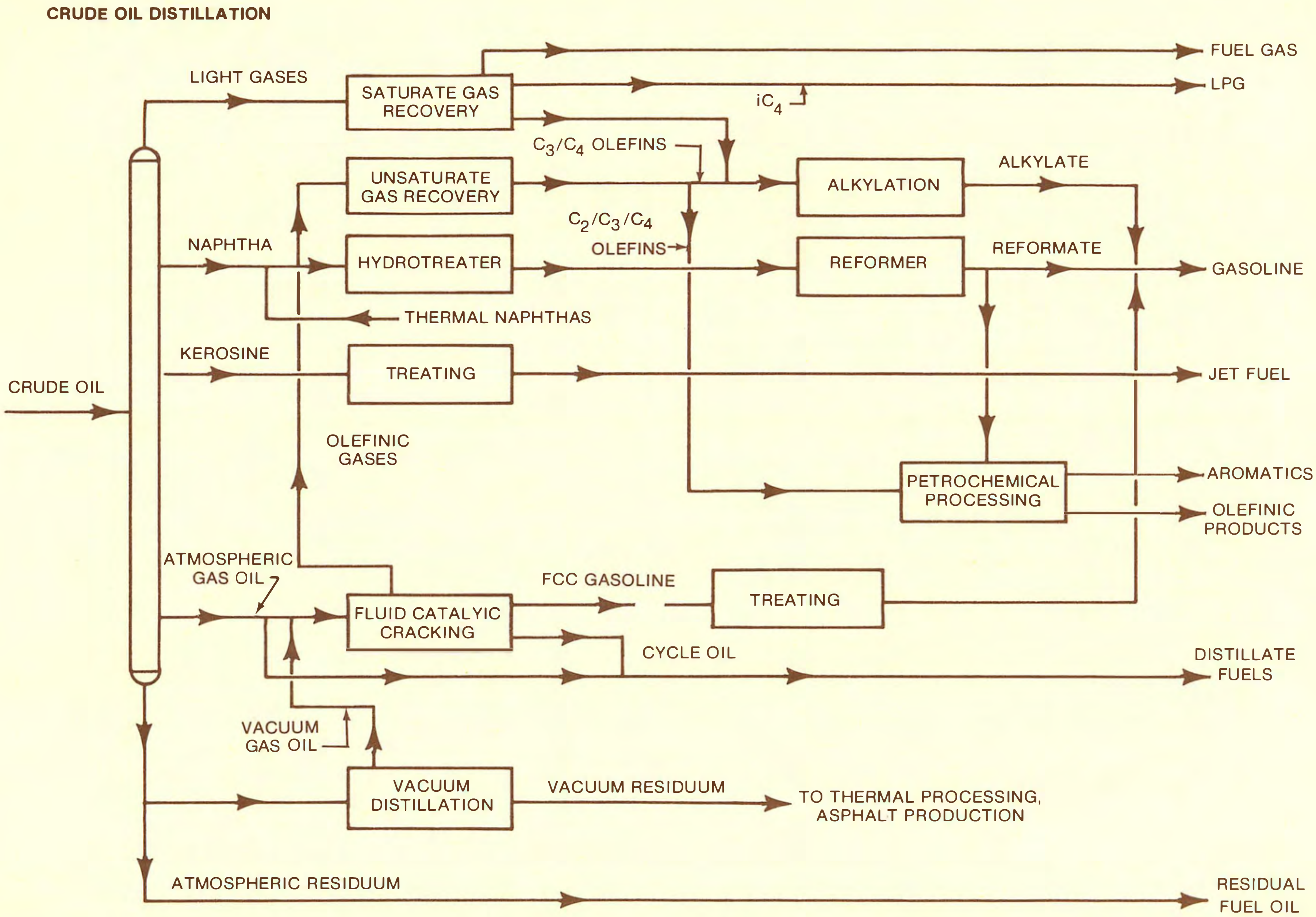


Figure D-5. U.S. Petroleum Refinery (circa 1950's).

In the late 1950's and early 1960's, rapid acceptance by the airlines of the turbine engine resulted in a startling increase in jet fuel consumption. The petroleum industry was hard pressed to meet the demand. With the hydrocracking process in 1960, the refiner was provided with a tool for production of high quality jet fuel from materials otherwise unsuitable. Hydrocracking is a highly versatile process which can charge any fraction of crude oil to yield virtually any product lighter (lower boiling) and cleaner than the charge stock. The process can produce directly almost any material the refiner markets, such as liquified petroleum gas (LPG), light gasoline, turbine fuels, lubricating oils, and diesel and distillate fuels. It can also upgrade stocks for subsequent processing in other operations. With hydrocracking reactions, undesirable sulfur, nitrogen, and oxygen compounds are almost completely removed (see Figure D-6).

Hydrocracking flexibility permits ready adjustment of refinery production to whatever proportions are necessary for variations in seasonal, geographic, or marketing requirements.

Hydrocracking is a catalytic process and, as is hydrotreating, a hydrogen consumer. Total yield of liquid products, that is, gasoline and heavier materials, will exceed 100 volume percent of feed. The yield of specific products will depend on the application. For example, yields of jet fuel approximating 85 to 90 volume percent of feed can be achieved, with the concurrent production of LPG and light gasoline.

Hydrogen for hydrocracking and hydrotreating is most often supplied by catalytic reforming operations. Process selection and flow scheme in many instances have been dictated by "hydrogen balance" considerations. Where this has not been possible, supplementary hydrogen generation facilities have been installed.

The decade of the 1960's saw rapid growth in the production of petrochemicals, particularly in the area of light olefins. For example, U.S. domestic demand for ethylene tripled during the 1960-1970 period. A representative configuration of a refinery operating in the 1970's is presented in Figure D-7.

During the latter part of the 1960's and continuing to the present, increasing emphasis has been placed on environmental considerations. Such concerns have affected the design of every process unit in the refinery. Proper handling of waste materials, such as contaminant-containing water, gas streams, and spent chemicals, has required creation of new and improved antipollution techniques.

The choice of refinery processes will be based on the specific circumstances of each operation and is dependent on crude oil type, product slate, product quality requirements, and economic factors such as crude costs, product values, availability and cost of utilities, availability of equipment and capital.

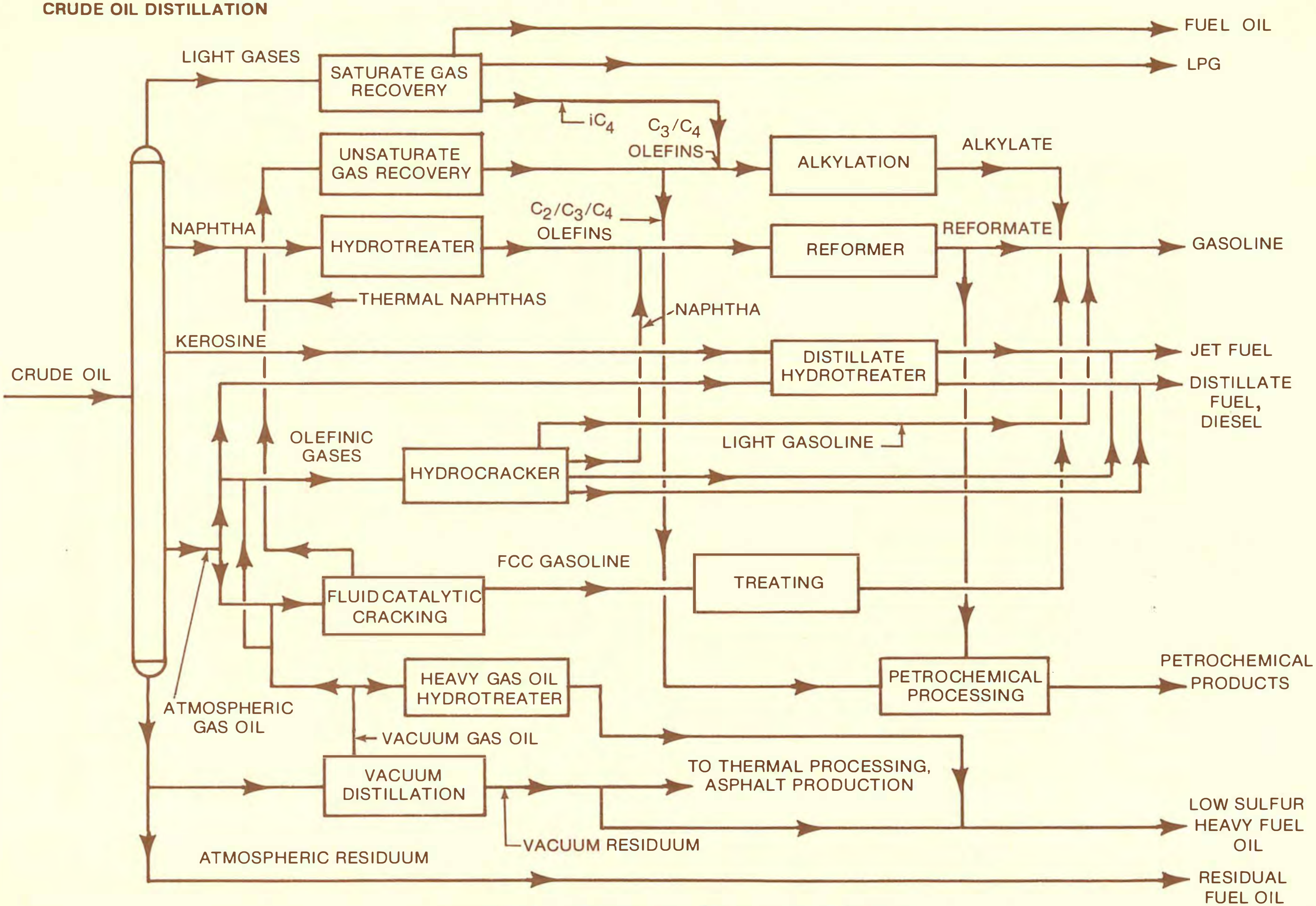


Figure D-6. U.S. Petroleum Refinery (circa 1960's).

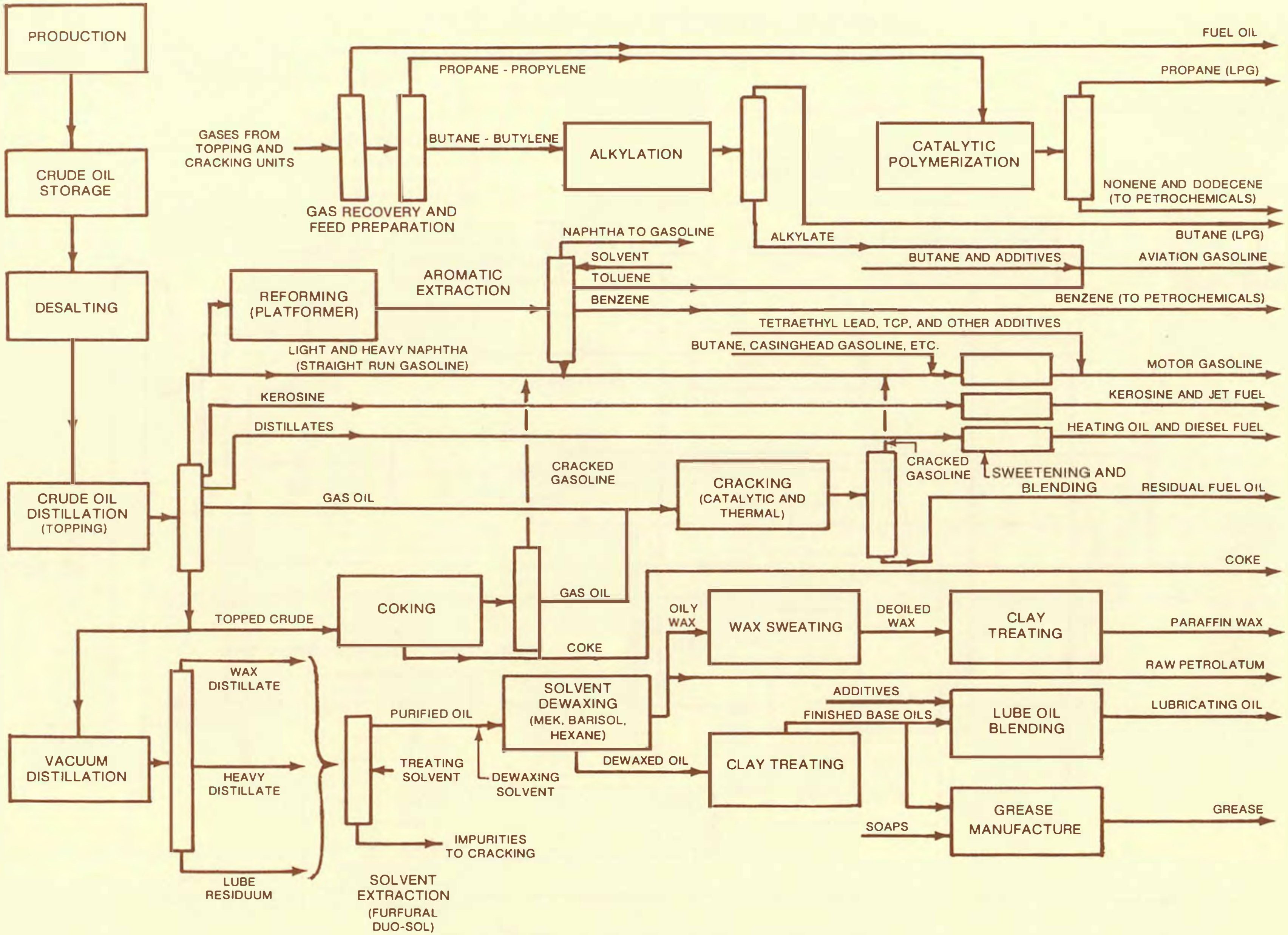


Figure D-7. Simplified Flow Chart of a Refinery.

The characteristics of the crude oil feedstock are critical to process selection. There are hundreds of crude oils available on the world market today which vary widely in physical properties. Many crude oils from the Middle East tend to be high in sulfur content and of moderate metals content, both important factors to be considered if low-sulfur heavy fuel oils are the desired products. Some of the more readily available Middle East crude oils, such as those from Kuwait, while lending themselves to production of low-sulfur residual fuels, have a poor naphtha component which makes them less desirable for gasoline operations. Many Venezuelan crude oils, while moderate in sulfur, contain a high level of metals which renders them all but unprocessable for the yielding of low-sulfur heavy fuel. Some North African crude oils are low in sulfur and other contaminants but are waxy and, therefore, less suitable for production of lubricating oils.

As for product slate, in a gasoline oriented refinery, the yields of heavy oils will be minimized through the application of conversion processes. Fluid catalytic cracking would be utilized to crack the distillate products from resid conversion processes as well as virgin distillate materials, to yield gasoline and olefins for motor fuel alkylate production.

In situations where quality distillates, such as turbine fuel, diesel and lube oils, and low-sulfur fuel oils are required, hydrogen refining concepts will apply, with hydrocracking and hydrodesulfurizing processes predominating.

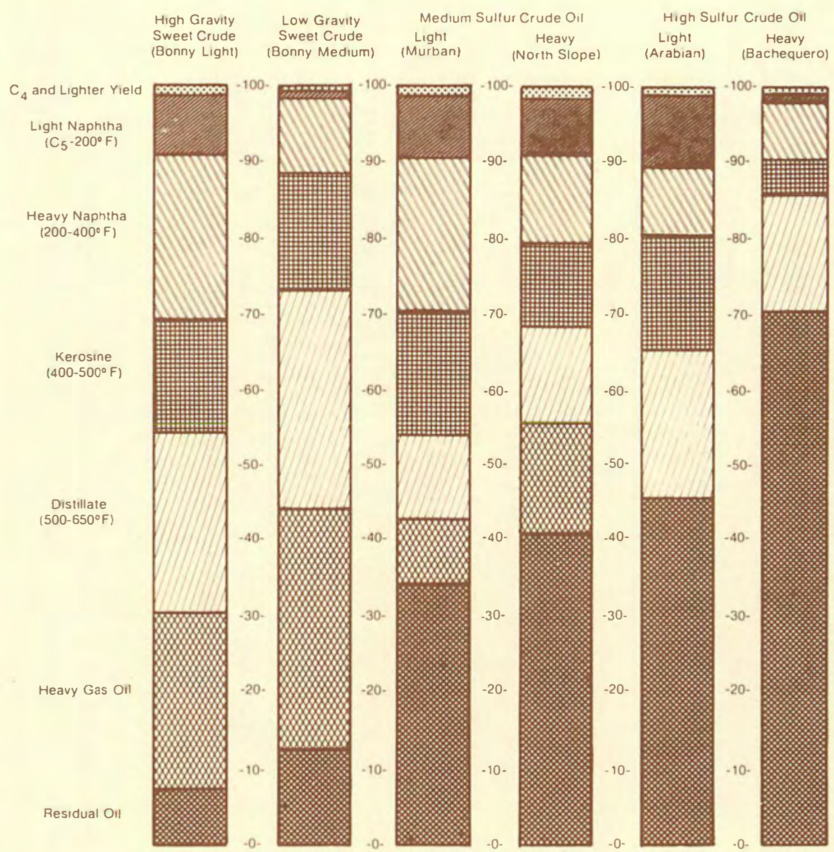
The variability of marketing requirements and the potential uncertainty in crude oil supply require that processing flexibility be a major consideration in the design of today's modern petroleum refinery. The general result is an overall operation combining cracking and hydrogen refining capabiities.

CRUDE OIL CHARACTERISTICS

Crude oil is a substance comprised of a 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. The characteristics and yields of a range of crude oils are presented in Table D-1.

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

TABLE D-1



YIELD
(Percentages)

	High Gravity Sweet Crude (Bonny Light)	Low Gravity Sweet Crude (Bonny Medium)	Medium Sulfur Crude Oil: Light (Murban)	Medium Sulfur Crude Oil: Heavy (North Slope)	High Sulfur Crude Oil: Light (Arabian)	High Sulfur Crude Oil: Heavy (Bachequero)
Crude Oil						
Gravity (°API)	37.6	26.0	39.4	26.8	33.4	16.8
Sulfur (Wt %)	0.13	0.23	0.74	1.0	1.80	2.40
Pour Point (°F)	5	<-5	+5	-5	-30	-10
Sulfur Range (Wt %)	0-0.5	0-0.5	0.51-1.0	0.51-1.0	1.0+	1.0+
C_4 and Lighter Yield	2.2	0.7	1.8	1.8	1.7	0.4
Light Naphtha (C_5-200°F)						
Yield (Vol %)	6.4	2.1	6.78	5.8	9.0	2.5
Gravity (°API)	79.9	79.2	82.2	68.3	78.5	65.0
Sulfur (Wt %)	0.0002	0.001	0.012	0.01	0.024	--
Naphthenes (Vol %)	21.5	24	--	30.0	10.4	51.9
Aromatics (Vol %)	1.5	3	--	--	2.4	4.7
Paraffins (Vol %)	77.0	73	--	48.8	87.2	43.4
Octane No. (RON Clear)	78	80	69	65	54.7	--
Heavy Naphtha (200-400°F)						
Yield (Vol %)	22.0	8.7	21.2	12.6	8.4	6.0
Gravity (°API)	53.6	50.1	56.9	49.7	59.6	49.0
Sulfur (Wt %)	0.003	0.01	0.013	0.02	0.027	--
Naphthenes (Vol %)	55	58.5	20	56.4	18.2	58.5
Aromatics (Vol %)	11	14.0	17	--	12.3	13.9
Paraffins (Vol %)	34	27.5	63	43.6	69.5	27.6
Kerosine (400-500°F)						
Yield (Vol %)	15.4	14.7	16.14	12.3	15.0	5.0
Gravity (°API)	40.2	34.4	45.4	37.4	38.5	36.4
Sulfur (Wt %)	0.03	0.063	0.058	0.20	0.094	0.48
Pour Point (°F)	-70	<-70	--	--	--	-80
Distillate (500-650°F)						
Yield (Vol %)	23.2	29.7	10.4	12.1	19.8	15.5
Gravity (°API)	33.2	27.5	37.8	31.3	37.1	--
Sulfur (Wt %)	0.13	0.18	0.47	0.56	1.05	0.99
Cetane No.	51	40.0	54	47	--	--
Pour Point (°F)	20	-15	0	--	0	--
Viscosity (@ 100°F)	40.3 SUS	44.6 SUS	4.2 cSt	--	3.28 cSt	--
Heavy Gas Oil						
Yield (Vol %)	23.1	31.3	9.24	14.7	*	*
Gravity (°API)	25.4	19.7	33.6	25.8		
Sulfur (Wt %)	0.21	0.31	1.06	0.90		
Pour Point (°F)	105	80	41	55		
Viscosity (@ 210°F)	48.1 SUS	53.1 SUS	--	77 SUS 100°F		
Residual Oil						
Yield (Vol %)	7.7	12.8	34.5	40.7	46.1	70.6
Gravity (°API)	11.8	10.1	22.6	13.0	17.6	--
Sulfur (Wt %)	0.39	0.48	1.49	1.74	3.08	3.0
Pour Point (°F)	--	--	85	475	40	60
Viscosity (@ 210°F)	2,030 SUS	3,690 SUS	--	391 SUS	21 cSt	--
Total (%)	100.00	100.00	100.00	100.00	100.00	100.00

*Data for Heavy Gas Oil included in Residual Oil.

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 crude oils 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 crude oils. These crude oils generally will fall in the medium to high gravity range. Sulfur content may fall between 0.1 and 2.5 wt % sulfur. The distillate from these crudes generally has pour point and cetane index characteristics suitable for burning oil and diesel fuel.

In addition to the paraffinic, naphthenic, and intermediate types of crude oils already discussed, there exist many combinations of these crude oils.

Crude oils are also classified as low-sulfur content (below 0.5 wt % sulfur), intermediate-sulfur content (between 0.5 and 1.0 wt % sulfur), and high-sulfur content (over 1.0 wt % sulfur). In general, the definition of a sweet crude oil is one that does not contain hydrogen sulfide and has below 0.5 wt % sulfur content, with only a minor portion of the sulfur content being present as mercaptans. Mercaptans (sulfur compounds) are of the most undesirable contaminants of crude oil and petroleum products.

COMPLEXITY

Chapters Three and Four of this report analyze the competitive aspects of the refining industry by size, region, and complexity factor. The report uses a standard known as the "Nelson factor" for comparing the complexity factor of differing process schemes.

Professor W. L. Nelson developed this "complexity factor" concept which permits categorizing of refining operations. The "completeness" of the refinery operation is arrived at by a calculation which states numerically how complex the refinery is, compared to one which conducts only crude oil distillation operations. Crude oil distillation is arbitrarily assigned a complexity factor of 1.0. Each downstream process operation will contribute to the overall complexity of the refinery in proportion to its own complexity, cost, and size in relation to the distillation capacity. Each operation is given a complexity factor which relates its cost and technical sophistication to those of crude oil distillation. For example, catalytic reforming has a complexity factor of 4.0 -- it is four times as complex as crude oil distillation.

As an illustration of how this complexity concept may be used to develop comparisons of petroleum operations with differing processing objectives, consider three basic types of refineries: (1) fuel oil, (2) gasoline, and (3) petrochemical.

The first is a hydroskimming operation which is oriented toward production of fuel oil. The term "hydroskimming" derives from the use of hydrogen to upgrade the distillates "skimmed" from the crude oil. The hydroskimming refinery product slate consists of gasoline, jet fuel, distillate, and heavy fuel oil. The process scheme is simple, involving crude oil distillation, hydrotreating, and catalytic reforming of naphtha to yield gasoline, hydrotreating of distillate for sulfur reduction, and chemical treating of the virgin light gasoline and kerosine to improve their odor and other characteristics. Waste gases are processed for recovery of sulfur.

To arrive at the overall complexity of this operation, a listing is made of all the process units along with the processing capacity and complexity factor of each. The contribution of each operation to the total is calculated by multiplying its complexity factor by the ratio of its process capacity to total crude oil capacity.

For illustration purposes, a crude oil capacity of 100,000 barrels per day has arbitrarily been chosen. The capacities of the other units are based on their processing the quantities of each of the components as they would for some basic crude oil.

The crude oil distillation unit, by definition, contributes a complexity of 1.0. Naphtha hydrotreating, with a complexity factor of 2, contributes 0.3 to the refiner -- 2.0 times the capacity ratio of 0.15. Catalytic reforming contributes 0.6, which is its complexity factor of four times its capacity ratio of 0.15. The complexities of the other units are calculated accordingly. Nelson estimates that environmental protection equipment adds from 1.5 to 13 percent to overall refinery complexity, depending on the type of processing and specific regulations. Thus, as shown in Table D-2, the hypothetical fuel oil refinery in the first example has a final complexity of 2.1, indicative of a very simple overall operation.

TABLE D-2

Complexity Factor of a Hypothetical Fuel Oil Refinery

Processing Unit	Capacity MB/D	Unit Complexity Factor	Capacity Ratio	Plant Complexity*
Crude Oil Distillation	100	1	1	1.0
Hydrotreating	15	2	0.15	0.3
Catalytic Reforming	15	4	0.15	0.6
Complexity of Process Units				1.9
Complexity of Environmental Prevention Equipment, 13 percent of Complexity of Process Units				0.2
Total Complexity of Plant				2.1

*Unit Complexity Factor x Capacity Ratio = Plant Complexity

The second example is a gasoline refinery, which has a process flow remarkably similar to that of the fuel oil refinery. The product slate again consists of gasoline, jet and distillate fuels, and residual fuel oil. However, several process operations have been added to the flow scheme to reduce the yield of heavy distillate and resid and increase gasoline production. Atmospheric and vacuum gas oil are charged to an FCC unit for conversion to lighter products. FCC gasoline is directed to the gasoline pool. FCC olefins are aklylated to yield additional gasoline. Vacuum pitch is visbroken to improve its fuel oil characteristics and blended with cycle oils from the FCC unit to yield residual fuel oil. Another process, isomerization, has also been added to improve the octane characteristics of the light virgin gasoline. This refinery, oriented toward gasoline production, has a complexity of 9.0.

The third example is a petrochemical refinery. There are no distillate fuel oils or jet fuel in the product slate. These materials have been upgraded to gasoline and other lighter products, such as the light olefins ethylene, propylene, and butylene, and the aromatics benzene, toluene, and xylene. This combination of processes in the petrochemical refinery consumes large amounts of hydrogen, often resulting in a requirement for a hydrogen manufacturing unit. The addition of the several petrochemical and cracking processes has increased the refinery complexity significantly. A complexity of 16, while indicating a substantially more costly and involved type of processing than in the fuel oil and gasoline refineries, is only moderate for a petrochemical facility.

While the three refineries just discussed are hypothetical, commercial counterparts can be found throughout the United States; they serve as examples of the plants involved in modern petroleum refining. The actual range of complexity factors in operation today is greater than the examples given.

The complexity concept can also be useful in the estimation of refinery investment requirements. Table D-3 presents the distribution of the 287 refineries operating in the United States in 1978 by size range, processing capacity, and complexity. The capital requirements for refineries are often stated in terms of dollars per barrel per day of crude oil capacity. The actual cost would vary considerably depending on plant location, labor factors, etc. These capital requirements do not include costs associated with transport of crude oil to the refinery (tankers, pipelines, truck fleet, etc.), product distribution, or marketing.

TABLE D-3

Distribution of Refineries by Size Range,
Processing Capacity, and Complexity -- 1978

Refinery Size Range (MB/D)	Percentage of Refineries	Percentage of Crude Oil Capacity	Average Complexity
0-10	30	3	2.25
10-30	26	8	3.35
30-50	12	8	5.32
50-100	14	17	7.74
100-175	10	21	8.82
175+	8	43	7.65
	100	100	avg. 7.15

The cost effect of the complexity factor is much more important than that of size. For example, in the 0-10 MB/D refinery size category, the original construction cost and replacement cost are almost five times greater for refineries with a complexity factor over 2.5 than for those with complexity factors under 2.5. The significant effect of complexity is also evident in the variation of refinery costs with size. Per-barrel gross fixed assets and replacement costs generally increase with increasing refinery size, contrary to the "economy of scale" effect; this is because complexity also increase with refinery size, masking any "scale" effect. Many of the larger refineries also have multiple processing trains which diminish the effect of size on investments.

The complexity of U.S. refineries has also been a function of various laws and regulations which affect refining operations and use of petroleum products. Table D-4 lists the major laws which affect the U.S. refining industry.

TABLE D-4

Legislation Significantly Affecting the U.S. Refining Industry

Antiquities Act

Clean Air Act

Clean Water Act

Coastal Zone Management Act

Crude Oil Windfall Profit Tax

Defense Production Act

Department of Energy Organization Act

Economic Stabilization Act

Emergency Petroleum Allocation Act

Endangered Species Act

Energy Conservation and Production Act

Energy Policy and Conservation Act

Energy Security Act

Energy Supply and Environmental Coordination Act

Export Administration Act

Merchant Marine Act

National Environmental Policy Act

Powerplant and Industrial Fuel Use Act

Resource Conservation and Recovery Act

Rivers and Harbors Act

Toxic Substances Control Act

Trade Expansion Act

PRODUCT CHARACTERISTICS

Motor Fuels

Motor Gasoline

Since World War II, gasoline has changed in hydrocarbon composition and is now a product made by blending of refinery stock prepared by involved processes and special additives developed in extensive research programs. The most outstanding change in gasoline in recent years has been a vast improvement in anti-knock quality. Since 1970 the compression ratio of automobiles has reduced the octane number requirement for motor gasoline. Subsequent to 1974 the octane number has remained virtually the same. During this same period, the control of gasoline volatility has improved, contributing to better engine performance.

Federal air quality regulations limit the lead alkyl content of motor gasolines. Only one grade of unleaded gasoline was available for public use in mid-1974; however, unleaded gasolines constitute an increasing portion of gasoline consumption (32 percent in 1978). Production of these types of fuels are projected to increase. Such motor fuel characteristics as sulfur content, volatility, and boiling range may require further modifications to satisfy automotive performance and automobile pollution control needs.

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 as 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 improvement such as lower pour points, ignition quality, and storage stability. Air pollution regulations have generated an increased interest in anti-smoking additives.

Aviation Fuels

Aviation Gasoline

Quality control is particularly important in aviation gasoline production. Other important quality factors are volatility, freezing point, heat of combustion, and oxidation stability. Quality control surveillance and close process control enable the industry the production of 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

Liquified Petroleum Gas (LPG)

The extensive use of catalytic cracking and catalytic reforming processes and the growth in hydrocracking have resulted in large quantities of LPG in addition to the production from natural gas processing. Prior to 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.

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 10 percent of the crude refined. The desulfurization of high metal-content fuel oil and stack gas desulfurization has become widespread.

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 semi-rigid 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 and 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 crude oils and by improving storage, transportation, and blending facilities.

APPENDIX E

NPC Surveys of U.S. and World Energy and Oil Supply/Demand Forecasts

NPC SURVEYS OF U.S. AND WORLD ENERGY AND OIL SUPPLY/DEMAND FORECASTS

TABLE OF CONTENTS

HIGH AND MEDIUM CASES

The NPC Survey of U.S. and World Energy and Oil Supply/Demand Forecasts was first distributed in April 1979 and, because the political and economic events which occurred in 1979 were not included in its responses, a second, less detailed, survey was distributed in December 1979. Both surveys were mailed to approximately 30 institutions which regularly prepare supply/demand forecasts.[1] A comparison of the response to the two surveys is shown in the following tabulation:

	First Survey*	Second Survey†
U.S. Oil Companies	12	12
Foreign Oil Companies	2	1
Banks	1	2
Research Organizations, etc.	5	3
Total	20	18

*Distributed April 1979.
†Distributed December 1979.

While the respondents to the second survey were not identical to those of the first, it is evident from the above table that the type of survey respondent is not significantly different. It is thus inferred that any differences between the two surveys are not due to differences in survey respondents. For the purposes of this report, the adjusted averages of the responses to the first and second surveys are called the high and medium cases, respectively. Their adjusted averages are located in this appendix.

As mentioned above, the two surveys are not identical. In the second survey, the year 1980 was eliminated from all tables. On Table I, the breakdown by consuming sector was deleted and the fuels breakdown was compressed such that hydroelectric, geothermal, and other energy components were combined. Table II (U.S. Energy Supplies) was deleted. Tables VI and VII were combined. The remaining tables were unchanged from the first survey.

[1]A list of the institutions surveyed is located in this Appendix.

For each survey, tables were generated from the data base presenting the high, low, median, mean, and standard deviation of the various totals and subtotals from the survey for all respondents. Using the methodology outlined below, balanced tables were generated and adjusted average projections prepared for Tables I, III, IV, V, and VI. Tables III and IV were further broken down into PAD V and PADs I-IV inclusive. Blank cells were completed by extending trends or interpolating between years. (A copy of the first survey and its complete survey results are located in Volume II of Refinery Flexibility, An Interim Report; a copy of the second survey and its complete results are found in this appendix.)

LOW CASE

In order to reflect the views of those respondents whose projections were substantially lower than the average, a low case was prepared from the second survey by means of the following methodology. The responses of the 16 companies which supplied usable data on domestic energy and domestic petroleum supply and demand were arrayed and divided into quartiles based upon their 1990 projection of total U.S. product demand. The four respondents in the lowest quartile, consisting of three oil companies and one non-oil company, were then used in developing the low case.

Data in each cell were combined and Tables I, III, IV, V, and VI were balanced, and adjusted average projections prepared. The adjustment procedure utilized was the same as that employed for the first and second surveys and is described below. The adjusted average projections of the low case are found in this appendix.

As the responses to the second survey were not as complete as those of the first, blank cells were completed by extending trends or interpolating between years. Regional data for petroleum product demand for PADs I-IV and PAD V could not be developed from the survey for the low case because of lack of sufficient data from the respondents.

As regional data were essential for this report, the Department of Energy provided PAD V petroleum product demand data consistent with the low case total U.S. petroleum product demand, domestic production, and import levels for the years 1985 and 1990. The PAD V figures developed by the Department of Energy were subtracted from the NPC's low case total U.S. petroleum product demand to obtain the data for PADs I-IV.

BALANCING METHODOLOGY

The basic methodology employed in balancing the tables utilized the mean and standard deviation of each cell. The mean values for each cell in a row or column were summed. This sum was compared to the value of the appropriate total or subtotal of that row or column. Due to the fact that different numbers of respondents answered each individual cell, these numbers would coincide only by accident. When these numbers were not equal, the difference between the sum of the individual cells and the total was taken. This difference was then apportioned to the individual cells on the basis of their absolute standard deviation, and the total was derived. For example, consider the row of numbers below. Numbers in parentheses below represent their associated standard deviations.

100	200	500	750
(10)	(50)	(40)	

Suppose the first three numbers should add to the fourth, 750. In this case they add to 800. Thus, taking the 750 as a given, the other numbers must be adjusted downward.

The total standard deviation of the three numbers is equal to 100. The standard deviation of the first number accounts for 10 percent of the total, the second number for 50 percent, and the third number for 40 percent. Thus, 10 percent of 50 (800 - 750 = 50 x 10% = 5) is subtracted from the first number, 50% x 50 = 25 is subtracted from the second, and 40% x 50 = 20 is subtracted from the third. The balanced series is thus:

95	+	175	+	480 = 750
(100-5)		(200-25)		(500-20)

This technique assigns the variation in proportion to the standard deviation. If the standard deviation is considered the "agreement index," then this system assigns a larger share of the difference to cells where there is less agreement among respondents.

Tables are balanced by this method such that the more aggregate the cell in question, the more agreement is shown. Table balancing begins with totals, backs through subtotals, and finally arrives at individual cells.

LIST OF ORGANIZATIONS SURVEYED IN APRIL AND DECEMBER 1979

Atlantic Richfield Company

The British Petroleum Company, Ltd.

The Chase Manhattan Bank

Citibank

Sherman H. Clark Associates

Compagnie Francaise des Petroles

Continental Oil Company

Data Resources, Inc.

Exxon Corporation

Gulf Oil Corporation

W. J. Levy Consultants Corporation

Japan Ministry of International Trade and Industry

Congressional Research Service
Library of Congress

Marathon Oil Company

Massachusetts Institute of Technology

Mobil Oil Corporation

Organization for Economic Cooperation and Development

Pace Company Consultants and Engineers, Inc.

Petrofina S.A.

Petroleum Economics, Ltd.

Petroleum Industry Research Foundation, Inc.

Phillips Petroleum Company

Scallop Corporation*

Shell Oil Company

Standard Oil Company of California

Standard Oil Company (Indiana)

The Standard Oil Company (Ohio)*

Stanford Research Institute

Sun Company, Inc.*

Texaco Inc.

Union Oil Company of California

Office of Oil and Gas Analysis
U.S. Department of Energy

Policy and Evaluation
U.S. Department of Energy

The Wharton School
University of Pennsylvania

World Energy Models, Ltd.

*Received the second survey (December 1979) only.

TABLE I

High Case

Total U.S. Energy Consumption by Fuels and by Consuming Sectors
(Trillion Btu)

TOTAL--ALL RESPONDENTS
ADJUSTED AVERAGE

		PETROL. LIQUIDS	NAT. GAS (DRY)	COAL	NUCLEAR	HYDRO-ELEC.	GEO-THERMAL	OTHER	TOTAL PRIMARY ENERGY	ELEC. DIST. SECTOR	TOTAL ENERGY
RESIDENTIAL/COMMERCIAL:	1977	5142.0	7476.0	243.0	0.0	0.0	0.0	0.0	12861.0	4381.0	17242.0
	1980	5416.3	7984.1	206.7	0.0	0.0	0.0	4.0	13611.1	4720.2	18331.3
	1982	5492.4	8434.6	176.4	0.0	0.0	0.0	12.2	14115.6	5170.3	19285.9
	1985	5567.1	8767.9	169.5	0.0	0.0	0.0	40.9	14545.4	5783.7	20329.1
	1990	5603.5	9534.1	142.8	0.0	0.0	0.0	158.7	15439.1	6873.2	22312.3
TRANSPORTATION:	1977	19362.0	544.0	0.0	0.0	0.0	0.0	0.0	19906.0	16.0	19922.0
	1980	20708.8	649.9	0.0	0.0	0.0	0.0	0.0	21358.7	25.9	21384.6
	1982	21011.0	729.4	0.0	0.0	0.0	0.0	0.0	21740.4	29.2	21769.6
	1985	21250.7	662.9	0.0	0.0	0.0	0.0	0.0	21913.6	29.4	21943.0
	1990	21960.6	678.4	0.0	0.0	0.0	0.0	0.0	22639.0	37.3	22676.3
INDUSTRIAL:	1977	4524.0	7927.0	3529.0	0.0	36.0	0.0	0.0	16016.0	2921.0	18937.0
	1980	4681.1	8161.5	3793.4	0.0	36.6	0.0	3.7	16676.3	3119.1	19795.4
	1982	5063.3	8308.4	4005.0	0.0	37.3	0.0	7.8	17421.8	3414.8	20836.6
	1985	5301.1	8492.3	4491.3	0.0	38.2	0.0	7.2	18330.1	3845.3	22175.4
	1990	5751.0	8569.1	5571.9	0.0	39.3	0.0	14.3	19945.6	4632.0	24577.6
ELECTRIC UTILITY:	1977	4025.0	3256.0	10263.0	2674.0	2475.0	103.0	0.0	22796.0	-7318.0	15478.0
	1980	3848.2	2827.4	11924.5	3547.6	3291.9	114.1	5.3	25559.0	-7865.2	17693.8
	1982	3846.0	2466.2	13257.7	4542.0	3463.2	159.6	9.0	27743.7	-8614.3	19129.4
	1985	3987.2	2095.9	14995.0	6305.1	3617.2	221.1	104.3	31325.8	-9658.4	21667.4
	1990	3526.0	1460.5	18661.4	9159.6	3896.2	359.0	176.2	37238.9	-11542.5	25696.4
NON-ENERGY & OTHERS:	1977	3917.0	728.0	98.0	0.0	0.0	0.0	0.0	4743.0	0.0	4743.0
	1980	4212.8	687.4	93.9	0.0	0.0	0.0	0.0	4994.1	0.0	4994.1
	1982	4643.3	709.1	105.1	0.0	0.0	0.0	0.0	5457.5	0.0	5457.5
	1985	4940.5	764.4	112.3	0.0	0.0	0.0	0.0	5817.2	0.0	5817.2
	1990	5595.5	842.8	138.7	0.0	0.0	0.0	0.0	6577.0	0.0	6577.0
SYNTHETIC CONVERSION ADJUSTMENT	1977	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	1980	279.3	-247.7	4.0	0.0	0.0	0.0	0.0	35.6	0.0	35.6
	1982	309.4	-271.7	6.6	0.0	0.0	0.0	0.0	44.3	0.0	44.3
	1985	257.8	-314.4	135.2	0.0	0.0	0.0	0.0	78.6	0.0	78.6
	1990	207.2	-598.6	639.7	0.0	0.0	0.0	0.0	248.3	0.0	248.3
TOTAL:	1977	36970.0	19931.0	14133.0	2674.0	2511.0	103.0	0.0	76322.0	0.0	76322.0
	1980	39146.5	20062.6	16022.5	3547.6	3328.5	114.1	12.9	82234.6	0.0	82234.6
	1982	40365.3	20376.0	17550.8	4542.0	3500.5	159.6	29.1	86523.3	0.0	86523.3
	1985	41304.3	20469.0	19903.3	6305.1	3655.4	221.1	152.4	92010.7	0.0	92010.7
	1990	42643.8	20486.2	25154.4	9159.6	3935.5	359.0	349.3	102087.9	0.0	102087.9

TABLE II

High Case

U.S. Energy Supplies

ADJUSTED AVERAGE
TOTAL--ALL RESPONDENTS

	1977	1980	1982	1985	1990
OIL (MILLION BARRELS/YEAR)					
DOMESTIC PRODUCTION - TOTAL	3,599.8	3,738.8	3,665.9	3,570.4	3,586.1
CRUDE & LEASE CONDENSATE	3,009.3	3,179.4	3,118.7	3,058.5	3,112.7
NGL	590.5	559.4	547.2	511.9	473.4
IMPORTS - TOTAL	3,214.6	3,342.7	3,609.8	3,812.6	3,980.3
CRUDE	2,414.3	2,509.0	2,691.5	2,897.7	2,952.9
PRODUCTS (INCL. NGL & UNFINISHED)	800.3	833.7	918.3	914.9	1,027.4
EXPORTS	-88.6	-106.3	-113.9	-95.4	-94.7
PROCESSING GAIN, ETC.	201.8	193.5	209.1	192.4	192.7
SYNCRUDE	0.0	0.0	1.5	16.7	92.4
FROM SHALE	0.0	0.0	1.5	16.2	75.7
FROM COAL	0.0	0.0	0.0	0.5	16.7
FROM INVENTORY	-200.1	-32.2	-18.3	-6.6	-7.7
CRUDE	-62.2	-23.0	-17.7	-3.9	-4.6
PRODUCTS	-137.9	-9.2	-0.6	-2.7	-3.1
TOTAL OIL SUPPLY	6,727.5	7,136.5	7,354.1	7,490.1	7,749.1
MEMO: TRILLION BTU'S/YR.	36,970.0	39,146.5	40,365.3	41,304.3	42,643.8
GAS (BILLION CUBIC FEET/YEAR)					
PRODUCTION	20,025.0	18,783.0	18,144.9	17,507.7	16,885.4
EXTRACTION LOSS, TRANSFERS OUT	-862.0	-706.0	-615.7	-694.6	-676.8
IMPORTS - TOTAL	1,001.0	1,413.9	2,009.0	2,516.0	2,785.2
EXPORTS	-56.0	-53.0	-54.1	-37.2	-36.1
FROM INV., TRANSMILLION LOSS & UNACCOUNTED	-597.0	-260.3	-198.6	-216.1	-211.2
TOTAL DRY NATURAL GAS	19,511.0	19,177.8	19,285.5	19,075.8	18,746.5
SYNGAS	0.0	214.1	265.9	335.3	536.8
FROM COAL	0.0	15.1	25.3	106.1	307.1
FROM LIQUIDS	0.0	199.0	240.6	229.2	229.7
TOTAL GAS SUPPLY	19,511.0	19,391.9	19,551.4	19,411.1	19,283.3
MEMO: TRILLION BTU'S/YR.	19,931.0	20,062.6	20,376.0	20,469.0	20,486.2
COAL (ANTHRACITE, BITUMINOUS, & LIGNITE): THOUSAND SHORT TONS PER YEAR					
PRODUCTION - TOTAL	694,755.0	779,336.5	845,443.0	982,173.6	1,258,422.0
FOR CONVENTIONAL DOMESTIC MARKETS	694,755.0	779,028.3	845,443.0	975,737.5	1,235,753.0
FOR SYNTHETIC OIL &/OR GAS PLANTS	0.0	308.2	0.0	6,436.1	22,669.5
NET EXPORTS	-52,509.0	-49,323.5	-51,511.9	-60,262.5	-62,684.5
FROM INV., LOSSES, GAINS, & UNACCOUNTED FOR	-16,575.0	-4,367.1	0.0	-5,801.5	-5,810.5
TOTAL COAL SUPPLY	625,671.0	725,645.9	793,931.1	916,109.6	1,189,927.0
MEMO: TRILLION BTU'S/YR.	14,133.0	16,022.5	17,550.8	19,903.3	25,154.4
NUCLEAR: TRILLION BTU'S/YR.	2,674.0	3,547.6	4,542.0	6,305.1	9,159.6

TABLE III

High Case

Domestic Demand for Products -- Total U.S.
(THOUSAND BARRELS/DAY)

ADJUSTED AVERAGE
TOTAL--ALL RESPONDENTS

	1977	1980	1982	1985	1990
MOTOR GASOLINE: LEADED - PREMIUM	1,061.0	418.4	154.1	21.4	0.0
- NON-PREMIUM	4,207.0	3,508.7	2,867.7	1,949.8	1,088.9
S.TOTAL	5,268.0	3,927.1	3,021.8	1,971.2	1,088.9
UNLEADED - PREMIUM	0.0	900.2	1,341.8	1,882.6	2,235.3
- NON-PREMIUM	1,908.0	2,755.7	3,189.3	3,302.6	3,429.1
S.TOTAL	1,908.0	3,655.9	4,531.1	5,185.2	5,664.4
TOTAL MOTOR GASOLINE	7,176.0	7,583.0	7,552.9	7,156.4	6,753.3
AVIATION GASOLINE	38.0	41.6	43.4	44.9	49.0
JET FUEL: NAPTHA TYPE	208.0	196.8	184.1	170.8	140.2
KEROSINE TYPE	831.0	921.4	1,001.1	1,101.5	1,298.1
TOTAL JET FUEL	1,039.0	1,118.2	1,185.2	1,272.3	1,438.3
SPECIAL NAPTHA	86.0	98.1	103.0	104.2	112.5
KEROSINE	175.0	191.0	189.0	168.7	163.1
DISTILLATE FUEL OIL: NO.2 OIL	1,292.0	1,302.2	1,292.3	1,279.5	1,218.4
NO.4 OIL	62.0	64.2	66.6	70.3	74.3
DIESEL - ON HIGHWAY	724.0	939.1	1,088.0	1,352.0	1,822.4
- OFF HIGHWAY	172.0	195.6	205.9	220.9	251.2
OTHER DISTILLATE	1,102.0	1,079.3	1,153.6	1,172.6	1,227.5
TOTAL DISTILLATE FUEL OIL	3,352.0	3,580.4	3,806.4	4,095.4	4,593.9
RESIDUAL FUEL OIL: 0 - .5%S	959.0	996.3	1,070.7	1,137.7	1,048.6
.51 - 1.0%S	693.0	815.1	839.7	876.2	898.3
1.1 - 2.0%S	612.0	641.5	651.2	654.0	643.9
2.0%S +	807.0	686.9	679.1	659.6	634.1
TOTAL RESIDUAL FUEL OIL	3,071.0	3,139.9	3,240.7	3,327.5	3,225.0
LIQUEFIED GASES: ETHANE	412.0	417.9	403.3	402.0	390.3
PROPANE	866.0	900.1	941.3	1,017.4	1,123.6
BUTANE	115.0	147.9	170.0	193.4	210.2
PROPANE/BUTANE MIX	29.0	20.6	22.5	23.8	26.7
TOTAL LIQUEFIED GASES	1,422.0	1,486.5	1,537.0	1,636.6	1,750.7
PETROCHEMICAL FEEDSTOCKS: STILL GAS	48.0	53.0	58.2	50.7	47.0
400 EP NAPTHA	204.0	239.9	272.0	318.6	435.8
OTHER	269.0	353.5	438.4	555.2	771.2
TOTAL PETROCHEMICAL FEEDSTOCKS	521.0	646.4	768.6	924.4	1,254.0
LUBRICANTS	160.0	172.6	180.3	189.6	209.8
WAXES	16.0	19.1	19.8	21.2	24.2
COKE	267.0	269.5	276.5	284.2	304.9
ASPHALT & ROAD OIL	437.0	474.8	488.4	508.0	543.5
STILL GAS FOR FUEL	524.0	560.0	580.8	582.3	599.6
MISCELLANEOUS PRODUCTS	147.0	171.0	176.1	205.2	208.6
TOTAL DEMAND	18,431.5	19,552.1	20,148.2	20,520.8	21,230.4
ETHANE	412.0	392.6	389.4	371.0	336.9
PROPANE	123.0	160.6	175.6	216.2	259.0
BUTANE	93.0	96.1	103.4	104.5	109.2
PROPANE/BUTANE MIX	5.0	3.1	3.3	3.7	4.5
TOTAL	633.0	652.4	671.7	695.3	709.7

TABLE III

High Case

Domestic Demand for Products -- PADs I-IV
(Thousand Barrels/Day)

ADJUSTED AVERAGE
TOTAL--ALL RESPONDENTS

	1977	1980	1982	1985	1990
MOTOR GASOLINE: LEADED - PREMIUM	307.0	102.2	37.6	8.1	0.0
- NON-PREMIUM	508.0	479.5	387.7	266.6	150.0
S.TOTAL	815.0	581.7	425.3	274.7	150.0
UNLEADED - PREMIUM	0.0	114.4	206.3	323.7	422.5
- NON-PREMIUM	268.0	447.2	517.5	517.6	496.7
S.TOTAL	268.0	561.6	723.8	841.3	919.2
TOTAL MOTOR GASOLINE	1,083.0	1,143.3	1,149.1	1,116.0	1,069.2
AVIATION GASOLINE	9.0	9.8	10.0	10.7	11.4
JET FUEL: NAPTHA TYPE	59.0	55.1	51.7	48.5	35.8
KEROSINE TYPE	240.0	269.6	294.1	327.0	400.2
TOTAL JET FUEL	299.0	324.7	345.8	375.5	436.0
SPECIAL NAPTHA	8.0	10.6	10.9	11.6	13.0
KEROSINE	13.0	13.9	13.3	14.5	15.4
DISTILLATE FUEL OIL: NO.2 OIL	39.0	45.0	45.2	44.2	40.9
NO.4 OIL	2.0	3.1	3.2	3.4	3.4
DIESEL - ON HIGHWAY	102.0	140.5	160.7	197.0	261.8
- OFF HIGHWAY	22.0	24.7	25.5	26.9	31.3
OTHER DISTILLATE	160.0	139.6	147.3	147.4	156.7
TOTAL DISTILLATE FUEL OIL	325.0	353.0	381.9	419.0	494.2
RESIDUAL FUEL OIL: 0 - .5%S	326.0	359.4	382.3	411.1	345.5
.51 - 1.0%S	39.0	31.6	36.6	40.0	43.9
1.1 - 2.0%S	184.0	130.6	133.3	130.4	131.4
2.0%S +	21.0	28.6	29.2	28.3	24.8
TOTAL RESIDUAL FUEL OIL	570.0	550.2	581.5	609.8	545.5
LIQUEFIED GASES: ETHANE	2.0	2.2	2.3	2.1	2.0
PROPANE	46.0	52.1	53.6	56.4	61.4
BUTANE	4.0	4.2	5.2	6.8	8.4
PROPANE/BUTANE MIX	3.0	3.2	3.2	3.1	3.1
TOTAL LIQUEFIED GASES	55.0	61.8	64.2	68.4	74.9
PETROCHEMICAL FEEDSTOCKS: STILL GAS	2.0	2.2	1.9	2.6	2.3
400 EP NAPTHA	3.0	2.0	4.3	9.6	17.2
OTHER	8.0	11.3	11.3	20.9	32.9
TOTAL PETROCHEMICAL FEEDSTOCKS	13.0	15.5	17.6	33.0	52.4
LUBRICANTS	15.0	16.1	16.6	18.1	20.1
WAXES	3.0	3.1	3.6	3.9	4.4
COKE	49.0	47.2	48.6	50.5	54.5
ASPHALT & ROAD OIL	63.0	67.5	69.4	72.3	76.3
STILL GAS FOR FUEL	101.0	100.8	104.3	107.7	109.7
MISCELLANEOUS PRODUCTS	8.0	12.0	12.0	13.6	13.5
TOTAL DEMAND	2,614.0	2,729.9	2,828.9	2,924.7	2,990.6
ETHANE	2.0	2.2	2.3	1.9	1.4
PROPANE	5.0	6.8	7.5	8.5	10.6
BUTANE	2.0	1.3	1.4	1.7	1.8
PROPANE/BUTANE MIX	1.0	0.8	0.8	0.8	0.6
TOTAL	10.0	11.1	12.0	12.8	14.5

TABLE III

High Case

Domestic Demand for Products -- PAD V
(Thousand Barrels/Day)

ADJUSTED AVERAGE
TOTAL--ALL RESPONDENTS

	1977	1980	1982	1985	1990
MOTOR GASOLINE: LEADED - PREMIUM	754.0	316.2	116.5	13.3	0.0
- NON-PREMIUM	3,699.0	3,029.2	2,480.0	1,683.2	938.9
S.TOTAL	4,453.0	3,345.4	2,596.5	1,696.5	938.9
UNLEADED - PREMIUM	0.0	785.8	1,135.5	1,558.9	1,812.8
- NON-PREMIUM	1,640.0	2,308.5	2,671.8	2,785.0	2,932.4
S.TOTAL	1,640.0	3,094.3	3,807.3	4,343.9	4,745.2
TOTAL MOTOR GASOLINE	6,093.0	6,439.7	6,403.8	6,040.4	5,684.1
AVIATION GASOLINE	29.0	31.8	33.4	34.2	37.6
JET FUEL: NAPTHA TYPE	149.0	141.7	132.4	122.3	104.4
KEROSINE TYPE	591.0	651.8	707.0	774.5	897.9
TOTAL JET FUEL	740.0	793.5	839.4	896.8	1,002.3
SPECIAL NAPTHA	78.0	87.5	92.1	92.6	99.5
KEROSINE	162.0	177.1	175.7	154.2	147.7
DISTILLATE FUEL OIL: NO.2 OIL	1,253.0	1,257.2	1,247.1	1,235.3	1,177.5
NO.4 OIL	60.0	61.1	63.4	66.9	70.9
DIESEL - ON HIGHWAY	622.0	798.6	927.3	1,155.0	1,560.6
- OFF HIGHWAY	150.0	170.9	180.4	194.0	219.9
OTHER DISTILLATE	942.0	939.7	1,006.3	1,025.2	1,070.8
TOTAL DISTILLATE FUEL OIL	3,027.0	3,227.4	3,424.5	3,676.4	4,099.7
RESIDUAL FUEL OIL: 0 - .5%S	633.0	636.9	688.4	726.6	703.1
.51 - 1.0%S	654.0	783.5	803.1	836.2	854.4
1.1 - 2.0%S	428.0	510.9	517.9	523.6	512.5
2.0%S +	786.0	658.3	649.9	631.3	609.3
TOTAL RESIDUAL FUEL OIL	2,501.0	2,589.7	2,659.2	2,717.7	2,679.5
LIQUEFIED GASES: ETHANE	410.0	415.7	401.0	399.9	388.3
PROPANE	820.0	848.0	887.7	961.0	1,062.2
BUTANE	111.0	143.7	164.8	186.6	201.8
PROPANE/BUTANE MIX	26.0	17.4	19.3	20.7	23.6
TOTAL LIQUEFIED GASES	1,367.0	1,424.7	1,472.8	1,568.2	1,675.8
PETROCHEMICAL FEEDSTOCKS: STILL GAS	46.0	50.8	56.3	48.1	44.7
400 EP NAPTHA	201.0	237.9	267.7	309.0	418.6
OTHER	261.0	342.2	427.1	534.3	738.3
TOTAL PETROCHEMICAL FEEDSTOCKS	508.0	630.9	751.0	891.4	1,201.6
LUBRICANTS	145.0	156.5	163.7	171.5	189.7
WAXES	13.0	16.0	16.2	17.3	19.8
COKE	218.0	222.3	227.9	233.7	250.4
ASPHALT & ROAD OIL	374.0	407.3	419.0	435.7	467.2
STILL GAS FOR FUEL	423.0	459.2	476.5	474.6	489.9
MISCELLANEOUS PRODUCTS	139.0	159.0	164.1	191.6	195.1
TOTAL DEMAND	15,817.5	16,822.2	17,319.3	17,596.1	18,239.8
ETHANE	410.0	390.4	387.1	369.1	335.5
PROPANE	118.0	153.8	168.1	207.7	248.4
BUTANE	91.0	94.8	102.0	102.8	107.4
PROPANE/BUTANE MIX	4.0	2.3	2.5	2.9	3.9
TOTAL	623.0	641.3	659.7	682.5	695.2

TABLE IV

High Case

U.S. Petroleum Supply/Demand Balance -- Total U.S.
(Thousand Barrels/Day)

ADJUSTED AVERAGE
TOTAL--ALL RESPONDENTS

	1977	1980	1982	1985	1990
DEMAND - TOTAL	18,690.3	19,862.3	20,472.9	20,811.7	21,518.8
1. LOCAL PRODUCT DEMAND	18,431.5	19,552.1	20,148.2	20,520.8	21,230.4
2. CRUDE AND PRODUCT EXPORTS	242.7	291.2	312.1	261.4	259.5
3. PRODUCT SHIPMENTS TO OTHER DISTRICTS	0.0	0.0	0.0	0.0	0.0
4. CRUDE, NGL & UNF. SHIPMENTS TOD	0.0	0.0	0.0	0.0	0.0
5. CRUDE LOSSES	16.1	19.0	12.6	29.5	28.9
SUPPLY - TOTAL	18,690.3	19,862.3	20,472.9	20,811.7	21,518.8
1. PRODUCTION - TOTAL	9,862.5	10,243.3	10,043.6	9,781.9	9,824.9
CRUDE AND LEASE CONDENSATE	8,244.7	8,710.7	8,544.4	8,379.4	8,527.9
NGL	1,617.8	1,532.6	1,499.2	1,402.5	1,297.0
2. RECEIPTS FROM OTHER DISTRICTS	0.0	0.0	0.0	0.0	0.0
CRUDE, NGL, AND UNFINISHED	0.0	0.0	0.0	0.0	0.0
PRODUCTS	0.0	0.0	0.0	0.0	0.0
3. PROCESSING GAIN, ETC.	569.0	549.1	585.5	556.6	556.8
4. IMPORTS - TOTAL	8,807.1	9,158.1	9,889.9	10,445.5	10,904.9
CRUDE AND UNFINISHED	6,646.0	7,103.6	7,665.4	8,180.6	8,491.6
FROM OVERLAND	279.0	206.5	130.5	88.3	82.1
FROM OFFSHORE	6,367.0	6,897.1	7,534.9	8,092.3	8,409.5
NGL	42.0	77.7	88.1	120.1	162.2
FINISHED PRODUCTS	2,119.1	1,976.8	2,136.4	2,144.8	2,251.1
5. SYNCRUDE	0.0	0.0	4.1	45.8	253.2
FROM SHALE	0.0	0.0	4.1	44.4	207.4
FROM COAL	0.0	0.0	0.0	1.4	45.8
6. FROM INVENTORY	-548.2	-88.2	-50.1	-18.1	-21.1
CRUDE	-170.4	-63.0	-48.5	-10.7	-12.6
PRODUCTS	-377.8	-25.2	-1.6	-7.4	-8.5
7. CRUDE RUNS	14,602.0	15,581.8	15,903.9	16,413.3	16,978.6

TABLE IV

High Case

U.S. Petroleum Supply/Demand Balance -- PADs I-IV
(Thousand Barrels/Day)

ADJUSTED AVERAGE
TOTAL--ALL RESPONDENTS

	1977	1980	1982	1985	1990
DEMAND - TOTAL	16,139.3	17,142.3	17,671.1	17,892.4	18,554.7
1. LOCAL PRODUCT DEMAND	15,817.5	16,822.2	17,319.3	17,596.1	18,239.8
2. CRUDE AND PRODUCT EXPORTS	171.7	168.7	203.0	154.2	166.4
3. PRODUCT SHIPMENTS TO OTHER DISTRICTS	126.0	132.1	131.7	119.6	123.8
4. CRUDE, NGL & UNF. SHIPMENTS TOD	9.0	3.5	10.3	2.7	3.4
5. CRUDE LOSSES	15.1	15.8	6.7	19.8	21.3
SUPPLY - TOTAL	16,139.3	17,142.3	17,671.1	17,892.4	18,554.7
1. PRODUCTION - TOTAL	8,414.5	7,764.4	7,392.0	6,950.4	6,680.2
CRUDE AND LEASE CONDENSATE	6,820.7	6,262.8	5,927.5	5,590.5	5,446.5
NGL	1,593.8	1,501.6	1,464.5	1,359.9	1,233.7
2. RECEIPTS FROM OTHER DISTRICTS	68.0	427.4	503.0	614.3	866.0
CRUDE, NGL, AND UNFINISHED	47.0	402.5	476.3	582.7	821.1
PRODUCTS	21.0	24.9	26.7	31.6	44.9
3. PROCESSING GAIN, ETC.	535.0	445.1	479.3	447.9	455.0
4. IMPORTS - TOTAL	7,593.1	8,590.5	9,342.1	9,848.2	10,316.9
CRUDE AND UNFINISHED	5,547.0	6,641.0	7,239.6	7,709.8	8,049.9
FROM OVERLAND	259.0	192.3	119.0	83.2	77.9
FROM OFFSHORE	5,288.0	6,448.7	7,120.6	7,626.6	7,972.0
NGL	38.0	75.1	85.2	116.6	159.8
FINISHED PRODUCTS	2,008.1	1,874.4	2,017.2	2,021.8	2,107.2
5. SYNCRUDE	0.0	0.0	4.1	45.8	253.2
FROM SHALE	0.0	0.0	4.1	44.4	207.4
FROM COAL	0.0	0.0	0.0	1.4	45.8
6. FROM INVENTORY	-471.2	-85.1	-49.4	-14.2	-16.8
CRUDE	-103.4	-61.9	-48.5	-8.9	-11.7
PRODUCTS	-367.8	-23.2	-0.9	-5.3	-5.1
7. CRUDE RUNS	12,279.0	13,132.4	13,374.1	13,782.3	14,308.7

TABLE IV

High Case

U.S. Petroleum Supply/Demand Balance -- PAD V
(Thousand Barrels/Day)

ADJUSTED AVERAGE
TOTAL--ALL RESPONDENTS

	1977	1980	1982	1985	1990
DEMAND - TOTAL	2,754.0	3,283.0	3,446.8	3,655.9	3,957.3
1. LOCAL PRODUCT DEMAND	2,614.0	2,729.9	2,828.9	2,924.7	2,990.6
2. CRUDE AND PRODUCT EXPORTS	71.0	122.5	109.1	107.2	93.1
3. PRODUCT SHIPMENTS TO OTHER DISTRICTS	21.0	24.9	26.7	31.6	44.9
4. CRUDE, NGL & UNF. SHIPMENTS TOD	47.0	402.5	476.3	582.7	821.1
5. CRUDE LOSSES	1.0	3.2	5.9	9.7	7.6
SUPPLY - TOTAL	2,754.0	3,283.0	3,446.8	3,655.9	3,957.3
1. PRODUCTION - TOTAL	1,448.0	2,478.9	2,651.6	2,831.5	3,144.7
CRUDE AND LEASE CONDENSATE	1,424.0	2,447.9	2,616.9	2,788.9	3,081.4
NGL	24.0	31.0	34.7	42.6	63.3
2. RECEIPTS FROM OTHER DISTRICTS	135.0	135.6	142.0	122.3	127.2
CRUDE, NGL, AND UNFINISHED	9.0	3.5	10.3	2.7	3.4
PRODUCTS	126.0	132.1	131.7	119.6	123.8
3. PROCESSING GAIN, ETC.	34.0	104.0	106.2	108.7	101.8
4. IMPORTS - TOTAL	1,214.0	567.6	547.8	597.3	588.0
CRUDE AND UNFINISHED	1,099.0	462.6	425.8	470.8	441.7
FROM OVERLAND	20.0	14.2	11.5	5.1	4.2
FROM OFFSHORE	1,079.0	448.4	414.3	465.7	437.5
NGL	4.0	2.6	2.9	3.5	2.4
FINISHED PRODUCTS	111.0	102.4	119.2	123.0	143.9
5. SYNCRUDE	0.0	0.0	0.0	0.0	0.0
FROM SHALE	0.0	0.0	0.0	0.0	0.0
FROM COAL	0.0	0.0	0.0	0.0	0.0
6. FROM INVENTORY	-77.0	-3.1	-0.7	-3.9	-4.3
CRUDE	-67.0	-1.1	0.0	-1.8	-0.9
PRODUCTS	-10.0	-2.0	-0.7	-2.1	-3.4
7. CRUDE RUNS	2,323.0	2,449.4	2,529.8	2,631.0	2,669.9

TABLE V

High Case

World Oil Consumption
(Million Barrels/Day)

ADJUSTED AVERAGE
TOTAL--ALL RESPONDENTS

	1977	1980	1982	1985	1990
OECD					
UNITED STATES	18.4	19.6	20.1	20.5	21.2
WESTERN EUROPE	14.2	14.7	15.2	16.0	16.8
JAPAN	5.3	5.6	6.0	6.6	7.1
OTHER OECD	2.6	2.7	2.7	3.0	3.0
NON-OECD (EXCL. USSR, E. EUROPE, CHINA)					
NON-OECD	9.3	10.9	11.6	13.3	15.9
NON-COMMUNIST COUNTRIES	49.8	53.4	55.6	59.4	64.0
USSR	8.0	9.1	9.6	10.3	11.2
EAST EUROPE	2.1	2.4	2.6	2.9	3.2
CHINA	1.5	2.1	2.5	3.0	3.8
COMMUNIST COUNTRIES	11.6	13.7	14.6	16.1	18.2
TOTAL CONSUMPTION	61.4	67.1	70.2	75.5	82.2

TABLES VI and VII

High Case

World Oil and Natural Gas Liquids Supplies
(Million Barrels/Day)

ADJUSTED AVERAGE
TOTAL--ALL RESPONDENTS

	1977	1980	1982	1985	1990
OECD					
U.S.	9.9	10.2	10.0	9.8	9.8
CANADA	1.6	1.6	1.7	1.8	1.8
W. EUROPE	1.5	3.0	3.8	4.2	4.6
JAPAN, AUSTRALIA, NEW ZEALAND	0.5	0.5	0.6	0.6	0.7
SUB-TOTAL	13.4	15.4	16.1	16.4	16.9
OPEC					
VENEZUELA	2.3	2.3	2.3	2.3	2.3
ECUADOR	0.2	0.2	0.2	0.2	0.2
INDONESIA	1.7	1.7	1.7	1.7	1.6
AFRICA	5.6	5.9	6.2	6.0	5.7
ALGERIA	1.2	1.2	1.4	1.3	1.2
LIBYA	2.1	2.2	2.3	2.3	2.1
NIGERIA	2.1	2.3	2.3	2.3	2.1
GABON	0.2	0.2	0.2	0.2	0.2
MIDDLE EAST	22.1	21.1	22.7	24.9	26.9
IRAN	5.7	4.1	4.3	4.6	4.6
KUWAIT	1.9	2.0	2.1	2.2	2.3
S. ARABIA	9.2	8.8	9.7	10.5	11.7
IRAQ	2.5	3.1	3.5	4.0	4.4
UAE	2.0	1.9	2.1	2.4	2.6
QATAR	0.4	0.5	0.5	0.5	0.5
NEUTRAL ZONE	0.4	0.6	0.6	0.6	0.6
SUB-TOTAL	31.9	31.1	33.1	35.1	36.7
NON-OPEC (EXCL. USSR, E. EUROPE, CHINA)					
MEXICO	1.1	2.1	2.6	3.1	4.2
OTHER L. AMERICA	1.2	1.4	1.5	1.7	1.9
AFRICA	0.7	1.0	1.1	1.3	1.4
MIDDLE EAST	0.6	0.6	0.6	0.7	0.7
ASIA	0.7	0.9	1.1	1.3	1.5
SUB-TOTAL	4.3	5.9	7.0	8.0	9.7
USSR	10.9	12.0	12.4	12.8	13.6
EAST EUROPE	0.4	0.4	0.4	0.4	0.4
CHINA	1.8	2.4	2.8	3.5	4.5
SUB-TOTAL	13.1	14.8	15.6	16.6	18.5
REFINERY PROCESSING GAINS					
U.S.	0.5	0.5	0.5	0.5	0.5
OTHER	0.0	0.0	0.0	0.0	-0.1
SUB-TOTAL	0.5	0.5	0.5	0.5	0.5
TOTAL SUPPLY	63.2	67.7	72.2	76.6	82.3

INSTRUCTIONS

NPC SURVEY OF U.S. AND WORLD ENERGY AND OIL SUPPLY/DEMAND FORECASTS

(distributed December 1979)

The majority of the responses to the recent NPC survey of current energy and oil supply/demand forecasts were prepared in late 1978 or very early 1979 and, thus, do not reflect the political and economic events which have occurred in 1979. Several respondents have indicated that they have updated or are updating their data to reflect the changed economic and political conditions.

If you have revised data available, we would appreciate your completing the attached tables as soon as possible. All data supplied will be held in strict confidence and should be forwarded directly to the attention of:

Dr. Dimitri A. Plionis
Arthur Young & Company
1025 Connecticut Avenue, N.W.
Washington, D.C. 20036

Arthur Young has been contracted to receive, process, compile, and consolidate results of the survey, and has been instructed to return your survey forms to you along with a copy of the results of the survey for your further review and comment.

You are requested to complete the attached survey questionnaire forms as fully as possible based on whatever assumptions you deem necessary and reflective of your best current estimate of future trends. It is further requested that you return with the completed survey forms any explanatory notes you feel necessary for an accurate interpretation of the forecast data you supply. Such explanations should include the key assumptions used in your forecasts regarding political, economic, demographic, and logistical conditions. You are also requested to indicate the date of the internal forecast on which your questionnaire data are based. Additionally, forms are attached to provide key assumptions used in developing the forecasts in Table I - "Total U.S. Primary Energy Consumption by Fuels," and Table III - "Domestic Demand for Products."

In order to expedite the processing of your response, leave blank any question you are unable to answer. If you wish to indicate zero quantity for a product, insert a "0". A negative quantity should be bracketed, i.e., (159). Only provide information for the categories indicated on the tables. If you wish to supply information not requested in the tables, please attach additional sheets. Also, please use the units indicated on the table when completing the survey. If your data is in a different form, please provide conversion factors and note the units used on the table.

You will note that the table numbers correspond to those on the previous survey, although some tables have been eliminated and the amount of detail on other tables has been reduced.

Each survey table requests data for the years 1982, 1985, and 1990. 1980 data are not requested in this survey. To provide guidance and to ensure an accurate interpretation of your data, 1977 information has been provided.

You will also note that certain survey forms--"U.S. Domestic Product Demand" and "U.S. Oil Supply/Demand Balances"--request that data be provided for Petroleum Administration for the Defense (PAD) districts I-IV and V (see Exhibit A for map of PAD districts). This information is needed to help assess U.S. refining capacity and hardware requirements by PAD's for the forecast period. This information will also be used to develop comparative refining economic assessments by size and location.

If any questions arise regarding the survey, please contact Mr. Marshall W. Nichols, Deputy Executive Director, National Petroleum Council, 1625 K Street, N.W., Washington, D.C. 20006 [(202) 393-6100]. It is requested that your completed survey forms be returned to Arthur Young & Company by December 21, 1979. Please include the name and phone number of the individual in your organization to be contacted if any questions arise.

EXHIBIT A

PETROLEUM ADMINISTRATION FOR DEFENSE – (PAD) DISTRICTS

TABLE I

Total U.S. Primary Energy Consumption by Fuels

(Trillion Btu)

	1977	1982	1985	1990
Petroleum Liquids	36,970			
Natural Gas (Dry)	19,931			
Coal	14,133			
Nuclear	2,674			
Other	2,614			
Total Primary Energy	76,322			

TABLE IA

Economic and Energy Assumptions

Pertinent to U.S. Energy Demand/Supply Forecast

Economic Assumptions	1977	1982	1985	1990
Real GNP (Billion 1972 $)	1332.7			
FRB Index of Industrial Production (1967=100)	137.1			
Population (Mid-year, 000)	216,820			
Disposable Personal Income (Billion 1972 $)	926.3			

Note: Table II has been deleted.

TABLE III (Pg. 1 of 3)

DOMESTIC DEMAND FOR PRODUCTS - TOTAL U.S.

(MB/D)

		Actual[1] 1977	Forecast 1982	Forecast 1985	Forecast 1990
	Motor Gasoline: Leaded - Premium	1,061			
	- Non-premium	4,207			
	S.Total	5,268			
	Unleaded - Premium	0			
	- Non-premium	1,908			
	S.Total	1,908			
1.	Total Motor Gasoline	7,176			
2.	Aviation Gasoline	38			
	Jet Fuel: Naphtha Type	208			
	Kerosine Type	831			
3.	Total Jet Fuel	1,039			
4.	Special Naphtha	86			
5.	Kerosine	175			
	Distillate Fuel Oil: #2 Oil	1,292			
	#4 Oil	62			
	Diesel - On Highway	724			
	- Off Highway	172			
	Other Distillate	1,102			
6.	Total Distillate Fuel Oil	3,352			
	Residual Fuel Oil: 0 - .5%	959			
	.51 - 1.0%S	693			
	1.1 - 2.0%S	612			
	2.0%S +	807			
7.	Total Residual Fuel Oil	3,071			
	Liquefied Gases: Ethane	412			
	Propane	866			
	Butane	115			
	Propane/Butane Mix	29			
8.	Total Liquefied Gases[2]	1,422			
	Petrochemical Feedstocks: Still Gas	48			
	400 EP Naphtha	204			
	Other	269			
9.	Total Petrochemical Feedstocks	521			
10.	Lubricants	160			
11.	Waxes	16			
12.	Coke	267			
13.	Asphalt & Road Oil	437			
14.	Still Gas for Fuel	524			
15.	Miscellaneous Products	147			
	Total Domestic Demand for Products	18,431			

[1]Total U.S. per Annual Petroleum Statement, Final Summary, 12/28/78. Detail for U.S. PAD's per PAD District Supply/Demand, Annual, 5/31/78 adjusted to conform with Total U.S. Final Summary figures.

[2]Amount of Liquefied Gases Included Above Consumed for Chemical Uses:

Ethane	412			
Propane	123			
Butane	93			
Propane/Butane Mix	5			
Total	633			

*Items 1-15 should sum to Total Demand for Products.

TABLE III (Pg. 2 of 3)

DOMESTIC DEMAND FOR PRODUCTS - PADs I-IV

(MB/D)

	Actual[1] 1977	Forecast 1982	1985	1990
Motor Gasoline: Leaded - Premium	754			
- Non-premium	3,699			
S.Total	4,453			
Unleaded - Premium	0			
- Non-premium	1,640			
S.Total	1,640			
1. Total Motor Gasoline	6,093			
2. Aviation Gasoline	29			
Jet Fuel: Naphtha Type	149			
Kerosine Type	591			
3. Total Jet Fuel	740			
4. Special Naphtha	78			
5. Kerosine	162			
Distillate Fuel Oil: #2 Oil	1,253			
#4 Oil	60			
Diesel - On Highway	622			
- Off Highway	150			
Other Distillate	942			
6. Total Distillate Fuel Oil	3,027			
Residual Fuel Oil: 0 - .5%	633			
.51 - 1.0%S	654			
1.1 - 2.0%S	428			
2.0%S +	786			
7. Total Residual Fuel Oil	2,501			
Liquefied Gases: Ethane	410			
Propane	820			
Butane	111			
Propane/Butane Mix	26			
8. Total Liquefied Gases[2]	1,367			
Petrochemical Feedstocks: Still Gas	46			
400 EP Naphtha	201			
Other	261			
9. Total Petrochemical Feedstocks	508			
10. Lubricants	145			
11. Waxes	13			
12. Coke	218			
13. Asphalt & Road Oil	374			
14. Still Gas for Fuel	423			
15. Miscellaneous Products	139			
Total Domestic Demand for Products, PADs I-IV	15,817			

[1]Total U.S. per Annual Petroleum Statement, Final Summary, 12/28/78. Detail for U.S. PAD's per PAD District Supply/Demand, Annual, 5/31/78 adjusted to conform with Total U.S. Final Summary figures.

[2]Amount of Liquefied Gases Included Above Consumed for Chemical Uses:

Ethane	410			
Propane	118			
Butane	91			
Propane/Butane Mix	4			
Total	623			

*Items 1-15 should sum to Total Domestic Demand for Products, PADs I-IV.

TABLE III (Pg. 3 of 3)

DOMESTIC DEMAND FOR PRODUCTS - PAD V

(MB/D)

		Actual[1] 1977	Forecast 1982	1985	1990
1.	Motor Gasoline: Leaded - Premium	307			
	- Non-premium	508			
	S.Total	815			
	Unleaded - Premium	0			
	- Non-premium	268			
	S.Total	268			
	Total Motor Gasoline	1,083			
2.	Aviation Gasoline	9			
	Jet Fuel: Naphtha Type	59			
	Kerosine Type	240			
3.	Total Jet Fuel	299			
4.	Special Naphtha	8			
5.	Kerosine	13			
	Distillate Fuel Oil: #2 Oil	39			
	#4 Oil	2			
	Diesel - On Highway	102			
	- Off Highway	22			
	Other Distillate	160			
6.	Total Distillate Fuel Oil	325			
	Residual Fuel Oil: 0 - .5%	326			
	1.1 - 2.0%S	184			
	2.0%S +	21			
7.	Total Residual Fuel Oil	570			
	Liquefied Gases: Ethane	2			
	Propane	46			
	Butane	4			
	Propane/Butane Mix	3			
8.	Total Liquefied Gases[2]	55			
	Petrochemical Feedstocks: Still Gas	2			
	400 EP Naphtha	3			
	Other	8			
9.	Total Petrochemical Feedstocks	13			
10.	Lubricants	15			
11.	Waxes	3			
12.	Coke	49			
13.	Asphalt & Road Oil	63			
14.	Still Gas for Fuel	101			
15.	Miscellaneous Products	8			
	Total Domestic Demand for Products, PAD V	2,614			

[1]Total U.S. per Annual Petroleum Statement, Final Summary, 12/28/78. Detail for U.S. PAD's per PAD District Supply/Demand, Annual, 5/31/78 adjusted to conform with Total U.S. Final Summary figures.

[2]Amount of Liquefied Gases Included Above Consumed for Chemical Uses:

Ethane	2			
Propane	5			
Butane	2			
Propane/Butane Mix	1			
Total	10			

*Items 1-15 should sum to Total Domestic Demand for Products, PAD V.

TABLE IIIA

MOTOR GASOLINE DEMAND ASSUMPTIONS

	1977	1982	1985	1990
Passenger Cars In Use (Thousands)	99,904[1]			
New Car Registrations (Thousands)	10,319[1]			
Total Miles Traveled-Passenger Cars (Millions)	1,118,649[2]			
Average Miles Per Car (All Cars)	11,197			
Average Miles Per Gallon (New Cars)	18.7[3]			
Average Miles Per Gallon (All Cars)	13.9[2]			
Diesel Passenger Car Sales (Thousands)	N/A			
Average Miles Per Gallon (New Trucks)	14.9[4]			
Octane Level Implicit in Your Mogas Demand Forecast $\left(\frac{R+M}{2}\right)$				
Leaded Premium	95.0[5]			
Leaded Non-Premium	89.6[5]			
Unleaded Premium } Unleaded Non-Premium }	88.4[5]			

[1]Source: R. L. Polk. Mid-year estimate.

[2]Source: Department of Transportation.

[3]EPA estimate. If you regularly apply a discount factor to EPA estimate, please indicate both your MPG number and your discount factor.

[4]Source: DOT. Two wheel drive vehicles only.

[5]Source: Motor Gasoline, Winter 1977-1978. DOE. Calendar year 1977 calculated as average of Summer 1977 and Winter 77-78.

TABLE IV

U.S. PETROLEUM SUPPLY/DEMAND BALANCE FOR U.S. TOTAL AND PAD V

(Thousand Barrels Daily)

	1977		1982		1985		1990	
	U.S. TOTAL	PAD V	U.S. TOTAL	PAD V	U.S. TOTAL	PAD V	U.S. TOTAL	PAD V
DEMAND - TOTAL	18,690	2,754						
1. Local Product Demand[1]	18,431	2,614						
2. Crude and Product Exports	243	71						
3. Product Shipments to Other Districts	0	21						
4. Crude, NGL and Unfinished Shipments to Other Districts	0	47						
5. Crude Losses	16	1						
SUPPLY - TOTAL	18,690	2,754						
1. Production - Total[2]	9,861	1,448						
Crude and Lease Condensate	8,244	1,424						
NGL	1,617	24						
2. Receipts From Other Districts	0	135						
Crude NGL and Unfinished	0	9						
Products	0	126						
3. Processing Gain, Etc.[3]	569	34						
4. Imports - Total	8,808	1,214						
Crude and Unfinished	6,646	1,099						
From Overland	279	20						
From Offshore	6,367	1,079						
NGL	42	4						
Finished Products	2,120	111						
5. Syncrude	0	0						
From Shale	0	0						
From Coal	0	0						
6. From Inventory	(548)	(77)						
Crude	(170)	(67)						
Products	(378)	(10)						
7. Crude Runs	14,602	2,323						

[1] These figures are equivalent to the Table III entries-Total Domestic Demand for Products, Total U.S. and PAD V.

[2] Amount of Alaskan North Slope Production Included:	310	310						

[3] Includes other hydrocarbon and hydrogen refinery inputs, "unaccounted for" crude inputs.

TABLE V

WORLD OIL CONSUMPTION[1]
(Million Barrels/Day)

	1977[2]	Forecast 1982	Forecast 1985	Forecast 1990
OECD				
United States[3]	18.4			
Western Europe	14.2			
Japan	5.3			
Other OECD	2.6			
NON-OECD (Excl. USSR, E. Europe China)	9.3			
Sub-Total	49.8			
USSR	8.0			
East Europe	2.1			
China	1.5			
Sub-Total	11.6			
TOTAL CONSUMPTION	61.4			

[1]Including International Bunkers and Refinery Fuel and Losses.
[2]Product Basis. Data for outside U.S. from BP 1977 Statistical Review of the World Oil Industry.
[3]This figure should be equivalent to the Table III entry-Domestic Demand for Products (U.S. Total).

TABLES VI and VII

WORLD CRUDE OIL AND NATURAL GAS LIQUIDS SUPPLY[1]
(Million Barrels/Day)

	1977	Forecast 1982	1985	1990
OECD -				
U.S.[2]	9.8			
Canada	1.6			
W. Europe	1.5			
Japan, Australia, New Zealand	0.5			
Sub-Total	13.4			
OPEC -				
Venezuela	2.3			
Ecuador	0.2			
Indonesia	1.7			
Africa	5.6			
Algeria	1.2			
Libya	2.1			
Nigeria	2.1			
Gabon	0.2			
Middle East	22.1			
Iran	5.7			
Kuwait	1.9			
S. Arabia	9.2			
Iraq	2.5			
UAE	2.0			
Qatar	0.4			
Neutral Zone	0.4			
Sub-Total	31.9			
NON-OPEC (Excl. USSR, E. Europe, China) -				
Mexico	1.1			
Other L. America	1.2			
Africa	0.7			
Middle East	0.6			
Asia	0.7			
Sub-Total	4.3			
USSR	10.9			
East Europe	0.4			
China	1.8			
Sub-Total	13.1			
Refinery Processing Gains				
U.S.	0.5			
Other	0.0			
Sub-Total	0.5			
TOTAL SUPPLY	63.2			

[1]Including field condensate and non-conventional supplies from Tar Sands (Canada) and heavy oil (Venezuela's Heavy Oil Belt).

[2]This figure should be equivalent to Table IV entry-U.S. Production-Total.

NOTE: Forecast only such quantities that you feel oil exporting countries will produce. You are asked to take into account the political and economic constraints which may lower production from that physically sustainable.

TABLE I

Medium Case

Total U.S. Primary Energy Consumption by Fuels
(Trillion Btu)

ADJUSTED AVERAGE
TOTAL--ALL RESPONDENTS

	1977	1978	1982	1985	1990
PETROLEUM LIQUIDS	36,970.0	38,014.0	37,051.9	37,757.7	37,829.8
NAT.GAS (DRY)	19,931.0	20,039.0	19,977.8	19,863.1	19,769.1
COAL	14,133.0	14,070.0	17,138.0	19,601.3	24,328.2
NUCLEAR	2,674.0	2,977.0	3,953.8	5,251.3	7,448.8
OTHER SPECIFY	2,614.0	3,343.0	3,498.7	3,846.7	4,514.9
TOTAL PRIMARY ENERGY	76,322.0	78,443.0	81,620.1	86,320.1	93,890.8

TABLE III

Medium Case

Domestic Demand for Products -- Total U.S.
(Thousand Barrels/Day)

ADJUSTED AVERAGE
TOTAL--ALL RESPONDENTS

	1977	1978	1982	1985	1990
MOTOR GASOLINE: LEADED - PREMIUM	1,061.0	934.0	679.1	158.2	58.6
- NON-PREMIUM	4,207.0	4,106.0	1,832.2	1,385.6	624.2
S.TOTAL	5,268.0	5,040.0	2,511.3	1,543.8	682.8
UNLEADED - PREMIUM	0.0	185.0	281.8	1,453.9	1,806.7
- NON-PREMIUM	1,908.0	2,187.0	4,126.1	3,652.9	3,634.3
S.TOTAL	1,908.0	2,372.0	4,407.9	5,106.8	5,441.0
TOTAL MOTOR GASOLINE	7,176.0	7,412.0	6,919.3	6,650.6	6,123.8
AVIATION GASOLINE	38.0	39.0	42.8	45.7	51.0
JET FUEL: NAPTHA TYPE	208.0	199.0	184.7	171.3	124.0
KEROSINE TYPE	831.0	858.0	946.1	1,033.8	1,202.6
TOTAL JET FUEL	1,039.0	1,057.0	1,130.8	1,205.1	1,326.6
SPECIAL NAPTHA	86.0	103.0	102.0	109.7	120.0
KEROSINE	175.0	215.0	166.1	162.1	157.1
DISTILLATE FUEL OIL: NO.2 OIL	1,292.0	1,385.0	1,218.0	1,177.7	1,082.1
NO.4 OIL	62.0	61.0	71.9	85.4	93.1
DIESEL - ON HIGHWAY	724.0	797.0	1,009.0	1,302.8	1,732.4
- OFF HIGHWAY	172.0	191.0	198.0	215.7	256.1
OTHER DISTILLATE	1,102.0	958.0	976.4	957.3	954.5
TOTAL DISTILLATE FUEL OIL	3,352.0	3,392.0	3,473.3	3,738.8	4,118.2
RESIDUAL FUEL OIL: 0 - .5%S	959.0	862.0	761.7	832.6	694.9
.51 - 1.0%S	693.0	716.0	596.3	497.8	408.1
1.1 - 2.0%S	612.0	641.0	527.2	720.2	756.2
2.0%S +	807.0	804.0	714.8	575.4	485.1
TOTAL RESIDUAL FUEL OIL	3,071.0	3,023.0	2,600.1	2,626.0	2,344.3
LIQUEFIED GASES: ETHANE	412.0	433.0	438.2	391.1	374.6
PROPANE	866.0	778.0	896.6	1,029.5	1,134.4
BUTANE	115.0	167.0	193.0	211.0	236.8
PROPANE/BUTANE MIX	20.0	35.0	42.4	48.0	47.7
TOTAL LIQUEFIED GASES	1,422.0	1,413.0	1,570.2	1,679.6	1,793.4
PETROCHEMICAL FEEDSTOCKS: STILL GAS	48.0	55.0	52.2	70.5	68.5
400 EP NAPTHA	204.0	205.0	245.2	303.2	392.7
OTHER	269.0	335.0	470.4	495.5	622.7
TOTAL PETROCHEMICAL FEEDSTOCKS	521.0	595.0	767.8	869.1	1,083.8
LUBRICANTS	160.0	172.0	182.4	191.5	211.5
WAXES	16.0	17.0	19.3	20.8	22.7
COKE	267.0	256.0	266.6	274.5	288.5
ASPHALT & ROAD OIL	437.0	479.0	488.7	511.1	539.4
STILL GAS FOR FUEL	524.0	548.0	534.8	540.9	558.0
MISCELLANEOUS PRODUCTS	147.0	128.0	154.0	155.6	158.6
TOTAL DEMAND	18,431.0	18,847.0	18,418.2	18,781.3	18,896.8
ETHANE	412.0	433.0	437.2	380.5	331.9
PROPANE	123.0	85.0	136.0	213.0	304.1
BUTANE	93.0	136.0	150.0	170.0	190.0
PROPANE/BUTANE MIX	5.0	11.0	10.0	11.0	12.0
TOTAL	633.0	665.0	733.2	774.4	838.0

TABLE III

Medium Case

Domestic Demand for Products -- PADs I-IV
(Thousand Barrels/Day)

ADJUSTED AVERAGE
TOTAL--ALL RESPONDENTS

	1977	1978	1982	1985	1990
MOTOR GASOLINE: LEADED - PREMIUM	754.0	656.0	693.8	151.7	58.6
- NON-PREMIUM	3,699.0	3,600.0	1,468.5	1,172.8	543.6
S.TOTAL	4,453.0	4,256.0	2,112.3	1,324.5	602.2
UNLEADED - PREMIUM	0.0	0.0	98.2	1,134.6	1,390.6
- NON-PREMIUM	1,640.0	2,026.0	3,640.6	3,142.3	3,145.1
S.TOTAL	1,640.0	2,026.0	3,728.8	4,276.9	4,535.7
TOTAL MOTOR GASOLINE	6,093.0	6,283.0	5,841.2	5,601.4	5,137.9
AVIATION GASOLINE	29.0	30.0	33.8	35.7	39.9
JET FUEL: NAPTHA TYPE	149.0	143.0	136.5	122.4	107.5
KEROSINE TYPE	591.0	613.0	672.1	735.1	837.7
TOTAL JET FUEL	740.0	756.0	808.6	857.5	945.2
SPECIAL NAPTHA	78.0	88.0	86.7	92.2	98.7
KEROSINE	162.0	194.0	153.1	148.8	144.3
DISTILLATE FUEL OIL: NO.2 OIL	1,253.0	1,344.0	1,172.2	1,134.6	1,042.6
NO.4 OIL	60.0	58.0	69.4	83.3	90.6
DIESEL - ON HIGHWAY	622.0	679.0	599.6	1,035.4	1,440.5
- OFF HIGHWAY	150.0	165.0	173.4	189.4	224.1
OTHER DISTILLATE	942.0	801.0	874.1	862.8	861.5
TOTAL DISTILLATE FUEL OIL	3,027.0	3,047.0	3,099.9	3,335.4	3,659.3
RESIDUAL FUEL OIL: 0 - .5%S	633.0	641.0	547.3	863.2	495.6
.51 - 1.0%S	654.0	672.0	566.3	472.8	388.1
1.1 - 2.0%S	428.0	426.0	304.7	518.0	537.8
2.0%S +	786.0	796.0	694.8	555.4	470.1
TOTAL RESIDUAL FUEL OIL	2,501.0	2,535.0	2,113.2	2,109.4	1,891.6
LIQUEFIED GASES: ETHANE	410.0	432.0	436.2	389.1	372.6
PROPANE	820.0	729.0	844.7	975.6	1,073.9
BUTANE	111.0	162.0	188.0	204.0	228.8
PROPANE/BUTANE MIX	26.0	31.0	39.4	45.0	44.7
TOTAL LIQUEFIED GASES	1,367.0	1,355.0	1,508.3	1,613.7	1,719.9
PETROCHEMICAL FEEDSTOCKS: STILL GAS	46.0	53.0	50.7	69.3	66.8
400 EP NAPTHA	201.0	201.0	241.8	298.5	380.1
OTHER	261.0	331.0	461.4	485.4	398.7
TOTAL PETROCHEMICAL FEEDSTOCKS	508.0	586.0	733.9	853.1	1,045.5
LUBRICANTS	145.0	153.0	164.2	171.0	189.0
WAXES	13.0	14.0	16.8	18.3	19.8
COKE	218.0	215.0	218.3	223.2	236.7
ASPHALT & ROAD OIL	374.0	401.0	419.6	436.7	460.6
STILL GAS FOR FUEL	423.0	444.0	440.4	447.2	450.1
MISCELLANEOUS PRODUCTS	139.0	117.0	134.7	135.8	141.2
TOTAL DEMAND	15,817.0	16,216.0	15,792.7	16,079.6	16,179.7
ETHANE	410.0	432.0	435.2	378.5	330.9
PROPANE	118.0	81.0	129.0	203.0	291.1
BUTANE	91.0	133.0	148.0	168.0	185.0
PROPANE/BUTANE MIX	4.0	10.0	9.0	10.0	11.0
TOTAL	623.0	656.0	721.2	759.4	821.0

TABLE III

Medium Case

Domestic Demand for Products -- PAD V
(Thousand Barrels/Day)

ADJUSTED AVERAGE
TOTAL--ALL RESPONDENTS

	1977	1978	1982	1985	1990
MOTOR GASOLINE: LEADED - PREMIUM	307.0	278.0	35.3	6.5	0.0
- NON-PREMIUM	508.0	506.0	363.7	212.8	80.6
S.TOTAL	815.0	784.0	399.0	219.3	80.6
UNLEADED - PREMIUM	0.0	184.0	193.6	319.3	416.1
- NON-PREMIUM	268.0	161.0	485.5	510.6	489.2
S.TOTAL	268.0	345.0	679.1	829.9	905.3
TOTAL MOTOR GASOLINE	1,083.0	1,129.0	1,078.1	1,049.2	985.9
AVIATION GASOLINE	9.0	9.0	9.0	10.0	11.1
JET FUEL: NAPTHA TYPE	59.0	56.0	48.2	48.9	16.5
KEROSINE TYPE	240.0	245.0	274.0	298.7	364.9
TOTAL JET FUEL	299.0	301.0	322.2	347.6	381.4
SPECIAL NAPTHA	8.0	15.0	15.5	17.5	21.3
KEROSINE	13.0	21.0	13.0	13.3	12.8
DISTILLATE FUEL OIL: NO.2 OIL	39.0	41.0	45.8	43.1	39.5
NO.4 OIL	2.0	3.0	2.5	2.1	2.5
DIESEL - ON HIGHWAY	102.0	118.0	198.2	237.4	291.9
- OFF HIGHWAY	22.0	26.0	24.6	26.3	32.0
OTHER DISTILLATE	160.0	157.0	102.3	94.5	93.0
TOTAL DISTILLATE FUEL OIL	325.0	345.0	373.4	403.4	458.9
RESIDUAL FUEL OIL: 0 - .5%S	326.0	221.0	214.4	269.4	199.3
.51 - 1.0%S	39.0	44.0	30.0	25.0	20.0
1.1 - 2.0%S	184.0	215.0	222.5	202.2	218.4
2.0%S +	21.0	8.0	20.0	20.0	15.0
TOTAL RESIDUAL FUEL OIL	570.0	488.0	486.9	516.6	452.7
LIQUEFIED GASES: ETHANE	2.0	1.0	2.0	2.0	2.0
PROPANE	46.0	49.0	51.9	53.9	60.5
BUTANE	4.0	5.0	5.0	7.0	8.0
PROPANE/BUTANE MIX	3.0	3.0	3.0	8.0	3.0
TOTAL LIQUEFIED GASES	55.0	58.0	61.9	65.9	73.5
PETROCHEMICAL FEEDSTOCKS: STILL GAS	2.0	2.0	1.5	1.2	1.7
400 EP NAPTHA	3.0	3.0	3.4	4.7	12.6
OTHER	8.0	4.0	9.0	10.1	24.0
TOTAL PETROCHEMICAL FEEDSTOCKS	13.0	9.0	13.9	16.0	38.3
LUBRICANTS	15.0	19.0	18.2	20.5	22.5
WAXES	3.0	3.0	2.5	2.5	2.9
COKE	49.0	41.0	48.3	51.3	51.8
ASPHALT & ROAD OIL	63.0	78.0	69.1	74.4	78.8
STILL GAS FOR FUEL	101.0	104.0	94.4	93.7	107.9
MISCELLANEOUS PRODUCTS	8.0	11.0	19.3	19.8	17.4
TOTAL DEMAND	2,614.0	2,631.0	2,625.5	2,701.7	2,717.1
ETHANE	2.0	1.0	2.0	2.0	1.0
PROPANE	5.0	4.0	7.0	10.0	13.0
BUTANE	2.0	3.0	2.0	2.0	2.0
PROPANE/BUTANE MIX	1.0	1.0	1.0	1.0	1.0
TOTAL	10.0	9.0	12.0	15.0	17.0

TABLE IV

Medium Case

U.S. Petroleum Supply/Demand Balance -- Total U.S.
(Thousand Barrels/Day)

ADJUSTED AVERAGE
TOTAL--ALL RESPONDENTS

	1977	1978	1982	1985	1990
DEMAND - TOTAL	18,690.0	19,224.0	18,769.4	19,096.4	19,205.2
1. LOCAL PRODUCT DEMAND	18,431.0	18,847.0	18,418.2	18,781.3	18,896.8
2. CRUDE AND PRODUCT EXPORTS	243.0	362.0	334.0	294.1	287.0
3. PRODUCT SHIPMENTS TO OTHER DISTRICTS	0.0	0.0	0.0	0.0	0.0
4. CRUDE, NGL & UNF. SHIPMENTS TOD	0.0	0.0	0.0	0.0	0.0
5. CRUDE LOSSES	16.0	16.0	17.2	20.9	20.5
SUPPLY - TOTAL	18,690.0	19,224.0	18,769.4	19,096.4	19,205.2
1. PRODUCTION - TOTAL	9,861.0	10,274.0	9,818.6	9,574.2	9,354.0
CRUDE AND LEASE CONDENSATE	8,244.0	8,707.0	8,334.8	8,154.2	8,032.1
NGL	1,617.0	1,567.0	1,483.8	1,420.0	1,321.9
2. RECEIPTS FROM OTHER DISTRICTS	0.0	0.0	0.0	0.0	0.0
CRUDE, NGL, AND UNFINISHED	0.0	0.0	0.0	0.0	0.0
PRODUCTS	0.0	0.0	0.0	0.0	0.0
3. PROCESSING GAIN, ETC.	569.0	439.0	545.5	532.5	541.5
4. IMPORTS - TOTAL	8,808.0	8,364.0	8,442.9	8,920.4	8,783.1
CRUDE AND UNFINISHED	6,646.0	6,383.0	6,423.5	6,755.9	6,598.6
FROM OVERLAND	279.0	564.0	65.6	31.4	25.9
FROM OFFSHORE	6,367.0	5,819.0	6,357.9	6,724.5	6,572.7
NGL	42.0	17.0	120.1	290.4	407.9
FINISHED PRODUCTS	2,120.0	1,964.0	1,899.3	1,874.1	1,776.6
5. SYNCRUDE	0.0	0.0	3.2	110.3	545.8
FROM SHALE	0.0	0.0	0.7	78.6	371.6
FROM COAL	0.0	0.0	2.5	31.7	174.2
6. FROM INVENTORY	-548.0	94.0	-40.8	-41.0	-19.2
CRUDE	-170.0	-78.0	-38.1	-43.7	-16.1
PRODUCTS	-378.0	172.0	-2.7	2.7	-3.1
7. CRUDE RUNS	14,602.0	14,739.0	14,658.0	14,968.5	15,122.4
ALASKAN PRODUCTION	310.0	1,089.0	1,480.5	1,578.6	1,572.6

TABLE IV

Medium Case

U.S. Petroleum Supply/Demand Balance -- PADs I-IV
(Thousand Barrels/Day)

ADJUSTED AVERAGE
TOTAL--ALL RESPONDENTS

	1977	1978	1982	1985	1990
DEMAND - TOTAL	16,139.0	16,112.0	16,094.1	16,361.7	16,473.8
1. LOCAL PRODUCT DEMAND	15,817.0	16,216.0	15,792.7	16,079.6	16,179.7
2. CRUDE AND PRODUCT EXPORTS	172.0	120.0	183.0	161.4	178.4
3. PRODUCT SHIPMENTS TO OTHER DISTRICTS	126.0	152.0	102.7	102.9	98.9
4. CRUDE, NGL & UNF. SHIPMENTS TOD	9.0	7.0	0.5	0.9	1.3
5. CRUDE LOSSES	15.0	14.0	15.2	16.8	15.5
SUPPLY - TOTAL	16,139.0	16,112.0	16,094.1	16,361.7	16,473.8
1. PRODUCTION - TOTAL	8,413.0	8,065.0	7,104.4	6,768.2	6,290.9
CRUDE AND LEASE CONDENSATE	6,820.0	6,523.0	5,634.4	5,366.1	4,986.2
NGL	1,593.0	1,543.0	1,470.0	1,402.1	1,304.7
2. RECEIPTS FROM OTHER DISTRICTS	68.0	316.0	483.0	523.3	777.4
CRUDE, NGL, AND UNFINISHED	47.0	301.0	459.2	503.9	755.8
PRODUCTS	21.0	15.0	23.8	19.4	21.6
3. PROCESSING GAIN, ETC.	535.0	470.0	475.0	448.6	442.2
4. IMPORTS - TOTAL	7,594.0	7,639.0	8,066.6	8,550.3	8,441.1
CRUDE AND UNFINISHED	5,547.0	5,781.0	6,112.4	6,463.9	6,337.8
FROM OVERLAND	259.0	552.0	65.2	31.4	25.9
FROM OFFSHORE	5,288.0	5,229.0	6,047.2	6,432.5	6,311.9
NGL	38.0	15.0	119.3	283.5	399.1
FINISHED PRODUCTS	2,009.0	1,843.0	1,834.9	1,802.9	1,704.2
5. SYNCRUDE	0.0	0.0	3.2	110.3	540.9
FROM SHALE	0.0	0.0	0.7	78.6	366.7
FROM COAL	0.0	0.0	2.5	31.7	174.2
6. FROM INVENTORY	-471.0	53.0	-38.2	-39.1	-18.8
CRUDE	-103.0	-106.0	-36.4	-42.6	-16.1
PRODUCTS	-368.0	159.0	-1.8	3.5	-2.7
7. CRUDE RUNS	12,279.0	12,452.0	12,209.7	12,459.2	12,589.4

TABLE IV

Medium Case

U.S. Petroleum Supply/Demand Balance -- PAD V
(Thousand Barrels/Day)

ADJUSTED AVERAGE
TOTAL--ALL RESPONDENTS

	1977	1978	1982	1985	1990
DEMAND - TOTAL	2,754.0	3,112.0	3,261.5	3,361.8	3,609.0
1. LOCAL PRODUCT DEMAND	2,614.0	2,631.0	2,625.5	2,701.7	2,717.1
2. CRUDE AND PRODUCT EXPORTS	71.0	163.0	151.0	132.7	109.5
3. PRODUCT SHIPMENTS TO OTHER DISTRICTS	21.0	15.0	23.8	19.4	21.6
4. CRUDE, NGL & UNF. SHIPMENTS TOO	47.0	301.0	459.2	503.9	755.8
5. CRUDE LOSSES	1.0	1.0	2.0	4.1	5.0
SUPPLY - TOTAL	2,754.0	3,112.0	3,261.5	3,361.8	3,609.0
1. PRODUCTION - TOTAL	1,448.0	2,209.0	2,714.2	2,806.0	3,063.1
CRUDE AND LEASE CONDENSATE	1,424.0	2,188.0	2,700.4	2,788.1	3,045.9
NGL	24.0	24.0	13.8	17.9	17.2
2. RECEIPTS FROM OTHER DISTRICTS	135.0	159.0	103.2	103.8	100.2
CRUDE, NGL, AND UNFINISHED	9.0	6.0	0.5	0.9	1.3
PRODUCTS	126.0	153.0	102.7	102.9	98.9
3. PROCESSING GAIN, ETC.	34.0	-31.0	70.5	83.9	99.3
4. IMPORTS - TOTAL	1,214.0	725.0	376.3	370.1	342.0
CRUDE AND UNFINISHED	1,099.0	602.0	311.1	292.0	260.8
FROM OVERLAND	20.0	12.0	0.4	0.0	0.0
FROM OFFSHORE	1,079.0	590.0	310.7	292.0	260.8
NGL	4.0	2.0	0.8	6.9	8.8
FINISHED PRODUCTS	111.0	121.0	64.4	71.2	72.4
5. SYNCRUDE	0.0	0.0	0.0	0.0	4.9
FROM SHALE	0.0	0.0	0.0	0.0	4.9
FROM COAL	0.0	0.0	0.0	0.0	0.0
6. FROM INVENTORY	-77.0	41.0	-2.6	-1.9	-0.4
CRUDE	-67.0	28.0	-1.7	-1.1	0.0
PRODUCTS	-10.0	13.0	-0.9	-0.8	-0.4
7. CRUDE RUNS	2,323.0	2,287.0	2,448.3	2,509.3	2,533.0
ALASKAN PRODUCTION	310.0	1,089.0	1,487.5	1,537.5	1,528.3

TABLE V

Medium Case

World Oil Consumption
(Million Barrels/Day)

ADJUSTED AVERAGE
TOTAL--ALL RESPONDENTS

	1977	1978	1982	1985	1990
OECD					
UNITED STATES	18.4	18.8	18.4	18.8	18.9
WESTERN EUROPE	14.2	14.6	14.6	14.8	15.3
JAPAN	5.3	5.4	5.7	6.1	6.3
OTHER OECD	2.6	2.6	2.7	2.8	2.8
NON-OECD (EXCL. USSR, E. EUROPE, CHINA)					
NON-OECD	9.3	10.0	12.0	13.1	15.9
NON-COMMUNIST COUNTRIES	49.8	51.4	53.4	55.6	59.3
USSR	8.0	8.4	9.2	9.9	10.5
EAST EUROPE	2.1	2.1	2.4	2.5	2.8
CHINA	1.5	1.7	2.3	3.0	3.8
COMMUNIST COUNTRIES	11.6	12.2	13.9	15.4	17.2
TOTAL CONSUMPTION	61.4	63.6	67.3	71.0	76.5

TABLE VI

Medium Case

World Crude Oil and Natural Gas Liquids Supply
(Million Barrels/Day)

ADJUSTED AVERAGE
TOTAL--ALL RESPONDENTS

	1977	1978	1982	1985	1990
OECD					
U.S.	9.9	10.3	9.8	9.6	9.4
CANADA	1.6	1.6	1.7	1.6	1.8
W. EUROPE	1.5	1.8	3.3	3.8	4.5
JAPAN, AUSTRALIA, NEW ZEALAND	0.5	0.5	0.6	0.5	0.6
SUB-TOTAL	13.4	14.2	15.4	15.5	16.3
OPEC					
VENEZUELA	2.3	2.2	2.3	2.2	2.2
ECUADOR	0.2	0.2	0.2	0.2	0.2
INDONESIA	1.7	1.6	1.7	1.7	1.6
AFRICA	5.6	5.3	5.7	5.7	5.7
ALGERIA	1.2	1.2	1.2	1.1	1.1
LIBYA	2.1	2.0	2.1	2.1	2.2
NIGERIA	2.1	1.9	2.2	2.2	2.2
GABON	0.2	0.2	0.2	0.2	0.2
MIDDLE EAST	22.1	20.8	20.3	21.0	22.8
IRAN	5.7	5.2	3.2	3.3	3.6
KUWAIT	1.9	1.9	1.9	1.9	2.1
S. ARABIA	9.2	8.3	9.1	9.3	10.3
IRAQ	2.5	2.6	3.1	3.5	3.8
UAE	2.0	1.8	2.0	2.0	2.2
QATAR	0.4	0.5	0.5	0.5	0.4
NEUTRAL ZONE	0.4	0.5	0.5	0.5	0.5
SUB-TOTAL	31.9	30.1	30.1	30.8	32.6
NON-OPEC (EXCL. USSR, E. EUROPE, CHINA)					
MEXICO	1.1	1.3	2.6	3.1	4.2
OTHER L. AMERICA	1.2	1.2	1.5	1.6	2.0
AFRICA	0.7	0.8	1.1	1.3	1.6
MIDDLE EAST	0.6	0.6	0.6	0.7	0.7
ASIA	0.7	0.8	1.0	1.3	1.7
SUB-TOTAL	4.3	4.7	6.8	8.0	10.1
USSR	10.9	11.7	11.7	12.1	12.6
EAST EUROPE	0.4	0.4	0.4	0.4	0.4
CHINA	1.8	1.9	2.7	3.2	4.3
SUB-TOTAL	13.1	14.0	14.8	15.6	17.3
REFINERY PROCESSING GAINS					
U.S.	0.5	0.5	0.5	0.5	0.5
OTHER	0.0	0.0	0.0	0.0	0.0
SUB-TOTAL	0.5	0.5	0.5	0.5	0.5
TOTAL SUPPLY	63.2	63.5	67.7	70.4	76.7

Medium Case

TABLE I

Total U.S. Primary Energy Consumption by Fuels
(Trillion Btu)

ALL RESPONDENTS

High

	1977	1978	1982	1985	1990
PETROLEUM LIQUIDS	36,970	38,014	39,664	40,808	42,400
NAT.GAS (DRY)	19,931	20,039	21,400	22,800	23,800
COAL	14,133	14,070	18,295	21,800	26,776
NUCLEAR	2,674	2,977	4,700	6,335	9,200
OTHER SPECIFY	2,614	3,343	4,164	4,666	5,840
TOTAL PRIMARY ENERGY	76,322	78,443	85,545	90,801	100,400

Low

	1977	1978	1982	1985	1990
PETROLEUM LIQUIDS	36,970	38,014	34,930	33,387	31,921
NAT.GAS (DRY)	19,931	20,039	18,652	18,380	17,850
COAL	14,133	14,070	16,130	18,270	22,630
NUCLEAR	2,674	2,977	3,177	4,146	4,437
OTHER SPECIFY	2,614	3,343	3,182	3,282	3,715
TOTAL PRIMARY ENERGY	76,322	78,443	79,830	81,986	87,085

AVERAGE AND STANDARD DEVIATION

	AVERAGE					STANDARD DEVIATION AS A % OF THE MEAN		
	1977	1978	1982	1985	1990	1982	1985	1990
PETROLEUM LIQUIDS	36,970	38,014	37,052	37,758	37,830	3.22%	5.14%	7.85%
NAT.GAS (DRY)	19,931	20,039	19,978	19,863	19,769	3.47%	5.48%	6.79%
COAL	14,133	14,070	17,138	19,601	24,328	3.19%	5.10%	5.26%
NUCLEAR	2,674	2,977	3,954	5,251	7,449	11.54%	13.62%	16.90%
OTHER SPECIFY	2,614	3,343	3,499	3,847	4,515	7.51%	8.11%	12.63%
TOTAL PRIMARY ENERGY	76,322	78,443	81,620	86,320	93,891	1.88%	2.91%	4.21%

Median

	1977	1978	1982	1985	1990
PETROLEUM LIQUIDS	36,970	38,014	37,240	38,232	38,144
NAT.GAS (DRY)	19,931	20,039	19,930	19,974	19,728
COAL	14,133	14,070	17,000	19,445	24,131
NUCLEAR	2,674	2,977	3,810	5,366	7,560
OTHER SPECIFY	2,614	3,343	3,430	3,750	4,460
TOTAL PRIMARY ENERGY	76,322	78,443	81,400	86,430	94,230

Medium Case

TABLE IA

Economic Assumptions

ALL RESPONDENTS

High

		1977	1978	1982	1985	1990
GNP ASSUMPTION	(BILLION 1972 $)	1,333	1,386	1,600	1,750	2,050
FRB INDEX OF IND. PROD.	(1967=100)	137	146	165	193	228
POPULATION	(MID-YEAR, 000)	216,820	218,500	230,000	236,000	247,000
DISPOSABLE PERSONAL INCOME	(BILLION 1972 $)	926	966	1,093	1,221	1,429

Low

		1977	1978	1982	1985	1990
GNP ASSUMPTION	(BILLION 1972 $)	1,333	1,386	1,452	1,541	1,701
FRB INDEX OF IND. PROD.	(1967=100)	137	1,461	156	159	203
POPULATION	(MID-YEAR, 000)	216,820	218,500	223,000	226,000	232,000
DISPOSABLE PERSONAL INCOME	(BILLION 1972 $)	926	966	1,018	1,084	1,198

AVERAGE AND STANDARD DEVIATION

		AVERAGE					STANDARD DEVIATION AS A % OF THE MEAN		
		1977	1978	1982	1985	1990	1982	1985	1990
GNP ASSUMPTION	(BILLION 1972 $)	1,333	1,386	1,503	1,647	1,883	2.30%	3.21%	4.79%
FRB INDEX OF IND. PROD.	(1967=100)	137	1,461	160	178	213	1.82%	4.27%	3.72%
POPULATION	(MID-YEAR, 000)	216,820	218,500	226,261	232,458	242,528	.66%	.89%	1.42%
DISPOSABLE PERSONAL INCOME	(BILLION 1972 $)	926	966	1,056	1,162	1,344	1.94%	3.01%	4.31%

Median

		1977	1978	1982	1985	1990
GNP ASSUMPTION	(BILLION 1972 $)	1,333	1,386	1,499	1,646	1,893
FRB INDEX OF IND. PROD.	(1967=100)	137	1,461	161	177	214
POPULATION	(MID-YEAR, 000)	216,820	218,500	226,300	232,900	243,500
DISPOSABLE PERSONAL INCOME	(BILLION 1972 $)	926	966	1,058	1,163	1,336

TABLE III

Medium Case

Domestic Demand for Products -- Total U.S.
(Thousand Barrels/Day)

ALL RESPONDENTS
High

	1977	1978	1982	1985	1990
MOTOR GASOLINE: LEADED - PREMIUM	1,061	934		695	410
- NON-PREMIUM	4,207	4,106		1,733	1,203
S.TOTAL	5,268	5,040	2,692	1,733	1,203
UNLEADED - PREMIUM	0	185		2,619	3,134
- NON-PREMIUM	1,908	2,187		5,246	5,351
S.TOTAL	1,908	2,372	4,717	5,515	6,500
TOTAL MOTOR GASOLINE	7,176	7,412	7,300	7,100	6,900
AVIATION GASOLINE	38	39	45	55	65
JET FUEL: NAPTHA TYPE	208	199	212	212	212
KEROSINE TYPE	831	858	1,000	1,125	1,475
TOTAL JET FUEL	1,039	1,057	1,190	1,335	1,585
SPECIAL NAPTHA	86	103	126	142	165
KEROSINE	175	215	212	215	235
DISTILLATE FUEL OIL: NO.2 OIL	1,292	1,385	1,243	1,305	1,201
NO.4 OIL	62	61		150	204
DIESEL - ON HIGHWAY	724	797	1,096	1,822	2,519
- OFF HIGHWAY	172	191		234	315
OTHER DISTILLATE	1,102	958		1,308	1,399
TOTAL DISTILLATE FUEL OIL	3,352	3,392	3,882	4,267	5,001
RESIDUAL FUEL OIL: 0 - .5%S	959	862	800	1,471	1,189
.51 - 1.0%S	693	716	650	675	577
1.1 - 2.0%S	612	641	576	1,832	2,114
2.0%S +	807	804	737	719	576
TOTAL RESIDUAL FUEL OIL	3,071	3,023	3,171	3,999	4,050
LIQUEFIED GASES: ETHANE	412	433	473	504	548
PROPANE	866	778		1,118	1,265
BUTANE	115	167		371	482
PROPANE/BUTANE MIX	29	35			
TOTAL LIQUEFIED GASES	1,422	1,413	1,737	1,915	2,185
PETROCHEMICAL FEEDSTOCKS: STILL GAS	48	55	61	137	137
400 EP NAPTHA	204	205	263	351	546
OTHER	269	335	580	650	1,100
TOTAL PETROCHEMICAL FEEDSTOCKS	521	595	1,376	1,389	1,619
LUBRICANTS	160	172	198	229	266
WAXES	16	17	23	25	31
COKE	267	256	326	352	410
ASPHALT & ROAD OIL	437	479	587	618	673
STILL GAS FOR FUEL	524	548	595	617	635
MISCELLANEOUS PRODUCTS	147	128	200	240	227
TOTAL DEMAND	18,431	18,847	19,601	20,244	21,405
ETHANE	412	433	473	504	548
PROPANE	123	85		350	450
BUTANE	93	136		190	206
PROPANE/BUTANE MIX	5	11			
TOTAL	633	665	905	970	1,053

TABLE III -- Total U.S. (Continued) Medium Case

ALL RESPONDENTS
Low

	1977	1978	1982	1985	1990
MOTOR GASOLINE: LEADED - PREMIUM	1,061	934		0	0
- NON-PREMIUM	4,207	4,106		400	0
S. TOTAL	5,268	5,040	2,205	1,095	410
UNLEADED - PREMIUM	0	185		100	100
- NON-PREMIUM	1,908	2,187		2,322	2,364
S. TOTAL	1,908	2,372	4,155	4,755	5,097
TOTAL MOTOR GASOLINE	7,176	7,412	6,681	6,300	5,524
AVIATION GASOLINE	38	39	38	37	35
JET FUEL: NAPTHA TYPE	208	199	165	140	0
KEROSINE TYPE	831	858	897	982	1,113
TOTAL JET FUEL	1,039	1,057	1,100	1,050	1,000
SPECIAL NAPTHA	86	103	88	89	90
KEROSINE	175	215	141	122	98
DISTILLATE FUEL OIL: NO.2 OIL	1,292	1,385	1,189	1,094	987
NO.4 OIL	62	61		60	57
DIESEL - ON HIGHWAY	724	797	895	960	1,191
- OFF HIGHWAY	172	191		194	207
OTHER DISTILLATE	1,102	958		525	610
TOTAL DISTILLATE FUEL OIL	3,352	3,392	3,258	3,350	3,500
RESIDUAL FUEL OIL: 0 - .5%S	959	862	640	310	168
.51 - 1.0%S	693	716	432	196	53
1.1 - 2.0%S	612	641	310	139	22
2.0%S +	807	804	673	338	342
TOTAL RESIDUAL FUEL OIL	3,071	3,023	2,055	1,115	585
LIQUEFIED GASES: ETHANE	412	433	355	320	315
PROPANE	866	778		1,003	1,025
BUTANE	115	167		140	150
PROPANE/BUTANE MIX	29	35			
TOTAL LIQUEFIED GASES	1,422	1,413	1,483	1,548	1,571
PETROCHEMICAL FEEDSTOCKS: STILL GAS	48	55	45	45	42
400 EP NAPTHA	204	205	217	225	251
OTHER	269	335	339	249	257
TOTAL PETROCHEMICAL FEEDSTOCKS	521	595	601	621	685
LUBRICANTS	160	172	173	174	185
WAXES	16	17	17	17	17
COKE	267	256	244	244	249
ASPHALT & ROAD OIL	437	479	450	440	425
STILL GAS FOR FUEL	524	548	450	456	438
MISCELLANEOUS PRODUCTS	147	128	100	59	70
TOTAL DEMAND	18,431	18,847	17,400	16,630	15,900
ETHANE	412	433	355	320	315
PROPANE	123	85		114	192
BUTANE	93	136		113	161
PROPANE/BUTANE MIX	5	11			
TOTAL	633	665	635	610	620

TABLE III -- Total U.S. (Continued) <u>Medium Case</u>

ALL RESPONDENTS
AVERAGE AND STANDARD DEVIATION

	AVERAGE					STANDARD DEVIATION AS A % OF THE MEAN		
	1977	1978	1982	1985	1990	1982	1985	1990
MOTOR GASOLINE: LEADED - PREMIUM	1,061	934		149	82		183.79%	200.00%
- NON-PREMIUM	4,207	4,106		1,369	680		36.02%	57.17%
S.TOTAL	5,268	5,040	2,494	1,548	699	8.36%	12.10%	32.88%
UNLEADED - PREMIUM	0	185		1,493	1,785		54.01%	55.93%
- NON-PREMIUM	1,908	2,187		3,699	3,612		25.71%	28.42%
S.TOTAL	1,908	2,372	4,391	5,112	5,470	4.58%	5.39%	7.71%
TOTAL MOTOR GASOLINE	7,176	7,412	6,948	6,679	6,143	2.23%	3.63%	5.43%
AVIATION GASOLINE	38	39	43	46	51	5.26%	11.91%	18.21%
JET FUEL: NAPTHA TYPE	208	199	194	185	151	8.74%	12.76%	43.66%
KEROSINE TYPE	831	858	964	1,061	1,250	3.33%	4.27%	9.13%
TOTAL JET FUEL	1,039	1,057	1,137	1,214	1,335	2.88%	5.95%	10.87%
SPECIAL NAPTHA	86	103	105	112	122	13.31%	15.73%	21.99%
KEROSINE	175	215	170	165	159	12.69%	16.32%	23.29%
DISTILLATE FUEL OIL: NO.2 OIL	1,292	1,385	1,214	1,177	1,089	1.84%	6.81%	7.28%
NO.4 OIL	62	61		85	99		44.41%	62.14%
DIESEL - ON HIGHWAY	724	797	995	1,300	1,775	7.17%	21.44%	27.44%
- OFF HIGHWAY	172	191		216	260		6.63%	16.26%
OTHER DISTILLATE	1,102	958		954	983		32.17%	33.55%
TOTAL DISTILLATE FUEL OIL	3,352	3,392	3,510	3,772	4,146	5.72%	7.53%	11.65%
RESIDUAL FUEL OIL: 0 - .5%S	959	862	726	790	634	9.07%	45.62%	49.67%
.51 - 1.0%S	693	716	547	479	372	16.34%	33.80%	50.48%
1.1 - 2.0%S	612	641	465	657	625	24.30%	82.47%	109.05%
2.0%S +	807	804	700	560	467	3.87%	24.23%	20.00%
TOTAL RESIDUAL FUEL OIL	3,071	3,023	2,645	2,695	2,389	9.32%	21.71%	33.39%
LIQUEFIED GASES: ETHANE	412	433	414	409	401	11.63%	13.71%	19.66%
PROPANE	866	778		1,044	1,165		4.29%	7.77%
BUTANE	115	167		242	284		39.76%	50.20%
PROPANE/BUTANE MIX	29	35						
TOTAL LIQUEFIED GASES	1,422	1,413	1,585	1,692	1,803	5.12%	6.43%	9.46%
PETROCHEMICAL FEEDSTOCKS: STILL GAS	48	55	51	65	66	10.48%	43.46%	43.90%
400 EP NAPTHA	204	205	243	294	384	6.71%	14.25%	27.65%
OTHER	269	335	458	469	601	17.65%	27.58%	42.63%
TOTAL PETROCHEMICAL FEEDSTOCKS	521	595	805	889	1,096	25.42%	19.42%	19.47%
LUBRICANTS	160	172	184	193	213	5.12%	7.75%	10.44%
WAXES	16	17	20	21	23	9.51%	13.49%	19.20%
COKE	267	256	271	278	291	8.93%	9.81%	14.37%
ASPHALT & ROAD OIL	437	479	497	516	543	8.51%	8.78%	11.69%
STILL GAS FOR FUEL	524	548	543	547	561	8.54%	9.60%	10.16%
MISCELLANEOUS PRODUCTS	147	128	161	162	161	24.81%	32.74%	29.49%
TOTAL DEMAND	18,431	18,847	18,418	18,781	18,897	3.09%	5.17%	7.93%
ETHANE	412	433	414	393	374	11.63%	15.93%	21.66%
PROPANE	123	85		256	352		39.91%	32.43%
BUTANE	93	136		148	188		21.50%	10.34%
PROPANE/BUTANE MIX	5	11						
TOTAL	633	665	733	774	838	11.50%	16.32%	17.19%

TABLE III -- Total U.S. (Continued) <u>Medium Case</u>

ALL RESPONDENTS
Median

	1977	1978	1982	1985	1990
MOTOR GASOLINE: LEADED - PREMIUM	1,061	934		10	0
- NON-PREMIUM	4,207	4,106		1,577	704
S. TOTAL	5,268	5,040	2,600	1,597	686
UNLEADED - PREMIUM	0	185		1,605	2,011
- NON-PREMIUM	1,908	2,187		3,748	3,456
S.TOTAL	1,908	2,372	4,400	5,082	5,459
TOTAL MOTOR GASOLINE	7,176	7,412	6,998	6,683	6,123
AVIATION GASOLINE	38	39	44	49	52
JET FUEL: NAPTHA TYPE	208	199	198	194	175
KEROSINE TYPE	831	858	971	1,053	1,212
TOTAL JET FUEL	1,039	1,057	1,140	1,239	1,355
SPECIAL NAPTHA	86	103	106	107	109
KEROSINE	175	215	173	167	155
DISTILLATE FUEL OIL: NO.2 OIL	1,292	1,385	1,209	1,157	1,089
NO.4 OIL	62	61		65	67
DIESEL - ON HIGHWAY	724	797	995	1,315	1,784
- OFF HIGHWAY	172	191		217	259
OTHER DISTILLATE	1,102	958		950	952
TOTAL DISTILLATE FUEL OIL	3,352	3,392	3,497	3,709	4,087
RESIDUAL FUEL OIL: 0 - .5%S	959	862	737	746	649
.51 - 1.0%S	693	716	560	520	408
1.1 - 2.0%S	612	641	510	498	416
2.0%S +	807	804	690	556	473
TOTAL RESIDUAL FUEL OIL	3,071	3,023	2,620	2,692	2,295
LIQUEFIED GASES: ETHANE	412	433	415	406	381
PROPANE	866	778		1,028	1,184
BUTANE	115	167		215	221
PROPANE/BUTANE MIX	29	35			
TOTAL LIQUEFIED GASES	1,422	1,413	1,581	1,680	1,768
PETROCHEMICAL FEEDSTOCKS: STILL GAS	48	55	51	54	54
400 EP NAPTHA	204	205	244	285	340
OTHER	269	335	450	508	595
TOTAL PETROCHEMICAL FEEDSTOCKS	521	595	745	859	1,084
LUBRICANTS	160	172	181	190	216
WAXES	16	17	20	20	22
COKE	267	256	267	275	283
ASPHALT & ROAD OIL	437	479	493	516	556
STILL GAS FOR FUEL	524	548	555	554	579
MISCELLANEOUS PRODUCTS	147	128	181	167	170
TOTAL DEMAND	18,431	18,847	18,500	18,994	18,841
ETHANE	412	433	415	402	339
PROPANE	123	85		305	415
BUTANE	93	136		141	197
PROPANE/BUTANE MIX	5	11			
TOTAL	633	665	718	773	806

TABLE III

Medium Case

Domestic Demand for Products -- PADs I-IV
(Thousand Barrels/Day)

ALL RESPONDENTS
High

	1977	1978	1982	1985	1990
MOTOR GASOLINE: LEADED - PREMIUM	754	656			
- NON-PREMIUM	3,699	3,600			
S.TOTAL	4,453	4,256			
UNLEADED - PREMIUM	0	0			
- NON-PREMIUM	1,640	2,026			
S.TOTAL	1,640	2,026			
TOTAL MOTOR GASOLINE	6,093	6,283	5,988	5,900	5,810
AVIATION GASOLINE	29	30		39	50
JET FUEL: NAPTHA TYPE	149	143		145	145
KEROSINE TYPE	591	613		758	1,009
TOTAL JET FUEL	740	756	833	887	1,060
SPECIAL NAPTHA	78	88			
KEROSINE	162	194		165	165
DISTILLATE FUEL OIL: NO.2 OIL	1,253	1,344			
NO.4 OIL	60	58			
DIESEL - ON HIGHWAY	622	679		1,543	2,134
- OFF HIGHWAY	150	165			
OTHER DISTILLATE	942	801			
TOTAL DISTILLATE FUEL OIL	3,027	3,047	3,533	3,898	4,287
RESIDUAL FUEL OIL: 0 - .5%S	633	641			
.51 - 1.0%S	654	672			
1.1 - 2.0%S	428	426			
2.0%S +	786	796			
TOTAL RESIDUAL FUEL OIL	2,501	2,535	2,659	3,273	3,259
LIQUEFIED GASES: ETHANE	410	432			
PROPANE	820	729			
BUTANE	111	162			
PROPANE/BUTANE MIX	26	31			
TOTAL LIQUEFIED GASES	1,367	1,355		1,703	1,948
PETROCHEMICAL FEEDSTOCKS: STILL GAS	46	53			
400 EP NAPTHA	201	201			
OTHER	261	331			
TOTAL PETROCHEMICAL FEEDSTOCKS	508	586			
LUBRICANTS	145	153			
WAXES	13	14			
COKE	218	215			
ASPHALT & ROAD OIL	374	401			
STILL GAS FOR FUEL	423	444			
MISCELLANEOUS PRODUCTS	139	117			
TOTAL DEMAND	15,817	16,216	16,860	17,331	18,267
ETHANE	410	432			
PROPANE	118	81			
BUTANE	91	133			
PROPANE/BUTANE MIX	4	10			
TOTAL	623	656			

TABLE III -- PADs I-IV (Continued) Medium Case

ALL RESPONDENTS
Low

	1977	1978	1982	1985	1990
MOTOR GASOLINE: LEADED - PREMIUM	754	656			
- NON-PREMIUM	3,699	3,600			
S.TOTAL	4,453	4,256			
UNLEADED - PREMIUM	0	0			
- NON-PREMIUM	1,640	2,026			
S.TOTAL	1,640	2,026			
TOTAL MOTOR GASOLINE	6,093	6,283	5,796	5,346	4,845
AVIATION GASOLINE	29	30		28	26
JET FUEL: NAPTHA TYPE	149	143		103	0
KEROSINE TYPE	591	613		704	768
TOTAL JET FUEL	740	756	774	750	700
SPECIAL NAPTHA	78	88			
KEROSINE	162	194		151	142
DISTILLATE FUEL OIL: NO.2 OIL	1,253	1,344			
NO.4 OIL	60	58			
DIESEL - ON HIGHWAY	622	679		1,036	1,240
- OFF HIGHWAY	150	165			
OTHER DISTILLATE	942	801			
TOTAL DISTILLATE FUEL OIL	3,027	3,047	3,000	3,050	3,100
RESIDUAL FUEL OIL: 0 - .5%S	633	641			
.51 - 1.0%S	654	672			
1.1 - 2.0%S	428	426			
2.0%S +	786	796			
TOTAL RESIDUAL FUEL OIL	2,501	2,535	1,655	880	453
LIQUEFIED GASES: ETHANE	410	432			
PROPANE	820	729			
BUTANE	111	162			
PROPANE/BUTANE MIX	26	31			
TOTAL LIQUEFIED GASES	1,367	1,355		1,508	1,701
PETROCHEMICAL FEEDSTOCKS: STILL GAS	46	53			
400 EP NAPTHA	201	201			
OTHER	261	331			
TOTAL PETROCHEMICAL FEEDSTOCKS	508	586			
LUBRICANTS	145	153			
WAXES	13	14			
COKE	218	215			
ASPHALT & ROAD OIL	374	401			
STILL GAS FOR FUEL	423	444			
MISCELLANEOUS PRODUCTS	139	117			
TOTAL DEMAND	15,817	16,216	14,949	14,189	13,584
ETHANE	410	432			
PROPANE	118	81			
BUTANE	91	133			
PROPANE/BUTANE MIX	4	10			
TOTAL	623	656			

TABLE III -- PADs I-IV (Continued)

Medium Case

ALL RESPONDENTS
AVERAGE AND STANDARD DEVIATION

	AVERAGE					STANDARD DEVIATION AS A % OF THE MEAN		
	1977	1978	1982	1985	1990	1982	1985	1990
MOTOR GASOLINE: LEADED - PREMIUM	754	656						
- NON-PREMIUM	3,699	3,600						
S.TOTAL	4,453	4,256						
UNLEADED - PREMIUM	0	0						
- NON-PREMIUM	1,640	2,026						
S.TOTAL	1,640	2,026						
TOTAL MOTOR GASOLINE	6,093	6,283	5,883	5,661	5,221	1.28%	3.55%	6.05%
AVIATION GASOLINE	29	30		34	38		12.75%	22.66%
JET FUEL: NAPTHA TYPE	149	143		131	65		14.98%	91.92%
KEROSINE TYPE	591	613		736	889		2.69%	11.13%
TOTAL JET FUEL	740	756	796	820	866	2.99%	7.16%	15.56%
SPECIAL NAPTHA	78	88						
KEROSINE	162	194		156	151	2.48%	3.59%	5.77%
DISTILLATE FUEL OIL: NO.2 OIL	1,253	1,344						
NO.4 OIL	60	58						
DIESEL - ON HIGHWAY	622	679		1,282	1,728		6.17%	21.39%
- OFF HIGHWAY	150	165						
OTHER DISTILLATE	942	801						
TOTAL DISTILLATE FUEL OIL	3,027	3,047	3,286	3,432	3,690	6.36%	7.79%	12.82%
RESIDUAL FUEL OIL: 0 - .5%S	633	641						
.51 - 1.0%S	654	672						
1.1 - 2.0%S	428	426						
2.0%S +	786	796						
TOTAL RESIDUAL FUEL OIL	2,501	2,535	2,120	2,147	1,869	17.06%	33.15%	42.21%
LIQUEFIED GASES: ETHANE	410	432						
PROPANE	820	729						
BUTANE	111	162						
PROPANE/BUTANE MIX	26	31						
TOTAL LIQUEFIED GASES	1,367	1,355		1,602	1,784		4.98%	6.50%
PETROCHEMICAL FEEDSTOCKS: STILL GAS	46	53						
400 EP NAPTHA	201	201						
OTHER	261	331						
TOTAL PETROCHEMICAL FEEDSTOCKS	508	586						
LUBRICANTS	145	153						
WAXES	13	14						
COKE	218	215						
ASPHALT & ROAD OIL	374	401						
STILL GAS FOR FUEL	423	444						
MISCELLANEOUS PRODUCTS	139	117						
TOTAL DEMAND	15,817	16,216	15,750	16,037	16,013	5.15%	6.97%	9.18%
ETHANE	410	432						
PROPANE	118	81						
BUTANE	91	133						
PROPANE/BUTANE MIX	4	10						
TOTAL	623	656						

TABLE III -- PADs I-IV (Continued)

Medium Case

ALL RESPONDENTS
Median

	1977	1978	1982	1985	1990
MOTOR GASOLINE: LEADED - PREMIUM	754	656			
- NON-PREMIUM	3,699	3,600			
S. TOTAL	4,453	4,256			
UNLEADED - PREMIUM	0	0			
- NON-PREMIUM	1,640	2,026			
S. TOTAL	1,640	2,026			
TOTAL MOTOR GASOLINE	6,093	6,283	5,900	5,680	5,123
AVIATION GASOLINE	29	30		34	38
JET FUEL: NAPTHA TYPE	149	143		144	51
KEROSINE TYPE	591	613		742	889
TOTAL JET FUEL	740	756	788	818	867
SPECIAL NAPTHA	78	88			
KEROSINE	162	194		153	148
DISTILLATE FUEL OIL: NO.2 OIL	1,253	1,344			
NO.4 OIL	60	58			
DIESEL - ON HIGHWAY	622	679		1,266	1,809
- OFF HIGHWAY	150	165			
OTHER DISTILLATE	942	801			
TOTAL DISTILLATE FUEL OIL	3,027	3,047	3,305	3,419	4,008
RESIDUAL FUEL OIL: 0 - .5%S	633	641			
.51 - 1.0%S	654	672			
1.1 - 2.0%S	428	426			
2.0%S +	786	796			
TOTAL RESIDUAL FUEL OIL	2,501	2,535	2,083	1,964	1,850
LIQUEFIED GASES: ETHANE	410	432			
PROPANE	820	729			
BUTANE	111	162			
PROPANE/BUTANE MIX	26	31			
TOTAL LIQUEFIED GASES	1,367	1,355		1,596	1,703
PETROCHEMICAL FEEDSTOCKS: STILL GAS	46	53			
400 EP NAPTHA	201	201			
OTHER	261	331			
TOTAL PETROCHEMICAL FEEDSTOCKS	508	586			
LUBRICANTS	145	153			
WAXES	13	14			
COKE	218	215			
ASPHALT & ROAD OIL	374	401			
STILL GAS FOR FUEL	423	444			
MISCELLANEOUS PRODUCTS	139	117			
TOTAL DEMAND	15,817	16,216	15,596	16,245	16,073
ETHANE	410	432			
PROPANE	118	81			
BUTANE	91	133			
PROPANE/BUTANE MIX	4	10			
TOTAL	623	656			

Medium Case

TABLE III

Domestic Demand for Products -- PAD V
(Thousand Barrels/Day)

ALL RESPONDENTS
High

	1977	1978	1982	1985	1990
MOTOR GASOLINE: LEADED - PREMIUM	307	278			
- NON-PREMIUM	508	506			
S.TOTAL	815	784			
UNLEADED - PREMIUM	0	184			
- NON-PREMIUM	268	161			
S.TOTAL	268	345			
TOTAL MOTOR GASOLINE	1,083	1,129	1,144	1,135	1,090
AVIATION GASOLINE	9	9		12	15
JET FUEL: NAPTHA TYPE	59	56		59	59
KEROSINE TYPE	240	245		336	466
TOTAL JET FUEL	299	301	334	383	490
SPECIAL NAPTHA	8	15			
KEROSINE	13	21		14	13
DISTILLATE FUEL OIL: NO.2 OIL	39	41			
NO.4 OIL	2	3			
DIESEL - ON HIGHWAY	102	118		279	385
- OFF HIGHWAY	22	26			
OTHER DISTILLATE	160	157			
TOTAL DISTILLATE FUEL OIL	325	345	430	483	561
RESIDUAL FUEL OIL: 0 - .5%S	326	221			
.51 - 1.0%S	39	44			
1.1 - 2.0%S	184	215			
2.0%S +	21	8			
TOTAL RESIDUAL FUEL OIL	570	488	541	726	675
LIQUEFIED GASES: ETHANE	2	1			
PROPANE	46	49			
BUTANE	4	5			
PROPANE/BUTANE MIX	3	3			
TOTAL LIQUEFIED GASES	55	58		69	83
PETROCHEMICAL FEEDSTOCKS: STILL GAS	2	2			
400 EP NAPTHA	3	3			
OTHER	8	4			
TOTAL PETROCHEMICAL FEEDSTOCKS	13	9			
LUBRICANTS	15	19			
WAXES	3	3			
COKE	49	41			
ASPHALT & ROAD OIL	63	78			
STILL GAS FOR FUEL	101	104			
MISCELLANEOUS PRODUCTS	8	11			
TOTAL DEMAND	2,614	2,631	2,760	2,913	3,138
ETHANE	2	1			
PROPANE	5	4			
BUTANE	2	3			
PROPANE/BUTANE MIX	1	1			
TOTAL	10	9			

TABLE III -- PAD V (Continued)

Medium Case

ALL RESPONDENTS
Low

	1977	1978	1982	1985	1990
MOTOR GASOLINE: LEADED - PREMIUM	307	278			
- NON-PREMIUM	508	506			
S. TOTAL	815	784			
UNLEADED - PREMIUM	0	184			
- NON-PREMIUM	268	161			
S. TOTAL	268	345			
TOTAL MOTOR GASOLINE	1,083	1,129	1,000	950	900
AVIATION GASOLINE	9	9		9	9
JET FUEL: NAPTHA TYPE	59	56		47	0
KEROSINE TYPE	240	245		297	327
TOTAL JET FUEL	299	301	300	300	300
SPECIAL NAPTHA	8	15			
KEROSINE	13	21		13	12
DISTILLATE FUEL OIL: NO.2 OIL	39	41			
NO.4 OIL	2	3			
DIESEL - ON HIGHWAY	102	118		176	210
- OFF HIGHWAY	22	26			
OTHER DISTILLATE	160	157			
TOTAL DISTILLATE FUEL OIL	325	345	300	350	400
RESIDUAL FUEL OIL: 0 - .5%S	326	221			
.51 - 1.0%S	39	44			
1.1 - 2.0%S	184	215			
2.0%S +	21	8			
TOTAL RESIDUAL FUEL OIL	570	488	400	235	130
LIQUEFIED GASES: ETHANE	2	1			
PROPANE	46	49			
BUTANE	4	5			
PROPANE/BUTANE MIX	3	3			
TOTAL LIQUEFIED GASES	55	58		62	67
PETROCHEMICAL FEEDSTOCKS: STILL GAS	2	2			
400 EP NAPTHA	3	3			
OTHER	8	4			
TOTAL PETROCHEMICAL FEEDSTOCKS	13	9			
LUBRICANTS	15	19			
WAXES	3	3			
COKE	49	41			
ASPHALT & ROAD OIL	63	78			
STILL GAS FOR FUEL	101	104			
MISCELLANEOUS PRODUCTS	8	11			
TOTAL DEMAND	2,614	2,631	2,400	2,400	2,316
ETHANE	2	1			
PROPANE	5	4			
BUTANE	2	3			
PROPANE/BUTANE MIX	1	1			
TOTAL	10	9			

TABLE III -- PAD V (Continued)

<u>Medium Case</u>

ALL RESPONDENTS
AVERAGE AND STANDARD DEVIATION

	AVERAGE 1977	1978	1982	1985	1990	STANDARD DEVIATION AS A % OF THE MEAN 1982	1985	1990
MOTOR GASOLINE: LEADED - PREMIUM	307	278						
- NON-PREMIUM	508	506						
S.TOTAL	815	784						
UNLEADED - PREMIUM	0	184						
- NON-PREMIUM	268	161						
S.TOTAL	268	345						
TOTAL MOTOR GASOLINE	1,083	1,129	1,079	1,050	990	4.58%	5.64%	6.05%
AVIATION GASOLINE	9	9		10	11		12.25%	20.25%
JET FUEL: NAPTHA TYPE	59	56		54	28		9.44%	87.56%
KEROSINE TYPE	240	245		313	389		4.61%	13.26%
TOTAL JET FUEL	299	301	323	348	386	4.12%	7.84%	15.97%
SPECIAL NAPTHA	8	15		18	22		8.57%	11.63%
KEROSINE	13	21		13	13		3.27%	3.40%
DISTILLATE FUEL OIL: NO.2 OIL	39	41						
NO.4 OIL	2	3						
DIESEL - ON HIGHWAY	102	118		228	313		18.47%	23.98%
- OFF HIGHWAY	22	26						
OTHER DISTILLATE	160	157						
TOTAL DISTILLATE FUEL OIL	325	345	375	404	464	14.21%	10.82%	14.67%
RESIDUAL FUEL OIL: 0 - .5%S	326	221						
.51 - 1.0%S	39	44						
1.1 - 2.0%S	184	215						
2.0%S +	21	8						
TOTAL RESIDUAL FUEL OIL	570	488	488	519	465	10.87%	26.12%	34.21%
LIQUEFIED GASES: ETHANE	2	1						
PROPANE	46	49						
BUTANE	4	5						
PROPANE/BUTANE MIX	3	3						
TOTAL LIQUEFIED GASES	55	58		66	74		4.46%	9.03%
PETROCHEMICAL FEEDSTOCKS: STILL GAS	2	2						
400 EP NAPTHA	3	3						
OTHER	8	4						
TOTAL PETROCHEMICAL FEEDSTOCKS	13	9						
LUBRICANTS	15	19						
WAXES	3	3						
COKE	49	41						
ASPHALT & ROAD OIL	63	78						
STILL GAS FOR FUEL	101	104						
MISCELLANEOUS PRODUCTS	8	11						
TOTAL DEMAND	2,614	2,631	2,626	2,702	2,717	5.48%	7.11%	10.15%
ETHANE	2	1						
PROPANE	5	4						
BUTANE	2	3						
PROPANE/BUTANE MIX	1	1						
TOTAL	10	9						

TABLE III -- PAD V (Continued)

Medium Case

ALL RESPONDENTS
Median

	1977	1978	1982	1985	1990
MOTOR GASOLINE: LEADED - PREMIUM	307	278			
- NON-PREMIUM	508	506			
S.TOTAL	815	784			
UNLEADED - PREMIUM	0	184			
- NON-PREMIUM	268	161			
S.TOTAL	268	345			
TOTAL MOTOR GASOLINE	1,083	1,129	1,100	1,060	986
AVIATION GASOLINE	9	9		10	11
JET FUEL: NAPTHA TYPE	59	56		56	24
KEROSINE TYPE	240	245		310	381
TOTAL JET FUEL	299	301	328	359	393
SPECIAL NAPTHA	8	15			
KEROSINE	13	21		13	13
DISTILLATE FUEL OIL: NO.2 OIL	39	41			
NO.4 OIL	2	3			
DIESEL - ON HIGHWAY	102	118		228	344
- OFF HIGHWAY	22	26			
OTHER DISTILLATE	160	157			
TOTAL DISTILLATE FUEL OIL	325	345	385	413	420
RESIDUAL FUEL OIL: 0 - .5%S	326	221			
.51 - 1.0%S	29	44			
1.1 - 2.0%S	184	215			
2.0%S +	21	8			
TOTAL RESIDUAL FUEL OIL	570	488	506	532	482
LIQUEFIED GASES: ETHANE	2	1			
PROPANE	46	49			
BUTANE	4	5			
PROPANE/BUTANE MIX	3	3			
TOTAL LIQUEFIED GASES	55	58		67	72
PETROCHEMICAL FEEDSTOCKS: STILL GAS	2	2			
400 EP NAPTHA	3	3			
OTHER	8	4			
TOTAL PETROCHEMICAL FEEDSTOCKS	13	9			
LUBRICANTS	15	19			
WAXES	3	3			
COKE	49	41			
ASPHALT & ROAD OIL	63	78			
STILL GAS FOR FUEL	101	104			
MISCELLANEOUS PRODUCTS	8	11			
TOTAL DEMAND	2,614	2,631	2,671	2,784	2,769
ETHANE	2	1			
PROPANE	5	4			
BUTANE	2	3			
PROPANE/BUTANE MIX	1	1			
TOTAL	10	9			

TABLE IIIA

Medium Case

Motor Gasoline Demand Assumptions

ALL RESPONDENTS

High

	1977	1978	1982	1985	1990
PASSENGER CARS IN USE (THOUSANDS)	99,904	102,957	129,000	136,740	142,000
NEW CAR REGISTRATION (THOUSANDS)	10,319	10,946	12,502	13,170	14,011
TOTAL MILES TRAVELED-MILLIONS	1,118,649	1,171,092	1,717,031	2,079,270	2,648,292
AVERAGE MILES PER CAR (ALL CARS)	11,197	10,046	11,506	12,012	12,298
AVERAGE MILES PER GALLON (NEW CARS)	19	20	25	29	31
AVERAGE MPG (ALL CARS)	14	15	17	20	24
DIESEL PASSENGER CAR SALES (THOUSANDS)	0	135	792	2,783	3,510
AVERAGE MILES PER GALLON (NEW TRUCKS)	15	16	21	26	21
LEADED PREMIUM	95	94	95	96	96
LEADED NON-PREMIUM	90	90	90	91	91
UNLEADED PREMIUM	0	0	93	94	95
UNLEADED NON-PREMIUM	88	89	89	89	89

Low

	1977	1978	1982	1985	1990
PASSENGER CARS IN USE (THOUSANDS)	99,904	102,957	100,400	103,200	110,100
NEW CAR REGISTRATION (THOUSANDS)	10,319	10,946	9,530	10,100	10,000
TOTAL MILES TRAVELED-MILLIONS	1,118,649	1,171,092	1,082,886	1,113,400	1,207,800
AVERAGE MILES PER CAR (ALL CARS)	11,197	10,046	9,347	9,351	9,348
AVERAGE MILES PER GALLON (NEW CARS)	19	20	19	21	23
AVERAGE MPG (ALL CARS)	14	15	15	17	19
DIESEL PASSENGER CAR SALES (THOUSANDS)	0	135	179	232	230
AVERAGE MILES PER GALLON (NEW TRUCKS)	15	16	11	11	12
LEADED PREMIUM	95	94	92	92	95
LEADED NON-PREMIUM	90	90	88	88	88
UNLEADED PREMIUM	0	0	91	91	91
UNLEADED NON-PREMIUM	88	89	87	87	87

TABLE IIIA (Continued)

Medium Case

ALL RESPONDENTS
AVERAGE AND STANDARD DEVIATION

	AVERAGE 1977	1978	1982	1985	1990	STANDARD DEVIATION AS A % OF THE MEAN 1982	1985	1990
PASSENGER CARS IN USE (THOUSANDS)	99,904	102,957	112,328	118,757	125,635	7.19%	7.43%	7.17%
NEW CAR REGISTRATION (THOUSANDS)	10,319	10,946	10,769	11,687	12,129	6.16%	6.88%	7.91%
TOTAL MILES TRAVELED-MILLIONS	1,118,649	1,171,092	1,257,431	1,362,579	1,516,542	13.30%	16.22%	23.08%
AVERAGE MILES PER CAR (ALL CARS)	11,197	10,046	10,536	10,839	11,118	6.77%	6.98%	7.86%
AVERAGE MILES PER GALLON (NEW CARS)	19	20	21	24	26	9.43%	9.75%	9.81%
AVERAGE MPG (ALL CARS)	14	15	16	18	22	3.69%	5.19%	6.51%
DIESEL PASSENGER CAR SALES (THOUSANDS)	0	135	557	1,153	1,776	36.97%	60.02%	56.41%
AVERAGE MILES PER GALLON (NEW TRUCKS)	15	16	16	17	17	20.71%	27.03%	20.84%
LEADED PREMIUM	95	94	94	94	95	1.25%	1.44%	.49%
LEADED NON-PREMIUM	90	90	89	89	89	.70%	1.07%	1.07%
UNLEADED PREMIUM	0	0	92	92	92	.84%	1.28%	1.52%
UNLEADED NON-PREMIUM	88	89	87	87	87	.66%	.60%	.83%

Median

	1977	1978	1982	1985	1990
PASSENGER CARS IN USE (THOUSANDS)	99,904	102,957	112,800	118,950	124,100
NEW CAR REGISTRATION (THOUSANDS)	10,319	10,946	10,785	11,798	12,100
TOTAL MILES TRAVELED-MILLIONS	1,118,649	1,171,092	1,237,600	1,356,338	1,476,800
AVERAGE MILES PER CAR (ALL CARS)	11,197	10,046	10,839	10,945	11,250
AVERAGE MILES PER GALLON (NEW CARS)	19	20	21	23	26
AVERAGE MPG (ALL CARS)	14	15	16	18	22
DIESEL PASSENGER CAR SALES (THOUSANDS)	0	135	600	1,200	1,500
AVERAGE MILES PER GALLON (NEW TRUCKS)	15	16	15	17	16
LEADED PREMIUM	95	94	94	95	95
LEADED NON-PREMIUM	90	90	89	89	89
UNLEADED PREMIUM	0	0	92	92	92
UNLEADED NON-PREMIUM	88	89	87	87	87

TABLE IV

Medium Case

U.S. Petroleum Supply/Demand Balance
(Thousand Barrels/Day)

ALL RESPONDENTS
High

	1977	1978	1982	1985	1990
DEMAND - TOTAL	18,690	19,224	20,030	20,520	21,603
1. LOCAL PRODUCT DEMAND	18,431	18,847	19,601	20,244	21,405
2. CRUDE AND PRODUCT EXPORTS	243	362	450	450	650
3. PRODUCT SHIPMENTS TO OTHER DISTRICTS	0	0	0	0	0
4. CRUDE, NGL & UNF. SHIPMENTS TOD	0	0	0	0	0
5. CRUDE LOSSES	16	16	20	50	50
SUPPLY - TOTAL	18,690	19,224	20,030	20,520	21,603
1. PRODUCTION - TOTAL	9,861	10,274	10,406	10,318	10,864
CRUDE AND LEASE CONDENSATE	8,244	8,707	9,000	8,998	9,744
NGL	1,617	1,567	1,660	1,715	1,695
2. RECEIPTS FROM OTHER DISTRICTS	0	0	0	0	0
CRUDE, NGL, AND UNFINISHED	0	0	0	0	0
PRODUCTS	0	0	0	0	0
3. PROCESSING GAIN, ETC.	569	439	610	610	630
4. IMPORTS - TOTAL	8,808	8,364	10,122	10,581	11,603
CRUDE AND UNFINISHED	6,646	6,383	7,580	7,778	8,352
FROM OVERLAND	279	564	150	192	290
FROM OFFSHORE	6,367	5,819	7,440	7,715	8,160
NGL	42	17	368	561	923
FINISHED PRODUCTS	2,120	1,964	2,542	2,838	2,918
5. SYNCRUDE	0	0	25	400	1,000
FROM SHALE	0	0	5	300	630
FROM COAL	0	0	20	100	370
6. FROM INVENTORY	-548	94	119	99	0
CRUDE	-170	-78	0	0	0
PRODUCTS	-378	172	0	17	0
7. CRUDE RUNS	14,602	14,739	15,350	15,867	16,542
ALASKAN PRODUCTION	310	1,089	1,555	2,000	2,000

TABLE IV -- Total U.S. (Continued)

Medium Case

ALL RESPONDENTS
Low

	1977	1978	1982	1985	1990
DEMAND - TOTAL	18,690	19,224	17,730	16,810	16,080
1. LOCAL PRODUCT DEMAND	18,431	18,847	17,400	16,630	15,900
2. CRUDE AND PRODUCT EXPORTS	243	362	180	180	180
3. PRODUCT SHIPMENTS TO OTHER DISTRICTS	0	0	0	0	0
4. CRUDE, NGL & UNF. SHIPMENTS TOD	0	0	0	0	0
5. CRUDE LOSSES	16	16	15	15	15
SUPPLY - TOTAL	18,690	19,224	17,730	16,810	16,080
1. PRODUCTION - TOTAL	9,861	10,274	9,031	7,879	6,135
CRUDE AND LEASE CONDENSATE	8,244	8,707	7,860	6,820	5,370
NGL	1,617	1,567	1,171	910	389
2. RECEIPTS FROM OTHER DISTRICTS	0	0	0	0	0
CRUDE, NGL, AND UNFINISHED	0	0	0	0	0
PRODUCTS	0	0	0	0	0
3. PROCESSING GAIN, ETC.	569	439	480	245	252
4. IMPORTS - TOTAL	8,808	8,364	7,326	5,923	3,220
CRUDE AND UNFINISHED	6,646	6,383	5,158	5,330	3,927
FROM OVERLAND	279	564	0	0	0
FROM OFFSHORE	6,367	5,819	6,079	6,449	5,416
NGL	42	17	0	0	0
FINISHED PRODUCTS	2,120	1,964	1,041	593	695
5. SYNCRUDE	0	0	0	0	110
FROM SHALE	0	0	0	0	110
FROM COAL	0	0	0	0	0
6. FROM INVENTORY	-548	94	-337	-200	-200
CRUDE	-170	-78	-315	-200	-128
PRODUCTS	-378	172	-22	0	-24
7. CRUDE RUNS	14,602	14,739	14,158	14,140	13,568
ALASKAN PRODUCTION	310	1,089	1,400	1,450	1,074

TABLE IV -- Total U.S. (Continued)

Medium Case

ALL RESPONDENTS
AVERAGE & STANDARD DEVIATION

	AVERAGE					STANDARD DEVIATION AS A % OF THE MEAN		
	1977	1978	1982	1985	1990	1982	1985	1990
DEMAND - TOTAL	18,690	19,224	18,769	19,096	19,205	3.39%	5.29%	7.93%
1. LOCAL PRODUCT DEMAND	18,431	18,847	18,410	18,761	18,822	3.21%	5.31%	8.06%
2. CRUDE AND PRODUCT EXPORTS	243	362	329	286	288	24.93%	31.43%	43.44%
3. PRODUCT SHIPMENTS TO OTHER DISTRICTS	0	0	0	0	0	0%	0%	0%
4. CRUDE, NGL & UNF. SHIPMENTS TOD	0	0	0	0	0	0%	0%	0%
5. CRUDE LOSSES	16	16	17	20	21	13.80%	51.04%	50.19%
SUPPLY - TOTAL	18,690	19,224	18,769	19,096	19,205	3.39%	5.29%	7.93%
1. PRODUCTION - TOTAL	9,861	10,274	9,800	9,511	9,101	3.76%	7.64%	14.51%
CRUDE AND LEASE CONDENSATE	8,244	8,707	8,321	8,105	7,828	4.05%	7.71%	15.14%
NGL	1,617	1,567	1,479	1,406	1,273	8.18%	12.52%	22.26%
2. RECEIPTS FROM OTHER DISTRICTS	0	0	0	0	0	0%	0%	0%
CRUDE, NGL, AND UNFINISHED	0	0	0	0	0	0%	0%	0%
PRODUCTS	0	0	0	0	0	0%	0%	0%
3. PROCESSING GAIN, ETC.	569	439	543	525	524	8.10%	16.71%	17.05%
4. IMPORTS - TOTAL	8,808	8,364	8,406	8,822	8,363	8.86%	12.92%	26.22%
CRUDE AND UNFINISHED	6,646	6,383	6,373	6,695	6,566	9.13%	11.73%	18.25%
FROM OVERLAND	279	564	86	79	86	63.52%	94.66%	121.64%
FROM OFFSHORE	6,367	5,819	6,538	7,045	7,062	7.36%	7.13%	12.09%
NGL	42	17	107	271	398	141.45%	93.30%	94.72%
FINISHED PRODUCTS	2,120	1,964	1,861	1,826	1,759	23.75%	34.07%	36.36%
5. SYNCRUDE	0	0	3	101	498	282.84%	106.19%	50.64%
FROM SHALE	0	0	1	62	326	282.84%	133.99%	45.71%
FROM COAL	0	0	2	25	136	282.84%	137.02%	93.51%
6. FROM INVENTORY	-548	94	-47	-49	-32	272.01%	193.08%	206.48%
CRUDE	-170	-78	-53	-56	-14	223.61%	148.22%	232.84%
PRODUCTS	-378	172	-4	2	-3	223.61%	282.84%	282.84%
7. CRUDE RUNS	14,602	14,739	14,658	14,969	15,122	2.39%	3.94%	6.05%
ALASKAN PRODUCTION	310	1,089	1,481	1,579	1,573	3.15%	8.65%	15.65%

TABLE IV -- Total U.S. (Continued)

Medium Case

ALL RESPONDENTS
Median

	1977	1978	1982	1985	1990
DEMAND - TOTAL	18,690	19,224	18,725	19,314	19,257
1. LOCAL PRODUCT DEMAND	18,431	18,847	18,363	18,981	18,900
2. CRUDE AND PRODUCT EXPORTS	243	362	325	298	238
3. PRODUCT SHIPMENTS TO OTHER DISTRICTS	0	0	0	0	0
4. CRUDE, NGL & UNF. SHIPMENTS TOD	0	0	0	0	0
5. CRUDE LOSSES	16	16	16	16	16
SUPPLY - TOTAL	18,690	19,224	18,725	19,314	19,257
1. PRODUCTION - TOTAL	9,861	10,274	9,775	9,600	9,500
CRUDE AND LEASE CONDENSATE	8,244	8,707	8,220	8,200	7,900
NGL	1,617	1,567	1,480	1,400	1,277
2. RECEIPTS FROM OTHER DISTRICTS	0	0	0	0	0
CRUDE, NGL, AND UNFINISHED	0	0	0	0	0
PRODUCTS	0	0	0	0	0
3. PROCESSING GAIN, ETC.	569	439	535	550	545
4. IMPORTS - TOTAL	8,808	8,364	8,370	8,690	8,465
CRUDE AND UNFINISHED	6,646	6,383	6,330	6,530	6,530
FROM OVERLAND	279	564	70	63	40
FROM OFFSHORE	6,367	5,819	6,490	7,094	7,000
NGL	42	17	30	254	355
FINISHED PRODUCTS	2,120	1,964	1,965	1,900	1,770
5. SYNCRUDE	0	0	0	78	500
FROM SHALE	0	0	0	50	300
FROM COAL	0	0	0	5	75
6. FROM INVENTORY	-548	94	0	0	0
CRUDE	-170	-78	0	0	0
PRODUCTS	-378	172	0	0	0
7. CRUDE RUNS	14,602	14,739	14,553	15,140	15,175
ALASKAN PRODUCTION	310	1,089	1,500	1,500	1,500

TABLE IV

Medium Case

U.S. Petroleum Supply/Demand Balance -- PAD V
(Thousand Barrels/Day)

ALL RESPONDENTS
High

	1977	1978	1982	1985	1990
DEMAND - TOTAL	2,754	3,112	3,447	3,745	4,395
1. LOCAL PRODUCT DEMAND	2,614	2,631	2,760	2,856	2,957
2. CRUDE AND PRODUCT EXPORTS	71	163	247	200	200
3. PRODUCT SHIPMENTS TO OTHER DISTRICTS	21	15	36	25	28
4. CRUDE, NGL & UNF. SHIPMENTS TOD	47	301	500	750	1,380
5. CRUDE LOSSES	1	1		12	13
SUPPLY - TOTAL	2,754	3,112	3,447	3,745	4,395
1. PRODUCTION - TOTAL	1,448	2,209	3,700	4,000	4,000
CRUDE AND LEASE CONDENSATE	1,424	2,185	3,675	3,975	3,975
NGL	24	24	34	35	40
2. RECEIPTS FROM OTHER DISTRICTS	135	159	151	165	165
CRUDE, NGL, AND UNFINISHED	9	6	7	10	10
PRODUCTS	126	153	151	155	155
3. PROCESSING GAIN, ETC.	34	-31	140	140	140
4. IMPORTS - TOTAL	1,214	725	619	594	520
CRUDE AND UNFINISHED	1,099	602	514	484	500
FROM OVERLAND	20	12	10	0	0
FROM OFFSHORE	1,079	590	514	484	450
NGL	4	2			
FINISHED PRODUCTS	111	121	105	117	130
5. SYNCRUDE	0	0	0	0	50
FROM SHALE	0	0	0	0	50
FROM COAL	0	0	0	0	0
6. FROM INVENTORY	-77	41	0	0	0
CRUDE	-67	28	0	0	0
PRODUCTS	-10	13	0	0	0
7. CRUDE RUNS	2,323	2,287	2,485	2,640	2,745
ALASKAN PRODUCTION	310	1,089	1,500	1,675	1,820

TABLE IV -- PAD V (Continued)

<u>Medium Case</u>

ALL RESPONDENTS
LOW

	1977	1978	1982	1985	1990
DEMAND - TOTAL	2,754	3,112	3,100	2,983	2,905
1. LOCAL PRODUCT DEMAND	2,614	2,631	2,400	2,400	2,316
2. CRUDE AND PRODUCT EXPORTS	71	163	74	74	74
3. PRODUCT SHIPMENTS TO OTHER DISTRICTS	21	15	15	15	15
4. CRUDE, NGL & UNF. SHIPMENTS TOD	47	301	421	453	400
5. CRUDE LOSSES	1	1		2	2
SUPPLY - TOTAL	2,754	3,112	3,100	2,983	2,905
1. PRODUCTION - TOTAL	1,448	2,209	2,500	2,575	2,400
CRUDE AND LEASE CONDENSATE	1,424	2,185	2,500	2,600	2,400
NGL	24	24	0	0	0
2. RECEIPTS FROM OTHER DISTRICTS	135	159	50	50	50
CRUDE, NGL, AND UNFINISHED	9	6	0	0	0
PRODUCTS	126	153	50	50	50
3. PROCESSING GAIN, ETC.	34	-31	50	50	50
4. IMPORTS - TOTAL	1,214	725	300	200	97
CRUDE AND UNFINISHED	1,099	602	218	167	64
FROM OVERLAND	20	12	0	0	0
FROM OFFSHORE	1,079	590	208	216	252
NGL	4	2			
FINISHED PRODUCTS	111	121	50	33	33
5. SYNCRUDE	0	0	0	0	0
FROM SHALE	0	0	0	0	0
FROM COAL	0	0	0	0	0
6. FROM INVENTORY	-77	41	-6	-7	-2
CRUDE	-67	28	-4	-4	0
PRODUCTS	-10	13	-2	-3	-2
7. CRUDE RUNS	2,323	2,287	2,400	2,400	2,400
ALASKAN PRODUCTION	310	1,089	1,450	1,450	1,300

TABLE IV -- PAD V (Continued)

Medium Case

ALL RESPONDENTS
AVERAGE & STANDARD DEVIATION

	AVERAGE					STANDARD DEVIATION AS A % OF THE MEAN		
	1977	1978	1982	1985	1990	1982	1985	1990
DEMAND - TOTAL	2,754	3,112	3,262	3,362	3,609	4.77%	8.33%	17.84%
1. LOCAL PRODUCT DEMAND	2,614	2,631	2,626	2,667	2,658	5.48%	7.61%	9.54%
2. CRUDE AND PRODUCT EXPORTS	71	163	155	145	116	45.63%	33.70%	38.91%
3. PRODUCT SHIPMENTS TO OTHER DISTRICTS	21	15	24	20	22	35.88%	17.59%	23.00%
4. CRUDE, NGL & UNF. SHIPMENTS TOD	47	301	462	531	814	8.35%	20.97%	52.57%
5. CRUDE LOSSES	1	1		5	6		98.39%	91.51%
SUPPLY - TOTAL	2,754	3,112	3,262	3,362	3,609	4.77%	8.33%	17.84%
1. PRODUCTION - TOTAL	1,448	2,209	2,903	2,947	3,180	14.82%	16.60%	19.96%
CRUDE AND LEASE CONDENSATE	1,424	2,185	2,869	2,998	3,276	16.58%	16.70%	19.02%
NGL	24	24	18	23	22	69.57%	52.53%	58.56%
2. RECEIPTS FROM OTHER DISTRICTS	135	159	122	117	109	34.37%	39.09%	44.15%
CRUDE, NGL, AND UNFINISHED	9	6	2	2	2	173.21%	200.00%	200.00%
PRODUCTS	126	153	120	115	107	33.96%	38.06%	42.91%
3. PROCESSING GAIN, ETC.	34	-31	87	94	105	43.25%	37.44%	28.70%
4. IMPORTS - TOTAL	1,214	725	434	410	370	30.46%	33.73%	40.92%
CRUDE AND UNFINISHED	1,099	602	371	333	295	36.99%	36.25%	50.13%
FROM OVERLAND	20	12	3	0	0	141.42%	0%	0%
FROM OFFSHORE	1,079	590	391	363	341	33.73%	26.81%	25.37%
NGL	4	2						
FINISHED PRODUCTS	111	121	76	83	81	33.98%	41.59%	43.89%
5. SYNCRUDE	0	0	0	0	8	0%	0%	223.61%
FROM SHALE	0	0	0	0	8	0%	0%	223.61%
FROM COAL	0	0	0	0	0	0%	0%	0%
6. FROM INVENTORY	-77	41	-2	-1	0	173.21%	223.61%	223.61%
CRUDE	-67	28	-1	-1	0	173.21%	223.61%	0%
PRODUCTS	-10	13	-1	-1	0	173.21%	223.61%	223.61%
7. CRUDE RUNS	2,323	2,287	2,448	2,509	2,533	1.46%	3.60%	5.12%
ALASKAN PRODUCTION	310	1,089	1,488	1,538	1,528	1.46%	4.95%	10.35%

TABLE IV -- PAD V (Continued) <u>Medium Case</u>

ALL RESPONDENTS
Median

	1977	1978	1982	1985	1990
DEMAND - TOTAL	2,754	3,112	3,250	3,479	3,399
1. LOCAL PRODUCT DEMAND	2,614	2,631	2,671	2,784	2,769
2. CRUDE AND PRODUCT EXPORTS	71	163	150	170	100
3. PRODUCT SHIPMENTS TO OTHER DISTRICTS	21	15	22	21	23
4. CRUDE, NGL & UNF. SHIPMENTS TOO	47	301	463	500	500
5. CRUDE LOSSES	1	1		2	2
SUPPLY - TOTAL	2,754	3,112	3,250	3,479	3,399
1. PRODUCTION - TOTAL	1,448	2,209	2,776	2,774	3,132
CRUDE AND LEASE CONDENSATE	1,424	2,185	2,651	2,813	3,520
NGL	24	24	20	25	25
2. RECEIPTS FROM OTHER DISTRICTS	135	159	143	143	123
CRUDE, NGL, AND UNFINISHED	9	6	0	0	0
PRODUCTS	126	153	139	143	123
3. PROCESSING GAIN, ETC.	34	-31	60	90	105
4. IMPORTS - TOTAL	1,214	725	409	400	382
CRUDE AND UNFINISHED	1,099	602	375	400	260
FROM OVERLAND	20	12	0	0	0
FROM OFFSHORE	1,079	590	450	375	330
NGL	4	2			
FINISHED PRODUCTS	111	121	74	105	85
5. SYNCRUDE	0	0	0	0	0
FROM SHALE	0	0	0	0	0
FROM COAL	0	0	0	0	0
6. FROM INVENTORY	-77	41	0	0	0
CRUDE	-67	28	0	0	0
PRODUCTS	-10	13	0	0	0
7. CRUDE RUNS	2,323	2,287	2,460	2,499	2,494
ALASKAN PRODUCTION	310	1,089	1,500	1,500	1,500

TABLE V

<u>Medium Case</u>

World Oil Consumption
(Million Barrels/Day)

ALL RESPONDENTS
High

	1977	1978	1982	1985	1990
UNITED STATES	18.4	18.8	19.6	20.2	20.4
WESTERN EUROPE	14.2	14.6	16.1	17.4	18.9
JAPAN	5.3	5.4	6.5	7.5	8.2
OTHER OECD	2.6	2.6	2.9	3.1	3.5
NON-OECD	9.3	10.0	14.1	16.0	18.5
NON-COMMUNIST COUNTRIES	49.8	51.4	57.7	62.8	68.1
USSR	8.0	8.4	9.5	10.5	11.8
EAST EUROPE	2.1	2.1	2.8	3.0	3.4
CHINA	1.5	1.7	2.7	3.5	4.7
COMMUNIST COUNTRIES	11.6	12.2	14.6	16.7	19.3
TOTAL CONSUMPTION	61.4	63.6	72.3	79.2	87.1

ALL RESPONDENTS
Low

	1977	1978	1982	1985	1990
UNITED STATES	18.4	18.8	17.4	16.6	15.9
WESTERN EUROPE	14.2	14.6	14.1	13.3	12.9
JAPAN	5.3	5.4	5.3	5.2	4.8
OTHER OECD	2.6	2.6	2.3	2.5	2.4
NON-OECD	9.3	10.0	11.0	11.4	14.3
NON-COMMUNIST COUNTRIES	49.8	51.4	51.3	51.6	52.4
USSR	8.0	8.4	8.9	9.4	9.4
EAST EUROPE	2.1	2.1	2.3	2.1	2.0
CHINA	1.5	1.7	2.0	2.4	3.1
COMMUNIST COUNTRIES	11.6	12.2	12.0	12.7	13.0
TOTAL CONSUMPTION	61.4	63.6	64.0	66.7	71.0

TABLE V (Continued)

Medium Case

ALL RESPONDENTS
AVERAGE AND STANDARD DEVIATION

	AVERAGE					STANDARD DEVIATION AS A % OF THE MEAN		
	1977	1978	1982	1985	1990	1982	1985	1990
UNITED STATES	18.4	18.8	18.4	18.6	18.5	3.3%	5.1%	7.3%
WESTERN EUROPE	14.2	14.6	14.7	14.9	15.5	3.6%	5.7%	8.6%
JAPAN	5.3	5.4	5.8	6.1	6.4	6.5%	9.4%	12.4%
OTHER OECD	2.6	2.6	2.7	2.8	2.9	7.1%	7.4%	12.9%
NON-OECD	9.3	10.0	12.1	13.2	16.1	8.3%	9.9%	9.0%
NON-COMMUNIST COUNTRIES	49.8	51.4	53.3	55.7	59.2	3.2%	4.5%	6.1%
USSR	8.0	8.4	9.3	10.0	10.8	2.4%	4.0%	8.1%
EAST EUROPE	2.1	2.1	2.5	2.6	3.0	7.2%	10.5%	15.7%
CHINA	1.5	1.7	2.4	3.1	4.0	9.4%	11.7%	12.7%
COMMUNIST COUNTRIES	11.6	12.2	13.9	15.4	17.2	5.9%	6.7%	11.2%
TOTAL CONSUMPTION	61.4	63.6	67.3	71.0	76.5	3.4%	4.6%	6.1%

ALL RESPONDENTS
Median

	1977	1978	1982	1985	1990
UNITED STATES	18.4	18.8	18.5	18.7	18.8
WESTERN EUROPE	14.2	14.6	14.6	14.9	15.3
JAPAN	5.3	5.4	5.7	6.1	6.4
OTHER OECD	2.6	2.6	2.7	2.8	3.0
NON-OECD	9.3	10.0	12.0	13.2	16.2
NON-COMMUNIST COUNTRIES	49.8	51.4	53.2	55.6	59.2
USSR	8.0	8.4	9.3	10.0	11.3
EAST EUROPE	2.1	2.1	2.4	2.6	3.0
CHINA	1.5	1.7	2.4	3.2	4.2
COMMUNIST COUNTRIES	11.6	12.2	14.3	15.5	17.7
TOTAL CONSUMPTION	61.4	63.6	67.4	70.2	75.6

TABLES VI and VII

Medium Case

World Crude Oil and Natural Gas Liquids Supply
(Million Barrels/Day)

ALL RESPONDENTS
High

	1977	1978	1982	1985	1990
OECD					
U.S.	9.8	10.3	10.4	10.3	10.9
CANADA	1.6	1.6	1.9	2.0	2.3
W. EUROPE	1.5	1.8	4.1	4.9	5.2
JAPAN, AUSTRALIA, NEW ZEALAND	0.5	0.5	0.8	1.0	1.2
SUB-TOTAL	13.4	14.2	16.1	17.8	18.1
OPEC					
VENEZUELA	2.3	2.2	2.7	2.7	2.6
ECUADOR	0.2	0.2	0.2	0.3	0.4
INDONESIA	1.7	1.6	1.9	2.0	2.0
AFRICA	5.6	5.3	6.4	6.8	6.5
ALGERIA	1.2	1.2	1.5	1.5	1.4
LIBYA	2.1	2.0	2.6	2.8	3.0
NIGERIA	2.1	1.9	2.6	2.7	2.5
GABON	0.2	0.2	0.2	0.3	0.3
MIDDLE EAST	22.1	20.8	23.3	26.4	30.4
IRAN	5.7	5.2	4.8	5.3	5.2
KUWAIT	1.9	1.9	2.5	2.5	3.0
S. ARABIA	9.2	8.3	10.0	11.6	13.4
IRAQ	2.5	2.6	4.0	4.7	4.9
UAE	2.0	1.8	2.5	3.2	3.7
QATAR	0.4	0.5	0.6	0.6	0.6
NEUTRAL ZONE	0.4	0.5	0.6	0.6	0.7
SUB-TOTAL	31.9	30.1	34.1	37.6	41.2
NON-OPEC (EXCL. USSR, E. EUROPE, CHINA)					
MEXICO	1.1	1.3	3.3	3.9	6.1
OTHER L. AMERICA	1.2	1.2	1.8	2.1	2.7
AFRICA	0.7	0.8	1.7	1.9	2.2
MIDDLE EAST	0.6	0.6	1.0	1.0	1.1
ASIA	0.7	0.8	1.1	1.6	2.1
SUB-TOTAL	4.3	4.7	8.6	10.0	13.7
USSR	10.9	11.7	12.4	13.3	14.6
EAST EUROPE	0.4	0.4	0.4	0.5	0.6
CHINA	1.8	1.9	3.2	4.2	5.9
SUB-TOTAL	13.1	14.0	16.0	17.6	20.0
REFINERY PROCESSING GAINS					
U.S.	0.5	0.5	0.6	0.7	0.9
OTHER	0.0	0.0	0.0	0.1	0.1
SUB-TOTAL	0.5	0.5	0.6	0.7	0.9
TOTAL SUPPLY	63.2	63.5	73.5	79.9	87.5

TABLES VI and VII (Continued) Medium Case

ALL RESPONDENTS
Low

	1977	1978	1982	1985	1990
OECD					
U.S.	9.8	10.3	9.5	8.2	6.7
CANADA	1.6	1.6	1.5	1.4	1.3
W. EUROPE	1.5	1.8	2.3	3.3	3.3
JAPAN, AUSTRALIA, NEW ZEALAND	0.5	0.5	0.4	0.2	0.2
SUB-TOTAL	13.4	14.2	14.1	13.7	12.8
OPEC					
VENEZUELA	2.3	2.2	2.0	1.8	1.5
ECUADOR	0.2	0.2	0.2	0.2	0.1
INDONESIA	1.7	1.6	1.6	1.5	1.3
AFRICA	5.6	5.3	5.2	4.9	4.5
ALGERIA	1.2	1.2	1.0	0.9	0.7
LIBYA	2.1	2.0	1.8	1.9	1.7
NIGERIA	2.1	1.9	2.0	1.9	1.8
GABON	0.2	0.2	0.2	0.2	0.2
MIDDLE EAST	22.1	20.8	18.4	17.7	17.6
IRAN	5.7	5.2	2.2	2.2	3.0
KUWAIT	1.9	1.9	1.6	1.6	1.8
S. ARABIA	9.2	8.3	8.5	8.1	9.0
IRAQ	2.5	2.6	2.7	3.2	3.1
UAE	2.0	1.8	1.7	1.6	1.7
QATAR	0.4	0.5	0.4	0.3	0.3
NEUTRAL ZONE	0.4	0.5	0.4	0.2	0.2
SUB-TOTAL	31.9	30.1	28.0	27.2	27.2
NON-OPEC (EXCL. USSR, E. EUROPE, CHINA)					
MEXICO	1.1	1.3	2.2	2.6	3.4
OTHER L. AMERICA	1.2	1.2	1.1	1.1	1.1
AFRICA	0.7	0.8	0.7	0.7	0.8
MIDDLE EAST	0.6	0.6	0.5	0.4	0.3
ASIA	0.7	0.8	0.8	0.9	1.2
SUB-TOTAL	4.3	4.7	5.8	6.6	7.3
USSR	10.9	11.7	11.3	11.6	10.6
EAST EUROPE	0.4	0.4	0.3	0.3	0.2
CHINA	1.8	1.9	2.1	2.3	2.5
SUB-TOTAL	13.1	14.0	13.6	14.4	14.7
REFINERY PROCESSING GAINS					
U.S.	0.5	0.5	0.5	0.5	0.4
OTHER	0.0	0.0	0.0	0.0	0.0
SUB-TOTAL	0.5	0.5	0.5	0.5	0.4
TOTAL SUPPLY	63.2	63.5	64.8	58.2	71.5

TABLES VI and VII (Continued)

Medium Case

ALL RESPONDENTS
AVERAGE AND STANDARD DEVIATION

	AVERAGE					STANDARD DEVIATION AS A % OF THE MEAN		
	1977	1978	1982	1985	1990	1982	1985	1990
OECD								
U.S.	9.8	10.3	9.9	9.7	9.5	3.01%	5.59%	11.14%
CANADA	1.6	1.6	1.7	1.7	1.8	6.59%	10.55%	15.09%
W. EUROPE	1.5	1.8	3.4	4.0	4.4	13.68%	10.68%	12.03%
JAPAN, AUSTRALIA, NEW ZEALAND	0.5	0.5	0.6	0.6	0.6	20.33%	31.76%	38.42%
SUB-TOTAL	13.4	14.2	15.5	15.8	16.2	3.70%	5.99%	9.15%
OPEC								
VENEZUELA	2.3	2.2	2.3	2.2	2.2	7.50%	9.98%	13.39%
ECUADOR	0.2	0.2	0.2	0.2	0.2	0%	15.56%	28.98%
INDONESIA	1.7	1.6	1.7	1.7	1.6	6.63%	7.52%	10.03%
AFRICA	5.6	5.3	5.7	5.8	5.7	6.99%	7.77%	7.55%
ALGERIA	1.2	1.2	1.2	1.2	1.1	12.03%	14.75%	15.36%
LIBYA	2.1	2.0	2.1	2.2	2.2	11.18%	12.56%	16.62%
NIGERIA	2.1	1.9	2.2	2.3	2.2	8.14%	8.18%	7.25%
GABON	0.2	0.2	0.2	0.2	0.2	0%	15.93%	16.33%
MIDDLE EAST	22.1	20.8	20.4	21.3	22.7	6.66%	8.85%	12.00%
IRAN	5.7	5.2	3.3	3.5	3.7	19.44%	21.40%	19.37%
KUWAIT	1.9	1.9	2.0	2.0	2.1	13.58%	13.74%	14.04%
S. ARABIA	9.2	8.3	9.2	9.6	10.4	5.26%	10.44%	13.13%
IRAQ	2.5	2.6	3.2	3.6	3.8	10.81%	10.89%	13.57%
UAE	2.0	1.8	2.0	2.1	2.2	11.62%	18.25%	22.59%
QATAR	0.4	0.5	0.5	0.5	0.4	13.61%	14.98%	22.12%
NEUTRAL ZONE	0.4	0.5	0.5	0.5	0.5	13.33%	21.76%	25.10%
SUB-TOTAL	31.9	30.1	30.3	31.4	32.5	5.89%	7.16%	9.09%
NON-OPEC (EXCL. USSR, E. EUROPE, CHINA)								
MEXICO	1.1	1.3	2.6	3.2	4.2	11.34%	11.46%	15.69%
OTHER L. AMERICA	1.2	1.2	1.5	1.7	2.0	12.39%	15.14%	21.57%
AFRICA	0.7	0.8	1.1	1.4	1.6	24.07%	22.44%	23.20%
MIDDLE EAST	0.6	0.6	0.6	0.7	0.7	23.39%	26.46%	33.73%
ASIA	0.7	0.8	1.0	1.3	1.7	10.00%	16.46%	15.83%
SUB-TOTAL	4.3	4.7	6.9	8.2	10.0	10.83%	9.22%	15.25%
USSR	10.9	11.7	11.8	12.3	12.7	2.99%	4.73%	9.10%
EAST EUROPE	0.4	0.4	0.4	0.4	0.4	12.86%	16.56%	29.16%
CHINA	1.8	1.9	2.7	3.4	4.4	12.29%	16.48%	22.90%
SUB-TOTAL	13.1	14.0	14.9	15.9	17.2	5.61%	6.48%	10.30%
REFINERY PROCESSING GAINS								
U.S.	0.5	0.5	0.5	0.5	0.5	8.25%	11.18%	20.55%
OTHER	0.0	0.0	0.0	0.0	0.0	0%	374.17%	360.56%
SUB-TOTAL	0.5	0.5	0.5	0.5	0.5	8.25%	11.15%	19.89%
TOTAL SUPPLY	63.2	63.5	67.7	70.4	76.7	3.44%	6.72%	5.61%

TABLES VI and VII (Continued) Medium Case

ALL RESPONDENTS
Median

	1977	1978	1982	1985	1990
OECD					
U.S.	9.8	10.3	9.9	9.8	9.5
CANADA	1.6	1.6	1.7	1.7	1.8
W. EUROPE	1.5	1.8	3.5	3.9	4.4
JAPAN, AUSTRALIA, NEW ZEALAND	0.5	0.5	0.5	0.5	0.6
SUB-TOTAL	13.4	14.2	15.7	16.0	16.6
OPEC					
VENEZUELA	2.3	2.2	2.3	2.3	2.3
ECUADOR	0.2	0.2	0.2	0.2	0.2
INDONESIA	1.7	1.6	1.6	1.7	1.6
AFRICA	5.6	5.3	5.7	5.8	5.7
ALGERIA	1.2	1.2	1.2	1.1	1.2
LIBYA	2.1	2.0	2.0	2.1	2.1
NIGERIA	2.1	1.9	2.2	2.3	2.3
GABON	0.2	0.2	0.2	0.2	0.2
MIDDLE EAST	22.1	20.8	20.3	21.0	22.1
IRAN	5.7	5.2	3.1	3.5	3.4
KUWAIT	1.9	1.9	2.0	1.9	2.1
S. ARABIA	9.2	8.3	9.1	9.4	9.8
IRAQ	2.5	2.6	3.2	3.5	3.7
UAE	2.0	1.8	1.9	2.0	2.0
QATAR	0.4	0.5	0.5	0.5	0.5
NEUTRAL ZONE	0.4	0.5	0.5	0.5	0.5
SUB-TOTAL	31.9	30.1	30.0	31.0	32.2
NON-OPEC (EXCL. USSR, E. EUROPE, CHINA)					
MEXICO	1.1	1.3	2.6	3.2	4.1
OTHER L. AMERICA	1.2	1.2	1.5	1.7	2.1
AFRICA	0.7	0.8	1.1	1.3	1.5
MIDDLE EAST	0.6	0.6	0.6	0.6	0.6
ASIA	0.7	0.8	1.0	1.3	1.7
SUB-TOTAL	4.3	4.7	6.7	8.1	10.0
USSR	10.9	11.7	11.9	12.2	13.0
EAST EUROPE	0.4	0.4	0.4	0.4	0.4
CHINA	1.8	1.9	2.8	3.5	4.4
SUB-TOTAL	13.1	14.0	15.2	15.5	16.4
REFINERY PROCESSING GAINS					
U.S.	0.5	0.5	0.5	0.5	0.5
OTHER	0.0	0.0	0.0	0.0	0.0
SUB-TOTAL	0.5	0.5	0.5	0.5	0.5
TOTAL SUPPLY	63.2	63.5	67.4	70.7	77.1

TABLE I

Medium Case

Total Primary U.S. Energy Consumption by Fuels

ALL RESPONDENTS
CELL COUNT

	1982	1985	1990
PETROLEUM LIQUIDS	13	16	16
NAT.GAS (DRY)	13	16	16
COAL	13	16	16
NUCLEAR	13	16	16
OTHER SPECIFY	13	16	16
TOTAL PRIMARY ENERGY	13	16	16

TABLE IA

Medium Case

Economic Assumptions

ALL RESPONDENTS
CELL COUNT

		1982	1985	1990
GNP ASSUMPTION	(BILLION 1972 $)	14	17	16
FRB INDEX OF IND. PROD.	(1967=100)	12	14	13
POPULATION	(MID-YEAR, 000)	13	16	15
DISPOSABLE PERSONAL INCOME	(BILLION 1972 $)	11	13	12

TABLE III

Medium Case

Domestic Demand for Products -- Total U.S.

ALL RESPONDENTS
CELL COUNT

	1982	1985	1990
MOTOR GASOLINE: LEADED - PREMIUM	2	5	5
- NON-PREMIUM	2	5	5
S.TOTAL	5	8	8
UNLEADED - PREMIUM	2	5	5
- NON-PREMIUM	2	5	5
S. TOTAL	5	8	8
TOTAL MOTOR GASOLINE	13	16	16
AVIATION GASOLINE	10	13	13
JET FUEL: NAPTHA TYPE	6	10	10
KEROSINE TYPE	6	10	10
TOTAL JET FUEL	13	16	16
SPECIAL NAPTHA	9	11	11
KEROSINE	10	13	13
DISTILLATE FUEL OIL: NO.2 OIL	3	6	6
NO.4 OIL	2	4	4
DIESEL - ON HIGHWAY	4	8	8
- OFF HIGHWAY	1	4	4
OTHER DISTILLATE	2	5	5
TOTAL DISTILLATE FUEL OIL	13	16	16
RESIDUAL FUEL OIL: 0 - .5%S	3	6	6
.51 - 1.0%S	3	6	6
1.1 - 2.0%S	3	6	6
2.0%S +	3	6	6
TOTAL RESIDUAL FUEL OIL	13	16	16
LIQUEFIED GASES: ETHANE	3	6	6
PROPANE	1	4	4
BUTANE	1	3	3
PROPANE/BUTANE MIX	1	2	2
TOTAL LIQUEFIED GASES	11	14	13
PETROCHEMICAL FEEDSTOCKS: STILL GAS	5	8	8
400 EP NAPTHA	5	7	7
OTHER	5	8	8
TOTAL PETROCHEMICAL FEEDSTOCKS	10	13	13
LUBRICANTS	8	11	11
WAXES	8	11	11
COKE	8	11	11
ASPHALT & ROAD OIL	8	11	11
STILL GAS FOR FUEL	8	11	11
MISCELLANEOUS PRODUCTS	7	10	10
TOTAL DEMAND	13	16	16
ETHANE	3	6	6
PROPANE	1	3	3
BUTANE	1	3	3
PROPANE/BUTANE MIX	1	1	1
TOTAL	6	9	9

Medium Case

TABLE III

Domestic Demand for Products -- PADs I-IV

ALL RESPONDENTS
CELL COUNT

	1982	1985	1990
MOTOR GASOLINE: LEADED - PREMIUM	0	1	1
- NON-PREMIUM	0	1	1
S.TOTAL	1	2	2
UNLEADED - PREMIUM	0	1	1
- NON-PREMIUM	0	1	1
S.TOTAL	1	2	2
TOTAL MOTOR GASOLINE	5	8	8
AVIATION GASOLINE	2	4	4
JET FUEL: NAPTHA TYPE	1	3	3
KEROSINE TYPE	1	4	4
TOTAL JET FUEL	4	6	6
SPECIAL NAPTHA	1	2	2
KEROSINE	2	4	4
DISTILLATE FUEL OIL: NO.2 OIL	0	1	1
NO.4 OIL	0	0	1
DIESEL - ON HIGHWAY	2	3	3
- OFF HIGHWAY	0	1	1
OTHER DISTILLATE	0	1	1
TOTAL DISTILLATE FUEL OIL	4	7	7
RESIDUAL FUEL OIL: 0 - .5%S	0	2	2
.51 - 1.0%S	0	1	1
1.1 - 2.0%S	0	2	2
2.0%S +	0	2	2
TOTAL RESIDUAL FUEL OIL	4	7	7
LIQUEFIED GASES: ETHANE	1	2	2
PROPANE	0	1	1
BUTANE	0	1	1
PROPANE/BUTANE MIX	0	0	0
TOTAL LIQUEFIED GASES	2	3	3
PETROCHEMICAL FEEDSTOCKS: STILL GAS	0	1	1
400 EP NAPTHA	0	1	1
OTHER	0	1	1
TOTAL PETROCHEMICAL FEEDSTOCKS	1	2	2
LUBRICANTS	1	2	2
WAXES	1	2	2
COKE	1	2	2
ASPHALT & ROAD OIL	1	2	2
STILL GAS FOR FUEL	1	2	2
MISCELLANEOUS PRODUCTS	1	2	2
TOTAL DEMAND	4	7	7
ETHANE	1	2	2
PROPANE	0	1	1
BUTANE	0	1	1
PROPANE/BUTANE MIX	0	0	0
TOTAL	1	2	2

TABLE III

Medium Case

Domestic Demand for Products -- PAD V

ALL RESPONDENTS
CELL COUNT

	1982	1985	1990
MOTOR GASOLINE: LEADED - PREMIUM	0	1	1
- NON-PREMIUM	0	1	1
S.TOTAL	1	2	2
UNLEADED - PREMIUM	0	1	1
- NON-PREMIUM	0	1	1
S.TOTAL	1	2	2
TOTAL MOTOR GASOLINE	5	8	8
AVIATION GASOLINE	2	4	4
JET FUEL: NAPTHA TYPE	1	3	3
KEROSINE TYPE	1	4	4
TOTAL JET FUEL	4	6	6
SPECIAL NAPTHA	1	2	2
KEROSINE	2	4	4
DISTILLATE FUEL OIL: NO.2 OIL	0	1	1
NO.4 OIL	0	0	0
DIESEL - ON HIGHWAY	2	3	3
- OFF HIGHWAY	0	1	1
OTHER DISTILLATE	0	1	1
TOTAL DISTILLATE FUEL OIL	4	7	7
RESIDUAL FUEL OIL: 0 - .5%S	0	2	2
.51 - 1.0%S	0	1	1
1.1 - 2.0%S	0	2	2
2.0%S +	0	2	2
TOTAL RESIDUAL FUEL OIL	4	7	7
LIQUEFIED GASES: ETHANE	1	2	2
PROPANE	0	1	1
BUTANE	0	1	1
PROPANE/BUTANE MIX	0	0	0
TOTAL LIQUEFIED GASES	2	3	3
PETROCHEMICAL FEEDSTOCKS: STILL GAS	0	1	1
400 EP NAPTHA	0	1	1
OTHER	0	1	1
TOTAL PETROCHEMICAL FEEDSTOCKS	1	2	2
LUBRICANTS	1	2	2
WAXES	1	2	2
COKE	1	2	2
ASPHALT & ROAD OIL	1	2	2
STILL GAS FOR FUEL	1	2	2
MISCELLANEOUS PRODUCTS	1	2	2
TOTAL DEMAND	4	7	7
ETHANE	1	2	2
PROPANE	0	1	1
BUTANE	0	1	1
PROPANE/BUTANE MIX	0	0	0
TOTAL	1	2	2

TABLE IIIA

Medium Case

Motor Gasoline Assumptions

ALL RESPONDENTS
CELL COUNT

	1982	1985	1990
PASSENGER CARS IN USE (THOUSANDS)	10	12	11
NEW CAR REGISTRATION (THOUSANDS)	12	14	13
TOTAL MILES TRAVELED-MILLIONS	12	14	13
AVERAGE MILES PER CAR (ALL CARS)	12	14	13
AVERAGE MILES PER GALLON (NEW CARS)	12	14	13
AVERAGE MPG (ALL CARS)	11	13	13
DIESEL PASSENGER CAR SALES (THOUSANDS)	7	9	9
AVERAGE MILES PER GALLON (NEW TRUCKS)	5	6	5
LEADED PREMIUM	6	5	3
LEADED NON-PREMIUM	7	9	9
UNLEADED PREMIUM	7	9	9
UNLEADED NON-PREMIUM	7	9	9

Medium Case

TABLE IV

U.S. Petroleum Supply/Demand Balance

ALL RESPONDENTS
CELL COUNT

	1982	1985	1990
DEMAND - TOTAL	11	14	14
1. LOCAL PRODUCT DEMAND	12	15	15
2. CRUDE AND PRODUCT EXPORTS	11	14	14
3. PRODUCT SHIPMENTS TO OTHER DISTRICTS	11	14	14
4. CRUDE, NGL & UNF. SHIPMENTS TOD	11	14	14
5. CRUDE LOSSES	8	10	10
SUPPLY - TOTAL	11	14	14
1. PRODUCTION - TOTAL	12	15	15
CRUDE AND LEASE CONDENSATE	12	15	15
NGL	12	15	15
2. RECEIPTS FROM OTHER DISTRICTS	11	14	14
CRUDE, NGL, AND UNFINISHED	11	14	14
PRODUCTS	11	14	14
3. PROCESSING GAIN, ETC.	12	15	15
4. IMPORTS - TOTAL	11	14	14
CRUDE AND UNFINISHED	9	11	11
FROM OVERLAND	5	7	7
FROM OFFSHORE	5	7	7
NGL	4	6	6
FINISHED PRODUCTS	9	11	11
5. SYNCRUDE	9	12	13
FROM SHALE	9	10	11
FROM COAL	9	10	11
6. FROM INVENTORY	9	12	12
CRUDE	6	9	9
PRODUCTS	6	9	9
7. CRUDE RUNS	8	10	10
ALASKAN PRODUCTION	10	13	13

TABLE IV

Medium Case

U.S. Petroleum Supply/Demand Balance -- PAD V

	ALL RESPONDENTS CELL COUNT		
	1982	1985	1990
DEMAND - TOTAL	4	5	5
1. LOCAL PRODUCT DEMAND	4	5	5
2. CRUDE AND PRODUCT EXPORTS	4	5	5
3. PRODUCT SHIPMENTS TO OTHER DISTRICTS	3	4	4
4. CRUDE, NGL & UNF. SHIPMENTS TOD	4	5	5
5. CRUDE LOSSES	2	3	3
SUPPLY - TOTAL	4	5	5
1. PRODUCTION - TOTAL	5	6	6
CRUDE AND LEASE CONDENSATE	4	5	5
NGL	4	5	5
2. RECEIPTS FROM OTHER DISTRICTS	4	5	5
CRUDE, NGL, AND UNFINISHED	4	5	5
PRODUCTS	4	5	5
3. PROCESSING GAIN, ETC.	5	6	6
4. IMPORTS - TOTAL	4	5	5
CRUDE AND UNFINISHED	4	5	5
FROM OVERLAND	3	4	4
FROM OFFSHORE	3	4	4
NGL	2	2	2
FINISHED PRODUCTS	4	5	5
5. SYNCRUDE	5	6	6
FROM SHALE	5	6	6
FROM COAL	5	6	6
6. FROM INVENTORY	4	6	6
CRUDE	4	6	6
PRODUCTS	4	6	6
7. CRUDE RUNS	3	4	4
ALASKAN PRODUCTION	4	6	6

TABLE V

Medium Case

World Oil Consumption

ALL RESPONDENTS
CELL COUNT

	1982	1985	1990
UNITED STATES	11	15	15
WESTERN EUROPE	10	14	14
JAPAN	10	14	14
OTHER OECD	7	9	9
NON-OECD	7	10	9
NON-COMMUNIST COUNTRIES	11	16	15
USSR	5	7	7
EAST EUROPE	5	7	7
CHINA	5	7	7
COMMUNIST COUNTRIES	9	11	11
TOTAL CONSUMPTION	9	11	11

TABLES VI and VII

Medium Case

World Crude Oil and Natural Gas Liquids Supply

ALL RESPONDENTS
CELL COUNT

	1982	1985	1990
OECD			
U.S.	12	16	15
CANADA	12	16	15
W. EUROPE	12	16	15
JAPAN, AUSTRALIA, NEW ZEALAND	12	16	15
SUB-TOTAL	12	17	16
OPEC			
VENEZUELA	12	16	15
ECUADOR	12	16	15
INDONESIA	12	16	15
AFRICA	12	16	15
ALGERIA	11	15	14
LIBYA	11	15	14
NIGERIA	11	15	14
GABON	11	15	14
MIDDLE EAST	12	16	15
IRAN	11	15	14
KUWAIT	11	15	14
S. ARABIA	11	15	14
IRAQ	11	15	14
UAE	11	15	14
QATAR	11	15	14
NEUTRAL ZONE	9	13	12
SUB-TOTAL	12	17	16
NON-OPEC (EXCL. USSR, E. EUROPE, CHINA)			
MEXICO	12	16	15
OTHER L. AMERICA	10	13	13
AFRICA	10	13	13
MIDDLE EAST	10	13	13
ASIA	10	13	13
SUB-TOTAL	12	17	16
USSR	6	7	7
EAST EUROPE	6	7	7
CHINA	6	7	7
SUB-TOTAL	9	11	11
REFINERY PROCESSING GAINS			
U.S.	12	15	14
OTHER	12	15	14
SUB-TOTAL	12	16	15
TOTAL SUPPLY	9	12	11

TABLE I
Low Case
Total U.S. Primary Energy Consumption by Fuels
(Trillion Btu)

	1978	1982	1985	1990
Petroleum Liquids	38,014	35,755	34,910	33,680
Natural Gas (Dry)	20,039	19,940	19,535	19,590
Coal	14,070	17,145	19,555	24,180
Nuclear	2,977	4,065	5,295	7,015
Other	3,343	3,375	3,620	4,125
Total Primary Energy	78,443	80,280	82,915	88,590

TABLE IA
Low Case
Economic and Energy Assumptions
Pertinent to U.S. Energy Demand/Supply Forecast

Economic Assumptions	1978	1982	1985	1990
Real GNP (Billion 1972 $)	1,383	1,490	1,630	1,820
FRB Index of Industrial Production (1967=100)	146	160	175	205
Population (Mid-year, 000)	218,500	226,385	232,815	243,750
Disposable Personal Income (Billion 1972 $)	966	1,040	1,135	1,285

Note: Table II has been deleted.

TABLE III

Domestic Demand for Products -- Total U.S.*
(MB/D)

	Actual† 1978	Low Case Projection 1982	1985	1990
Motor Gasoline: Leaded - Premium	934	500	0	0
- Non-premium	4,106	2,100	1,600	500
Subtotal	5,040	2,600	1,600	500
Unleaded - Premium	185	300	1,700	2,000
- Non-premium	2,187	4,000	3,200	3,500
Subtotal	2,372	4,300	4,900	5,500
Total Motor Gasoline	7,412	6,900	6,500	6,000
Aviation Gasoline	39	45	40	55
Jet Fuel: Naphtha Type	199	195	200	215
Kerosine Type	858	885	900	985
Total Jet Fuel	1,057	1,080	1,100	1,200
Special Naphtha	103	95	100	115
Kerosine & Heating Oil #1	215	176	163	155
Distillate Fuel Oil: #2 Oil	1,385	1,190	1,120	1,040
#4 Oil	61	60	65	65
Diesel - On Highway	797	890	1,000	1,150
- Off Highway	191	200	215	230
Other Distillate	958	924	962	975
Total Distillate Fuel Oil	3,392	3,264	3,362	3,460
Residual Fuel Oil: 0 - 0.5%S	862	720	555	410
0.51 - 1.0%S	716	515	440	310
1.1 - 2.0%S	641	430	380	250
2.0%S +	804	735	625	480
Total Residual Fuel Oil	3,023	2,400	2,000	1,450
Liquified Gases: Ethane	433	440	420	415
Propane	778	890	1,030	1,065
Butane	167	130	145	175
Propane/Butane Mix	35	40	50	45
Total Liquified Gases	1,413	1,500	1,645	1,700
Petrochemical Feedstocks: Still Gas	55	50	55	55
400 EP Naphtha	205	265	280	340
Other	335	435	465	555
Total Petrochemical Feedstocks	595	750	800	950
Lubricants	172	175	180	190
Waxes	17	20	20	20
Coke	256	250	265	260
Asphalt & Road Oil	479	490	530	550
Still Gas for Fuel	548	510	520	500
Miscellaneous Products	128	140	150	190
Total Domestic Demand for Products	18,847	17,795	17,375	16,795

*Data derived from the December 1979 NPC Survey of U.S. and World Energy and Oil Supply/Demand Forecasts. Components may not add to subtotals due to independent rounding.

†Total U.S. per Petroleum Statement, Annual, Final Summary, November 7, 1979.

TABLE IIIA

Motor Gasoline Demand Assumptions -- Low Case

	1978	1982	1985	1990
Passenger Cars In Use (Thousands)	102,957[1]	106,000	110,250	117,100
New Car Registrations (Thousands)	10,946[1]	10,900	10,850	10,900
Total Miles Traveled-Passenger Cars (Millions)	1,171,092[2]	1,168,900	1,223,700	1,329,400
Average Miles Per Car (All Cars)	10,046	10,950	10,945	11,085
Average Miles Per Gallon (New Cars)	20[3]	21	23	25
Average Miles Per Gallon (All Cars)	15[2]	16	18	20
Diesel Passenger Car Sales (Thousands)	135			
Average Miles Per Gallon (New Trucks)	16[4]	17	18	19
Octane Level Implicit in Your Mogas Demand Forecast $\left(\frac{R+M}{2}\right)$				
Leaded Premium	94[5]	94		
Leaded Non-Premium	90[5]	89	89	89
Unleaded Premium }	89[5]	93	94	94
Unleaded Non-Premium }		87	87	87

[1]Source: R. L. Polk. Mid-year estimate.

[2]Source: Department of Transportation.

[3]EPA estimate.

[4]Source: DOT. Two wheel drive vehicles only.

[5]Source: Motor Gasoline, Winter 1977-1978. DOE. Calendar year 1977 calculated as average of Summer 1977 and Winter 77-78.

TABLE IV

U.S. Petroleum Supply/Demand Balance for U.S. Total and PAD V -- Low Case

(Thousand Barrels Daily)

	1978		1982		1985		1990	
	U.S. TOTAL	PAD V	U.S. TOTAL	PAD V	U.S. TOTAL	PAD V	U.S. TOTAL	PAD V
DEMAND - TOTAL	19,224	3,112	18,035		17,615		17,035	
1. Local Product Demand	18,847	2,631	17,795		17,375		16,795	
2. Crude and Product Exports	362	163	225		225		225	
3. Product Shipments to Other Districts	0	15			0		0	
4. Crude, NGL and Unfinished Shipments to Other Districts	0	301			0		0	
5. Crude Losses	18	1	15		15		15	
SUPPLY - TOTAL	19,224	3,112	18,035		17,615		17,035	
1. Production - Total[1]	10,274	2,209	9,635		9,270		8,510	
Crude and Lease Condensate	8,707	2,185	8,255		8,025		7,525	
NGL	1,567	24	1,380		1,245		985	
2. Receipts From Other Districts	0	159	0		0		0	
Crude NGL and Unfinished	0	6	0		0		0	
Products	0	153	0		0		0	
3. Processing Gain, Etc.[2]	439	(31)	520		515		510	
4. Imports - Total	8,364	725	7,850		7,720		7,520	
Crude and Unfinished	6,384	602	6,100		6,020		5,725	
From Overland	564	12	75		15		15	
From Offshore	5,819	590	6,025		6,005		5,710	
NGL	17	2	300		420		630	
Finished Products	1,964	121	1,450		1,280		1,165	
5. Syncrude	0	0	0		75		505	
From Shale	0	0	0		50		355	
From Coal	0	0	0		25		150	
6. From Inventory	94	41	30		35		-(10)	
Crude	(78)	28	20		20		-(5)	
Products	172	13	10		15		-(5)	
7. Crude Runs	14,739	2,287	14,365		14,233		14,029	

[1] Amount of Alaskan North Slope Production Included:	1,089	1,089	1,485		1,566		1,458	

[2] Includes other hydrocarbon and hydrogen refinery inputs, "unaccounted for" crude inputs.

TABLE V

World Oil Consumption -- Low Case*
(Million Barrels/Day)

	1978†	Forecast 1982	1985	1990
OECD				
United States	18.8	17.8	17.4	16.8
Western Europe	14.6	14.4	14.9	15.6
Japan	5.4	5.7	6.0	6.3
Other OECD	2.6	2.8	3.0	3.5
Non-OECD (Excluding USSR, E. Europe, and China)	10.0	11.8	13.5	16.2
Subtotal	51.4	52.5	54.8	58.3
USSR	8.9	8.9	9.7	10.4
East Europe	2.1	2.7	2.4	2.7
China	1.7	2.3	3.2	4.1
Subtotal	12.2	13.9	15.3	17.2
Total Consumption	63.6	66.4	70.1	75.5

*Including international bunkers and refinery fuel and losses.

†Product basis. Data for outside the United States from BP 1977 Statistical Review of the World Oil Industry.

TABLE VI

World Crude Oil and Natural Gas Liquids Supply[1] -- Low Case
(Million Barrels/Day)

	1978	Forecast 1982	1985	1990
OECD -				
U.S.	10.3	9.6	9.3	8.5
Canada	1.6	1.7	1.7	1.7
W. Europe	1.8	3.1	3.8	4.0
Japan, Australia, New Zealand	0.5	0.6	0.6	0.7
Sub-Total	14.2	15.0	15.4	14.9
OPEC -				
Venezuela	2.2	2.2	2.2	2.2
Ecuador	0.2	0.2	0.2	0.2
Indonesia	1.6	1.6	1.7	1.6
Africa	5.3	5.8	5.8	5.7
Algeria	1.2	1.3	1.3	1.3
Libya	2.0	2.1	2.1	2.0
Nigeria	1.9	2.2	2.2	2.2
Gabon	0.2	0.2	0.2	0.2
Middle East	20.8	19.5	20.5	22.5
Iran	5.2	3.1	3.3	3.4
Kuwait	1.9	1.7	1.8	1.9
S. Arabia	8.3	8.7	8.9	9.9
Iraq	2.6	3.1	3.5	3.9
UAE	1.8	1.9	2.0	2.1
Qatar	0.5	0.5	0.4	0.4
Neutral Zone	0.5	0.5	0.6	0.6
Sub-Total	30.1	29.3	30.4	31.9
NON-OPEC (Excl. USSR, E. Europe, China) -				
Mexico	1.3	2.6	3.3	4.1
Other L. America	1.2	1.6	1.8	2.0
Africa	0.8	1.3	1.6	1.8
Middle East	0.6	0.6	0.7	0.7
Asia	0.8	1.0	1.1	1.8
Sub-Total	4.7	7.1	8.5	10.4
USSR	11.7	12.0	12.3	13.0
East Europe	0.4	0.4	0.4	0.4
China	1.9	2.1	2.8	4.3
Sub-Total	14.0	14.5	15.5	17.7
Refinery Processing Gains				
U.S.	0.5	0.5	0.5	0.5
Other	0.0	0.0	0.0	0.0
Sub-Total	0.5	0.5	0.5	0.5
TOTAL SUPPLY	63.2	66.4	70.3	75.4

[1]Including field condensate and non-conventional supplies from Tar Sands (Canada) and heavy oil (Venezuela's Heavy Oil Belt).

APPENDIX F

Comparison of Requirements for U.S. Refinery Downstream Processing Facilities

COMPARISON OF REQUIREMENTS FOR U.S. REFINERY DOWNSTREAM PROCESSING FACILITIES

The National Petroleum Council, in the interim report and in this final report on refinery flexibility, published two estimations of expanded process facility requirements to meet various supply/demand scenarios: this appendix compares these estimates and discusses their similarities and differences.

REFINERY FLEXIBILITY, AN INTERIM REPORT, VOLUME I

The data for process facility expansion in response to Part III of the January 1979 NPC Survey of Petroleum Refining Capabilities were published in Chapter Three of Volume I of the December 1979 interim report. The data were based on individual refiner response to the following questions.

High-Sulfur Crude Oil Processing Capability

What facilities would be required over and above those planned for completion by January 1, 1982, to process high-sulfur crude oil under existing environmental regulations? The increase is specified to be 20 percent of crude oil charge capacity for two separate cases; the first case uses light, high-sulfur crude oil and the second uses heavy, high-sulfur crude oil.

Unleaded Gasoline Manufacturing Capability

What facilities would be required over and above those planned for completion by January 1, 1982, to produce 90 percent unleaded and 10 percent leaded gasoline for approximately the same volume as projected for 1982? Assume that the crude oil slates are the same as in the interim report for 1982 (shown in Table F-1) and that the lead content of leaded gasoline meets applicable government regulations and normal refinery specifications.

Low-Sulfur Fuel Oil Manufacturing Capability

Based on projected 1982 crude oil slates and product volumes from the interim report, what facilities would be required over and above those planned for completion by January 1, 1982, to increase the production of low-sulfur (max. 0.7 wt %) residual fuel oils by 25 percent? The incremental crude oil slate for the 25 percent increase is to be of a type that the respondent expects to be available in 1982.

THIS REPORT

The data for process facility expansion in response to various petroleum supply/demand scenarios are published in this report.

TABLE F-1

Crude Oil Slate for 1982* and Crude Oil Slates A and B
for 1990 High and Low Supply/Demand Cases†

	1982 Crude Oil Slate§	1990 High Case		1990 Low Case	
		Slate A	Slate B	Slate A	Slate B
Sweet Crude Oil	8,091	7,675	6,866	6,293	5,582
Medium-Sulfur Crude Oil					
Light Medium-Sulfur	937	932	745	770	624
Heavy Medium-Sulfur	1,462	1,512	1,483	1,305	1,332
Total Medium-Sulfur	2,399	2,444	2,228	2,075	1,956
High-Sulfur Crude Oil					
Light High-Sulfur	3,572	3,892	4,687	3,195	3,795
Heavy High-Sulfur	2,568	2,863	3,096	2,380	2,619
Total High-Sulfur	6,140	6,755	7,783	5,575	6,414
Total Crude Oil	16,630	16,874	16,877	13,943	13,952

*From Refinery Flexibility, An Interim Report, Volume I, December 1979.

†From this report.

§As projected by refiners in response to the January 1979 NPC Survey of Petroleum Refining Capabilities.

Three cases were developed from responses to two surveys (NPC Surveys of U.S. and World Energy and Oil Supply/Demand Forecasts) distributed by the Council in April 1979 and December 1979, respectively. For the purposes of this report, the average of the first and second surveys' responses were called the high and medium supply/demand cases, respectively. A low case was prepared from the second survey's lowest quartile to the total 1990 demand for petroleum products. From these surveys, supply/demand cases were developed for each of three years -- 1982, 1985, and 1990. In addition, two crude oil supply quality slates (designated crude oil slate A and crude oil slate B) were developed to match each of the three supply/demand cases. The approach taken in this study was to use the Bonner & Moore Associates, Inc., Refinery and Petrochemical Modeling System to build a composite LP model of the refining industry. Two separate models were developed, one for PADs I-IV and one for PAD V.

COMPARISON OF THE PROCESS FACILITY REQUIREMENTS IN THE TWO REPORTS

Validation of the model approach was attempted by reconciliation with the survey results for the one case that was roughly comparable. Specifically, the model-indicated expansion program for the 1990 high demand case with crude oil slate B was compared to the survey scenario for the 20 percent increase in high-sulfur crude oil combined with 90 volume percent 89 (R+M)/2 unleaded gasoline manufacture. In making this comparison the following comments were considered:

Interim Report

- The "required" facilities reported in Chapter Three of the interim report were developed by summation of estimated individual company estimates, in response to the hypothetical question posed.
- The facilities requirement for each of the three questions (high-sulfur crude oil, unleaded gasoline, and low-sulfur fuel oil production) was developed separately. Simply adding them together would result in duplication.
- Utilization factors for existing facilities varied between companies. Those companies that needed to expand were not affected by others that may have had excess capacity.
- The facility requirements reported in the interim report were in barrels per calendar day.

This Report

- The required facilities indicated in Chapter Two of this report were determined with a model which optimizes the expansions for the overall industry needs, rather than for individual refiners' situations.

- Inherent in the approach is an assumption that any excess capacity in one refinery would compensate for the expansion requirement in another refinery, primarily by segmentation of product markets and the shifting of the various grades of available crude oils among refiners.

- The facility requirements in Chapter Two of this report are expressed in barrels per stream day.

Crude oil slate B for the 1990 high demand case was similar to the projected 1982 crude oil slate from Chapter One of the interim report (see Table F-1). The total requirement for process facilities as derived from the survey information was determined by combining the light, high-sulfur crude oil increment case and the 89 (R+M)/2 unleaded gasoline case, and overlaying the 1982 "planned facilities" from Chapter One of the interim report (see Table F-2). The process facility requirements from Chapter Two of this report were changed to barrels per calendar day for comparability (see Table F-3).

The results of the comparison are shown in Table F-4:

- Both methods indicated need for a significant capacity increase in catalytic reforming, hydrotreating (naphtha and distillate), and residual conversion.

- The survey indicated an expansion in catalytic cracking of 556 MB/D, compared to only 105 MB/D indicated by the model. This difference could be due partly to model "over optimization" and partly to the failure of the survey approach to recognize existing underutilized capacity.

- New capacity for catalytic reforming is 1,220 MB/CD according to the model and 1,041 MB/CD according to the survey. However, the total facilities for producing high octane number blending stocks (including catalytic reforming, alkylation, and isomerization) was 1,577 MB/CD for the model and 1,602 MB/CD for the survey, which is in better agreement than could have been reasonably expected.

COMPARISON OF CAPITAL COSTS IN THE TWO REPORTS

In the survey approach, each refining company upgraded its facilities to meet the hypothetical supply/demand situations which probably required more numerous, smaller expansions than would actually occur. Conversly, the model approach, driven by economics, built fewer but larger units. For example, the average size new reformer was about 10 MB/D in the survey and about 30 MB/D in the model.

Associated costs calculated from these two approaches are similarly divergent. The survey results would imply almost $14 billion (1978 dollars) of investment while the model (in the high case and

TABLE F-2

Planned Process Facilities for the 1978-1982 Period and Additional Process Facilities
For Light High-Sulfur Crude Oil and 89 (R+M)/2 Unleaded Gasoline
(MB/CD)

Process Facility	Planned Facilities 1978-1982	89 (R+M)/2	Light High-Sulfur Crude Oil	Total Planned Plus 89 (R+M)/2 Plus LHS*
Hydrotreating				
Naphtha	638	--	398	--
Distillate	323	--	1,279	--
Heavy Fuel Oil	19	--	685	--
Total	980	504	2,362	3,342
Crude Oil Distillation	1,092	37	601	1,693
Vacuum Distillation	407	50	382	789
Catalytic Cracking	408	96	142	550
Alkylation	55	43	--	98
Catalytic Reforming	474	567	199	1,041
Isomerization	42	421	50	463
Residual Conversion				
Coking	48	--	299	--
Visbreaking	--	--	26	--
Total	48	--	325	373
BTX Recovery	22	--	--	22
Polymerization	8	6	--	14
Hydrocracking	22	51	--	73
Sulfur Recovery (LT/CD)	1,820	--	4,527	6,347
Hydrogen Manufacturing (MMSCF/D)	--	85	531	531
Naphtha Splitting	--	298	--	298
Tankage (MB)	--	--	20,816	20,816
Treating	--	--	31	31
Total Estimated Cost (Billion $)	6.3	1.8	6.8	13.7

*Light high-sulfur crude oil.

TABLE F-3

Model-Indicated Process Facilities for 1990 Crude Oil Slate B for High, Medium, and Low Supply/Demand Cases

Process Facility	High Case		Medium Case		Low Case	
	MB/SD	MB/CD	MB/SD	MB/CD	MB/SD	MB/CD
Hydrotreating						
Naphtha	1,397	--	1,166	--	673	--
Distillate	2,453	--	1,583	--	1,353	--
Heavy Fuel Oil	--	--	--	--	--	--
Total	3,850	3,247	2,749	2,317	2,026	1,708
Crude Oil Distillation	1,396	1,233	99	87	0	0
Vacuum Distillation	558	493	40	33	0	0
Catalytic Cracking	105	88	23	19	18	15
Alkylation	429	356	25	21	23	19
Catalytic Reforming	1,457	1,220	1,256	1,051	1,179	987
Isomerization	1	1	0	0	0	0
Hydrorefining	30	25	68	57	130	0
Residual Conversion	537	449	689	577	639	535
Total Estimated Cost (Billion $)	5.6		3.8		3.4	

TABLE F-4

Comparison of Major Process Facility Requirements

Process Facility	Survey (1978-1982)* MB/CD	Model (1990 High Case, Crude Oil Slate B) MB/SD	MB/CD
Hydrotreating	3,342	3,850	3,247
Crude Oil Distillation	1,693	1,396	1,233
Vacuum Distillation	789	558	493
Catalytic Cracking	550	105	88
Alkylation	98	429	356
Catalytic Reforming	1,041	1,457	1,220
Isomerization	463	1	1
Residual Conversion†	446	537	449
Hydrorefining	--	30	27

*Processing additional 20 percent light, high-sulfur crude oil and 90 percent gasoline pool @ 89 (R+M)/2 unleaded gasoline.

†Residual conversion includes coking and visbreaking.

crude oil slate B) estimates $5.6 billion. About $1.2 billion of this difference is in certain facilities included in the survey but not in the model (see Table F-5). In addition to the construction differences, each approach used different cost calculations, which are estimated to account for about 10 percent of the difference. It is concluded, therefore, that the model has understated the costs while the survey has overstated them, and that a more probable range is $8 to $12 billion (1978 dollars). Considering all three supply/demand cases used in this report, the capital cost range is $5 to $12 billion (1978 dollars).

TABLE F-5

Additional Process Facilities from the Survey -- 1978-1982

Process Facility	MB/CD
BTX Recovery	22
Polymerization	14
Sulfur Recovery (LT/CD)	6,347
Hydrocracking	22
Hydrogen Manufacturing (MMSCF/D)	531
Naphtha Splitting	298
Treating	31
Tankage (MB)	20,816
Total Estimated Cost (Billion $)	1.3

The costs in both reports are only for the new process facilities noted. Neither report includes any of the very large investment requirements for sustaining existing facilities, improving efficiency, energy conservation, environmental protection, safety, or any facilities outside the refinery.

APPENDIX G

Domestic Crude Oil Allocation Program (Entitlements Program)

DOMESTIC CRUDE OIL ALLOCATION PROGRAM
(ENTITLEMENTS PROGRAM)

INTRODUCTION

The first part of this appendix briefly explains the history of domestic crude oil price controls from 1971 to the present and through their expiration in 1981. In the second section of this appendix, specific details are provided on how the provisions of the program were applied to the data received in the 1979 NPC Survey of Petroleum Refining Capabilities.

U.S. CRUDE OIL PRICE CONTROLS/ENTITLEMENTS

Federal price controls on domestic crude oil were imposed in 1971. In August 1973, the Cost of Living Council promulgated Phase IV price regulations establishing a tiered price system for domestic production: "old" oil was price-controlled, and "new" oil was free of price controls. This two-tiered pricing system was designed to provide adequate price incentives to stimulate new crude oil production while concurrently holding average domestic crude oil prices below world levels in order to insulate consumers from the effects of higher prices.

By the end of the 1973-1974 embargo, the consequent increase in world oil prices has imposed a significant disparity between the cost of domestic "old" oil and imported crude oil in the United States. This differential in crude oil prices accordingly resulted in a wide range of prices paid by consumers for refined petroleum products.

In the interests of "equalizing" domestic refiners' crude oil acquisition costs and consequently U.S. consumer costs for petroleum products, the Federal Energy Administration (FEA) under the legislative mandate of the Emergency Petroleum Allocation Act of 1973 (EPAA), established the Old Oil Allocation or Entitlements Program, effective November 1974. The purpose of the entitlements program was to equalize (to the maximum practical extent) U.S. refiners' crude oil costs by distributing the benefits of access to lower priced domestic crude oil proportionately to all domestic refiners (and consequently all sectors of the petroleum industry and their customers), through a system of monetary rather than physical transfers.

As a procedural matter, the FEA calculated and published, on a monthly basis, a national average ratio of old oil supplies vs. total crude oil runs to stills. Refiners were then issued entitlements equal to the product of this ratio and their adjusted crude oil receipts. Each entitlement gave a refiner the right to receive into inventory and refine one barrel of domestic old oil. Cost equalization was achieved by requiring various refiners to purchase or sell entitlements, based on whether their access to controlled domestic oil supplies was higher or lower than the national average.

Refiners with greater than average access to price controlled domestic oil were required to purchase entitlements; refiners who used a disproportionate amount of foreign or uncontrolled domestic crude oil were required to sell entitlements. The FEA initially set the value of an entitlement as the difference between the average cost of imported oil and the average cost of price controlled domestic oil, minus 21 cents. The 21 cents, equal to the fee imposed on imported crude oil, represented an incentive to encourage the refining of domestic oil and to discourage the importation of higher priced foreign oil.

Regulations implementing the 1975 amendments to the EPAA imposed controls on new oil, thus creating a third regulatory tier. Old oil (now called "lower tier") had the lowest wellhead price followed by new oil (now "upper tier"), then by the highest priced oil, imports. For purposes of the entitlements program, the newly-controlled upper tier oil was equal to a calculated fraction of lower tier oil. While a refiner of lower tier oil was required to possess a full entitlement for each barrel, a refiner of upper tier oil was required to possess only a portion (varying from nearly 20 percent in 1978 to over 70 percent in mid-1980's of an entitlement for each barrel.

The entitlements program additionally included a provision known as the "small refiner bias." The small refiner bias was, in theory, a compensation awarded to small refiners to offset their lack of economies of scale and relatively higher operating and capital costs. Modeled after the sliding scale that had been present in the Mandatory Oil Import Program (1959-1973), this portion of the entitlements program partially exempted small refiners (those with 175 MB/D of capacity or less) from entitlement purchase requirements or awarded them additional entitlements to sell. The amount of additional entitlements was scaled in an inverse relation to refinery runs so that the greatest benefits were derived by refiners running 10 MB/D or less.

RECENT DEVELOPMENTS

In April of 1979, phased deregulation of domestic crude oil prices began. The program was designed to provide incentives to increase domestic crude oil production while concurrently reducing U.S. dependence on imported oil. The gradual decontrol schedule was adopted to "minimize" the inflationary impacts of price deregulation and to provide an orderly transition from the regulated environment under the EPAA to one determined by market forces after the EPAA's scheduled expiration on September 30, 1981.

On June 1, 1979, newly discovered oil as well as incremental production from enhanced oil recovery (tertiary) projects and some production from marginally economic wells were released to world price levels. The price ceilings on the remaining categories of upper and lower tier oil are gradually being phased out, with all controls being removed by October 1, 1981. On August 17, 1979, and December 21, 1979, price controls on certain grades of "heavy" crude oil were also removed. As a consequence of these measures and earlier legislative mandates decontrolling oil from very small wells and from certain federally-owned reserves, about 55 percent of domestic crude oil production was free of price controls as of September 1980.

APPLICATION OF CRUDE OIL ENTITLEMENTS PROGRAM IN THE NPC STUDY

Among the factors determining the net crude oil cost to refining companies in 1978 was the U.S. Department of Energy's crude oil entitlements program.

Respondents to the January 1979 NPC Survey of Petroleum Refining Capabilities provided 1978 crude oil volumes and costs by regulatory classification excluding entitlements effects. The weighted average 1978 national figures for entitlements prices, domestic oil supply ratio (DOSR), and deemed old oil ratio (DOOR), as published by the Department of Energy (DOE), were programmed into the computer to calculate the effects on crude oil costs of the entitlements program as administered in 1978 (i.e., on a company basis). The small refiner bias feature of the entitlements program was similarly programmed, using DOE published equations and factors for the various size categories.

The entitlements and small refiner bias programs were also simulated on the computer for a hypothetical refinery basis. The DOE factors and equations were modified to appropriately reflect this change of basis.

For both bases, crude oil costs were estimated for the "after entitlements without small refiner bias" and "after entitlements with small refiner bias" costs. The methods used for computing the various entitlements costs are discussed below.

Company Basis

I. "After Entitlements With Small Refiner Bias"

(a) For each company refinery system, determine the total refinery crude oil runs, lower tier crude oil runs, and upper tier crude oil runs for 1978 on a daily average basis.

(b) 1. Determine "Entitlements Issued" = [(total refinery runs) x (DOSR)], where DOSR denotes "domestic oil supply ratio" which had an average value of 0.1934 in 1978.

2. In addition to the number of entitlements issued in accordance with (1) above, issue to each refining company with an average volume of crude oil runs to stills of less than 175 MB/D the number of additional entitlements computed in accordance with the Schedule for Small Refiner Bias Entitlements shown later in this appendix.

(c) Determine "Entitlements Required" = [lower tier runs + (upper tier runs x DOOR)], where DOOR denotes "deemed old oil ratio," the fractional entitlement required for each barrel of upper tier oil, which had an average value of 0.1897 in 1978.

(d) Determine "Entitlements Cost With Small Refiner Bias" = (entitlement price) x (entitlements required less entitlements issued), where the average entitlements price was $8.26.

(e) Divide "Entitlements Cost With Small Refiner Bias" by total refinery runs to determine per-barrel cost (or benefit).

(f) Add entitlements cost (or subtract entitlements benefit) from (e) above to average crude oil cost before entitlements to obtain "after entitlements with small refiner bias crude oil costs."

II. "After Entitlements Without Small Refiner Bias"

Compute entitlements cost as in (I) above except:

(a) Use DOSR[1] = 0.2084

(b) Omit calculation of additional entitlements under small refiner bias provision.

Individual Refinery Basis

I. "After Entitlements With Small Refiner Bias"

The entitlements calculations on a hypothetical individual refinery basis differ from the company basis calculations in the following ways:

(a) All individual refineries with crude oil capacities of less than 175 MB/D qualified for the small refiner bias,

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[1]The change in DOSR value results from omitting the term for small refiner bias (SRB) in the Department of Energy equation for DOSR; i.e.,

$$DOSR = [OOR + (DOOR)(UTR) - SRB - EAR - COR - Naphtha - Cal] \div [Crude\ oil\ runs - 0.5\ (DRD) + 0.5\ (IR)]. \quad \text{(Equation A)}$$

not just those companies with aggregate capacity less than 175 MB/D.

(b) Small refiner bias entitlements were calculated on an individual refinery basis. Therefore, in the case of each company, the number of such entitlements is greater than or equal to the figure calculated on a company basis.

A revised DOSR was calculated by modifying the small refiner bias (SRB) term in the DOSR formulation to reflect the above changes. More specifically, a revised national average DOSR was calculated based on an estimation of the total U.S. small refiner bias entitlements consistent with items (a) and (b) above.

The following procedure was utilized in the estimation of the SRB term:

(a) Assume that the companies that did not respond to Part II of the January 1979 NPC survey, requesting crude oil costs, are single refinery companies. This is approximately correct because most of the non-respondents are small companies (and most likely single refinery companies). Sixty-nine (69) out of a total of 159 refineries in the 0-30 MB/D range did not respond to the relevant items of Part II. The non-response in this category is over 80 percent of the total non-response.

(b) Based on the above assumption (which leads directly to the conclusion that the number of small refiner bias entitlements accounted for by the non-respondents will be approximately the same regardless of whether the basis for calculation is by refinery or by company), estimate the number of small refiner bias entitlements on a refinery basis using the following equation:

$$SRB_{refinery} = SRB_{DOE} - SRB_{CS} + SRB_{RS}$$

where

$SRB_{refinery}$ = Estimated total U.S. small refiner bias entitlements on an individual refinery basis

SRB_{DOE} = DOE daily average U.S. total small refiner bias entitlements

SRB_{CS} = Actual daily average small refiner bias entitlements among Part II respondents on acompany basis

SRB_{RS} = Calculated daily average small refiner bias entitlements among Part II respondents on a refinery basis.

Crude oil costs on an individual refinery basis were subsequently estimated based on the above SRB term and Equation A (see Page G-4), which is the standard formulation for the DOSR (estimated at 0.1829 for this case). The same general procedure as the corresponding company basis case was adopted, except for the different factors as discussed above.

For refineries of more than 175 MB/D, the cost of the entitlements program is greater under the hypothetical refinery basis than under the company basis. This is because these refineries bear the entire cost of the bigger, modified, hypothetical small refiner bias program. As expected, the U.S. average cost of crude oil is also unchanged under this small refiner bias program because the additional credits to the small refiners are offset by the additional debits to the bigger (greater than 175 MB/D) refineries.

This hypothetical version of the small refiner bias program increases the estimated nationwide small refiner bias pool from about $715 million to over $1,200 million annually.

II. "After Entitlements Without Small Refiner Bias"

The calculation of entitlements costs without small refiner bias uses the same procedure and DOSR as the corresponding case for the company basis.

SCHEDULE FOR SMALL REFINER BIAS ENTITLEMENTS

In addition to the number of entitlements issued in accordance with the entitlements program, each refiner with an average volume of crude oil runs to stills of less than 175 MB/D is issued the following number of additional entitlements:

(a) For average volume of runs of 100-175 MB/D, 1,258 entitlements less the number of entitlements obtained by multiplying the difference between that daily volume of crude oil runs and 100,000 by 0.0167733.

(b) For average volume of runs of 50-100 MB/D, 2,079 entitlements less the number of entitlements obtained by multiplying the differences between that daily volume of crude oil runs and 50,000 by 0.01642.

(c) For average volume of runs of 30-50 MB/D, 3,123 entitlements less the number of entitlements between that daily volume of crude oil runs and 30,000 by 0.052.

(d) For average volume of runs of 10-30 MB/D, 2,288 entitlements plus the number of entitlements obtained by multiplying the difference between that daily volume of crude oil runs and 10,000 by 0.04175.

(e) For average volume of runs of 0-10 MB/D, 0.02288 entitlements for each barrel of that small refiner's daily average volume of crude oil runs.

DOE VS. NPC ENTITLEMENT ADJUSTMENTS

The entitlements program is a closed system, both in theory and as administered by the DOE; every entitlement buyer is matched by an entitlement seller. Almost all of the monies are transferred among refiners, and the program therefore has only a very small impact on <u>average</u> refiner crude oil acquisition cost. During 1978, the differences in industry-wide crude oil costs before and after entitlements transactions are approximately $0.03/bbl, due to payments to non-refiners who either imported residual fuel oil into the East Coast or supplied crude oil to the Strategic Petroleum Reserve. (Almost all of these payments went to residual fuel oil importers.)

The tables in Chapter Three of this report show a difference of $0.33/bbl between average pre- and post-entitlements crude oil costs. The variation between actual data as shown in DOE figures (a $0.03/bbl difference) and the difference reported here ($0.33/bbl) is due to a variety of factors, which result from the use of the DOSR, DOOR, and entitlement price calculated by the DOE.

The largest difference arises from the fact that not all refiners included in the DOE's calculations responded fully to Part II of the NPC's Survey of Petroleum Refining Capabilities, and thus could not be included in NPC computations. In addition, entitlement calculations use specific average prices; DOE's reported average prices are different from NPC's due to the variation in the universes for the two computations. Constructing a hypothetical DOSR for the two sets of data gives an indication of the impact of the application of DOE factors to NPC survey respondents' data. This simplified DOSR calculation, which is based only on deemed old oil as a percentage of crude oil runs and thus excludes the effect of all special programs, shows that net crude oil costs reported for the NPC's sample were raised by approximately $0.15/bbl by the use of DOE's published DOSR, DOOR, and entitlement price.

The granting of special entitlement benefits, another portion of the entitlements program as administered in 1978, would have provided reductions in certain respondents' crude oil costs. The cumulative cost of these additional entitlements is included in the Chapter Three post-entitlement figures because the published national average DOSR and DOOR values were used. However, the benefits of the programs were not distributed to the specific recipients by the calculation.

As shown in DOE entitlement notices, a small number of companies dominated special entitlement receipts in 1978. For example, one company (four percent of the NPC's Part II survey population) received 46 percent of the special entitlements awarded to the 0-10 MB/D company class (exlusive of the small refiner bias). It was concluded that to generalize the effect of these special benefits by averaging the crude oil cost reductions across an entire category could be misleading in that the data could be skewed away from the "average" refiner in a given class. It should be recognized, however, that special entitlements are a major financial factor for certain companies in the industry.

The special programs which concern us here are exceptions and appeals relief, entitlements for refiners of California crude oil, treatment of residual fuel oil marketed on the East Coast, and naphtha imported into Puerto Rico. Although the small refiner bias is also a special program which reduces crude oil costs for given refiners, the bias benefits have been distributed to recipients for the purposes of this study, because the benefits are automatically available to all small refiners. In the ensuing discussion, therefore, no data on small refiner bias benefits are included.

A rough estimate of the value of these benefits can be computed by using DOE monthly entitlement notices. Table G-1 shows the grants and the special entitlements to specific NPC survey respondents by company size.

In examining Table G-1, one should bear in mind that particular refiners got the preponderance of benefits in certain categories, as will be discussed below. In addition, the average net crude oil costs for all NPC survey respondents would be reduced by some $0.11/bbl. The effect of a reduction on the competitive postion of any group of refiners, therefore, should be assessed as a net effect against the reduction for all refiner-respondents. Lastly, no offsetting upward adjustments in crude oil costs are necessary for refiner categories, because the cost of these programs has been subsumed in the original calculation.

Exceptions and Appeals Relief

The DOE grants relief to specific refiners when they can show particular harm from the entitlements program, unique market factors, or other aberrant situations. For instance, it was the policy of DOE's Office of Hearings and Appeals to grant relief to small refiners who were net buyers of entitlements if those refiners were unable to meet certain criteria of historical profitability. No similar relief was available to small refiners who were net sellers of entitlements, and by no means all grants of relief came under this policy. The total value of entitlements issued to recipients of exceptions and appeals relief in 1978 was $320 million, $240 million of which was issued to refiners among the NPC survey respondents. As indicated in Table G-1, the distribution of the relief benefits by company size shows great variation among different categories. The companies in the 50-100 MB/D size range received the highest grants of exceptions relief. However, three companies received virtually all of these benefits. Of the total of 11 refiners included in this category, six were issued no exceptions relief entitlements at all.

TABLE G-1

Estimated Value of Special Entitlements Earned in 1978
by Companies Participating in the NPC Survey

Company Size Range (MB/D)	1978 Throughput* (MB/D)	Value of 1978 Entitlements (MM$)			
		Exceptions and Appeals	Product	California	Total
0-10	124	12.1	0.1	9.3	21.5
10-30	457	61.0	1.3	19.9	82.2
30-50	314	2.4	0	5.1	7.5
50-100	644	128.1	0	0.8	128.9
100-175	375	1.6	0.1	0.3	2.0
175+	11,010	36.0	90.4	149.6	276.0
All	12,924	241.2	91.9	185.0	518.1

*Throughput data from January 1979 NPC Survey of U.S. Petroleum Refining Capabilities for companies receiving entitlements.

California Entitlements

Downward pressure on posted wellhead prices for California crude oils (particularly heavier oil) threatened to encourage the shutting-in of productive capcity in 1978. Since the result would have been to increase imports to replace the supply, DOE began a program in June 1978 to grant extra entitlements to refiners of California crude oil. The entitlement issuances had the effect of lowering post-entitlement acquisition cost for these refiners, thus encouraging them to pay higher prices to producers. The benefits are granted on a sliding scale, inversely related to gravity between June and December 1978, the total value of California entitlements was some $212 million, $185 million of which went to NPC survey respondents. Approximately 80 percent of the entitlements went to companies in the 175+ MB/D category. Of this amount, seven out of the 10 large refiners operating in PAD V received the vast majority. It should be noted, however, that specific smaller companies also benefited; one refiner in the 10-30 MB/D size range received 64 percent of all California entitlements issued to that size category.

Product Entitlements

The DOE grants portions of entitlements for imports of residual fuel oil into the U.S. East Coast. Entitlements are also granted for imports of naphtha into Puerto Rico for petrochemical feedstocks. The major recipients of naphtha entitlements are not among the NPC survey respondents, however. With respect to residual fuel oil the entitlements are awarded to the importer of record, whether a refiner or non-refiner. To the extent that the entitlements go to non-refiners, crude oil costs of all U.S. refiners are increased. By contrast, the entitlements awarded to refiners for residual fuel oil imports have no bearing on the recipients' competitive position for U.S. crude oil refining operations. The data are included only to illustrate the cost/benefit of all special entitlement programs. The total value of product entitlements issued by DOE in 1978 was $302 million. Of this amount, approximately $92 million went to companies participating in the NPC survey. The $210 million granted to non-respondents includes $60 million for naphtha imports into Puerto Rico, and payments to refiners and non-refiners who imported residual fuel oil.

From January to June 1978, U.S. refiners were penalized portions of entitlements for shipments of domestic residual fuel oil to the U.S. East Coast, a provision known as the "reverse entitlement." The total value of this penalty, which effectively increased crude oil costs for certain refiners in the Gulf Coast, East Coast, and Virgin Islands, was $63 million. The monthly entitlement notices do not provide the data necessary to allocate the penalty to specific refiners, however. It should be noted that the reverse entitlement adjustments are not included in the product entitlement figures cited above.

APPENDIX H

Comparison of NPC and Pace Company Economic Analyses

COMPARISON OF NPC AND PACE COMPANY ECONOMIC ANALYSES

A study was released to the Department of Energy in December 1979 by the Pace Company Consultants and Engineers, Inc., entitled Competitive Economics of United States and Foreign Refining. A comparison between the Pace Company study and the NPC report is made below.

The data in Table H-1, based on the actual 1978 competitive environment (from the NPC study) that existed between U.S. and foreign export refineries, show PAD III to have a competitive advantage over the Caribbean refinery of $0.87/bbl of crude oil processed. Table B-2 on page 24 of the Pace Company report shows a 100 MB/D high conversion refinery in PAD III to have a competitive disadvantage of $0.45/bbl in 1980, relative to a Caribbean hydro-skimming refinery, the latter based on projected 1980 world prices from the Pace Company study.

When the refineries in this study are evaluated on the same basis as the Pace Company study, the PAD III refinery has a competitive disadvantage of $0.51/bbl, or only a $0.06/bbl greater disadvantage than the Pace Company results. The primary reasons for the seeming disparity between the 1978 and 1980 bases are: (1) the incremental entitlements throughput credit received by a domestic refiner in 1978 of $1.61/bbl; (2) the average FOB crude oil cost of a PAD III refiner with controlled prices on domestic crude was an advantage of $0.68/bbl for this study relative to the Pace Company study; and (3) the different product prices and taxes which account for most of the remaining differences.

The calculations in Table H-1 were based on the relative profit (before income tax), which was derived from delivered product value less crude oil costs and other product processing costs from Tables 131, 132, 133, 135, 137, and 138 of Chapter Four, for the 85-100 percent operating capacity increment. The relative profit (before income tax) was reduced by the total fixed costs ($/bbl from Table 154 of Chapter Four). This result was entered on Table H-1 as "Taxes." The following is an example of the calculation for taxes:

PAD I

Use Column for 100% Operating Capacity (Table 132)

Relative Profit (Before Income Tax)	$2.48
Total Fixed Assets (Table 154)	$1.15
Relative Profit less Fixed Assets	$1.33
Income Tax (50% Rate, see Table 149)	$0.67

TABLE H-1

Estimated 1978 Relative Advantage (Disadvantage) -- Total Cost Basis
(All Cost Figures in U.S. $/Bbl of Crude Oil Charge)

	PAD I	PAD III	Caribbean Existing Capacity	Caribbean Retrofitted Downstream	E. Canada Existing Capacity	E. Canada Retrofitted Downstream	Netherlands	Italy
Base: PAD I, 100% Capacity -- Profitability								
Due to:								
Crude Oil Cost (FOB)	Base	(0.25)	0.13	0.13	0.09	0.09	(0.04)	(0.04)
Crude Oil Transportation	Base	0.40	0.53	0.53	0.55	0.55	0.39	0.44
Crude Oil Fees and Duties	Base	0.05	0.11	0.11	0.11	0.11	0.11	0.11
Delivered Product Value	Base	0.35	(1.78)	(0.06)	(1.42)	0.22	(1.85)	(1.91)
Product Transportation	Base	(0.74)	(0.06)	(0.05)	0.15	0.18	(0.53)	(0.68)
Product Fees and Duties	Base	--	(0.09)	(0.31)	(0.24)	(0.38)	(0.10)	(0.09)
Fuel Cost	Base	0.16	0.43	0.02	0.26	(0.13)	0.42	0.47
Other Variable Costs	Base	0.03	0.12	0.06	0.01	(0.01)	0.14	0.14
Fixed Costs*	Base	0.09	0.40	0.47	0.26	0.77	0.41	0.51
Subtotal (Pre-Entitlements and Taxes)	Base	0.09	(0.21)	(0.04)	(0.23)	(0.14)	(1.05)	(1.05)
Entitlements -- Crude Oil Throughput	Base	--	(1.61)	(1.61)	(1.61)	(1.61)	(1.61)	(1.61)
Entitlements -- Residual Produced	Base	--	0.06	0.06	0.06	0.06	0.06	0.06
Entitlements -- Residual Imports	Base	--	0.22	0.07	0.21	0.10	0.20	0.19
Total Advantage (Disadvantage) (Without Taxes)	Base	0.00	(1.54)	(1.52)	(1.57)	(1.59)	(2.40)	(2.41)
Taxes	Base	(0.05)	0.72	0.72	0.79	0.79	1.18	1.10
Total Advantage (Disadvantage) (With Taxes)	Base	0.05	(0.82)	(0.80)	(0.78)	(0.80)	(1.22)	(1.31)

*See Table 154 of Chapter Four for fixed cost data.

Caribbean

Use Column for 100% Operating Capacity (Table 134)		
Relative Profit (Before Income Tax)	$0.54	
Total Fixed Assets (Table 154)	$0.75	
Relative Profit less Fixed Assets		(0.19)
Income Tax (25% Rate, see Table 149)	(0.05)	

The income tax difference between PAD I and the Caribbean refinery is $0.67 less (0.05) equal to $0.72.