Refinery Flexibility

An Interim Report of the National Petroleum Council

Volume I

December 1979

Refinery Flexibility

An Interim Report of the National Petroleum Council

Volume I

December 1979

Committee on Refinery Flexibility
Jerry McAfee, Chairman

NATIONAL PETROLEUM COUNCIL

C. H. Murphy, Jr., *Chairman*
H. J. Haynes, *Vice Chairman*
J. Carter Perkins, *Executive Director*

U.S. DEPARTMENT OF ENERGY

Charles W. Duncan, Jr., *Secretary*

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.

Library of Congress Catalog Card Number: 79-93025

Printed in the United States of America

VOLUME I

Table of Contents

VOLUME II

INTRODUCTION

By letter dated September 18, 1978, the National Petroleum Council, an industry advisory committee to the Secretary of Energy, was requested to prepare an analysis of the factors which affect the ability of the domestic refining industry to respond to demands for essential petroleum products. The Council last prepared such a study in 1973. In requesting the new study the Secretary specified that it should be:

> ...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. [See Appendix A for complete text of the Secretary's letter.]

In response to this request, the National Petroleum Council established a Committee on Refinery Flexibility under the chairmanship of Jerry McAfee, Chairman of the Board, Gulf Oil Corporation. The Committee is assisted by a Coordinating Subcommittee and two Task Groups. John R. Hall, Vice Chairman and Chief Operating Officer, Ashland Oil, Inc., is Chairman of the Refinery Capability Task Group; S. E. Watterson, Jr., Corporation Manager-Tanker and Distribution Planning Staff, Standard Oil Company of California, is Chairman of the Oil Supply, Demand and Logistics Task Group; and Warren B. Davis, Chief Economist, Gulf Oil Corporation, is Chairman of the Coordinating Subcommittee. The members of the two Task Groups are industry experts in their respective fields and the membership of the Coordinating Subcommittee includes the chairmen of the two Task Groups and individuals from outside of the industry who provide a broader point of view for the study. (Rosters of all study participants are included in Appendix B.)

An early decision in the study effort was the need to develop a new, comprehensive data base on all U.S. refining facilities in place and under construction. In order to obtain such a data base, a questionnaire was prepared and sent to all U.S. refining companies.

As of January 1, 1979, 174 companies operated 287 refineries in the continental United States, Alaska, Hawaii and Guam,[1] with a total crude oil processing capacity of 17.3 million barrels per day (MMB/D). The Council received a most gratifying response to its request for very detailed and, in some cases, sensitive data on each refining facility. The Council wishes to acknowledge this high level of cooperation and thank the respondents for their time and thoughtful consideration of this matter. In total, responses were received on 16.9 MMB/D, or 98 percent, of total U.S. refining capacity. Responses were also received from an additional two refineries scheduled for start-up prior to January 1, 1982.

Another early decision in the study effort was the need to prepare a comprehensive data base of petroleum supply and demand projections to 1990. Such a data base was deemed necessary to be able to respond to the Secretary's request for an analysis of future trends in refining capability and competitive economics to 1990. It was further agreed, however, that it would be inappropriate for the Council to forecast petroleum supply and demand, and that it would be necessary to retain a third party to prepare an aggregation of numerous private forecasts. A list of 32 institutions in the United States and abroad was prepared in an attempt to

[1]Caribbean refineries are not included in this Interim Report. Survey responses were received from several offshore plants, but were not included in the tabulation because they were a low percentage of total Caribbean capacity and were judged to be unrepresentative of the area as a whole.

solicit forecasts from all organizations thought to have or be capable of preparing supply/demand data in the detail needed. A total of 20 responses was received, 14 of which were from firms in the petroleum industry. The other six represent a mix of consulting and research firms, and U.S. and foreign governmental agencies.

The purpose of this Interim Report is to present the aggregation of these two surveys and the individual findings derived therefrom. The surveys were conducted in early 1979 and do not reflect the events which have occurred since then. The final report will contain data which update certain parts of the material presented herein.

This Interim Report specifically does not analyze the survey findings nor draw any conclusions regarding the future adequacy of current and planned refining capacity or the competitive economics of refining in the United States. These issues as well as an analysis of the industry's flexibility in times of supply dislocations will be discussed in detail in the final report. Further, this Interim Report does not analyze the results of the two surveys as a unit. The final report will present appropriate analyses which will compare the separate results of these two efforts.

METHODOLOGY OF PROCESSING SURVEY RESPONSE DATA

The certified public accounting firm of Arthur Young & Company was retained by the National Petroleum Council to receive and aggregate the responses of both the Refinery Capability survey and the Supply/Demand Forecast survey. Arthur Young & Company was instructed to treat all responses in strictest confidence and to release no identifiable individual company data. The accounting firm was also instructed not to release any aggregated data element unless the responses of at least three organizations were included (or a written waiver of confidentiality was obtained). Through these procedures, Arthur Young & Company has assured that no identifiable individual company data were made available to study participants or others, nor can such information be derived from the data presented.

Arthur Young & Company was provided a number of tests to apply to all data from respondents to check the reasonableness of the entry, but did not audit the submissions. Based on provided guidelines, data processing routines were developed for aggregating and reporting the Refinery Capability survey data by company and refinery size (0-10, 10-30, 30-50, 50-100, 100-175, and 175+ MMB/D, by geographic region (PAD districts, see Figure 1) and by complexity factor (1-3, 3-5, 5-7, 7-9, 9-11, and 11+). The complexity factor employed in the study is essentially the Nelson Refining

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

Complexity Factor, excluding asphalt and lubricating oils capacity. Total process complexity is based upon weighting factors for each process operation, with crude distillation assigned a value of one. The complexity for each refinery is computed by summing the weighted arithmetic factors for all of its processes. Individual process complexity factors and the procedure for computing refinery complexity are provided in Appendix C.

REFINERY CAPABILITY SURVEY

The Refinery Capability survey was distributed to all U.S. refineries in January 1979 and responses were received in the spring and summer of 1979. The survey consisted of three parts. Part I sought detailed data on each refinery's 1978 through 1982 operations, and included those facilities in place as of January 1, 1979 and those facilities firmly committed for installation prior to January 1, 1982. The results of Part I are summarized in Chapter One and Appendix C. Part II of the survey addressed 1978 crude oil costs and refinery operating costs. Data were also sought on refinery gross fixed assets and replacement costs as of January 1, 1979. Details of Part II are presented in Chapter Two and Appendix D. Part III of the survey was concerned with new facilities (in addition to those indicated in Part I as already committed to be completed prior to January 1, 1982), which would be required by refining companies under three specific hypothetical cases: (1) Provide capability to substitute additional high sulfur crude oil equal to 20 percent of 1982 crude oil capacity; (2) increase production of unleaded gasoline to 90 percent of total 1982 gasoline pool; and (3) increase production of low sulfur heavy fuel oil by 25 percent over total heavy fuel oil that was projected for 1982. Chapter Three contains the results of this part of the survey. For reference, the Refinery Capability survey and instruction sheets are reproduced in Appendix E.

SUPPLY/DEMAND SURVEY

Detailed historical supply/demand data for the period 1972-1977 are presented in Appendix F. If 1978 actual data are available at the time of the preparation of the final report, they will be included. The Supply/Demand survey form and instructions are reproduced in Appendix G. Aggregations of the responses to the survey form are shown in Appendix H and discussed in Chapter Four.

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 in Chapter Four 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 Chapter Four data.

While no longer representative of industry's current forecasts, the initial survey results contained in the Interim Report are deemed useful for the purposes of this study. Each refiner bases his construction and operating decisions on his perception of the future supply/demand environment. The facilities in place and under construction, as reported in Chapter One, are based on a supply/ demand outlook which was prepared in about the same time frame as those reflected in the Chapter Four data. Since one of the areas to be covered by the final report is an analysis of the flexibility of the industry to respond to changing patterns in crude sources and product demands, the aggregated supply/demand forecasts will provide a basis for determining future requirements. As noted earlier, however, no comparison of the data from the two surveys has been made for this Interim Report.

FINAL PHASE OF THE STUDY

The final report will build on the data presented in this Interim Report and will provide analyses and discussions in response to the three main areas requested by the Secretary: (1) future projections of crude oil availability and quality, and refining capability; (2) competitive economics of small, medium, and large refining operations in the U.S. and their relative position vis a vis foreign refining operations; and (3) flexibility to meet dislocations of supply.

The final report will expand on the supply/demand data presented in this interim report in an attempt to bracket a reasonable range of availabilities and requirements through 1990. As noted earlier, this will be accomplished in part by updating certain portions of the supply/demand data shown in this report. The facilities in place or under construction will be tested against this range of supply/demand outlooks to determine what, if any, new facilities will be required to be constructed. If new facilities are required, their construction costs will be estimated.

It is anticipated that the analysis of these and other related issues will be completed by the second quarter of 1980.

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.

---

[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.

- 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 <u>individual</u> 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.

<u>World Oil Supply/Demand</u>

- 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.

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.

CHAPTER ONE

CURRENT AND PROJECTED REFINERY OPERATIONS AND FACILITIES[1]

Refining companies provided data on each of their refineries for 1978, 1980, and 1982 operations and included facilities existing on January 1, 1979 or committed for operation by January 1, 1980 and by 1982. Facilities surveyed included atmospheric distillation and specific downstream processing units for fuels, aromatics, sulfur recovery, and specialty products.

Respondents furnished actual calender year 1978 and projected 1980 and 1982 slates of crude oil and other feed and blending stocks. The composition of crude oil slates were reported according to sulfur content (sweet, medium, and high) and gravity (light and heavy).

Companies reported actual 1978 and projected 1980 and 1982 product yields of motor gasoline, jet fuels, distillates, residual fuels, asphalt, BTX, blending stocks, and other specialty products.

Survey participants also furnished data on the capability of each refinery to substitute medium or high sulfur crude for sweet under known environmental restraints or, in the event of a national emergency, with suspended restraints.

The participants reported the capability of each refinery to maximize the production of unleaded gasoline under alternate octane number specifications.

Low sulfur heavy fuel oil manufacturing capabilities for various sulfur contents were reported for two conditions: (1) meeting normal demands for other products, and (2) maximizing heavy fuel oil products at the expense of light products.

---

[1]All data have been rounded to the nearest MB/D. Totals were calculated from whole numbers and thus may differ from the sum of rounded data shown.

Responses to this part of the survey were received for 246 refineries representing 86 percent of the 289 refineries owned by the refining companies in the United States. As of January 1, 1979, the responding companies had a combined capacity of 16,878 MB/D. Projections for January 1, 1980 and 1982 show that these same refineries will have aggregate estimated capacities of 17,260 MB/D and 17,969 MB/D for the two dates, respectively.

REFINING CAPACITY

Tables 1 and 2 present a summary of January 1, 1979, crude oil refining capacity, the number of refineries within the United States and Guam, and the distribution of these refineries by geographic area and size. It should be noted that the capacity of refineries in Hawaii, the Hawaiian Trade Zone, Alaska, and Guam is aggregated within the PAD V figures.

Table 3 compares the January 1, 1979 capacity with the projected total capacity on January 1, 1980 and 1982 in the several geographic areas surveyed. During 1979 there will be an expansion in capacity of some 382 MB/D, with 34.6 percent of this added capacity in PAD II, 27.5 percent in PAD V, and approximately 15 percent each in PADs I and III. The capacity for another 709 MB/D will be added during 1980 and 1981. The majority of this added capacity (72.8 percent) will be located in PAD III, with 11 percent in PAD II and seven percent each in PADs I and V.

Table 4 indicates little change in the relative percentages of total refining capacity in 1980 and 1982, among the refinery size categories. The drop in refinery capacity for the smallest MB/D category is the result of expansion: nine refineries will move upward into the 10-30 MB/D category during the 1979-1982 time period. Similar size group reclassifications will occur throughout the industry during this three-year period. Of the total increase in capacity (1,091 MB/D through 1982), nearly 800 MB/D is in refineries of greater than 100 MB/D capacity.

TABLE 1

Crude Oil Refining Capacity in Existence
as of January 1, 1979
(MB/D)

Refinery Size Category (MB/D)	Refinery Location PAD I	PAD II	PAD III	PAD IV	PAD V	Respondent Capacity	Non-Respondent† Capacity
0- 10	59	59	121	34	54	327	116
10- 30	99	225	421	173	276	1,193	241
30- 50	§	460	348	358	289	1,454	-
50-100	388	1,056	853	§	635	2,932	80
100-175	*	1,297	878	0	*	3,605	0
175 & Larger	*	1,038	4,698	0	*	7,367	0
Total							
Respondents	1,871	4,135	7,317	564	2,990	16,878	
Non-Respondents	0	73	246	26	92	437	437
Total U.S.A.	1,871	4,208	7,563	590	3,082	17,315	

*Withheld due to confidentiality. Data included in total.
†From Oil and Gas Journal, March 1979.
§Reclassified in order to protect confidentiality.

TABLE 2

Number of Refineries in Existence
as of January 1, 1979

Refinery Size Category (MB/D)	Refinery Location PAD I	PAD II	PAD III	PAD IV	PAD V	Total Respondents†	Number of Non-Respondents
0- 10	9	11	21	7	9	57	28
10- 30	6	11	21	9	13	60	14
30- 50	§	10	9	8	7	34	0
50-100	6	16	11	§	8	41	1
100-175	*	10	7	0	*	28	0
175 & Larger	*	4	14	0	*	24	0
Total							
Respondents	28	62	83	24	47	244	
Non-Respondents	0	11	17	7	8	43	43
Total 50 States and Guam	28	73	100	31	55	287	

*Withheld due to confidentiality. Data included in total.
†In addition, two reported startup in 1980.
§Reclassified in order to protect confidentiality.

TABLE 3

Geographic Distribution of Crude Oil Refinery Capacity
Projected to January 1, 1982

	January 1, 1979		January 1, 1980		January 1, 1982	
Location	Capacity (MB/D)	Percentage of Respondents	Capacity (MB/D)	Percentage of Respondents	Capacity (MB/D)	Percentage of Respondents
PAD I	1,871	11.1	1,927	11.2	1,981	11.0
PAD II	4,135	24.5	4,267	24.7	4,348	24.2
PAD III	7,317	43.4	7,381	42.8	7,897	44.0
PAD IV	564	3.3	590	3.4	598	3.3
PAD V	2,990	17.7	3,095	17.9	3,146	17.5
Total Respondents	16,878	100.0	17,260	100.0	17,969	100.0
Non-Respondents	437*	--	550†	--	593†	--
Planned New and Expanded	--	--	249§	--	568§	--
Total 50 States and Guam	17,315	--	18,059	--	19,130	--

*From Oil & Gas Journal, March 26, 1979.

†January 1, 1979, capacities plus expansions scheduled and reported to the Department of Energy.

§New refineries and expansions planned for construction January 1, 1979, to January 1, 1982, and reported to the Department of Energy.

TABLE 4

Distribution of Crude Oil Processing Capacity
by Refinery Size

Refinery Size Category (MB/D)	January 1, 1979 Capacity (MB/D)	January 1, 1979 Percentage of Respondents	January 1, 1980 Capacity (MB/D)	January 1, 1980 Percentage of Respondents	January 1, 1982 Capacity (MB/D)	January 1, 1982 Percentage of Respondents
0- 10	327	1.9	314	1.8	292	1.6
10- 30	1,193	7.1	1,183	6.9	1,257	7.0
30- 50	1,454	8.6	1,534	8.9	1,475	8.2
50-100	2,932	17.4	3,140	18.2	3,181	17.7
100-175	3,605	21.4	3,476	20.1	3,674	20.4
175 & Larger	7,367	43.6	7,614	44.1	8,090	45.0
Total Respondents	16,878	100.0	17,260	100.0	17,969	100.0
Non-Respondents	437*	--	550†	--	593†	--
Planned New and Expanded	--	--	249§	--	568§	--
Total 50 States and Guam	17,315	--	18,059	--	19,130	--

*From Oil & Gas Journal, March 26, 1979.

†January 1, 1979, capacities plus expansions scheduled and reported to the Department of Energy.

§New refineries and expansions planned for construction January 1, 1979, to January 1, 1980, and reported to the Department of Energy.

PROCESS FACILITY CAPABILITIES

Capacities of key process facilities in existence on January 1, 1979, are presented in Table 5, while increases (or decreases) in these key processes for 1982, aggregated by refinery size category are shown in Table 6. The trends shown by these data provide an insight into the planned expansion employed by the industry to meet growing demands for unleaded gasoline, to comply with phasedown of lead additives in other motor fuel grades, and to accommodate higher sulfur, heavier crude oils. With respect to octane number improvement and crude capacity gains, increases of 8.5 percent in catalytic cracking, 13.5 percent in reforming, 72.4 percent in isomerization pentane/hexane, 6.5 percent in alkylation, and 2.7 percent in hydrocracking capacities are projected between January 1, 1979, and January 1, 1982. The 13.5 percent gain in hydrotreating capacity, which is directed in part to crude oil refining capacity and octane number capability, is also a provision for increasing runs of higher sulfur crude oil.

Capacity data for key process facilities aggregated on a geographic basis are displayed in Table 7, presenting capacities existing on January 1, 1979, and the increases in these key processes for 1982. Particularly noteworthy is the emphasis upon octane-increasing facilities in PADs III, IV, and V. In this regard, there was an increase of 321 MB/D, or 21.4 percent, in reforming capacity in PAD III. An increase of 723 MB/D, or 23.1 percent, in hydrotreating is shown also in PAD III. The total increase in 50 states was 474 MB/D, or 13.5 percent, for reforming, and 980 MB/D, or 13.4 percent, for hydrotreating.

Estimated complexity factors were calculated for each reporting refinery. The factor employed in the study is essentially the Nelson Refining Complexity Factor, excluding asphalt and lubricating oils manufacturing capacity. The Nelson Factor is a more formal method of defining the complexity of refining operations. In complexity factor calculations, each process operation is weighted

TABLE 5
Process Facility Capacities
as of January 1, 1979
(Figures Shown are Aggregate Capacities)

Type of Unit	Refinery Size Category (MB/D) 0-10	10-30	30-50	50-100	100-175	175 & Larger	Total
Atmospheric Distillation	327	1,175	1,454	2,907	3,564	7,367	16,793¶
Vacuum Distillation	60	209	477	888	1,550	2,930	6,114
Reforming (90 RONC)†	19	147	301	686	850	1,516	3,519
BTX Recovery (In Terms of Aromatic Product)	0	*	*	31	46	134	218
Catalytic Cracking (Fresh Feed)	10	173	347	1,046	1,180	2,037	4,793
Alkylation	0	30	69	208§	190	312§	847
C_5 and C_6 Isomerization	0	0	0	21	12	25	58
Catalytic Hydrotreating	37	194	461	1,315	1,804	3,514	7,324
Catalytic Hydrocracking	5	*	31	65§	272	420	811
Coking (Delayed and Fluid)	0	31	56	204	329	379	1,000

*Withheld due to confidentiality. Data included in total.
†RONC - research octane number clear of debutanized reformate.
§Understated in order to protect confidentiality. Data included in total.
¶Does not include crude charge capacities for units other than crude atmospheric distillation.

TABLE 6

Changes in Process Capacities
1982 Versus 1979
(Figures Shown are Aggregate Capacity Changes, and
Numbers in Parentheses are Net Changes in Number of Reporting Refineries)

Type of Unit	Refinery Size Category (MB/D) 0-10	10-30	30-50	50-100	100-175	175 & Larger	Total
January 1, 1982							
Atmospheric Distillation	-35 (-9)	+64 (+4)	+21 (0)	+249 (+5)	+69 (0)	+723 (+2)	+1,092 (+2)
Vacuum Distillation	- 1 (-1)	+50 (+5)	+46 (+1)	+54 (+2)	- 2 (0)	+259 (+2)	+406 (+9)
Reforming (90 RONC)†	+20 (+4)	+21 (+3)	+25 (0)	+85 (+4)	+83 (0)	+239 (+1)	+473 (+12)
BTX Recovery (In Terms of Aromatic Produced)	* (+1)	* (0)	* (-1)	+ 2 (0)	-1 (-1)	+19 (+2)	+22 (+1)
Catalytic Cracking (Fresh Feed)	-10 (-3)	+41 (+4)	+73 (+2)	+19 (-1)	+14 (0)	+271 (+3)	+408 (+5)
Alkylation	N/A (0)	-3 (-1)	+11 (+1)	* (-1)	+5 (+1)	+43§ (+3)	+56 (+3)
C_5 and C_6 Isomerization	+0.25 (+1)	N/A (0)	N/A (0)	+12 (+2)	-12 (-1)	+42 (+3)	+42 (+5)
Catalytic Hydrotreating	+11 (0)	+38 (+2)	+11 (0)	+154 (+3)	+76 (0)	+691 (+2)	+980 (+7)
Catalytic Hydrocracking	+3 (+1)	* (0)	0 (0)	* (0)	+10 (0)	(0) (0)	+22 (+1)
Coking (Delayed and Fluid)	N/A (0)	0 (+1)	-18 (-1)	+ 31 (+1)	+6 (+1)	+29 (0)	+48 (+2)

*Data withheld due to confidentiality. Data included in total.
†RONC - research octane number clear of debutanized reformate.
§Understated to protect confidentiality. Data included in total.

TABLE 7

Geographic Distribution of Key Process Facilities as of January 1, 1979, and for 1982 (Capacities are Aggregated in MB/D)

Process Facility	Refinery Location PAD I	PAD II	PAD III	PAD IV	PAD V	Total
Atmospheric Distillation	1,871	4,135	7,306	564	2,917	16,793†
1979-1982 Increase	110	213	580	34	156	1,092
Percentage Increase	5.3	5.1	7.9	6.0	5.4	6.5
Vacuum Distillation	862	1,428	2,425	204	1,194	6,114
1979-1982 Increase	8	44	286	14	55	407
Percentage Increase	0.9	3.1	11.8	6.9	4.6	6.7
Reforming (90 RONC)	399	905	1,497	107	613	3,519
1979-1982 Increase	9	62	321	14	67	474
Percentage Increase	2.2	6.9	21.4	13.1	10.9	13.5
BTX Recovery	18	36	159	0	6	218§
1979-1982 Increase	0	6	16	0	0	22
Percentage Increase	0	16.7	10.1	0	0	10.1
Catalytic Cracking	569	1,440	2,030	166	589	4,793
1979-1982 Increase	-6	75	289	25	25	408
Percentage Increase	-1.1	5.2	14.2	15.1	4.2	8.5
Alkylation	63	276	366	27	115	847
1979-1982 Increase	0	12	41	2	0	55
Percentage Increase	0	4.3	11.2	7.4	0	6.5
C_5 and C_6 Isomerization	*	12	46	0	0	58
1979-1982 Increase	*	21	21	0	0	42
Percentage Increase	*	175	46.6	0	0	72.4
Catalytic Hydrotreating	1,049	1,714	3,128	225	1,208	7,325
1979-1982 Increase	5	123	723	13	117	980
Percentage Increase	0.5	7.2	23.1	5.8	9.7	13.4
Catalytic Hydrocracking	72	140	257	5	336	811
1979-1982 Increase	0	0	3	0	18	22
Percentage Increase	0	0	1.2	0	5.4	2.7
Coking (Delayed and Fluid)	74	280	277	17	352	1,000
1979-1982 Increase	0	5	19	13	11	48
Percentage Increase	0	1.8	6.9	76.5	3.1	4.8

*Reclassified due to confidentiality. Data included in total.

†Does not include five units in PAD V, which have a crude charge capacity of 84 MB/D but are not atmospheric distillation units.

§Does not include BTX units in chemical plants that were not covered by this survey.

in terms of its relative complexity, with that of crude distillation being assigned a value of one. The data from the survey illustrate that a refinery's capability to process higher sulfur crude oil and diversify its product mixes correlates with an increased complexity factor.

The complexity factor for each refinery is computed using the summation of the arithmetic factors for each process. Factors for each process were determined by multiplying the "percent capacity" of the unit by the relative factor for the unit. (The percent capacity is equal to the capacity of the unit divided by the capacity of the atmospheric distillation unit.) Table C.0 in Appendix C explains the complexity factor calculation in greater detail. The breakdown of complexity factor by refinery size is shown in Table 8, and Table 9 shows a breakdown by PAD district.

Of the 244 refineries reporting for 1979, 90, representing 7.7 percent of the capacity, were under a factor of 3.0, and 42 refineries, representing 35.3 percent, were in a factor range of 7-9. Refineries below 3.0 complexity factor normally have only distillation units and are capable of manufacturing residual oil, No. 2 oil, naphtha, and asphalt. Refineries in the 5-7 range typically have catalytic cracking units, reformers, and alkylation units, and are able to produce a wide range of products. The plant in the 7-9 range generally has hydrodesulfurization capability in addition to the facilities of a 5-7 range refinery. A refinery in the over-9 category generally has hydrocracking units.

1978 CRUDE OIL SLATES

In Table 10, 1978 crude oil slates are aggregated by refinery size category. Three general crude oil grades are shown: sweet (less than 0.5 wt % sulfur), medium sulfur (between 0.5 and 1.0 wt % sulfur), and high sulfur (greater than 1.0 wt % sulfur). Subgrades of light (less than 15 percent 1050°F+ residuum) and heavy

TABLE 8

Refining Capacity Distribution
by Process Complexity Factor
as of January 1, 1979
(Capacities aggregated in MB/D, with
Number of Reporting Refineries in Parentheses)

Size	Under 3	3-5	5-7	7-9	9-11	Over 11	Total
0- 10	264 (48)	43 (7)	0	*	0	*	327 (57)
10- 30	636 (34)	*	245 (12)	*	0	0	1,193 (60)
30- 50	*	493 (12)	356 (8)	217 (5)	*	*	1,454 (34)
50-100	*	*	1,041 (16)	963 (13)	233 (3)	316 (4)	2,931 (41)
100-175	0	*	1,071 (8)	1,107 (8)	688 (6)	*	3,605 (28)
175 & Larger	0	*	2,668 (7)	3,603 (13)	*	*	7,367 (24)
Total	1,308 (90)	1,458 (37)	5,380 (51)	5,959 (42)	1,487 (13)	1,285 (11)	16,878 (244)

*Data withheld to protect confidentiality. Data included in total.

TABLE 9

Refining Capacity Distribution
by Process Complexity Factor and Geographic Area
as of January 1, 1979
(Capacities Aggregated in MB/D, with
Number of Reporting Refineries in Parentheses)

Geographic Area (PAD)	Under 3	3-5	5-7	7-9	9-11	Over 11	Total
I	125 (11)	*	826 (6)	669 (6)	*	*	1,871 (28)
II	99 (13)	386 (9)	1,487 (21)	1,702 (14)	*	*	4,135 (62)
III	440 (35)	738 (12)	2,171 (12)	2,732 (16)	660 (4)	570 (4)	7,317 (83)
IV	103 (6)	175 (9)	206 (7)	*	*	*	564 (24)
V	541 (25)	*	690 (5)	*	358 (4)	448 (4)	2,990 (47)
Total	1,308 (90)	1,478 (37)	5,380 (51)	5,959 (42)	1,487 (13)	1,285 (11)	16,878 (244)

*Data withheld to protect confidentiality. Data included in total.

TABLE 10

Crude Oil and Other Feedstock Slates
Actual Calendar 1978
(MB/D)

Feedstocks†	Refinery Size Category (MB/D)						
	0-10	10-30	30-50	50-100	100-175	175 & Larger	Total
Sweet Crude Oil	117	528	718	1,743	1,726	3,052	7,883
Percentage Sweet Crude§	51.3	58.4	57.7	65.5	54.3	48.0	54.1
Medium Sulfur Crude Oil							
Light Medium Sulfur	20	52	162	209	139	253	834
Heavy Medium Sulfur	¶	100	50	175	302	538	1,164
High Sulfur Crude Oil							
Light High Sulfur	25	36	60	358	296	1,716	2,491
Heavy High Sulfur	66	188	254	177	716	796	2,196
Total Crude Oil	228	904	1,244	2,662	3,179	6,355	14,568
Field Condensate	21	18	15	*	*	23	87
Other Feedstocks	23	65	79	373**	206**	540	1,374
Total Crude Oil, Field Condensate, and Other Feedstocks	271	987	1,336	3,070	3,448	6,917	16,029

*Data withheld to protect confidentiality. Data included in total.
†Description of Feedstocks:
Sweet: Under 0.5 wt % sulfur
Medium Sulfur: Between 0.5 and 1.0 wt % sulfur
Light Medium: 15% or less @ 1050°F+ residuum assay
Heavy Medium: Greater than 15% @ 1050°F+ residuum assay
High Sulfur: In excess of 1.0 wt % sulfur
Light High: 15% or less @ 1050°F+ residuum assay
Heavy High: Greater than 15% @ 1050°F+ residuum assay
Other Feedstocks: Natural gasoline, butane, reduced crudes, naphtha, etc.
§Percentage of total crude oil exclusive of condensate and other feedstocks.
¶Reported with light medium sulfur crude oil to protect confidentiality.
**In the feedstock category, in refinery sizes 50-100 and 100-175, the numbers 373 and 206 are understated due to confidentiality.

(greater than 15 percent 1050°F+ residuum) are shown for the higher sulfur crude oils. For all respondents combined, sweet crude oils represented 54 percent, medium sulfur oils represented 14 percent, and high sulfur oils represented 32 percent of total runs.

Table 11 restates in percentages the crude oil and other field condensate data from Table 10. The data illustrate the average percentage of each type of feedstock by refinery size. The large percentage of heavy high sulfur crude oil in refineries of less than 30 MB/D, and particularly in those of less than 10 MB/D, is associated with asphalt production.

With respect to geographic area, Table 12 shows quantities of the various crude oil grades processed in all PAD districts. Generally, crude oil slates in PAD V contained substantially larger percentages of medium and high sulfur crude oil than those of other PAD districts.

FUTURE CRUDE OIL SLATES

Companies anticipate that it will be necessary to process increasingly greater quantities of higher sulfur crude oils in 1980 and 1982. Table 13 shows these projections, apparently reflecting declining sweet crude oil availability as well as expansion of overall crude oil throughputs. While total medium and high sulfur crude oil throughputs increase by 28 percent from 1978 to 1982, only 36 percent of this increase is in the heavy medium and heavy high sulfur grades which may reflect limited economic markets for high sulfur residuum and limited residual conversion process capacities.

The percentage of medium and high sulfur crude oils in PADs III and V are anticipated to increase significantly by 1982 as shown in Table 14.

TABLE 11

Percentage Distribution of
Crude Oil and Field Condensate Slates
Actual Calendar 1978

	Refinery Size Category (MB/D)						
Types of Feedstock	0-10	10-30	30-50	50-100	100-175	175 & Larger	All Respondent Refineries
Sweet Crude Oil§	47.0%	57.3%	57.0%	65.5%	54.2%	47.9%	53.8%
Medium Sulfur Crude Oil							
Light Medium Sulfur	8.0	5.6	12.9	7.9	4.4	4.0	5.7
Heavy Medium Sulfur	†	10.9	4.0	6.6	9.5	8.4	7.9
High Sulfur Crude Oil							
Light High Sulfur	10.0	3.9	4.8	13.5	9.3	26.9	17.0
Heavy High Sulfur	26.5	20.4	20.2	6.7	22.5	12.5	15.0
Field Condensate	8.4	2.0	1.2	*	*	0.4	0.6
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

*Data withheld to protect confidentiality.
†Reported with light medium sulfur crude oil to protect confidentiality.
§Percentage of crude charge and field condensate.

TABLE 12

Geographic Distribution of Crude Oil,
Field Condensate, and other Feedstock Slates in 1978
(MB/D)

	Refinery Location					
	PAD I	PAD II	PAD III	PAD IV	PAD V	Total
Sweet Crude Oil	883	2,388	3,610	258	744	7,883
Percentage Sweet Crude†	(50.6)	(63.1)	(57.2)	(53.6)	(31.9)	(53.8)
Medium Sulfur Crude Oil						
Light Medium Sulfur	37	231	346	84	136	834
Heavy Medium Sulfur	101	75	167	0	822	1,164
High Sulfur Crude Oil						
Light High Sulfur	308	587	1,543	*	53	2,491
Heavy High Sulfur	416	488	587	125	579	2,196
Total Crude Oil	1,745	3,769	6,254	467	2,334	14,568
Field Condensate	Nil	15	58	14	*	87
Other Feedstocks	137	270	746	26	195	1,374
Total Crude Oil, Field Condensate and Other Feedstocks	1,882	4,054	7,058	507	2,529	16,029

*Reclassified to protect confidentiality.
†Percentage of crude charge and field condensate.

TABLE 13

Crude Oil and Other Feedstock Slates
Actual Calendar 1978 and Projected 1980 and 1982

	1978		1980		1982	
Type of Feedstock	MB/D	Percentage*	MB/D	Percentage*	MB/D	Percentage*
Sweet Crude Oil	7,883	53.8	8,003	50.5	8,091	48.3
Medium Sulfur Crude Oil						
Light Medium Sulfur	834	5.7	838	5.3	937	5.6
Heavy Medium Sulfur	1,164	7.9	1,382	8.7	1,462	8.7
High Sulfur Crude Oil						
Light High Sulfur	2,491	17.0	3,192	20.1	3,572	21.3
Heavy High Sulfur	2,196	15.0	2,331	14.7	2,568	15.3
Total Crude Oil	14,568		15,747		16,630	
Field Condensate	87	0.6	115	0.7	110	0.7
		100.0		100.0		100.0
Other Feedstocks	1,374		1,320		1,244	
Total Crude Oil, Field Condensate & Other Feedstocks	16,029		17,182		17,984	

*Percentages included only crude oil and condensate.

TABLE 14

Geographic Distribution
of Crude Oil and Other Feedstock Slates in 1982
(MB/D)

	Refinery Location					
	PAD I	PAD II	PAD III	PAD IV	PAD V	Total
Sweet Crude Oil	944	2,534	3,652	273	687	8,091
Percentage Sweet Crude§	(49.2%)	(61.2%)	(49.5%)	(51.5%)	(24.8%)	(48.3%)
Medium Sulfur Crude Oil						
Light Medium Sulfur	50	187	386	96	219	937
Heavy Medium Sulfur	*	176	270	0	1,016	1,462
High Sulfur Crude Oil						
Light High Sulfur	481	762	2,288	†	41	3,572
Heavy High Sulfur	443	474	698	152	802	2,568
Total Crude Oil	1,918	4,133	7,294	521	2,765	16,630
Field Condensate	Nil	10	91	9	Nil	110
Other Feedstocks	105	220	715	29	177	1,244
Total Crude Oil, Field Condensate, and Other Feedstocks	2,023	4,363	8,099	559	2,942	17,984

*Reported with light medium sulfur crude oil to protect confidentiality.
†Reported with heavy high sulfur crude oil to protect confidentiality.
§Percentage of crude charge and field condensate.

PRODUCT YIELDS

Product slates for 1978 are shown aggregated by refinery size in Table 15 which illustrates the generally greater capability of refineries of 50 MB/D and greater capacity to yield more gasoline, other light fuels and specialty products. Table 16 depicts how 1978 product slates varied by geographic area. Trends in product slates over the 1978-1982 period are shown in Table 17.

Gasoline production increases from 7,237 MB/D in 1978 to 7,588 MB/D in 1980 and then to 7,846 MB/D in 1982. However, percentage yields of gasoline decline during this period as crude oil slates become heavier and higher in sulfur and as process severities are increased to meet growing demands for unleaded gasoline and achieve compliance with lead phasedown regulations. Table 18 shows the geographic distribution of the gasoline production trend.

Respondents reported significant growth trends in yields of kerosine-based jet fuel and feedstocks sold to others.

SUBSTITUTION OF HIGHER SULFUR CRUDE OIL

The capability to substitute higher sulfur crude oils in refinery slates in 1980 under known environmental restraints is summarized by geographic area in Table 19. Medium and high sulfur crude oil refining capacity presently not fully utilized is greatest in PAD III and least in PAD V. The table shows that, for the 50 states and Guam, 634 MB/D of light high sulfur or 397 MB/D of heavy high sulfur could be substituted for sweet crude which would reduce the sweet crude 717 and 566 MB/D, respectively. This illustrates that losses in refining capacity result when high sulfur crude oil is substituted for sweet crude oil.

TABLE 15

Product Slates
Actual Calendar 1978
(MB/D)

	Refinery Size Category (MB/D)						
	0-10	10-30	30-50	50-100	100-175	175 & Larger	Total
Motor Gasoline (All Grades)	49	332	561	1,501	1,742	3,051	7,237
Jet Fuel							
Naphtha Base	20	40	41	20	56	44	222
Kerosine Base	0	9	48	105	144	484	789
Kerosine and No. 1 Heating Oil	3	13	39	50	59	98	262
Diesel	29	106	123	164	300	320	1,043
Distillate No. 2	19	98	141	460	363	860	1,940
Heavy Fuel Oils (#4,#5,#6, et al.)	68	179	154	237	233	752	1,623
Asphalt	24	69	62	59	86	153	453
Finished Lubricants	17	*	*	18	34	120	196
Coke (M Short Tons/Day)	0	1	2	7	13	17	39
BTX	0	*	*	15	29	65	115
Refinery Fuel Produced (Include Refinery Coke)	6	37	67	171	225	365	870
Feedstocks Sold	14	30	27	95	58	384	608
Other (except Sulfur, Wax)	11	71	74	215	172	328	872
Total (except Coke, Sulfur, Wax)	260	988	1,346	3,110	3,502	7,023	16,228

*Data withheld due to confidentiality. Data included in total.

TABLE 16

Geographic Distribution of Product Slates in 1978

	PAD I	PAD II	PAD III	PAD IV	PAD V	Total
Motor Gasoline (All Grades)	797	2,161	2,996	244	1,039	7,237
Jet Fuels	67	178	475	26	266	1,011
Middle Distillates	463	909	1,421	121	329	3,244
Heavy Fuel Oils	218	195	700	24	487	1,623
Asphalt	94	167	103	29	60	453
Feedstocks Sold	27	45	480	18	37	608
Other (except Coke, Sulfur, Wax)	127	196	649	14	196	1,182
Refinery Fuel Produced	120	258	312	32	148	870
Total (except Coke, Sulfur, Wax)	1,913	4,109	7,135	509	2,563	16,228

TABLE 17

Product Slates Actual Calendar 1978 and Projected 1980 and 1982

	1978		1980		1982	
	MB/D	Percentage of Feedstock	MB/D	Percentage of Feedstock	MB/D	Percentage of Feedstock
Motor Gasoline (All Grades)	7,237	45.1	7,588	44.2	7,846	43.6
Jet Fuels	1,011	6.3	1,139	6.6	1,207	6.7
Middle Distillates	3,245	20.2	3,388	19.7	3,499	19.5
Heavy Fuel Oils	1,623	10.1	1,676	9.8	1,843	10.2
Asphalt	453	2.8	465	2.7	488	2.7
Feedstocks Sold	608	3.8	801	4.7	928	5.2
Other (except Coke, Sulfur, Wax)	1,182	7.4	1,315	7.7	1,345	7.5
Refinery Fuel Produced	870	5.4	970	5.6	1,018	5.7
Total (except Coke, Sulfur, Wax)	16,229	101.1	17,343	101.0	18,174	101.1
Total Crude Oil, Field Condensate, and Other Feedstocks	16,029	100.0	17,182	100.0	17,984	100.0

TABLE 18

Geographic Distribution of Gasoline Production
(Aggregate MB/D)

Refinery Location	Actual 1978	Projected 1980	Projected 1982
PAD I	797	784	812
PAD II	2,161	2,258	2,270
PAD III	2,996	3,194	3,359
PAD IV	244	263	277
PAD V	1,039	1,090	1,128
Total	7,237	7,588	7,846

TABLE 19

Capability to Substitue Crude Oils of Greater than
0.5 Wt % Sulfur Content for Sweet Crude Oils
Under Known Environmental Constraints (1980)*
(Aggregate MB/D)

	Refinery Location					
	PAD I	PAD II	PAD III	PAD IV	PAD V	Total
Medium Sulfur Crude Oil						
Light Medium Sulfur Substituted	171	183	418	112	84	968
Sweet Crude Backed Out	171	192	447	117	84	1,010
Net Reduction in Crude Capability	0	9	29	5	0	43
Heavy Medium Sulfur Substituted	165	77	266	19	63	590
Sweet Crude Backed Out	171	105	320	25	70	691
Net Reduction in Crude Capability	6	28	54	6	7	101
High Sulfur Crude Oil						
Light High Sulfur Substituted	155	78	301	45	55	634
Sweet Crude Backed Out	155	115	339	51	57	717
Net Reduction in Crude Capability	0	37	38	6	2	83
Heavy High Sulfur Substituted	71	50	208	25	43	397
Sweet Crude Backed Out	134	87	258	34	53	566
Net Reduction in Crude Capability	63	37	50	9	10	169

*Figures by grade of crude oil substituted are not additive.

It is evident from Table 20 that the greatest physical obstacles to substituting additional higher sulfur oils are environmental considerations (sulfur in products, and air emissions and sulfur emissions from refinery fuel) and metallurgy. Temporary suspension of environmental constraints would enable refineries to substitute four times as much crude oil (Table 21) as possible under known environmental constraints (Table 19).

UNLEADED GASOLINE CAPABILITY

Although the capability to produce unleaded gasoline is constantly increasing, it is affected significantly by the octane number required for the unleaded product. This is illustrated both in Table 22 and Figure 2, which show the maximum capability to produce specific grades of unleaded gasoline. The number of refineries that can produce gasoline of an octane number of 90 (R+M)/2 is only

TABLE 20

Major Constraints on the Ability to Substitute High Sulfur Crude Oil (1978)

Constraints	Number of Refineries	Related 1978 Crude* Oil Capacity (MB/D)
Sulfur Content of Products	166	12,823
Air Emissions at Refinery	117	9,478
Sulfur Content of Refinery Fuel	104	8,085
Metallurgy	78	6,933
Effluent Water Quality	34	941
Total Refineries Reporting One or More Constraints	204	15,927
Total Refineries Not Reporting Constraints	42	951

*Capacities are not additive.

TABLE 21

Capability to Substitute Crude Oils of Greater than
0.5 Wt % Sulfur Content for Sweet Crude Oils
Under Suspension of Environmental Constraints (1980)*
(Aggregate MB/D)

	Refinery Location					
	PAD I	PAD II	PAD III	PAD IV	PAD V	Total
Medium Sulfur Crude Oil						
Light Medium Sulfur Substituted	634	838	1,230	155	325	3,182
Sweet Crude Backed Out	655	846	1,244	159	325	3,230
Net Reduction in Crude Capability	21	8	14	4	0	48
Heavy Medium Sulfur Substituted	568	533	758	38	329	2,226
Sweet Crude Backed Out	645	662	864	42	348	2,560
Net Reduction in Crude Capability	77	129	106	4	19	334
High Sulfur Crude Oil						
Light High Sulfur Substituted	591	602	808	92	246	2,339
Sweet Crude Backed Out	643	634	831	101	252	2,461
Net Reduction in Crude Capability	52	32	23	9	6	122
Heavy High Sulfur Substituted	476	383	569	50	291	1,769
Sweet Crude Backed Out	570	525	691	62	296	2,144
Net Reduction in Crude Capability	94	142	122	12	5	375

*Figures by grade of crude oil substituted are not additive.

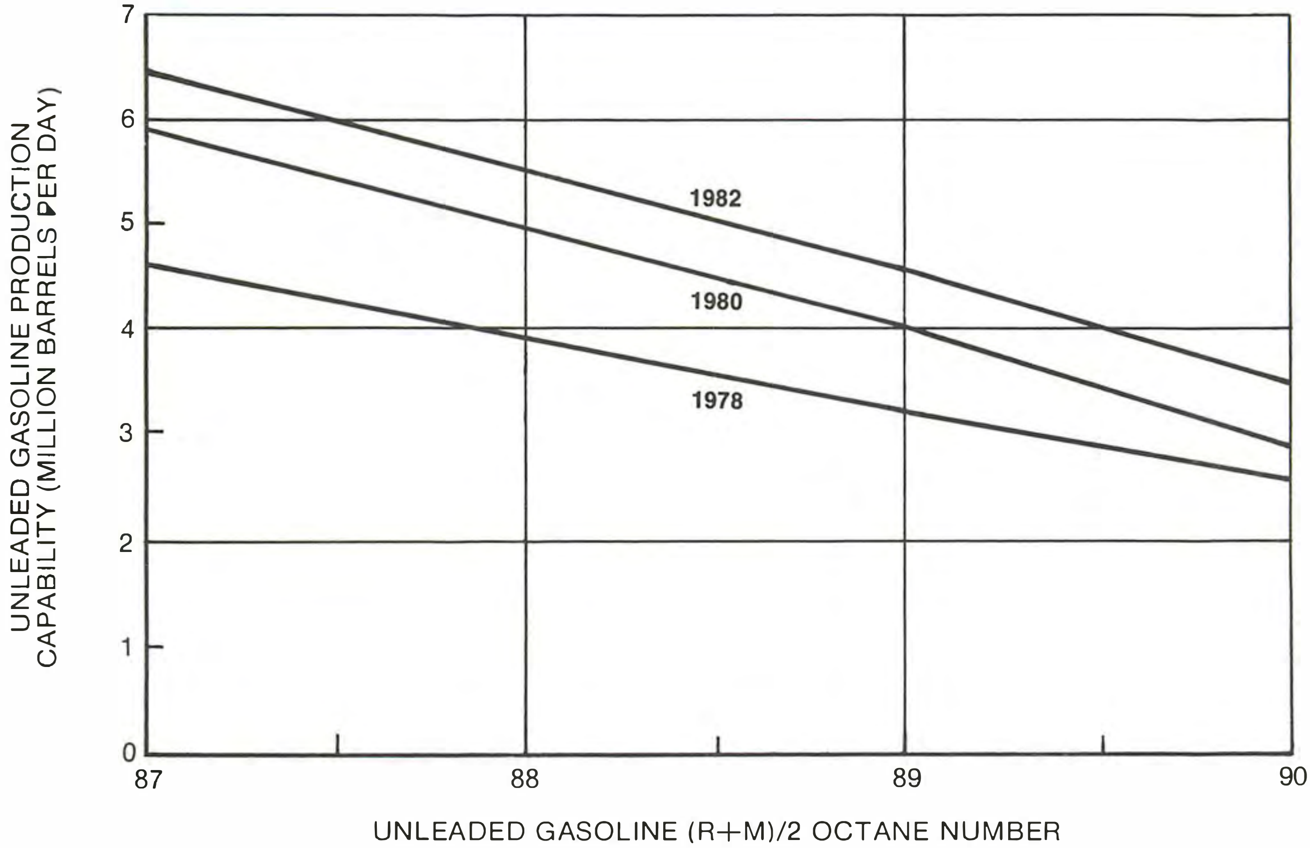


Figure 2. Unleaded Gasoline Manufacturing Capabilities for All U.S. Refineries.

TABLE 22

Unleaded Gasoline Manufacturing Capabilities at Uniform R+M/2 Octane Numbers for all Responding Refineries
(Aggregate MB/D)

	87 (R+M)/2*		89 (R+M)/2*		90 (R+M)/2*	
	MB/D Maximum Unleaded Gasoline	Number of Refineries Reporting Capability	MB/D Maximum Unleaded Gasoline	Number of Refineries Reporting Capability	MB/D Maximum Unleaded Gasoline	Number of Refineries Reporting Capability
1978	4,615	169	3,195	124	2,573	113
1980	5,927	178	4,018	138	2,886	119
1982	6,484	183	4,560	141	3,464	122

*Maximum at indicated octane number.

two-thirds of the total that can produce 87 (R+M)/2 gasoline. The quantity of 90 (R+M)/2 gasoline that can be produced is approximately 60 to 65 percent of the amount for 87 (R+M)/2 gasoline.

Table 23 shows the total unleaded gasoline capability when maximizing a particular grade. In this tabulation the refineries unable to manufacture the grade maximized are assumed to produce the highest octane unleaded gasoline possible given their capabilities. As the table illustrates, however, those refineries which cannot make the higher octane unleaded grades will increase the total production by less than 20 percent. These data are displayed in Figure 3 which also shows the composite octane number of the unleaded gasoline pool.

It should be understood that because the basis for the data in Table 23 did not restrict the refineries to making a prescribed ratio of unleaded to leaded gasoline, the data cannot be used to imply that the higher volumes of leaded gasoline resulting from increasing unleaded gasoline octane number are marketable. Furthermore, it appears that most refineries answered this survey question assuming that total gasoline volume would be kept constant. Different volume estimates would undoubtedly result if total gasoline volumes were allowed to decrease and/or if the ratio of unleaded to leaded gasoline were fixed.

The total (unleaded and leaded) gasoline production capability as a function of octane number of unleaded grade maximized is shown for the three survey years in Table 24.

Table 25 characterizes the leaded gasoline associated with maximizing unleaded gasoline by specific (R+M)/2 octane numbers. The research octane numbers ranged from 92.9 to 93.4. The lead content in 1978 was 2.3 grams/gallon; in 1980 and 1982 the lead content of the leaded gasoline was reduced to a range of 0.9-1.7 grams/gallon, and in total gasoline that reduced to a maximum of 0.5 grams/gallon.

TABLE 23

Unleaded Gasoline Manufacturing Capabilities
For Specific Octane Numbers

Unleaded Gasoline Octane Number (R+M)/2	1978		1980		1982	
	MB/D	Octane No. Unleaded Pool	MB/D	Octane No. Unleaded Pool	MB/D	Octane No. Unleaded Pool
87	4,615	87.0	5,927	87.0	6,484	87.0
89	3,195		4,018		4,560	
87*	320		317		376	
Total	3,515	88.8	4,335	88.9	4,936	88.8
90	2,573		2,886		3,464	
89*	80		255		285	
87*	320		317		376	
Total	2,973	89.6	3,458	89.7	4,125	89.7

*Capabilities of refineries operating at maximum possible octane number, which is lower than the desired level.

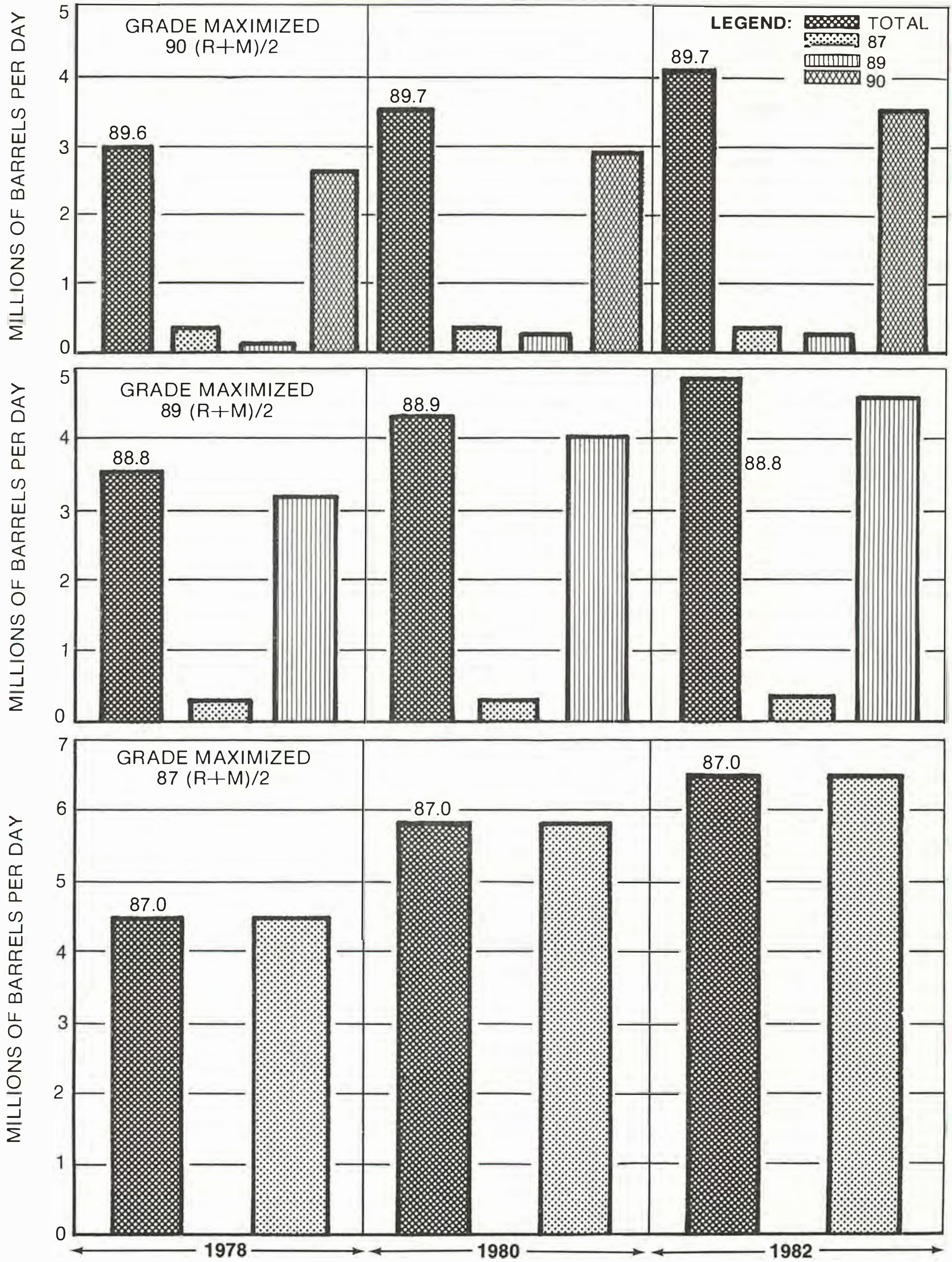


Figure 3. Unleaded Gasoline Manufacturing Capabilities—Millions of Barrels per Day.

TABLE 24

Estimated Total Gasoline Production
Associated with Maximizing Certain Grades
of Unleaded Gasoline
(MB/D)

Unleaded Gasoline Octane Number Being Maximized (R+M)/2	Gasoline Type	1978	1980	1982
87	Unleaded-87	4,615	5,927	6,484
	Leaded-Balance*	2,613	1,659	1,383
	Leaded-Others†	37	20	22
	Total	7,265	7,606	7,889
89	Unleaded-89 & 87	3,515	4,335	4,936
	Leaded-Balance*	3,678	3,159	2,829
	Leaded-Others†	37	20	22
	Total	7,230	7,514	7,787
90	Unleaded-90, 89 & 87	2,973	3,458	4,125
	Leaded-Balance*	4,203	4,004	3,605
	Leaded-Others†	37	20	22
	Total	7,213	7,482	7,752

*Refineries producing both unleaded and leaded gasoline.
†100 percent leaded gasoline refineries.

TABLE 25

Characteristics of Leaded Gasoline Pool*
Associated with Maximization of Certain Grades
of Unleaded Gasoline

		Leaded Gasoline		Pool
Year	Unleaded Gasoline (R+M)/2	Research Octane Number (RON)	Lead Content (gm/gal)	Lead Content (gm/gal)
1978	87	93.4	2.3	0.8
	89	93.3	2.3	1.1
	90	93.4	2.3	1.3
1980	87	93.0	1.5	0.3
	89	93.0	1.1	0.5
	90	93.0	0.9	0.5
1982	87	92.9	1.7	0.3
	89	92.9	1.3	0.5
	90	92.9	1.0	0.5

*Excluding product manufactured by facilities unable to make 87(R+M)/2 unleaded gasoline.

Figures 4 and 5 and Table 26 provide indications of the relatively poorer capability of smaller refineries to produce unleaded gasoline, especially at the higher octane numbers. In addition, a total of 63 refineries indicate no capability to manufacture unleaded gasoline of 87 (R+M)/2 or higher octane number as of 1982. Most of the refineries which do not plan to produce unleaded gasoline are of 30 MB/D or smaller capacity range.

Table 27 shows the maximum unleaded gasoline manufacturing capability at specified octane number specifications as a percentage of total gasoline for each of the PAD districts. Refineries in PAD IV report lower capabilities to manufacture unleaded grade gasoline relative to their total gasoline pools.

TABLE 26

Unleaded Gasoline Manufacturing Capabilities
at Uniform R+M/2 Octane Numbers
Related to Refinery Size Categories

Year	Refinery Size Category, MB/D	@87 (R+M)/2	@89* (R+M)/2	@90* (R+M)/2	Total Gasoline MB/D
1980	0-10	36.5	7.4	1.6	62
	10-30	48.7	25.1	16.1	323
	30-50	69.7	47.6	40.6	598
	50-100	74.5	50.2	31.9	1,643
	100-175	78.0	47.2	33.8	1,748
	175 & Larger	85.3	62.1	45.9	3,215
					7,588
	Average Percentage	78.1	53.0	38.0	
1982	0-10	47.4	9.2	1.8	62
	10-30	53.3	23.8	16.8	353
	30-50	74.5	51.0	43.8	620
	50-100	82.6	59.0	42.2	1,582
	100-175	82.4	53.2	40.7	1,829
	175 & Larger	87.9	66.1	50.5	3,401
					7,846
	Average Percentage	82.6	58.1	44.1	

*Does not include production of unleaded gasoline manufacturers unable to reach the specified R+M/2.

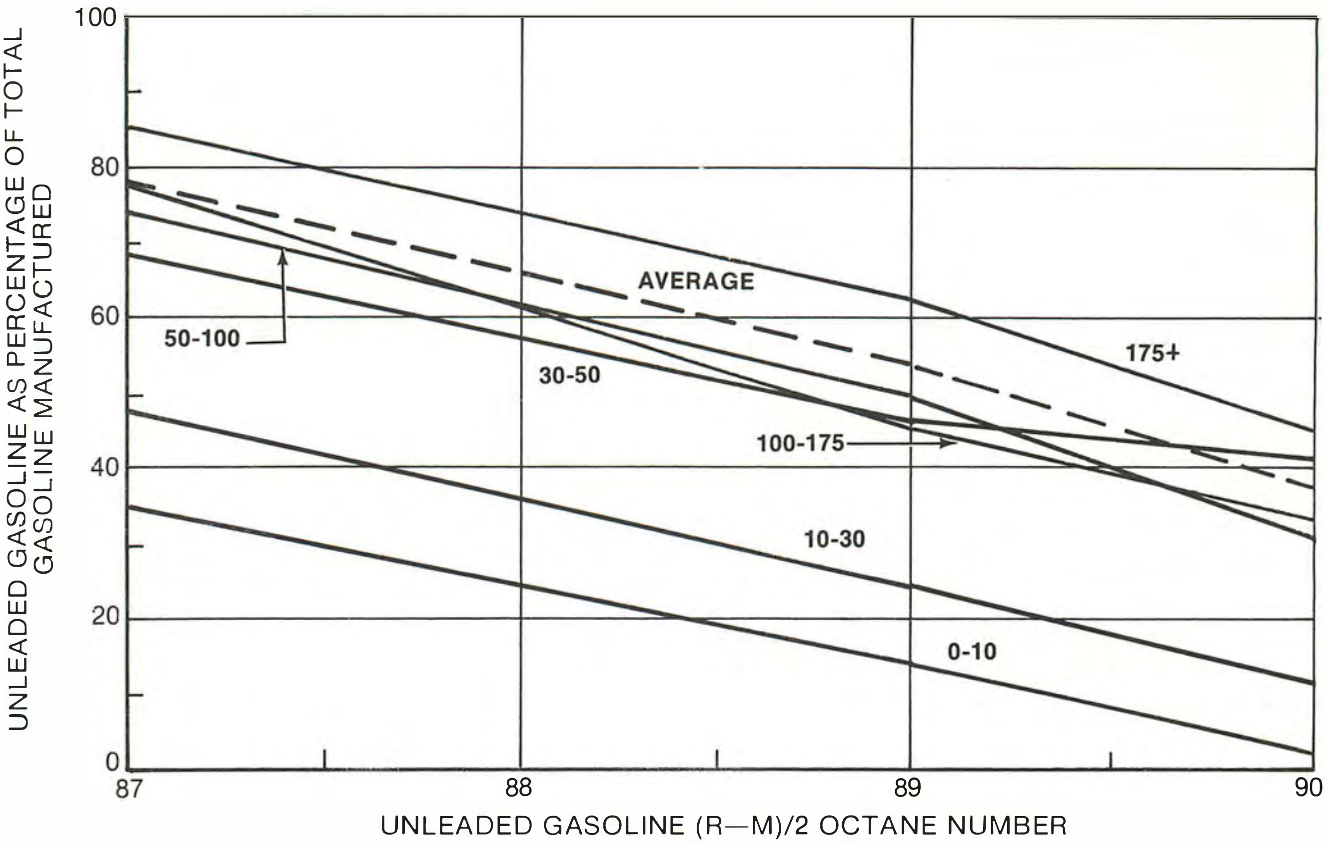


Figure 4. Effect of Increased (R+M)/2 Octane Number on Percentage of Unleaded Gasoline Manufactured—1980 Total U.S. and by Refinery Size.

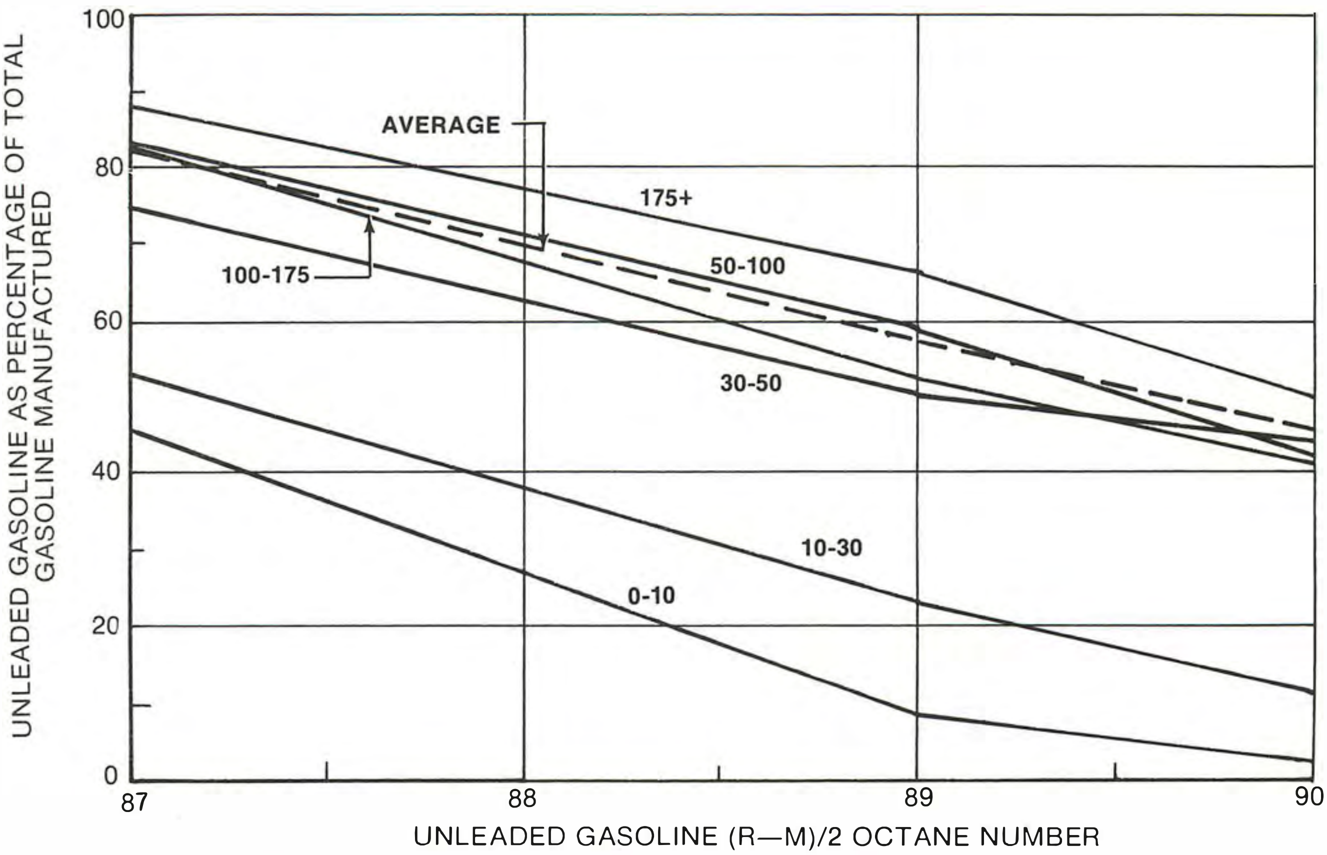


Figure 5. Effect of Increased (R+M)/2 Octane Number on Percentage of Unleaded Gasoline Manufactured—1982 Total U.S. and by Refinery Size.

TABLE 27

Geographic Distribution of Unleaded Gasoline Capabilities
at Uniform R+M/2 Octane Numbers

Year	Geographic Area	Maximum Percentage Unleaded Gasoline @87 (R+M)/2	@89* (R+M)/2	@90* (R+M)/2	Total Gasoline MB/D
1980	PAD I	86.2	52.8	35.2	784
	PAD II	77.0	41.4	23.9	2,258
	PAD III	77.5	59.7	46.8	3,194
	PAD IV	60.9	41.8	32.6	263
	PAD V	80.4	59.8	44.9	1,090
					7,588
	Average Percentage	77.8	52.9	38.0	
1982	PAD I	88.0	57.3	39.7	812
	PAD II	81.8	46.0	30.9	2,270
	PAD III	83.0	65.1	51.1	3,359
	PAD IV	64.7	36.8	31.7	277
	PAD V	83.6	67.4	56.4	1,128
					7,846
	Average Percentage	82.6	58.1	44.1	

*Does not include production by unleaded gasoline manufacturers unable to reach the specified R+M/2.

LOW SULFUR HEAVY FUEL OIL MANUFACTURING CAPABILITY

The future capability of the industry to manufacture a number of grades of low sulfur heavy fuel oil is presented in Table 28. Refineries in PADs III and V exhibit capability to produce substantial volumes of 0.3 and 0.7 wt % sulfur heavy fuel oil. At sulfur levels of 2.0 wt %, most refineries exhibit a significant production capability. Also reported in this table are the volumes and sulfur contents of the balance of the heavy fuel oil pool, other than low sulfur fuels, for those refineries indicating the capability to manufacture one or more low sulfur grades. Volumes and sulfur contents of those refineries which did not report a capability to produce the low sulfur grades of fuel oil are not included in this table. This applies to a substantial part (over 50 percent in the case of 0.3 wt %) of the residual fuel oil in the product slate projection.

TABLE 28

Low Sulfur Heavy Fuel Oil Manufacturing Capabilities
(Normal Volume of Other Products)
(Aggregated MB/D)

	Refinery Location						Balance of Heavy Fuel Oil	
	PAD I	PAD II	PAD III	PAD IV	PAD V	Total	MB/D	Wt % Sulfur
1980								
Low Sulfur Fuel Oil Grade*								
0.3 wt % Sulfur Maximum	37	7	86	1	266	397	296	1.61
0.7 wt % Sulfur Maximum	124	33	268	3	342	771	200	2.21
2.0 wt % Sulfur Maximum	193	177	498	14	560	1,441	56	2.69
1982								
Low Sulfur Fuel Oil Grade*								
0.3 wt % Sulfur Maximum	37	5	69	1	296	408	329	1.37
0.7 wt % Sulfur Maximum	131	37	310	3	375	856	203	2.03
2.0 wt % Sulfur Maximum	210	183	536	15	567	1,511	79	2.65

*Figures by sulfur content for low sulfur fuel oil are not additive vertically.

The manufacturing capability for heavy fuel oil of less than 2.0 wt % sulfur content as projected for 1982 is 1,511 MB/D. Compared with the 1980 projection of 1,441 MB/D, this is not a significant increase.

As shown in Table 29, low sulfur fuel oil manufacturing could be greatly increased if necessary in the case of a national emergency. This would be accomplished by shifting refinery yield at the expense of light products, but would not entail reducing jet fuel and distillates more than 10 percent. These adjustments would substantially increase the capability to produce low sulfur fuel oil. For example, 0.3 wt % sulfur heavy fuel oil production could increase in 1980 to 828 MB/D when production was maximized. As a result, gasoline production would drop 305 MB/D. The availability of fuel oil would be increased greatly by shifting to higher sulfur levels. By increasing sulfur content from 0.3 to 0.7 wt % sulfur, there would be an increase in production of heavy fuel oil of 692 MB/D, or 83.5 percent.

The reduction in gasoline production under these circumstances indicates that companies would be forced to greatly curtail throughputs and conversion levels for catalytic crackers, hydrocrackers, etc. The volume of gasoline reduction varies with the volume of heavy fuel oil which, in turn, varies with the sulfur level of the fuel oil. For example, to maximize heavy fuel oil production of 2,483 MB/D of 2.0 wt % sulfur in 1980, the gasoline production for the nation would be reduced by 553 MB/D, or 7.3 percent. A similar relationship is observed for 1982 in Table 30.

TABLE 29

1980
Maximum Low Sulfur Heavy Fuel Oil
Manufacturing Capabilities and
Resulting Gasoline Volume Reductions*
(Aggregate MB/D)

Refinery Location	Maximum Volume of Low Sulfur Fuel Oil Grades†					
	0.3 Wt % Sulfur		0.7 Wt % Sulfur		2.0 Wt % Sulfur	
	HFO Production	Gasoline Reduction	HFO Production	Gasoline Reduction	HFO Production	Gasoline Reduction
PAD I						
MB/D	94	¶	213	42	321	42
Percentage§				5.4		5.4
PAD II						
MB/D	120	¶	246	117	480	179
Percentage§				5.2		7.9
PAD III						
MB/D	187	68	529	128	882	182
Percentage§		2.1		4.0		5.7
PAD IV						
MB/D	14	10	23	10	43	23
Percentage§		3.8		3.8		8.7
PAD V						
MB/D	413	133	508	117	757	127
Percentage§		12.2		10.7		11.7
Total PADs I-V						
MB/D	828	305	1,520	413	2,483	553
Percentage§		4.0		5.4		7.3
Balance of Fuel Oil	446		260		70	
Wt % Sulfur in Balance	1.68		2.36		2.93	

*Reduction in jet fuel and distillate not to exceed 10 percent in the event of a national emergency.

†Each of the sulfur grades were maximized separately and are not additive.

§Percentage of gasoline production projected for 1980 in each PAD. See Table 18.

¶Data withheld to protect confidentiality. Data included in total.

TABLE 30

1982
Maximum Low Sulfur Heavy Fuel Oil
Manufacturing Capabilities and
Resulting Gasoline Volume Reductions*
(Aggregate MB/D)

Refinery Location	Maximum Volume of Low Sulfur Fuel Oil Grades†					
	0.3 Wt % Sulfur		0.7 Wt % Sulfur		2.0 Wt % Sulfur	
	HFO Production	Gasoline Reduction	HFO Production	Gasoline Reduction	HFO Production	Gasoline Reduction
PAD I						
MB/D	99	¶	227	42	347	42
Percentage§				5.2		5.2
PAD II						
MB/D	108	¶	246	114	494	184
Percentage§				5.0		8.1
PAD III						
MB/D	175	9	568	161	1,003	223
Percentage§		2.9		4.8		6.6
PAD IV						
MB/D	14	10	24	10	43	23
Percentage§		3.6		3.6		8.3
PAD V						
MB/D	446	138	546	117	772	127
Percentage§		12.2		10.4		11.3
Total PADs I-V						
MB/D	842	339	1,610	444	2,659	599
Percentage§		4.3		5.7		7.6
Balance of Fuel Oil	496		340		103	
Wt % Sulfur in Balance	1.55		2.21		2.86	

*Reduction in jet fuel and distillate not to exceed 10 percent in the event of a national emergency.
†Each of the sulfur grades were maximized separately and are not additive.
§Percentage of gasoline production projected for 1982 in each PAD. See Table 18.
¶Data withheld to protect confidentiality. Data included in total.

CHAPTER TWO

CRUDE OIL COSTS, REFINERY OPERATING COSTS AND ASSETS

Refining companies reported crude oil quality and costs, operating costs, refinery gross fixed assets, and replacement assets.

Crude oil slates for 1978 were defined in terms of volume, quality (sulfur and gravity), DOE regulatory classification (lower tier, upper tier, exempt), and percentage of owned production plus royalty owners' share. Costs for each crude classification on a before-entitlements basis were also reported. The before-entitlements crude costs were adjusted to a net crude cost basis using 1978 DOE factors for the entitlements system and hypothetical scenarios as discussed later.

Respondents reported 1978 total operating costs, including categories for fuel and purchased utilities, depreciation, and all other costs. Fuel consumption per barrel and unit fuel costs were provided included separately in the fuel cost data. Respondents also reported original gross fixed assets for individual refineries as well as replacement costs for those refineries as of January 1, 1979.

Responses represent aggregate capacity of 15,445 MB/D or 89 percent of the total estimated capacity of the 50 states and Guam. Responses to some or all elements of the survey were received from 203 refineries, about 70 percent of U.S. refineries. The attrition in the number of refineries reporting was primarily in refineries with a capacity below 30 MB/D; only half of the plants in this range, representing 60 percent of its capacity, reported Part II data.

Detailed discussions of cost and investment data follow on the basis of company size, location (PAD District), refinery size, and refinery complexity. Complete aggregation of the data is available in Appendix D.

The following discussion of costs is not intended to be a competitive analysis of the domestic refining industry; it is a presentation of refinery cost data aggregated from the survey. 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.

CRUDE OIL COSTS AND QUALITY

Tables 31, 32, 33, and 34 present crude oil costs and quality data for refineries by company size, geographic area, and refinery size and complexity. Respondents were requested to report their actual crude oil data for 1978 by the applicable regulatory classifications (lower tier, upper tier, exempt) with respect to volume, price before entitlements, API gravity, and sulfur content.

Data were obtained from 203 domestic refineries for one or more areas of each section of this part of the survey. Their combined throughput in 1978 was 12,924 MB/D of crude oil, equivalent to 83.7 percent of their associated reported capacity. Of this combined throughput, some 21 percent was lower tier and 19.9 percent was upper tier, yielding a total of 40.8 percent price-controlled oil. The remainder, 59.2 percent, was exempt from price controls, being either stripper, tertiary, Naval Petroleum Reserve production, or imported. Lower tier oil averaged $5.99 per barrel and upper tier averaged $12.67 per barrel, with the weighted average cost for controlled oil at $9.24 per barrel. Exempt oil averaged $14.52 per barrel in delivered costs to the refineries. The composite average crude oil cost to the refineries in the survey was $12.36 per barrel exclusive of entitlement effects.

TABLE 31

1978 Crude Oil Costs and Quality by Company Size

	Company Size (MB/D)							
	0-10	10-30	30-50	50-100	100-175	175+	Total	DOE 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	

TABLE 31 (continued)

	Company Size (MB/D)							
	0-10	10-30	30-50	50-100	100-175	175+	Total	DOE 1978 Data*
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 32

1978 Crude Oil Costs and Quality by Refinery Location

	Refinery Location						
	PAD I	PAD II	PAD III	PAD IV	PAD V	Total	DOE 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 percentage							
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 U.S Refineries, Virgin Islands, Puerto Rico, Guam, Free Trade Zone, and Strategic Petroleum Reserve.

†Entitlements calculated on the hypothetical basis that each refinery, regardless of size, was treated as a separate company.

§Part II respondent total divided by U.S. total for the respective districts.

TABLE 33

1978 Crude Oil Costs and Quality by Refinery Size

	Refinery Size (MB/D)/Complexity													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	Total	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 percentage														
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, percentage	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 U.S. Refineries, Virgin Islands, Puerto Rico, Free Trade Zone, Guam, and Strategic Petroleum Reserve.

†Entitlements calculated on the hypothetical basis that each refinery, regardless of size, was treated as a separate company.

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

¶Part II respondent total divided by U.S. totals for the respective size ranges.

TABLE 34

1978 Crude Oil Costs and Quality by Refinery Complexity

	Complexity							
	1-3	3-5	5-7	7-9	9-11	11+	Total	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 percentage								
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, percentage	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 U.S Refineries, Virgin Islands, Puerto Rico, Free Trade Zone, Guam, and Strategic Petroleum Reserve.

†Entitlements calculated on the hypothetical basis that each refinery, regardless of size, was treated as a separate company.

§Part II respondent totals divided by Part I totals for the respective complexity ranges.

Fewer refineries (163, with a total throughput capacity of 10,455 MB/D of crude oil) provided complete data for all parts of the survey dealing with crude oil costs and quality; their aggregated data are presented in Tables 35, 36, 37, and 38. The composition, quality, and cost of crude oil by regulatory classification (lower tier, upper tier, and exempt) for this smaller group of respondents did not differ markedly from that obtained from the aforementioned 203 refiners who responded to one or more parts of this section.

Crude Oil Cost

Factors affecting crude oil costs included crude oil slate composition classifications (lower tier, upper tier, exempt), quality, location, and entitlements regulations.

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 entitlement program factors for 1978 [domestic oil supply ratio (DOSR), deemed oil oil ratio (DOOR), etc.] were applied to the aggregated data supplied by the respondent refineries to determine the effects of the entitlements and small refiner bias programs on crude oil costs by company size. Table 31 displays the crude oil costs on three bases aggregated in each case by company size range: (1) before entitlements, (2) after entitlements but before small refiner bias, and (3) after entitlements and small refiner bias. This information is also presented in the form of a graph in Figure 6.

Under the Department of Energy program as actually administered in 1978, net crude oil cost ranged from $10.53 per barrel for companies of less than 10 MB/D capacity to a maximum of $12.99 per barrel for companies having system capacities in the range of 50-100 MB/D. Generally, smaller companies experienced lower net crude oil costs. Although Department of Energy programs contributed

TABLE 35

1978 Crude Oil Costs and Quality by Company Size
(Complete Reports Only)*

	Company Size (MB/D)						
	0-10	10-30	30-50	50-100	100-175	175+	Total
Weight Average Complexity	1.51	3.07	4.78	5.68	7.15	7.86	7.15
1978 Throughput, MB/D							
Lower Tier	38	115	44	122	41	1,458	1,816
Upper Tier	46	120	80	177	77	1,314	1,816
Exempt	36	197	190	345	247	4,453	5,468
Total	120	432	314	644	365	7,225	9,100
Volume Percentage							
Lower Tier	31.7	26.6	14.0	18.9	11.2	20.2	20.0
Upper Tier	38.3	27.8	25.5	27.5	21.1	18.2	20.0
Exempt	30.0	45.6	60.5	53.6	67.7	61.6	60.0
Cost, $/Bbl							
Lower Tier	5.95	6.16	5.90	6.02	6.20	6.01	6.02
Upper Tier	12.59	12.37	12.66	13.22	12.86	12.76	12.77
Exempt	13.47	14.64	14.86	15.13	14.76	14.59	14.63
Average Before Entitlements	10.72	11.75	13.06	12.88	13.42	12.52	12.54
After Entitlements (Without Small Refiner Bias)	12.19	12.68	12.87	13.16	12.95	12.75	12.78
After Entitlements (With Small Refiner Bias†)	10.43	11.49	12.22	12.99	13.02	12.88	12.77
API Gravity							
Lower Tier	27.6	30.3	31.9	34.5	35.4	35.4	34.8
Upper Tier	35.4	32.6	43.9	37.9	36.6	36.0	36.3
Exempt	25.4	34.6	36.9	36.7	35.0	34.1	34.4
Average	30.0	32.9	38.0	36.6	35.4	34.7	34.8

TABLE 35 (continued)

	Company Size (MB/D)						
	0-10	10-30	30-50	50-100	100-175	175+	Total
Wt % Sulfur							
Lower Tier	0.73	1.11	0.81	1.13	0.94	0.75	0.80
Upper Tier	0.47	1.02	0.60	0.58	1.05	0.78	0.77
Exempt	1.27	0.72	0.80	0.46	0.92	0.90	0.86
Average	0.79	0.91	0.75	0.62	0.95	0.85	0.83
Crude Charge Capacity, MB/D	168	611	424	740	426	8,062	10,455
Number of Refineries	27	37	11	19	6	63	163
Number of Companies	26	29	11	11	3	15	95

*Data for companies that furnished complete information on crude oil costs and quality.
†Based on company size as actually administered.

TABLE 36

1978 Crude Oil Costs and Quality by Refinery Location
(Complete Reports Only)*

	Refinery Location					
	PAD I	PAD II	PAD III	PAD IV	PAD V	Total
Weight Average Complexity	7.33	7.04	7.35	5.01	7.24	7.15
1978 Throughput, MB/D						
Lower Tier	72	541	875	129	199	1,816
Upper Tier	86	575	916	143	97	1,816
Exempt	1,223	1,187	2,151	96	810	5,468
Total	1,381	2,303	3,942	368	1,106	9,100
Volume percentage						
Lower Tier	5.2	23.5	22.2	35.0	18.0	20.0
Upper Tier	6.2	25.0	23.2	38.9	8.8	20.0
Exempt	88.6	51.5	54.6	26.1	73.2	60.0
Cost, $/barrel						
Lower Tier	6.29	6.20	5.98	6.21	5.52	6.02
Upper Tier	13.02	13.07	12.72	13.06	10.91	12.77
Exempt	14.75	15.15	14.63	15.48	13.62	14.63
Average before Entitlements	14.20	12.53	12.26	11.30	11.92	12.54
After Entitlements (without small refiner bias)	13.00	13.14	12.73	13.09	11.83	12.78
After Entitlements (with small refiner bias†)	13.04	13.08	12.79	12.50	11.64	12.75
API Gravity						
Lower Tier	33.8	36.5	36.1	32.9	26.1	34.8
Upper Tier	35.0	37.4	36.9	35.7	26.3	36.3
Exempt	34.3	36.3	34.9	37.9	29.8	34.4
Average	34.3	36.6	35.6	35.3	28.8	34.8
Wt % Sulfur						
Lower Tier	0.89	0.68	0.73	1.32	1.07	0.80
Upper Tier	0.85	0.65	0.80	0.93	1.01	0.77
Exempt	0.80	0.80	0.93	0.64	0.89	0.86
Average	0.81	0.73	0.86	0.99	0.93	0.83

TABLE 36 (continued)

	Refinery Location					
	PAD I	PAD II	PAD III	PAD IV	PAD V	Total
Crude Charge Capacity, MB/D	1,548	2,574	4,538	450	1,346	10,455
Percentage of Total Capacity§	82.7	61.2	60.0	76.3	43.7	60.4
Number of Refineries	23	43	51	18	28	163

*Data from companies that furnished complete information on crude oil costs and quality.

†Entitlements calculated on the hypothetical basis that each refinery, regardless of size, was treated as a separate company.

§Part II respondent totals divided by U.S. totals for the respective districts.

TABLE 37

1978 Crude Oil Costs and Quality by Refinery Size
(Complete Reports Only)*

	Refinery Size (MB/D)/Complexity												
	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	Total
Weight Average Complexity	1.32	5.18	2.25	1.39	5.11	3.35	1.31	5.98	5.32	7.74	8.82	7.65	7.15
1978 Throughput, MB/D													
Lower Tier	41	5	46	62	92	155	14	205	219	353	256	787	1,816
Upper Tier	46	15	61	70	101	171	24	234	258	334	242	751	1,816
Exempt	42	25	67	141	155	296	74	307	381	1,008	1,153	2,562	5,468
Total	129	45	174	273	348	621	112	746	858	1,695	1,651	4,100	9,100
Volume Percentage													
Lower Tier	31.8	11.1	26.4	22.7	26.4	25.0	12.5	27.5	25.5	20.8	15.5	19.2	20.0
Upper Tier	35.7	33.3	35.1	25.6	29.0	27.5	21.4	31.4	30.0	19.7	14.7	18.3	20.0
Exempt	32.5	55.6	38.5	51.7	44.6	47.7	66.1	41.1	45.5	59.5	69.8	62.5	60.0
Cost, $/Bbl													
Lower Tier	5.88	5.74	5.87	5.64	6.42	6.10	5.92	5.92	5.92	6.11	6.18	5.96	6.02
Upper Tier	12.52	13.20	12.69	11.91	13.03	12.58	12.91	12.85	12.89	12.99	12.72	12.71	12.77
Exempt	13.94	15.67	14.60	14.16	14.82	14.51	14.18	15.17	14.96	14.82	14.43	14.61	14.63
Average before Entitlements	10.87	13.78	11.63	11.65	12.07	11.88	12.88	11.91	12.03	12.78	12.90	12.60	12.54
After Entitlements (without small refiner bias)	12.27	13.55	12.61	12.21	12.99	12.65	12.54	13.15	13.07	12.78	12.69	12.75	12.78
After Entitlements (with small refiner bias†)	10.61	11.86	10.93	11.03	11.97	11.35	11.94	12.50	12.43	12.94	12.82	12.96	12.75
API Gravity													
Lower Tier	25.5	41.2	27.2	23.7	36.4	31.3	33.6	34.2	34.4	36.1	34.8	35.4	34.8
Upper Tier	33.6	40.7	35.3	31.1	37.4	34.9	38.7	38.8	38.7	37.9	36.7	35.1	36.3
Exempt	27.7	37.1	31.3	30.1	36.6	33.5	36.4	36.3	36.3	35.7	32.6	34.5	34.4
Average	29.1	38.7	31.6	28.9	36.8	33.3	37.3	36.5	36.6	36.2	33.6	34.8	34.8
Wt % Sulfur													
Lower Tier	1.11	0.36	1.03	1.45	0.77	1.04	0.19	0.78	0.74	0.73	0.83	0.79	0.80
Upper Tier	0.71	0.19	0.58	0.91	0.83	0.86	0.23	0.69	0.64	0.56	0.87	0.87	0.77
Exempt	1.09	0.27	0.78	1.20	0.70	0.94	0.88	0.66	0.70	0.64	0.96	0.93	0.86
Average	0.96	0.25	0.78	1.18	0.75	0.94	0.65	0.70	0.69	0.64	0.92	0.89	0.83
Crude Charge Capacity, MB/D	1.81	57	238	402	444	846	156	945	1,131	1,800	1,908	4,561	10,455
Percentage of Total Capacity§			53.7			59.0			77.8	58.8	52.9	61.9	60.4
Number of Refineries	30	9	39	21	21	42	4	22	26	26	15	15	163

*Data from refinery companies that reported complete data on crude oil.
†Entitlements calculated on the hypothetical basis that each refinery, regardless of size, was treated as a separate company.
§Part II respondent totals divided by U.S. totals for the respective size ranges.

TABLE 38

1978 Crude Oil Costs and Quality By Refinery Complexity
(Complete Reports Only)*

	Complexity 1-3	3-5	5-7	7-9	9-11	11+	Total
Weight Average Complexity	1.49	4.36	6.16	7.82	9.94	13.54	7.15
Volume, MB/D							
Lower Tier	122	220	518	627	202	128	1,816
Upper Tier	148	307	617	486	138	120	1,816
Exempt	334	475	1,628	1,909	474	647	5,468
Total	604	1,002	2,764	3,022	814	895	9,100
Volume percentage							
Lower Tier	20.2	22.0	18.7	20.7	24.8	14.3	20.0
Upper Tier	24.5	30.7	22.3	16.1	17.0	13.4	20.0
Exempt	55.3	47.3	58.9	63.2	58.2	72.3	60.0
Cost, $/barrel							
Lower Tier	5.80	6.24	6.11	5.98	5.80	6.10	6.02
Upper Tier	12.33	12.87	12.98	12.68	12.44	12.70	12.77
Exempt	14.27	14.78	14.92	14.64	14.35	14.19	14.63
Average before Entitlements	12.07	12.32	12.83	12.53	11.91	12.83	12.54
After Entitlements (without small refiner bias)	13.62	12.17	13.01	12.77	12.49	12.49	12.78
After Entitlements (with small refiner bias[†])	11.45	12.54	13.07	12.89	12.57	12.59	12.75
API Gravity							
Lower Tier	26.9	35.6	34.9	36.5	32.4	36.3	34.8
Upper Tier	34.5	39.8	35.8	36.6	33.3	35.5	36.3
Exempt	32.2	35.7	35.0	34.9	33.2	32.1	34.4
Average	31.4	36.9	35.2	35.5	33.0	33.2	34.8

TABLE 38 (continued)

	Complexity						
	1-3	3-5	5-7	7-9	9-11	11+	Total
Wt % Sulfur							
Lower Tier	1.15	0.74	0.99	0.65	0.84	0.54	0.80
Upper Tier	0.71	0.63	0.92	0.73	0.75	0.67	0.77
Exempt	0.96	0.79	0.90	0.78	0.93	0.98	0.86
Average	0.94	0.73	0.92	0.74	0.88	0.88	0.83
Crude Charge Capacity, MB/D	841	1,258	3,072	3,359	864	1,061	10,455
Percentage of Total Capacity§	69.8	81.3	57.1	56.4	58.1	82.6	60.4
Number of Refineries	60	31	28	26	9	9	163

*Data from companies that furnished complete information on crude oil.

†Entitlements calculated on the hypothetical basis that each refinery, regardless of size, was treated as a separate company.

§Part II respondent total divided by Part I totals for respective complexity factor ranges.

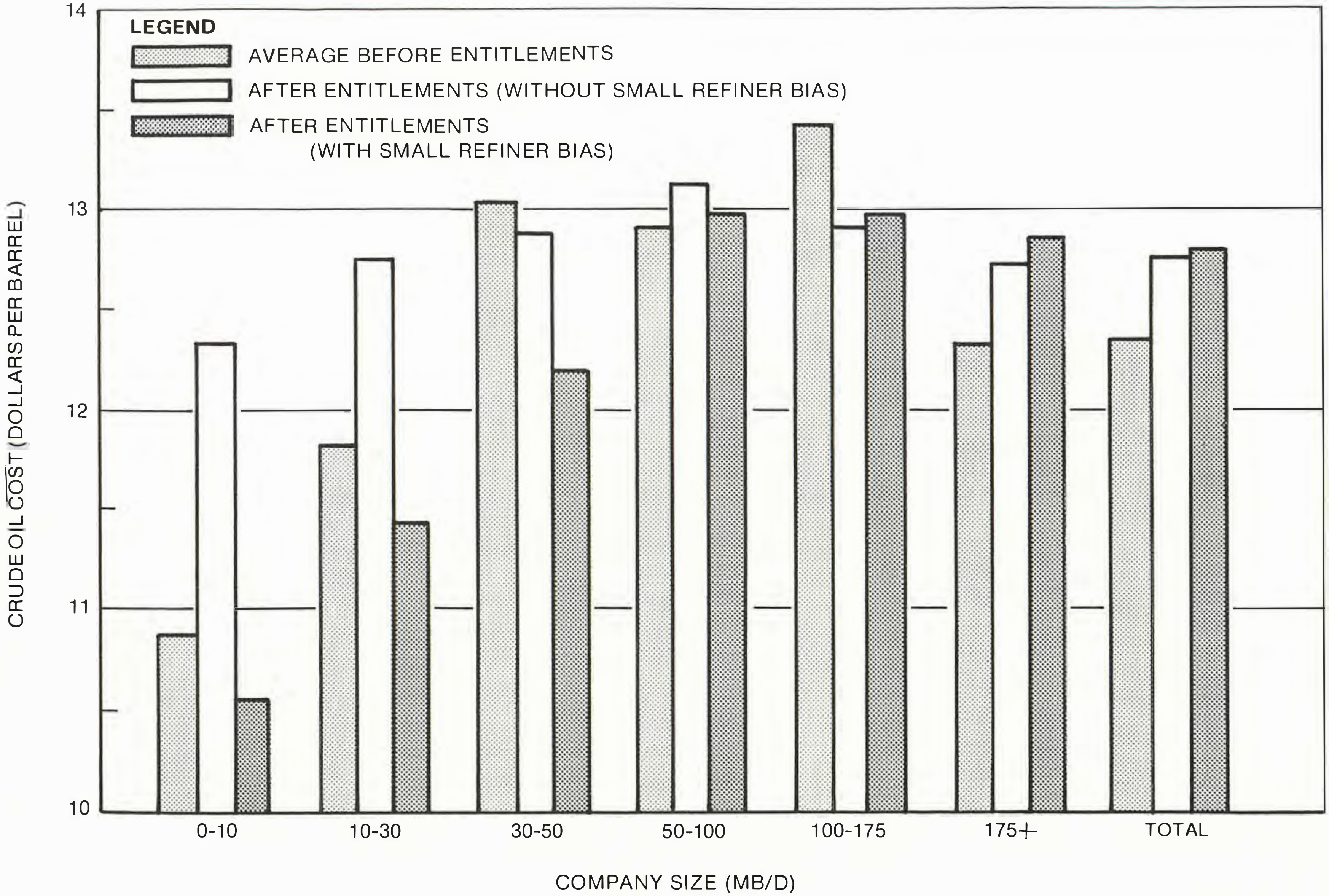


Figure 6. 1978 Crude Oil Costs Aggregated by Company Size.

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.

In the absence of entitlements programs, the respondents' average crude oil costs would have been about $0.35 per barrel lower for 1978. This differential results from entitlements being given for certain imported products and to other non-crude exceptions in the entitlements program.

It should also be noted that, because a number of the smaller companies which benefited from the small refiner bias and exception relief programs were not among respondents to the survey, the total aggregate computed difference for all respondents between the before-entitlements crude oil cost and the after-entitlements and small refiner bias crude oil cost is greater than would have been the case if all U.S. refineries had participated in the survey.

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

Individual Refinery Basis

Although both the entitlements and bias programs are actually administered on a company basis rather than on an individual refinery basis, it is considered meaningful to examine crude oil costs aggregated by location, refinery size, and complexity as documented in Tables 32, 33, and 34 as though these programs were applied on an individual refinery basis. The expected trends of the effects of the entitlements and bias programs with refinery size would be similar to those observed for company size except that the cost spread might be greater between size ranges on the refinery size basis.

The calculation of net crude costs (after entitlements with small refiner bias) for individual refineries is, by definition, hypothetical since 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 purposes of the bias calculation. This includes a number of refineries in the bias credit that did not actually qualify on the company basis, and increases the small refiner bias pool. This larger "credit" pool is offset by higher crude costs for those refineries with capacities greater than 175 MB/D.

The calculation of crude costs for individual refineries on an "after entitlements without small refiner bias" basis uses factors adapted from the entitlements factors applied in the company basis (See Appendix D).

It may be observed from Table 34 that the refineries benefiting most significantly from the bias program are those of less than 3 complexity factor. This is due to the fact that the refineries of less than 3 complexity include no refineries of greater than 100 MB/D, and that 80 percent of the capacity in this complexity category was in refineries of less than 30 MB/D.

With respect to geographic area, Table 32 indicates that PAD I, which refined relatively small quantities of lower tier oil (6.3 percent) and a larger percentage of exempt oil (87.2 percent), experienced a reduction in crude oil costs due to the entitlements program.

Crude Oil Classifications

As previously mentioned, the larger and more complex refineries processed higher cost crude oil slates in 1978. This in part reflects higher percentages of oils in the exempt category in these slates, as shown in Table 33. Certain small refineries also processed substantial percentages of exempt, more costly oils.

With respect to geographic location as reported in Table 32, the eastern and western regions of the country (PADs I and V) refined high percentages of exempt oils, perhaps reflecting historic dependence on imported supply and the influx of Alaskan North Slope oil in PAD V. PAD IV utilized the lowest percentage of exempt 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 PAD V, in which the cost of each classification of oil was below the national average, possibly reflecting quality.

Crude Oil Quality

Fewer refineries (163) reported quality-related information. Complete data for the crude oil section of the survey for these refineries appear in Tables 35, 36, 37, and 38. This smaller group processed 9,100 MB/D in 1978 at a capacity of 10,455 MB/D, or a capacity utilization of 87 percent. For these refineries, there was 20 percent lower tier oil averaging $6.02 per barrel, 20 percent upper tier oil averaging $12.77 per barrel, and 60 percent exempt oil averaging $14.63 per barrel. On the average, exempt crude oils have higher sulfur content and lower API gravity than either upper or lower tier oils.

In general, refineries whose capacities were of less than 30 MB/D with complexities of less than 2.5 processed heavier, higher sulfur grades. Other small refineries (of under 10 MB/D capacity and greater than 2.5 complexity) exhibited the highest percentage of low sulfur, high gravity oils in their slates.

Refineries with capacities of 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.

Own Production and Royalty Owners' Share

One hundred eighty-two refineries having 11,988 MB/D of capacity responded to the survey with data reflecting the amount of crude oil processed which was their own production or royalty owners' share.

On the basis of company size (Table 31), it is apparent that a considerably greater portion of larger refiners' crude oil requirement is available from their own production or royalty owners' share. Companies with capacities of greater than 175 MB/D reported that 44.5 percent of the crude oil throughput was from their own production or royalty owners' share, in contrast to 7.9-11.4 percent for all other company size categories.

These data show that, in general, all refinery categories are quite dependent upon others for crude oil supplies. This degree of dependence ranges from a low of about 48 percent to a high of 100 percent. Refineries in PAD V reported processing the highest percentage of their own or royalty owners' share of crude oil (51.7 percent). Table 33 shows that the larger, more complex refineries have the greatest associated availability of crude for refinery runs that was produced by the refinery operator or was a royalty owners' share.

OPERATING COSTS

Tables 39, 40, 41, and 42 present summaries of 1978 operating costs aggregated by company size, geographic area, refinery size, and complexity. It should be noted that the capacity of refineries in the Hawaiian Trade Zone, Alaska, and Guam is aggregated in the PAD V figures.

In 1978, total operating costs for respondent U.S. domestic refiners, exclusive of crude oil and other raw materials, averaged \$2.29 per barrel of crude oil. Nearly half these costs, \$1.08 per barrel, was for fuel and purchased utilities. Depreciation charges amounted to about \$0.18 per barrel of crude oil, approximately eight percent of total operating costs. Maintenance and other operating costs (payroll, catalysts, administration, etc.) were responsible for \$1.02 per barrel of crude oil refining costs.

Complexity of operation has a substantial effect upon total operating costs. The effects of refinery size and location are much less dramatic.

Table 42 presents survey results for the operating cost categories as aggregated by complexity factor alone, disregarding refinery size or refinery location. Total operating costs for the highest complexity range (greater than 11), representing eight percent of aggregate respondent capacity, were reported to be \$3.13 per barrel, twice that of refineries with a complexity factor of less than three.

With respect to aggregation by refinery size category regardless of complexity (Table 41), total operating costs ranged from \$1.89 to \$2.61 per barrel. The highest average total costs were for those refineries in the 100-175 MB/D capacity range (these also exhibit the highest complexity). Those refineries of less than 10 MB/D and greater than 175 MB/D had nearly the same average operating costs (and were also nearly equal to the respondent average).

TABLE 39

1978 Operating Costs 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							
MM Btu/barrel	0.255	0.389	0.404	0.550	0.505	0.576	0.559
$/MM Btu	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 40

1978 Operating Costs 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						
MM Btu/barrel	0.538	0.557	0.544	0.579	0.616	0.559
$/MM Btu	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	.946	.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

*Part II totals divided by U.S. totals for respective districts.

TABLE 41

1978 Operating Costs by Refinery Size

	Refinery Size (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													
MM Btu/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
$/MM Btu	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

*Part II totals divided by U.S. totals for respective size ranges.

TABLE 42

1978 Operating Costs by Refinery Complexity

	Complexity 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							
MM Btu/barrel	0.267	0.423	0.518	0.581	0.690	0.777	0.559
$/MM Btu	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

*Part II totals divided by Part I totals for respective complexity factor ranges.

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 refinery size categories.

A masking effect occurs when aggregation of operating expenses is made by size range alone, without regard to complexity. In order to reduce this masking effect, Figure 7 has been prepared. However, the masking effect is particularly pronounced in the case of the 175+ refinery because of the very broad range in size represented. Further analysis to reduce the masking effect is planned. This figure distinguishes somewhat the effects of complexity and size on total operating costs (fuel, purchased utilities, depreciation maintenance, etc.). As would be expected, for a given complexity, costs generally decline with increasing refinery size for refineries in the 50 MB/D and smaller size categories. The impact of refinery size upon operating expense is less significant for refineries of greater than 50 MB/D capacity. For a given size range, operating costs increase significantly with complexity.

Table 40 shows that PAD III refineries reported the lowest range of total operating costs, at $2.10 per barrel, while PAD V reported the highest costs, at $2.71 per barrel. 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 (dollars per million BTU) are also a substantial factor in the variation of operating costs among PAD districts.

Total operating costs per barrel generally increased with company size (although this increase was not continuous throughout all size ranges), from a low of $1.35 per barrel to a high of $2.35 per barrel (Table 39). Increasing complexity with increasing company size significantly influenced this trend.

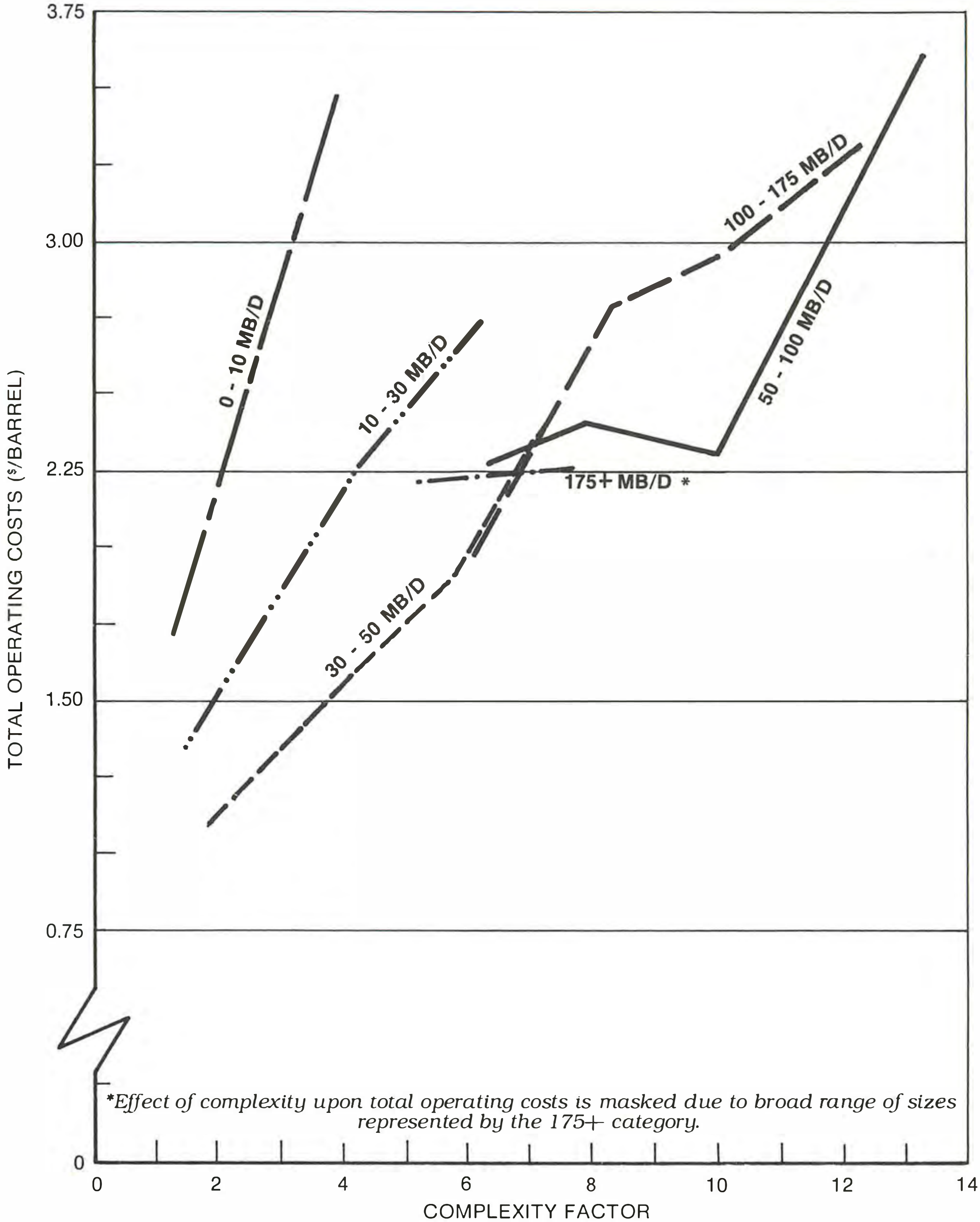


Figure 7. 1978 Total Operating Costs as a Function of Complexity--Aggregated by Refinery Size.

Individual Operating Cost Elements

Fuel and Purchased Utilities

The amount of fuel and purchased utilities required to operate a refinery differs greatly among 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 (six percent of respondent capacity) had fuel and purchased utility consumption averaging about 0.27 million BTU per barrel, less than half of that for the U.S. average. The highest energy consumption, 0.78 million BTU per barrel, 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.

The unit cost of energy, on a dollar-per-million-BTU basis, is not a function of complexity; it ranges from $1.81 to $2.05 per million BTU (Table 43) within the various complexities, while the U.S. average is $1.92 per million BTU. 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 43

1978 Unit Energy Costs
Aggregated by Refinery Size
and Complexity Factor

Refinery Size (MB/D)	Complexity Factor	Weight Average Complexity	Unit Energy Cost ($/MM Btu)
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 8, which presents energy (fuel and purchased utilities) consumption as a function of both refinery complexity and refinery size range. 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 complexity-dependent.

Figure 9 plots energy costs versus refinery complexity within the parameters of refinery size. The "breaks" in the plot of energy costs in Figure 9 for refineries in the 50-100 and 100-175 MB/D size ranges are not due to energy consumption, but rather to the value reported for unit energy cost. This apparent anomaly was not evidenced by Figure 8, which displays energy consumption as a function of complexity and size. Table 43 shows unit energy cost data by refinery size and complexity aggregations.

The unit cost of energy by refinery size category ranges from $1.72 to $2.07 per million BTU. This appears to be due more to geographic location (Table 40) than to refinery size (Table 41). It is not clear from the survey results why these variations occur, but there were apparently fuel gas and oil market price variations between PAD districts. Survey respondents were instructed to value internally produced refinery fuel based upon local incremental purchase/sale fuel prices.

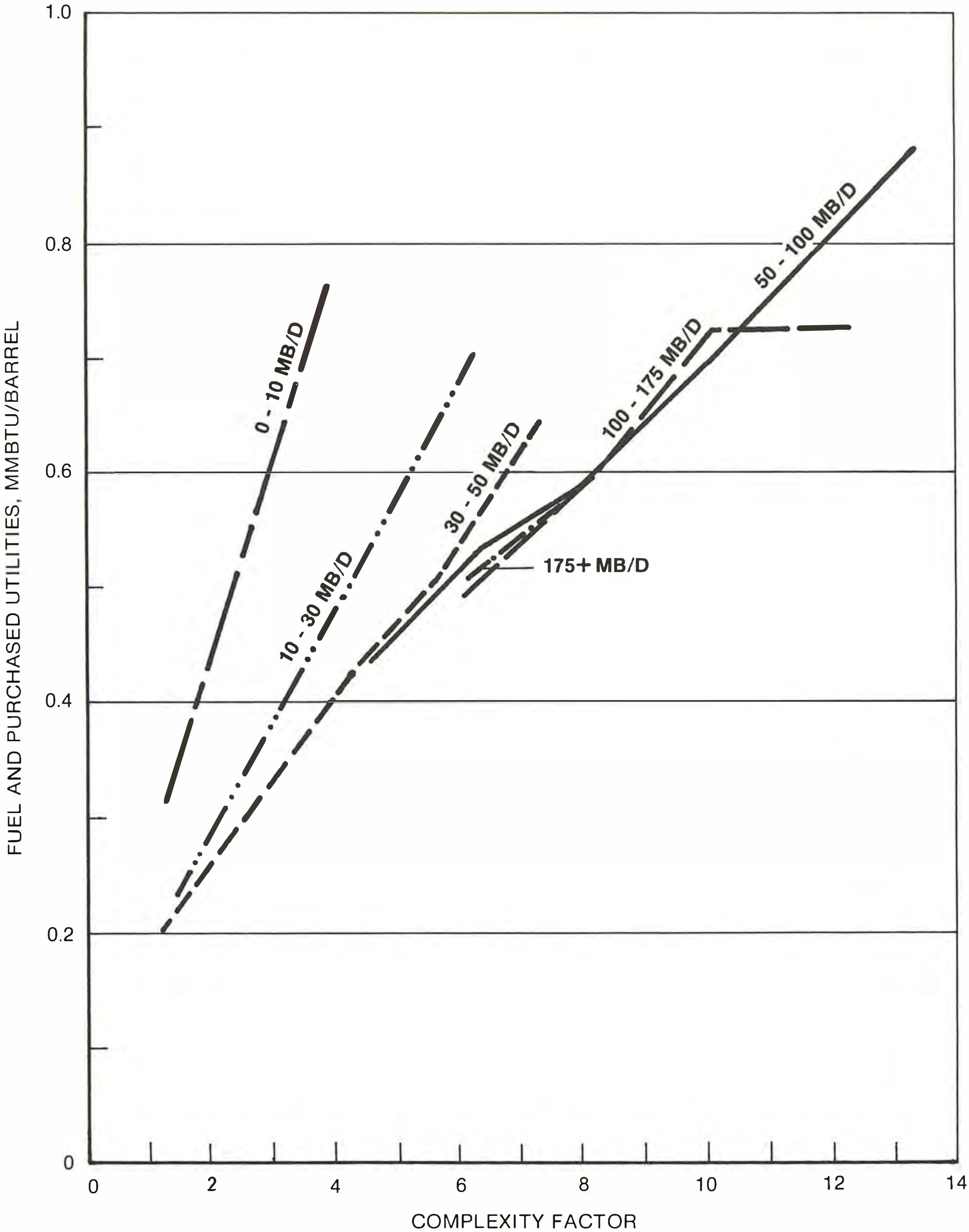


Figure 8. 1978 Fuel and Purchased Utilities Consumption as a Function of Complexity--Aggregated by Refinery Size.

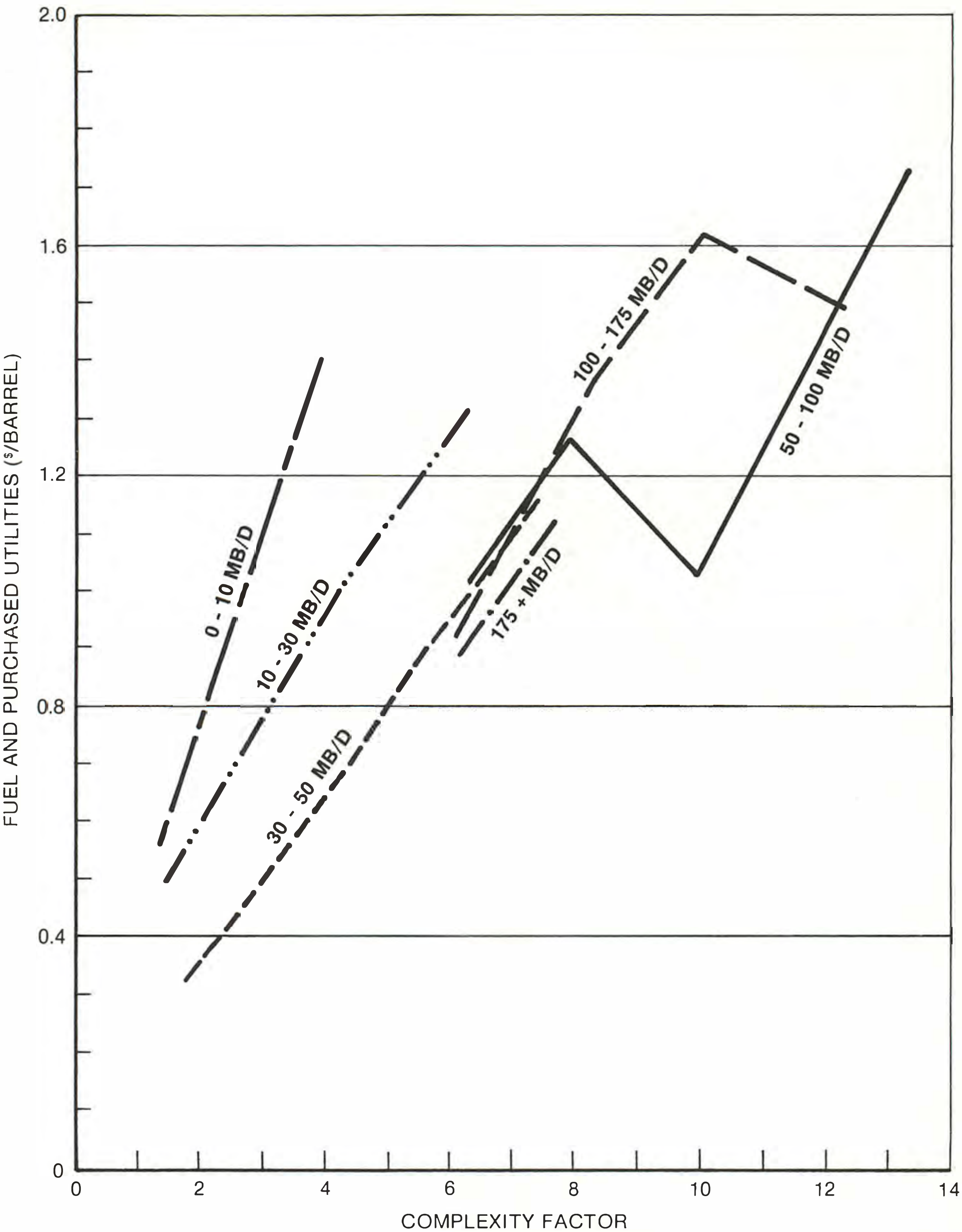


Figure 9. Refinery Fuel and Purchased Utilities Costs as a Function of Complexity—Aggregated by Refinery Size.

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

Energy consumption/cost as a function of company size (Table 39) 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 per barrel of crude oil, while the average was $1.08 per barrel, and refiners having system capacities of greater than 175 MB/D experienced energy costs of $1.13 per barrel. 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 per barrel figure shown for PAD V (Table 40). That district's response includes eight refineries (897 MB/D crude charge capacity and complexity in the 7-9 range or higher) with an average depreciation cost of $0.35 per barrel which increased the PAD V average significantly.

As would be expected, depreciation charges generally increase with complexity, ranging from $0.16 per barrel for refineries of less than 3 complexity to $0.27 per barrel for those greater than 11 complexity (Table 42).

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 (discussed in greater detail later in this report) 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 41), depreciation charges ranged from $0.15 to $0.22 per barrel 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 10 was prepared in an attempt to eliminate the otherwise masking effects between complexity and refinery size as they relate to depreciation. The data do not correlate well with refinery size in this figure, but do generally show the trend of capital-related charges with complexity. The expected relationship between size and depreciation may be obscured by vintage considerations. Generally, it may be observed from this figure that depreciation charges may more than double between low and high complexity ranges. Also observed is the relatively high depreciation charge for refineries in the 0-10 MB/D size range.

With one exception, as company size increased depreciation also increased throughout all size ranges, from $0.12 per barrel for those companies of less than 10 MB/D capacity to $0.19 per barrel for refiners of greater than 175 MB/D capacity (Table 39). The single exception was the 10-30 MB/D companies, at $0.18 per barrel.

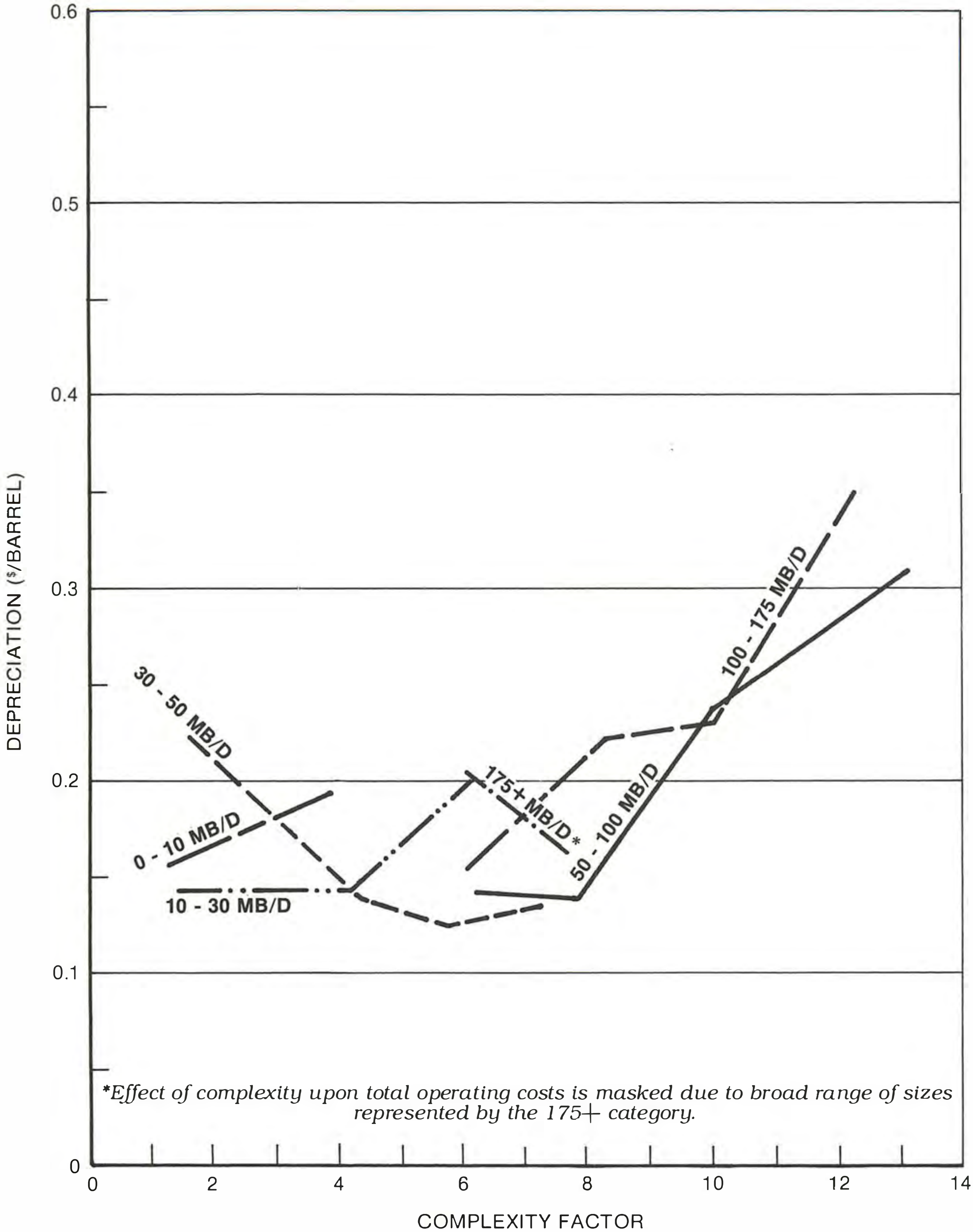


Figure 10. 1978 Depreciation as a Function of Complexity--Aggregated by Refinery Size.

Apparently, some of the higher complexity small refineries (those of less than 10 MB/D capacity) are owned by these companies.

Maintenance and Other Operating Costs

Costs for maintenance and other operating expense items (payroll, catalysts, administration, etc.) ranged from $0.77 to $0.81 per barrel for the under five complexity refineries to $1.27 per barrel for those in the 11+ category (Table 42); 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 41) shows the lowest costs for those refineries in the 30-50 MB/D range. Refineries of greater capacity display higher maintenance and other operating costs, illustrating the effect of greater complexity. Figure 11 differentiates between the effects of complexity and size upon refinery maintenance and other operating expenses. The more complex plants have operating expenses of three to four times those of low complexity refineries of the same size range. In the larger refinery size categories, the effect of size at a given complexity is less significant, but Figure 11 does illustrate that, under 50 MB/D capacity and for a given complexity level, maintenance and other operating expenses decrease as refinery size increases.

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

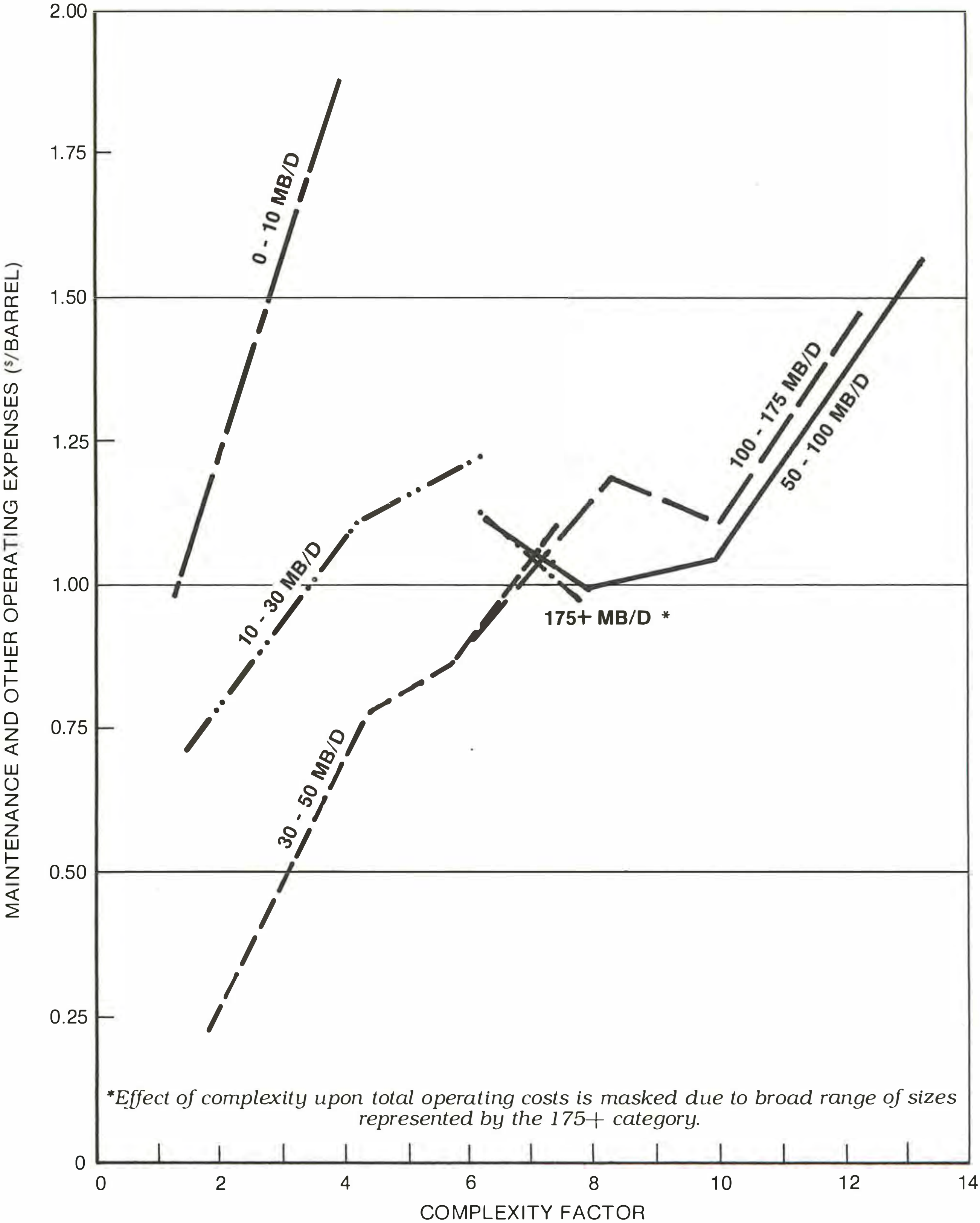


Figure 11. 1978 Maintenance and Other Operating Expenses as a Function of Complexity--Aggregated by Refinery Size

COMBINED CRUDE OIL AND OPERATING COSTS

Company Size Aggregation

Table 44 and 45 show combined crude oil and operating costs aggregated on the basis of company size. It also depicts the differential for the combined costs from the respondent average.

Companies in the smaller size categories reported cost data indicating significantly lower combined costs than the large refiners. Refiners of 50 MB/D and less capacity appear to have had combined costs of $1.11-$3.13 per barrel of crude oil less than the average, while refiners in the larger size ranges had costs in 1978 that were $0.14 above the average. For reasons previously discussed, both crude oil costs and operating costs are lower for the smaller refinery size categories.

Refinery Aggregations

Tables 46, 47, and 48 present combined crude oil and operating costs aggregated by refinery location, size, and complexity.

Combined crude oil and operating costs vary by geographic area, with PADs I and II above the respondent average and PADs III, IV, and V below that average. The relative contribution of crude oil cost and operating cost to the combined costs differed considerably between PAD districts, as documented in Table 46.

Table 47 shows that, in general, combined crude oil and operating costs increased with refinery size range. This trend reflects higher crude oil costs as well as added operating costs (associated with complexity). The variances from the respondent average amount to as much as $2.70 per barrel under the average for refineries of less than 10 MB/D and 2.5 complexity to $0.37 above the average for refineries in the 100-175 MB/D range.

TABLE 44

1978 Crude Oil Cost Plus Operating Costs by Company Size

	Company Size (MB/D) 0-10	10-30	30-50	50-100	100-175	175+	Total
Weight Average Complexity	1.49	3.01	4.78	5.68	7.21	7.71	7.24
Crude Oil Cost, Net After Entitlements and Bias, $/barrel	10.53	11.50	12.22	12.99	12.92	12.78	12.71
Operating Costs, $/barrel	1.35	1.87	1.67	2.08	2.01	2.35	2.28
Total Cost, $/barrel Throughput	11.88	13.37	13.89	15.07	14.93	15.13	14.99
Differential, Total Cost Relative to Combined U.S. Average	(3.13)	(1.64)	(1.11)	0.08	(0.06)	0.16	Base
Crude Charge Capacity, MB/D*	174	631	424	765	670	12,782	15,445
Number of Refineries	29	38	11	19	8	98	203
Number of Companies	28	30	11	11	5	18	103

*Capacity data is for refineries reporting crude oil data in Part II of the NPC study.

TABLE 45

Impact of Entitlements and Small Refiner Bias
On 1978 Crude Oil Costs Plus Operating Costs by Company Size

	Company Size (MB/D)						
	0-10	10-30	30-50	50-100	100-175	175+	Total
Crude Oil Cost Plus Operating Costs, $/barrel							
Before Entitlements Without Bias	12.23	13.73	14.73	14.96	15.41	14.69	14.66
After Entitlements Without Bias	13.65	14.53	14.54	15.24	14.93	15.02	14.99
After Entitlements With Bias	11.88	13.37	13.88	15.07	14.93	15.15	14.99
Differential, Total Cost Relative To Combined U.S. Average, $/barrel							
Before Entitlements Without Bias	(2.43)	(0.93)	(0.07)	0.30	0.75	0.03	Base
After Entitlements Without Bias	(1.34)	(0.46)	(0.45)	0.25	(0.06)	0.03	Base
After Entitlements With Bias	(3.11)	(1.62)	(1.11)	0.08	(0.06)	0.16	Base

TABLE 46

1978 Net Crude Oil Costs and Operating Costs by Refinery Location

	Refinery Location PAD I	PAD II	PAD III	PAD IV	PAD V	Total
Weight Average Complexity	7.08	7.14	7.38	5.16	7.52	7.24
Crude Oil Costs Before Entitlements	14.00	12.46	12.11	11.08	11.89	12.36
Crude Oil Cost, Net After Entitlements, $/barrel*	12.94	13.01	12.77	12.43	11.83	12.69
Operating Costs, $/barrel	2.51	2.22	2.10	2.26	2.71	2.29
Total Net Crude Oil and Operating Costs, $/barrel Throughput	15.45	15.23	14.87	14.69	14.54	14.98
Differential, Total Costs Relative to U.S. Average, $/barrel	0.46	0.24	(0.09)	(0.30)	(0.41)	Base
Associated 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

*Entitlements calculated on the hypothetical basis that each refinery, regardless of size, was treated as a separate company.

†Part II respondents divided by U.S. totals.

TABLE 47

1978 Crude Oil Costs and Operating Costs by Refinery Size

	Refinery Size (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	Total
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
Crude Oil Cost, Before Entitlements	10.96	13.78	11.68	11.76	11.85	11.81	12.88	11.47	11.62	12.52	12.86	12.33	12.36
Crude Oil Cost, Net After Entitlements, $/barrel*	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
Operating Costs, $/barrel	1.58	3.98	2.21	1.30	2.36	1.89	0.78	2.08	1.96	2.40	2.61	2.22	2.29
Total Crude Oil and Operating Costs, $/barrel Throughput	12.28	15.84	13.20	12.30	14.26	13.40	12.72	14.51	14.34	15.24	15.36	15.07	14.98
Differential, Total Costs Relative to U.S. Average, $/barrel	(2.70)	(0.86)	(1.78)	(2.68)	(0.72)	(1.58)	(2.26)	(0.47)	(0.64)	0.26	0.38	(0.09)	Base
Associated 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	85.5	100.0	89.2

*Entitlements calculated on the hypothetical basis that each refinery, regardless of size, was treated as a separate company.
†Part II respondents divided by U.S. totals for each size category.

TABLE 48

1978 Crude Oil Costs and Operating Costs by Refinery Complexity

	Complexity 1-3	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
Crude Oil Costs, Before Entitlements	11.97	12.44	12.53	12.31	12.04	12.53	12.36
Crude Oil Costs, Net After Entitlements, $/barrel*	11.41	12.55	12.86	12.80	12.70	12.45	12.69
Operating Costs, $/barrel	1.49	1.66	2.18	2.36	2.56	3.13	2.29
Total Crude Oil and Operating Costs, $/barrel Throughput	12.90	14.21	15.04	15.16	15.26	15.58	14.98
Differential, Total Costs Relative to U.S. Average, $/barrel	(2.08)	(0.77)	0.06	0.18	0.28	0.60	Base
Associated 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

*Entitlements calculated on the hypothetical basis that each refinery, regardless of size, was treated as a separate company.

†Part II respondents divided by U.S. totals.

With respect to refinery complexity, combined costs in Table 48 are generally greater at higher complexities. This is due to higher operating expenses as well as higher crude oil costs. The combined cost aggregated by complexity ranges from $2.35 per barrel below the average for the least complex refineries to $0.60 per barrel above that average for the most complex refineries.

GROSS FIXED ASSETS AND REPLACEMENT COSTS

The average original construction cost of a refinery (gross fixed assets) was reported to have been $1,354 per daily barrel of crude charge capacity, and the average replacement cost as of January 1, 1979, to have been $3,727 per daily barrel of crude charge capacity.

Table 49 shows the variations in refinery construction cost by company size. The per-barrel cost of refineries, both on a gross fixed asset and a replacement cost basis, increases with company size. While this may appear contrary to an expected effect of economy of size, complexity apparently overrides the effect of size.

Table 50 indicates refinery construction cost variations by refinery location. PAD I and V refineries appear to be more costly per barrel of crude charge capacity than refineries in other districts. Some known factors contributing to this include the fact that more complex refineries and very stringent environmental restrictions exist in PAD V. PAD III refinery costs appear to be the lowest on a replacement cost basis. Some factors believed to influence this include lower per-barrel construction costs and higher average refinery size. On an original cost basis, PAD IV refineries appear to have the lowest cost. This may be a result of refineries being of an average earlier vintage, as indicated by the high ratio of replacement cost to original cost.

TABLE 49

January 1, 1979, Refinery Assets by Company Size

	Company Size (MB/D)						
	0-10	10-30	30-50	50-100	100-175	175+	Total
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.

TABLE 50

January 1, 1979, Refinery Assets by Refinery Location

	Refinery Location					
	PAD I	PAD II	PAD III	PAD IV	PAD V	Total
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

*Part II respondents divided by U.S. totals.

Table 51 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 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. As shown in Table 51, 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 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.

This is further illustrated by Figures 12 and 13, which were prepared to more fully differentiate between the effects of complexity and refinery size upon gross fixed assets and current replacement cost. Respondent data show little evidence of an economy of scale except among the small size ranges. The figures do emphasize that per-barrel capital investment costs are particularly sensitive to complexity factor.

The ratio of replacement cost to gross fixed assets gives a clue to the age of the refinery in that a lower ratio indicates less inflation and, therefore, more recent construction. As shown in Table 49, refineries of companies of less than 30 MB/D capacity are apparently newer on the average than those in the larger size categories. Also, the 7-9 complexity refineries as a group appear to be the oldest, and the 1-3 complexity refineries seem to be the most recently constructed (Table 52).

TABLE 51

January 1, 1979, Refinery Assets by Refinery Size

	Refinery Size (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	Total
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

*Withheld to protect confidentiality of participants.
†Part II respondents divided by U.S. totals.

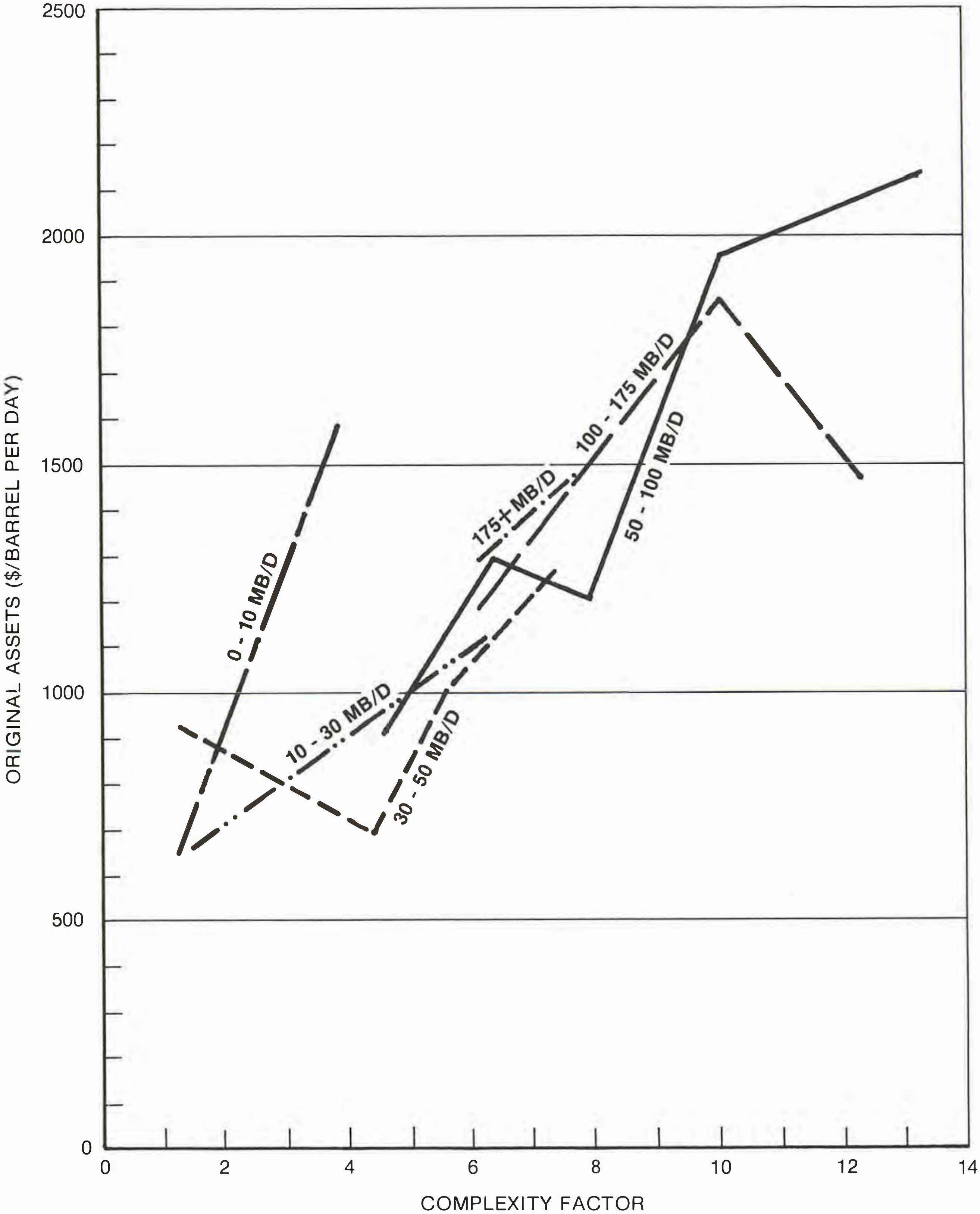


Figure 12. 1978 Gross Fixed Assets as a Function of Complexity--
Aggregated by Refinery Size.

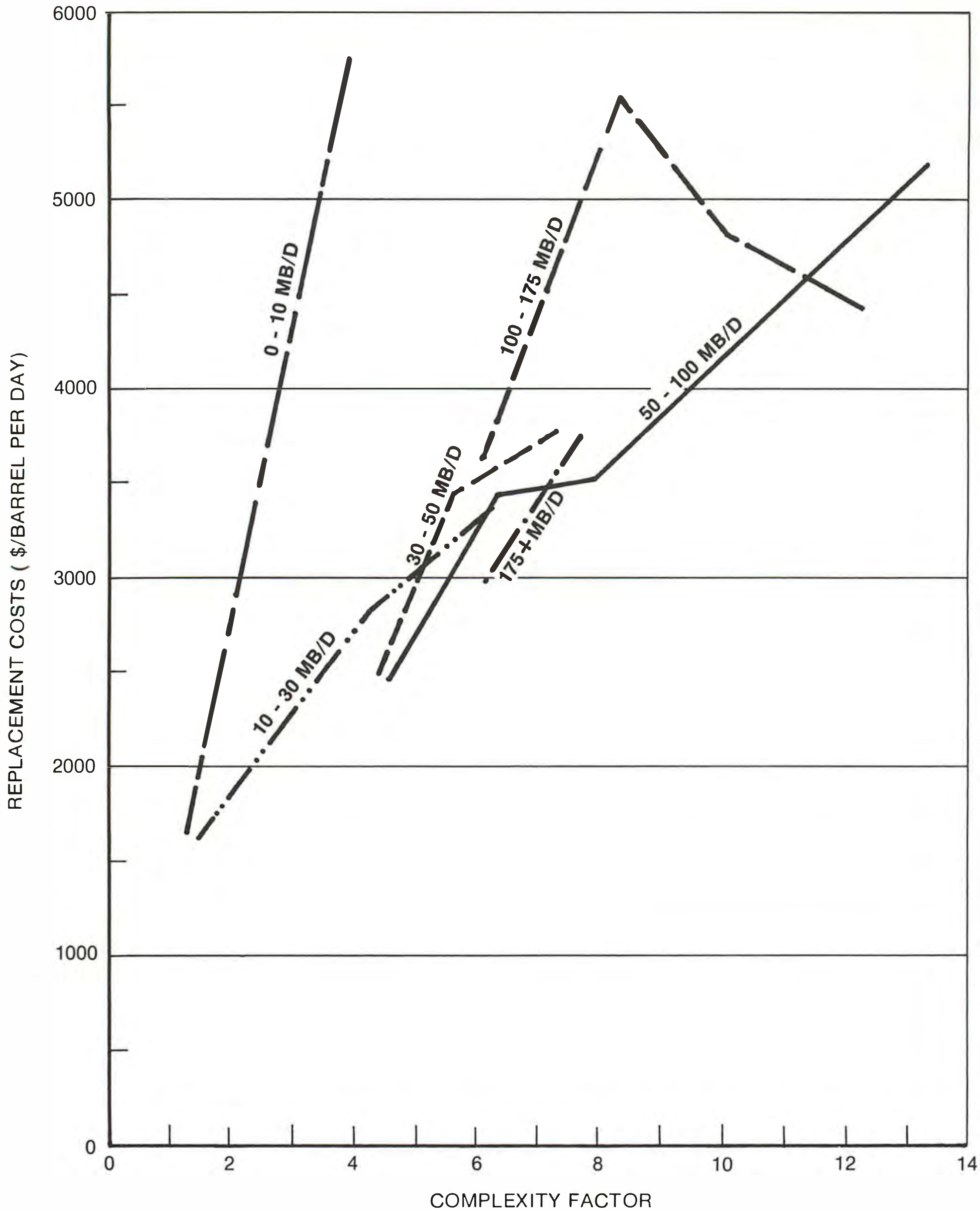


Figure 13. 1978 Replacement Costs as a Function of Complexity--
Aggregated by Refinery Size.

TABLE 52

January 1, 1979, Refinery Assets By Refinery Complexity

	Complexity						
	1-3	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
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
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

*Part II respondents divided by U.S. totals.
†Replacement cost data were submitted for 186 refineries, having 14,330 MB/D of crude charge capacity.

Table 52 also indicates that the original cost and replacement cost generally increased with the complexity factor of the refinery, ranging from $715 to $1,800 per barrel original cost and $1,706 to $4,522 per barrel replacement cost.

This chapter addressed crude oil costs, operation costs, combined crude oil and operation costs, and refinery assets on both a company basis (aggregated by size range) and on a refinery basis (aggregated by complexity, location, and size). Tables 53, 54, and 55 provide demographic data for the respondents to Part II.

TABLE 53

January 1, 1979, Refining Capacity Distribution
By Process Complexity For Part II Respondents
(Figures Shown Are Aggregate Capacity (MB/D) with
Number of Reporting Refineries in Parentheses)

Size (MB/D)	Weight Average Complexity	Complexity: 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
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)

*Withheld to protect confidentiality of participants.

TABLE 54

January 1, 1979, Refining Capacity Distribution
By Process Complexity and Refinery Location
For Part II Respondents
(Figures Shown Are Aggregate Capacity (MB/D) with
Number of Reporting Refineries in Parentheses)

Geographic Area		Complexity						
		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
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)

*Withheld to protect confidentiality of participants.

TABLE 55

January 1, 1979, Refinery Capacity Distribution
By Refinery Size and Location for Part II Respondents
(Figures Shown Are Aggregate Capacity (MB/D) with
Number of Reporting Refineries in Parentheses)

		Refinery Location					
		PAD I	PAD II	PAD III	PAD IV	PAD V	Total
	Weight Average Complexity	7.08	7.14	7.38	5.16	7.52	7.24
Size (MB/D)							
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)

*Withheld to protect confidentiality of participants.
†Reclassified to protect confidentiality.

CHAPTER THREE

ADDITIONAL FACILITIES TO MEET THREE ALTERNATE SUPPLY/DEMAND CASES

New facilities beyond those firmly committed to be installed as of January 1, 1982, which would be required under the following three scenarios, were reported in the survey:

- Process 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 this survey

- Increase production of two different grades (87 and 89 R+M/2 of unleaded gasoline to 90 percent of the projected total 1982 gasoline pool reported in response to Part I of this survey

- 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.

Responses indicating new facilities required to process more high sulfur crude oil were received from companies owning 147 refineries with a total capacity of 15,004 MB/D, representing about 78.4 percent of total capacity 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 new facilities required to produce low sulfur fuel oil were received from companies owning 148 refineries with a total capacity of 14,027 MB/D, representing about 73.3 percent of total capacity and 51.2 percent of U.S. refineries.

INCREASED HIGH SULFUR CRUDE OIL PROCESSING CAPABILITY

The supporting data for the following discussion of increased high sulfur crude oil processing capability are aggregated by refinery size in Tables 56, 57, and 58; by refinery location in Tables 59, 60, and 61; by refinery complexity in Tables 62, 63, and 64; and by company size in Tables 65, 66, and 67. In addition, Tables 68, 69, 70, 71, 72, and 73 provide demographic data on the number and capacity of refineries responding to Part III of the survey.

Refiners were requested to identify and size the additional facilities necessary to increase the capability to process light and heavy (under and over 15 percent 1050°F+ residual) high sulfur (over 1 percent sulfur) crude oil by at least 20 percent of expected 1982 crude oil processing capacity. Responses reporting such facilities were received from companies representing 147 refineries with a combined crude oil capacity of 15,004 MB/D (as of January 1, 1982). This represents about 78 percent of total capacity and 51 percent of U.S. refineries. Based on the respondents' expected 1982 capacity, this represents an increase of at least 3,000 MB/D over the 6,140 MB/D of high sulfur and 2,399 MB/D of medium sulfur crude runs projected for 1982 in Part I of the survey. To accomplish the assumed crude oil grade substitution using primarily heavy high sulfur crude oil, modifications or additions would be plannned at 108 refineries with a combined January 1, 1982 capacity of 11,469 MB/D. This represents 60.0 percent of total capacity and 37.4 percent of U.S. refineries as of January 1, 1982.

The most significant processing capability increases required were for desulfurization, sulfur plant and tail gas cleanup, hydrogen manufacture, and residual conversion (primarily coking). Increasing light high sulfur crude oil processing capability by at least 20 percent would require 2,362 MB/D of various desulfurization facilities (naphtha, distillate, catalytic cracker feed, heavy

TABLE 56

Additional Facilities Necessary to Increase
the Processing of Light High Sulfur Crude Oil by At Least 20 Percent
Beyond Facilities Committed to Prior to January 1, 1982
(Capacities Aggregated in MB/D)

	Refinery Size (MB/D)						
Process Type	0-10	10-30	30-50	50-100	100-175	175+	Total
1. Desulfurization Facilities							
Naphtha	20	20	52	82	95	128	398
Distillate	22	52	70	285	246	603	1,279
HFO	21	51	45	314	121	134	685
2. Sulfur Plant and Tail Gas (LT/D)	281	299	299	1,362	833	1,453	4,527
3. Vacuum Distillation	15	22	22	111	42	171	382
4. Tankage (Mbbl)	1,415	751	1,090	10,950	2,090	4,520	20,816
5. Residual Conversion	*	*	20	20	29	*	190
6. Reforming	26	10	*	44	*	65	199
7. Isomerization		*	*	*	*	*	50
8. Hydrogen Manufacture (MMCF/D)	†	50	54	135	173	119	531
9. Catalytic Cracking			*	82	*	*	142
10. Coking (ST/D)				*		*	5,970
11. Crude Atmospheric Distillation		37	54	291		219	601
12. Visbreaking				*	*		26
13. Treating		*	*	14			31
14. Refineries Reporting Above Added Facilities							
1982 Crude Oil Capacity	39	464	632	1,738	2,138	5,398	10,408
1982 Crude Oil Throughput	35	408	563	1,690	1,997	5,095	9,788
Number of Refineries	5	21	14	23	16	16	95
15. Associated Refining Systems							
1982 Crude Oil Capacity	45	635	862	2,532	2,826	6,977	13,878
1982 Crude Oil Throughput	41	542	773	2,437	2,614	6,598	13,005
Number of Refineries	6	29	19	35	22	22	133
20 Percent Increase in High Sulfur Crude Capability	9	127	172	506	565	1,396	2,776

*Entry withheld to protect confidentiality.
†Merged with adjacent higher size category to protect confidentiality.

TABLE 57

Additional Facilities Necessary to Increase
the Processing of Heavy High Sulfur Crude Oil by At Least 20 Percent
Beyond Facilities Committed to Prior to January 1, 1982
(Capacities Aggregated in MB/D)

Process Type	Refinery Size (MB/D) 0-10	10-30	30-50	50-100	100-175	175+	Total
1. Desulfurization Facilities							
Naphtha	20	15	41	78	32	115	300
Distillate	23	46	67	295	257	628	1,316
HFO	23	45	52	356	190	236	902
2. Sulfur Plant and Tail Gas (LT/D)	286	130	469	1,650	1,327	2,415	6,277
3. Vacuum Distillation	22	26	47	134	111	234	574
4. Tankage (Mbbl)	1,432	1,176	1,125	10,295	1,340	5,040	20,408
5. Residual Conversion	*	*	30	51	55	143	288
6. Reforming	24	10	10	42	†	86	172
7. Isomerization	*	*	*	*	*	*	48
8. Hydrogen Manufacture (MMCF/D)	14	56	70	185	272	191	788
9. Catalytic Cracking		12	*	100	23	*	183
10. Coking (ST/D)				*		*	10,989
11. Crude Atmospheric Distillation		23	53	298		219	593
12. Visbreaking				*	*		43
13. Treating		*	*				23
14. Refineries Reporting Above Added Facilities							
1982 Crude Oil Capacity	47	395	641	1,996	2,002	5,763	10,842
1982 Crude Oil Throughput	40	359	566	1,925	1,872	5,396	10,159
Number of Refineries	6	18	14	28	15	17	98
15. Associated Refining Systems							
1982 Crude Oil Capacity	53	566	921	2,790	2,706	7,342	14,377
1982 Crude Oil Throughput	46	494	826	2,671	2,505	6,899	13,441
Number of Refineries	7	26	20	40	21	23	137
20 Percent Increase in High Sulfur Crude Capability	11	113	184	558	541	1,468	2,875

*Entry withheld to protect confidentiality.
†Merged with adjacent higher size category to protect confidentiality.

TABLE 58

Additional Facilities Necessary to Increase
the Processing of Light or Heavy High Sulfur Crude Oil
(Capacities Aggregated in MB/D)

Factors	Refinery Size (MB/D) 0-10	10-30	30-50	50-100	100-175	175+	Total
1. Metallurgy Adequate?							
• Associated Crude Charge Capacity							
Yes	31	179	360	1,440	1,351	2,601	5,963
No	48	264	377	530	1,067	2,493	4,740
• Associated Number of Refineries							
Yes	5	7	8	19	10	8	57
No	6	12	9	7	8	7	49
2. Permits Likely for These Facilities?							
• Associated Crude Charge Capacity							
Yes	52	354	*	1,464	1,228	*	8,536
No	21	100	*	316	902	*	1,782
• Number of Refineries							
Yes	6	16	*	20	9	*	79
No	4	5	*	4	7	*	22
3. Lead Time Required							
• Associated Crude Capacity	52	354	698	1,716	1,619	4,282	8,720
• Number of Months	30	36	41	43	51	56	43
4. Likelihood of Installation							
• Associated Crude Capacity							
Low	29	283	469	1,125	1,396	4,197	7,498
Medium	*	96	180	672	635	*	2,316
High	*	*	*	*	*	*	621
Impossible	*	*	*	*	*	*	564
• Number of Refineries							
Low	4	13	11	15	10	12	66
Medium	*	4	4	9	5	*	28
High	*	*	*	*	*	*	7
Impossible	*	*	*	*	*	*	7

TABLE 58 (continued)

5. Refineries Reporting Above Added Facilities							
1982 Crude Capacity	47	395	641	1,996	2,002	5,763	10,842
1982 Crude Throughput	40	359	566	1,925	1,872	5,396	10,159
Number of Refineries	6	18	14	28	15	17	98
6. Associated Refining Systems							
1982 Crude Capacity	53	566	921	2,790	2,706	7,342	14,377
1982 Crude Throughput	46	494	826	2,671	2,505	6,899	13,441
Number of Refineries	7	26	20	40	21	23	137
20 Percent Increase in High Sulfur Crude Capability	11	113	184	558	541	1,468	2,875
7. Refineries Providing Only Qualitative Responses†							
Number of Refineries	21	17	11	*	*	3	55
1982 Crude Oil Capacity	126	310	447	*	*	748	1,993
1982 Crude Oil Runs	118	265	361	*	*	670	1,740
8. System Responses Requiring Facilities for Heavy High Sulfur Crude Oil, but not Light High							
Number of Refineries	*	*	*	6	*	*	14
1982 Crude Oil Capacity	*	*	*	337	*	*	1,126
1982 Crude Oil Runs	*	*	*	313	*	*	1,030
9. System Responses for Light High Sulfur Crude Oil Only							
Number of Refineries	*	4	*	*	3	0	10
1982 Crude Oil Capacity	*	88	*	*	414		627
1982 Crude Oil Runs	*	66	*	*	389		579

*Data withheld to protect confidentiality.
†Not included in aggregation of responses to Sections 1-6 above.

TABLE 59

Additional Facilities Necessary to Increase
the Processing of Light High Sulfur Crude Oil by At Least 20 Percent
Beyond Facilities Committed to Prior to January 1, 1982
(Capacities Aggregated in MB/D)

Process Type	Geographic Area (PAD) I	II	III	IV	V	Total
1. Desulfurization Facilities						
Naphtha	†	145	204	17	33	398
Distillate	70	331	785	15	78	1,279
HFO	89	120	392	8	76	685
2. Sulfur Plant and Tail Gas (LT/D)	388	1,115	2,578	36	410	4,527
3. Vacuum Distillation	29	120	144	†	89	382
4. Tankage (Mbbl)	6,820	1,655	8,670	1,210	2,461	20,816
5. Residual Conversion	*	76	80	*	25	190
6. Reforming	43	21	98	13	24	199
7. Isomerization	*	*	*		*	50
8. Hydrogen Manufacture (MMCF/D)	*	201	232	*	47	531
9. Catalytic Cracking	*	50	*	*	*	142
10. Coking (ST/D)		*	*		*	5,970
11. Crude Atmospheric Distillation	*	213	228	*		601
12. Visbreaking			26			26
13. Treating		31	§			31
14. Refineries Reporting Above Added Facilities						
1982 Crude Oil Capacity	661	2,430	5,617	174	1,526	10,408
1982 Crude Oil Throughput	651	2,345	5,247	146	1,400	9,788
Number of Refineries	6	28	36	7	18	95
15. Associated Refining Systems						
1982 Crude Oil Capacity	1,373	3,812	6,416	281	1,997	13,878
1982 Crude Oil Throughput	1,333	3,630	5,998	234	1,810	13,005
Number of Refineries	15	42	43	10	23	133
20 Percent Increase in High Sulfur Crude Capability	275	762	1,283	56	399	2,776

*Data withheld to protect confidentiality.
†Merged with adjacent higher size category to protect confidentiality.
§Merged with adjacent lower size category to protect confidentiality.

TABLE 60

Additional Facilities Necessary to Increase
the Processing of Heavy High Sulfur Crude Oil by At Least 20 Percent
Beyond Facilities Committed to Prior to January 1, 1982
(Capacities Aggregated in MB/D)

Process Type	Geographic Area (PAD) I	II	III	IV	V	Total
1. Desulfurization Facilities						
Naphtha	48	49	162	17	25	300
Distillate	67	334	787	14	115	1,316
HFO	132	181	500	9	79	902
2. Sulfur Plant and Tail Gas (LT/D)	540	1,475	3,482	54	726	6,277
3. Vacuum Distillation	39	183	229	21	101	574
4. Tankage (Mbbl)	7,200	1,205	8,355	1,297	2,351	20,408
5. Residual Conversion	*	97	123	*	53	288
6. Reforming	57	†	86	13	17	172
7. Isomerization	*	*	*		*	48
8. Hydrogen Manufacture (MMCF/D)	75	241	403	†	69	788
9. Catalytic Cracking	*	53	39	13	*	183
10. Coking (ST/D)		*	*		*	10,989
11. Crude Atmospheric Distillation	*	200	234	*	*	593
12. Visbreaking			43			43
13. Treating		*	*			23
14. Refineries Reporting Above Added Facilities						
1982 Crude Oil Capacity	878	2,327	5,380	219	2,038	10,842
1982 Crude Oil Throughput	866	2,243	5,050	184	1,816	10,159
Number of Refineries	9	26	34	8	21	98
15. Associated Refining Systems						
1982 Crude Oil Capacity	1,590	3,759	6,179	326	2,524	14,377
1982 Crude Oil Throughput	1,548	3,578	5,801	272	2,241	13,441
Number of Refineries	18	41	41	11	26	137
20 Percent Increase in High Sulfur Crude Capability	318	752	1,236	65	505	2,875

*Data withheld to protect confidentiality.
†Merged with adjacent higher size category to protect confidentiality.

TABLE 61

Additional Facilities Necessary to Increase
the Processing of High Sulfur Crude Oil
(Capacities Aggregated in MB/D)

Factors	Geographic Area (PAD) I	II	III	IV	V	Total
1. Metallurgy Adequate?						
• Associated Crude Charge Capacity (MB/D)						
Yes	*	1,074	2,222	*	1,739	5,963
No	*	1,349	2,897	*	237	4,740
• Associated Number of Refineries						
Yes	*	12	17	*	16	57
No	*	18	19	*	6	49
2. Permits Likely for These Facilities?						
• Associated Crude Charge Capacity						
Yes	*	1,812	4,836	*	1,152	8,536
No	*	456	375	*	781	1,782
• Number of Refineries						
Yes	*	22	31	*	13	79
No	*	5	6	*	8	22
3. Lead Time Required						
• Refinery Crude Capacity	538	2,282	4,685	199	1,016	8,720
• Number of Months	37	46	44	34	42	43
4. Likelihood of Installation						
• Refinery Crude Charge Capacity						
Low	662	1,840	3,585	80	1,331	7,488
Medium	145	*	1,145	*	*	2,316
High			*	*	*	621
Impossible		*	*	*	246	564
• Number of Refineries						
Low	6	24	22	4	10	66
Medium	3	*	11	*	*	28
High			*	*	*	7
Impossible		*	*	*	4	7

TABLE 61 (continued)

5. Refineries Reporting Above Added Facilities						
1982 Crude Capacity	878	2,327	5,380	219	2,038	10,842
1982 Crude Throughput	866	2,243	5,050	184	1,816	10,159
Number of Refineries	9	26	34	8	21	98
6. Associated Refining Systems						
1982 Crude Capacity	1,590	3,759	6,179	326	2,524	14,377
1982 Crude Throughput	1,548	3,578	5,801	272	2,241	13,441
Number of Refineries	18	41	41	11	26	137
20 Percent in High Sulfur Crude Capacity	318	752	1,236	65	505	2,875
7. Refineries Providing Only Qualitative Responses†						
Number of Refineries	6	8	21	11	9	55
1982 Crude Oil Capacity	353	138	1,037	236	228	1,993
1982 Crude Oil Runs	321	122	926	215	156	1,740
8. System Responses Requiring Facilities for Heavy High Sulfur Crude Oil, but not Light High						
Number of Refineries	3	*	3	*	5	14
1982 Crude Oil Capacity	218	*	437	*	365	1,126
1982 Crude Oil Runs	215	*	420	*	306	1,030
9. System Responses for Light High Sulfur Crude Oil Only						
Number of Refineries	0	3	4	0	3	10
1982 Crude Oil Capacity		165	348		113	627
1982 Crude Oil Runs		164	302		113	579

*Data withheld to protect confidentiality.
†Not included in aggregation of responses to Sections 1-6 above.

TABLE 62

Additional Facilities Necessary to Increase
the Processing of Light High Sulfur Crude Oil by At Least 20 Percent
Beyond Facilities Committed to Prior to January 1, 1982
(Capacities Aggregated in MB/D)

Process Type	Complexity Factor 0-3	3-5	5-7	7-9	9-11	11+	Total
1. Desulfurization Facilities							
Naphtha	29	12	233	53	†	70	398
Distillate	47	64	529	351	110	179	1,279
HFO	48	75	198	311	§	52	685
2. Sulfur Plant and Tail Gas (LT/D)	527	327	1,429	1,519	233	492	4,527
3. Vacuum Distillation	26	24	123	173	§	36	382
4. Tankage (Mbbl)	1,105	1,931	10,685	3,380	1,165	2,550	20,816
5. Residual Conversion	14	*	*	88	*	*	190
6. Reforming	29	12	99	48	*	*	199
7. Isomerization			41	*		*	50
8. Hydrogen Manufacture (MMCF/D)	28	43	171	166	62	61	531
9. Catalytic Cracking			71	50	*	*	142
10. Coking (ST/D)			*	*			5,970
11. Crude Atmospheric Distillation	*	*	288	220	*		601
12. Visbreaking		*	*		*		26
13. Treating			*		*		31
14. Refineries Reporting Above Added Facilities							
1982 Crude Oil Capacity	336	594	3,930	3,650	740	1,159	10,408
1982 Crude Oil Throughput	283	572	3,707	3,449	691	1,086	9,788
Number of Refineries	13	13	29	25	8	7	95
15. Associated Refining Systems							
1982 Crude Oil Capacity	402	776	5,076	5,130	1,234	1,259	13,878
1982 Crude Oil Throughput	323	741	4,809	4,814	1,161	1,156	13,005
Number of Refineries	17	16	45	35	12	8	133
20 Percent Increase in High Sulfur Crude Capability	80	155	1,015	1,026	247	252	2,776

*Entry withheld to protect confidentiality.
†Merged with adjacent higher size category to protect confidentiality.
§Merged with adjacent lower size category toprotect confidentiality.

TABLE 63

Additional Facilities Necessary to Increase
the Processing of Heavy High Sulfur Crude Oil by At Least 20 Percent
Beyond Facilities Committed to Prior to January 1, 1982
(Capacities Aggregated in MB/D)

Process Type	Complexity Factor 0-3	3-5	5-7	7-9	9-11	11+	Total
1. Desulfurization Facilities							
Naphtha	18	10	161	46	†	65	300
Distillate	39	53	547	376	102	200	1,316
HFO	48	89	326	374	§	65	902
2. Sulfur Plant and Tail Gas (LT/D)	358	382	2,355	2,024	372	786	6,277
3. Vacuum Distillation	26	40	200	197	37	74	574
4. Tankage (Mbbl)	1,485	1,503	9,380	3,625	1,365	3,050	20,408
5. Residual Conversion	16	†	38	116	20	99	288
6. Reforming	17	12	93	41	*	*	172
7. Isomerization		*	40	*		*	48
8. Hydrogen Manufacture (MMCF/D)	41	63	252	250	76	106	788
9. Catalytic Cracking	*	*	87	53	5	30	183
10. Coking (ST/D)			*	*			10,989
11. Crude Atmospheric Distillation	22	*	281	220	*		593
12. Visbreaking		*	*		*		43
13. Treating			*		*		23
14. Refineries Reporting Above Added Facilities							
1982 Crude Oil Capacity	311	433	3,758	4,337	785	1,219	10,842
1982 Crude Oil Throughput	276	416	3,526	4,070	729	1,141	10,159
Number of Refineries	13	12	26	30	9	8	98
15. Associated Refining Systems							
1982 Crude Oil Capacity	377	615	4,904	5,760	1,279	1,442	14,377
1982 Crude Oil Throughput	316	585	4,628	5,391	1,200	1,321	13,441
Number of Refineries	17	15	42	40	13	10	137
20 Percent Increase in High Sulfur Crude Capability	75	123	981	1,152	256	288	2,875

*Entry withheld to protect confidentiality.
†Merged with adjacent higher size category to protect confidentiality.
§Merged with adjacent lower size category to protect confidentiality.

TABLE 64

Additional Facilities to Increase
the Processing of High Sulfur Crude Oil

Factors	Complexity Factor 0-3	3-5	5-7	7-9	9-11	11+	Total
1. Metallurgy Adequate?							
• Associated Crude Charge Capacity							
Yes	102	470	2,071	2,447	*	*	5,963
No	243	191	2,110	1,570	*	*	4,740
• Associated Number of Refineries							
Yes	8	8	15	16	*	*	57
No	12	6	14	11	*	*	49
2. Permits Likely for These Facilities?							
• Associated Crude Charge Capacity							
Yes	281	*	3,149	3,144	*	601	8,536
No	112	*	765	593	*	195	1,782
• Number of Refineries							
Yes	14	*	23	21	*	3	79
No	8	*	4	5	*	3	22
3. Lead Time Required							
• Refinery Crude Capacity	281	652	3,269	2,911	885	721	8,720
• Number of Months	33	39	46	47	48	44	43
4. Likelihood of Installation							
• Refinery Crude Capacity							
Low	*	316	3,583	2,371	546	*	7,498
Medium	*	*	316	823	299	*	2,316
High	*	*	*	*	*		621
Impossible	*		*	*	*		564
• Number of Refineries							
Low	*	7	20	15	4	*	66
Medium	*	*	5	8	3	*	28
High	*	*	*	*	*		7
Impossible	*		*	*	*		7

TABLE 64 (continued)

5. Refineries Reporting Above Added Facilities							
1982 Crude Capacity	311	433	3,758	4,337	785	1,219	10,842
1982 Crude Throughput	276	416	3,526	4,070	729	1,141	10,159
Number of Refineries	13	12	26	30	9	8	98
6. Associated Refining Systems							
1982 Crude Capacity	377	615	4,904	5,760	1,279	1,442	14,377
1982 Crude Oil Throughput	316	585	4,628	5,391	1,200	1,321	13,441
Number of Refineries	17	15	42	40	13	10	137
20 Percent in High Sulfur Crude Capability	75	123	981	1,152	256	288	2,875
7. Refineries Providing Only Qualitative Responses†							
Number of Refineries	31	11	8	*		*	55
1982 Crude Oil Capacity	437	245	566	*		*	1,993
1982 Crude Oil Runs	346	215	503	*		*	1,740
8. System Responses Requiring Facilities for Heavy High Sulfur Crude Oil, but not Light High							
Number of Refineries	4	0	*	6	*	*	14
1982 Crude Oil Capacity	77		*	873	*	*	1,126
1982 Crude Oil Runs	72		*	802	*	*	1,030
9. System Responses for Light High Sulfur Crude Oil Only							
Number of Refineries	4	*	4	*	0	0	10
1982 Crude Oil Capacity	102	*	244	*			627
1982 Crude Oil Runs	79	*	242	*			579

*Data withheld to protect confidentiality.
†Not included in aggregation of responses to Sections 1-6 above.

TABLE 65

Additional Facilities Necessary to Increase
the Processing of Light High Sulfur Crude Oil by At Least 20 Percent
Beyond Facilities Committed to Prior to January 1, 1982
(Capacities Aggregated in MB/D)

Process Type	Company Size (MB/D) 0-10	10-30	30-50	50-100	100-175	175+	Total
1. Desulfurization Facilities							
Naphtha	14	20	*	37	*	297	398
Distillate	18	41	26	88	44	1,062	1,279
HFO	21	43	3	43	73	503	685
2. Sulfur Plant and Tail Gas (LT/D)	274	286	95	334	233	3,305	4,527
3. Vacuum Distillation	*	22	*	28	*	303	382
4. Tankage (Mbbl)	665	1,166	*	2,270	†	16,535	20,816
5. Residual Conversion		*	*	21	*	151	190
6. Reforming	20	10	8	10		151	199
7. Isomerization				*		47	50
8. Hydrogen Manufacture (MMCF/D)		45	13	61	25	387	531
9. Catalytic Cracking			*	*	*	116	142
10. Coking (ST/D)						5,970	5,970
11. Crude Atmospheric Distillation		*	*	*		547	601
12. Visbreaking				*	*	*	26
13. Treating	*			*		*	31
14. Refineries Reporting Above Added Facilities							
1982 Crude Oil Capacity	34	363	291	716	673	8,332	10,408
1982 Crude Oil Throughput	29	324	253	685	618	7,880	9,788
Number of Refineries	4	17	6	14	7	47	95
15. Associated Refining Systems							
1982 Crude Oil Capacity	34	363	291	759	673	11,759	13,878
1982 Crude Oil Throughput	29	324	253	723	618	11,059	13,005
Number of Refineries	4	17	6	15	7	84	133
20 Percent Increase in High Sulfur Crude Capacity	7	73	58	152	135	2,352	2,776

*Entry withheld to protect confidentiality.
†Merged with adjacent higher size category to protect confidentiality.

TABLE 66

Additional Facilities Necessary to Increase
the Processing of Heavy High Sulfur Crude Oil by At Least 20 Percent
Beyond Facilities Committed to Prior to January 1, 1982
(Capacities Aggregated in MB/D)

Process Type	Company Size (MB/D)						
	0-10	10-30	30-50	50-100	100-175	175+	Total
1. Desulfurization Facilities							
Naphtha	14	12	†	43	28	203	300
Distillate	19	32	25	85	69	1,085	1,316
HFO	23	36	†	58	92	693	902
2. Sulfur Plant and Tail Gas (LT/D)	†	389	170	446	411	4,861	6,277
3. Vacuum Distillation	17	22	*	59	*	453	574
4. Tankage (Mbbl)	682	1,566	*	2,330	*	15,100	20,408
5. Residual Conversion		7	*	30	*	224	288
6. Reforming	19	7		13		134	172
7. Isomerization				†		48	48
8. Hydrogen Manufacture (MMCF/D)	63	*	*	71	41	594	788
9. Catalytic Cracking		*	*	23	*	144	183
10. Coking (ST/D)					†	10,989	10,989
11. Crude Atmospheric Distillation		*	*	*		547	593
12. Visbreaking				*	*	*	43
13. Treating				*		*	23
14. Refineries Reporting Above Added Facilities							
1982 Crude Oil Capacity	41	294	254	808	795	8,651	10,842
1982 Crude Oil Throughput	34	275	218	775	735	8,122	10,159
Number of Refineries	5	14	5	16	9	49	98
15. Associated Refining Systems							
1982 Crude Oil Capacity	41	294	304	851	795	12,093	14,377
1982 Crude Oil Throughput	34	275	268	813	735	11,316	13,441
Number of Refineries	5	14	6	17	9	86	137
20 Percent Increase in High Sulfur Crude Capacity	8	59	61	170	159	2,419	2,875

*Entry withheld to protect confidentiality.
†Merged with adjacent higher size category to protect confidentiality.

TABLE 67

Additional Facilities Necessary to Increase
the Processing of High Sulfur Crude Oil
(Capacities Aggregated in MB/D)

Factors	Company Size (MB/D) 0-10	10-30	30-50	50-100	100-175	175+	Total
1. Metallurgy Adequate?							
• Associated Crude Charge Capacity (MB/D)							
Yes	31	155	*	272	*	4,817	5,963
No	34	164	*	386	*	3,843	4,740
• Associated Number of Refineries							
Yes	5	6	*	5	*	32	57
No	4	10	*	9	*	21	49
2. Obtain Necessary Permits?							
• Associated Crude Charge Capacity							
Yes	*	267	*	653	351	7,093	8,536
No	*	100	*		307	1,316	1,782
• Number of Refineries							
Yes	*	13	*	13	4	41	79
No	*	5	*		3	9	22
3. Lead Time Required							
• Associated Crude Capacity	44	267	173	474	550	7,034	8,720
• Number of Months	31	33	38	36	44	50	43
4. Likelihood of Installation							
• Associated Crude Capacity							
Low	*	212	*	*	499	6,352	7,498
Medium	*	96	*	347	291	1,461	2,316
High		*				*	621
Impossible	*	*		*		*	564
• Number of Refineries							
Low	*	10	*	*	6	35	66
Medium	*	4	*	5	3	10	28
High		*				*	7
Impossible	*	*		*		*	7

TABLE 67 (continued)

5. Refineries Reporting Above Added Facilities							
1982 Crude Capacity	41	294	254	808	795	8,651	10,842
1982 Crude Throughput	34	275	218	775	735	8,122	10,159
Number of Refineries	5	14	5	16	9	49	98
6. Associated Refining Systems							
1982 Crude Capacity	41	294	304	851	795	12,093	14,377
1982 Crude Throughput	34	275	268	813	735	11,316	13,441
Number of Refineries	5	14	6	17	9	86	137
20 Percent in High Sulfur Crude Capacity	8	59	61	170	159	2,419	2,875
7. Refineries Providing Only Qualitative Responses†							
Number of Refineries	14	11	10	5	0	15	55
1982 Crude Oil Capacity	84	160	300	110		1,340	1,993
1982 Crude Oil Runs	76	147	214	93		1,210	1,740
8. System Responses Requiring Facilities for Heavy High Sulfur Crude Oil, but not Light High							
Number of Refineries	*	*	0	*	*	6	14
1982 Crude Oil Capacity	*	*		*	*	876	1,126
1982 Crude Oil Runs	*	*		*	*	792	1,030
9. System Responses for Light High Sulfur Crude Oil Only							
Number of Refineries	*	4	*	0	0	4	10
1982 Crude Oil Capacity	*	88	*			492	627
1982 Crude Oil Runs	*	66	*			468	579

*Data withheld to protect confidentiality.
†Not included in Sections 1-6 above.

TABLE 68

System Crude Charge Capacity (MB/D) and Number of Refineries for Refiners Reporting Additional Facilities Needed to Increase the Processing of Light High Sulfur Crude Oil by At Least 20 Percent Beyond Facilities Committed to Prior to January 1, 1982

Geographic Area (PAD)	Refinery Size (MB/D) 0-10	10-30	30-50	50-100	100-175	175+	Total
I	*	*	0	438 (7)	*	708 (3)	1,373 (15)
II	*	*	371 (8)	957 (14)	1,051 (8)	*	3,812 (42)
III	0	260 (11)	204 (5)	647 (8)	940 (7)	4,366 (12)	6,416 (43)
IV	*	113 (6)	*				281 (10)
V	*	118 (5)	*	491 (6)	*	*	1,997 (23)
Total	45 (6)	635 (29)	862 (19)	2,532 (35)	2,826 (22)	6,977 (22)	13,878 (133)

*Data withheld to protect confidentiality.

TABLE 69

System Crude Charge Capacity (MB/D) and Number of Refineries for Refiners Reporting Additional Facilities Needed to Increase the Processing of Heavy High Sulfur Crude Oil by At Least 20 Percent Beyond Facilities Committed to Prior to January 1, 1982

Geographic Area (PAD)	Refinery Size (MB/D)						
	0-10	10-30	30-50	50-100	100-175	175+	Total
I	23 (3)	*	0	478 (8)	*	*	1,590 (18)
II	*	*	421 (9)	1,019 (15)	919 (7)	1,318 (5)	3,759 (41)
III	0	230 (10)	167 (4)	758 (10)	659 (5)	4,366 (12)	6,179 (41)
IV	*	*	203 (4)	0	0	0	326 (11)
V	*	112 (5)	130 (3)	536 (7)	*	*	2,524 (26)
Total	53 (7)	566 (26)	921 (20)	2,790 (40)	2,706 (21)	7,342 (23)	14,377 (137)

*Data withheld to protect confidentiality.

TABLE 70

System Crude Charge Capacity (MB/D) and Numbers of Refineries
for Refiners Reporting Additional Facilities Needed
to Increase Light High Sulfur Crude Oil by At Least 20 Percent
Beyond Facilities Committed Prior to January 1, 1982

Refinery Size (MB/D)	Complexity Factor						
	Under 3	3-5	5-7	7-9	9-11	11+	Total
0-10	31 (4)	*	0	0	*	0	46 (6)
10-30	213 (10)	*	190 (9)	*	0	0	635 (29)
30-50	*	133 (3)	361 (8)	181 (4)	*	*	862 (19)
50-100	*	*	1,074 (16)	819 (11)	266 (3)	254 (3)	2,532 (35)
100-175	0	391 (3)	550 (4)	*	727 (6)	*	2,826 (22)
175+	0	0	2,901 (8)	3,160 (11)	*	*	6,977 (22)
Total	402 (17)	776 (16)	5,076 (45)	5,130 (35)	1,234 (12)	1,259 (8)	13,878 (133)

*Data withheld to protect confidentiality.

TABLE 71

System Crude Charge Capacity (MB/D) and Numbers of Refineries
for Refiners Reporting Additional Facilities Needed
to Increase the Processing of Heavy High Sulfur Crude Oil by At Least 20 Percent
Beyond Facilities Committed to Prior to January 1, 1982

	Complexity Factor						
Refinery Size (MB/D)	Under 3	3-5	5-7	7-9	9-11	11+	Total
0-10	38 (5)	*	0	0	*	0	53 (7)
10-30	177 (9)	*	157 (7)	*	0	0	566 (26)
30-50	*	133 (3)	361 (8)	231 (5)	*	*	921 (20)
50-100	*	*	1,067 (16)	984 (14)	266 (3)	314 (4)	2,790 (40)
100-175	0	*	418 (3)	*	727 (6)	370 (3)	2,706 (21)
175+	0	0	2,901 (8)	3,525 (12)	*	*	7,342 (23)
Total	377 (17)	615 (15)	4,904 (42)	5,760 (40)	1,279 (13)	1,442 (10)	14,377 (137)

*Data withheld to protect confidentiality.

TABLE 72

System Crude Charge Capacity (MB/D) and Number of Refineries
for Refiners Reporting Additional Facilities Needed to Increase
the Processing of Light High Sulfur Crude Oil by At Least 20 Percent
Beyond Facilities Committed to Prior to January 1, 1982

Geographic Area (PAD)	Complexity Factor						
	Under 3	3-5	5-7	7-9	9-11	11+	Total
I	105 (5)	0	891 (6)	*	*	0	1,373 (15)
II	*	175 (3)	1,536 (21)	1,749 (12)	206 (3)	*	3,812 (42)
III	133 (5)	331 (4)	1,893 (10)	2,664 (16)	582 (4)	814 (4)	6,416 (43)
IV	*	82 (4)	85 (3)	*	0	0	281 (10)
V	55 (3)	189 (5)	671 (5)	399 (3)	*	*	1,997 (23)
Total	402 (17)	776 (16)	5,076 (45)	5,130 (35)	1,234 (12)	1,259 (8)	13,878 (133)

*Data withheld to protect confidentiality.

TABLE 73

System Crude Charge Capacity (MB/D) and Number of Refineries for Refiners Reporting Additional Facilities Needed to Increase the Processing of Heavy High Sulfur Crude Oil by At Least 20 Percent Beyond Facilities Committed to Prior to January 1, 1982

Geographic Area (PAD)	Complexity Factor: Under 3	3-5	5-7	7-9	9-11	11+	Total
I	152 (7)	0	891 (6)	*	*	0	1,590 (18)
II	*	175 (3)	1,371 (18)	1,861 (14)	206 (3)	*	3,759 (41)
III	66 (3)	170 (3)	1,893 (10)	2,594 (16)	582 (4)	874 (5)	5,179 (41)
IV	*	82 (4)	85 (3)	*	*	0	326 (11)
V	55 (3)	189 (5)	664 (5)	816 (5)	*	*	2,524 (26)
Total	377 (17)	615 (15)	4,904 (42)	5,760 (40)	1,279 (13)	1,442 (10)	14,377 (137)

*Data withheld to protect confidentiality.

fuel oil), roughly a 30 percent increase over expected 1982 capacity. In addition, 4,527 LT/D of sulfur recovery (a 30 percent increase), 531 million SCF/D of hydrogen manufacture (a 33 percent increase), and 299 MB/D of residual conversion (a 29 percent increase) would be required. Minor increases in other processing would also be required, as summarized in Tables 56, 59, 62, and 65 for refineries aggregated by complexity, size, and location and for companies by size.

Increasing heavy high sulfur crude oil processing capability by at least 20 percent would require 2,518 MB/D of desulfurization facilities (a 30 percent increase), 6,277 LT/D of sulfur recovery (a 44 percent increase), 788 million SCF/D of hydrogen manufacture (a 50 percent increase), and 488 MB/D of residual conversion (a 47 percent increase). Additional processing requirements are summarized in Tables 57, 60, 63, and 66 for refineries aggregated by complexity, size, and location and for companies by size. The increased residual conversion capability previously referred to has been approximated from these tables by assuming that coking yields are 0.055 tons of coke per barrel charge. (Because there was no specific category of coking capacity in the questionnaire, some respondents included it in the residual conversion category, while others provided coking capacity in tons per day and footnoted it as such.) The capital cost of facilities required for processing more high sulfur crude oil will be deferred for the final report.

Exhibit 1 is a summary of the total additional refinery facilities required to process more high sulfur crude oil equivalent to at least 20 percent of the total crude oil capacity, based on the 1982 projection reported in responses to Part I of the survey.

A breakdown of the data by refinery size, complexity, geographic region, and company size is somewhat limited because of the

EXHIBIT 1

Facilities	Light High Sulfur Crude Oil: Added Capacity (MB/D)	Light High Sulfur Crude Oil: Number of Refineries	Heavy High Sulfur Crude Oil: Added Capacity (MB/D)	Heavy High Sulfur Crude Oil: Number of Refineries
Desulfurization				
Naphtha	398	33	300	30
Distillate	1,279	77	1,316	76
Heavy Fuel Oil	685	51	902	52
	2,362		2,518	
Sulfur Plant & Tail Gas (LT/D)	4,527	71	6,277	68
Atmospheric Distillation	601	15	593	15
Vacuum Distillation	382	31	574	47
Tankage (Storage) (Mbbl)	20,816	53	20,408	51
Residual Conversion*	299	24	488	34
Reforming	199	23	172	21
Isomerization	50	7	48	8
Hydrogen Manufacturing (MMSCF/D)	531	40	788	44
Catalytic Cracking	142	11	183	18
Visbreaking	26	4	43	4
Treating	31	5	23	4

*Coking facilities were included with residual conversion.

insufficient number of responses for some of the categories, thus requiring consolidation to protect the confidentiality of respondents.

With respect to refinery size, the most significant increases (relative to their present capability) occurred in refineries of 50-100 MB/D, especially for vacuum distillation and sulfur recovery. This is not surprising when considering that refineries of this size indicated the lowest 1978 percentage of medium and high sulfur crude processing in Part I of the survey (about 35 percent as compared to 50 percent on company average). Refineries in the 175+ MB/D capacity range reported the lowest need for added facilities to process more high sulfur crude oil.

With respect to geographic location, the necessity for additional facilities to process high sulfur crude oil appears to be concentrated in PADs II and III. These districts have the bulk of the refining capacity and are relatively limited in their present capacity to process medium and high sulfur crudes.

The part of the survey which concerned high sulfur crude processing capability addressed such issues as present metallurgical limitations, permitting problems, lead time required, and likelihood of installing the required facilities.

A number of refineries (55, with a combined 1982 crude capacity of 1,993 MB/D) answered only the qualitative questions posed by the questionnaire and provided no response on the additional capacity required to process more high sulfur crude; their answers were not included in the aggregation of responses to the qualitative question as including these responses would not significantly change the results of the survey, except with regard to the question of whether present metallurgy is adequate for high sulfur crude processing. It appears that a much larger than average percentage of the refining capacity responding only to the qualitative question did not have adequate metallurgy to process added high sulfur crude oil.

Present metallurgy is not adequate for about 44 percent of the respondents' refining capacity. Those small refiners (companies) of under 100 MB/D appear to be in relatively worse shape than large ones in this respect. Although 83 percent of respondent capacity looked with optimism upon the likelihood of obtaining permits for these facilities, there is a very low expectation that such facilities will be installed (about 73 percent of respondent capacity indicating low probability and only six percent indicating high probability). This apparent inconsistency might be explained by the existing plans for a significant increase in high and medium sulfur crude processing capability for 1982 as compared with 1978; an additional 20 percent of crude capacity to process high sulfur crude would push this capability to about 70 percent or more (medium plus high sulfur). Respondents may have considered that the additional capability for high sulfur crude capacity over their firm plans for 1982 is not required.

The average lead time required to bring the facilities on stream, including time for authorization, permitting, design, engineering, and construction, was estimated to be 43 months. This lead time estimate increases as refinery size, refinery complexity, and company size increase. With respect to geographic region, refineries in PADs II and III, where most activity is centered have the highest lead time requirements. Supporting data for the above observations concerning metallurgy, permitting, lead times, and probability of implementation are found in Tables 58, 61, 64, and 67.

INCREASED UNLEADED GASOLINE MANUFACTURING CAPABILITY

The data base for the following observations on the added facilities which would be needed to increase the manufacture of unleaded gasoline to 90 percent of the total gasoline pool are aggregated by refinery size in Tables 74, 75, and 76; by refinery location in Tables 77, 78, and 79; by refinery complexity in Tables 80, 81, and 82; and by company size in Tables 83, 84, and 85. Tables 86, 87, 88, 89, 90, and 91 provide demographic data for refineries responding to Part III of the survey.

Companies representing 77.5 percent of total U.S. refining capacity reported a requirement for additional facilities beyond those planned to be in operation by 1982 if they were to provide 90 percent of their gasoline product mix as 89 (R+M)/2 unleaded gasoline without significantly sacrificing the gasoline production volume; respondents generally are much better equipped to supply 87 (R+M)/2 unleaded gasoline. The types of processing most commonly selected to increase gasoline pool octane were reforming and isomerization, as well as the required feedstock hydrotreating; some refiners also expected to have to either provide additional facilities for naphtha fractionation or increase catalytic cracking and alkylation unit capacity. A small number of additional crude processing facilities were required to maintain the gasoline production volume at the 90 percent unleaded gasoline pool mix.

Respondents to the survey indicated a need to increase reforming capacity by 231 MB/D at 55 refineries in order to produce a 90 percent unleaded gasoline mix at 87 (R+M)/2 octane. The respondents also indicated a need to increase isomerization capacity by 146 MB/D at 33 refineries. Over half of the respondents with crude oil capacity of 30 MB/D or less will require additional reforming capacity to meet this level of unleaded gasoline production. Few of the larger refineries (of 175+ MB/D crude capacity) require additional facilities to meet this unleaded octane level (Table 74). With respect to geographic location, PAD V projections of 1982 capability to manufacture 90 percent unleaded gasoline appear to be more nearly adequate than other areas (Table 77).

TABLE 74

Additional Facilities Necessary to Increase
Unleaded Gasoline Manufacturing Capacity
to 90 Percent of Total 1982 Gasoline Production
(87 R+M/2)
(Capacities Aggregated in MB/D)

	Refinery Size (MB/D)						
Process Type	0-10	10-30	30-50	50-100	100-175	175+	Total
1. Crude Oil Distillation	*	1	*		*		32
2. Vacuum Distillation	10	12	†	*	*	*	57
3. Reforming	35	54	31	54	*	*	231
4. Isomerization	*	13	26	44	37	*	146
5. Alkylation	*	*	11	17	5	*	40
6. Catalytic Cracking	18	5	26	*	*	*	148
7. Hydrotreating	9	48	29	73	*	*	181
8. Hydrocracking	9		*	*	*		43
9. Hydrogen Generation	9	45	*	*	*		77
10. Polymerization	*		*	*			6
11. Naphtha Splitter		29	*	*	39		132
12. Refineries Reporting Above Facilities							
1982 Crude Oil Capacity	84	502	594	1,026	1,562	1,618	5,385
1982 Crude Oil Throughput	75	431	551	1,011	1,456	1,513	5,037
Number of Refineries	13§	25	13	16	12	7	86
1982 Gasoline Production	22	180	252	550	850	766	2,621
13. Associated Refining Systems							
1982 Crude Oil Capacity	84	541	819	1,377	1,898	2,698	7,417
1982 Crude Oil Throughput	75	454	740	1,338	1,772	2,506	6,885
Number of Refineries	13§	27	18	22	15	10	105
1982 Gasoline Production	22	180	371	717	999	1,209	3,499
90 Percent of 1982 Gasoline Production	20	162	334	645	899	1,088	3,149

*Data withheld to protect confidentiality.
†Merged with adjacent higher size category to protect confidentiality.
§Includes two refineries with no crude runs, but substantive feedstocks of other types.

TABLE 75

Additional Facilities Necessary to Increase
Unleaded Gasoline Manufacturing Capacity
to 90 Percent of Total 1982 Production
(89 R+M/2)
(Capacities Aggregated in MB/D)

Process Type	Refinery Size (MB/D) 0-10	10-30	30-50	50-100	100-175	175+	Total
1. Crude Oil Distillation	*	1	*	*	*		37
2. Vacuum Distillation		11	7	*	*		50
3. Reforming	21	61	41	122	133	189	567
4. Isomerization		26	53	94	90	158	421
5. Alkylation		5	14	18	5		43
6. Catalytic Cracking	9	7	26	*	*		96
7. Hydrotreating	8	49	33	124	58	231	504
8. Hydrocracking	*	*	*	*	*		51
9. Hydrogen Generation (MMCF/D)	*	45	*	*	*		85
10. Polymerization	*		*	*			6
11. Naphtha Splitter		40	*	125	58	*	298
12. Refineries Reporting Above Facilities							
1982 Crude Oil Capacity	44	597	979	2,035	2,555	6,215	12,425
1982 Crude Oil Throughput	32	514	894	1,959	2,417	5,833	11,649
Number of Refineries	7†	29	22	28	19	19	124
1982 Gasoline Production	12	214	475	1,158	1,359	2,522	4,740
13. Associated Refining Systems							
1982 Crude Oil Capacity	44	694	1,126	2,705	2,921	7,340	14,830
1982 Crude Oil Throughput	32	591	1,027	2,589	2,738	6,919	13,896
Number of Refineries	7†	34	25	38	22	23	149
1982 Gasoline Production	12	244	547	1,449	1,519	3,068	6,838
90 Percent of 1982 Gasoline Production	11	220	492	1,304	1,367	2,761	6,154

*Data withheld to protect confidentiality.
†Includes one refinery with no crude runs, but substantive feedstocks of other types.

TABLE 76

Additional Facilities Necessary to Increase
Unleaded Gasoline Manufacturing Capacity
to 90 Percent of Total 1982 Gasoline Production

Factors	Refinery Size 0-10	10-30	30-50	50-100	100-175	175+	Total
1. Obtain Necessary Permits?							
• Associated Crude Capacity							
Yes	*	*	*	*	1,440	5,747	10,380
No	*	*	*	*	564		894
• Associated Number of Refineries							
Yes	*	*	*	*	11	18	115
No	*	*	*	*	4		10
2. Leadtime Required							
• Refinery Crude Capacity	47	569	890	1,895	1,851	5,204	10,485
• Number of Months Leadtime	35	33	37	38	43	43	37
3. Likelihood of Installation							
• Refinery Crude Capacity							
Low	28	274	573	739	1,142	2,429	5,185
Medium	43	301	235	1,134	947	2,197	4,857
High	32	*	118	179	*	1,121	1,606
Impossible	*		*				*
• Number of Refineries							
Low	4	13	13	10	8	7	55
Medium	6	14	6	15	8	6	55
High	5	*	*	3	*	5	18
Impossible	*		*				*
4. Refineries Reporting Above Facilities							
1982 Crude Capacity	44	597	979	2,035	2,555	6,215	12,425
1982 Crude Throughput	32	514	894	1,959	2,417	5,833	11,649
Number of Refineries	7†	29	22	28	19	19	124
1982 Gasoline Production	12	214	475	1,158	1,359	2,522	5,740
5. Associated Refining System							
1982 Crude Capacity	44	694	1,126	2,705	2,921	7,340	14,830
1982 Crude Throughput	32	591	1,027	2,589	2,738	5,919	13,896
Number of Refineries	7†	34	25	38	22	23	149
1982 Gasoline Production	12	244	547	1,449	1,519	3,068	6,838
90 Percent of 1982 Production	11	220	492	1,304	1,367	2,761	6,154

TABLE 76 (continued)

6. Refineries Providing Only Qualitative Responses§							
Number of Refineries	3	4	*	*	3	0	14
1982 Crude Oil Capacity	16	83	*	*	393		691
1982 Gasoline Production	5	21	*	*	148		246
7. System Responses Requiring Facilities at 89, but not 87							
Number of Refineries	0	3	9	13	8	15	48
1982 Crude Oil Capacity		76	379	995	1,113	5,329	7,892
1982 Gasoline Production		27	188	598	560	2,168	3,541
8. System Responses Specifying Facilities for 87 R+M/2 Only							
Number of Refineries	4	*	*	*	0	*	8
1982 Crude Oil Capacity	26	*	*	*		*	377
1982 Gasoline Production	10	*	*	*		*	131

*Data withheld to protect confidentiality.

†Includes one refinery with no crude runs, but substantive feedstocks of other types.

§Most typical supplementary comments: (1) Already at 90 percent or Greater Unleaded; (2) Refinery does not manufacture gasoline.

TABLE 77

Additional Facilities Necessary to Increase
Unleaded Gasoline Manufacturing Capacity
to 90 Percent of Total 1982 Gasoline Production
(87 R+M/2)
(Capacities Aggregated in MB/D)

Process Type	Geographic Area (PAD)					Total
	I	II	III	IV	V	
1. Crude Oil Distillation		*	*	*		32
2. Vacuum Distillation		6	41	*	*	57
3. Reforming	†	67	112	29	22	231
4. Isomerization	*	67	60	*	6	146
5. Alkylation	†	27	10		4	40
6. Catalytic Cracking	*	59	60	*	*	148
7. Hydrotreating		34	107	28	12	181
8. Hydrocracking		*	*	*	29	43
9. Hydrogen Generation (MMCF/D)		*	48	*	*	77
10. Polymerization	*	*	*	*		6
11. Naphtha Splitter	*	*	*	24	*	132
12. Refineries Reporting Above Facilities						
1982 Crude Oil Capacity	318	1,606	2,203	255	1,003	5,385
1982 Crude Oil Throughput	302	1,555	2,055	214	912	5,037
Number of Refineries	4	24	28§	13	17	86
1982 Gasoline Production	145	924	993	119	440	2,621
13. Associated Refining Systems						
1982 Crude Oil Capacity	595	2,465	2,760	341	1,257	7,417
1982 Crude Oil Throughput	560	2,331	2,583	281	1,131	6,885
Number of Refineries	8	30	31§	15	21	105
1982 Gasoline Production	251	1,290	1,267	153	538	3,499
90 Percent of 1982 Gasoline Production	226	1,161	1,140	138	484	3,149

*Data withheld to protect confidentiality.
†Merged with adjacent higher size category to protect confidentiality.
§Includes two refineries with no crude runs, but substantive feedstocks of other types.

TABLE 78

Additional Facilities Necessary to Increase
Unleaded Gasoline Manufacturing Capacity
to 90 Percent of Total 1982 Gasoline Production
(89 R+M/2)
(Capacities Aggregated in MB/D)

Process Type	Geographic Area (PAD) I	II	III	IV	V	Total
1. Crude Oil Distillation	*	10	*	*		37
2. Vacuum Distillation		9	36	*	*	50
3. Reforming	47	125	285	34	76	567
4. Isomerization	29	172	149	12	59	421
5. Alkylation	*	27	6	*	4	43
6. Catalytic Cracking	*	64	*	*	*	96
7. Hydrotreating	†	103	300	24	77	504
8. Hydrocracking		*	18	*	*	51
9. Hydrogen Generation (MMCF/D)		20	65	§		85
10. Polymerization	*	*	*	*		6
11. Naphtha Splitter	*	78	177	28	*	298
12. Refineries Reporting Above Facilities						
1982 Crude Oil Capacity	1,209	3,319	5,175	437	2,285	12,425
1982 Crude Oil Throughput	1,189	3,174	4,899	379	2,007	11,649
Number of Refineries	8	37	39¶	18	24	124
1982 Gasoline Production	596	1,769	2,278	208	890	5,740
13. Associated Refining Systems						
1982 Crude Oil Capacity	1,617	3,875	6,184	505	2,649	14,830
1982 Crude Oil Throughput	1,571	3,706	5,846	433	2,341	13,896
Number of Refineries	14	43	45¶	18	29	149
1982 Gasoline Production	755	2,063	2,758	233	1,030	6,838
90 Percent of 1982 Gasoline Production	680	1,857	2,482	210	927	6,154

*Data withheld to protect confidentiality.
†Merged with adjacent higher size category to protect confidentiality.
§Merged with adjacent lower size category to protect confidentiality.
¶Includes one refinery with no crude runs, but substantive feedstocks of other types.

TABLE 79

Additional Facilities Necessary to Increase
Unleaded Gasoline Manufacturing Capacity
(Capacities Aggregated in MB/D)

Factors	Geographic Area (PAD) I	II	III	IV	V	Total
1. Obtain Necessary Permits?						
• Associated Crude Charge Capacity						
Yes	*	2,539	*	*	1,790	10,380
No	*	374	*	*	282	894
• Associated Number of Refineries						
Yes	*	33	*	*	19	115
No	*	3	*	*	4	10
2. Lead Time Required						
• Refinery Crude Capacity	934	2,932	4,561	416	1,642	10,485
• Number of Months	34	39	36	34	41	37
3. Likelihood of Installation						
• Refinery Crude Capacity						
Low	476	1,912	1,106	270	1,462	5,227
Medium	*	874	2,816	*	590	4,857
High	*	267	1,063	*	63	1,606
Impossible†						
• Number of Refineries						
Low	3	21	8	12	13	57
Medium	*	14	24	*	8	55
High	*	3	10	*	3	18
Impossible†						
4. Refineries Reporting Above Facilities						
1982 Crude Capacity	1,209	3,319	5,175	437	2,285	12,425
1982 Crude Throughput	1,189	3,174	4,899	379	2,007	11,649
Number of Refineries	8	37	39§	18	24	124
1982 Gasoline Production	596	1,769	2,278	208	890	5,740
5. Associated Refining Systems						
1982 Crude Capacity	1,617	3,875	6,184	505	2,649	14,830
1982 Crude Throughput	1,571	3,706	5,846	433	2,341	13,896
Number of Refineries	14	43	45§	18	29	149
1982 Gasoline Production	755	2,063	2,758	233	1,030	6,838
90 Percent of 1982 Gasoline Production	680	1,857	2,482	210	927	6,154

TABLE 79 (continued)

6. Refineries Providing Only Qualitative Responses¶						
Number of Refineries	*	*	4	*	3	14
1982 Crude Oil Capacity	*	*	245	*	152	691
1982 Gasoline Production	*	*	74	*	65	246
7. System Responses Requiring Facilities at 89, but not 87						
Number of Refineries	6	15	14	6	7	48
1982 Crude Oil Capacity	984	1,831	3,678	238	1,161	7,892
1982 Gasoline Production	488	888	1,669	107	389	3,541
8. System Responses Specifying Facilities for 87 R+M/2 Only						
Number of Refineries	0	*	4	*	*	8
1982 Crude Oil Capacity		*	299	*	*	377
1982 Gasoline Production		*	95	*	*	131

*Data withheld to protect confidentiality.
†Merged with "Low" to protect confidentiality.
§Includes one refinery with no crude runs, but substantive feedstocks with other types.
¶Not included in Sections 1-5 above.

TABLE 80

Additional Facilities Necessary to Increase
Unleaded Gasoline Manufacturing Capacity
to 90 Percent of Total 1982 Gasoline Production
(87 R+M/2)
(Capacities Aggregated in MB/D)

Process Type	Complexity Factor 0-3	3-5	5-7	7-9	9-11	11+	Total
1. Crude Oil Distillation	*	*	*	*		*	32
2. Vacuum Distillation	*	9	20	*		*	57
3. Reforming	69	35	31	85		*	231
4. Isomerization	*	40	55	15	*	15	146
5. Alkylation	*	*	17	16	*	*	40
6. Catalytic Cracking	19	*	80	33		*	148
7. Hydrotreating	41	14	17	66		42	181
8. Hydrocracking	29	*		*		*	43
9. Hydrogen Generation (MMCF/D)	15	*	*	*		*	77
10. Polymerization		*	*				6
11. Naphtha Splitter	*	*	43	76			132
12. Refineries Reporting Above Facilities							
1982 Crude Oil Capacity	392	681	1,226	2,220	506	361	5,385
1982 Crude Oil Throughput	327	642	1,207	2,033	484	343	5,037
Number of Refineries	20†	18	21	18	5	4	86
1982 Gasoline Production	69	231	688	1,087	322	223	2,621
13. Associated Refining Systems							
1982 Crude Oil Capacity	486	838	1,741	2,905	652	796	7,417
1982 Crude Oil Throughput	389	786	1,689	2,656	611	753	6,885
Number of Refineries	23†	20	27	23	7	5	105
1982 Gasoline Production	82	296	906	1,387	397	431	3,499
90 Percent of 1982 Gasoline Production	74	266	815	1,248	357	388	3,149

*Data withheld to protect confidentiality.
†Includes two refineries with no crude runs, but substantive feedstocks of other types.

TABLE 81

Additional Facilities Necessary to Increase
Unleaded Gasoline Manufacturing Capacity
to 90 Percent of Total 1982 Production
(89 R+M/2)
(Capacities Aggregated in MB/D)

Process Type	Complexity Factor 0-3	3-5	5-7	7-9	9-11	11+	Total
1. Crude Oil Distillation	*	*	*	27		*	37
2. Vacuum Distillation	48	9	5	19	*	*	50
3. Reforming	9	70	166	184	38	61	567
4. Isomerization	*	59	109	177	46	21	421
5. Alkylation	12	3	16	16	*	*	43
6. Catalytic Cracking	38	*	30	*		*	96
7. Hydrotreating	*	27	173	194	†	73	504
8. Hydrocracking	*	*		*	*	*	51
9. Hydrogen Generation (MMCF/D)	*	*	*	*		*	85
10. Polymerization		*	*				6
11. Naphtha Splitter	*	*	89	137	*		298
12. Refineries Reporting Above Facilities							
1982 Crude Oil Capacity	320	863	4,746	4,806	867	824	12,425
1982 Crude Oil Throughput	261	799	4,524	4,486	820	759	11,649
Number of Refineries	16§	20	40	31	9	8	124
1982 Gasoline Production	67	310	2,015	2,348	531	469	5,740
13. Associated Refining Systems							
1982 Crude Oil Capacity	414	910	5,439	5,748	1,061	1,259	14,830
1982 Crude Oil Throughput	323	832	5,173	5,391	1,008	1,169	13,896
Number of Refineries	19§	21	50	39	11	9	149
1982 Gasoline Production	80	325	2,299	2,841	617	676	6,838
90 Percent of 1982 Gasoline Production	72	292	2,069	2,557	555	608	6,154

*Data withheld to protect confidentiality.
†Merged with adjacent lower size category to protect confidentiality.
§Includes one refinery with no crude runs, but substantive feedstocks of other types.

TABLE 82

Additional Facilities Necessary to Increase Unleaded Gasoline Manufacturing Capacity to 90 Percent of Total 1982 Gasoline Production

Factors	Complexity Factor Range 0-3	3-5	5-7	7-9	9-11	11+	Total
1. Obtain Necessary Permits?							
• Associated Crude Charge Capacity							
Yes	*	*	*	*	790	*	10,380
No	*	*	*	*		*	894
• Associated Number of Refineries							
Yes	*	*	*	*	8	*	115
No	*	*	*	*		*	10
2. Lead Time Required							
• Refinery Crude Capacity	386	980	4,100	3,683	790	546	10,485
• Number of Months	34	34	39	38	43	42	37
3. Likelihood of Installation							
• Refinery Crude Capacity							
Low	209	417	*	2,043	*	402	5,227
Medium	*	440	1,931	*	625	*	4,857
High	*	293	*	*	*	*	1,606
Impossible†							
• Number of Refineries							
Low	11	9	*	13	*	5	57
Medium	*	9	12	*	5	*	55
High	*	6	*	*	*	*	18
Impossible†							
4. Refineries Reporting Above Facilities							
1982 Crude Capacity	320	863	4,746	4,806	867	824	12,425
1982 Crude Throughput	261	799	4,524	4,486	820	759	11,649
Number of Refineries	16§	20	40	31	9	8	124
1982 Gasoline Production	67	310	2,015	2,348	531	469	5,740
5. Associated Refining Systems							
1982 Crude Capacity	414	910	5,439	5,748	1,061	1,259	14,380
1982 Crude Throughput	323	832	5,173	5,391	1,008	1,169	13,896
Number of Refineries	19§	21	50	39	11	9	149
1982 Gasoline Production	80	325	2,299	2,841	617	676	6,838
90 Percent of 1982 Gasoline Production	72	292	2,069	2,557	555	608	6,154

TABLE 82 (continued)

6. Refineries Providing Only Qualitative Responses[¶]							
Number of Refineries	4	4	*	3	*	0	14
1982 Crude Oil Capacity	36	98	*	244	*		691
1982 Gasoline Production	8	24	*	92	*		246
7. System Responses Requiring Facilities at 89, but not 87							
Number of Refineries	*	4	20	15	*	5	48
1982 Crude Oil Capacity	*	222	3,186	3,054	*	1,083	7,892
1982 Gasoline Production	*	92	1,241	1,493	*	525	3,541
8. System Responses Specifying Facilities for 87 R+M/2 Only							
Number of Refineries	*	3	*	*	0	0	8
1982 Crude Oil Capacity	*	34	*	*			377
1982 Gasoline Production	*	11	*	*			131

*Data withheld to protect confidentiality.
†Merged with "Low" to protect confidentiality.
§Includes one refinery with no crude runs, but substantive feedstocks with other types.
¶Not included in Sections 1-5 above.

TABLE 83

Additional Facilities Necessary to Increase
Unleaded Gasoline Manufacturing Capacity
to 90 Percent of Total 1982 Production
(89 R+M/2)
(Capacities Aggregated in MB/D)

Process Type	Company Size (MB/D) 0-10	10-30	30-50	50-100	100-175	175+	Total
1. Crude Oil Distillation	*	*		*		*	32
2. Vacuum Distillation	10	*		*		35	57
3. Reforming	30	40	†	38		123	231
4. Isomerization	*	*	10	35	24	75	146
5. Alkylation		*	4	*	*	26	40
6. Catalytic Cracking	*	12	*	*		100	148
7. Hydrotreating	*	35	*	20	*	102	181
8. Hydrocracking	9			*		*	43
9. Hydrogen Generation (MMCF/D)	*	44		*		*	77
10. Polymerization		*	*	*		*	6
11. Naphtha Splitter		*		*		119	132
12. Refineries Reporting Above Facilities							
1982 Crude Oil Capacity	55	314	291	540	352	3,834	5,385
1982 Crude Oil Throughput	49	293	254	506	327	3,609	5,037
Number of Refineries	9§	18	7	14	4	34	86
1982 Gasoline Production	14	102	87	263	159	1,996	2,621
13. Associated Refining Systems							
1982 Crude Oil Capacity	55	314	390	595	352	5,711	7,417
1982 Crude Oil Throughput	49	293	350	544	327	5,323	6,885
Number of Refineries	9§	18	9	15	4	50	105
1982 Gasoline Production	14	102	146	275	159	2,802	3,499
90 Percent of 1982 Gasoline Production	13	92	131	248	143	2,522	3,149

*Data withheld to protect confidentiality.
†Merged with adjacent lower size category to protect confidentiality.
§Includes two refineries with no crude runs, but substantive feedstocks of other types.

TABLE 84

Additional Facilities Necessary to Increase
Unleaded Gasoline Manufacturing Capacity
to 90 Percent of Total 1982 Production
(89 R+M/2)
(Capacities Aggregated in MB/D)

Process Type	Company Size (MB/D)						
	0-10	10-30	30-50	50-100	100-175	175+	Total
1. Crude Oil Distillation	*	*		*		25	37
2. Vacuum Distillation	†	10		16		23	50
3. Reforming	15	40	†	38	22	453	567
4. Isomerization		12	13	28	48	320	421
5. Alkylation		4	7	7	†	25	43
6. Catalytic Cracking		15	*	*		*	96
7. Hydrotreating	*	39	*	19	*	421	504
8. Hydrocracking	*	*		*		*	51
9. Hydrogen Generation (MMCF/D)		55		†		30	85
10. Polymerization		*	*	*		*	6
11. Naphtha Splitter		*		*	*	240	298
12. Refineries Reporting Above Facilities							
1982 Crude Oil Capacity	15	359	304	625	681	10,442	12,425
1982 Crude Oil Throughput	*	*	265	594	633	9,824	11,649
Number of Refineries	3§	20	7	14	8	72	124
1982 Gasoline Production	4	116	112	353	330	4,825	5,740
13. Associated Refining Systems							
1982 Crude Oil Capacity	15	359	354	723	681	12,698	14,830
1982 Crude Oil Throughput	*	*	315	671	633	11,944	13,896
Number of Refineries	3§	20	8	16	8	94	149
1982 Gasoline Production	4	116	142	383	330	5,863	6,838
90 Percent of 1982 Gasoline Production	4	104	128	345	297	5,277	6,154

*Data withheld to protect confidentiality.
†Merged with adjacent lower size category to protect confidentiality.
§Includes one refinery with no crude runs, but substantive feedstocks of other types.

TABLE 85

Additional Facilities Necessary to Increase
Unleaded Gasoline Manufacturing Capacity
to 90 Percent of Total 1982 Gasoline Production
(Capacities Aggregated in MB/D)

Factors	Company Size Category (MB/D) 0-10	10-30	30-50	50-100	100-175	175+	Total
1. Obtain Necessary Permits?							
• Associated Crude Charge Capacity							
Yes	*	379	179	649	*	8,697	10,380
No	*				*	755	894
• Associated Number of Refineries							
Yes	*	21	5	15	*	59	115
No	*				*	8	10
2. Lead Time Required							
• Refinery Crude Capacity	48	367	223	664	546	8,658	10,485
• Number of Months	35	31	28	33	39	41	37
3. Likelihood of Installation							
• Refinery Crude Capacity							
Low	23	*	*	208	*	4,621	5,227
Medium	25	203	123	348	389	3,770	4,857
High	23	*	*	*	*	1,430	1,606
Impossible†							
• Number of Refineries							
Low	4	*	*	7	*	34	57
Medium	3	12	3	6	4	27	55
High	4	*	*	*	*	9	18
Impossible†							
4. Refineries Reporting Above Facilities							
1982 Crude Capacity	15	359	304	625	681	10,442	12,425
1982 Crude Throughput	*	*	265	594	633	9,824	11,649
Number of Refineries	3§	20	7	14	8	72	124
1982 Gasoline Production	4	116	112	353	330	4,825	5,740
5. Associated Refining Systems							
1982 Crude Capacity	15	359	354	723	681	12,698	14,380
1982 Crude Throughput	*	*	315	671	633	11,944	13,896
Number of Refineries	3§	20	8	16	8	94	149
1982 Gasoline Production	4	116	142	383	330	5,863	6,838
90 Percent of 1982 Gasoline Production	4	104	128	345	297	5,277	6,154

TABLE 85 (continued)

6. Refineries Providing Only Qualitative Responses¶							
Number of Refineries	*	3	*	*	0	4	14
1982 Crude Oil Capacity	*	68	*	*		399	691
1982 Gasoline Production	*	18	*	*		151	246
7. System Responses Requiring Facilities at 89, but not 87							
Number of Refineries	0	*	0	*	4	41	48
1982 Crude Oil Capacity		*		*	329	7,353	7,892
1982 Gasoline Production		*		*	171	3,243	3,541
8. System Responses Specifying Facilities for 87 R+M/2 Only							
Number of Refineries	4	*	*	*	0	*	8
1982 Crude Oil Capacity	26	*	*	*		*	377
1982 Gasoline Production	10	*	*	*		*	131

*Data withheld to protect confidentiality.
†Merged with "Low" to protect confidentiality.
§Includes one refinery with no crude runs, but substantive feedstocks with other types.
¶Not included in Sections 1-5 above.

TABLE 86

System Crude Charge Capacity (MB/D) and Number of Refineries
for Refiners Reporting Additional Facilities Needed
to Increase Unleaded Gasoline Production at 87 R+M/2
to 90 Percent of Total 1982 Gasoline Production

Geographic Area (PAD)	Refinery Size (MB/D)						
	0-10	10-30	30-50	50-100	100-175	175+	Total
I	0	*		199 (4)	*	*	595 (8)
II	*	*	237 (5)	665 (10)	602 (5)	855 (3)	2,465 (30)
III	35 (5)	171 (8)	174 (4)	336 (5)	566 (4)	1,478 (5)	2,760 (31)
IV	20 (4)	128 (7)	194 (4)	0	0	0	341 (15)
V	*	107 (5)	215 (5)	178 (3)	*	*	1,257 (21)
Total	84 (13)	541 (27)	819 (18)	1,377 (22)	1,898 (15)	2,698 (10)	7,417 (105)

*Data withheld to protect confidentiality.

TABLE 87

System Crude Charge Capacity (MB/D) and Number of Refineries for Refiners Reporting Additional Facilities Needed to Increase Unleaded Gasoline Production at 89 R+M/2 to 90 Percent of Total 1982 Gasoline Production

Geographic Area (PAD)	Refinery Size (MB/D) 0-10	10-30	30-50	50-100	100-175	175+	Total
I	0	*	0	388 (6)	482 (3)	*	1,617 (14)
II	*	*	421 (9)	959 (14)	1,051 (8)	1,318 (5)	3,875 (43)
III	28 (4)	228 (11)	170 (4)	689 (9)	706 (5)	4,364 (12)	6,184 (45)
IV	*	*	321 (7)	0	0	0	505 (18)
V	0	*	215 (5)	669 (9)	683 (6)	*	2,649 (29)
Total	44 (7)	694 (34)	1,126 (25)	2,705 (38)	2,921 (22)	7,340 (23)	14,830 (149)

*Data withheld to protect confidentiality.

TABLE 88

System Crude Charge Capacity (MB/D) and Numbers of Refineries
for Refiners Reporting Additional Facilities Needed
to Increase Unleaded Gasoline Production at 87 R+M/2
to 90 Percent of Total 1982 Gasoline Production

Refinery Size (MB/D)	Complexity Factor: Under 3	3-5	5-7	7-9	9-11	11+	Total
0-10	41 (7)	32 (4)	*	0	*	0	84 (13)
10-30	203 (11)	*	143 (7)	*	0	0	541 (27)
30-50	*	181 (4)	267 (6)	*	*	0	819 (18)
50-100	*	*	461 (8)	540 (8)	*	*	1,377 (22)
100-175	0	391 (3)	*	501 (4)	509 (4)	*	1,898 (15)
175+	0	0	*	1,650 (6)	0	*	2,698 (10)
Total	486 (23)	838 (20)	1,741 (27)	2,905 (23)	652 (7)	796 (5)	7,417 (105)

*Data withheld to protect confidentiality.

TABLE 89

System Crude Charge Capacity (MB/D) and Numbers of Refineries
for Refiners Reporting Additional Facilities Needed
to Increase Unleaded Gasoline Production at 89 R+M/2
to 90 Percent of Total 1982 Gasoline Production

Refinery Size (MB/D)	Complexity Factor						
	Under 3	3-5	5-7	7-9	9-11	11+	Total
0-10	20 (4)	*	0	0	*	0	44 (7)
10-30	229 (12)	*	226 (11)	*	0	0	694 (34)
30-50	*	221 (5)	443 (10)	*	*	0	1,126 (25)
50-100	*	*	1,085 (16)	915 (13)	266 (3)	314 (4)	2,705 (38)
100-175	0	391 (3)	550 (4)	962 (7)	509 (4)	510 (4)	2,921 (22)
175+	0	0	3,134 (9)	3,575 (12)	*	*	7,340 (23)
Total	414 (19)	910 (21)	5,439 (50)	5,748 (39)	1,061 (11)	1,259 (9)	14,830 (149)

*Data withheld to protect confidentiality.

TABLE 90

System Crude Charge Capacity (MB/D) and Numbers of Refineries
for Refiners Reporting Additional Facilities Needed
to Increase Unleaded Gasoline Production at 87 (R+M)/2
to 90 Percent of Total 1982 Gasoline Production

Geographic Area (PAD)	Complexity Factor						
	Under 3	3-5	5-7	7-9	9-11	11+	Total
I	*	0	*	*	0	0	595 (8)
II	*	138 (3)	1,010 (15)	1,059 (8)	*	*	2,465 (30)
III	140 (9)	377 (6)	328 (4)	1,093 (7)	*	*	2,760 (31)
IV	89 (4)	107 (5)	*	*	0	0	341 (15)
V	165 (6)	216 (6)	*	399 (3)	254 (3)	*	1,257 (21)
Total	486 (23)	838 (20)	1,741 (27)	2,905 (23)	652 (7)	796 (5)	7,417 (105)

*Data withheld to protect confidentiality.

TABLE 91

System Crude Charge Capacity (MB/D) and Numbers of Refineries
for Refiners Reporting Additional Facilities Needed
to Increase Unleaded Gasoline Production at 89 (R+M)/2
to 90 Percent of Total 1982 Gasoline Production

	Complexity Factor						
Geographic Area (PAD)	Under 3	3-5	5-7	7-9	9-11	11+	Total
I	*	0	891 (6)	*	*	*	1,617 (14)
II	*	199 (4)	1,476 (20)	1,861 (14)	206 (3)	*	3,875 (43)
III	96 (7)	397 (7)	2,126 (11)	2,547 (14)	468 (3)	550 (3)	6,184 (45)
IV	85 (3)	107 (5)	202 (7)	*	*	0	505 (18)
V	181 (6)	207 (5)	743 (6)	816 (5)	254 (3)	449 (4)	2,649 (29)
Total	414 (19)	910 (21)	5,439 (50)	5,748 (39)	1,061 (11)	1,259 (9)	14,830 (149)

*Data withheld to protect confidentiality.

The need for new facilities for 90 percent unleaded gasoline is rather broadly based throughout the industry. There is no apparent correlation with refinery complexity.

These relatively small increases in refinery capacity to produce a 90 percent mix of 87 (R+M)/2 unleaded gasoline support the Part I survey results which indicate that the industry is expected to have the capability to produce about 80 percent of an 87 (R+M)/2 octane unleaded product in 1982.

Increasing the unleaded octane quality to 89 (R+M)/2 would require additional reforming and additional isomerization capacity in over half of all respondent refineries. Respondents representing system crude oil refining capacity of 14,830 MB/D indicated a need to increase reforming capacity over the 1982 expected capacity levels by 567 MB/D at 76 refineries and to increase isomerization capacity by 421 MB/D in 69 refineries. At this higher octane level, reforming capacity would be increased about 14 percent and isomerization capacity would be increased over four times the current capacity forecast for 1982. Added octane improvement capability would be needed across all aggregations and would be roughly proportionate to their capacities. Although the larger refineries were generally able to meet the 90 percent unleaded mix at the lower octane level surveyed, additional processing requirements for 89 (R+M)/2 octane require reforming and isomerization in nearly half of the larger refineries as well. Here the greater need for additional capacity is supportive of the results to Part I of the survey, which project that only 64 percent of the 1982 pool will be unleaded gasoline if the unleaded octane is 89 (R+M)/2.

Exhibit 2 is a summary of the total additional facilities required to produce 90 percent unleaded gasoline based on total 1982 final requirements.

EXHIBIT 2

	87 (R+M)/2		89 (R+M)/2	
	Added Capacity (MB/D)	Number of Refineries	Added Capacity (MB/D)	Number of Refineries
Crude Distillation	32	7	37	9
Vacuum Distillation	57	12	50	14
Reforming	231	55	567	76
Isomerization	146	33	421	69
Alkylation	40	18	43	20
Catalytic Cracking	148	17	96	16
Hydrotreating	181	32	504	52
Hydrocracking	43	7	51	7
Hydrogen Generation (MMSCF/D)	77	12	85	10
Polymerization	6	4	6	4
Naphtha Splitting	132	15	298	21

A few respondents submitted qualitative comments only. These 14 refineries had a crude oil capacity of only 691 MB/D and their responses did not significantly affect the trends observed.

It is of interest to observe that eight refineries for systems having a combined capacity of 377 MB/D specified facilities for the 87 (R+M)/2 portion of the survey only, suggesting that these plants consider 89 (R+M)/2 either infeasible or unlikely for their situations. In addition, 48 refineries, representing systems with an aggregate crude oil capacity of 7,892 MB/D, supplied process data for the manufacture of 89 (R+M)/2 unleaded gasoline only. This may imply that these refineries already plan to have sufficient capability by 1982 to manufacture 90 percent 87 (R+M)/2 unleaded gasoline.

Refiners have been making major capital expenditures for a number of years for octane improvement facilities. For the period January 1, 1979, to January 1, 1982, refineries responding to Part I of this survey will be installing the following facilities:

Planned Capacity Increases [MB/D]
(January 1, 1979 - January 1, 1982)

Reforming	473
Isomerization	42
Alkylation	56
Catalytic Cracking	408
Hydrotreating	980
Hydrocracking	22
Polymerization	8

Expectations of obtaining the necessary permits and the likelihood of installation of additional octane capacity are much greater than for either sour crude processing or production of additional low sulfur heavy fuel oil. Refiners representing over 90 percent of the capacity of those requiring new facilities consider that it is possible to obtain the necessary permits. Refineries representing slightly over half of this respondent capacity (55 percent) have a medium or high expectation of adding these new facilities.

The average lead time that was estimated to be necessary to complete new or expanded facilities (if they were to be built) runs from 35 months for the smaller refineries to 43 months for the larger plants.

INCREASED LOW SULFUR HEAVY FUEL OIL MANUFACTURING CAPABILITY

Supporting data for the following discussion relative to added capability for the manufacture of low sulfur heavy fuel oil are provided for aggregation by refinery size in Tables 92 and 93; by refinery location in Tables 94 and 95; by refinery complexity in Tables 96 and 97; and by company size in Tables 98 and 99. In addition, Tables 100, 101, and 102 provide demographic data.

Refiners were requested to define those added facilities which would be necessary to increase the capability to produce low sulfur (0.7 percent) heavy fuel oil by an amount equivalent to 25 percent of the total heavy fuel oil projected to be produced in 1982. A further consideration was that there was to be minimum change in other product volumes.

Actual expansion would be required at 107 refineries with a combined crude oil capacity of 8,993 MB/D. This represents 37 percent of total U.S. refineries, or 47 percent of their capacity as of January 1, 1982. Since some companies elected the "systems" approach to new facilities, the response to this section of the survey may seem less than was actually represented. Associated with the 107 refineries at which new facilities might be added were 41 other refineries. Total systems capacity for all these refineries was 14,027 MB/D, equivalent to 73 percent of the January 1, 1982 capacity, as projected in Part I. In addition, 37 other refineries, with an aggregate 1982 capacity of 2,202 MB/D, responded to qualitative questions although they did not report process data. Thus, the total refining capacity responding to this section of the survey represented 85 percent of projected 1982 U.S. capacity.

The most significant increases in processing capability directly related to producing fuel oil of low sulfur quality were for hydrotreating naphtha and distillates (364 MB/D), hydrorefining (233 MB/D), hydrogen generation (210 MMSCF/D), and sulfur recovery (1,351 LT/D). Also reported were crude oil distillation and naphtha reforming facilities which would be necessary to permit refining the additional crude oil in order to maintain volumes of other products while increasing the quantity of heavy fuel oil.

TABLE 92

Additional Facilities Necessary to Increase
Low Sulfur (0.7 Percent) Heavy Fuel Oil Manufacturing Capability
by 25 Percent of Total 1982 Heavy Fuel Oil Manufacturing Capability
(Capacities Aggregated in MB/D)

Process Type	Refinery Size (MB/D) 0-10	10-30	30-50	50-100	100-175	175+	Total
1. Crude Oil Distillation	48	122	70	85	192	252	769
2. Vacuum Distillation	14	90	43	17	58	75	297
3. Reforming	12	10	10	10	40	26	108
4. Hydrotreating - Naphtha	6	6	*	42	29	*	91
5. Hydrotreating - Distillate	14	23	56	48	33	99	273
6. Hydrorefining	8	9	13	64	80	59	233
7. Hydrogen Generation (MMCF/D)	17	18	32	58	50	35	210
8. Sulfur Recovery and Tail Gas (LT/D)	81	59	353	315	264	279	1,351
9. Tankage (Mbbl)	1,042	1,255	1,100	2,285	1,930	2,520	10,132
10. Refineries Reporting Above Facilities							
1982 Crude Oil Capacity	142	498	675	1,408	2,028	4,243	8,993
1982 Crude Oil Throughput	134	445	612	1,332	1,878	3,950	8,351
Number of Refineries	20†	24	15	20	15	13	107
1982 Heavy Fuel Oil Production	47	106	84	163	203	599	1,202
11. Associated Refining Systems							
1982 Crude Oil Capacity	148	650	905	2,181	2,706	7,437	14,027
1982 Crude Oil Throughput	140	562	822	2,072	2,486	6,999	13,081
Number of Refineries	21†	31	20	32	21	23	148
1982 Heavy Fuel Oil Production	47	109	90	241	220	792	1,500
25 Percent Increase in HFO Production	12	27	23	60	55	198	375

*Data withheld to protect confidentiality.
†Includes two refineries with no crude runs, but substantive feedstocks of other types.

TABLE 93

Additional Facilities Necessary to Increase
Low Sulfur (0.7 Percent) Heavy Fuel Oil Manufacturing Capability
by 25 Percent of Total 1982 Heavy Fuel Oil Production

	Refinery Size (MB/D)						
Factors	0-10	10-30	30-50	50-100	100-175	175+	Total
1. 25 Percent HFO Increase (MB/CD) Classified by Incremental Crude Assumed							
Sweet	*	4	7	14	*	*	52
Light Medium		*	*	*			3
Heavy Medium	*	*	*	*	*	*	26
Light High	*	5	*	16	15	*	79
Heavy High	*	9	15	*	11	91	134
• Number of Refineries							
Sweet	*	9	5	4	*	*	27
Light Medium		*	*	*			4
Heavy Medium	*	*	*	*	*		9
Light High	*	3	*	11	4	*	25
Heavy High	*	7	8	*	3	6	32
2. Obtain Necessary Permits?							
• Refinery Crude Capacity							
Yes	*	380	*	*	1,058	*	6,067
No	*	117	*	*	959	*	1,965
• Number of Refineries							
Yes	*	18	*	*	8	*	79
No	*	6	*	*	7	*	19
3. Lead Time Required							
• Refinery Crude Capacity	102	380	599	1,112	1,617	3,359	7,169
• Number of Months	35	30	38	44	44	55	39
4. Likelihood of Installation							
• Refinery Crude Capacity							
Low	99	377	527	*	1,897	*	7,614
Medium	*	*	209	*	*	*	828
High	*	*			*		165
Impossible†							
• Number of Refineries							
Low							
Medium							
High	16	19	12	*	14	*	87
Impossible†	*	*	5	*	*	*	14

TABLE 93 (continued)

5. Refineries Reporting Above Facilities							
1982 Crude Capacity	142	498	675	1,408	2,028	4,243	8,993
1982 Crude Throughput	134	445	612	1,332	1,878	3,950	8,351
Number of Refineries	20§	24	15	20	15	13	107
Heavy Fuel Oil Production	47	109	84	163	203	599	1,202
6. Associated Refining Systems							
1982 Crude Capacity	148	650	905	2,181	2,706	7,437	14,207
1982 Crude Throughput	140	562	822	2,072	2,486	6,999	13,081
Number of Refineries	21§	31	20	32	21	23	148
Heavy Fuel Oil Production	47	109	90	241	220	792	1,500
25 Percent Increase in HFO Production	12	27	23	60	55	198	375
7. Refineries Providing Only Qualitative Responses¶							
Number of Refineries	6	9	9	9	*	*	37
1982 Crude Capacity	29	185	355	399	*	*	2,202
1982 HFO Production	7	20	40	38	*	*	178

*Data withheld to protect confidentiality.
†Merged with 10W to protect confidentiality.
§Includes two refineries with no crude runs, but substantive feedstocks of other types.
¶Not included in Sections 1-4 of this table.

TABLE 94

Additional Facilities Necessary to Increase
Low Sulfur (0.7 Percent) Heavy Fuel Oil Manufacturing Capability
by 25 Percent of Total 1982 Heavy Fuel Oil Production
(Capacities Aggregated in MB/D)

Process Type	Geographic Area (PAD) I	II	III	IV	V	Total
1. Crude Oil Distillation	110	124	348	23	165	769
2. Vacuum Distillation	35	73	92	11	87	297
3. Reforming	†	25	52	5	21	108
4. Hydrotreating - Naphtha	7	21	51	*	10	91
5. Hydrotreating - Distillation	21	58	84	8	103	273
6. Hydrorefining	24	47	124	†	39	233
7. Hydrogen Generation (MMCF/D)	19	64	80	†	47	210
8. Sulfur Recovery and Tail Gas (LT/D)	169	348	581	47	206	1,351
9. Tankage (Mbbl)	1,885	1,745	3,780	417	2,305	10,132
10. Refineries Reporting Above Facilities						
1982 Crude Oil Capacity	782	2,125	3,875	256	1,956	8,993
1982 Crude Oil Throughput	759	2,000	3,636	232	1,723	8,351
Number of Refineries	10	25	36§	10	26	107
1982 Heavy Fuel Oil Production	117	126	445	10	503	1,202
11. Associated Refining Systems						
1982 Crude Oil Capacity	1,770	3,043	6,226	363	2,626	14,027
1982 Crude Oil Throughput	1,720	2,872	5,839	320	2,330	13,081
Number of Refineries	20	38	44§	13	33	148
1982 Heavy Fuel Production	259	155	538	12	537	1,500
25 Percent Increase in HFO Production	65	39	134	3	134	375

*Data withheld to protect confidentiality.
†Merged with adjacent higher category to protect confidentiality.
§Includes two refineries with no crude runs, but substantive feedstocks of other types.

TABLE 95

Additional Facilities Necessary to Increase
Low Sulfur (0.7 Percent) Heavy Fuel Oil Manufacturing Capability
by 25 Percent of Total 1982 Heavy Fuel Oil Production

Questions	Geographic Area (PAD) I	II	III	IV	V	Total
1. Type of Crude Assumed						
• 25 Percent HFO Increase (MB/D) Classified by Incremental Crude Assumed						
Sweet	*	15	*	*		52
Light Medium	*		*	*		3
Heavy Medium					26	26
Light High	*	9	41	*	18	79
Heavy High	*	4	44	*	79	134
• Number of Refineries						
Sweet	*	11	*	*		27
Light Medium	*		*	*		4
Heavy Medium					9	9
Light High	*	7	10	*	4	25
Heavy High	*	4	12	*	11	32
2. Obtain Necessary Permits?						
• Refinery Crude Capacity						
Yes	410	*	3,301	*	664	6,067
No	351	*	306	*	1,027	1,965
• Number of Refineries						
Yes	7	*	31	*	14	79
No	3	*	4	*	10	19
3. Lead Time Required						
• Refinery Crude Capacity	578	1,769	3,150	240	1,488	7,169
• Number of Months	40	40	37	32	41	39
4. Likelihood of Installation						
• Refinery Crude Capacity						
Low	761	1,987	3,142	110	1,638	7,614
Medium		*	*	*	100	828
High		*	*	*	160	165
Impossible†						
• Number of Refineries						
Low	10	24	27	7	20	87
Medium		*	*	*	3	14
High		*	*	*	3	6
Impossible†						

TABLE 95 (continued)

5. Refineries Reporting Above Facilities						
1982 Crude Capacity	782	2,125	3,875	256	1,956	8,993
1982 Crude Throughput	759	2,000	3,636	232	1,723	8,351
Number of Refineries	10	25	36§	10	26	107
1982 Heavy Fuel Oil Production	117	126	445	10	503	1,202
6. Associated Refining Systems						
1982 Crude Capacity	1,770	3,043	6,226	363	2,626	14,027
1982 Crude Throughput	1,720	2,872	5,839	320	2,330	13,081
Number of Refineries	20	38	44§	13	33	148
1982 Heavy Fuel Production	259	155	538	12	537	1,500
25 Percent Increase in HFO Production	65	39	134	3	134	375
7. Refineries Providing Only Qualitative Responses						
Number of Refineries	*	9	17	*	3	37
1982 Crude Capacity	*	760	1,179	*	114	2,202
1982 HFO Production	*	28	106	*	38	178

*Data withheld to protect confidentiality.
†Merged with "Low" to protect confidentiality.
§Includes two refineries with no crude runs, but substantive feedstocks of other types.

TABLE 96

Additional Facilities Necessary to Increase
Low Sulfur (0.7 Percent) Heavy Fuel Oil Manufacturing Capability
by 25 Percent of Total 1982 Heavy Fuel Oil Production
(Capacities Aggregated in MB/D)

Process Type	Complexity Factor 0-3	3-5	5-7	7-9	9-11	11+	Total
1. Crude Oil Distillation	171	59	240	238	62	†	769
2. Vacuum Distillation	99	16	89	81	*	*	297
3. Reforming	13	18	33	41	*	*	108
4. Hydrotreating - Naphtha	11	9	26	12	*	*	91
5. Hydrotreating - Distillation	25	27	83	86	52	†	273
6. Hydrorefining	21	32	109	43	27	†	233
7. Hydrogen Generation (MMCF/D)	21	23	88	46	32	†	210
8. Sulfur Recovery and Tail Gas (LT/D)	110	204	721	264	52	†	1,351
9. Tankage (Mbbl)	2,180	1,827	3,005	1,735	1,375	†	10,132
10. Refineries Reporting Above Facilities							
1982 Crude Oil Capacity	564	493	2,464	4,100	627	746	8,993
1982 Crude Oil Throughput	501	473	2,324	3,811	568	674	8,351
Number of Refineries	33§	14	23	24	7	6	107
1982 Heavy Fuel Oil Production	158	110	384	421	63	66	1,202
11. Associated Refining Systems							
1982 Crude Oil Capacity	680	675	4,875	5,476	1,017	1,305	14,027
1982 Crude Oil Throughput	590	642	4,611	5,096	949	1,194	13,081
Number of Refineries	38§	17	41	34	10	8	148
1982 Heavy Fuel Oil Production	184	115	550	477	77	97	1,500
25 Percent Increase in HFO Production	46	29	137	119	19	24	375

*Data withheld to protect confidentiality.
†Merged with adjacent lower size category to protect confidentiality.
§Includes two refineries with no crude runs, but substantive feedstocks of other types.

TABLE 97

Additional Facilities Necessary to Increase
Low Sulfur (0.7 Percent) Heavy Fuel Oil Manufacturing Capability
by 25 Percent of Total 1982 Heavy Fuel Oil Production

	Complexity Factor						
Questions	0-3	3-5	5-7	7-9	9-11	11+	Total
1. Type of Crude Assumed							
• 25 Percent HFO Increase (MB/D) Classified by Incremental Crude Assumed							
Sweet	13	6	*	27	*	*	52
Light Medium	*		*				3
Heavy Medium	*	*			11		26
Light High	*	*	30	43	*	*	79
Heavy High	14	8	60	36	*	*	134
• Number of Refineries							
Sweet	6	5	*	7	*	*	27
Light Medium	*		*				4
Heavy Medium	*	*			3		9
Light High	*	*	6	12	*	*	25
Heavy High	13	4	7	4	*	*	32
2. Obtain Necessary Permits?							
• Refinery Crude Capacity							
Yes	366	*	1,433	2,561	*	*	6,067
No	124	*	933	687	*	*	1,965
• Number of Refineries							
Yes	27	*	16	15	*	*	79
No	7	*	5	3	*	*	19
3. Lead Time Required							
• Refinery Crude Capacity	376	773	2,126	2,664	824	406	7,169
• Number of Months	30	35	44	46	45	45	39
4. Likelihood of Installation							
• Refinery Crude Capacity							
Low	382	642	*	*	713	*	7,614
Medium	85	*	*	*	219		828
High	15	*				*	165
Impossible†							
• Number of Refineries							
Low	27	11	*	*	5	*	87
Medium	4	*	*	*	3		14
High	4	*				*	6
Impossible†							

TABLE 97 (Continued)

5. Refineries Reporting Above Facilities							
1982 Crude Capacity	564	493	2,464	4,100	627	746	8,993
1982 Crude Throughput	501	473	2,324	3,811	568	674	8,351
Number of Refineries	33§	14	23	24	7	6	107
1982 Heavy Fuel Oil Production	158	110	384	421	63	66	1,202
6. Associated Refining Systems							
1982 Crude Capacity	680	675	4,875	5,476	1,017	1,305	14,027
1982 Crude Throughput	590	642	4,611	5,096	949	1,194	13,081
Number of Refineries	38§	17	41	34	10	8	148
1982 Heavy Fuel Oil Production	184	115	550	477	77	97	1,500
25 Percent Increase in HFO Production	46	29	137	119	19	24	375
7. Refineries Providing Only Qualitative Responses¶							
Number of Refineries	9	8	10	8	*	*	37
1982 Crude Capacity	150	324	752	817	*	*	2,202
1982 HFO Production	38	41	42	48	*	*	178

*Data withheld to protect confidentiality.
†Merged with "Low" to protect confidentiality.
§Includes two refineries with no crude runs, but substantive feedstocks of other types.
¶Not included in Table 97 data.

TABLE 98

Additional Facilities Necessary to Increase
Low Sulfur (0.7 Percent) Heavy Fuel Oil Manufacturing Capability
by 25 Percent of Total 1982 Heavy Fuel Oil Production
(Capacities Aggregated in MB/D)

Process Type	Company Size (MB/D) 0-10	10-30	30-50	50-100	100-175	175+	Total
1. Crude Oil Distillation	48	113	36	45	33	495	769
2. Vacuum Distillation	14	86	15	29	33	119	297
3. Reforming	5	9	*	7	*	80	108
4. Hydrotreating - Naphtha	6	4	*	7	*	69	91
5. Hydrotreating - Distillate	9	23	*	30	*	190	273
6. Hydrorefining	*	6		*	33	174	233
7. Hydrogen Generation (MMCF/D)	12	11	*	24	*	139	210
8. Sulfur Recovery and Tail Gas (LT/D)	59	37	130	197	†	928	1,351
9. Tankage (Mbbl)	982	1,195	*	880	*	6,065	10,132
10. Refineries Reporting Above Facilities							
1982 Crude Oil Capacity	116	354	332	557	795	6,840	8,993
1982 Crude Oil Throughput	108	329	302	532	735	6,345	8,351
Number of Refineries	16§	19	7	13	9	43	107
1982 Heavy Fuel Oil Production	44	101	55	85	68	848	1,202
11. Associated Refining Systems							
1982 Crude Oil Capacity	116	354	332	710	795	11,720	14,027
1982 Crude Oil Throughput	108	329	302	626	735	10,932	13,081
Number of Refineries	16§	19	7	16	9	81	148
1982 Heavy Fuel Oil Production	4	101	55	124	68	1,108	1,500
25 Percent Increase in HFO Production	11	25	14	31	17	277	375

*Entry withheld to protect confidentiality.
†Merged with adjacent lower size category to protect confidentiality.
§Includes two refineries with no crude runs, but substantive feedstocks of other types.

TABLE 99

Additional Facilities to Increase
Low Sulfur (0.7 Percent) Heavy Fuel Oil Manufacturing Capability
by 25 Percent of Total 1982 Heavy Fuel Oil Production

Factors	Company Size Category (MB/D)						
	0-10	10-30	30-50	50-100	100-175	175+	Total
1. Type of Crude Assumed							
• 25 Percent HFO Increase (MB/CD) Classified by Incremental Crude Assumed							
Sweet	*	4	*	12	8	23	52
Light Medium		*	*	*		*	3
Heavy Medium	*		*	*		*	26
Light High	*	*		*	*	67	79
Heavy High	3	10	8	*	*	112	134
• Number of Refineries							
Sweet	*	6	*	6	3	8	27
Light Medium		*	*	*		*	4
Heavy Medium	*	*	*	*		*	9
Light High	*	*		*	*	17	25
Heavy High	4	8	4	*	*	14	32
2. Obtain Necessary Permits?							
• Refinery Crude Capacity							
Yes	*	255	170	452	*	4,696	6,067
No	*	100			*	1,609	1,965
• Number of Refineries							
Yes	*	14	4	11	*	31	79
No	*	5			*	10	19
3. Lead Time Required							
• Refinery Crude Capacity	86	255	214	402	550	5,663	7,169
• Number of Months	29	29	36	35	38	48	39
4. Likelihood of Installation							
• Refinery Crude Capacity							
Low	77	259	133	*	*	6,089	7,614
Medium	*	*	122	*	*	*	828
High	*	*				*	165
Impossible†							
• Number of Refineries							
Low	12	15	3	*	*	38	87
Medium	*	*	3	*	*	*	14
High	*	*				*	6
Impossible†							

TABLE 99 (continued)

5. Refineries Reporting Above Facilities							
1982 Crude Capacity	116	354	332	557	795	6,840	8,993
1982 Crude Throughput	108	329	302	532	735	6,345	8,351
Number of Refineries	16§	19	7	13	9	43	107
1982 Heavy Fuel Oil Production	44	101	55	85	68	848	1,202
6. Associated Refining Systems							
1982 Crude Capacity	116	354	332	710	795	11,720	14,027
1982 Crude Throughput	108	329	302	626	735	10,932	13,081
Number of Refineries	16§	19	7	16	9	81	148
1982 Heavy Fuel Oil Production	44	101	55	124	68	1,108	1,500
25 Percent Increase in HFO Production	11	25	14	31	17	277	375
7. Refineries Providing Only Qualitative Responses¶							
Number of Refineries	4	5	7	6	0	15	37
1982 Crude Capacity	19	105	245	251		1,581	2,202
1982 HFO Production	6	18	37	3		114	178

*Data withheld to protect confidentiality.
†Merged with "Low" to protect confidentiality.
§Includes two refineries with no crude runs, but substantive feedstocks of other types.
¶Not included in Table 99 data.

TABLE 100

System Crude Charge Capacity (MB/D) and Number of Refineries
for Refiners Reporting Additional Facilities Needed
to Increase Low Sulfur Fuel Oil Manufacturing Capability
by 25 Percent of Total 1982 Heavy Fuel Oil Production

Geographic Area (PAD)	Refinery Size (MB/D) 0-10	10-30	30-50	50-100	100-175	175+	Total
I	23 (3)	*	0	478 (8)	510 (3)	*	1,770 (20)
II	29 (4)	135 (6)	321 (7)	803 (12)	631 (5)	1,123 (4)	3,043 (38)
III	41 (7)	179 (9)	134 (3)	438 (6)	779 (6)	4,656 (13)	6,226 (44)
IV	16 (3)	111 (5)	235 (5)	0	0	0	363 (13)
V	39 (4)	*	215 (5)	462 (6)	787 (7)	*	2,626 (33)
Total	148 (21)	650 (31)	905 (20)	2,181 (32)	2,706 (21)	7,437 (23)	14,027 (148)

*Data withheld to protect confidentiality.

TABLE 101

System Crude Charge Capacity (MB/D) and Numbers of Refineries
for Refiners Reporting Additional Facilities Needed
to Increase Low Sulfur Fuel Oil Manufacturing Capability
by 25 Percent of Total 1982 Heavy Fuel Oil Production

Refinery Size (MB/D)	Complexity Factor: Under 3	3-5	5-7	7-9	9-11	11+	Total
0-10	124 (18)	*	0	0	*	0	148 (21)
10-30	269 (14)	*	144 (7)	*	0	0	650 (31)
30-50	*	180 (4)	403 (9)	*	*	0	905 (20)
50-100	*	*	971 (14)	667 (10)	*	215 (3)	2,181 (32)
100-175	0	*	418 (3)	1,082 (8)	607 (5)	*	2,706 (21)
175+	0	0	2,939 (8)	3,582 (12)	*	*	7,437 (23)
Total	680 (38)	675 (17)	4,875 (41)	5,476 (34)	1,017 (10)	1,305 (8)	14,027 (148)

*Data withheld to protect confidentiality.

TABLE 102

System Crude Charge Capacity (MB/D) and Numbers of Refineries
for Refiners Reporting Additional Facilities Needed
to Increase Low Sulfur Fuel Oil Manufacturing Capability
by 25 Percent of Total 1982 Heavy Fuel Oil Production

Geographic Area (PAD)	Complexity Factor						
	Under 3	3-5	5-7	7-9	9-11	11+	Total
I	164 (8)	0 (7)	1,059 (7)	*	*	0	1,770 (20)
II	64 (5)	199 (4)	905 (15)	1,669 (11)	*	*	3,043 (38)
III	205 (13)	176 (4)	2,059 (8)	2,467 (12)	485 (3)	835 (4)	6,226 (44)
IV	79 (3)	*	162 (6)	*	0	0	363 (13)
V	168 (9)	*	690 (5)	816 (5)	358 (4)	*	2,626 (33)
Total	680 (38)	675 (17)	4,875 (41)	5,476 (34)	1,017 (10)	1,305 (8)	14,027 (148)

*Data withheld to protect confidentiality.

Based upon the respondents' projected 1982 heavy fuel oil production of 1,500 MB/D, the "associated systems" increase in volume of the 0.7 percent sulfur content product would amount to 375 MB/D. Previous comments on qualitative questions also apply to the 25 percent increase on low sulfur heavy fuel oil; i.e., survey results are not significantly affected by the data exclusion for companies not reporting process data. The reduced response to this particular portion of the survey should be noted: total 1982 heavy fuel oil production, for all respondents to Part I of the survey, amounted to 1,843 MB/D, or 23 percent more than for respondents to this segment of the survey.

Many domestic refineries produce little or no heavy fuel oil. Therefore, a 25 percent increase in heavy fuel oil from those refineries represents limited additional production. Part I of this study demonstrated the relatively small amount (about 10 percent) of heavy fuel oil yielded as a percentage of feedstocks for all U.S. respondents.

The 25 percent increase in low sulfur heavy fuel oil production applies solely to onshore refineries. These refinery systems currently supply about 55 percent of U.S. residual requirements. Thus, the increase is equivalent to about a 15 percent gain in total supply or about a 30 percent reduction in imports.

Exhibit 3 is a summary of the total additional facilities required to produce a 25 percent increase in low sulfur heavy fuel above the amount that is now anticipated for 1982.

Refineries were also requested to designate the type of incremental crude oil which they expected to process in order to yield the greater volume of products. It is interesting to note that

EXHIBIT 3

Process Type	Added Capacity MB/D	Number of Refineries
Crude Oil Distillation	769	75
Vacuum Distillation	297	44
Reforming	108	35
Hydrotreating-Naphtha	91	29
Hydrotreating-Distillate	273	54
Hydrorefining	233	32
Hydrogen Generation (MMCF/D)	210	39
Sulfur Recovery & Tail Gas (LT/D)	1,351	48
Tankage (Mbbl)	10,132	65

approximately 17.7 percent of the associated crude oil refining capability indicated sweet crude oil as the assumed incremental feed, while 26.9 percent designated light high sulfur and 45.6 percent designated heavy high sulfur.

The smaller refineries (those under 100 MB/D) appear to be in relatively worse shape than larger ones in that they would account for over half the needed distillate hydrotreating capacity, 40 percent of the hydrorefining capacity, and 60 percent of the incremental hydrogen generation and sulfur recovery capacity additions, although their associated crude oil refining capacity was only 28 percent of total respondent capacity.

The only observation regarding variances by geographic area is that PAD V indicated a relatively high need for distillate hydrotreating.

Respondents in the lowest complexity category indicated a somewhat disproportionately large share of required added facilities.

With respect to company size, it is evident that the smaller companies have the least adequate facilities for producing more low sulfur heavy fuel oil.

Tables 93, 95, 97, and 99 provide some additional insight into the grades of incremental crude oil assumed and to perceptions of permit likelihood, lead times, and probabilities of implementation.

Refineries above 175 MB/D in capacity appear to expect that more of their incremental crude oil would be of the heavy high sulfur grade.

About 75 percent of the refineries responding believed that permits could be obtained for these facilities, but refineries representing nearly 90 percent of the additional capacity considered that it was quite unlikely that the facilities would be built. Average lead time for permitting, appropriation, engineering, and construction was estimated at 39 months; this lead time increased with refinery and company size range.

INVESTMENT COSTS OF ADDITIONAL FACILITIES

Investment cost calculations for all of the refinery expansions covered in Part III of this study will be made and reported in the final report; these estimates will be based on information provided by a major engineering contractor for each process unit. Investment calculation will be based on costs as of January 1, 1979 and will be a function of unit size and geographic location (PAD districts). The estimates will be based on certain assumptions for debottlenecking existing facilities versus building new units, as detailed below. Tankage is assumed to be 100 percent new facilities for all cases.

For all processes except tankage, overall costs will be determined as follows.

(1) Volume percent added capacity vs. 1982 capacity (for Part III) or 1979 capacity (for Part I, 1982 vs. 1979 increase) will be calculated.

(2) If volume percent added capacity is less than 20 percent, added capacity will be assumed to be all debottlenecking. If volume percent added capacity is greater than 60 percent, added capacity will be assumed to be a new unit. Between 20 and 60 percent, added capacity categorized as a new unit or debottlenecking will be based on the following equations:

Percentage New = 2.5 (Percentage Added Capacity) - 50

Percentage Debottlenecking = 100 - Percentage New

(3) The unit size will be assumed to be equal to the size of added capacity increment for a new unit and the present size (1982 or 1979) for debottlenecking. If the debottlenecking increment is greater than an assumed maximum reasonable size (Table 103), added capacity costs will be calculated based on entirely new unit costs.

(4) The cost of added capacity will be a combination (by their relative fractions) of new unit and debottlenecking costs, where debottlenecking cost (per barrel capacity) is assumed to be 70 percent of the cost of a new unit of the original size.

(5) The resulting unit cost will then be multiplied by 1.35 to reflect offsite costs and a multiplier for each PAD district to reflect differences in construction costs among geographical areas.

<u>Example for Cost Calculations</u>

For increased reforming to make 90 percent unleaded gasoline, a refinery has indicated a need for 15,000 barrels per day of

TABLE 103

Maximum Size for Debottlenecking of Processes

Process Technology	MB/D
Desulfurization	
Naphtha	25
Distillate	25
Heavy Fuel Oil	15
Sulfur Plant & Tail Gas Cleanup	50*
Vacuum Distillation	40
Tankage	0
Residual Conversion	10
Reforming	25
Isomerization	5
Hydrogen Manufacturing	(10)†
Catalytic Cracking	25
Coking	(10)§
Crude Atmospheric Distillation	50
Visbreaking	10
Treating	15
Alkylation	5
Hydrotreating	25
Polymerization	2
Naphtha Splitter	25
Hydrorefining	15

*Long tons per day.

†Thousand standard cubic feet per day.

§Short tons per day.

additional reforming capacity. In Part I, this refinery indicated a 1982 reforming capacity of 30,000 barrels per day.

(1) Percent added capacity AC = $100 \times \frac{15,000}{30,000} = 50$

(2) Percent <u>new</u> unit = 2.5 (AC) - 50

$2.5\ (50) - 50 = 75$

(3) Determine <u>cost</u> of new 15,000 barrel per day unit (NU) and cost of <u>new</u> 30,000 barrel per day unit (EU).

(4) Calculate added capacity costs

On-site cost = 0.75 NU + 0.25 EU (15,000/30,000) x 0.7

Total cost = On-site cost x 1.35

Note: If debottlenecking increment [0.25(15,000) = 3,750] had been greater than maximum debottlenecking size (25,000), all of the added capacity should have been costed out based on a new single unit.

<u>Symbol Key</u>

AC = Percent added capacity.
NU = Cost of expanded capacity in new unit.
EU = Cost of new unit on which debottlenecking is based.

CHAPTER FOUR

AGGREGATED ENERGY SUPPLY/DEMAND FORECASTS

A statistical projection of future petroleum supply and demand is necessary in order to analyze future refinery requirements. In order to provide such a projection, 32 institutions were surveyed to obtain their views on the outlook. This chapter summarizes the results of the survey.

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.

In order to provide a supply/demand matrix which represented both a consensus of the replies received and an internally consistent balance, an "adjusted average" response was prepared. This balance closely follows the arithmetic average of responses received. Appendix H provides the complete details of the adjusted average balance and a tabulation of the high, low, arithmetic average and standard deviation of each matrix cell. Technical notes, desribing the adjustment procedures, are also included in Appendix H. All data in this chapter are from the "adjusted average" balances unless otherwise noted.

WORLD OIL SUPPLY/DEMAND

Because of the interdependence of the United States and the rest of the world regarding petroleum supplies, the National

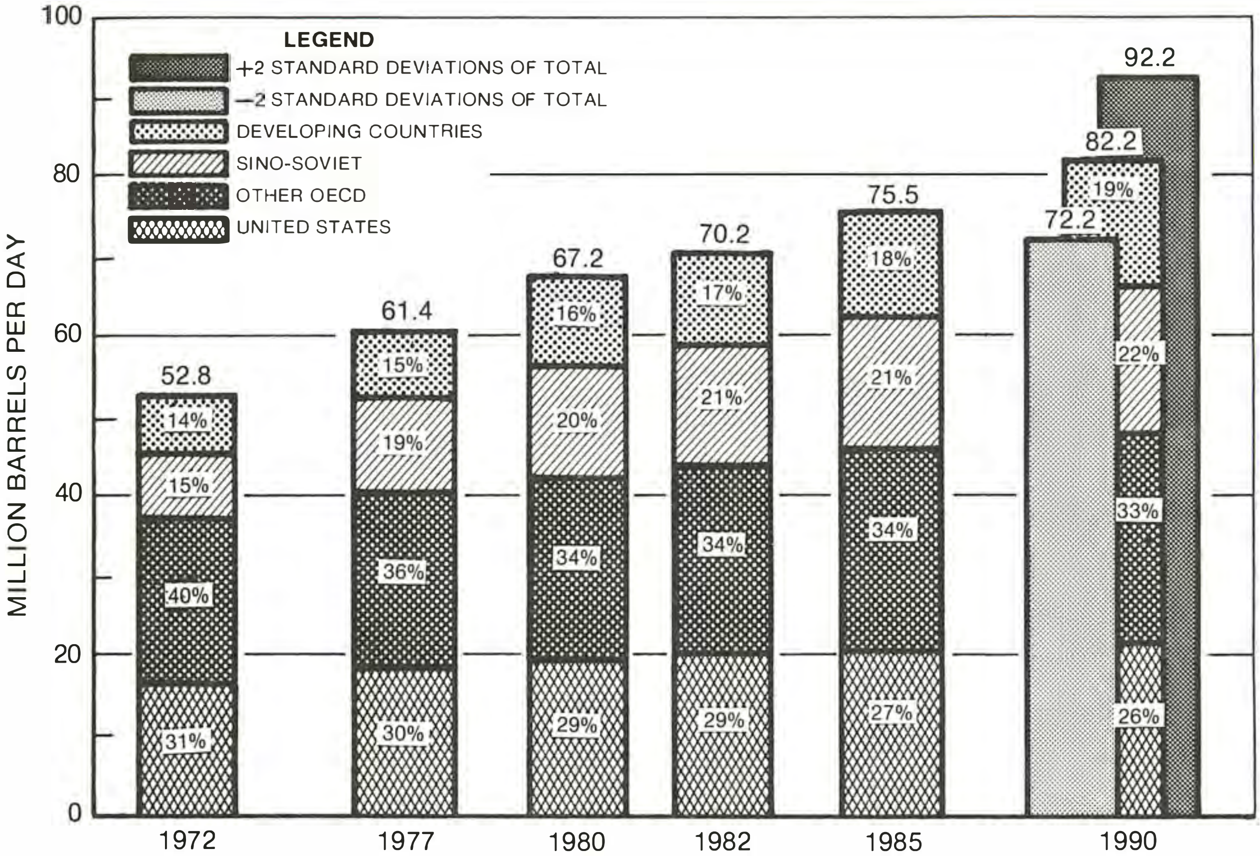
Petroleum Council thought it necessary to obtain, in addition to forecasts of United States petroleum supply/demand, projections of global petroleum supply/demand balances. Some of the non-U.S. institutions included in the 32 institutions surveyed by the Council were selected specifically for their expertise on international petroleum matters.

Ideally, one should have a fairly comprehensive rationale for each submitted projection, including forecasts of global economic growth, development of non-oil energy sources, trends in petroleum prices and their effects on economic growth and non-oil energy supplies, and any political ramifications, both national and international. In designing the survey, however, it was thought beyond the scope of this study to ask respondents to supply their assessment of such underlying variables. Consequently, users of the forecast global petroleum supply/demand balances are asked to make their own judgments about future energy prices, economic activity, alternate fuels development, and international political relations.

Although the forecasts convey a reasonable balance in future petroleum supply and demand, this is somewhat of an arithmetic illusion. With OPEC production forecast to reach 35 to 37 MMB/D by the mid-eighties, usable excess productive capacity will most likely be small. The supply/demand balance will remain uncomfortably tight. Any significant supply disruption, due to technical problems or political events, will be difficult or impossible to compensate.

Petroleum Consumption

World petroleum consumption is projected to increase from 61 MMB/D in 1977 to 82 MMB/D in 1990, as shown in Figure 14 and Table 104. While increasing in absolute terms, the rate of growth of petroleum consumption is expected to decline significantly over the next 10 years. Consumption growth is expected to average 2.3



NOTE: Percentages are country's share of total consumption in year shown.

Figure 14. World Petroleum Consumption.

TABLE 104

World Petroleum Consumption
(MMB/D)

	Actual 1972	Actual 1977	Survey Average 1980	Survey Average 1982	Survey Average 1985	Survey Average 1990
OECD	37.5	40.5	42.6	44.0	46.1	48.1
U.S.	16.4	18.4	19.6	20.1	20.5	21.2
West Europe	14.1	14.2	14.7	15.2	16.0	16.8
Other	7.0	7.9	8.3	8.7	9.6	10.1
Non-OECD	7.3	9.3	10.9	11.6	13.3	15.9
Subtotal	44.8	49.8	53.5	55.6	59.4	64.0
Sino-Soviet	8.0	11.6	13.7	14.6	16.1	18.2
TOTAL	52.8	61.4	67.2	70.2	75.5	82.2

percent per annum between 1977 and 1990, as compared with the 7.6 percent rate observed between 1960 and 1972 (Table 105). However, future growth rates exhibit considerable regional variability. The countries belonging to the Organization for Economic Co-operation and Development (OECD) are thought to be able to reduce the average annual growth in oil consumption to only 1.3 percent over the forecast period. It is believed that this reduction is due to a combination of lower economic growth, higher energy prices, government mandated conservation measures, and greater availability of non-oil energy supplies.

The so called "Developing Countries," that is, countries outside the OECD, Eastern Europe, USSR, and China, are expected to maintain relatively high growth rates in petroleum consumption. This appears reasonable on two accounts: because their capacity for economic growth is significantly higher than that of the OECD, their relative energy consumption growth will also be greater; and those countries self-sufficient in petroleum (e.g., OPEC, Mexico) will have priority access to low cost petroleum.

According to the survey results, the Sino-Soviet countries (USSR, Eastern Europe, and China) will also maintain relatively

TABLE 105

Growth in World Petroleum Consumption
(Annual Percent - Average of All Responses)

	1960/ 1972	1972/ 1977	1977/ 1980	1980/ 1985	1985/ 1990	1977/ 1990
OECD	7.5	1.6	1.7	1.6	0.9	1.4
U.S.	4.4	2.3	2.1	0.9	0.7	1.1
West Europe	11.3	0.1	1.2	1.7	1.0	1.3
Other	11.6	2.4	1.7	3.0	1.0	1.9
Non-OECD	7.5	5.0	5.4	4.1	3.6	4.2
SINO-Soviet	7.8	7.7	5.7	3.3	2.2	3.5
TOTAL	7.6	3.1	3.1	2.4	1.7	2.3

high rates of growth in petroleum consumption. Based on the average of responses, it is expected that this group of countries will remain self-sufficient in petroleum. However, the variances in the data indicate the fragility of this balance.

Understandably, because of different assessments of economic growth, energy prices, petroleum availability, etc., there is considerable variability in the 20 responses received on future global petroleum supply/demand balances. As shown in Table 106, the variability increases over time. The range of responses and their coefficients of variation are almost three times greater in

TABLE 106

Range and Coefficient of Variation in Forecast World Petroleum Consumption*

	1980		1985		1990	
	Range	†	Range	†	Range	†
U.S.	17.2-20.0	3.8%	17.3-21.8	5.1%	17.1-23.0	7.3%
West Europe	14.0-15.5	2.8%	14.2-17.6	5.1%	14.3-19.7	8.4%
Japan	5.1- 6.3	5.4%	5.6- 8.6	10.0%	5.5- 9.4	13.6%
Other OECD	2.5- 5.1	22.2%	2.7- 6.9	31.0%	2.4- 8.4	39.5%
Non-OECD	9.5-13.0	8.9%	10.3-16.3	11.8%	11.4-19.8	15.2%
Subtotal	51.0-56.5	2.7%	55.2-64.6	4.6%	55.7-72.1	7.0%
USSR	8.8- 9.5	2.4%	9.6-11.7	6.3%	10.1-13.8	10.3%
East Europe	2.1- 2.8	8.4%	2.4- 3.4	10.7%	2.6- 3.9	14.3%
China	1.7- 2.3	9.1%	2.2- 3.8	15.8%	2.8- 5.3	22.2%
Subtotal	12.7-14.5	3.0%	14.3-18.1	6.5%	15.5-21.2	9.7%
TOTAL	64.4-70.3	2.3%	69.9-79.9	4.3%	74.9-89.1	6.1%

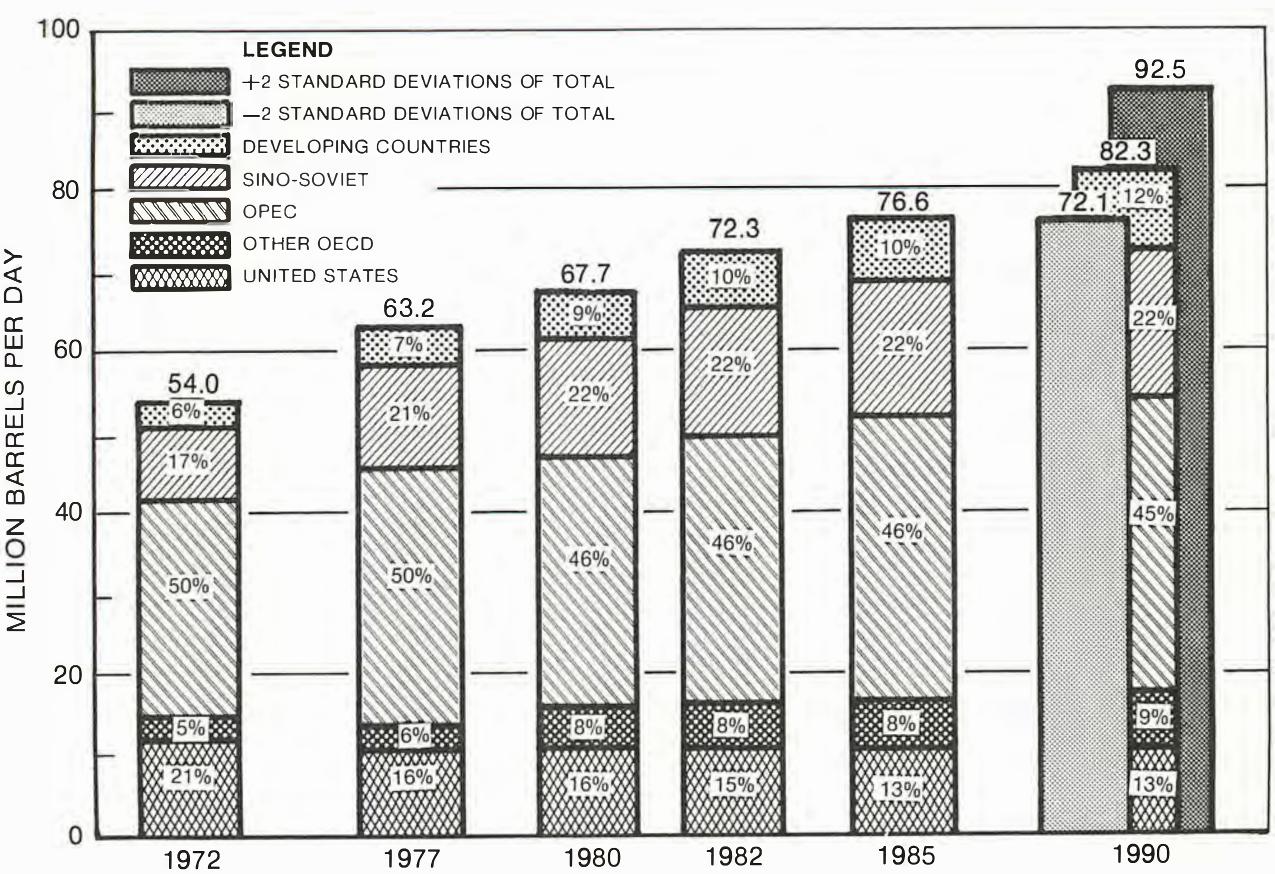
*Components do not add to totals since some respondents did not provide forecasts for components.

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

1990 than in 1980. However, both the range and the standard deviation appear too large for 1980. Although the reasons for this divergence are not known, the major cause is probably the submission by some of the respondents of forecasts prepared prior to 1979, which do not take into account recent developments in petroleum prices, changed macro-economic outlook, and reduced availability of petroleum supplies because of the Iranian political problems.

World Petroleum Supply

The geo-political distribution of future global petroleum production (crude oil and natural gas liquids) is shown in Figure 15 and summarized in Table 107.



NOTE: Percentages are country's share of total supply for year shown.

Figure 15. World Petroleum Supply.

TABLE 107

World Petroleum Production
(MMB/D)

	Actual		Survey Average			
	1972	1977	1980	1982	1985	1990
OECD	14.2	13.9	15.9	16.6	16.9	17.4
U.S.*	11.6	10.3	10.7	10.5	10.3	10.3
Canada	1.8	1.6	1.7	1.7	1.8	1.8
West Europe	0.4	1.5	3.0	3.8	4.2	4.6
Other	0.4	0.5	0.5	0.6	0.6	0.7
OPEC	27.4	31.9	31.1	33.1	35.1	36.7
Venezuela	3.3	2.3	2.3	2.3	2.3	2.3
Indonesia	1.1	1.7	1.7	1.7	1.7	1.6
Algeria	1.1	1.2	1.2	1.4	1.3	1.3
Libya	2.2	2.1	2.2	2.3	2.3	2.2
Nigeria	1.8	2.1	2.3	2.3	2.3	2.2
Iran	5.0	5.7	4.1	4.3	4.6	4.6
Kuwait	3.1	1.9	2.0	2.1	2.2	2.3
Saudi Arabia	5.8	9.2	8.8	9.6	10.5	11.7
Iraq	1.5	2.5	3.1	3.5	4.0	4.4
UAE	1.2	2.0	1.9	2.1	2.4	2.6
Other	1.3	1.2	1.5	1.5	1.5	1.5
Non-OPEC	3.4	4.3	5.9	7.0	8.0	9.7
Mexico	0.6	1.1	2.1	2.6	3.1	4.2
Other	2.8	3.2	3.8	4.4	4.9	5.5
Subtotal	45.0	50.1	52.9	56.7	60.0	63.8
Sino-Soviet	9.0	13.1	14.8	15.6	16.6	18.5
TOTAL	54.0	63.2	67.7	72.3	76.6	82.3

*Includes 0.5 MMB/D Processing Gain.

The reasonableness of the projected petroleum supplies from a technical point of view will be discussed first. (Note: The Sino-Soviet group of countries will be reviewed separately). In the aggregate, the production profile implies cumulative crude oil production of 255 billion barrels between 1979 and 1990, or a drawdown of current proved crude oil reserves by about 50 percent. However, if the rate of recent reserve additions (averaging 14 billion barrels a year during the 1972-1978 period) can be maintained, this drawdown in crude oil reserves by 1990 would be less than 20 percent.

Although the picture looks comfortable in the aggregate, potential trouble spots begin to appear when looked at on a regional basis. Table 108 lists, by region, cumulative crude oil production

TABLE 108

Required Annual Reserve Additions -- 1979-1990
(Billion Barrels per Year)

	United States	Other OECD	Mexico	Other L.A.	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 to 1990	37	27	13	18	33	115	13
Percent of Current Reserves Produced by 1990	132	110	46	70	58	37	93
Required Annual Reserve Additions	2.7	2.4	1.3	1.6	1.3	5.8	1.1
Average Annual Reserve Additions (1972-1978)†	1.7	2.1	3.9	1.2	2.6	1.8	0.6

*World Oil, August 15, 1979. A tabulation detailing reserves by country is appended.
†Based on World Oil reserve estimates.

for 1979-1990, percent of current crude oil reserves produced during the forecast period, annual crude oil reserve additions required for either technical reasons or to keep the reserve drawdown to politically acceptable levels, and crude oil reserve additions during 1972 to 1978.

For Mexico, the Middle East, and possibly Africa it would appear to be reasonably certain that the physical producing capability either already exists or can be installed to produce at the forecast rates. For the other regions, significant improvements in the rate of new reserve additions will be required if the forecast production is to materialize. The United States is in the most precarious position. Unless the rate of new reserve additions improves substantially, the forecast production rates cannot be realized. As to the other OECD countries, the required future new reserve additions may be difficult to achieve. For example, in the North Sea (the source of most of the past discoveries) a significant decline in new field discoveries has recently been experienced.

The production forecasts for the Middle East and Mexico are not without risk either. Future producing rates of these countries, while not restricted by physical resource limits, will be largely governed by internal economic and political considerations. Although there will be international political pressure to raise production close to what is technically sustainable, the goal of almost every one of these countries is to limit petroleum exports to levels compatible with domestic revenue needs. Thus the desire of some of the major exporters to reduce production conflicts with the forecast production rates which are invariably increasing over time.

The Sino-Soviet region's petroleum supply and demand balances (Table 109) project a continuation of net exports from these countries, albeit at decreasing rates. Table 109 shows production in

TABLE 109

Sino-Soviet Petroleum Supply and Demand
(MMB/D - Average of All Respondents)

	1977	1980	1982	1985	1990
USSR					
Production	10.9	12.0	12.4	12.7	13.6
Demand	8.0	9.2	9.5	10.2	11.2
Exports	2.9	2.8	2.9	2.5	2.4
CHINA					
Production	1.8	2.4	2.8	3.5	4.5
Demand	1.5	2.1	2.5	3.0	3.8
Exports	0.3	0.3	0.3	0.5	0.7
EAST EUROPE					
Production	0.4	0.4	0.4	0.4	0.4
Demand	2.1	2.4	2.6	2.9	3.2
Imports	(1.7)	(2.0)	(2.2)	(2.5)	(2.8)
NET EXPORTS	1.5	1.1	1.0	0.5	0.3

the Soviet Union increasing steadily throughout the forecast period. However, this future rate of USSR petroleum production has been contested by some Western experts on the Russian oil and gas industry. For example, the CIA has reached the conclusion that USSR petroleum production will peak in the early eighties. According to their latest estimates, the USSR and Eastern Europe will become a net importer of 0.7 MMB/D by 1982 instead of a net exporter of 0.7 MMB/D.

The variability in forecasts received on future global petroleum supplies is summarized in Table 110. By necessity, the variability of total supply closely matches that observed in forecast total consumption. Variability in components, on the other hand, although to some extent affected by overall variability, is thought to reflect different assessments of future discovery rates and political decisions regarding production allowables.

TABLE 110

Range and Coefficient of Variation in Forecast World Petroleum Supplies*

	1980		1985		1990	
	Range	†	Range	†	Range	†
OECD	14.5-17.9	4.7%	15.1-18.9	5.8%	16.0-19.9	6.8%
U.S.	10.2-12.0	4.1%	9.3-11.8	7.2%	8.1-12.8	11.3%
Canada	1.5- 1.9	6.8%	1.5- 2.1	10.1%	1.6- 2.3	12.3%
West Europe	2.6- 3.7	9.1%	3.5- 5.1	9.8%	3.8- 5.7	11.0%
Other	0.4- 0.8	17.6%	0.4- 1.0	29.0%	0.4- 1.5	43.0%
OPEC	29.8-35.0	4.5%	31.6-41.2	8.3%	31.3-44.2	10.8%
Venezuela	2.1- 2.5	4.5%	1.9- 2.6	6.1%	1.8- 2.5	9.2%
Indonesia	1.5- 1.9	6.7%	1.4- 2.3	13.6%	0.9- 2.2	20.1%
Algeria	1.1- 1.5	9.8%	0.9- 2.1	25.8%	0.7- 2.3	29.5%
Libya	2.0- 2.6	6.7%	2.0- 2.6	8.4%	1.5- 2.7	14.5%
Nigeria	2.0- 2.8	9.1%	1.6- 2.6	10.4%	1.4- 2.9	14.6%
Iran	3.0- 6.0	20.1%	3.6- 6.8	19.0%	3.7- 6.0	15.6%
Kuwait	1.7- 2.2	7.4%	1.8- 2.9	11.3%	2.0- 2.9	11.9%
Saudi Arabia	6.3- 9.4	8.4%	7.6-14.3	15.8%	7.8-15.5	19.3%
Iraq	2.5- 3.4	8.7%	3.2- 4.7	10.8%	3.5- 5.1	11.7%
UAE	1.8- 2.1	6.2%	1.9- 3.2	13.7%	1.8- 3.7	19.4%
Other	1.2- 1.8	N/A	1.1- 2.3	N/A	0.8- 2.2	N/A
NON-OPEC	5.2- 6.8	6.5%	6.6- 9.9	10.4%	7.6-12.4	12.7%
Mexico	1.8- 2.4	9.5%	2.5- 4.2	14.5%	3.5- 6.4	17.4%
Other	3.1- 4.6	N/A	3.2- 6.3	N/A	3.1- 8.4	N/A
SINO-SOVIET	14.2-15.3	1.9%	14.6-18.2	6.1%	15.0-22.0	9.8%
TOTAL	64.5-70.6	2.7%	71.4-83.5	5.1%	74.8-90.7	6.2%

*Components do not add to totals since some respondents did not provide forecasts of components.

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

U.S. ENERGY CONSUMPTION

Figure 16 and Table 111 present the adjusted average response to the U.S. Energy Consumption Forecast section of the questionnaire. Real GNP assumptions underlying the energy forecast are also shown. The forecast projects total U.S. energy consumption to increase 2.3 percent per year over the 1977-1990 period (from 76.3 to 102.1 quadrillion BTU's), while real GNP grows an average of 3.2 percent per year. One standard deviation from the average forecast of total energy consumption is ±3.2 percent in 1990.

Also shown in Figure 16 is the ratio of total energy to GNP. This declined from 61.2 thousand BTU's per dollar of GNP (in constant 1972 dollars) in 1972 to 57.3 thousand BTU's in 1977. The decline continues throughout the forecast period and by 1990 is 50.6 thousand BTU's per dollar of GNP.

The adjusted average U.S. primary energy consumption forecast by sector, as presented in Figure 17, shows energy consumption growth in the transportation sector slowing dramatically during the

TABLE 111

U.S. Energy Consumption and Gross National Product Forecasts

	Total Energy (Quadrillion BTU's)	GNP (Billion 1972 Dollars)
1977	76.32	1,333
1980	82.23	1,461
1982	86.52	1,562
1985	92.01	1,742
1990	102.09	2,018
	Annual Average Percent Change	
1977-80	2.5	3.1
1980-82	2.6	3.4
1982-85	2.1	3.7
1985-90	2.1	3.0
1977-90	2.3	3.2

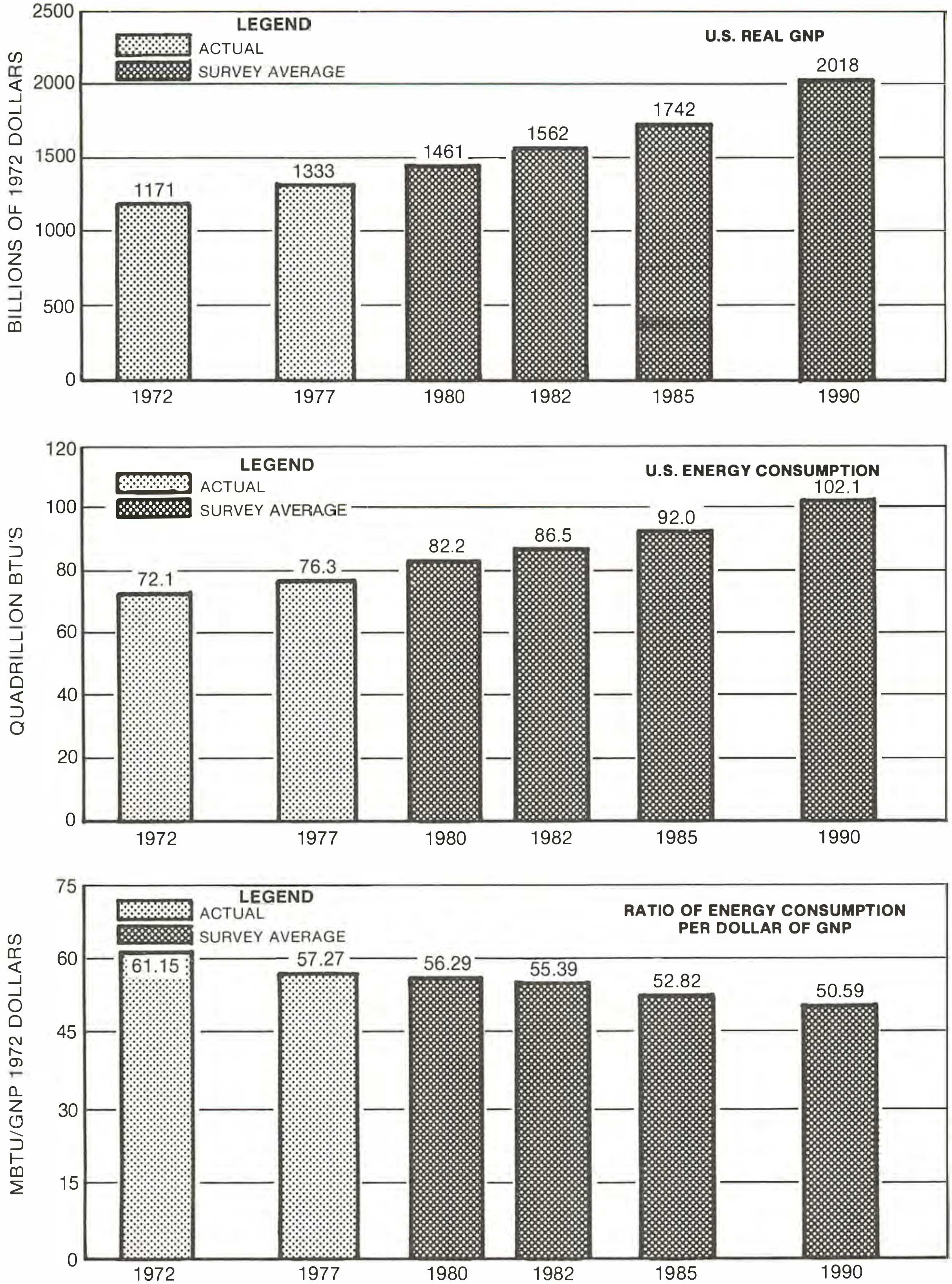


Figure 16. U.S. GNP and Energy Consumption Forecasts.

forecast period, while conversion losses (primarily electric utility losses) continue to grow substantially faster than total energy.

The U.S. energy consumption forecast is shown by fuel in Figure 18. The oil and gas combined share of total consumption is forecast to decline from 74.6 percent in 1977 to just under 62 percent in 1990, while coal and nuclear's combined share increase from 22 percent in 1977 to almost 34 percent in 1990. Seventy-six (76) percent of the projected increase in coal is in the electric utility sector. As a percent of total energy, hydro and "other" energy sources (including geothermal, solar, etc.) increase only from about three to four percent in 1977 to four to five percent in 1990.

U.S. oil consumption is expected to grow only about one percent per year over the forecast period, as shown in Figure 19. By 1990 the standard deviation from the average is forecast to be ±5.6 percent.

Table 112 shows U.S. oil consumption by sector. During the forecast period oil consumption is expected to grow most rapidly in the non-energy and industrial sectors, while a decline in consumption is forecast for the use of oil in the electric utility sector.

U.S. ENERGY SUPPLIES

Figure 20 presents the adjusted average of domestic liquids production (crude and condensate and natural gas liquids) and oil imports. While the average of liquids production forecasts holds at about 10 MMB/D throughout the period, by 1990 one standard deviation from the average is almost ±12 percent. Oil imports in the average forecast increase from 9.1 MMB/D in 1980 to 10.9 MMB/D in 1990 with a standard deviation of ±17.6 percent. Table 113 presents the adjusted average oil supply forecast.

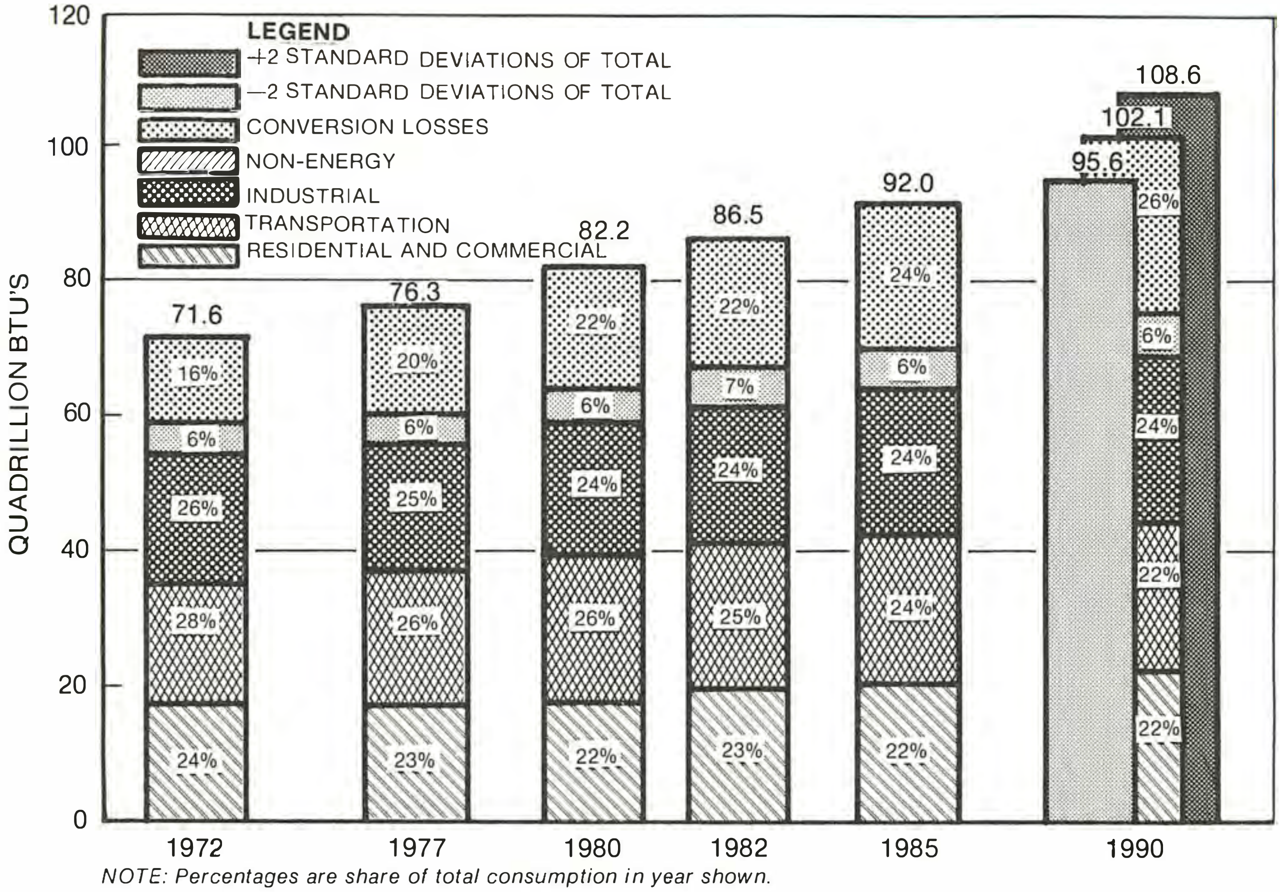


Figure 17. U.S. Energy Consumption by Sector.

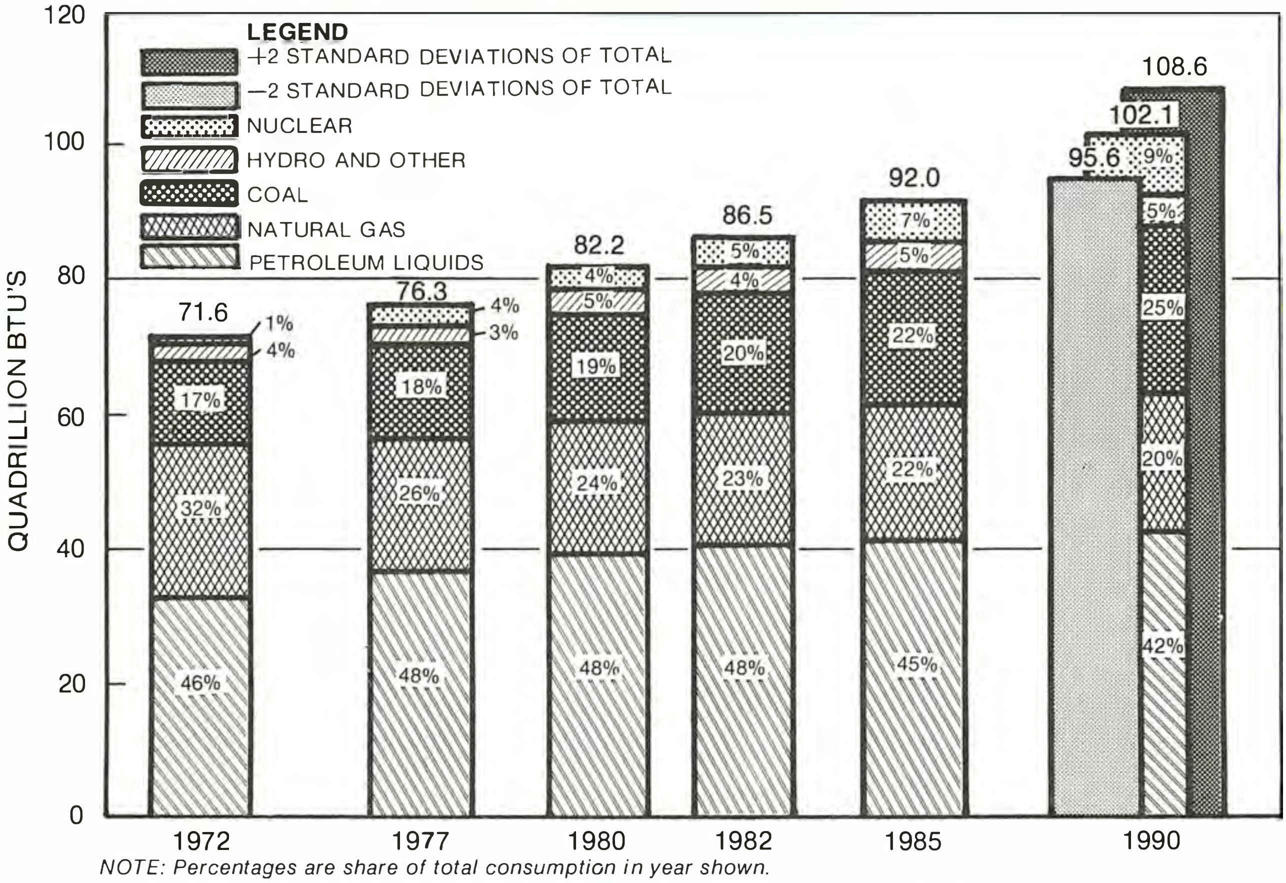


Figure 18. U.S. Energy Consumption by Fuel.

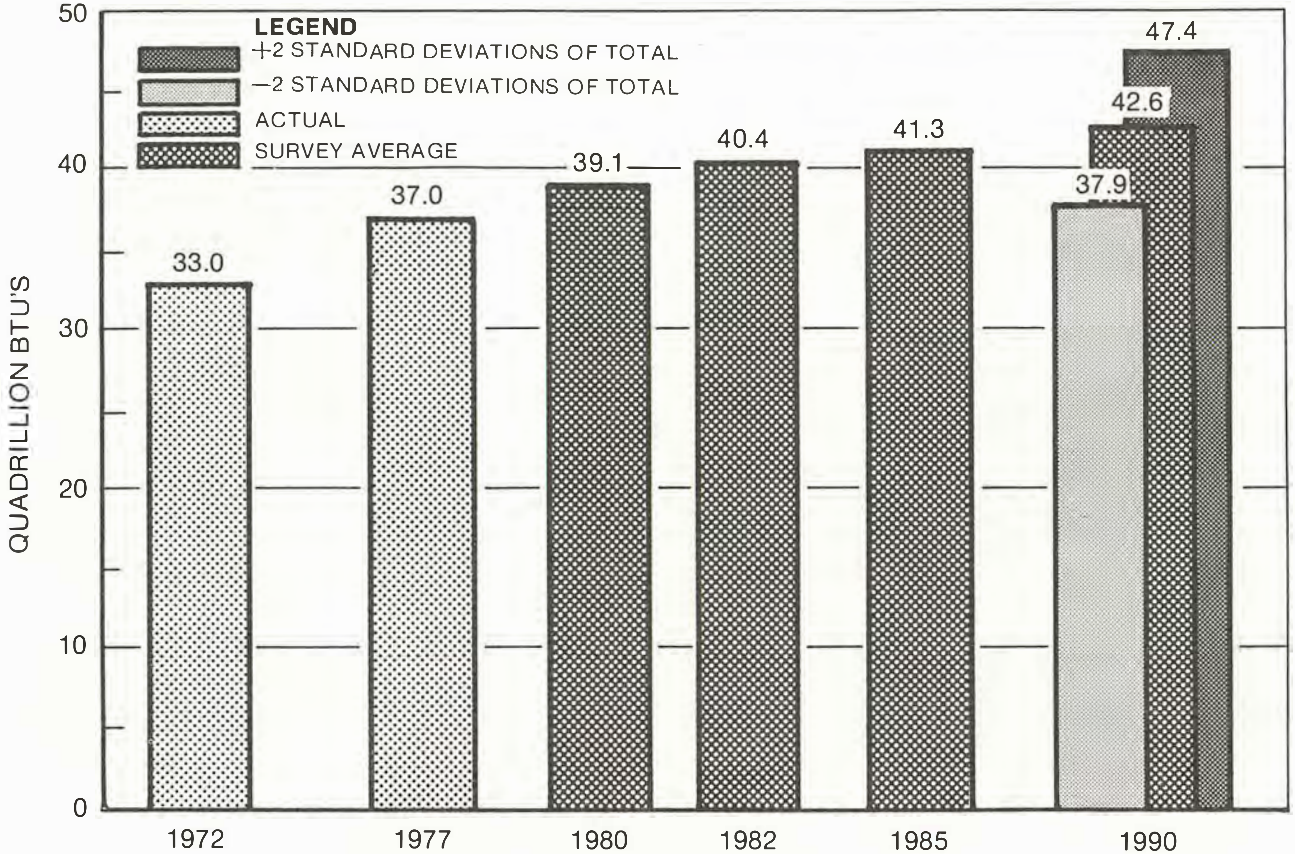
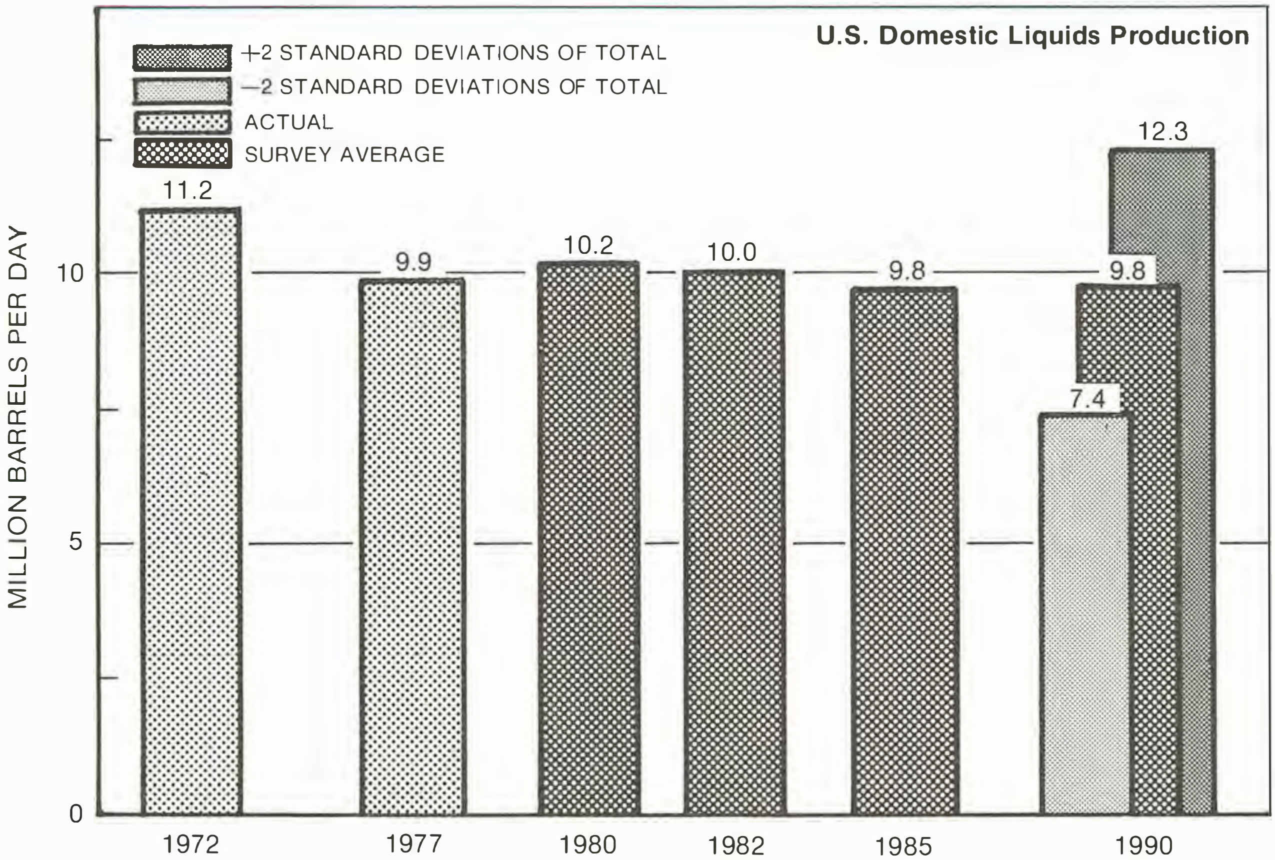
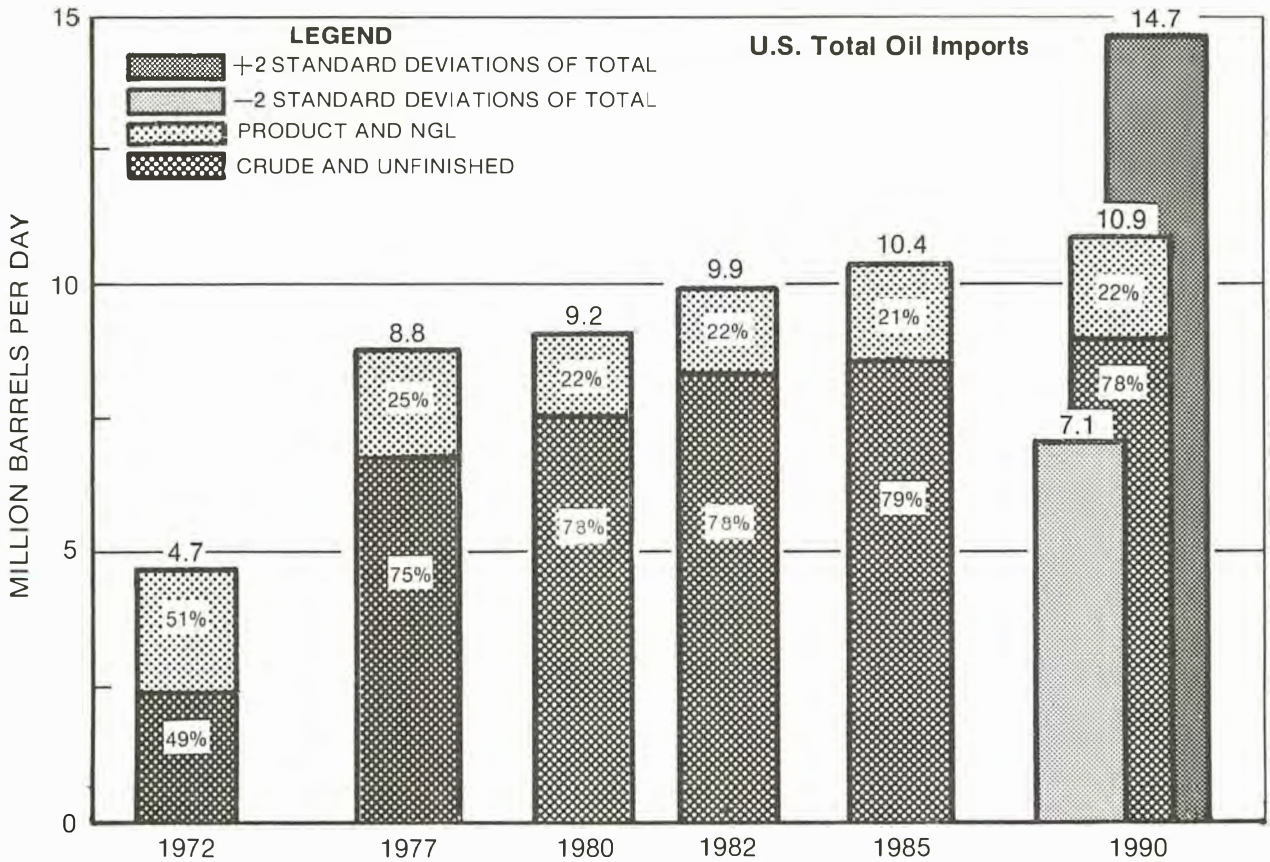


Figure 19. U.S. Oil Consumption.





NOTE: Percentages are share of total imports for years shown.

Figure 20. U.S.Oil Production and Imports.

TABLE 112

U.S. Oil Consumption by Sector*

	Actual (Quadrillion BTU's)	Survey	Average Annual Growth (Percent)	
Sector	1977	1990	1972-77	1977-1980
Residential and Commercial	5.14	5.60	-1.5	0.7
Transportation	19.36	21.96	2.5	1.0
Industrial	4.52	5.75	5.1	1.9
Electric Utility	4.03	3.53	5.1	-1.0
Non-Energy and Other†	3.92	5.80	1.4	3.1
Total	36.97	42.64	2.3	1.1

*Columns may not add due to rounding.
†Including synthetics in 1990.

TABLE 113

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

	Actual	Survey Average			
	1977	1980	1982	1985	1990
Domestic Production - Total	9.9	10.2	10.0	9.8	9.8
Crude and Condensate	8.2	8.7	8.5	8.4	8.5
NGL	1.6	1.5	1.5	1.4	1.3
Imports - Total	8.8	9.2	9.9	10.4	10.9
Crude and Unfinished	6.6	7.1	7.7	8.2	8.5
Product and NGL	2.2	2.1	2.2	2.3	2.4
Syncrude Production	0.0	0.0	†	†	0.3
Processing Gain and Stock Change	0.0	0.5	0.5	0.5	0.5
Total Oil Supply	18.7	9.9	20.5	20.8	21.5

*Columns may not add due to rounding.
†Less than 0.1 MB/D.

The U.S. gas production forecast is shown in Figure 21 and in Table 114. The forecast projects gas production to continue declining through the period, but at a diminishing rate. Total U.S. gas supplies are forecast to remain flat over the period, at about 19.4 TCF/year with increased imports offsetting continued declines in production. The standard deviation in total gas supplies is ±8.3 percent of the mean by 1990.

TABLE 114

U.S. Gas Supply
(Trillion Cubic Feet Per Year)

	Actual	Survey Average			
	1977	1980	1982	1985	1990
Production (Dry)	19.2	18.1	17.5	16.8	16.2
Imports	1.0	1.4	2.0	2.5	2.8
Syngas Production	N/A	0.2	0.3	0.3	0.5
Export, Transmission Loss, Stock Change, etc.	(0.7)	(0.3)	(0.3)	(0.3)	(0.2)
Total Gas Supply	19.5	19.4	19.4	19.4	19.3

*Columns may not add due to rounding.

The projected U.S. coal production forecast is shown in Figure 22. Compared to 1977, coal production in 1985 is expected to increase by 40 percent and in 1990 by 80 percent. The standard deviation from the average will be 8.7 percent in 1990. Over the forecast period, nuclear output grows at an average annual rate of nearly 10 percent. By 1990, the combined contribution of coal and nuclear energy will rise to about 34 percent of total energy supply, from 22 percent in 1977.

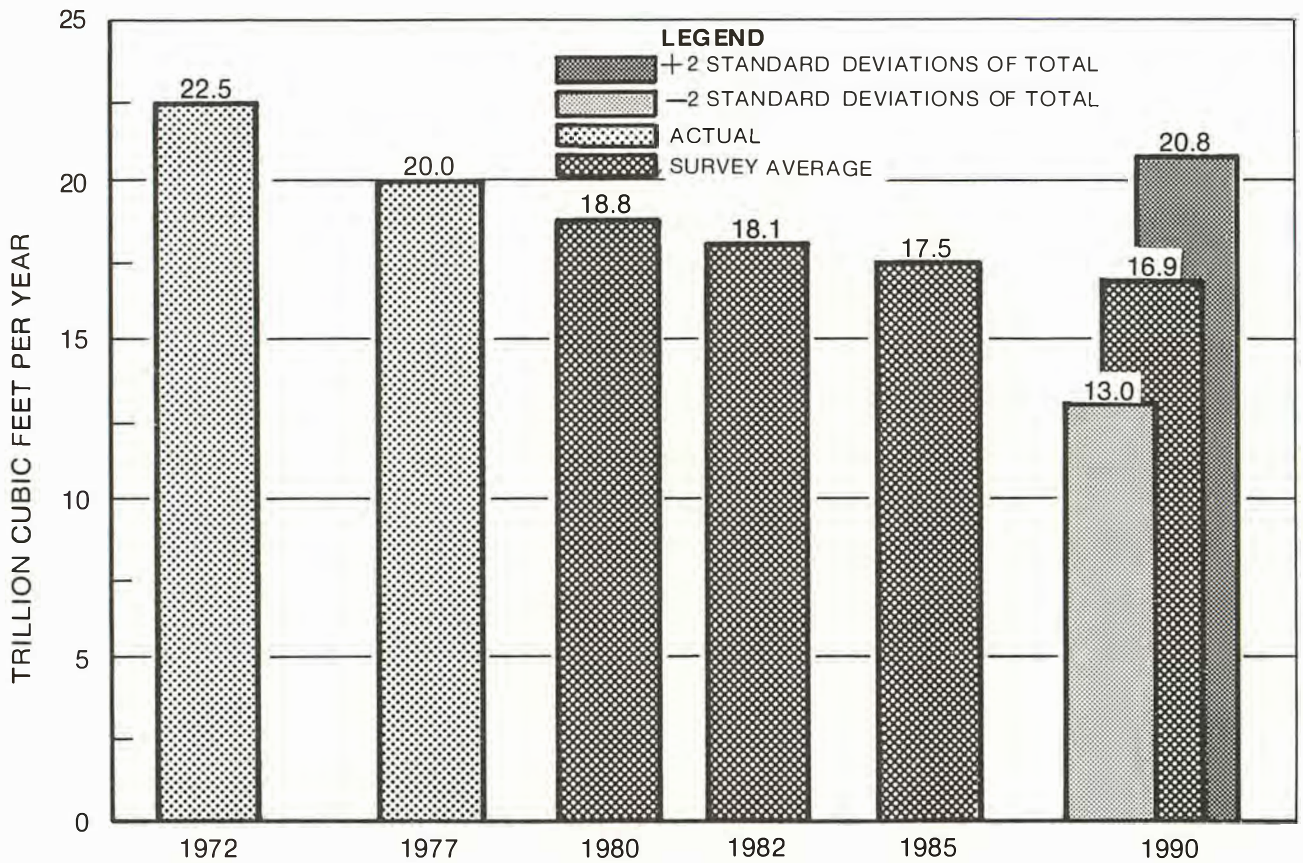


Figure 21. U.S.Gas Production (Marketed Production of Wet Gas).

PETROLEUM PRODUCTS SUPPLY/DEMAND

Total Product Demand

Projected total United States product demand for the years 1980, 1982, 1985, and 1990 are displayed in Figure 23 and Table 115 for the adjusted average case. Respondents expect demand to increase from 18.4 MMB/D in 1977 to 21.2 MMB/D by 1990 -- an annual increase of just over one percent. In general, demand growth will slow considerably during the forecasted intervals, from 2.0 percent annually during 1977-1980 to only 0.7 percent annually in 1985-1990. Figure 23 also indicates the variability of the demand forecasts by displaying the 1990 level, plus or minus two standard deviations. Since the standard deviation is 4.5 percent of the mean 1990 forecasted value, strong agreement existed among respondents with regard to total demand.

Motor Gasoline Demand

A primary cause of the slowing in aggregate petroleum demand is the anticipated peaking of motor gasoline requirements in the early 1980's. This trend is shown in Figure 24 and Table 116. Respondents expect the peak to occur no later than 1982, with a decline thereafter. The decline is expected to accelerate somewhat after 1985, in the range of one to two percent annually.

TABLE 115

United States Product Demand (MMB/D)

	Actual/ Adjusted Average		Average Annual Percent Change
1977	18.43	1980/1977	2.0
1980	19.55	1985/1980	1.0
1982	20.15	1990/1985	0.7
1985	20.52	1990/1977	1.1
1990	21.23		

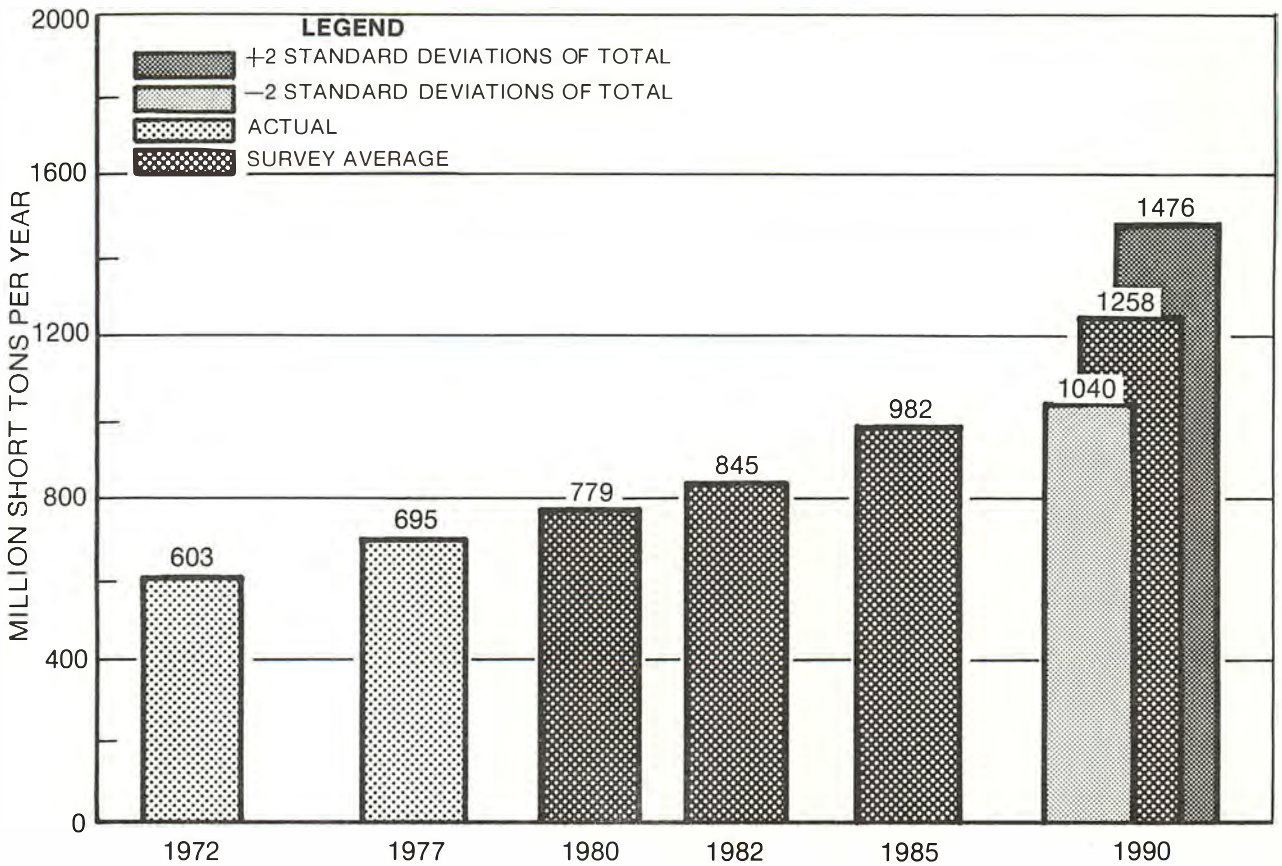


Figure 22. U.S.Coal Production.

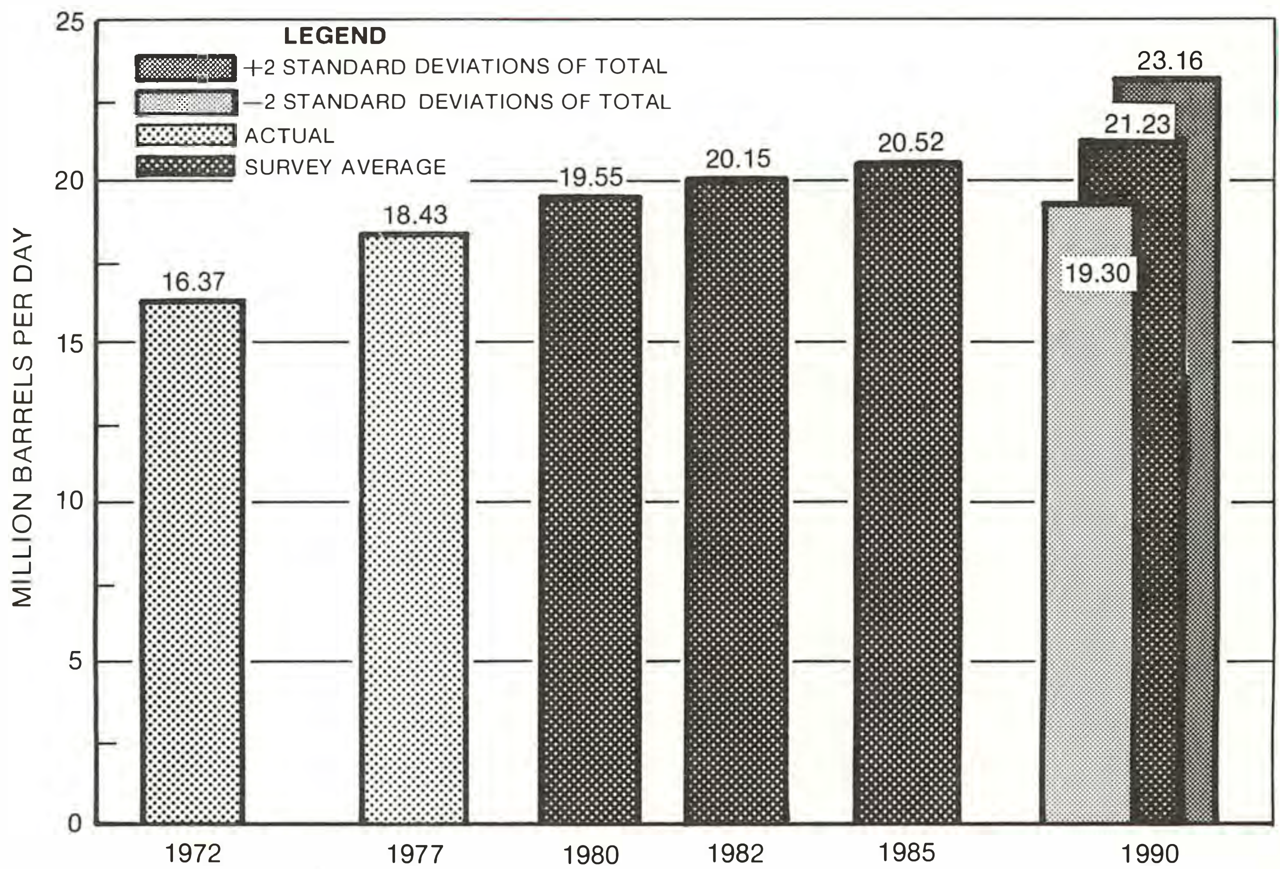
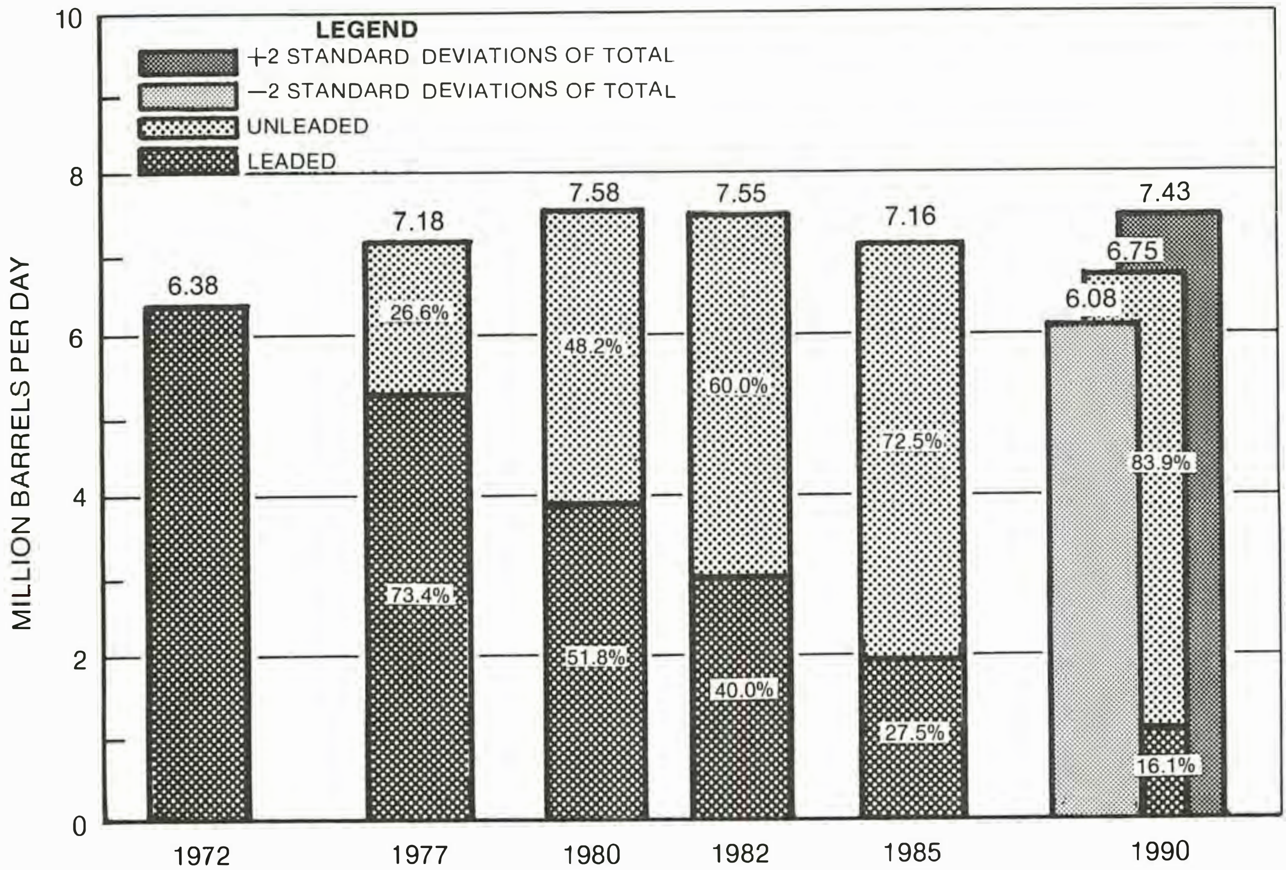


Figure 23. U.S. Total Product Demand.



NOTE: Percentages are share of total gasoline demand in year shown.

Figure 24. U.S. Motor Gasoline Demand.

TABLE 116

Motor Gasoline Demand (MMB/D)

	Actual/ Adjusted Average		Average Annual Percent Change
1977	7.18	1980/1977	1.9
1980	7.58	1985/1980	(1.2)
1982	7.55	1990/1985	(1.2)
1985	7.16	1990/1977	(0.5)
1990	6.75		

The principal reason for the peak and then decline in gasoline demand is the rapid improvement in automotive fuel economy. The basic assumptions for the low, mean, and high demands in 1990 are shown on Table 117. The key assumptions underlying the mean survey response are:

- Total passenger cars on the road will increase from 102.7 million in 1977 to 134.2 million in 1990.

- Diesel passenger cars will account for about 10 percent of total new car sales in 1990.

- New car fuel economy will increase from 18 miles per gallon in 1980 to 26 miles per gallon by 1990.

- The fuel economy of all passenger cars will average 22 miles per gallon in 1990, an increase of nearly 50 percent from the 1980 average.

In Figure 24, plus or minus two standard deviations are shown for motor gasoline in the year 1990. With a standard deviation of only five percent of the mean forecasted value, it could be concluded that agreement exists among respondents regarding demand levels. However, despite the low standard deviation, examination of the 1990 key asssumptions in Table 117 indicates otherwise. First, considerable variation exists with regard to diesel passenger car penetration. Second, the range of high/low estimates on the total passenger car population exceeds 30 million. Third, large ranges in total miles traveled and average miles per gallon for new cars create more uncertainty.

With regard to gasoline quality, respondents expect unleaded gasoline to represent more than 80 percent of total demand in 1990. On average, the responses indicate premium unleaded gasoline requirements to total about 40 percent of overall unleaded demand, with an octane rating of 92. Premium leaded gasoline requirements are expected to be negligible by 1985.

TABLE 11/

United States Motor Gasoline Situation

ASSUMPTIONS*	1977 Actual	1980 Average	1985 Average	1990 Low	1990 Average	1990 High
Passenger Cars In Use (Millions)	102.7	111.7	123.7	119.4	134.2	151.5
Average Annual % Change 1990/1977				1.2 %	2.1 %	3.0 %
New Car Registrations (Millions)	10.3	11.1	11.9	10.7	12.1	13.5
Average Annual % Change 1990/1977				0.3 %	1.3 %	2.1 %
Diesel Passenger Car Sales (Millions)	N.A	0.3	0.8	0.2	1.2	2.2
Average Annual % Change 1990/1977				–	–	–
Total Miles Traveled (Billions)	1,119	1,280	1,459	1,417	1,660	2,648
Average Annual % Change 1990/1977				1.8 %	3.1 %	6.9 %
Average Miles/Gallon -- New Cars	15	18	24	24	26	34
-- All Cars	14	15	18	20	22	24
MOTOR GASOLINE DEMAND†						
Adjusted Average Demand (MBPD)	7,176	7,583	7,156	6,024	6,753	7,240
Average Annual % Change 1990/1977				(1.3) %	(0.5) %	0.1 %
GASOLINE QUALITY*						
Unleaded as % of Total	26.6 %	48.2 %	72.5 %	88.7 %	83.9 %	69.0 %
Leaded as % of Total	73.4	51.8	27.5	11.3	16.1	31.0
Octane Level [(R+M)/2]						
Unleaded Non-Premium	88	88	88	87	88	92
Unleaded Premium	N.A.	92	91	87	92	94
Leaded Non-Premium	90	90	90	89	90	91

*Data reported are the low, high, and arithmetic average of responses to the survey.
†Total motor gasoline demand includes passenger car use, other highway use (trucks), and off-highway use.

Middle Distillate Demand

Respondent's estimates of kerosine, jet fuel, and distillate fuel oil demand were pooled to create a middle distillate demand category. These data were then re-grouped according to the following: jet fuel, on-highway diesel fuel, and other middle distillates. Figure 25 shows the demand trends for these groupings. On

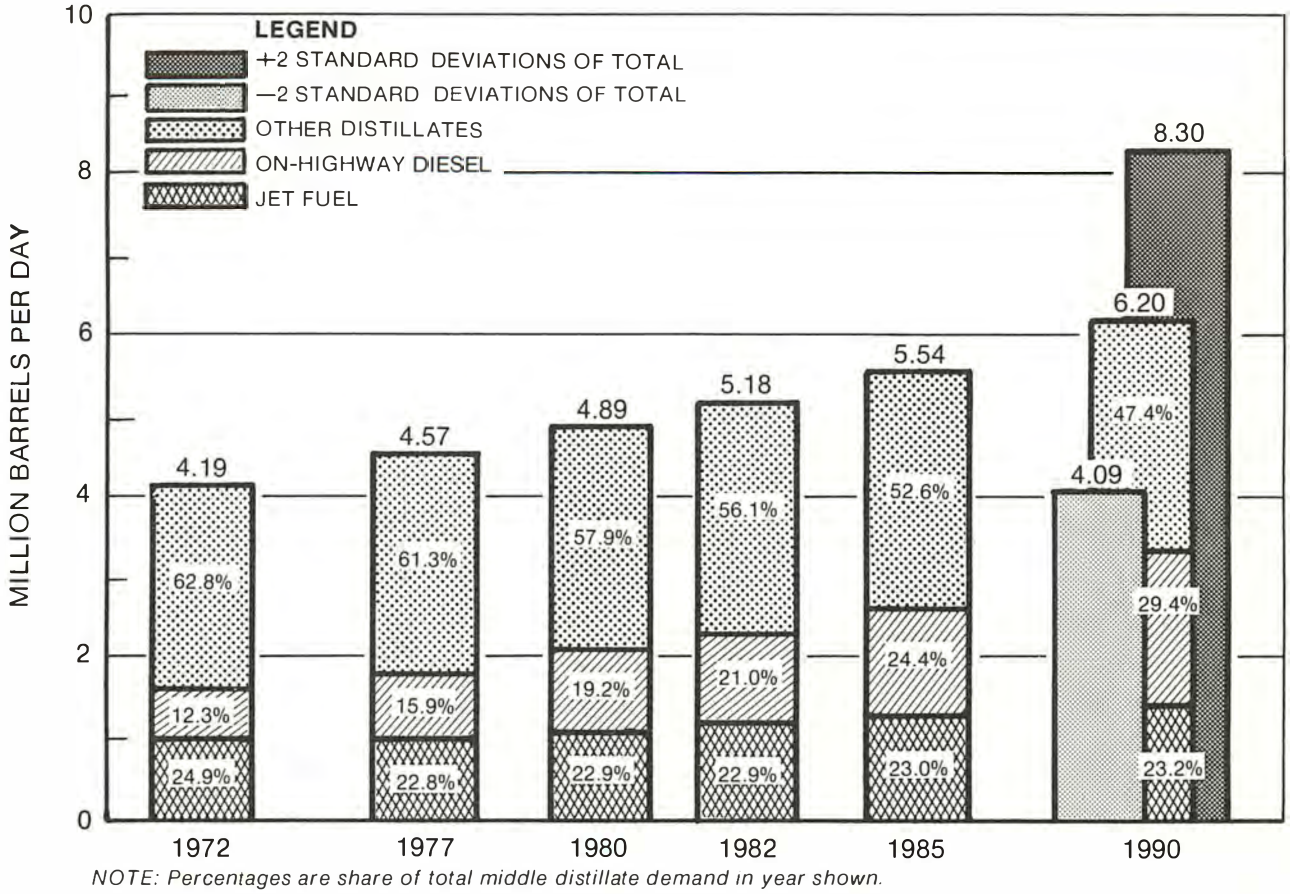


Figure 25. U.S. Middle Distillate Demand (Includes Kerosine, Jet Fuel and Distillate).

TABLE 118

United States Middle Distillate Demand (MMB/D)

	Actual/Adjusted Average		Average Annual Percent Change
1972	4.19	1977/1972	1.7
1977	4.57	1980/1977	1.4
1980	4.89	1985/1980	2.5
1982	5.18	1990/1985	2.3
1985	5.54	1990/1977	2.4
1990	6.20		

average, the data indicate that total middle distillate demand will increase 2.4 percent annually during 1977-1990. This is above the 1.7 percent annual growth during 1972-1977. Table 118 indicates this change, as well as the variation in growth during the forecast period.

Jet fuel's relative share of the middle distillate fraction will remain rather stable. However, primarily due to respondents' expectations concerning the growing number of diesel-powered automobiles, on-highway diesel demand will more than double to 1.82 MMB/D by 1990 -- an annual increase of more than seven percent. In contrast other middle distillate demand (including kerosine) will experience little growth. The demand by these three groupings are shown in Table 119.

TABLE 119

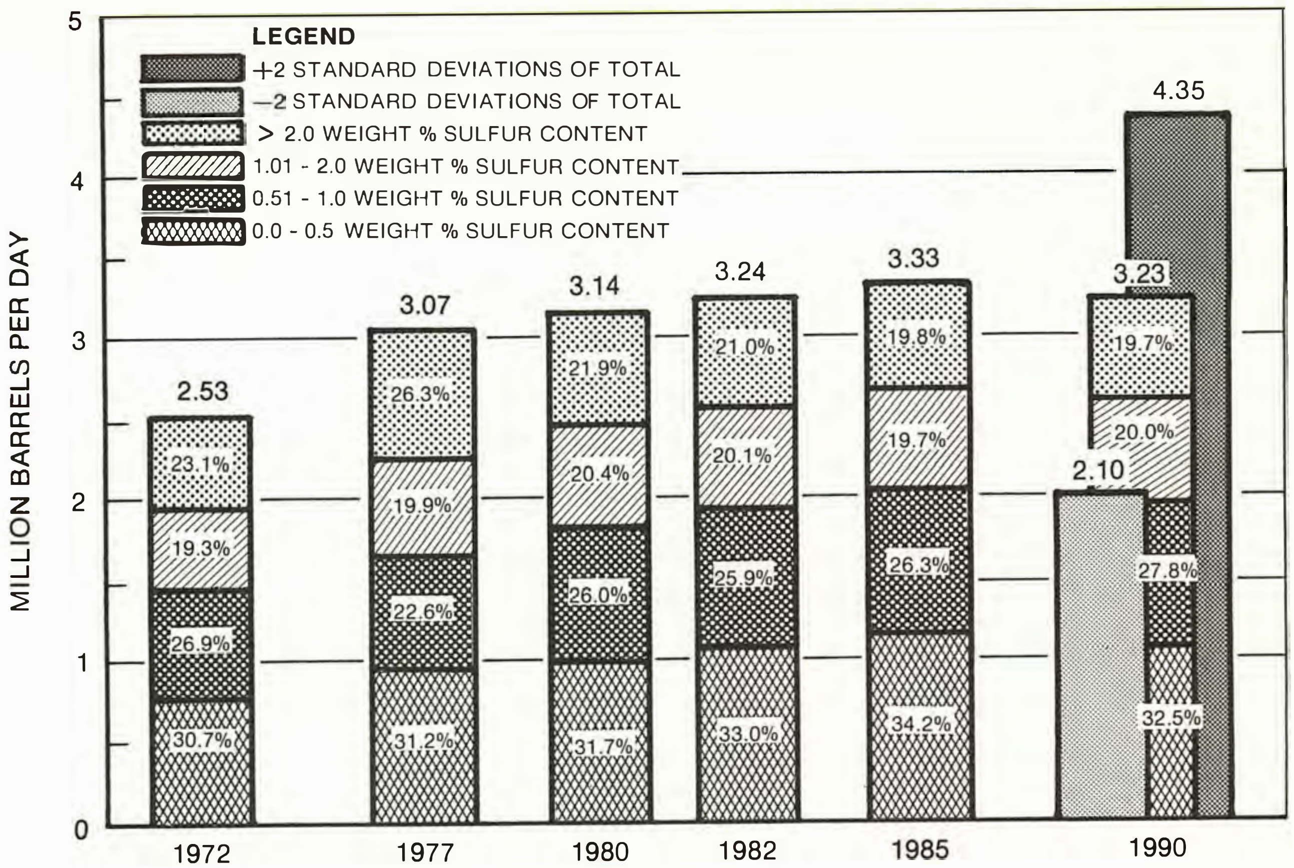
Middle Distillate Demand (MMB/D)

	Jet Fuel	On-Highway Diesel	Other Distillate	Total
1972	1.05	0.52	2.63	4.19
1977	1.04	0.72	2.80	4.57
1980	1.12	0.94	2.83	4.89
1982	1.19	1.09	2.91	5.18
1985	1.27	1.35	2.91	5.54
1990	1.44	1.82	2.93	6.20

Average Annual Percent Change

1977/1972	(0.1)	6.9	1.3	1.7
1970/1977	2.5	7.4	0.4	2.4

Survey results show residual fuel oil demand increasing throughout the early to mid-1980's and then declining modestly by 1990. These results are shown graphically in Figure 26. With about 50 percent of residual fuel consumed by electric utilities, the forecasted decline in utility petroleum consumption after 1985 accounts for the decrease in overall residual fuel demand. Also shown in Figure 26, the 1990 demand, plus or minus two standard deviations, indicates considerable differences in respondents' de-



NOTE: Percentages are share of total residual demand in year shown.

Figure 26. U.S. Residual Fuel Oil Demand by Sulfur Content.

mand levels. These uncertainties undoubtedly relate to respondents' expected trends in utility consumption of coal and natural gas. Table 120 summarizes future residual fuel oil demand trends.

TABLE 120

United States Residual Fuel Oil Demand (MMB/D)

	Actual/ Adjusted Average		Average Annual Percent Change
1977	3.07	1980/1977	0.7
1980	3.14	1985/1980	1.2
1982	3.24	1990/1985	(0.6)
1985	3.33	1990/1977	0.4
1990	3.23		

Changes in demand by sulfur grades are equally sensitive to utility fuel oil requirements. Demand by sulfur grade is shown in Figure 26 and in Table 121 for the forecast years. The demand for 0-0.5 percent grade fuel oil follows utility demand closely, and requirements also peak in 1985. From 1977 to 1990, low sulfur fuel oil demand (defined as 1.0 percent sulfur and lower) increases from about 54 percent of the total to 60 percent.

TABLE 121

United States Residual Fuel Demand
Percent by Sulfur Grade

Grade	1977	1980	1982	1985	1990
0-0.5%S	31.2%	31.6%	33.0%	34.2%	32.5%
0.51-1.0%S	22.6	26.0	25.9	26.3	27.8
1.01-2.0%S	19.9	20.5	20.1	19.7	20.0
2.0%S+	26.3	21.9	21.0	19.8	19.7
	100.0%	100.0%	100.0%	100.0%	100.0%

Survey results also provide additional data on anticipated demand by light-end versus heavy-end, and demand by region. Over the 1977-1990 period, the survey indicates a moderate increase in the proportion of light-end products consumed, despite the peak and then decline in motor gasoline requirements. This pattern is opposite to the trend during 1972-1977, when strong residual fuel demand growth increased the proportion of heavy-end products consumed. Table 122 summarizes the light and heavy product demands and trends.

TABLE 122

Light-End Versus Heavy-End Product Demand (MMB/D)*

Adjusted Average	1972	1977	1980	1982	1985	1990
Light-end	12.93	14.33	15.31	15.77	15.99	16.71
Heavy-end	3.44	4.10	4.25	4.38	4.54	4.52
Total	16.37	18.43	19.55	20.15	20.52	21.23
Percentage of Total						
Light-end	79.0%	77.8%	78.3%	78.3%	77.9%	78.7%
Heavy-end	21.0	22.2	21.7	21.7	22.1	21.3

*Light-end products include aviation gasoline, motor gasoline, kerosine, jet fuel, distillate fuel, LPG, still gas, naphtha, and petrochemical feedstocks.

REGIONAL PETROLEUM SUPPLY/DEMAND

The supply/demand survey sought detailed regional balances for each of the five PAD districts. The responses to the survey indicated that only a relatively few institutions forecast detailed balances for all five districts. As shown in the reply tallies in Appendix G, however, most respondents provided balances for PADs I-IV in aggregate and PAD V. It was concluded that the individual PAD data were too limited to provide a meaningful report, thus only PADs I-IV aggregate and PAD V data are included.

Local Product Demand

Figure 27 presents the average of the survey results and the variance of the responses for the year 1990. On average the forecasters are expecting very modest growth in product demands, in both the East and West, over the next decade. In PADs I-IV, the demand increase over the 1980-1990 period averages 140 MB/D and reaches a level of 18.2 MMB/D. In PAD V demand is expected to reach 3.0 MMB/D by 1990, growing at an average rate of 30 MB/D per annum beginning in 1980. As indicated by the 1990 variance, there is relatively good agreement among the respondents even at the extremes of the forecasts.

Percentage annual growth rates of product demands for various segments of the forecast period are shown in Table 123 and compared to actual rates for the 1972-1977 period.

TABLE 123

Product Demand Growth Rates

	Actual	Average Annual Increase (%)			
	72-77	77-80	80-85	85-90	77-90
PADs I-IV	2.2	2.1	0.9	0.7	1.1
PAD V	3.9	1.4	1.4	0.4	1.0

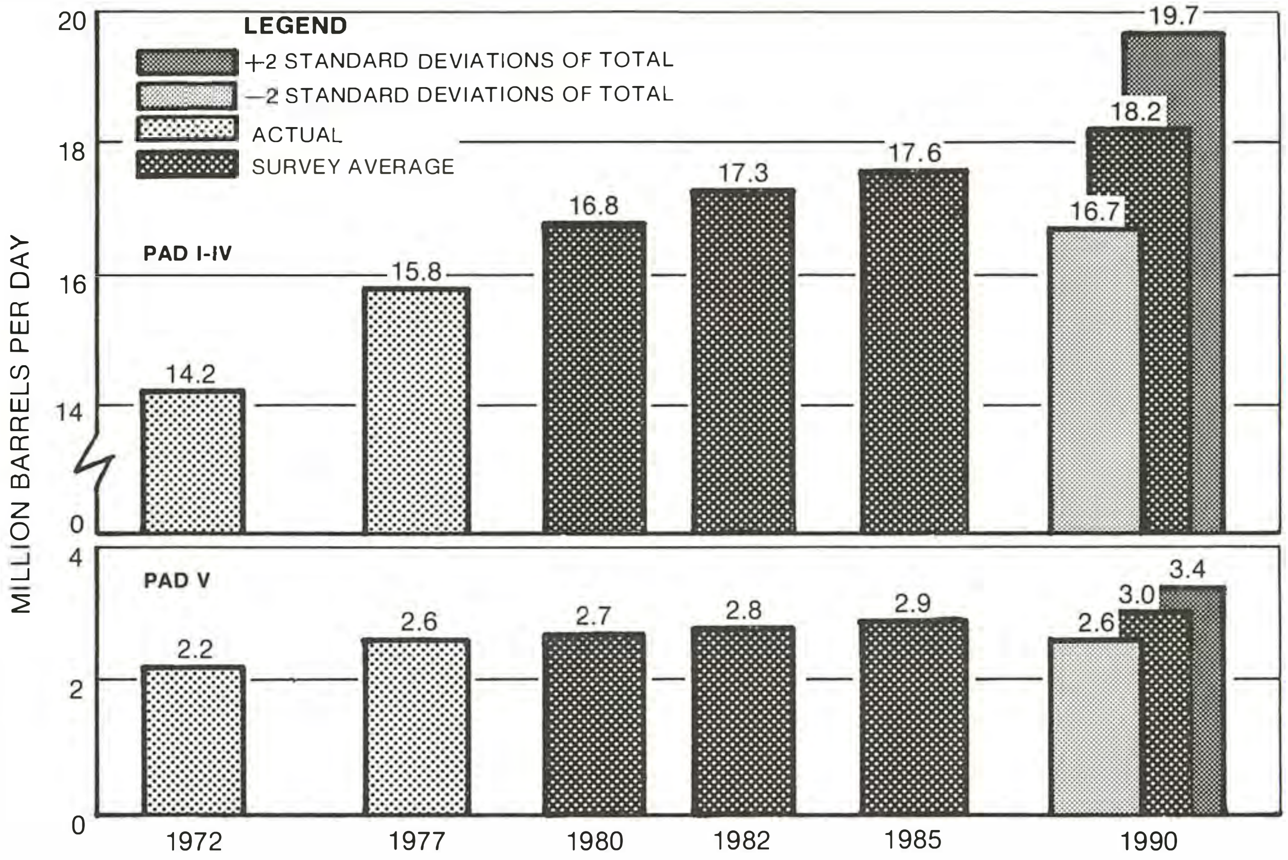


Figure 27. PAD Local Product Demand.

Although the growth rate profiles are substantially different for the two areas, the rates for the period 1977-1990 are essentially the same.

According to respondents' data, PAD V demand, as a percent of total U.S. demand, will remain relatively constant during the forecast period. This pattern is in contrast to that during 1972-1977 when PAD V demand increased faster than that of the United States as a whole. Although the shares among these regions are expected to remain constant, this is not the case with gasoline demand. Between 1977 and 1990, PAD V demand is projected to decline by only 0.2 percent annually, compared to a decline of 0.5 percent for PADs I-IV. Total product and motor gasoline demand trends by region are shown in Table 124.

TABLE 124

Regional Total Demand Trends
(Percentage of Total)

	1972	1977	1980	1982	1985	1990
PADs I-IV	86.8	85.8	86.0	86.0	85.7	86.0
PAD V	13.2	14.2	14.0	14.0	14.3	14.0

Regional Motor Gasoline Demand Trends
(Percentage of Total)

	1972	1977	1980	1982	1985	1990
PADs I-IV	85.3	84.9	85.0	84.8	84.6	84.4
PAD V	14.7	15.1	15.0	15.2	15.4	15.6

Crude Runs

As depicted in Figure 28, the respondents foresee only modest increases in crude runs within both PAD areas. This trend is consistent with that observed for total product demands. During the

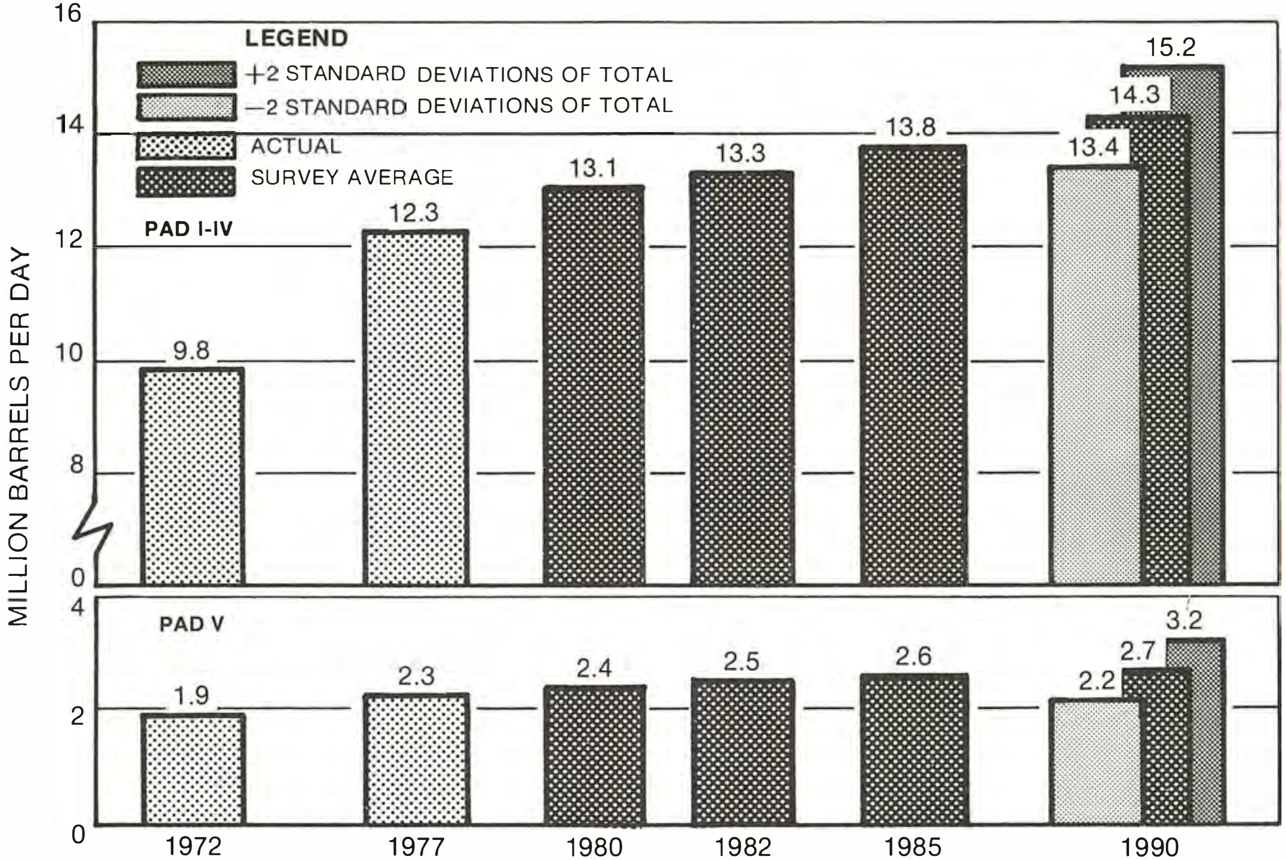


Figure 28. PAD Crude Runs.

next 10 years, runs in PADs I-IV are expected to rise to 14.3 MMB/D by 1990, at an average annual rate of 120 MB/D, while those in PAD V are anticipated to increase at an annual rate of 30 MB/D to a 1990 level of 2.7 MMB/D. The 1990 variance again implies fairly good agreement among the estimates. Variance in forecasts of PAD V crude runs is substantially higher than that for estimates of PADs I-IV crude runs and PAD V product demands.

Growth rate profiles depicted in Table 125 for crude runs are different for the two areas, while the rates for the entire 13 year period 1977-1990 are all but equal, at a modest 1.1 to 1.2 percent per annum.

TABLE 125

Growth Rate in Crude Runs

	Actual	Average Annual Increase (%)			
	72-77	77-80	80-85	85-90	77-90
PADs I-IV	4.6	2.2	1.0	0.8	1.2
PAD V	3.9	1.8	1.4	0.3	1.1

The growth rate profiles for crude runs are also consistent with those for local product demand.

Domestic Liquids Production

Figure 29 presents the survey average expectations for the sum of crude, condensate and natural gas production in the East and West. According to forecasters, the East will be a declining producing area, dropping 1.1 MMB/D of production capability over the 1980-1990 period, while the West will enjoy a production increase of 600 MB/D, albeit insufficient to offset the decline in PADs I-IV. The rates of change in regional production are shown in Table 126.

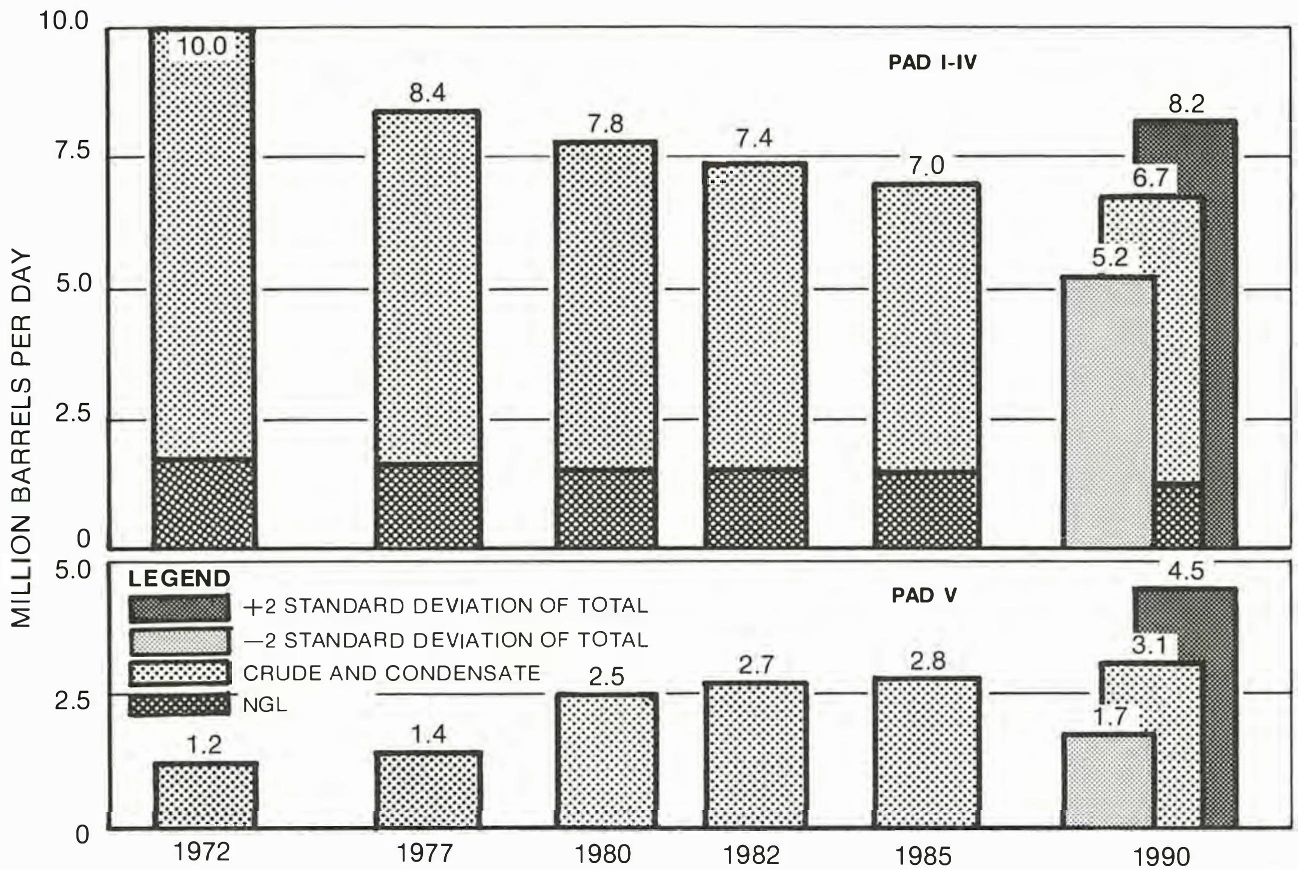


Figure 29. PAD Domestic Liquids Production.

TABLE 126

Domestic Petroleum Production Growth Rates

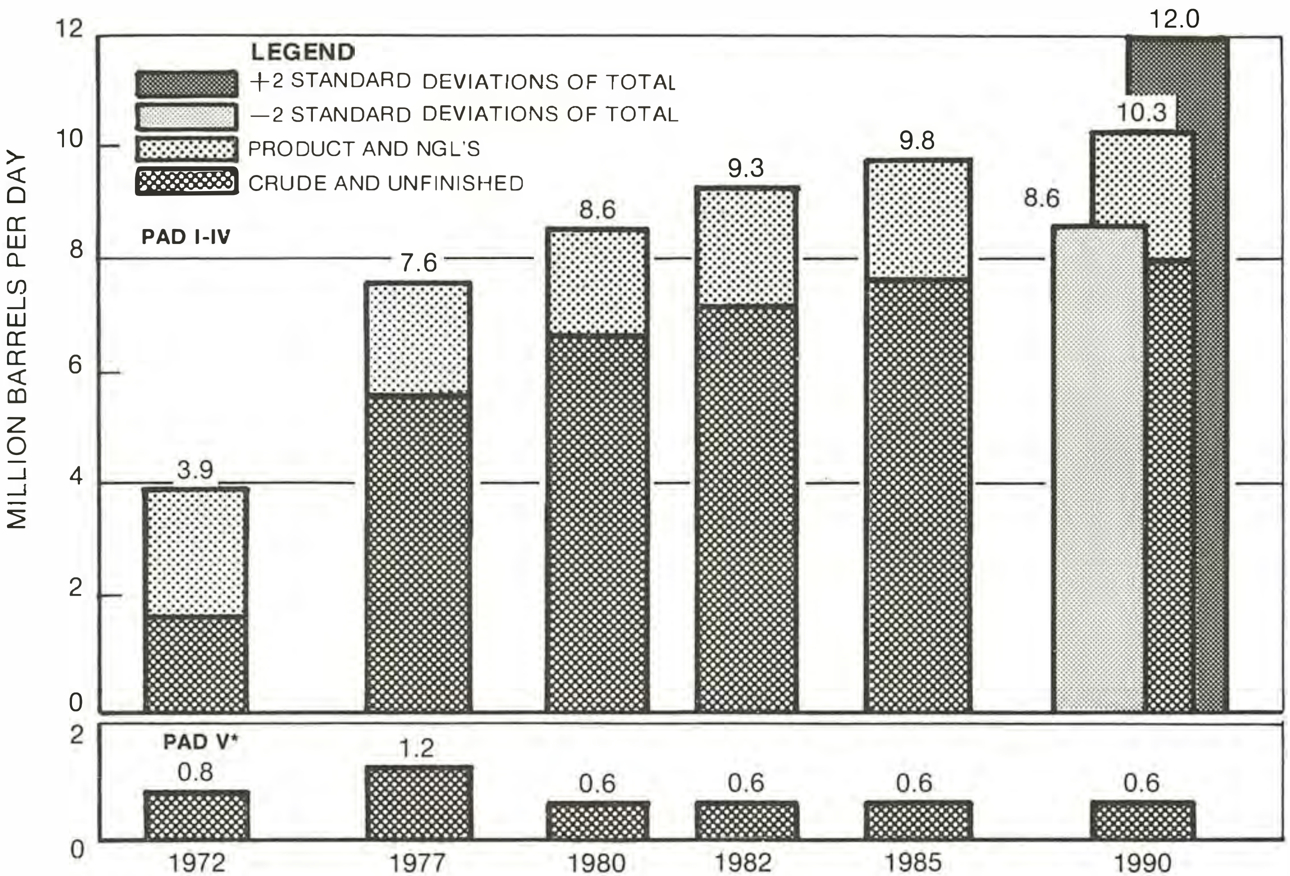
	Actual	Average Annual Increase (%)			
	72-77	77-80	80-85	85-90	77-90
PADs I-IV	-3.4	-2.6	-2.2	-0.8	-1.8
PAD V	4.0	19.4	2.7	2.1	6.1

The 1990 variance in the estimates suggests that all respondents agree that production in PADs I-IV will indeed decline, but with a greater or lesser expected severity. Expectations for PAD V ranged from proliferation to deterioration in production capability.

The production decline profile for PADs I-IV indicates that the rate of decline will decrease significantly over the latter years of the next decade. PADs I-IV NGL production, not delineated in figure or table, is estimated to decline at essentially the same rate during the 1977-1990 period as total liquid production. The PAD V growth profile shows an opposite but like trend -- a decrease in the rate of growth as the 1980-1990 decade closes. NGL production, which accounts for less than two percent of PAD V's total, is forecasted to increase at about the same average annual rate, reaching 63 MB/D in 1990.

Total Imports

All forecasters anticipated a growing dependence on imports, particularly in PADs I-IV. As depicted in Figure 30, imports into PADs I-IV are expected to increase steadily to a 1990 level of 10.3 MMB/D, about 2 MMB/D more than at present. The 1990 variance suggests fairly good agreement among the forecasters with respect to the level to which imports will rise. The forecasters expect product imports into PADs I-IV to remain a near constant two MMB/D.



*Product and NGL imports into PAD V range from 105 to 146 thousand barrels per day in the 1980-1990 period.

Figure 30. PAD Total Petroleum Imports.

While the respondents' expected level of imports into PAD V vary considerably, there is general agreement that whatever the level is, it will not change appreciably over the next decade. The average of the forecasts is 600 MB/D through 1990, with 100 to 150 MB/D being products.

Annual growth rate or rate of change profiles for imports are shown in Table 127. All of the changes in PAD V imports take place at the beginning of the forecast period, coincident with the advent of North Slope crude in 1977. Imports into PADs I-IV increase steadily over the period, but at declining annual rates that average 2.4 percent for the 13 year 1977-1990 period.

TABLE 127

Growth Rate in Total Petroleum Imports

	Actual	Average Annual Increase (%)			
	72-77	77-80	80-85	85-90	77-90
PADs I-IV	14.1	4.2	2.8	0.9	2.4
PAD V	8.2	-22.2	1.0	-0.3	-5.4

Inter-PAD Receipts

All respondents forecast a continuing dramatic change in inter-PAD movements for PADs I-IV. The survey averages presented in Figure 31 indicate a doubling of those movements between 1980 and 1990. Virtually all (95 percent) of the West to East shipments are crude oil. There is an extremely wide divergence among forecasters as to just how dramatic the change in PADs I-IV inter-PAD receipts will be. The variance is so great (one standard deviation equals about 75 percent of the average) that no clear consensus exists.

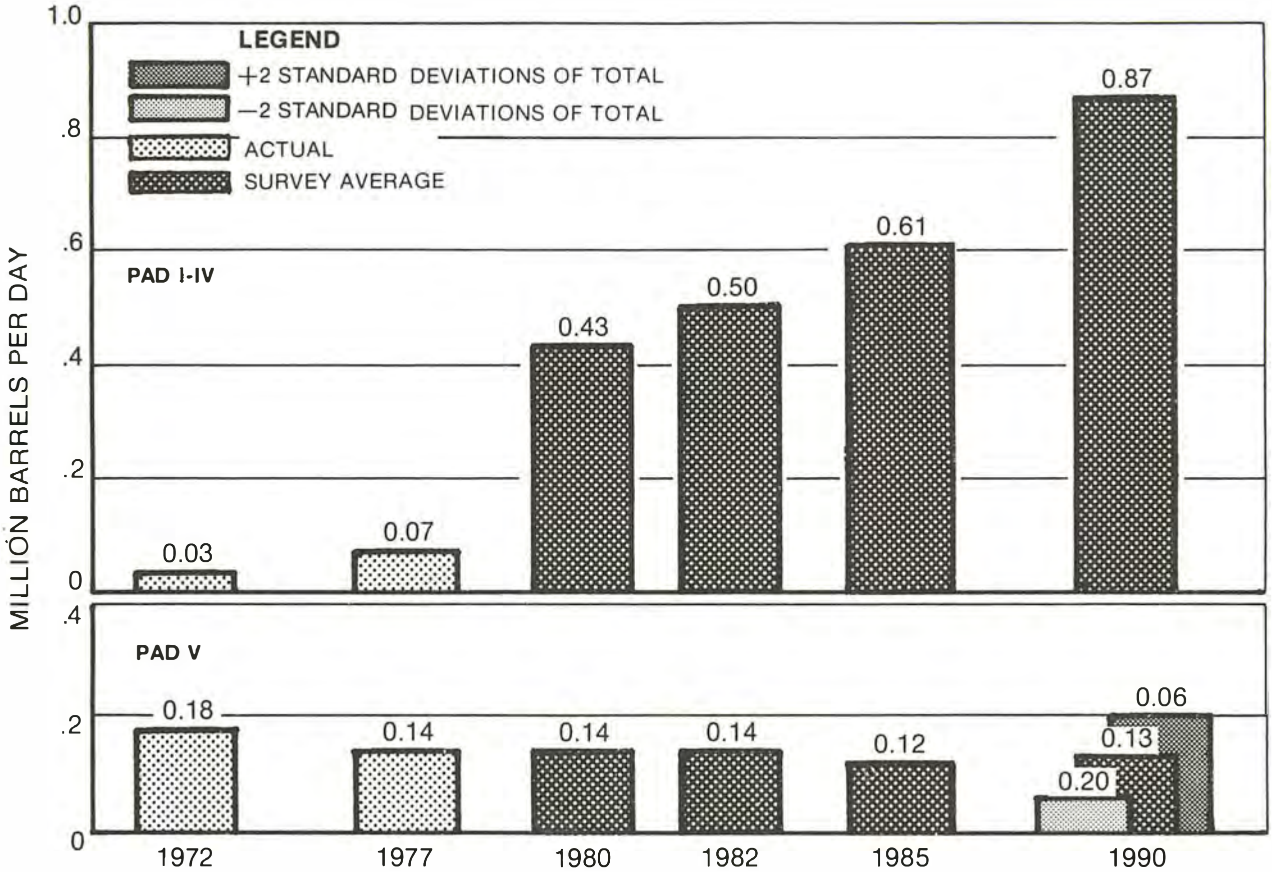


Figure 31. Inter-PAD Petroleum Receipts.

Inter-PAD shipments into PAD V are expected to remain at current rates over the next 10 years and will be over 95 percent petroleum products. The variance in the PAD V estimate is a matter of level.

Rate of change profiles in Table 128 indicate that even though the big jump in inter-PAD shipments into PADs I-IV has in effect occurred, a very substantial annual rate of upward movement could continue through 1990. That annual rate in the 1980-1990 period approximates 7.5 percent. Inter-PAD shipments into PAD V are not expected to change substantially.

TABLE 128

Rate of Change in Inter-district Petroleum Movements

	Actual	Average Annual Increase (%)			
	72-77	77-80	80-85	85-90	77-90
PADs I-IV	18.6	93.4	7.5	7.1	21.6
PAD V	-5.8	0.1	-2.0	0.8	-0.5

APPENDICES

APPENDIX A

REQUEST LETTER

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
Secretary

Mr. Collis P. Chandler, Jr.
Chairman, National Petroleum Council
1625 K Street, N.W.
Washington, DC 20006

APPENDIX B

ROSTERS

NATIONAL PETROLEUM COUNCIL
ROSTER

Jack H. Abernathy, Chairman
Big Chief Drilling Company

Jack M. Allen, President
Alpar Resources, Inc.

Robert O. Anderson
Chairman of the Board
Atlantic Richfield Company

R. E. Bailey
Chairman and
Chief Executive Officer
Conoco Inc.

R. F. Bauer
Chairman of the Board
Global Marine Inc.

Robert A. Belfer, President
Belco Petroleum Corporation

Harold E. Berg
Chairman of the Board and
Chief Executive Officer
Getty Oil Company

John F. Bookout
President and
Chief Executive Officer
Shell Oil Company

W. J. Bowen
Chairman of the Board
and President
Transco Companies Inc.

Howard Boyd
Chairman of the
Executive Committee
The El Paso Company

I. Jon Brumley
President and
Chief Executive Officer
Southland Royalty Company

Theodore A. Burtis
Chairman, President and
Chief Executive Officer
Sun Company, Inc.

John A. Carver, Jr.
Director of the Natural
Resources Program
College of Law
University of Denver

C. Fred Chambers, President
C & K Petroleum, Inc.

Collis P. Chandler, Jr.
President
Chandler & Associates, Inc.

E. H. Clark, Jr.
President and
Chief Executive Officer
Baker International

Edwin L. Cox
Oil and Gas Producer

Roy T. Durst
Consulting Engineer

James W. Emison, President
Western Petroleum Company

James H. Evans, Chairman
Union Pacific Corporation

Frank E. Fitzsimmons
General President
International Brotherhood
of Teamsters

John S. Foster, Jr.
Vice President
Energy Research and Development
TRW, Inc.

R. I. Galland
Chairman of the Board
American Petrofina, Incorporated

C. C. Garvin, Jr.
Chairman of the Board
Exxon Corporation

James F. Gary
Chairman and
Chief Executive Officer
Pacific Resources, Inc.

Melvin H. Gertz, President
Guam Oil & Refining Company, Inc.

Richard J. Gonzalez

F. D. Gottwald, Jr.
Chief Executive Officer,
Chairman of the Board and
Chairman of Executive Committee
Ethyl Corporation

Maurice F. Granville
Chairman of the Board
Texaco Inc.

Frederic C. Hamilton, President
Hamilton Brothers Oil Company

Armand Hammer
Chairman of the Board
and Chief Executive Officer
Occidental Petroleum Corporation

Jake L. Hamon
Oil and Gas Producer

John P. Harbin
Chairman of the Board and
Chief Executive Officer
Halliburton Company

Fred L. Hartley
Chairman and President
Union Oil Company of California

John D. Haun, President
American Association
of Petroleum Geologists

Denis Hayes
Executive Director
Solar Energy Research Institute

H. J. Haynes
Chairman of the Board
Standard Oil Company
of California

Robert A. Hefner III
Managing Partner
GHK Company

Robert R. Herring
Chairman of the Board and
Chief Executive Officer
Houston Natural Gas Corporation

Ruth J. Hinerfeld, President
League of Women Voters
of the United States

H. D. Hoopman
President and
Chief Executive Officer
Marathon Oil Company

Mary Hudson, President
Hudson Oil Company

Henry D. Jacoby
Director, Center for Energy
Policy Research
Massachusetts Institute
of Technology
Sloan School of Management

John A. Kaneb, President
Northeast Petroleum
Industries, Inc.

James L. Ketelsen
Chairman of the Board
President and
Chief Executive Officer
Tenneco Inc.

Thomas L. Kimball
Executive Vice President
National Wildlife Federation

George F. Kirby
Chairman and President
Texas Eastern
Transmission Corp.

Charles G. Koch
Chairman and
Chief Executive Officer
Koch Industries, Inc.

John H. Lichtblau
Executive Director
Chief Executive Officer
Petroleum Industry
  Research Foundation, Inc.

Jerry McAfee
Chairman of the Board
Gulf Oil Corporation

Paul W. MacAvoy
The Milton Steinbach Professor of
  Organization and Management
  and Economics
The Yale School of Organization
  and Management
Yale University

Peter MacDonald, Chairman
Council of Energy Resource Tribes

D. A. McGee, Chairman
Kerr-McGee Corporation

John G. McMillian
Chairman and
  Chief Executive Officer
Northwest Alaskan
  Pipeline Company

Cary M. Maguire, President
Maguire Oil Company

C. E. Marsh, II
President
Mallard Exploration, Inc.

W. F. Martin
Chairman of the Board and
  Chief Executive Officer
Phillips Petroleum Company

David C. Masselli
Energy Policy Director
Friends of the Earth

F. R. Mayer
Chairman of the Board
Exeter Company

C. John Miller, Partner
Miller Brothers

James R. Moffett, President
McMoRan Exploration Company

Kenneth E. Montague
Chairman of the Board
GCO Minerals Company

Jeff Montgomery
Chairman of the Board
Kirby Exploration Company

R. J. Moran, President
Moran Bros., Inc.

Robert Mosbacher

C. H. Murphy, Jr.
Chairman of the Board
Murphy Oil Corporation

John H. Murrell
Chief Executive Officer and
  Chairman of Executive Committee
DeGolyer and MacNaughton

R. L. O'Shields
Chairman and
  Chief Executive Officer
Panhandle Eastern
  Pipe Line Company

John G. Phillips
Chairman of the Board and
  Chief Executive Officer
The Louisiana Land
  & Exploration Company

T. B. Pickens, Jr.
President
Mesa Petroleum Company

L. Frank Pitts, Owner
Pitts Oil Company

Rosemary S. Pooler
Chairwoman and
  Executive Director
New York State
  Consumer Protection Board

Donald B. Rice, President
Rand Corporation

Corbin J. Robertson
Chairman of the Board
Quintana Petroleum Corporation

James C. Rosapepe, President
Rosapepe, Fuchs & Associates

Henry A. Rosenberg, Jr.
Chairman of the Board and
Chief Executive Officer
Crown Central Petroleum
Corporation

Ned C. Russo, President
Stabil-Drill Specialties, Inc.

Robert V. Sellers
Chairman of the Board
Cities Service Company

Robert E. Seymour
Chairman of the Board
Consolidated Natural Gas
Company

J. J. Simmons, Jr.
President
Simmons Royalty Company

Theodore Snyder, Jr.
President
Sierra Club

Charles E. Spahr

John E. Swearingen
Chairman of the Board
Standard Oil Company (Indiana)

Robert E. Thomas
Chairman of the Board
MAPCO Inc.

H. A. True, Jr.
Partner
True Oil Company

Martin Ward, President
United Association of Journeymen
and Apprentices of the
Plumbing and Pipe Fitting
Industry of the United States
and Canada

Rawleigh Warner, Jr.
Chairman of the Board
Mobil Corporation

John F. Warren
Independent Oil Operator/Producer

Lee C. White, President
Consumer Energy Council
of America

Alton W. Whitehouse, Jr.
Chairman of the Board and
Chief Executive Officer
The Standard Oil Company (Ohio)

Joseph H. Williams
Chairman of the Board and
Chief Executive Officer
The Williams Companies

Robert E. Yancey, President
Ashland Oil, Inc.

NATIONAL PETROLEUM COUNCIL

COMMITTEE ON
REFINERY FLEXIBILITY

CHAIRMAN

Jerry McAfee
Chariman of the Board
Gulf Oil Corporation

GOVERNMENT COCHAIRMAN

C. William Fischer*
Deputy Assistant Secretary
for Policy and Evaluation
U.S. Department of Energy

EX OFFICIO

C. H. Murphy, Jr.
Chairman
National Petroleum Council

EX OFFICIO

H. J. Haynes
Vice Chairman
National Petroleum Council

SECRETARY

Marshall W. Nichols
Deputy Executive Director
National Petroleum Council

* * *

Robert O. Anderson
Chairman of the Board
Atlantic Richfield Company

Glenn C. Ferguson
Ferguson & Bosworth

R. I. Galland
Chairman of the Board
American Petrofina, Incorporated

C. C. Garvin, Jr.
Chairman of the Board
Exxon Corporation

James F. Gary, Chairman
and Chief Executive Officer
Pacific Resources, Inc.

Melvin H. Gertz, President
Gual Oil & Refining Company, Inc.

F. D. Gottwald, Jr.
Chief Executive Officer,
Chairman of the Board and
Chairman of Executive Committee
Ethyl Corporation

Allan Grant, President
American Farm Bureau Federation

Alvin F. Grospiron
Immediate Past President
Oil, Chemical and Atomic Workers
International Union

Fred L. Hartley
Chairman and President
Union Oil Company of California

Leon Hess
Chairman of the Board
Amerada Hess Corporation

Mary Hudson, President
Hudson Oil Company

Professor Henry D. Jacoby
Director, Center for Energy
Policy Research
Massachusetts Institute of Technology

Charles G. Koch
Chairman and Chief Executive Officer
Koch Industries, Inc.

*Replaced Hon. Alvin L. Alm, November 1979.

REFINERY FLEXIBILITY

John H. Lichtblau
Executive Director
Chief Executive Officer
Petroleum Industry Research
Foundation, Inc.

David C. Masselli
Energy Policy Director
Friends of the Earth

Rosemary S. Pooler
Chairwoman and Executive Director
New York State Consumer Protection
Board

Donald B. Rice, President
Rand Corporation

Henry A. Rosenberg, Jr.
Chairman of the Board and
Chief Executive Officer
Crown Central Petroleum Corporation

Theodore Snyder, Jr.
President
Sierra Club

O. J. Tauber, Sr.
Chairman
Tauber Oil Company

Martin Ward, President
United Association of Journeymen
and Apprentices of the Plumbing
and Pipe Fitting Industry of the
United States and Canada

Robert E. Yancey, President
Ashland Oil, Inc.

NATIONAL PETROLEUM COUNCIL

COORDINATING SUBCOMMITTEE
OF THE COMMITTEE ON
REFINERY FLEXIBILITY

CHAIRMAN

Warren B. Davis
Chief Economist
Gulf Oil Corporation

GOVERNMENT COCHAIRMAN

Frank A. Verrastro
Executive Assistant to
Assistant Secretary for
International Affairs
U.S. Department of Energy

SECRETARY

Marshall W. Nichols
Deputy Executive Director
National Petroleum Council

* * *

Lawrence J. Goldstein
Senior Economist
Petroleum Industry Research
Foundation, Inc.

John R. Hall
Vice Chairman and
Chief Operating Officer
Ashland Oil, Inc.

Henry D. Jacoby
Director, Center for Energy
Policy Research
Massachusetts Institute of Technology

Frederick C. Spreyer
Government Affairs Representative
Pacific Resources, Inc.

S. E. Watterson, Jr.
Corporation Manager
Tanker and Distribution
Planning Staff
Standard Oil Company of California

Ellen Winchester
Sierra Club

NATIONAL PETROLEUM COUNCIL

REFINERY CAPABILITY TASK GROUP
OF THE COMMITTEE ON
REFINERY FLEXIBILITY

CHAIRMAN

John R. Hall
Vice Chairman and
Chief Operating Officer
Ashland Oil, Inc.

GOVERNMENT COCHAIRMAN

Eugene L. Peer
Director, Supply Initiatives
Oil and Natural Gas Supply
Development
U.S. Department of Energy

ASSISTANT TO CHAIRMAN

Lloyd E. Busch
Vice President
Operational Planning
Ashland Oil, Inc.

SECRETARY

Ray W. Whitson
Consultant
National Petroleum Council

* * *

F. D. Dennstedt
Senior Vice President
Exxon Company, U.S.A.

Charles W. Else, President
Southland Oil Company

Richard N. Hancock
Vice President
Process Plants Sales
Foster Wheeler Energy Corporation

J. F. Horner
Vice President
Refinery and Engineering
Standard Oil Company (Indiana)

Dale Kingsley
Vice President
Refining Administration
CRA, Inc.

James H. McDonald
Vice President
Supply, Transportation and
Refining Coordination
Gulf Oil Company - U.S.

A. John Morris, President
Crown Central Petroleum Corporation

Elmer L. Winkler, President
Rock Island Refining Corporation

NATIONAL PETROLEUM COUNCIL

OIL SUPPLY, DEMAND AND LOGISTICS TASK GROUP
OF THE COMMITTEE ON
REFINERY FLEXIBILITY

CHAIRMAN

S. E. Watterson, Jr.
Corporation Manager
Tanker and Distribution Planning Staff
Standard Oil Company of California

GOVERNMENT COCHAIRMAN

William R. Veno*
Policy and Evaluation
Office of Analytical Services
U.S. Department of Energy

SECRETARY

Marshall W. Nichols
Deputy Executive Director
National Petroleum Council

* * *

Daniel L. Davis
Vice President - Residual Products
Tauber Oil Company

John N. Garrett
Manager - Business Research
Gulf Energy and Minerals Company

J. James Hur, Manager
Information Systems and Services
Atlantic Richfield Company

J. R. Maroni
Energy Planning Manager
Ford Motor Company

David C. May
Staff Director
Industrial Demand Analysis
Standard Oil Company (Indiana)

Paul A. Saurer
Associate Chief Economist
Texaco Inc.

*Replaced Robert S. Long, September 1979.