U.S. Petroleum Refining

National Petroleum Council
October 1986

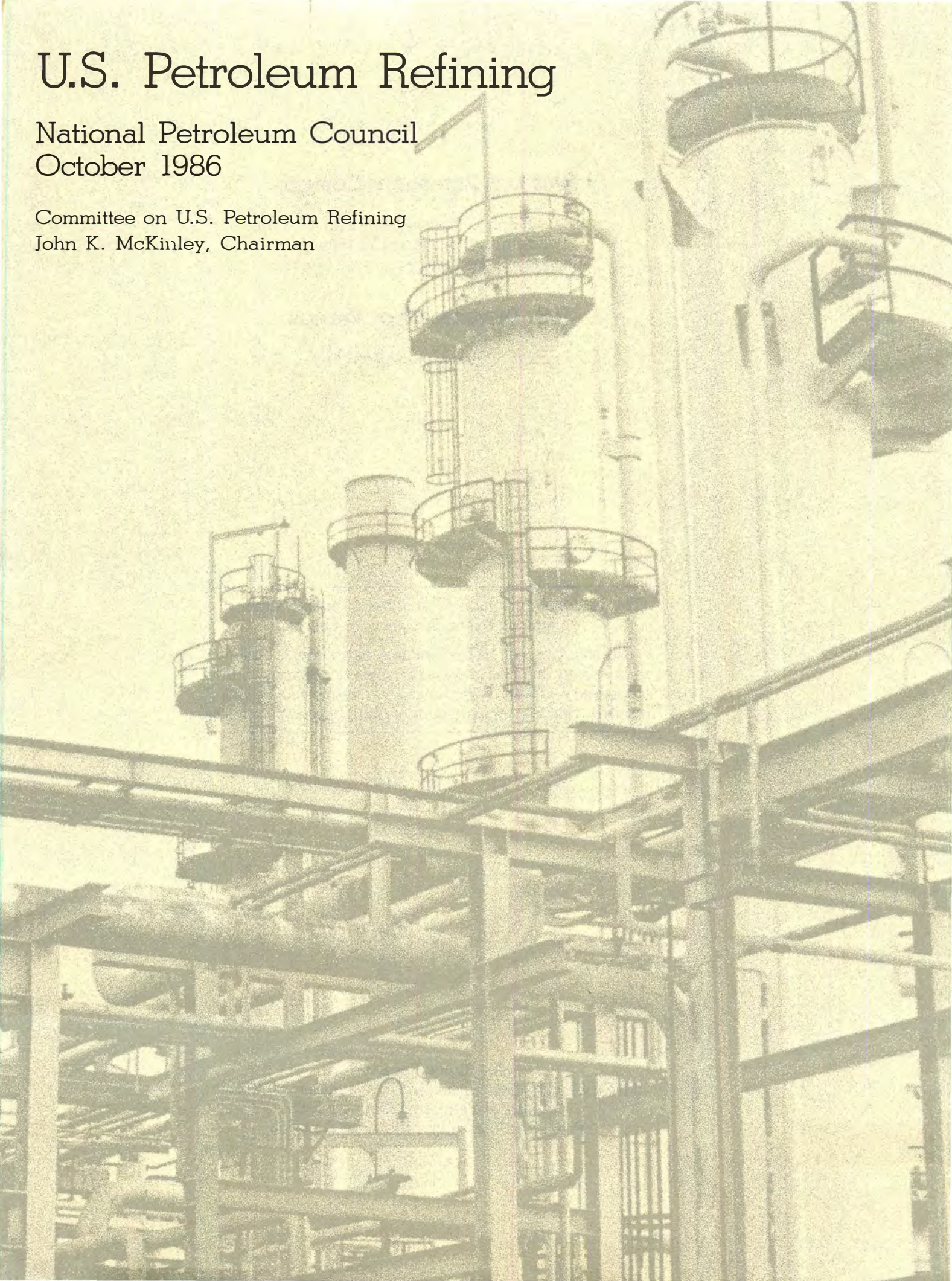


Cover Photograph: Desulfurizers at the Texaco Inc. Delaware City Refinery

U.S. Petroleum Refining

National Petroleum Council
October 1986

Committee on U.S. Petroleum Refining
John K. McKinley, Chairman



NATIONAL PETROLEUM COUNCIL

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

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TABLE OF CONTENTS

Introduction

Study Organization 1
Study Methodology 1

Executive Summary

Background 3
Major Findings and Conclusions 5
Other Findings and Conclusions 9
Observations 10

Chapter One: Survey of U.S. Petroleum Refineries

Introduction 11
Process Facilities Capabilities and Utilization 16
Crude Oil Slates 26
Feedstocks Other than Crude Oil 29
Product Yields 32
Crude Oil Substitutability 37
Gasoline Manufacturing Capabilities 41
Benzene in Gasoline 47
Sulfur Content Limitations on Distillates 48
Operational Expenses 49

Chapter Two: Analysis of Oil Supply and Demand

Introduction 55
Case Methodology 55
Historical Perspective 55
Initial Assumptions 60
Initial Case Balances 61
Alternate Cases 62

Chapter Three: Capabilities of the Domestic Refining Industry

Introduction 67
Conclusions 67
Industry Capability and Capacity 69
Refiner Response to Lead Phasedown 78
Gasoline Production Capability 82
Sulfur in Distillate Fuel 101
Model Development 101

Chapter Four: Assessment of Worldwide Refining Capability

Introduction 107
World Refining and Transportation Capacities 109
Modeling Oil Product Imports 112
Supply and Demand 117
Tariff and Trade Regulations 118

Chapter Five: Comparative Position of the Domestic Refining Industry

Introduction 119
Scenarios 119
The Reference Cases 120
Percentage of Residual Fuel in the Demand 121
Social and Political Constraints 122
U.S. Tariffs 123
Middle East Refining 124
Middle East/North Africa Natural Gas 126
Foreign vs. U.S. Light Oil Demands 126
Marine Transportation 127

Chapter Six: Other Issues

Introduction 129
Impact of Taxes and Tariffs on the Refining Industry 130
Los Angeles Basin Refineries 134
Regional Refineries 146

Appendices

Appendix A: Request Letter and Description of the National Petroleum Council A-1

Appendix B: Study Group Rosters B-1

Appendix C: History and Fundamentals of Refining Operations C-1

Appendix D: Aggregated Data from the NPC's 1985 Survey of U.S. Petroleum Refineries D-1

Appendix E: Questionnaire for the NPC's 1985 Survey of U.S. Petroleum Refineries E-1

Appendix F: Initial Supply/Demand Cases and Assumptions F-1

Appendix G: Trends in U.S. Petroleum Imports G-1

Appendix H: An Analysis of Oxygenate Usage H-1

Appendix I: Results of the Refinery Capability Modeling I-1

Appendix J: World Refining and Transportation Model Assumptions J-1

Appendix K: Regional Refiners K-1

Appendix L: Acronyms and Abbreviations L-1

Index IN-1

INTRODUCTION

STUDY ORGANIZATION

In recognition of the importance of the U.S. petroleum refining industry, the Secretary of Energy, on June 20, 1984, requested that the National Petroleum Council (NPC), a federal advisory committee to the Secretary, undertake a new study of the domestic refining industry. Specifically, the Secretary requested:

> . . . the National Petroleum Council to undertake a new study of the factors affecting domestic refining in the 1985–1990 time frame. This study would update previous Council refining studies and evaluate future refinery operations and the industry's ability to meet demands for petroleum products. The study should examine capacity changes including announced closings, debottlenecking, and additions; and the projected role of small regional refineries. Related environmental and regulatory issues should be addressed as appropriate.

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

To assist in its response to this request, the NPC established the Committee on U.S. Petroleum Refining, under the chairmanship of John K. McKinley, Chairman and Chief Executive Officer, Texaco Inc. The Honorable H. A. Merklein, Administrator, Energy Information Administration, served as Government Cochairman. The Committee established a Coordinating Subcommittee and four task groups to provide coordination and technical analyses to the Committee. Rosters of the NPC Committee on U.S. Petroleum Refining and its subgroups are included in Appendix B.

STUDY METHODOLOGY

The study was accomplished in several parts. Initially, three simultaneous efforts were undertaken:

- A survey of U.S. refineries (NPC Refinery Survey) was made to determine operating capacities and utilization of process units as well as the crude oil charge and product yields resulting from operations in 1984 and expected for 1986 and 1988.
- Statistics on worldwide refining and transportation facilities were developed to determine operational capacities.
- Petroleum product demand scenarios were developed that could result from different business and economic environments. These were designed to test industry capability and do not represent actual forecasts of demand.

With information derived from these initial efforts, models of refining operations were developed as follows:

- Technical models of the U.S. refining industry representing groupings of refineries by complexity and by geographic location.

- An overall model of the free-world refining and transportation systems with emphasis on the interaction of refining regions, both within and outside the United States, based on marginal refinery and transportation costs and a common source of incremental crude oil.

The U.S. models were used to test the industry capability to meet high and low demand scenarios, including changes in product mix and product specifications, and the effect of these changes on the industry. These models were demand driven and responsive primarily to refinery costs rather than to crude oil or product prices.

The world model, which includes its own U.S. simulation, was used to provide information on the impact upon U.S. refinery utilization that could result from changes in product demand, product mix, economic conditions, and governmental actions. The world model was like the U.S. model but was also responsive to transportation costs.

The U.S. models were verified with actual data from 1984 operations. The modeling results were checked against, and supported by, the information assembled from the NPC Refinery Survey. The world model was tested against historical patterns to ensure that the model reacted appropriately to extreme changes and would demonstrate the flexibility and dynamics of the system. The U.S. and world model results were evaluated by a group of experts from industry, government, and academia. Models used in this study are based on the facilities that existed in 1984 and 1985, and those planned for completion by 1988.

The study does not express judgements on the national security issues raised by imports of light products combined with the shutdown of significant U.S. refining capacity since 1981, as well as changes in demand and other factors. Even though the study does not address national security issues, the study does include important data relevant to such national security judgements, which should be helpful to U.S. policymakers responsible for these matters. Specifically, the study will enable policymakers to assess the physical impact of various future levels of product imports on different segments of the U.S. refining industry at varying levels of projected demand as well as the impact of other factors that affect product import levels. These factors include the trade policies and practices of the United States and other importing and exporting nations, together with applicable nonmarket factors in both producing and refining countries.

By necessity, the Executive Summary is an abbreviated discussion of a complex study. The reader is advised to consult the details in the body of the report before making any final judgements.

EXECUTIVE SUMMARY

BACKGROUND

The last decade has been a turbulent period for the refining industry in the United States as well as in the rest of the free world. Consumers responded to uncertain supplies and increased oil prices by conservation and by switching to alternate fuels.

Both U.S. and total free-world petroleum demand peaked in the 1978–1979 period. U.S. refinery capacity did not peak until 1981, lagging demand changes by about two years as shown in Figure 1. Total free-world refinery capacity also peaked in 1981 as shown in Table 1.

By 1985, free-world demand had fallen 12 percent, or 6.2 million barrels per calendar day (MMB/CD), from the 1979 level. Of this decrease, 5 MMB/CD was residual fuel oil. Refiners responded to these lower demands by closing some refineries and upgrading others to better meet the changing product mix. Adjusting to the decline in demand, by 1985 net free-world refinery capacity declined by almost 8 MMB/CD from its peak level in 1981. As shown in Table 1, the decline occurred primarily in the United States (3.1 MMB/CD, or 17 percent), and in Europe (4.2 MMB/CD, or 21 percent). During the same period, refinery capacity in Africa and the Middle East increased (1.1 MMB/CD, or 20 percent).

In the United States, total 1985 product demand was down from the 1979 level by 15 percent, or 2.8 MMB/CD, with residual fuel demand down 1.6 MMB/CD and motor gasoline and distillate demand down 0.6 MMB/CD. Based on preliminary data for the first seven months of 1986, U.S. demand is 0.3 MMB/CD higher than the same period in 1985.

As noted above, U.S. refinery capacity dropped 3.1 MMB/CD, or 17 percent, from its peak in 1981. This reduction reflects the decline in demand since 1979 (particularly for residual

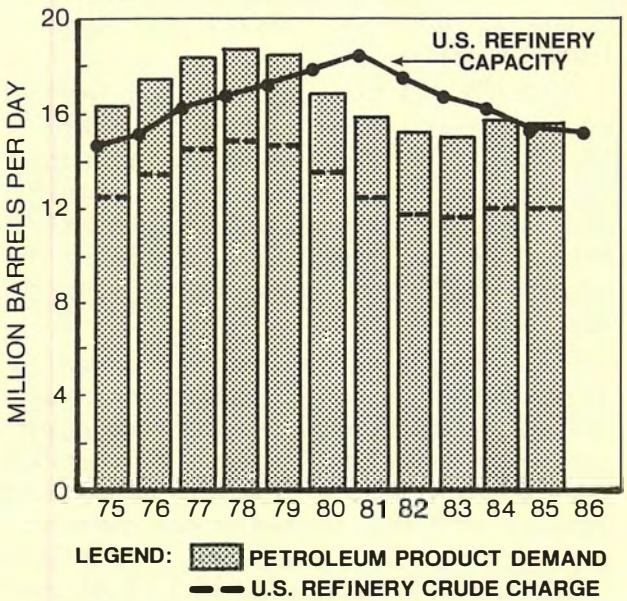


Figure 1. U.S. Petroleum Demand, Refinery Crude Oil Charge and Operable Crude Oil Distillation Capacity, 1975–1985.

Source: Energy Information Adminstration, *Petroleum Supply Annual 1985.* Annual average data except capacity data, which are January 1 data.

TABLE 1

FREE-WORLD REFINING CAPACITY AND OIL DEMAND (MMB/CD)

	1979		1981		1985	
	Capacity	Demand*	Capacity	Demand*	Capacity	Demand*
Western Europe	20.3	14.4	20.2	12.3	16.0	11.3
United States	17.2	18.5	18.5	16.1	15.4	15.7
Other Western Hemisphere	10.7	6.1	10.9	6.2	9.6	5.9
Asia/Pacific	10.3	9.3	10.6	8.7	10.4	8.4
Africa/Middle East	5.2	2.9	5.4	3.3	6.5	3.7
Total	**63.7**	**51.2**	**65.6**	**46.6**	**57.9**	**45.0**

*Demands cannot be compared directly to refinery capacities because there are other components to supply such as natural gas liquids supply, processing gain, inventory change, yield differences, crude oil quality, etc.

SOURCE: Capacity: *International Petroleum Encyclopedia*. Demand: Western Europe — OECD; United States — DOE; Other — *British Petroleum Statistical Review*.

fuel oil), the removal of price and allocation controls in January 1981, and the effect on refinery operations of restrictions on the use of lead in gasoline. Over the 1981–1985 period, employment in U.S. refineries dropped from its peak of 173,000 to 140,000 according to the Bureau of Labor Statistics.

Net U.S. petroleum product imports (excluding unfinished oils) declined from 1.6 MMB/CD in 1979 to 1.0 MMB/CD in 1985. The mix of these imports changed as gasoline imports increased from 0.2 to 0.4 MMB/CD and residual fuel oil imports declined from 1.1 to 0.3 MMB/CD.[1] The majority of U.S. product imports come into the East Coast.

An analysis of the economic impact of increased volumes of light product imports into U.S. markets should recognize that such imports are predominantly into Petroleum Administration for Defense District (PADD) I. The full economic impact cannot be measured simply by comparing the volumetric percentage of total imports against total U.S. demand. In PADD I, light product imports during 1985 represented 15 percent of total light product demand as compared to 6 percent nationwide. Domestic refiners, seeking to retain market share in PADD I, must compete against imports. This can affect the overall structure of prices in the market and have significant impact on refiner margins. The impact on refiner margins can be positive or negative, depending on the nature of the worldwide supply/demand situation. Since some of the PADD I supply comes from PADD III, the PADD I effect is transferred to refiners in PADD III.

Since export controls were lifted, the West Coast and Gulf Coast areas have become small net exporters of petroleum products, by increasing exports of residual fuel, petroleum coke, and distillates.

The refining industry is now facing another change in the business environment. Oil prices have dropped substantially, creating the potential for increasing demands and putting new economic forces in motion. Of continuing concern for world energy markets is the political instability of the Middle East, with approximately 60 percent of the free world's proven oil reserves and the expectation of their supplying an increasing share of the world's crude oil needs. (A review of the history and fundamentals of the refining industry is presented in Appendix C.)

[1]EIA Petroleum Supply Annual 1985, Volume 1.

MAJOR FINDINGS AND CONCLUSIONS

Major Findings and Conclusions

- *Based on the 1988 data from the NPC Refinery Survey and modeling results, the U.S. refining industry is approaching maximum gasoline manufacturing capacity.*
- *The operating rate of the U.S. refining industry is sensitive to the level of demand and product mix, both inside and outside the United States.*
- *Political, economic, or social actions by exporting and importing nations can change industry economics and impact world product flow patterns and U.S. refinery operations.*

The major findings and conclusions of this study were drawn from survey responses by U.S. refiners; from subsequent modeling of U.S. refinery configurations; and from testing wide variations in business environment scenarios with the models. Recognition must be given to the fact that the study represents industry facilities worldwide at a point in time and, as such, conclusions drawn represent likely happenings for the shorter term.

Based on the 1988 data from the NPC Refinery Survey and modeling results, the U.S. refining industry is approaching maximum gasoline manufacturing capacity.

U.S. production of gasoline during the first seven months of 1986 approached the maximum gasoline manufacturing capability estimated for 1988. Since the study was initiated, the environment in which U.S. refineries are operating has changed from one in which there was a view of declining future U.S. motor gasoline consumption to one in which there is a view of increasing future U.S. motor gasoline consumption. Some study participants believe that production capability may be higher than estimated by the study analysis in response to the new environment. However, other participants believe that the motor gasoline production capability developed in the study represents a realistic view of capacity, even in the new environment.

The study looked at a range of future demand environments. In the case where motor gasoline consumption increased, the increased demand will be met by new facilities, startup of idle capacity, changes in refinery operations, or imports. The difference in the method of providing the increased supply is related to the perception of economics. Some participants believe that the increase will be met in the traditional way through increased U.S. refinery production. Others believe that the increase will be met by increased product imports. If the increase is to be met by product imports, certain policy issues are presented with respect to the geographic source of such imports and the likelihood of future supply interruptions. If such imports are from government-owned refineries, a further issue is raised as to whether the price of such products may be set on a basis other than free-market factors.

- Motor gasoline manufacturing capability in 1988 is estimated both by modeling and survey results to be 6.7–6.8 MMB/CD on an annual average at a crude oil charge of about 13 MMB/CD. The modeling scenario that supports this stated gasoline production capability utilized all reported expansions plus all idle operable conversion and octane-enhancement facilities that exist and have operated since January 1, 1984. The lead content maximum in 1988 is assumed to be 0.10 grams of lead per gallon in leaded grades, which is more stringent than 1986 actual usage.
- Under the same facility conditions as above, the maximum capability to produce gasoline for portions of the year is estimated to be 7.0–7.4 MMB/CD. For perspective, during the first seven months of 1986, U.S. refinery gasoline production was about 6.6 MMB/CD. Production during each of the two highest production months in this period was about 7.1 MMB/CD, with a level of 6.0 MMB/CD for the lowest month.
- Reduction of motor gasoline volatility by lowering Reid Vapor Pressure (RVP) one pound per square inch (psi) nationwide would reduce gasoline production capability of 6.7–6.8 MMB/CD by more than 200 thousand barrels per calendar day (MB/CD). Increased octane level requirements for unleaded grades or further regulations affecting the composition of gasoline (e.g., benzene, aromatics,

sulfur, etc.) would cause further reductions in production capability.

- In meeting the requirements for changes in grade mix for unleaded gasoline and lead phasedown, refiners have tended to utilize downstream conversion and octane-enhancement facilities more fully than crude oil distillation capacity. At the 6.8 MMB/CD gasoline production rate, downstream conversion units are fully utilized and octane-enhancing units are nearing full capability (as shown in Figure 2 for reforming units). The model shows that when downstream capacity is fully utilized, crude oil distillation capacity is operating at about 84 percent of calendar-day capacity. Thus, very little additional gasoline production could be accomplished by increasing crude oil charge above 13 MMB/CD.
- Refiners reported in 1985 that by 1988 they plan an increase of 18 isomerization units totaling 156 MB/CD, a net addition of 50 MB/CD to alkylation unit capacity, and some addition to reformer capacity, as well as more severe operations to meet lead phasedown.
- Modeling results suggest that debottlenecking or minor additions to octane-enhancement facilities (reforming, isomerization, and/or alkylation), beyond that reported by refiners in early 1985 for 1988, could raise the annual gasoline production capability level above 6.8 MMB/CD. In view of the increase in 1986 demand and the current refining environment, some of these projects are likely underway.

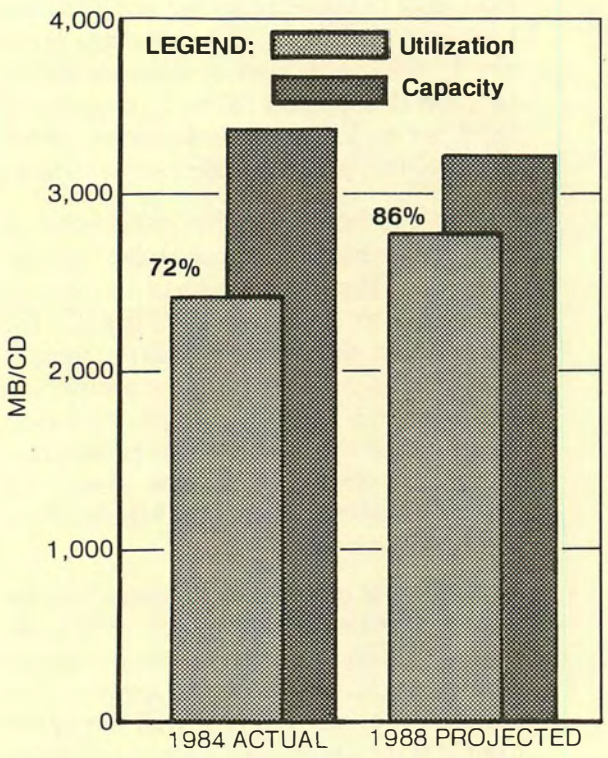


Figure 2. Adjusted Reformer Capacity and Utilization.

NOTE: Reformer capacity is restated to a severity of 95 research octane in 1984 and to 97 research octane for the 1988 projection. Calculations in this figure are based on data in Figure 7.

The operating rate of the U.S. refining industry is sensitive to level of demand and product mix, both inside and outside the United States.

The design of refineries around the world varies considerably with crude oil supply and with product mix for the markets they serve. The United States, with high gasoline demand and low residual fuel demand, has refineries that are complex, have many processing units, and produce high yields of gasoline. Generally, foreign markets, with higher fuel oil demands and lower gasoline demands, have less complex refineries designed to produce primarily distillate and residual fuel oil. Processing flexibility can adjust to minor changes in level and mix of product demands. With larger changes in demand or mix, any given refining region may find that as a result of maximizing yields of one product, other co-produced products may be surplus to demands in that region. This type of mismatch of yield to demand creates product flows to and from other markets throughout the world.

- An increase in world product demand with no change in the ratio of light to heavy products should result in an increase in U.S. refinery throughput up to the capability of the U.S. industry. The converse is also true. The change in supply to meet change in U.S. demand is shared by U.S. and foreign refiners with their resulting market shares approximately unchanged.
- An increase in the worldwide ratio of light product to heavy product demand with no change in total demand should result in an increase in U.S. refinery throughput and a decrease in imports. The converse is also true.

- Figure 3 helps illustrate the directional effects of these changes, separately and in the combinations evaluated.

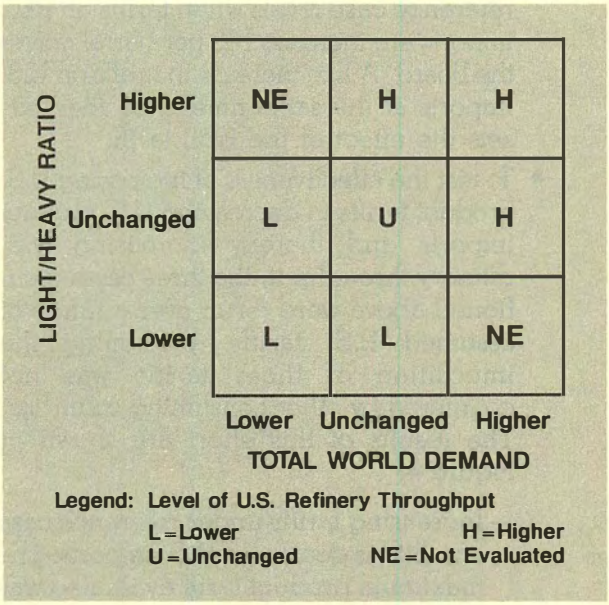


Figure 3. Directional Effect on U.S. Refinery Throughput of Changes in World Product Demand and Mix.

- The points at which the conflicting changes in U.S. refinery throughput intersect are described as "Not Evaluated" because the change in refinery operation is dependent on which factor has the greater influence. For example, comparing the first seven months of 1986 with the same period in 1985, U.S. total demand for products increased about 0.3 MMB/D. While U.S. consumption of both light and heavy products increased, the heavy product consumption increase was proportionally greater than for light products, thus lowering the light-to-heavy product ratio. In meeting these conditions, light product imports decreased and refinery output increased. While there are no reliable 1986 worldwide data available, if it assumed that consumption in the rest of the world is responding the same as in the United States, the lower right box in Figure 3 would be represented by "higher" U.S. refining throughput.
- If the demand and mix changes take place only in the United States, the effect on U.S. refinery operations is greater than if these changes take place outside the United States. However, there is an impact on U.S. refinery operations even if the changes take place only outside the United States.

Political, economic, or social actions by exporting and importing nations can change industry economics and impact world product flow patterns and U.S. refinery operations.

Since an increasing number of world refineries are owned or controlled by governments, a major concern is the potential for a change in the relationships between the various exporter and importer nations around the world. Much of the study analysis was done assuming these relationships remain constant at mid-1980s conditions. Clearly, exporter and importer nations can cause a change in this balance by providing their refineries with more or less incentive to run crude oil and produce product.

In the case of product importer nations that are also crude oil importers, product import controls in the form of tariffs or volumetric quotas can be varied to the benefit or detriment of local refineries. Product exporter nations that also export crude oil can artificially change the crude oil price they charge their refineries or other refineries in the world with whom they have processing arrangements relative to a fixed export crude oil price, thereby making their products more or less economic in the world market relative to refineries that purchase the same crude oil at the fixed export price. Local tax and regulatory incentives or disincentives can be imposed on refineries, which makes local refinery output more or less economical.

Influence on U.S. domestic refining margins may occur if crude oil producers were to abandon the practice of selling crude oil under "net back" contracts, where the price is determined on the basis of a formula related to the market price for refined products in the areas where the crude oils are processed. These arrangements have provided some margin of protection to some refiners against the 1986 decline in crude oil prices during the period between purchase and refining, thereby shifting some risk from the refiner to the crude oil producer.

All of the foregoing methods, and probably additional methods, might be used to impact the world product flow. Because there are such a large number of possible actions, the NPC decided to look at various product import tariff and refinery throughput minimum condition

possibilities in an attempt to quantify, at least as to direction and order of magnitude, the impact of these factors on U.S. refining. The points below describe the results of this effort.

For the purpose of this analysis, a reference case was constructed where tariffs and other importing/exporting constraints were included as they existed in 1985. In addition, each of the refining regions outside the United States was assigned a minimum refinery throughput. These minimums were based on numerous factors applicable to each region such as: availability of indigenous crude oil, local market demand, and non-economic, social factors. These assumptions are detailed in Appendix J. For example, the 1990 reference case includes existing, selective tariffs imposed by the European Economic Community (EEC) on product imports from the United States, Canada, and communist bloc countries, and not on product imports from other nations. Another example is a minimum throughput requirement of 75 percent of Arab Gulf refinery capacity. Two other cases were developed to describe a range of possible actions in the worldwide trade of petroleum. In one case, the minimum throughput constraints for the rest of the world were removed. In the other case, refineries in the Middle East and North Africa were forced to run at maximum throughput. The 1990 reference case product consumption volumes used in the three cases described above are on the low side of the demand range developed in the study. (See Chapter Two for descriptions of the supply/demand cases.)

- Removing the refinery utilization minimum assumptions from the reference case increased U.S. refinery throughput 0.5 percent and decreased net imports 0.1 MMB/CD. The changes were not more pronounced because some non-U.S. refining areas had been operating at their economic level in the reference case.

- In the other case, Middle East and North Africa refineries were run at estimated maximum throughput. Exports from this region increased by 0.9 MMB/CD above the reference case. The net increase in U.S. imports was 0.3 MMB/CD of light products with 0.2 MMB/CD coming directly from the Middle East and North Africa. Europe received 0.4 MMB/CD and the Far East 0.3 MMB/CD of Middle East and North Africa exports. The European and Far Eastern increase included all product categories except gasoline.

- Product imports into the United States increase about 0.4 MMB/CD over reference case levels when tariffs on EEC imports are increased $5 per barrel across the board. A like increase in tariffs on U.S. imports at the same time more than offsets the effect of the EEC tariff.

- To test the effectiveness of increasing U.S. product tariffs in decreasing U.S. product imports and thereby increasing U.S. refinery throughput, the three cases mentioned above were rerun over a range of assumed U.S. tariffs, presuming the imposition of those tariffs was not countered by other consuming countries. The results of this effort are shown in Figure 4.

  - Increasing tariffs under reference case conditions decreases U.S. imports. The maximum product tariff evaluated was $5 per barrel (on all products). As can be seen on Figure 4, reference case net U.S. product imports are eliminated by a $4 per barrel increase in U.S. tariffs.
  - When the same U.S. tariff test was applied to the case where reference case refinery minimum throughput constraints were removed, a $1 per barrel tariff reduced product imports by 75 percent and a $2 per barrel tariff completely eliminated net product imports. This is indicated by the bottom line on Figure 4.
  - In the Middle East/North Africa maximum throughput case, the level of imports is impacted less by increases in U.S. tariffs, as shown by the top curve in Figure 4. Tariff increases of up to $3 per barrel are effective in redistributing some U.S. imports to the rest of the world. Beyond this level, the curve essentially flattens, indicating that the exporting area is absorbing the U.S. tariff increase.
  - Should nations outside the United States impose product tariffs or other trade restraints, the United States would probably see an increase in product imports. This increase could be mitigated by imposition of additional U.S. tariffs or other import restraints.

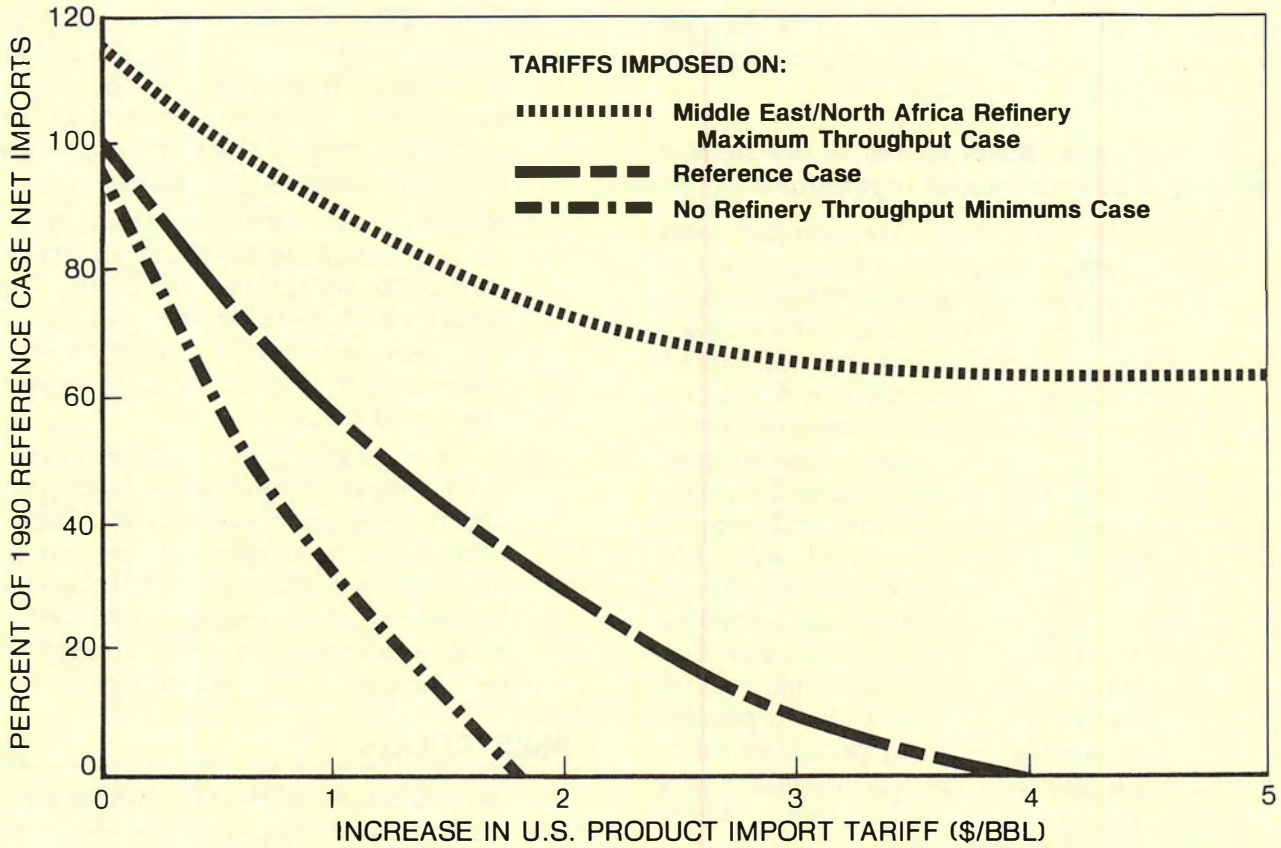


Figure 4. Impact of Sociopolitical Constraints on U.S. Tariff Effectiveness.

On the other hand, if the United States initially imposed product trade restraints, other nations could respond similarly and mitigate the impact of the action.

- The United States has a tariff disadvantage on petroleum exports into the EEC compared to most other free-world nations.
- There are anomalies in U.S. tariff schedules such as those applied to alcohols, motor fuel blending stocks, and distillates that, if corrected, would avoid misinterpretation and misapplication.

OTHER FINDINGS AND CONCLUSIONS

Measuring crude oil distillation capacity utilization may not fully describe the ability of U.S. refineries to produce light products.

- Traditionally the capability of U.S. refineries to produce additional product has been monitored by measuring crude oil distillation capacity utilization rates. The capacity available to increase motor gasoline production is constrained by the availability of downstream conversion and octane-enhancing facilities, e.g., catalytic cracking, reforming, and coking. In 1984, U.S. refineries processed 12 MMB/D of crude oil with a utilization rate of 77 percent of crude oil distillation capacity. However, downstream conversion facilities were operating at approximately 85 percent of capacity while producing 6.5 MMB/CD of motor gasoline. Similarly, in the high gasoline demand scenarios explored for 1988, downstream conversion and octane-enhancement capacity was fully utilized but the crude oil distillation capacity was operating at only 84 percent of calendar-day capacity.

Regional refineries play an important and unique role in meeting U.S. product demands.

- Approximately 15–20 percent of U.S. refining capacity is represented by regional refiners. Although many of these refineries are small, they each have their own niche in serving local and specialty markets with minimal transportation costs

for both crude oil and products. As long as these conditions exist, regional refiners should remain viable.

Los Angeles Basin refineries are subject to unique environmental regulations.

- The meteorologic, geographic, and demographic conditions found in the Los Angeles Basin have resulted in air quality that fails to meet federal and/or state standards. Unique emission control regulations have been imposed by the South Coast Air Quality Management District on virtually all major emission source types, including petroleum refineries. For example, product specifications and refinery emission limits associated with Los Angeles area refinery combustion and processing sources are more restrictive than in the rest of the United States. The refinery emission regulations require extensive pollution control and process unit investments by the petroleum refining industry in the Los Angeles Basin, which results in higher than industry average operating costs.

Further environmental constraints on products or refining facilities increase industry's cost and/or reduce capacity to produce products.

Emissions resulting from the use of petroleum products can be controlled by modification of user facilities such as motor vehicles, the methods of handling the products, or, alternatively, by changes in product specifications. This study addresses some of the impacts that changes in product specifications could impose on the refiner. The study does not deal with alternative solutions.

- Limitation of RVP specifications reduces motor gasoline production capability. For example, the model results indicate that a 1.0 psi reduction in RVP decreases gasoline production capability more than 200 MB/CD.
- Restrictions on benzene content of motor gasoline would require significant capital investment. Without knowledge of requirements, the specific impact on gasoline octane and volume capability cannot be quantified but would be severe.
- More stringent restrictions on the sulfur content in distillate fuel to 0.2 weight percent (0.05 weight percent in the Los Angeles Basin) would require additional U.S. refinery capital investment to increase hydrotreating capacity approximately 20 percent.
- Environmental constraints that are unique to U.S. refinery operations, as well as the facilities needed to reduce refinery emissions, result in increases in both investment and operating costs, which place the U.S. refiners at an economic disadvantage relative to foreign refiners who may not have to meet similar constraints.

OBSERVATIONS

In the process of analyzing the various cases in the study, several observations were made. These observations are self-evident in many instances. The following listing of these observations is provided so that they will not be overlooked by users of this report.

- The 1990 high demand case utilizes essentially all of the world refinery capacity now in place and projected to be on stream by 1988.
- U.S. refineries are, on average, the most complex and technologically sophisticated in the world.
- Imposition of an increase in the crude oil import fee without a compensating fee on product imports would reduce U.S. refinery throughput.
- U.S. refinery throughput is related to the level of domestic product consumption, product exports, and product imports.
- World product flows are not always determined by free-market principles.

CHAPTER ONE

Survey of U.S. Petroleum Refineries

INTRODUCTION

This chapter summarizes information provided by the respondents to the 1985 NPC Survey of U.S. Petroleum Refineries. The survey requested detailed data concerning refining facilities and operational capabilities for the period from January 1, 1984, through the end of 1988 from each refinery that had operable capacity as of January 1, 1984, and/or January 1, 1985. The aggregated results of the NPC's 1985 Survey of U.S. Petroleum Refineries are presented in Appendix D, and, for reference, the survey form is reproduced in Appendix E.

The survey questionnaire was divided into two parts:

- Part I: Current and Firmly Committed Facilities
  - Section A: Process Facilities Capabilities
  - Section B: Process Energy Production and Consumption
  - Section C: Crude Oil and Other Feedstocks; Product Yield
  - Section D: Gasoline Manufacturing Capabilities
  - Section E: Impact of Limitation on the Use of Oxygenates
  - Section F: Impact of Limitation on Vapor Pressure
  - Section G: Benzene in Gasoline
  - Section H: Sulfur Content Limitations on Distillates
- Part II: Operational Costs
  - Section A: Operational Expenses
  - Section B: 1984 Crude Oil Costs
  - Section C: Refinery Assets

The survey questionnaire was sent to all U.S. refining companies that reported to the Energy Information Administration (EIA) any facility or facilities operable as of January 1, 1984, and/or January 1, 1985. The Council received responses from 181 refineries in the United States that indicated they were operable as of January 1, 1984, or would be operable as of January 1, 1986, and/or January 1, 1988. These respondents reported an operable capacity of 15,314 MB/CD, as of January 1, 1985, which represented 96 percent of the total U.S. refining capacity reported to EIA as operable for the same date.

In addition, six U.S. refineries located in U.S. territories (U.S. Virgin Islands, Guam, Puerto Rico, and the Hawaiian Trade Zone) responded to the survey, indicating January 1, 1985, operable crude oil charge capacity of 771 MB/CD.

The many responses to the survey provided a valuable data base for the NPC's analysis of U.S. refining capability.

Survey Findings

The major findings reported in this chapter are outlined below:

PROCESS CAPACITY AND UTILIZATION

- As of January 1, 1984, the base date for the survey, refineries[2] responding to the

[2]Unless otherwise indicated, respondents in this text include only those in the 50 states, not including the Hawaiian Trade Zone.

survey had a combined crude oil charge capacity of 14,798 MB/CD to atmospheric distillation units, and an additional crude oil charge capacity of 91 MB/CD for other units.

- The respondents reported a 187 MB/CD decline in crude oil charge capacity between January 1, 1984, and January 1, 1988. This represents a loss of 1.3 percent during the four-year period.
- Although reported combined catalytic reforming capacity between actual 1984 and projected 1988 decreased from 3,364 MB/CD at 95.1 research octane number clear (RONC) design severity to 3,248 MB/CD at 96.7 RONC severity, the utilization increased from 2,445 MB/CD at 94.8 RONC severity to 2,776 MB/CD at 97.1 RONC severity for those years.
- Between 1984 and 1988, PADDs II and III projected an increase in research octane number for catalytic cracked gasoline—on the average of 0.3 and 0.4 RONC, respectively. PADDs I and IV showed only a slight increase of 0.1 RONC, while PADD V reported a significant loss of 0.4 RONC.

INPUTS OF CRUDE OIL AND OTHER FEEDSTOCKS

- Respondents to the survey reported an actual input of crude oil in 1984 of 11,642 MB/CD and a projected increase to 12,420 MB/CD by 1988. The percentage increase during the period was 6.7.
- Nearly 75 percent of the crude oil inputs and 90 percent of other feedstocks were of domestic origin throughout the survey period.

PRODUCT YIELDS

- The combined U.S. yield for all products was 13,920 MB/CD in 1984, and 14,499 MB/CD in 1988. Finished gasoline was the largest single product, with levels of 6,337 MB/CD in 1984, and 6,466 MB/CD in 1988, or 45.5 percent and 44.6 percent, respectively, of total yields. Based only on crude oil inputs, the percentage of gasoline would be 54.4 percent in 1984 and 52.1 percent in 1988.
- Major shifts in mix of gasoline grades during the survey period were foreseen:

	MB/CD*		
Type of Gasoline	**1984**	**1986**	**1988**
Unleaded Premium	887	1,074	1,170
Other Unleaded	2,964	3,774	4,214
Leaded	2,458	1,559	1,051
Total Motor Gasoline	6,310	6,408	6,435
Aviation Gasoline	28	MB	32
Total All Grades	**6.337**	**6.440**	**6.466**

*Columns may not add due to rounding.

- For the total respondents and for all PADDs, the production levels for unleaded gasoline reported in this survey are within anticipated blending capabilities, even under each of the constrained blending situations investigated in the survey.

GASOLINE MANUFACTURING CAPABILITIES

- Survey respondents reported their maximum gasoline production capability under various constraints as shown below. In each case, the lead level assumed for leaded gasoline in 1985 was 1.1 grams per leaded gallon (gplg):

	Survey Respondents' Maximum Gasoline Capability (MB/CD)	
	1985	**1988**
1.1 gplg, 1988	6,400	6,533
0.1 gplg, 1988	6,392	6,432
0.1 gplg, 1988 and oxygenates eliminated	6,338	6,332
0.1 gplg, 1988 and RVP lowered 1.0 psi	6,108	6,131
0.1 gplg, 1988 and unleaded octanes increased 1.0 octane number	—	5,920

- The reduction of the RVP by 1.0 psi for all grades of motor gasoline would reduce butane use, as a blending component, by 154 MB/CD and other gasoline blending components by 64 MB/CD, or a total of 218 MB/CD. The 218 MB/CD figure differs from 301 MB/CD, which could be calculated from the table above. The lower

number is due to differing numbers of respondents to each of the above scenarios. To present the RVP data on a consistent basis, the base figure for maximum unleaded gasoline production capability of 6,432 MB/CD was adjusted to 6,349 MB/CD to represent only those refiners who also responded to the RVP questions.

- In response to the survey question regarding the projected ability in 1988 to manufacture very low sulfur distillate, refineries indicate that 207 MB/CD of 0.05 wt.% sulfur diesel fuel could be provided for the L.A. Basin and 0.2 wt.% sulfur could be achieved in 1,864 MB/CD of distillates for all other geographic regions. This would be a total of 2,071 MB/CD, or 586 MB/CD less than the projected 1988 production of 2,657 MB/CD for all diesel/distillate No. 2 fuel oil.

Survey Methodology

The public accounting firm of Arthur Young & Company was retained by the NPC to receive, aggregate, and report the results of the survey. Arthur Young & Company was instructed to treat all responses in the strictest confidence and to release no individual respondent data. The accounting firm was also instructed not to release any aggregated data element unless it included at least three responses. In some instances, aggregated elements of three or more responses were also withheld, in order to prevent the indirect disclosure of confidential data.

The questionnaires from all respondents were reviewed for reasonableness and, in some cases, the respondent company was contacted to confirm or revise data. Responses were entered into computers for final edit checks. Aggregations were then produced using the Statistical Analysis System.

The responses were aggregated by region, and complexity within the region, in order to best analyze the data and to provide input for industry models. The aggregations are:

- PADD I no conversion (I-S)
- PADD I conversion (gas oil and deep conversion) (I-C)
- PADD II no conversion (II-S)
- PADD II gas oil conversion (II-LC)
- PADD II deep conversion (II-DC)
- PADD III no conversion (III-S)
- PADD III gas oil conversion (III-LC)
- PADD III deep conversion (III-DC)
- PADD IV all refineries (IV)
- PADD V no conversion (V-S)
- PADD V conversion outside California (gas oil and deep conversion) (V-COC)
- PADD V conversion inside California (gas oil and deep conversion) (V-CC).

The complexity groupings are defined as follows:

- "No conversion" refers to those refineries that have primary distillation capacity but lack capability to convert heavier fractions to motor gasoline. Included in this group are topping and hydroskimming plants (with or without reformers), some lube plants, and some asphalt refineries.
- "Gas oil conversion" refers to refineries that can convert heavy gas oil fractions to light products. In addition to primary distillation capacity, gas oil refineries have a hydrocracker or a catalytic cracking unit. These refineries do not have capability to process more than 50 percent of vacuum residuum through conversion facilities. (For survey purposes, vacuum residuum was defined as the 1,050°F+ boiling range.)
- "Deep conversion" refineries refer to plants that have heavy gas oil conversion capability and also process more than 50 percent of their vacuum residuum through conversion units, usually through such processes as coking, residual catalytic cracking, and hydroprocessing.

Due to the distribution of responses among these complexity classes in PADD IV, it was necessary to combine all refineries in the region into one aggregation. It was also necessary, in PADDs I and V, to combine the gas oil conversion and deep conversion refineries in a single "conversion" category. The conversion refineries in PADD V were grouped as either outside California or inside California. A subset of those conversion refineries in California that are located in the L.A. Basin was also generated to address environmental and operational issues specific to that region.

The responses were aggregated in two groups: one representing all U.S. respondents

TABLE 2

DISTRIBUTION OF NPC SURVEY RESPONDENTS AND CAPACITY BY REGION/COMPLEXITY GROUPING*

	January 1, 1986		January 1, 1988		
	Number of Respondents	Operable Crude Capacity (MB/CD)	Number of Respondents	Operable Crude Capacity (MB/CD)	Δ Capacity, 1986–1988 (MB/CD)
PADD I					
No Conversion	11	256	11	256	0
Conversion	10	1,165	10	1,165	0
Total PADD I	21	1,421	21	1,421	0
PADD II					
No Conversion	4	37	4	40	3
Gas Oil Conversion	9	650	9	650	0
Deep Conversion	22	2,435	22	2,435	0
Total PADD II	35	3,122	35	3,125	3
PADD III					
No Conversion	16	322	16	322	0
Gas Oil Conversion	14	1,542	14	1,537	(5)
Deep Conversion	30	5,235	30	5,133	(102)
Total PADD III	60	7,098	60	6,991	(107)
PADD IV					
Total PADD IV	14	465	14	464	(1)
PADD V					
No Conversion	19	411	19	411	0
Conversion Outside California	6	488	6	489	1
Conversion Inside California	16	1,787	15	1,716	(71)
[L.A. Basin]†	[10]	[1,038]	[10]	[1,105]	[67]
Total PADD V	41	2,686	40	2,615	(71)
Total U.S. Respondents	171	14,792	170	14,617	(175)
U.S. Nonrespondents‡		665			
Total U.S.		15,457			
Offshore Respondents	5	757	5	757	0

*Totals may not add due to independent rounding.
†L.A. Basin capacities are included in "Conversion Inside California."
‡Nonrespondent data represent January 1, 1986 data from EIA, *Petroleum Supply Annual 1985.*

(aggregating the 12 region/complexity groups), and another representing the offshore refineries in U.S. territories (U.S. Virgin Islands, Puerto Rico, Guam, and the Hawaiian Foreign Trade Zone).

Response Characterization

The NPC survey was distributed in February 1985 and responses were received throughout the spring of that year. All U.S. refineries with crude oil distillation capacity greater than 100 MB/CD responded, and only two refineries with capacity greater than 50 MB/CD failed to respond. The majority of nonrespondent refineries were plants of less than 30 MB/CD of crude oil charge capacity, and were spread throughout the United States, with the highest concentration of nonrespondents in PADD III. The respondents to the NPC Survey of U.S. Petroleum Refineries reported data on 181 of the 223 refineries operable as of January 1, 1985.

For January 1, 1986, survey data indicated that 171 responding refineries anticipated being operable, with an aggregate crude oil charge capacity of 14,792 MB/CD. Table 2 shows the distribution of NPC respondent refineries by the region/complexity groupings for which the data were aggregated, and their reported capacities for January 1, 1986, and January 1, 1988. Capacity for the nonrespondent refineries, as provided by EIA, is also shown.

As of January 1, 1986, total operable crude oil charge capacity in the United States (reported to EIA) was 15,459 MB/CD. Refineries responding to the survey represented 14,794 MB/CD, or 96 percent of the total. For January 1, 1988, respondent refineries reported slightly lower capacity, 14,617 MB/CD, representing a 1 percent decline in their operable capacity over the two-year period.

Operable capacity, as defined by EIA, is the amount of capacity that, at the beginning of the period, is either in operation; not in operation (idle) and not under active repairs but capable of being placed in operation within 30 days; or not in operation (idle) but under active repairs that can be completed within 90 days. Operable capacity is the sum of the operating and idle capacity.

Capacity is idled for a variety of commercial and technical reasons. Some refiners may idle only a portion of their crude oil distillation capacity while continuing to operate other crude oil units. Other plants may operate only certain downstream units and choose to idle all their crude oil charge capacity. Still other plants may be completely idled, with no operations in either crude oil distillation or downstream units.

Some concerns have been expressed as to the percentage of crude oil charge capacity carried as idle that could actually be placed in operation within the time periods defined by EIA. These concerns reflect a recognition of extensive maintenance procedures and prohibitive expense sometimes associated with the reconditioning and subsequent recommissioning of idle equipment.

In response to these concerns, an analysis of EIA data was conducted to determine the amount of operable crude oil charge capacity that was operating or idle as of January 1, 1986. The data in Table 3 are based on information provided by refiners to EIA on Form EIA 820,

TABLE 3

CLASSIFICATION OF U.S. REFINING CAPACITY, ENERGY INFORMATION ADMINISTRATION DATA JANUARY 1, 1986*

	NPC Respondents†		Non-Respondents		U.S. Total	
	MB/CD	%	MB/CD	%	MB/CD	%
Operating Capacity	14,102	95	537	81	14,639	95
Idle Capacity	692	5	128	19	820	5
Total Operable Capacity	**14,794**	**100**	**665**	**100**	**15,459**	**100**

*Based on data provided to the NPC by the EIA, June 1986.
†Reflects EIA reported capacities of refineries that responded to NPC survey. The total operable capacity differs from data in Table 2 due to slightly different data submitted to the NPC and the EIA.

"Annual Refinery Report," for refineries that responded to the NPC Survey of U.S. Petroleum Refineries and, separately, for NPC non-respondents.

Table 3 shows that about 5 percent of total operable crude oil charge capacity was idle on January 1, 1986. Of the 820 MB/CD of idle crude oil charge capacity, more than 470 MB/CD had not operated for a year or longer. Thus, almost 60 percent of the idle crude oil charge capacity shown in the table might be classified more realistically as inoperable as of January 1, 1986. The total operable capacity differs from data in Table 2 due to slightly different data submitted to the NPC and the EIA.

PROCESS FACILITIES CAPABILITIES AND UTILIZATION

NPC Survey Total of U.S. Refineries

Survey respondents indicated an atmospheric distillation charge capacity of 14,798 MB/CD as of January 1, 1984, with an additional crude oil charge capacity of 91 MB/CD in process units other than atmospheric distillation. They projected the January 1, 1988, atmospheric distillation capacity at 14,617 MB/CD, plus 86 MB/CD crude oil capacity in units other than atmospheric distillation. Thus, survey respondents predict a decline in atmospheric distillation crude oil charge capacity of 187 MB/CD, or 1.3 percent, by January 1, 1988. At the same time as crude oil charge capacity is projected to decline, the utilization is projected to increase from 11,907 MB/CD in 1984 to 12,511 in 1988 (an increase of 604 MB/CD). This would increase the utilization of operable crude oil capacity from 81 to 86 percent by 1988.

Capacities and utilization of key process facilities in existence on January 1, 1984, and gains/losses in these processes expected during the period from January 1, 1984, to January 1, 1988, are presented in Table 4. Tables 5 through 9 provide additional details on process capacities and their percentage utilization for the various refinery complexities within the PADD regions.

On a total U.S. basis, despite declining crude oil charge capacity, survey respondents projected increases in capacity and utilization of key process technologies during the survey period (see Table 4). The substantial capacity increase for C_5/C_6 isomerization of 156 MB/CD, or 139 percent, and the capacity increase for alkylation units of 50 MB/CD, or 6 percent, are believed to be due to requirements in meeting lead phasedown in leaded gasoline and higher demands for unleaded gasoline.

Under environmental regulations forcing the phaseout of lead antiknock additives, C_5/C_6 isomerization is being used in addition to high severity reforming. The utilization of C_5/C_6 isomerization increased from 52 percent in 1984 to 85 percent in 1988. The projected growth in alkylation capacity suggests a more nearly complete conversion of olefins into high-octane-number gasoline blending components. The increase to nearly complete utilization of available capacity in reforming is a response to the need from higher octane gasoline components to meet the lead phasedown requirement and increasing unleaded gasoline demand. The "as reported" reformer capacity decreased between 1984 and 1988, from 3,364 to 3,248 MB/CD (a loss of 116 MB/CD). However, projected total U.S. reformer throughput increased by 331 MB/CD and average severity increased by 2.3 RONC. Using a commonly accepted relationship to restate reformer capacity to an "as utilized" severity level for 1984 and 1988, one could compute a much closer approach to full utilization of reformer capabilities at required future severities. This "as adjusted" capacity in 1988 would be 3,204 MB/CD, representing a further loss of 44 MB/CD (see Table 4). This restatement reveals how little "slack" reforming capacity there will be for "catch-up" following operating upsets and unplanned outages. Although the reformer capacity decreased from 3,364 MB/CD in 1984 to 3,248 MB/CD in 1988, the utilization increased from 73 to 85 percent. Figures 5 and 6 depict reformer capacities and utilization on "as reported" and "as adjusted to planned severities" bases. (See Figure 7 for data on which Figure 6 was adjusted.)

Reference was made to higher severity reformer operations later in the survey period. This is shown graphically in Figure 8. Maximum design severity for total U.S. respondents rises only slightly between 1984 and 1988, from 98.8 to 99.0 RONC, while operating severity is expected to climb dramatically from 94.8 RONC in 1984 to 97.1 RONC in 1988.

Additional details on percentage utilization of key processes for the various region/complexity aggregations are set forth for 1984 and 1988 in Tables 8 and 9. As noted above for reforming,

TABLE 4

NPC SURVEY DATA FOR
GAIN/(LOSS) IN THE CAPACITY AND UTILIZATION OF KEY PROCESS FACILITIES
ACTUAL 1984 AND PROJECTED 1988
(Capacities in MB/CD Unless Otherwise Stated)

	Capacity				Throughput			
	1/1/84	1/1/88	Gain/(Loss)	Percent	1984	1988	Gain/(Loss)	Percent
Atmospheric Distillation	14,798*	14,617*	(181)	(1.2)	11,907	12,511	604	5
Vacuum Distillation	6,221	6,123	(98)	(1.6)	4,801	5,038	237	5
Reforming (As Reported)	3,364	3,248	(116)	(3.4)	2,445	2,776	331	14
Reforming (Adjusted to Projected Severity)	3,392	3,204	(188)	(3.5)	2,445	2,776	331	14
Fluid Catalytic Cracking	4,905	4,912	7	0.1	4,104	4,359	256	6
Alkylation	861	911	50	6	630	751	120	19
C_5/C_6 Isomerization	112	268	156	139	58	228	171	295
Heavy Gas Oil Hydrotreating	1,432	1,526	94	7	1,114	1,230	116	10
Catalytic Hydrocracking	855	925	71	8	723	930	207	29
Sulfur Recovery (LT/CD)	15,836	17,760	1,924	12	7,895	10,909	3,014	38
Coking (Delayed, Fluid, and Flexicoker)	1,291	1,339	48	5	1,102	1,216	114	10

*Does not include 7 units in 1984 and 6 units in 1988, which have had a capacity for crude oil charge of 91 MB/CD and 86 MB/CD, respectively, but are not atmospheric distillation units.

TABLE 5

NPC SURVEY DATA FOR JANUARY 1, 1984 CAPACITIES OF KEY FACILITIES BY REGION*

	PADD I		PADD II			PADD III			PADD IV	PADD V			U.S. Total
	I–S	I–C	II–S	II–LC	II–DC	III–S	III–LC	III–DC		V–S	V–COC	V–CC	
Atmospheric Distillation	274	1,165	37	734	2,450	353	1,610	5,103	463	391	462	1,755	14,798
Vacuum Distillation	142	585	§	302	941	95	657	2,063	168	138	§	926	6,221
Coker–Delayed	—	§	—	—	230	—	—	505	§	—	§	317	1,133
Coker–Fluid	—	§	—	—	—	—	—	§	—	—	—	80	158
Thermal Cracker/Visbreaker	—	—	—	§	§	—	41	46	—	—	§	§	146
Naphtha Hydrotreater	12	307	§	190	621	§	352	1,154	143	34	§	421	3,368
Distillate Hydrotreater	§	293	§	117	259	§	288	1,098	§	§	71	320	2,519
Heavy Gas Oil Hydrotreater	§	112	—	101	195	28	131	433	19	27	§	378	1,432
Atmospheric Resid Hydrotreater	§	—	—	—	—	—	—	§	—	—	—	—	240
Semi-Regenerative Reformer†	§	193	§	110	350	40	148	571	83	33	85	344	1,970
Semi-Regenerative Reformer‡	§	194	§	107	350	39	150	587	84	32	86	363	1,994
Continuous Regen. Reformer†	—	114	—	97	273	—	163	637	§	—	§	79	1,394
Continuous Regen. Reformer‡	—	107	—	106	273	—	165	641	§	—	§	79	1,397
Fluid Catalytic Cracker	—	529	—	248	911	—	500	1,887	164	—	110	556	4,905
Hydrocracker	—	68	—	§	111	—	§	230	§	—	§	292	855
Alkylation	—	59	—	56	180	—	71	344	27	—	§	§	861
Polymerization	—	12	—	§	17	—	6	17	5	§	§	§	66
Sulfur (LT/CD)	—	1,248	—	695	1,973	81	1,178	6,843	245	45	239	3,290	15,836
C_5/C_6 Isomerization	—	§	—	§	24	0	0	58	0	0	—	0	112
C_4 Isomerization	—	—	—	—	14	—	§	10	7	—	§	11	59
Lube Wax	20	§	—	§	29	15	32	93	§	—	—	14	228
Solvent Deasphalting	6	§	—	§	26	§	33	138	18	—	§	§	329

*All figures are actual for 1984 and in MB/CD unless otherwise noted.
†Capacity as reported (actual for 1984).
‡Capacity at actual severity level (adjusted operable severity to utilization severity).
§Data withheld due to confidentiality requirements. Data included in total.

TABLE 6

NPC SURVEY DATA FOR JANUARY 1, 1988 CAPACITIES OF KEY FACILITIES BY REGION*

	PADD I		PADD II			PADD III			PADD IV	PADD V			U.S. Total
	I–S	I–C	II–S	II–LC	II–DC	III–S	III–LC	III–DC		V–S	V–COC	V–CC	
Atmospheric Distillation	256	1,165	40	650	2,435	322	1,537	5,133	464	411	489	1,716	14,617
Vacuum Distillation	153	585	§	277	929	95	622	2,133	166	126	§	820	6,123
Coker–Delayed	—	§	—	—	243	—	—	523	§	—	§	324	1,190
Coker–Fluid	—	§	—	—	—	—	—	46	§	—	—	§	149
Thermal Cracker/Visbreaker	—	—	—	§	§	—	41	38	—	§	—	§	138
Naphtha Hydrotreater	14	307	§	153	617	51	346	1,176	143	29	§	386	3,301
Distillate Hydrotreater	0	293	§	105	278	§	288	1,080	§	§	72	282	2,469
Heavy Gas Oil Hydrotreater	§	112	—	101	210	28	137	532	19	21	§	358	1,526
Atmospheric Resid Hydrotreater	§	—	—	—	—	—	—	§	—	—	—	—	180
Semi-Regenerative Reformer†	§	168	§	79	351	34	128	583	80	27	88	338	1,889
Semi-Regenerative Reformer‡	§	168	§	79	346	33	122	580	80	25	87	335	1,868
Continuous Regen. Reformer†	—	114	—	97	240	—	163	651	§	—	§	62	1,360
Continuous Regen. Reformer‡	—	102	—	105	238	—	166	634	§	—	§	62	1,337
Fluid Catalytic Cracker	—	574	—	215	908	—	501	1,920	164	—	111	519	4,912
Hydrocracker	§	§	—	§	113	—	§	337	§	—	§	268	925
Alkylation	—	66	—	50	182	—	74	389	28	—	§	§	911
Polymerization	—	15	—	§	17	—	§	17	5	§	§	§	65
Sulfur (LT/CD)	—	1,258	—	696	2,118	81	1,178	8,614	253	41	311	3,211	17,760
C_5/C_6 Isomerization	—	§	—	14	82	§	§	97	§	§	—	§	268
C_4 Isomerization	—	—	—	0	9	—	§	10	8	—	§	11	55
Lube Wax	18	§	—	§	29	15	33	90	§	—	—	18	230
Solvent Deasphalting	7	§	—	§	16	§	33	143	18	—	§	§	327

*All figures in MB/CD unless otherwise noted.
†Capacity as reported (projected for 1988).
‡Capacity at projected severity level (adjusted operable severity to utilization severity).
§Data withheld due to confidentiality requirements. Data included in total.

TABLE 7

NPC SURVEY DATA FOR CHANGES IN OPERABLE CAPACITIES — 1988 vs. 1984*

	PADD I		PADD II			PADD III			PADD IV	PADD V			U.S. Total
	I–S	I–C	II–S	II–LC	II–DC	III–S	III–LC	III–DC		V–S	V–COC	V–CC	
Atmospheric Distillation	(18)	0	3	(84)	(15)	(32)	(73)	30	1	20	27	(39)	(181)
Vacuum Distillation	11	0	§	(25)	(12)	0	(35)	70	(2)	(12)	§	(106)	(98)
Coker–Delayed	—	§	—	—	12	—	—	18	§	—	§	7	57
Coker–Fluid	—	§	—	—	—	—	—	§	§	—	§	§	(9)
Thermal Cracker/Visbreaker	—	—	—	§	§	—	0	(8)	—	§	§	§	(8)
Naphtha Hydrotreater	2	0	§	(37)	(4)	§	(6)	22	—	(5)	§	(35)	(67)
Distillate Hydrotreater	§	0	§	(12)	19	§	—	(18)	§	§	1	(39)	(50)
Heavy Gas Oil Hydrotreater	§	0	—	0	15	0	6	99	2	(6)	§	(20)	94
Atmospheric Resid Hydrotreater	§	—	—	—	—	—	—	§	—	—	—	—	60
Semi-Regenerative Reformer†	§	(25)	§	(31)	1	(6)	(20)	12	(7)	(6)	3	(6)	(82)
Continuous Regen. Reformer†	—	—	§	0	(33)	—	(0)	14	§	—	§	(17)	(34)
Fluid Catalytic Cracker	—	45	—	(33)	(3)	—	1	33	(1)	—	1	(37)	7
Hydrocracker	§	§	—	—	2	—	§	107	—	§	§	(24)	71
Alkylation	—	7	—	(6)	2	—	3	45	1	—	§	§	50
Polymerization	—	3	—	§	0	—	§	0	—	§	§	§	(1)
Sulfur (LT/CD)	—	10	—	1	145	0	0	1,771	8	(4)	72	(79)	1,924
C_5/C_6 Isomerization	—	§	—	§	58	§	§	39	§	§	—	§	156
C_4 Isomerization	—	—	—	§	(5)	—	—	0	1	—	§	0	(5)
Lube Wax	(1)	§	—	§	0	0	0	(3)	§	—	—	(4)	2
Solvent Deasphalting	1	§	—	§	(10)	§	§	5	0	—	§	§	(2)

*All figures in MB/CD unless otherwise noted.
†Capacity as reported (1984 actual and 1988 projected).
§Data withheld due to confidentiality requirements. Data included in total.

TABLE 8

NPC SURVEY DATA FOR 1984 PERCENTAGE UTILIZATION OF OPERABLE CAPACITY*

	PADD I		PADD II			PADD III			PADD IV	PADD V			U.S. Total
	I–S	I–C	II–S	II–LC	II–DC	III–S	III–LC	III–DC		V–S	V–COC	V–CC	
Atmospheric Distillation	42	85	76	75	85	52	72	82	81	72	93	87	81
Vacuum Distillation	41	77	§	68	83	42	70	78	64	58	§	88	77
Coker–Delayed	—	§	—	—	84	—	—	83	§	—	§	91	87
Coker–Fluid	—	§	—	—	—	—	—	§	§	—	—	85	76
Thermal Cracker/Visbreaker	—	—	—	§	§	—	63	51	—	§	—	§	57
Naphtha Hydrotreater	77	77	§	62	74	§	66	78	64	63	§	68	72
Distillate Hydrotreater	§	66	§	57	77	§	54	66	§	§	66	64	65
Heavy Gas Oil Hydrotreater	§	44	—	82	92	§	78	84	§	50	§	81	78
Atmospheric Resid Hydrotreater	§	—	—	—	—	—	—	§	—	—	—	—	88
Semi-Regenerative Reformer†	§	97	§	48	77	71	61	69	56	64	83	65	69
Continuous Regen. Reformer†	—	92	—	69	71	—	78	77	§	—	§	88	77
Fluid Catalytic Cracker	—	80	—	80	85	—	80	82	79	—	90	96	84
Hydrocracker	§	83	—	§	86	—	§	84	§	—	§	91	85
Alkylation	—	59	—	60	77	—	75	75	76	—	§	§	73
Polymerization	—	61	—	§	76	—	57	40	85	§	§	§	61
Sulfur (LT/CD)	—	44	—	31	58	§	38	53	49	§	79	48	50
C_5/C_6 Isomerization	—	§	—	§	78	—	§	67	—	—	—	§	52
C_4 Isomerization	—	—	—	§	52	—	§	§	58	—	§	74	55
Lube Wax	63	§	—	§	80	73	72	79	§	—	—	92	78
Solvent Deasphalting	86	§	—	§	46	§	57	74	82	—	§	§	65

*All figures are percentage of capacity unless otherwise noted.
†Data as reported (1984 actual and 1988 projected).
§Data withheld due to confidentiality requirements. Data included in total.

TABLE 9

NPC SURVEY DATA FOR 1988 PERCENTAGE UTILIZATION OF OPERABLE CAPACITY*

	PADD I		PADD II			PADD III			PADD IV	PADD V			U.S. Total
	I–S	I–C	II–S	II–LC	II–DC	III–S	III–LC	III–DC		V–S	V–COC	V–CC	
Atmospheric Distillation	51	88	75	83	88	54	78	88	84	76	94	92	86
Vacuum Distillation	61	76	§	82	85	37	76	82	68	62	§	102	82
Coker–Delayed	—	§	—	—	85	—	—	87	§	—	§	98	89
Coker–Fluid	—	§	—	—	—	—	—	81	§	—	—	§	106
Thermal Cracker/Visbreaker	—	—	—	§	§	—	77	49	§	§	§	§	63
Naphtha Hydrotreater	81	79	§	59	82	53	77	85	69	77	§	77	80
Distillate Hydrotreater	§	65	§	53	80	§	55	74	§	§	§	82	71
Heavy Gas Oil Hydrotreater	§	57	—	65	97	§	66	87	§	60	§	87	81
Atmospheric Resid Hydrotreater	§	—	—	—	—	—	—	§	—	—	—	—	86
Semi-Regenerative Reformer†	§	78	§	57	86	76	82	88	71	80	88	88	84
Continuous Regen. Reformer†	—	90	—	80	88	—	89	88	§	—	§	121	88
Fluid Catalytic Cracker	—	80	—	93	86	—	82	90	82	—	93	103	90
Hydrocracker	§	§	—	§	89	—	§	105	§	—	§	104	101
Alkylation	—	70	—	66	81	—	86	87	74	—	§	§	82
Polymerization	—	75	—	§	83	—	§	64	94	§	§	§	75
Sulfur (LT/CD)	—	52	—	47	61	§	47	63	53	§	88	69	61
C_5/C_6 Isomerization	—	§	—	75	98	§	§	90	—	§	—	§	85
C_4 Isomerization	—	—	—	—	70	—	—	§	63	—	§	§	71
Lube Wax	96	§	—	§	88	86	86	91	§	—	—	94	91
Solvent Deasphalting	84	§	—	§	85	§	§	81	82	—	§	§	83

*All figures are percentage of capacity unless otherwise noted.
†Data as reported (1984 actual and 1988 projected).
§Data withheld due to confidentiality requirements. Data included in total.

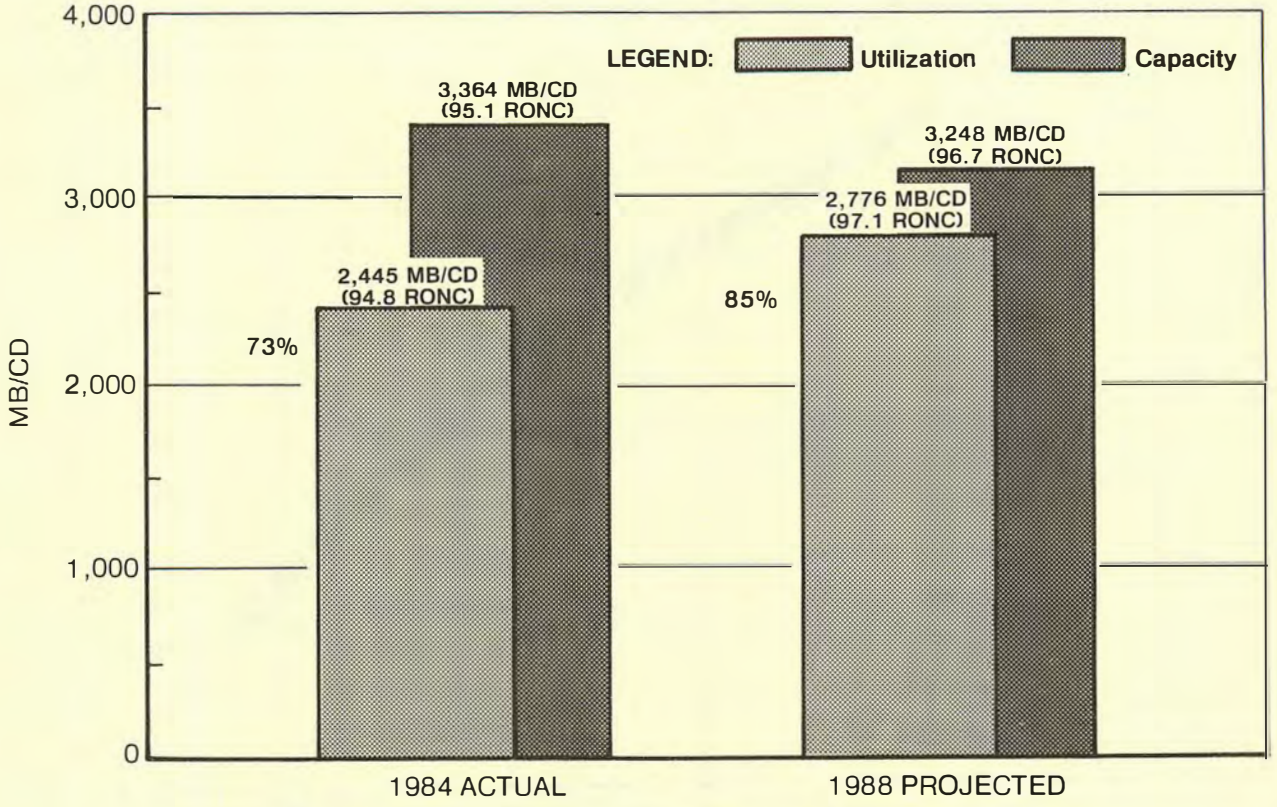


Figure 5. U.S. Reformer Capacity and Utilization as Reported.

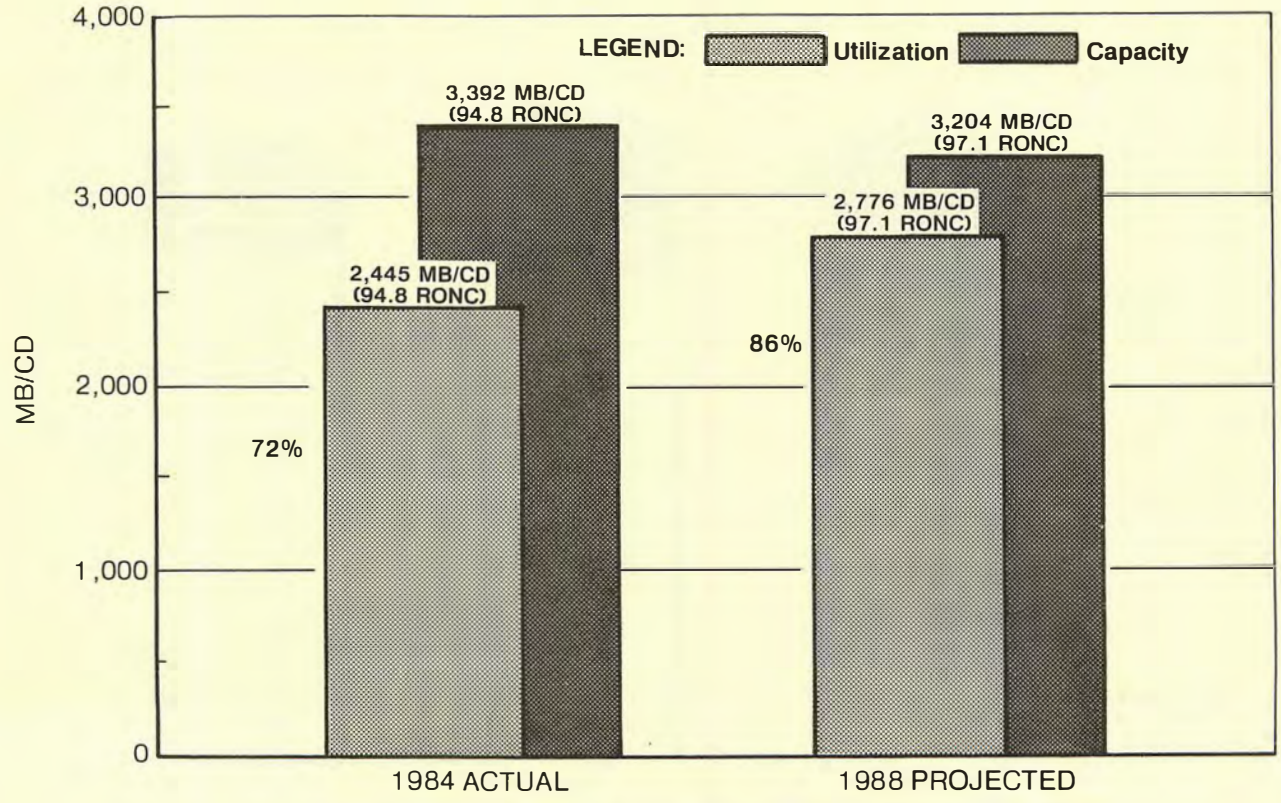


Figure 6. Adjusted U.S. Reformer Capacity and Utilization.

NOTE: Reformer capacity is restated to a severity of 95 research octane in 1984 and to 97 research octane for the 1988 projection. Calculations in this figure are based on data in Figure 7.

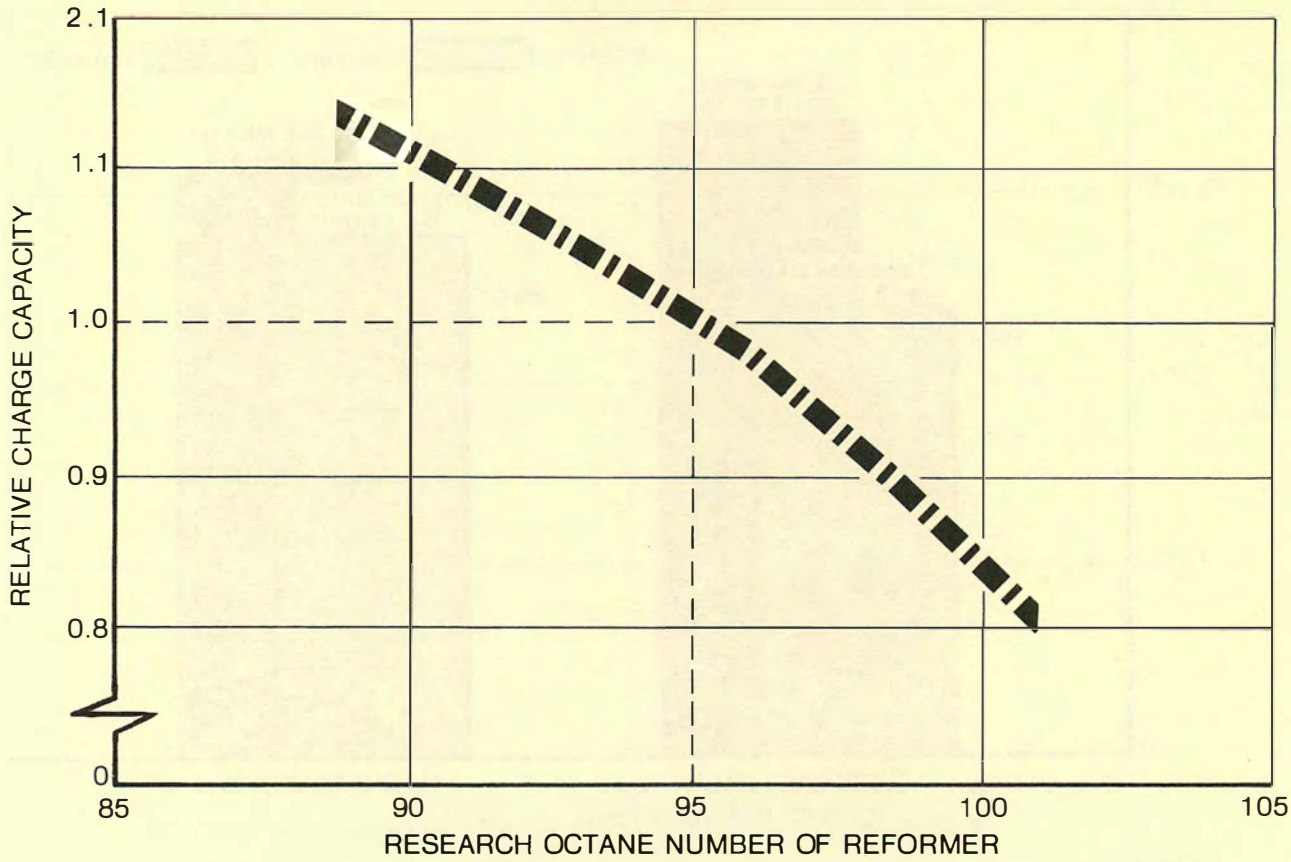


Figure 7. Relative Charge Capacity as a Function of Reformer Severity.

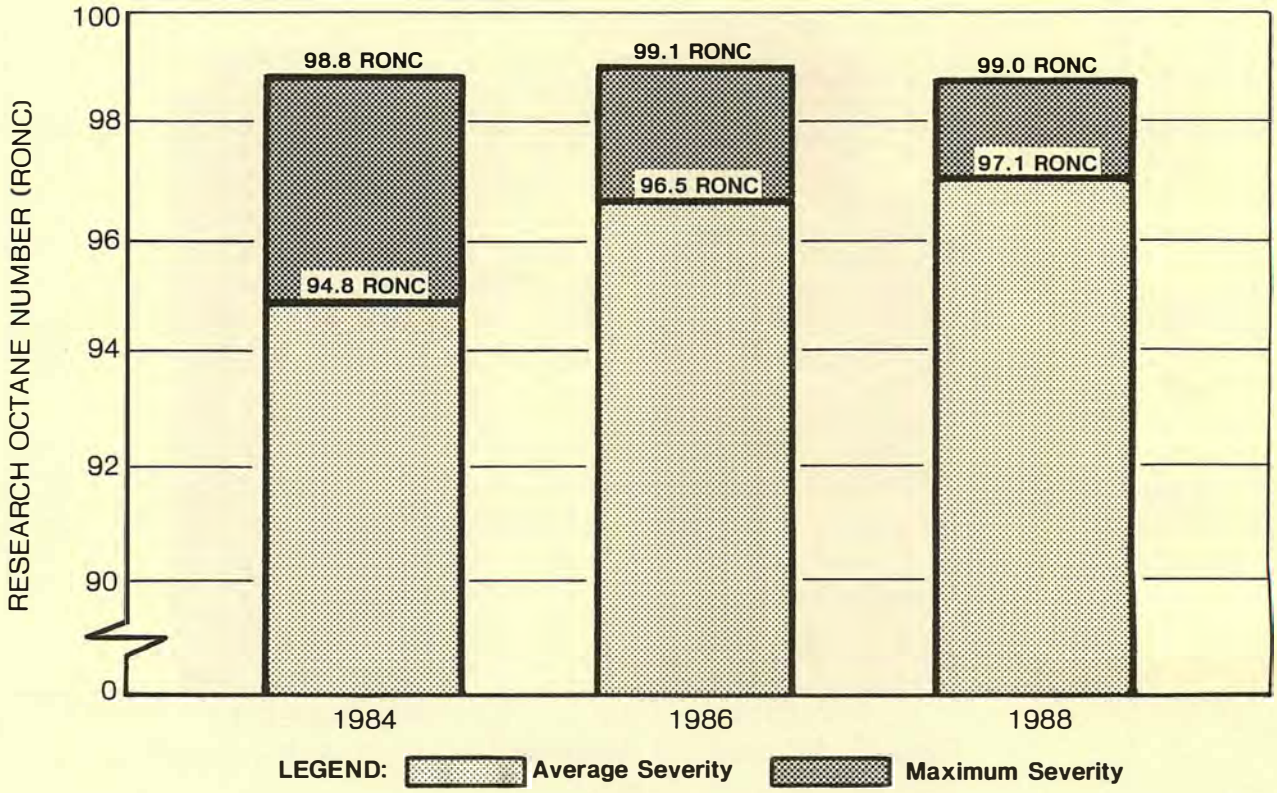


Figure 8. Survey Respondents' Reported Average and Maximum Reformer Severity- Total U.S.

fuller utilization of available capacities is expected for other facilities in 1988 for most of the key processes. There are a few instances in 1988 in which utilization was calculated to exceed 100 percent of start-of-year capacity (Table 9). This may reflect new capacity coming on stream after January 1, 1988, but operating during 1988. This inference is supported by a greater number of refineries reporting operations of these processes in 1988 than reported capacities on January 1, 1988.

The expectation that U.S. domestic refiners will upgrade residuum during the 1984–1988 period is evident by higher capacities for hydrocrackers and delayed cokers. During the survey period, respondents foresee increased throughputs of vacuum residuum of 77 MB/CD to hydrocrackers and 70 MB/CD to delayed cokers. For hydrocrackers, this represents 37 percent of the total increase of 207 MB/CD, and for delayed cokers, this represents 91 percent of the total increase of 76 MB/CD. An increase of 15 MB/CD of vacuum residuum charged to fluid catalytic cracking (FCC) units tends to be negated when balanced against the decrease of 48 MB/CD of atmospheric resid that contains vacuum residuum.

Both sulfur recovery and heavy gas oil hydrotreating capacities and utilization are expected to show significant capacity gains in the period surveyed for the total U.S., as refinery process facilities increase to more effectively handle lower quality feedstocks while achieving environmental objectives.

Capacity Changes in Refineries by Region/Complexity Groups

The total U.S. gains foreseen in some key downstream capabilities do not result in a uniform trend across the geographic regions and refinery complexities. The majority of all of the process unit capacity increases for 1988 shown in Tables 5, 6, and 7 occur in PADD III deep conversion refineries. Most of this increased capacity was expected to be in place by January 1, 1986. Capacity decreases were projected in some regions, mostly in PADD V California conversion refineries and PADD II and PADD III gas oil conversion refineries.

Similarly, there is no general pattern in regard to shifts in crude oil atmospheric distillation (see Tables 5, 6, and 7). The following comments illustrate this lack of a pattern between 1984 and 1988.

- In PADD I, all of the decline in capacity of 18 MB/CD is in the segment without conversion facilities, which is 6.6 percent of the capacity for this segment.
- In PADD II, most of the decline in capacity is in the gas oil conversion refineries, which show a drop of 84 MB/CD, or 11.4 percent.
- In PADD III, the deep conversion refineries expect a minimal increase in crude oil charge capacity, while the nonconversion and gas oil conversion refineries show declines of 8.8 and 4.5 percent, respectively.
- In PADD IV, there is essentially no change.
- In PADD V, both nonconversion and outside California conversion refineries project increased crude oil charge capacities of 5.1 and 5.8 percent, respectively, while California conversion refineries show a 2.2 percent decline.

Some of the 1984 and 1988 capacities shown in Tables 5, 6, and 7 are discussed in the following paragraphs.

Delayed coker capacity is projected to increase between 1984 and 1988 for the following refinery groups:

- Total U.S.: 5.0 percent (from 1,133 to 1,190 MB/CD)
- PADD II deep conversion: 5.6 percent (from 230 to 243 MB/CD)
- PADD III deep conversion: 3.6 percent (from 505 to 523 MB/CD)
- PADD V California conversion: 2.2 percent (from 317 to 324 MB/CD).

Combined fluid coker and flexicoker capacity decreased from 158 MB/CD to 149 MB/CD, or 5.7 percent, between 1984 and 1988.

PADD III deep conversion refineries show a 22.9 percent increase in *heavy gas oil hydrotreating* capacity between 1984 and 1988, accounting for most of the total U.S. increase.

PADD I conversion refineries and PADD III deep conversion refineries show an increase of 45 MB/CD and 33 MB/CD, respectively, in *fluid catalytic cracking* capacity by 1988. PADD II low conversion refineries and PADD V California conversion refineries show declines of 33 MB/CD and 37 MB/CD, respectively, generally reflecting

the crude oil capacity cutbacks in these areas. In PADD V California conversion refineries, however, the decline in FCC capacity of 37 MB/CD was almost the same as the decline in atmospheric distillation capacity of 39 MB/CD.

PADD III deep conversion refineries are projected to increase 107 MB/CD, or 46.5 percent, in *hydrocracking* capacity for 1988 over 1984. In PADD V California conversion refineries, the projected general decline in process capacities extends to hydrocracking, where the capacity decrease was 8.2 percent.

The total increase in *C_5/C_6 isomerization* capacity throughout the United States is projected to be 139 percent, and the increase will occur in almost all areas. PADD II deep conversion refineries are expected to increase isomerization capacity 58 MB/CD (242 percent) and PADD III deep conversion refineries are expected to add 39 MB/CD capacity for isomerization (67.2 percent). Throughput of C_5/C_6 isomerization process units is projected to increase between 1984 and 1988 by 171 MB/CD, to a level of 228 MB/CD, for an increase of 295 percent.

Average reformer severity is projected to increase in all PADDs during the survey period. The highest severities expected for 1988 are 99.6 RONC for PADD V California conversion and 99.4 RONC for PADD V nonconversion refineries. The lowest reformer severity expected in 1988 is 95.7 for PADD IV refineries (Table 10).

In the survey, refiners were requested to report the amount of *FCC naphtha* used as a reformer feedstock to the reformer. They reported that reforming of FCC naphtha is expected to increase from 1984 to 1988 by 27.9 MB/CD, with a 16.5 MB/CD increase in PADD V California conversion refineries and a 6.5 MB/CD increase in PADD II deep conversion refineries.

Operation of FCC units in a manner yielding *higher octane* cracked gasoline appears to be a way that refinery groups cope with the phaseout of lead antiknock additive. This is particularly true for refinery groups that previously yielded relatively low-octane-number cracked gasoline; i.e., gas oil conversion refineries in PADD II and PADD III. PADD V California conversion refineries forecast a significant drop in FCC gasoline octane quality, possibly related to more hydrotreating of catalytic cracker feedstock, with a resultant reduction in FCC gasoline aromaticity and, thus, a lower octane number.

CRUDE OIL SLATES

Actual 1984 and projected 1986 and 1988 crude oil slates by grade and origin as aggregated by geographic location and process complexity are set forth in Table 11. 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 vacuum residuum) and heavy (greater than 15 percent vacuum residuum) are shown for grades other than sweet.

For all U.S. respondents, sweet crude oils represented 50.5 percent, medium sulfur oils 16.8 percent, and high sulfur oils 32.7 percent of actual runs of 11,642 MB/CD in 1984. Some 8,561 MB/CD, or 73.5 percent, of crude oil processed in 1984 was of domestic origin; 3,081 MB/CD, or 26.5 percent, was from foreign sources.

Foreign crude oils were 87 percent of the 1984 crude oil slate in all of PADD I refineries, 12 percent in PADD II refineries with conversion facilities, 29 percent in all of the refineries responding in PADD III, 9 percent of those in PADD IV, and 10 percent in PADD V refineries with conversion facilities. Confidentiality requirements prevent reporting origins of crude oils for nonconversion refineries in PADD II and PADD V. Of total imported crude oil, 31.2 percent went to PADD I refineries, 9.9 percent to PADD II, 51.7 percent to PADD III, 1.1 percent to PADD IV, and 6.1 percent to PADD V.

In 1984, refineries with "deep" (i.e., residuum) conversion facilities processed the highest quality crude oil slates of any of the NPC refinery aggregations. PADD II deep conversion refineries' crude oil slates were 70 percent sweet, and PADD III deep conversion refineries' crude oil slates were 55 percent sweet. These two refinery groups also featured mainly domestic crude oils, together accounting for 55 percent of the total domestic oil processed.

Respondents processed an aggregate crude oil slate in 1984 averaging 32.6°API with 16.3 percent vacuum residuum and 0.96 wt.% sulfur content. Conversion-type refineries in California handled the lowest gravity mix of crude oils (23.9°API, 24.7 percent vacuum residuum, 1.16 wt.% sulfur), followed by PADD V nonconversion refineries (25.7°API, 25.8 percent vacuum residuum, and 1.09 wt.% sulfur) and PADD I nonconversion refineries (26.1°API, 34.8 percent vacuum residuum, and 2.31 percent sulfur). The

TABLE 10

NPC SURVEY DATA FOR PROCESS OPERATING CONDITIONS — ACTUAL 1984 AND PROJECTED 1988

	PADD I		PADD II			PADD III			PADD IV	PADD V			U.S. Total
	I–S	I–C	II–S	II–LC	II–DC	III–S	III–LC	III–DC		V–S	V–COC	V–CC	
Actual 1984													
Average Reformer Severity (RONC)‡	—	96.5	†	94.1	93.9	91.0	95.2	94.5	87.6*	97.5	94.2*	97.2	94.8
Maximum Reformer Severity (RONC)‡	—	99.7	†	98.0	98.7	94.9	98.6	98.5	97.5*	99.5	99.1*	99.8	98.8
Average C_5/C_6 Isomerization Octane (RONC)	—	†	—	†	84.1	—	†	90.1	—	—	—	—	88.1
FCC Gasoline Octane (RONC)	—	91.7	—	90.1	91.3	—	90.9	91.1	90.4	—	91.0	92.2	91.3
FCC Gasoline Octane (MONC)	—	80.7	—	80.4	81.1	—	79.7	79.9	79.4	—	80.9	79.8	80.2
Vol. % Atmospheric Resid to FCC	—	12.8	†	†	14.1	—	12.4	8.4	23.6	—	†	0.0	9.3
Vol. % Vacuum Resid to FCC	—	—	—	3.9	2.1	—	—	3.5	3.0	—	0.0	0.0	2.6
FCC Feed (°API)	—	25.3	—	27.1	25.5	—	25.6	24.6	26.8	—	24.9	21.3	24.7
FCC Feed (Conradson Carbon)	—	0.7	—	0.9	0.9	—	0.6	1.1	1.1	—	0.7	0.3	0.8
FCC Conversion (%)	—	73.4	—	77.2	74.5	—	71.0	74.7	76.4	—	75.4	61.5	72.3
Vol. % Vacuum Resid to Hydrocracker	—	0.0	—	0.0	0.0	—	0.0	0.0	0.0	—	0.0	0.0	0.0
MB/CD Reforming of Cat Naphtha	—	†	—	0.0	8.9	—	0.0	†	—	—	—	17.5	55.6
Projected 1988													
Average Reformer Severity (RONC)‡	—	98.2	—	95.9	96.3	96.2	97.7	96.5	95.7*	99.4	97.4*	99.6	97.1
Maximum Reformer Severity (RONC)‡	—	100.2	—	98.7	98.6	96.2	99.1	98.7	97.7*	99.4	99.1	100.0	99.0
Average C_5/C_6 Isomerization Octane (RONC)	—	†	—	83.3	84.3	†	†	87.2	†	†	†	—	84.9
FCC Gasoline Octane (RONC)	—	91.6	—	90.9	91.4	—	91.5	91.4	90.5	—	91.5	91.8	91.4
FCC Gasoline Octane (MONC)	—	80.7	—	81.0	80.9	—	80.2	80.0	79.5	—	80.2	79.5	80.2
Vol. % Atmospheric Resid to FCC	—	—	—	†	11.3	—	11.9	6.5	23.4	—	0.0	0.0	7.7
Vol. % Vacuum Resid to FCC	—	—	—	6.0	1.2	—	—	3.8	2.9	—	0.0	0.0	2.8
FCC Feed (°API)	—	25.1	—	27.2	25.4	—	25.4	24.3	26.8	—	23.8	21.6	24.5
FCC Feed (Conradson Carbon)	—	0.7	—	0.8	0.8	—	0.6	1.2	1.1	—	0.5	0.4	0.9
FCC Conversion (%)	—	74.1	—	73.1	74.3	—	73.4	74.4	76.7	—	77.3	68.0	73.6
Vol. % Vacuum Resid to Hydrocracker	—	0.0	—	0.0	0.0	—	0.0	†	0.0	0.0	0.0	†	8.3
MB/CD Reforming of Cat Naphtha	—	†	—	0.0	15.4	—	†	†	0.0	0.0	†	34.0	83.5

*Based on semi-regenerative reformer data only.
†Data withheld due to confidentiality requirements. Data included in total.
‡Research Octane Numbers (RONC) are the weight average for semi-regeneration and continuous reformers.

TABLE 11

NPC SURVEY DATA FOR CRUDE OIL SLATES — ACTUAL 1984, PROJECTED 1986, AND PROJECTED 1988*

	PADD I		PADD II			PADD III			PADD IV	PADD V			U.S. Total
	I–S	I–C	II–S	II–LC	II–DC	III–S	III–LC	III–DC		V–S	V–COC	V–CC	
Actual 1984													
Origin													
Domestic	41	100	†	463	1,741	188	688	3,031	336	†	364	1,316	8,561
Foreign	83	877	†	69	236	0	445	1,136	34	†	57	131	3,081
Grade													
Sweet	49	†	†	375	1,381	148	601	2,280	†	†	†	†	5,884
Medium Sulfur–Light	0	0	0	†	†	†	†	†	80	35	0	†	296
Medium Sulfur–Heavy	0	121	†	†	†	0	†	†	†	109	305	†	1,655
High Sulfur–Light	0	0	0	15	†	0	†	727	†	0	0	†	1,072
High Sulfur–Heavy	75	†	†	130	409	†	312	712	†	†	†	636	2,735
Total, All Grades	124	977	28	532	1,977	188	1,133	4,167	370	280	421	1,447	11,642
Crude Oil Quality													
°API	26.1	32.8	29.9	36.6	35.4	41.4	35.5	33.3	36.4	25.7	28.9	23.9	32.6
% Sulfur	2.31	0.88	1.14	0.83	0.85	0.55	1.00	0.95	0.92	1.09	0.87	1.16	0.96
% Resid	34.8	17.7	34.3	13.2	13.6	13.0	13.7	14.0	11.9	25.8	23.1	24.7	16.3
Projected 1986													
Origin													
Domestic	†	81	†	440	1,780	175	744	3,262	331	†	402	1,427	8,996
Foreign	†	942	†	97	249	0	457	1,211	54	†	43	123	3,295
Grade													
Sweet	39	†	†	†	†	154	610	2,287	184	†	†	†	5,837
Medium Sulfur–Light	0	†	0	11	†	0	†	73	†	36	0	†	245
Medium Sulfur–Heavy	0	†	†	†	†	0	†	541	†	100	324	654	1,820
High Sulfur–Light	0	†	0	15	169	0	†	707	†	0	0	0	1,187
High Sulfur–Heavy	110	†	†	193	403	21	345	867	†	†	†	737	3,202
Total, All Grades	149	1,023	30	537	2,029	175	1,201	4,473	385	295	445	1,550	12,291
Crude Oil Quality													
°API	23.6	32.8	29.6	35.4	35.4	42.1	34.6	32.4	36.2	25.6	28.3	23.2	31.9
% Sulfur	2.69	0.90	1.21	1.00	0.89	0.57	1.06	0.96	0.93	1.14	0.89	1.20	1.00
% Resid	38.5	17.8	36.0	13.9	13.7	12.0	13.8	14.6	12.3	26.3	23.0	25.1	16.8
Projected 1988													
Origin													
Domestic	†	80	†	459	1,779	180	713	3,103	334	†	403	1,489	8,916
Foreign	†	921	†	92	248	0	481	1,426	52	†	58	93	3,503
Grade													
Sweet	39	†	†	†	†	159	584	2,221	184	†	†	†	5,741
Medium Sulfur–Light	0	0	0	11	†	0	†	85	†	37	0	†	251
Medium Sulfur–Heavy	0	†	†	†	53	0	†	425	†	101	326	684	1,752
High Sulfur–Light	0	†	0	24	†	0	†	751	†	†	0	0	1,209
High Sulfur–Heavy	123	†	†	205	436	21	348	1,047	†	†	†	770	3,466
Total, All Grades	163	1,001	30	551	2,027	180	1,193	4,529	386	316	461	1,582	12,420
Crude Oil Quality													
°API	22.6	33.0	29.6	34.9	35.3	42.0	34.3	32.3	36.1	25.1	28.8	22.9	31.7
% Sulfur	2.67	0.86	1.21	1.04	0.91	0.57	1.08	1.06	0.96	1.30	0.88	1.32	1.06
% Resid	39.6	17.6	36.0	14.4	13.9	11.9	13.9	15.0	12.4	26.0	22.3	25.6	17.0

*All figures in MB/CD unless otherwise indicated.
†Data withheld due to confidentiality requirements. Data included in total.

separation between domestic and foreign crude oil shows that PADD I nonconversion refiners reported domestic crude oil at 39.9°API, 16.7 percent vacuum residuum, and 0.42 wt.% sulfur, and foreign crude oil at 19.4°API, 43.8 percent vacuum residuum, and 3.24 wt.% sulfur. The more paraffinic nature of crude oil used in the PADD I lubricant refineries is evident in the domestic crude oil data. The deep conversion refineries in PADD II and PADD III had higher quality crude oil slates than PADD I conversion refineries, assaying 35.4°API, 13.6 percent residuum, and 0.85 wt.% sulfur, and 33.3°API, 14.0 percent residuum, and 0.95 wt.% sulfur, respectively.

With respect to future crude oil slates, responding refiners projected their combined slates to increase from the aforementioned 1984 total of 11,642 MB/CD to 12,291 MB/CD in 1986 and 12,420 MB/CD in 1988. All of the increase was projected to be in the medium sulfur–heavy and high sulfur grades, particularly the latter. Little change was seen in the distribution as to origin, with the percentage of domestic crude oils dropping slightly from 73.5 percent actual in 1984 to 73.2 percent projected for 1986 and 71.3 percent projected for 1988.

PADD III refineries without conversion facilities were the only group that projected a declining throughput for the survey period, and that reduction amounted to only 8 MB/CD between 1984 and 1988. PADD III deep conversion refineries accounted for 362 MB/CD, or nearly half the amount of the total U.S. crude oil throughput increase projected between 1984 and 1988. If such an increase materializes, it would be an 8.7 percent increase for this group of refineries for the survey period, significantly above the 6.7 percent for all U.S. respondents combined. The PADD III deep conversion refineries aggregation is the largest of the NPC groupings, accounting for more than 35 percent of total respondents' throughputs.

Among the refinery groups without conversion facilities, PADD I refineries, which include a number of refiners with lubestock and asphalt manufacturing capabilities, appeared optimistic about their future, with 1988 runs projected to be 39 MB/CD, or 31.7 percent, above 1984 actual levels.

Between 1984 and 1988, the following regional changes in crude oil throughputs were foreseen: PADD I, +63 MB/CD; PADD II, +71 MB/CD; PADD III, +414 MB/CD; PADD IV, +16 MB/CD; PADD V, +211 MB/CD.

The combined perception of trends in quality of crude oil slates by total U.S. respondents is illustrated by the aggregated data shown below:

	Actual 1984	Projected 1986	Projected 1988
Total Throughput (MB/CD)	11,642	12,291	12,420
Averaged Qualities			
°API	32.6	31.9	31.7
% Sulfur	0.96	1.00	1.06
% Vacuum Residuum	16.3	16.8	17.0

The shift toward a lower gravity, higher sulfur mix of crude oil is seen in Table 11 for 9 of 12 region/complexity refinery groups.

FEEDSTOCKS OTHER THAN CRUDE OIL

Actual 1984 and projected 1988 slates of feedstocks other than crude oil for both the United States and the region/complexity groups are summarized in Tables 12 and 13. Volumes of these other feedstocks projected for 1986, although not listed in these tables, closely approximated those expected for 1988.

Total feedstocks other than crude oil in 1984 for all U.S. respondents amounted to 1,838 MB/CD and are projected to decrease slightly to 1,809 MB/CD by 1988. These volumes represent 14 percent and 13 percent of total refinery throughputs in 1984 and 1988, respectively.

The expected reduction in processing of field condensate and natural gasoline from 213 MB/CD in 1984 to 135 MB/CD in 1988 may be attributable to lead phaseout regulations.

Non-crude oil feedstocks other than whole crude oil to refineries were identified as primarily domestic in origin, with a total of 546 MB/CD in 1984 and 648 MB/CD in 1988. Foreign feedstocks received by respondents totalled only slightly less than 200 MB/CD in each year.

Unfinished intermediates requiring further processing or blending accounted for 740 MB/CD (40 percent of total other feedstocks) in 1984 and 843 MB/CD (47 percent) in 1988. These materials included light olefins, naphtha, middle and heavy distillates, lubestock intermediates, and residuals. Gas oil, at 341 MB/CD in 1984 and 405 MB/CD in 1988, was the largest volume single unfinished stock moved between refineries.

TABLE 12

NPC SURVEY DATA FOR FEEDSTOCKS OTHER THAN CRUDE OIL — ACTUAL 1984*

	PADD I		PADD II			PADD III			PADD IV	PADD V			U.S. Total
	I–S	I–C	II–S	II–LC	II–DC	III–S	III–LC	III–DC		V–S	V–COC	V–CC	
Unfinished Feedstocks													
Origin													
Domestic	4	59	0	18	28	13	83	198	4	3	19	118	546
Foreign	0	55	0	†	†	0	39	95	0	†	0	†	194
Type													
C_3/C_4 Olefins	0	†	0	†	†	†	18	18	1	0	†	†	45
Naphtha	†	15	0	†	2	3	17	55	†	†	3	12	127
Distillate	†	†	0	†	1	†	†	1	0	†	†	10	33
Gas Oil	†	38	0	14	18	†	38	104	2	0	4	76	341
Atmospheric Resid	†	0	0	0	†	0	3	75	†	†	0	†	123
Other Resid	0	2	0	†	4	†	†	†	†	†	†	19	65
Lubestock Intermediate	0	0	0	0	†	†	0	†	†	†	0	0	1
Total	4	114	0	18	28	13	122	293	4	†	19	118	740
Field Condensate & Natural Gasoline	0	0	0	5	55	3	26	79	15	2	0	9	213
Natural Gas & Hydrogen (FOE)	2	13	0	9	23	3	29	137	4	2	10	34	265
Propanes	†	0	0	0	†	†	†	†	0	1	0	†	18
Butane	0	12	0	20	89	0	32	107	7	0	10	21	302
Oxygenates	†	†	0	†	2	†	4	15	0	†	0	†	26
Domestic Blendstocks													
Gasoline	0	†	0	†	†	†	28	56	†	†	†	†	106
[(R + M) /2]	[0]	[†]	[0]	[†]	[†]	[†]	[92.3]	[85.4]	[†]	[†]	[†]	[†]	[89.0]
Distillate	0	9	0	0	†	†	10	3	0	†	0	†	25
Heavy Fuel Oil	0	†	0	0	0	0	†	2	†	†	†	15	41
Foreign Blendstocks	0	†	0	0	0	0	0	†	0	0	0	0	10
Other Feedstocks	4	2	†	2	14	†	13	40	0	5	†	7	91
Total Feedstocks (Other than Crude Oil)	**10**	**162**	**28.9**	**70**	**221**	**28**	**273**	**752**	**31**	**23**	**53**	**214**	**1,838**

*All figures in MB /CD unless otherwise noted.
†Data withheld due to confidentiality requirements. Data included in total.

TABLE 13

NPC SURVEY DATA FOR FEEDSTOCKS OTHER THAN CRUDE OIL — PROJECTED 1988*

	PADD I		PADD II			PADD III			PADD IV	PADD V			U.S. Total
	I–S	I–C	II–S	II–LC	II–DC	III–S	III–LC	III–DC		V–S	V–COC	V–CC	
Unfinished Feedstocks													
Origin													
Domestic	†	94	0	†	25	12	123	237	3	5	†	131	648
Foreign	0	0	0		0	†	†	87	0	†	0	†	195
Type													
C_3/C_4 Olefins	0	†	0	0	†	†	†	15	1	†	0	0	31
Naphtha	†	22	0	†	†	†	40	68	†	0	0	7	169
Distillate	0	†	0	†	0	†	†	†	0	†	†	9	50
Gas Oil	0	68	0	†	17	†	44	98	2	†	†	78	405
Atmospheric Resid	0	0	0	0	0	†	†	†	†	†	0	0	84
Other Resid	0	†	0	0	†	†	†	42	†	†	†	37	104
Lubestock Intermediate	0	0	0	0	0	†	0	0	†	†	0	0	†
Total	†	94	0	†	25	†	123	324	†	†	†	131	843
Field Condensate & Natural Gasoline	0	0	0	†	37	†	†	56	15	2	0	4	135
Natural Gas & Hydrogen (FOE)	2	10	0	7	23	4	39	134	4	2	11	37	272
Propanes	†	0	0	0	0	0	†	†	0	0	0	†	†
Butane	0	16	0	16	97	0	36	12	7	0	12	17	314
Oxygenates	†	6	0	2	8	†	4	23	0	†	0	†	49
Domestic Blendstocks													
Gasoline	†	†	0	†	†	†	0	43	†	†	†	†	83
[(R+M)/2]	[†]	[†]	[0]	[†]	[†]	[†]	[0]	[84.4]	[†]	[†]	[†]	[†]	[90.7]
Distillate	0	†	0	0	†	0	0	†	0	†	0	0	8
Heavy Fuel Oil	0	0	0	0	0	0	0	†	†	†	†	†	19
Foreign Blendstocks	0	0	0	0	0	0	0	†	0	†	0	0	10
Other Feedstocks	2	†	†	†	8	†	15	24	0	†	0	†	60
Total Feedstocks (Other than Crude Oil)	**6**	**191**	†	**42**	**208**	**26**	**295**	**739**	**29**	**26**	**41**	**206**	**1,809**

*All figures in MB/CD unless otherwise noted.
†Data withheld due to confidentiality requirements. Data included in total.

Finished domestic and foreign blendstocks (gasoline, distillate, and heavy fuel oil) at 182 MB/CD in 1984 and 120 MB/CD in 1988 represented only 1.5 percent or less of refinery input for the survey period. Oxygenates for gasoline blending at 26 MB/CD in 1984 and 49 MB/CD in 1988 are an even smaller volume factor in refinery feedstocks. Any oxygenates blended into gasoline outside the refinery are not included in the survey data.

The higher complexity larger refineries display the greatest relative utilization of feedstocks other than crude oils. Refineries without conversion in all PADDs, together with PADD IV refineries in 1984, utilized less than 100 MB/CD of feedstocks other than crude oil.

A substantial shift in the distribution of these other feedstocks among the various aggregations of refineries is not anticipated during the period surveyed.

PRODUCT YIELDS

Production levels for all finished and unfinished products plus refinery fuels for actual 1984 and projected 1986 and 1988 operations are presented in Tables 14, 15, and 16.

For total U.S. respondents, product yields amounted to 13,920 MB/CD in 1984 and are projected to increase to 14,355 MB/CD and 14,499 MB/CD in 1986 and 1988, respectively. Finished gasoline, of course, was easily the largest volume single product.

In 1984, all grades of gasoline for all respondents amounted to 6,337 MB/CD, or 54.4 percent by volume, of crude oil refined. This represents over 98 percent of total gasoline production reported to DOE for the year. Unleaded grades totalled 3,852 MB/CD, 61 percent of total gasolines. Nationally, (R+M)/2 octanes averaged 87.1 for unleaded regular, 91.9 for unleaded premium, and 88.8 for leaded regular grades.

Future gasoline volumes are projected to be 6,440 MB/CD and 6,466 MB/CD for all respondents in 1986 and 1988, respectively. These figures indicate diminished fractional yields of 52.4 and 52.1 percent of crude oil throughput. Distribution between grades is foreseen to change significantly, with unleaded grades increasing first to 75 percent by 1986 and then to 83 percent by 1988. It is interesting that the respondents projected continuing leaded gasoline manufacture in 1988 at the 0.1 gplg limitation proposed by the Environmental Protection Agency (EPA) at the time of the survey. At 0.1 gplg, there is approximately a one octane number boost over unleaded while the leaded octane specification is two octane numbers higher than unleaded. Respondents plan to continue manufacturing leaded gasoline despite its higher manufacturing costs at this lead level relative to unleaded gasoline. All regions indicated manufacture of leaded gasoline in 1988 with PADD IV showing a higher percentage of this grade than all other regions. For 1984, the percentage of unleaded regular (with intermediates) and unleaded premium amounted to 46.8 percent and 14.0 percent, respectively, and 1988 figures are 65.4 percent and 18.1 percent, respectively. Thus, the ratio of unleaded regular to unleaded premium was nearly constant at about 3.4:1 throughout the survey period.

Throughout the survey period, 1984–1988, unleaded regular gasoline octane specifications were consistently between 87.1 and 87.5 (R+M)/2 in all PADDs, irrespective of complexity, except for PADD IV, where this product averaged 85.5. Leaded regular (R+M)/2 quality ranged from about 87 in PADD IV, to 88 on the West Coast in PADD V, to 88.7–89.1 in PADDs I, II, and III.

Premium unleaded gasoline volumes are expected to grow significantly during the survey period. By 1988, the 1,170 MB/CD yield projected for this product exceeded that of leaded regular, which was at 1,050 MB/CD. Blending of unleaded premium was predicted to increase by about one-third during the four-year span. The national average 91.8 (R+M)/2 quality is fairly representative of the various refinery groups with the exceptions that PADD I conversion refiners average 92.4 (R+M)/2 quality while PADD IV refiners blend to about 89.0 (R+M)/2. Refiners without conversion units do not report any plans to blend significant quantities of unleaded premium gasoline.

The volumes and qualities of gasolines reported in this section are within the blending capabilities addressed elsewhere in this report. It should be recognized, however, that these yield forecasts are predicated upon no change in current specifications (including Reid Vapor Pressure) and no new limitations on the use of oxygenates or increase in octane number.

In Tables 14 and 15, significant increases in both sulfur and coke yields for 1986 were reported. Data for 1988 (Table 16) showed further

TABLE 14

NPC SURVEY DATA FOR PRODUCT YIELDS — ACTUAL 1984*

	PADD I		PADD II			PADD III			PADD IV	PADD V			U.S. Total
	I–S	I–C	II–S	II–LC	II–DC	III–S	III–LC	III–DC		V–S	V–COC	V–CC	
LPG	0	30	0	15	55	6	20	118	5	†	†	15	271
Gasoline													
Unleaded Regular	4	279	0	157	627	14	258	1,035	79	13	74	329	2,870
[(R+M)/2]	[87.4]	[87.4]	[0]	[87.2]	[87.1]	[87.2]	[87.1]	[87.1]	[85.1]	[87.5]	[87.1]	[87.3]	[87.1]
Unleaded Intermediate	0	†	0	0	0	0	0	12	†	0	0	†	95
[(R+M)/2]	[0]	[†]	[0]	[0]	[0]	[0]	[0]	[92.2]	[†]	[0]	[0]	[†]	[89.3]
Unleaded Premium	0	107	0	34	105	3	86	413	6	3	34	98	887
[(R+M)/2]	[0]	[92.4]	[0]	[91.8]	[91.7]	[91.7]	[91.5]	[92.0]	[89.1]	[91.0]	[91.7]	[91.6]	[91.9]
Leaded Regular	†	169	†	130	560	19	246	835	108	13	87	239	2,413
[(R+M)/2]	[†]	[89.1]	[†]	[88.9]	[88.7]	[89.0]	[88.8]	[89.0]	[87.0]	[88.0]	[88.0]	[88.1]	[88.8]
Leaded Premium	0	0	0	0	†	0	†	†	5	2	†	32	45
[(R+M)/2]	[0]	[0]	[0]	[0]	[†]	[0]	[†]	[†]	[88.4]	[91.1]	[†]	[92.0]	[91.5]
Aviation Gasoline	0	†	0	†	2	0	†	15	1	0	†	7	28
Total Gasoline	†	558	†	†	†	36	591	2,295	199	31	200	†	6,337
Jet Fuel — Naphtha	†	†	†	†	15	31	13	51	11	3	†	36	190
— Kerosene	0	38	0	48	93	10	82	442	23	16	67	162	982
Kerosene No. 1	†	8	2	11	41	1	6	13	7	0	†	3	95
Diesel	†	17	†	36	181	9	142	336	52	39	20	151	1,028
Distillate No. 2	13	219	6	60	296	22	101	590	38	6	60	64	1,474
No. 4 Fuel Oil	†	†	0	†	2	3	0	0	†	1	0	0	6
Heavy Fuel Oil (Nos. 5&6)													
Less than 0.3% Sulfur	9	†	0	0	0	†	†	0	†	†	0	†	43
0.3–1.0% Sulfur	0	38	†	†	7	†	†	†	†	†	†	†	186
1.0–2.0% Sulfur	0	†	0	5	27	†	17	41	1	30	63	112	302
More than 2.0% Sulfur	†	10	†	2	9	0	102	106	1	17	0	42	297
Total Heavy Fuel Oil	15	95	4	15	45	11	141	†	6	62	†	178	834
Asphalt & Road Oil	45	41	†	48	48	10	42	31	20	32	†	19	340
Lubricants — Paraffinic	†	†	0	†	†	†	†	48	†	0	0	†	105
— Naphthene	†	0	0	0	†	†	†	16	0	0	0	†	42
Waxes (ST/CD)	444	0	0	0	353	†	1,042	1,354	†	0	0	†	4,555‡
Benzene, Toluene, Xylene	0	†	0	†	9	†	17	85	0	0	0	0	130
Other Petrochemicals & Specialties	1	14	0	5	28	†	12	141	†	†	0	8	209
Unfinished Oils	12	18	0	†	28	47	†	209	†	†	13	88	634
Sulfur (LT/CD)	0	541	0	182	1,161	†	492	3,335	120	†	175	1,536	7,568‡
Coke (ST/CD)	0	1,830	0	0	†	0	0	23,742	†	0	†	15,658	55,722†
Miscellaneous Finished Products	†	10	†	†	10	†	4	112	4	†	†	16	165
Blendstocks to Others	0	†	†	†	†	0	†	17	†	†	†	†	43
Refinery Fuel, FOE													
Distillate, Liquids & Other	2	†	†	10	11	1	2	8	4	1	4	6	127
By-product Gas & LPG	†	45	†	21	85	3	48	175	14	3	16	96	507
Purchased Gas	†	8	†	7	26	2	27	97	4	2	2	20	197
Coke	0	15	†	8	27	0	14	60	†	0	5	25	166
Inventory Change	†	(1)	0	(1)	5	38	7	3	(.02)	†	(7)	†	44
Total Products	133	1,172	29	624	2,330	245	1,456	5,066	404	301	473	1,689	13,920

*All figures in MB/CD unless otherwise indicated. Totals may not add due to independent rounding.
†Data withheld due to confidentiality requirements. Data included in total.
‡This item must be converted to barrel equivalent to give the reported total.

TABLE 15

NPC SURVEY DATA FOR PRODUCT YIELDS — PROJECTED 1986*

	PADD I		PADD II			PADD III			PADD IV	PADD V			U.S. Total
	I–S	I–C	II–S	II–LC	II–DC	III–S	III–LC	III–DC		V–S	V–COC	V–CC	
LPG	0	26	0	14	55	6	40	111	5	†	†	22	286
Gasoline													
Unleaded Regular	8	366	0	193	808	16	402	1,284	103	20	106	360	3,666
[(R+M)/2]	[87.2]	[87.3]	[0]	[87.1]	[87.1]	[87.2]	[87.1]	[87.1]	[85.5]	[87.0]	[87.1]	[87.2]	[87.1]
Unleaded Intermediate	†	0	0	0	0	†	0	23	†	0	0	†	108
[(R+M)/2]	[†]	[0]	[0]	[0]	[0]	[†]	[0]	[90.7]	[†]	[0]	[0]	[†]	[89.3]
Unleaded Premium	†	119	0	39	121	†	78	509	9	3	35	156	1,074
[(R+M)/2]	[†]	[92.4]	[0]	[91.6]	[91.9]	[†]	[91.1]	[91.9]	[89.1]	[91.3]	[91.8]	[91.7]	[91.9]
Leaded Regular	†	84	†	78	335	11	153	536	93	†	55	157	1,516
[(R+M)/2]	[†]	[89.1]	[†]	[88.6]	[88.6]	[89.0]	[88.3]	[89.0]	[87.1]	[†]	[88.0]	[88.1]	[88.6]
Leaded Premium	0	0	0	0	0	0	†	0	†	†	0	42	43
[(R+M)/2]	[0]	[0]	[0]	[0]	[0]	[0]	[†]	[0]	[†]	[†]	[0]	[90.0]	[90.0]
Aviation Gasoline	0	0	0	†	2	0	†	18	1	0	†	6	32
Total Gasoline	11	570	†	†	1,267	†	637	2,370	209	†	†	†	6,440
Jet Fuel — Naphtha	†	†	†	9	20	32	17	47	10	2	†	37	204
— Kerosene	0	43	0	†	116	†	98	483	23	17	79	181	1,098
Kerosene No. 1	†	10	2	10	35	†	5	20	6	†	†	5	96
Diesel	†	27	†	33	193	8	149	366	68	33	19	198	1,107
Distillate No. 2	11	226	6	50	313	21	97	655	39	6	61	49	1,534
No. 4 Fuel Oil	†	†	0	†	†	2	0	†	†	2	0	0	19
Heavy Fuel Oil (Nos. 5&6)													
Less than 0.3% Sulfur	1	†	0	0	0	†	†	†	†	†	0	0	36
0.3–1.0% Sulfur	0	42	†	6	7	†	†	36	1	†	†	8	195
1.0–2.0% Sulfur	0	†	0	3	26	†	10	64	1	31	65	98	303
More than 2.0% Sulfur	11	†	†	†	8	0	105	38	1	†	0	52	261
Total Heavy Fuel Oil	†	117	4	18	41	9	151	149	6	58	†	158	813
Asphalt & Road Oil	64	37	†	49	49	10	45	34	22	35	†	†	369
Lubricants — Paraffinic	†	†	0	†	†	†	†	51	†	0	0	†	132
— Naphthene	†	0	0	0	†	†	†	17	0	0	0	†	44
Waxes (ST/CD)	542	0	0	†	343	†	1,497	1,328	†	0	0	†	5,059‡
Benzene, Toluene, Xylene	0	†	0	0	15	†	7	94	†	0	0	0	146
Other Petrochemicals & Specialties	†	14	0	†	29	†	13	162	†	†	0	9	236
Unfinished Oils	18	26	0	†	28	35	85	260	7	†	†	86	603
Sulfur (LT/CD)	0	633	0	103	1,285	†	568	3,921	127	†	211	1,589	8,459‡
Coke (ST/CD)	0	1,536	0	0	†	0	0	25,722	†	0	†	16,351	58,156‡
Miscellaneous Finished Products	†	13	0	†	10	†	5	86	4	4	†	12	139
Blendstocks to Others	0	†	†	†	†	0	0	17	†	†	†	†	43
Refinery Fuel, FOE													
Distillate, Liquids & Other	1	†	†	8	16	1	5	9	4	1	3	3	145
By-product Gas & LPG	2	45	†	18	85	3	45	198	15	3	†	107	538
Purchased Gas	†	8	†	6	26	2	39	96	4	2	4	20	209
Coke	0	15	†	4	27	0	13	67	†	0	5	21	169
Inventory Change	†	0	0	0	†	0	†	(1)	†	0	0	(1)	7
Total Products	157	1,242	30	599	2,371	188	1,496	5,299	416	318	484	1,755	14,355

*All figures in MB/CD unless otherwise indicated. Totals may not add due to independent rounding.
†Data withheld due to confidentiality requirements. Data included in total.
‡This item must be converted to barrel equivalent to give the reported total.

TABLE 16

NPC SURVEY DATA FOR PRODUCT YIELDS — PROJECTED 1988*

	PADD I		PADD II			PADD III			PADD IV	PADD V			U.S. Total
	I–S	I–C	II–S	II–LC	II–DC	III–S	III–LC	III–DC		V–S	V–COC	V–CC	
LPG	0	28	0	14	55	6	40	118	5	†	†	22	297
Gasoline													
Unleaded Regular	8	377	0	213	879	27	411	1,430	131	19	109	396	4,000
[(R+M)/2]	[87.2]	[87.3]	[0]	[87.1]	[87.1]	[87.1]	[87.0]	[87.1]	[85.5]	[87.0]	[87.1]	[87.3]	[87.1]
Unleaded Intermediate	†	0	0	12	28	†	†	45	†	†	†	93	214
[(R+M)/2]	[†]	[0]	[0]	[86.3]	[89.2]	[†]	[†]	[89.9]	[†]	[†]	[†]	[88.9]	[89.2]
Unleaded Premium	†	126	0	37	144	†	106	518	11	4	46	174	1,170
[(R+M)/2]	[†]	[92.4]	[0]	[91.6]	[91.7]	[†]	[91.2]	[92.0]	[88.9]	[91.2]	[91.9]	[91.7]	[91.8]
Leaded Regular	†	73	†	46	213	†	97	385	62	†	40	125	1,050
[(R+M)/2]	[†]	[89.1]	[†]	[88.6]	[88.6]	[†]	[88.7]	[89.1]	[87.3]	[†]	[88.0]	[88.1]	[88.6]
Leaded Premium	0	0	0	0	0	0	†	0	†	0	0	0	1
[(R+M)/2]	[0]	[0]	[0]	[0]	[0]	[0]	[†]	[0]	[†]	[†]	[0]	[0]	[91.2]
Aviation Gasoline	0	0	0	†	2	0	†	18	1	0	†	7	32
Total Gasoline	†	576	†	†	1,266	33	635	2,395	208	31	206	794	6,466
Jet Fuel — Naphtha	†	†	†	9	20	32	17	52	11	2	†	38	211
— Kerosene	0	43	0	†	115	†	91	494	24	17	80	193	1,117
Kerosene No. 1	†	10	2	10	34	†	5	21	5	†	†	5	96
Diesel	†	27	†	35	196	8	146	354	68	33	23	211	1,132
Distillate No. 2	10	219	†	48	323	20	95	675	39	8	59	†	1,525
No. 4 Fuel Oil	†	†	0	†	†	2	0	†	†	2	0	0	18
Heavy Fuel Oil (Nos. 5&6)													
Less than 0.3% Sulfur	1	†	0	0	0	†	†	0	†	†	0	0	35
0.3–1.0% Sulfur	0	39	†	6	7	†	†	36	1	†	†	8	193
1.0–2.0% Sulfur	0	†	0	4	26	†	10	50	1	31	67	126	319
More than 2.0% Sulfur	13	†	†	†	10	0	100	35	1	19	0	38	233
Total Heavy Fuel Oil	†	97	4	18	†	9	148	†	6	66	†	172	799
Asphalt & Road Oil	72	37	†	49	49	10	42	39	22	38	†	†	386
Lubricants — Paraffinic	†	†	0	†	†	†	†	54	†	0	0	†	135
— Naphthene	†	0	0	0	†	†	†	18	0	0	0	†	48
Waxes (ST/CD)	542	0	0	0	343	†	1,497	1,428	†	0	0	†	5,192‡
Benzene, Toluene, Xylene	0	†	0	†	16	0	7	97	0	0	0	0	148
Other Petrochemicals & Specialties	†	16	0	†	29	†	13	156	†	†	0	9	232
Unfinished Oils	18	26	0	†	29	37	95	280	7	†	†	97	655
Sulfur (LT/CD)	0	620	0	109	1,323	†	578	4,334	135	†	209	1,986	9,319‡
Coke (ST/CD)	0	1,732	0	0	†	0	0	25,333	†	0	†	15,834	56,751‡
Miscellaneous Finished Products	†	7	0	†	10	†	5	97	4	4	†	13	144
Blendstocks to Others	0	†	†	†	†	0	†	16	†	†	†	†	45
Refinery Fuel, FOE													
Distillate, Liquids & Other	1	†	†	7	14	1	4	16	4	1	3	3	143
By-product Gas & LPG	2	†	†	20	85	3	45	190	14	3	16	109	536
Purchased Gas	†	9	†	6	26	2	37	92	4	2	2	22	204
Coke	0	16	†	4	27	0	13	68	†	0	5	22	171
Inventory Change	†	0	0	0	†	0	†	1	†	0	†	†	10
Total Products	171	1,219	30	599	2,382	192	1,490	5,366	429	338	502	1,781	14,499

*All figures in MB/CD unless otherwise indicated. Totals may not add due to independent rounding.
†Data withheld due to confidentiality requirements. Data included in total.
‡This item must be converted to barrel equivalent to give the reported total.

TABLE 17

NPC SURVEY DATA FOR OTHER PRIMARY FUELS AND SPECIALTIES (MB/CD)

	Actual 1984		Projected 1986		Projected 1988	
	MB/CD	Percent Sulfur	MB/CD	Percent Sulfur	MB/CD	Percent Sulfur
Jet Fuel-Naphtha	190		204		211	
Jet Fuel-Kerosene Based	982	0.11	1,098	0.13	1,117	0.14
Kerosene	95		96		96	
Diesel Fuel	1,028	0.30	1,107	0.30	1,132	0.30
Distillate No. 2	1,474	0.27	1,534	0.29	1,525	0.29
Heavy Fuel Oils	834		813		799	
Asphalt and Road Oils	340		369		386	
Lubricants	147		176		183	
Benzene, Toluene, Xylene	130		146		148	
Other Specialties and Petrochemicals	209		236		232	
Total	**5,429**		**5,779**		**5,829**	
Percentage of Crude Oil Throughput	46.6		47.0		47.0	

increases in sulfur recovery but coke tonnage was projected to be less than in 1986. The reason for this pattern of coke yields is not evident but the shift is noted to occur in at least two refinery groups: PADD III deep conversion and PADD IV.

Respondents were collectively optimistic about the future demand and their capability to produce other primary fuel and specialties (see Table 17).

However, when the product forecasts for the various region/complexity groups are examined, it becomes apparent that the overall increases with time in volumes of distillate and lighter products, including benzene, toluene, and xylene (BTX), are associated only with the deep conversion refineries in PADDs II and III, and California refineries with conversion capabilities.

Survey respondents did not project major overall changes in the volume of unfinished oils leaving their refineries during the survey period (see Table 18). However, increased movements of naphtha were evident, possibly a result of lead phaseout forcing elimination of this stock from the blending of gasoline for some refineries with

TABLE 18

NPC SURVEY DATA FOR UNFINISHED OIL PRODUCTION (MB/CD)

	Actual 1984	Projected 1986	Projected 1988
C_3/C_4 Olefins	67	56	54
Naphtha	137	185	218
Distillate	86	82	83
Gas Oil	249	208	224
Atmospheric and Vacuum Resids	76	61	63
Lubestock Intermediates	20	12	12
Total*	**635**	**604**	**654**
Percentage of Crude Oil Throughput	5.5	4.9	5.3

*Total may not add due to independent rounding.

limited octane number capabilities constraints. Examination of the detailed aggregated survey data shows the naphtha being from fewer refineries in 1988 than in 1984.

Actual volume of refinery fuel consumption was reported to increase slightly in quantity in 1986 followed by a slight reduction in 1988. This reflects some conservation efforts since refinery fuel used as a percentage of crude oil throughputs diminishes throughout the survey period (see Table 19).

TABLE 19

NPC SURVEY DATA FOR REFINERY FUELS CONSUMED (FOE) (MB/CD)

	Actual	Projected	
	1984	1986	1988
Distillate and Heavier Liquids	127	145	143
By-Product Gas and LPG	507	538	535
Purchased Gas	197	209	204
Coke (Incl. Catalytic)	166	169	171
Total	**997**	**1,061**	**1,054**
Percentage of Crude Oil Throughput	8.6	8.6	8.5

CRUDE OIL SUBSTITUTABILITY

Refiners participating in the survey were requested to report capability to substitute lower quality crude oils of more than 0.5 wt.% sulfur content in place of sweet crude oils (less than 0.5 wt.% sulfur) in facilities to be operable in 1988 while maintaining current product quality. Maximum substitution of each of four classifications of lower quality crude oils was to be reported. Survey results are summarized in Table 20.

Among the 168 U.S. refineries reporting their projected crude oil slates for 1988, only 40 respondents provided information pertaining to crude oil substitutability. The refineries answering this question had an associated crude oil capacity of 5,323 MB/CD projected for 1988; this represents 37 percent of total operable capacity foreseen for 1988. It cannot be ascertained from the survey results the extent to which any other refiners actually possessed substitution capability but did not provide such information to the NPC.

For those combined refineries reporting substitution capability, the additional quantities of lower quality crude oil that could replace sweet crude oil ranged from 1,128 MB/CD for medium sulfur–light to 795 MB/CD for the high sulfur–heavy classification. If maximum substitution were practiced, the amounts of displaced sweet crude oils would range from 1,130 MB/CD for substitution by medium sulfur–light to 852 MB/CD by the high sulfur–heavy grade. These volumes of substitutable sweet crude oil represent 21.2 percent and 17.0 percent, respectively, of total crude oil throughput projected for 1988 for refineries providing survey data for this question.

Deep conversion refineries in PADDs II and III accounted for nearly half of the reported substitution capability. Other conversion refineries in all PADDs accounted for most of the remaining reported capacity for substituting higher sulfur crude oils. Only three nonconversion refineries acknowledged any capability to alter crude oil slates to handle additional higher sulfur crude oil.

Only 28 refineries responded to the question regarding the loss or gain of motor gasoline, diesel fuel, distillate No. 2, heavy fuel oil, and coke based on assuming the substitution of crude oil over 0.5 wt.% sulfur in place of sweet crude oil. While this limited response may not typify the entire U.S. refining industry, the data in Table 21 for those that did respond show that there was: a greater loss of gasoline, diesel fuel, and distillate No. 2 and a gain in heavy fuel oil and coke in the heavy grades of medium sulfur and high sulfur crude oil. For example, the loss of gasoline was 62.8 MB/CD for medium sulfur–heavy crude oil and 76.2 MB/CD for high sulfur–heavy crude oil, while the loss in gasoline for medium sulfur–light was 28.2 MB/CD, and 33.0 MB/CD for high sulfur–light.

As many as 104 survey participants identified constraints on substitution of higher sulfur crude oil. The data compiled in Table 22 seem to suggest that these constraints might have a larger impact in 1986 than in 1988. For example, the number of refineries reporting sulfur content of products to be a constraint declines from 104 in 1986 to 89 in 1988. Similarly, refineries reporting plant fuel sulfur content as a constraint are reduced from 57 to 45 between the two years. Reported air emission concerns were evidenced for 1986 by 61 refineries but dropped in 1988 to

TABLE 20

NPC SURVEY DATA FOR CRUDE OIL SUBSTITUTION CAPABILITY — PROJECTED 1988*

	PADD I		PADD II			PADD III			PADD IV	PADD V			U.S. Total
	I–S	I–C	II–S	II–LC	II–DC	III–S	III–LC	III–DC		V–S	V–COC	V–CC	
Medium Sulfur Crude Oil													
Med. Sulfur–Lt. Crude Substituted	0	†	0	†	205	†	144	327	19	†	†	†	1,128
Sweet Crude Replaced	0	†	0	†	205	†	144	327	19	†	†	†	1,130
Sulfur in Substituted Crude (Wt.%)	0	†	0	†	0.89	†	0.72	0.71	19	†	†	†	0.80
No. of Refineries	0	2	0	2	11	2	5	9	4	1	2	2	40
Associated Crude Oil Charge	0	†	0	†	1,224	†	862	1,545	152	†	†	†	5,323
Med. Sulfur–Hvy. Crude Substituted	0	†	0	†	72	†	148	271	†	0	40	†	825
Sweet Crude Replaced	0	†	0	†	72	†	161	293	†	0	41	†	867
Sulfur in Substituted Crude (Wt.%)	0	†	0	†	0.97	†	0.82	0.99	†	0	1.01	†	0.95
No. of Refineries	0	2	0	2	7	2	6	9	2	0	4	2	36
Associated Crude Oil Charge	0	†	0	†	1,021	†	981	1,545	†	0	264	†	5,280
High Sulfur Crude Oil													
High Sulfur–Lt. Crude Substituted	0	197	0	†	87	†	127	276	18	0	†	†	880
Sweet Crude Replaced	0	191	0	†	87	†	132	283	18	0	†	†	891
Sulfur in Substituted Crude (Wt.%)	0	1.55	0	†	1.71	†	1.65	2.17	1.47	0	†	†	1.92
No. of Refineries	0	3	0	2	5	2	5	9	4	0	2	2	34
Associated Crude Oil Charge	0	484	0	†	531	†	862	1,496	182	0	†	†	4,762
High Sulfur–Hvy. Crude Substituted	0	213	0	†	80	†	107	242	11	†	†	†	795
Sweet Crude Replaced	0	207	0	†	82	†	124	257	11	†	†	†	852
Sulfur in Substituted Crude (Wt.%)	0	1.90	0	†	2.32	†	2.09	2.91	2.51	†	†	†	2.40
No. of Refineries	0	5	0	2	5	2	5	8	4	1	2	2	36
Associated Crude Oil Charge	0	709	0	†	587	†	862	1,496	161	†	†	†	5,011

*All figures in MB/CD unless otherwise indicated.
†Data withheld due to confidentiality requirements. Data included in total.

TABLE 21

NPC SURVEY DATA FOR PRODUCT CHANGE DUE TO SUBSTITUTION FOR SWEET CRUDE OIL — PROJECTED 1988*

	PADD I		PADD II			PADD III			PADD IV	PADD V			Total U.S.
	I–S	I–C	II–S	II–LC	II–DC	III–S	III–LC	III–DC		V–S	V–COC	V–CC	
Medium Sulfur Crude Oil													
Medium Sulfur–Light													
Total Gasoline	0	‡	0	‡	(6.6)	0	‡	(5.7)	(1.6)	‡	‡	‡	(28.2)
Diesel Fuel	0	‡	0	‡	(6.2)	0	‡	‡	0	‡	‡	‡	0.6
Distillate No. 2	0	‡	0	‡	2.3	0	0	1.2	‡	0	0	0	(18.0)
Heavy Fuel Oil	0	‡	0	‡	7.5	0	‡	‡	0.7	‡	‡	0	38.6
Coke (ST/CD)	0	‡	0	0	819	0	0	610	0	0	0	0	1,429
No. of Refineries†	0	2	0	2	7	0	2	4	3	1	2	1	22
Associated Charge†	0	‡	0	0	1,048	0	‡	869	127	‡	‡	‡	3,149
Medium Sulfur–Heavy													
Total Gasoline	0	‡	0	‡	(1.8)	‡	‡	(23.2)	‡	0	(7.7)	‡	(62.8)
Diesel Fuel	0	0	0	‡	(6.4)	‡	‡	‡	0	0	‡	0	(17.1)
Distillate No. 2	0	‡	0	‡	2.2	‡	0	(3.0)	‡	0	0	0	(25.3)
Heavy Fuel Oil	0	‡	0	‡	5.1	‡	4.8	2.7	‡	0	8.2	‡	(62.8)
Coke (ST/CD)	0	0	0	0	650	0	0	904	0	0	0	0	1,554
No. of Refineries†	0	2	0	2	7	1	3	6	2	0	4	2	28
Associated Charge†	0	‡	0	‡	1,021	‡	425	1,055	‡	0	265	‡	3,946
High Sulfur Crude Oil													
High Sulfur–Light													
Total Gasoline	0	‡	0	‡	(1.8)	0	‡	(12.4)	(0.4)	0	‡	‡	(33.0)
Diesel Fuel	0	‡	0	‡	‡	0	‡	‡	‡	0	‡	‡	(8.8)
Distillate No. 2	0	‡	0	‡	‡	0	0	(6.8)	0	0	0	0	(27.3)
Heavy Fuel Oil	0	‡	0	‡	6.7	0	(0.7)	0.6	1.1	0	‡	‡	48.3
Coke (ST/CD)	0	‡	0	0	‡	0	0	720	0	0	0	0	1,339
No. of Refineries†	0	2	0	2	5	0	3	6	3	0	2	2	24
Associated Charge†	0	‡	0	‡	532	0	425	1,055	141	0	‡	‡	3,255
High Sulfur–Heavy													
Total Gasoline	0	(12.5)	0	‡	(6.8)	‡	‡	(14.6)	(1.1)	‡	‡	‡	(76.2)
Diesel Fuel	0	‡	0	‡	‡	‡	‡	‡	‡	‡	‡	‡	(25.8)
Distillate No. 2	0	(32.9)	0	‡	(0 .8)	‡	0	(5.7)	‡	0	0	0	(47.3)
Heavy Fuel Oil	0	49.1	0	‡	6.0	‡	2.0	2.1	1.7	‡	‡	‡	89.8
Coke (ST/CD)	0	‡	0	0	‡	0	0	1,058	0	0	0	0	2,158
No. of Refineries†	0	4	0	2	4	1	3	5	3	1	2	2	26
Associated Charge†	0	609	0	‡	408	‡	425	1,006	141	‡	‡	‡	3,497

*Gain/loss in products due to substitution of medium-sulfur crude oil. All figures in MB/CD unless otherwise indicated.
†These are the maximum numbers that responded to the survey. However, the number of respondents to each item varies for each product.
‡Data withheld due to confidentiality requirements. Data included in total.

TABLE 22

NPC SURVEY DATA FOR CONSTRAINTS LIMITING CRUDE OIL SUBSTITUTION — PROJECTED 1986 AND 1988*

Constraints on Substitutability	PADD I		PADD II			PADD III			PADD IV	PADD V			U.S. Total
	I–S	I–C	II–S	II–LC	II–DC	III–S	III–LC	III–DC		V–S	V–COC	V–CC	
Sulfur Content of Products													
1986													
No. of Refineries	4	6	1	8	20	12	9	21	8	6	1	8	104
Associated Crude Charge	24	526	†	400	2,118	275	786	3,746	238	164	†	728	9,083
1988													
No. of Refineries	3	5	1	7	18	10	6	15	8	6	1	9	89
Associated Crude Charge	24	436	†	338	2,011	233	652	2,463	223	164	†	867	7,489
Sulfur Content of Refinery Fuels													
1986													
No. of Refineries	3	4	1	3	7	5	6	15	5	3	1	4	57
Associated Crude Charge	24	324	†	98	576	120	528	2,596	130	67	†	237	4,753
1988													
No. of Refineries	3	3	1	3	5	5	3	9	4	3	1	5	45
Associated Crude Charge	24	234	†	98	469	120	394	1,310	77	67	†	237	3,083
Air Emissions													
1986													
No. of Refineries	2	6	0	3	6	5	9	17	4	2	1	7	61
Associated Crude Charge	†	530	0	115	482	120	768	2,740	98	†	†	904	5,872
1988													
No. of Refineries	2	5	0	3	5	5	6	12	5	2	1	9	55
Associated Crude Charge	†	440	0	115	422	120	710	1,732	137	†	†	1,060	4,850
Effluent Water Quality													
1986													
No. of Refineries	2	1	0	0	0	4	2	4	0	0	0	4	17
Associated Crude Charge	†	†	0	0	0	74	†	396	0	0	0	701	1,567
1988													
No. of Refineries	2	1	0	0	0	4	2	4	0	0	0	5	18
Associated Crude Charge	†	†	0	0	0	74	†	399	0	0	0	133	1,601
Others (e.g., Metallurgy)													
1986													
No. of Refineries	3	0	1	6	8	9	7	14	5	1	1	2	57
Associated Crude Charge	27	0	†	284	1,040	223	660	2,129	134	†	†	†	4,884
1988													
No. of Refineries	3	1	1	5	8	9	8	14	5	1	2	2	59
Associated Crude Charge	27	†	†	222	1,135	223	736	2,134	133	†	†	†	5,229

*Associated crude oil charge capacity in MB/CD.
†Data withheld due to confidentiality requirements. Data included in total.

55. Since the survey did not show 1988 crude oil slates to be lower in sulfur content and since hydrotreating was not practiced more extensively in 1988, the rationale for the lessened reports of environmental constraint is not obvious. It may simply reflect a smaller response population for the later year, or completion of new emissions control facilities.

GASOLINE MANUFACTURING CAPABILITIES

Although the capability of the U.S. refining industry to produce unleaded gasoline has been steadily increasing, it would be significantly influenced by the following current or prospective changes in product specifications:

- Lead antiknock additives
- Oxygenate additives
- Reid Vapor Pressure
- Increase in octane number.

To assess the effect of these changes, the 1985 NPC Survey of U.S. Petroleum Refineries asked the refineries to report their maximum capability to produce unleaded gasoline based on specific scenarios, while limiting crude oil throughputs and leaded gasoline production to survey projected levels. Table 23 summarizes the survey responses as well as respondents' projected capability based on the above four changes in product specifications.

Lead Phasedown

In 1984 the average lead content of leaded gasoline in the United States was almost 1.1 gplg, the legal limit. In the last quarter the average dropped slightly because California imposed its own 0.8 gplg average lead use limitation.

TABLE 23

NPC SURVEY DATA FOR UNLEADED AND TOTAL GASOLINE MAXIMUM PRODUCIBILITY PROJECTION* (MB/CD)

	1985	1986	1987	1988
Under lead standard of 1.1 gplg (in effect at time of survey)				
Total Unleaded	4,911	5,237	5,362	5,402
Total Gasoline	6,400	6,521	6,581	6,533
Under phasedown of lead standard of 1.1 gplg in 1985 to 0.1 gplg in 1986, 1987, and 1988				
Total Unleaded	4,917	5,351	5,506	5,620
Total Gasoline	6,392	6,415	6,466	6,432
Under phasedown of lead standard of 1.1 gplg in 1985 to 0.1 gplg in 1986, 1987, and 1988 — without oxygenates				
Total Unleaded	4,868	5,274	5,420	5,509
Total Gasoline	6,338	6,334	6,389	6,332
Under phasedown of lead standard of 1.1 gplg in 1985 to 0.1 gplg in 1986, 1987, and 1988 — with reduction in RVP of 1 psi				
Total Unleaded	4,685	5,150	5,198	5,347
Total Gasoline	6,108	6,098	6,134	6,131
Under phasedown of lead standard of 1.1 gplg in 1985 to 0.1 gplg in 1986, 1987, and 1988 — with 1 (R + M)/2 increases for unleaded gasoline				
Total Unleaded	—	—	—	5,164
Total Gasoline	—	—	—	5,920

*The figures for gasoline, in addition to limitations stated for each product specification change, are based on maximum production of unleaded gasoline and limiting crude oil throughput and leaded gasoline to levels projected from the survey data.

At the time the forms and instructions for the NPC Survey of U.S. Petroleum Refineries were being prepared (late 1984–early 1985), the EPA had announced its intention to reduce the lead content of gasoline, but had not announced its final regulation. The proposed regulation the EPA issued for comments was a single-step reduction of the lead in leaded gasoline from 1.1 gplg to 0.1 gplg, starting January 1, 1986. The octane increase provided by 1.1 gplg is about five octane numbers. Only about one octane number is provided by 0.1 gplg.

The final EPA regulation, announced in March 1985, was for a two-step reduction in lead: from 1.1 gplg maximum to 0.5 gplg maximum starting July 1, 1985, and from 0.5 gplg maximum to 0.10 gplg maximum starting January 1, 1986. The EPA also provided for "banking" any lead allowed but not used in 1985 for use in 1986 and 1987. Hence, the average lead content of leaded gasoline was about 0.4 gplg in 1985 and is expected to be, through the use of banked lead rights, about 0.3 gplg of gasoline in 1986 and 1987.

The survey respondents reported that if they had been permitted to maximize the production of unleaded gasoline at the lead level of 1.1 gplg, and limit crude oil throughput and leaded gasoline production to levels projected from the survey data, they would be able to achieve the percentage grade split and total unleaded and total gasoline production in MB/CD shown in Table 24 for 1985, 1986, 1987, and 1988. The total production of all grades of gasoline would increase from 6,400 MB/CD in 1985 to 6,533 MB/CD in 1988. Of these two totals, unleaded gasoline was 77 percent and 83 percent, respectively. Table 24 also shows utilization of oxygenates and their percentage of total gasoline.

Based on the data in Tables 24 and 25:

- The capability of these refineries to produce unleaded gasoline would have

TABLE 24

NPC SURVEY DATA FOR MAXIMUM PRODUCIBILITY PROJECTION OF MOTOR GASOLINE WITHOUT LEAD PHASEDOWN*
(1.1 gplg)

	1985	1986	1987	1988
Gasoline Grades				
Regular Unleaded (%)	58	61	62	63
Other Unleaded (%)	19	19	19	20
Total % Unleaded	77	80	81	83
Leaded Gasoline (%)	23	20	19	17
Total % All Grades	100	100	100	100
Total Unleaded (MB/CD)	4,911	5,237	5,362	5,402
Total Gasoline (MB/CD)	**6,400**	**6,521**	**6,581**	**6,533**
Oxygenates (MB/CD)				
Ethanol	6	7	15	16
MTBE	23	24	25	25
Methanol	2	4	4	5
Tertiary Butyl Alcohol	6	6	6	6
Total Oxygenates	**37**	**41**	**50**	**52**
Total Oxygenates as Percentage of Total Gasoline	**0.58**	**0.62**	**0.76**	**0.79**

*The figures for gasoline, in addition to limitations stated for each product specification change, are based on maximum production of unleaded gasoline and limiting crude oil throughput and leaded gasoline to levels projected from the survey data.

TABLE 25

NPC SURVEY DATA FOR ACTUAL 1984 AND PROJECTED 1988 PRODUCTION OF GASOLINE

	Percentage of Total Motor Gasoline*		
	Actual 1984	Projected 1986	Projected 1988
Gasoline Grades			
Regular Unleaded	45	57	62
Other Unleaded	16	19	22
Total % Unleaded	61	76	84
Leaded Gasoline	39	24	16
Total % All Grades	100	100	100
Total Unleaded (MB/CD)	3,852	4,848	5,384
Total Motor Gasoline (MB/CD)	**6,310**	**6,408**	**6,435**
Aviation Gasoline (MB/CD)	28	32	32
Total All Grades Gasoline (MB/CD)	**6,337†**	**6,440**	**6,466**

*Percentages do not include aviation gasoline data.
†Columns do not add due to rounding.

increased 500 MB/CD in the 1984–1988 period if the lead standard had remained at 1.1 gplg. The proportion of unleaded gasoline in the total gasoline pool would be 83 percent. At the same time, the producibility of total gasoline increased 133 MB/CD.

- There is a significant growth in the projected use of oxygenates over this period; however, oxygenates used would remain less than 0.8 percent of total gasoline produced by refineries and only provide 52 MB/CD of the refineries' production of gasoline. Oxygenates blended into gasoline outside the refinery were not included in the NPC survey.
- Most of the growth reported by refiners for use of oxygenates between 1984 and 1988 is in the use of alcohols, primarily ethanol, which increased from 6 to 16 MB/CD as compared to methyl tertiary butyl ether (MTBE), which increased from 23 to 25 MB/CD. However, MTBE is over 62 percent of total oxgenates in 1985 and 48 percent of projected oxygenate use in 1988.
- Table 25 is a summary of the data from earlier sections of this report, in which the respondents to the NPC survey reported their actual production of unleaded and leaded gasoline in 1984, and what they plan to produce in 1986 and 1988. The total motor gasoline production was 6,310 MB/CD in 1984 and is projected to be 6,435 MB/CD in 1988. Of these two totals, unleaded gasoline was 61 percent and 84 percent, respectively. By comparison with the data in Table 23, it may be seen that refineries could easily have met their forecast gasoline production (all grades) if the 1.1 gplg of lead standard had remained in effect.

The survey respondents reported that if they were to maximize the production of unleaded gasoline with 1.1 gplg in 1985 and the proposed 0.1 gplg standard in 1986, 1987, and 1988, and limit crude oil throughput and leaded gasoline production to levels projected from the survey data, the total manufacturing capability for each year after 1984 would be reduced by more than 100 MB/CD. However, the producibility of unleaded grades would be maintained, provided no new limitations on the use of oxygenates or RVP were imposed (see Tables 24 and 26).

TABLE 26

NPC SURVEY DATA FOR MAXIMUM PRODUCIBILITY PROJECTION OF MOTOR GASOLINE WITH LEAD PHASEDOWN (1.0 gplg in 1985, and 0.1 gplg in 1986, 1987, and 1988)

	1985	1986	1987	1988
Gasoline Grades				
Regular Unleaded (%)	59	65	66	67
Other Unleaded (%)	18	18	19	20
Total % Unleaded	77	83	85	87
Leaded Gasoline (%)	23	17	15	13
Total % All Grades	100	100	100	100
Total Unleaded (MB/CD)	4,917	5,351	5,506	5,620
Total Gasoline (MB/CD)	**6,392**	**6,415**	**6,466**	**6,432**
Oxygenates (MB/CD)				
Ethanol	6	22	27	29
MTBE	26	39	41	42
Methanol	2	2	2	3
Tertiary Butyl Alcohol	6	5	5	5
Total Oxygenates	**40**	**68**	**75**	**79**
Oxygenates as Percentage of Gasoline	**0.63**	**1.06**	**1.16**	**1.23**

*The figures for gasoline, in addition to limitations stated for each product specification change, are based on maximum production of unleaded gasoline and limiting crude oil throughput and leaded gasoline to levels projected from the survey data.

Based on the data in Table 26:

- By comparison with the response for the 1.1 gplg lead standard, the reduction of the lead standard to 0.1 gplg reduced gasoline producibility over 100 MB/CD each year between 1986 and 1988. This is based on maximum production of unleaded gasoline, not to exceed the projected levels for crude oil throughput rates and production of leaded gasoline.
- Respondents reported a significant increase in the use of oxygenates in this reduced lead scenario. Oxygenates in 1988 would be 1.23 percent of total gasoline produced by refineries, or a total of 79 MB/CD. The growth of the use of oxygenates would be mostly in ethanol and MTBE.
- The proportion of unleaded gasoline in the total gasoline pool in 1988 could be as much as 87 percent.

The survey respondents reported the following: if, in 1988, they had to increase the octane number of all unleaded gasoline one road octane number while still maximizing the production of unleaded gasoline under a 0.1 gplg standard and limiting crude oil throughput and leaded gasoline to levels projected from survey data, the results would be as summarized in Table 27.

- Respondents would reduce unleaded gasoline producibility 456 MB/CD to 5,164 MB/CD, and total gasoline producibility by 512 MB/CD, or 8 percent, to 5,920 MB/CD.
- The refiners project that 78 percent of the reduced gasoline producibility would come out of the "other" unleaded gasoline grade (primarily premium unleaded). Thus the refiners cannot produce the same mix of regular and premium unleaded gasoline if all unleaded gasolines are increased by one octane number.

- The refiners project that they would increase the use of oxygenates from 1.23 to 1.67 percent of the gasoline pool, or an additional 20 MB/CD of oxygenates, to bring the total oxygenate use to about 99 MB/CD.

Oxygenate Limitations

The respondents to the NPC survey reported that if they maximize the capacity for blending unleaded gasoline without the use of oxygenates, while maintaining crude oil charge rates not to exceed those currently projected and not increasing the production of leaded gasoline with a lead standard of 1.1 gplg in 1985 and 0.1 gplg in 1986, 1987, and 1988, they would be able to achieve the following grade split (data from Table 28):

	MB/CD			
	1985	**1986**	**1987**	**1988**
Unleaded Gasoline	4,868	5,274	5,420	5,509
Leaded Gasoline	1,470	1,060	969	823
Total Gasoline	**6,338**	**6,334**	**6,389**	**6,332**

Based on the producibility of gasoline shown in Tables 26 and 28, the elimination of oxygenates could result in the following reduction of all grades of this product:

Reduction	**1985**	**1986**	**1987**	**1988**
MB/CD	54	81	77	100
Percent	0.9	1.3	1.2	1.6

TABLE 27

NPC SURVEY DATA FOR 1988 MAXIMUM PRODUCIBILITY PROJECTION OF MOTOR GASOLINE WITH LEAD PHASEDOWN*
[Unleaded Gasoline Octane Number Increase of 1.0 (R+M)/2]†

	Before Increase‡	**After Increase**	**Gain/(Loss)**
Gasoline Grades			
Regular Unleaded (%)	67	72	5
Other Unleaded (%)	20	15	(5)
Total % Unleaded	87	87	0
Leaded Gasoline (%)	13	13	0
Total % All Grades	100	100	0
Total Unleaded (MB/CD)	5,620	5,164	(456)
Total Gasoline (MB/CD)	**6,432**	**5,920**	**(512)**
Oxygenates (MB/CD)			
Ethanol	29	33	4
MTBE	42	58	16
Methanol	3	3	0
Tertiary Butyl Alcohol	5	5	0
Total Oxygenates	**79**	**99**	**20**
Oxygenates as Percentage of Gasoline	**1.23**	**1.67**	**0.44**

*The figures for gasoline, in addition to limitations stated for each product specification change, are based on maximum production of unleaded gasoline and limiting crude oil throughput and leaded gasoline to levels projected from the survey data.
†Octane number after increase of 1.0 (R+M)/2 is 88.06 for Regular Unleaded, 92.84 for Other Unleaded, 88.66 for Leaded Gasoline, and 88.66 for Total All Grades.
‡From Table 26 — producibility before increase of 1.0 (R+M)/2.
§Calculated from unleaded and leaded gasoline data.

TABLE 28

NPC SURVEY DATA FOR MAXIMUM PRODUCIBILITY PROJECTION OF MOTOR GASOLINE WITH LEAD PHASEDOWN AND ELIMINATION OF OXYGENATES* (0.1 gplg)

	1985	1986	1987	1988
Gasoline Grades				
Regular Unleaded (%)	59	65	66	68
Other Unleaded (%)	18	18	18	19
Total % Unleaded	77	83	85	87
Leaded Gasoline (%)	23	17	15	13
Total % All Grades	100	100	100	100
Total Unleaded (MB/CD)	4,868	5,274	5,420	5,509
Total Gasoline (MB/CD)	**6,338**	**6,334**	**6,389**	**6,332**

*The figures for gasoline, in addition to limitations stated for each product specification change, are based on maximum production of unleaded gasoline and limiting crude oil throughput and leaded gasoline to levels projected from the survey data.

The ratio between the above reduced producibility of gasoline and the oxygenates that were eliminated (Table 26) reveals that some lower octane number blending components could no longer be used or higher severity processing could occur, resulting in less gasoline production if oxygenates were eliminated.

	MB/CD			
	1985	1986	1987	1988
Gasoline Reduction	54	81	77	100
Oxygenate Eliminated	40	68	75	79
Ratio	1.4:1	1.2:1	1.0:1	1.3:1

Reid Vapor Pressure Reduction

The survey respondents reported that if they were required to reduce RVP specification by 1 psi below current ASTM (American Society for Testing and Materials) standards but not below 9 psi under the 1.1 gplg lead standard for 1985 and the 0.1 gplg standard for 1986, 1987, and 1988, and limit crude oil throughputs and leaded gasoline production to current projected levels while maximizing unleaded gasoline manufacture, the percentage gasoline grade split and total unleaded and leaded gasoline production would be as shown in Table 29. The data in this table indicate that the survey respondents believe that the reduction of gasoline RVP in the 1985–1988 time period would result in:

- Reduced unleaded gasoline production of 162 MB/CD, or 2.9 percent, in 1988; reduced total gasoline producibility for the same year by 3.4 percent, or 218 MB/CD
- Increased volume of excess butane (i.e., butane not needed in the refineries, but without a current market) by 63 MB/CD in 1985 and 75 MB/CD in 1988
- Reduced purchase of butanes by the refineries of 72 MB/CD in 1985 and 79 MB/CD in 1988
- Reduced butane blended into gasoline (i.e., excess butanes plus reduced purchases) of about 150 MB/CD
- Reduced volume of some other lower octane number gasoline blending components blended into gasoline or higher severity processing.

The total impact on the butane market could be 150 MB/CD. The EIA's *Petroleum Supply Annual* for 1985 shows that of the total butane product supplied that year, 300 MB/CD was used in the refining industry, 141 MB/CD went to the petrochemical industry (including a small volume to miscellaneous uses), and 11 MB/CD was exported. The natural gas liquids industry provided 298 MB/CD of this butane, refineries 81 MB/CD, importers 71 MB/CD, and the balance

TABLE 29

NPC SURVEY DATA FOR MAXIMUM PRODUCIBILITY PROJECTION OF MOTOR GASOLINE (Reducing RVP 1.0 psi and utilizing 0.1 gplg)

	1985	1986	1987	1988
RVP Before Reduction (psi)	11.65	11.65	11.64	11.65
RVP After Reduction (psi)	10.67	10.67	10.67	10.67
Total Unleaded Gasoline (MB/CD)				
Before RVP Reduction	4,886	5,253	5,372	5,509
After RVP Reduction	4,685	5,150	5,198	5,347
Production Loss	201	103	174	162
Percent Production Loss	4.1	2.0	3.2	2.9
Total Gasoline (MB/CD)				
Before RVP Reduction	6,372	6,332	6,384	6,349
After RVP Reduction	6,108	6,098	6,134	6,131
Production Loss	264	234	250	218
Percent Production Loss	4.1	4.0	4.0	3.4
Butane Reduction (MB/CD)				
Excess Butane Reduction	63	71	74	75
Purchase Reduction	72	79	79	79
	135	150	153	154
Other Gasoline Components				
Reduction (MB/CD)	129	134	97	64
Total Reduction in Gasoline Production	**264**	**284**	**250**	**218**

*Calculated differences between total gasoline production and butane reduction are subject to error to the extent that they result from one refinery, having associated capacity of 137 MB/CD, not providing data for gasoline and butane volumes at the reduced RVP specification.

was withdrawn from storage. Hence, the impact of reducing gasoline RVP 1 psi would be to reduce refinery butane purchases to 215 MB/CD and increase refinery butane sales to 142 MB/CD.

The responses do not differ significantly from year to year except for one item: the volume of gasoline production was reduced by an amount greater than that of the reduced butane blended into gasoline. In 1985, a 1 psi reduction of RVP reduces gasoline producibility 264 MB/CD, 135 MB/CD of butanes, and 129 MB/CD of other gasoline components. In 1986, 1987, and 1988, the butane reduction is about 150 MB/CD in each year and the reduction of other gasoline components is 134 MB/CD, 97 MB/CD, and 64 MB/CD, respectively. Butane has a higher octane than average gasoline, so the reduction of butane in gasoline means that some low octane component may have to be rejected from gasoline to maintain gasoline octane balance.

RVP reduction did not have a significant impact on the respondents' planned use of oxygenates in gasoline.

BENZENE IN GASOLINE

Some benzene is present in the components that are blended by a refinery to make gasoline. The sources of this benzene are crude oil itself, which typically contains a few tenths of a percent

benzene, and some of the refining processes that make gasoline components. Since concentration of this hydrocarbon in gasoline has been of concern, the survey requested data on typical benzene content of motor gasoline. Table 30 is a summary of the response from 103 refineries having a combined crude oil charge capacity of 11,184 MB/CD. For those respondents, there was only a minimal change between the 1984 and 1988 benzene content for both unleaded and leaded gasoline. The total for unleaded gasoline was 1.70 volume percent in 1984 and 1.78 in 1988; and for leaded gasoline the total was 1.78 volume percent in 1984 and 1.79 in 1988.

SULFUR CONTENT LIMITATIONS ON DISTILLATES

The sulfur specification for distillate No. 2 fuel oil and diesel fuel in most of the United States is 0.5 wt.% maximum. In some areas, the specification is lower, 0.2 or 0.3 wt.% maximum being a typical specification in local parts of PADD I. In the L.A. Basin, large refiners were required to produce 0.05 wt.% maximum sulfur diesel for on-highway sale starting in January 1985.

Distillate and diesel fuel No. 2 are generally fungible products. That is, refineries produce a single No. 2 oil product that meets both the distillate No. 2 fuel oil specification and the diesel No. 2 oil specification. This allows tankage and transportation savings that are economically much more significant than the small differences in specifications between the two products.

The average sulfur content of distillate No. 2 and of diesel fuel produced in the United States in 1984, projected for 1988 by the respondents to the NPC survey, are shown in Table 31.

The maximum production reported by the respondents for 0.05 wt.% sulfur transportation diesel fuel for the L.A. Basin was 207 MB/CD. In addition, the maximum production for 0.20 wt.% sulfur for other areas in the United States was 1,864 MB/CD. This would be a total of 2,071 MB/CD of low sulfur distillates. Of the 207 MB/CD of 0.05 wt.% sulfur diesel fuel, 97 MB/CD

TABLE 30

NPC SURVEY DATA FOR ACTUAL 1984 AND PROJECTED 1988 VOLUME PERCENT OF BENZENE IN MOTOR GASOLINE

	Unleaded Gasoline				
	Regular and Other	Premium	Total Unleaded Gasoline	Total Leaded Gasoline	Total All Gasoline
1984					
Benzene (Volume Percent)	1.75	1.54	1.70	1.78	1.73
Associated Volume Gasoline (MB/CD)	2,117	634	2,751	1,481	4,232
Total Benzene (MB/CD)	37.1	10.5	47.6	26.1	73.7
No. of Refineries	103	71	—	72	—
Associated Crude Oil Charge Capacity (MB/CD)	11,184	9,483	—	8,349	—
1988					
Benzene (Volume Percent)	1.82	1.77	1.78	1.79	1.81
Associated Volume Gasoline (MB/CD)	3,101	896	3,996	682	4,678
Total Benzene (MB/CD)	56.4	15.8	72.2	13	85.2
No. of Refineries	103	71	—	72	—
Associated Crude Oil Charge Capacity (MB/CD)	11,100	9,451	—	8,315	—

TABLE 31

NPC SURVEY DATA FOR ACTUAL 1984 AND PROJECTED 1988 PRODUCTION AND SULFUR CONTENT OF DISTILLATES

Product	1984 Actual MB/CD	1984 Actual Percent Sulfur	1988 Projected MB/CD	1988 Projected Percent Sulfur
Diesel Fuel				
Very Low Sulfur	242	0.17	311	0.18
Other Sulfur	786	0.34	821	0.35
Distillate No. 2	1,474	0.27	1,525	0.29
Total	**2,502**	**0.28**	**2,657**	**0.30**

could be produced by conversion refineries in California. This product is currently only required within the L.A. Basin and only for certain classes of trade, i.e., required for highway vehicles and not required for railroad engines.

The total volume of very low sulfur distillates that can be produced, 2,071 MB/CD, is only 586 MB/CD less than the total projected production (2,657 MB/CD) of distillates (diesel plus distillate No. 2 oil) for 1988.

The added new facilities that would be required by the respondents to reduce the sulfur content of distillates to 0.2 wt.% maximum nationwide and 0.05 wt.% maximum for the L.A. Basin are:

- 530 MB/CD of hydrotreating and hydrorefining
- 202 million standard cubic feet per calendar day (SCF/CD) of hydrogen manufacturing capacity
- 2,349 long tons per calendar day (LT/CD) of sulfur recovery facilities
- 1,274 thousand barrels of tankage.

These facilities would be a substantial increase of the nation's refinery processing capacity for the necessary facilities; for example, a 33 percent increase in distillate hydrotreating capacity.

OPERATIONAL EXPENSES

The survey participants were asked to provide itemized financial data for calendar-year 1984, including: operating costs; crude oil costs; crude oil transportation costs for movements within the United States; and refinery asset values. The refinery assets included gross fixed costs (undepreciated) and replacement costs (1984 year-end).

Table 32 presents the survey results for operating costs for all 12 region/complexity groups and for the total United States. Total operational expenses reported ranged from $1.69/bbl for refineries without conversion in PADD II to $6.92/bbl in PADD V for conversion refineries inside California. The average operational costs for all refineries responding to the survey was $4.60/bbl. The number of respondents for the 9 operational expense categories ranged from 129 for antiknock compounds to 166 for payrolls.

Refinery fuels and utilities expenses were the highest single operating cost and exhibited wide range or variation depending upon refinery location, complexity, and size range. Table 33 shows these costs for the 12 region/complexity groups. PADD II refineries without conversion capabilities reported fuel and utility costs of only $0.40/bbl while PADD V conversion plants inside California experienced a cost of $3.75/bbl. For the latter group, some $2.56/bbl of crude oil was for fuel and utilities produced internally, while the remaining $1.19/bbl was purchased energy. Also presented in Table 33 are data on fuels and utility consumption on a million British thermal units (MMBTUs) per barrel of crude oil basis and the computed unit cost in $/MMBTUs. The costs

TABLE 32

NPC SURVEY DATA FOR 1984 OPERATING COSTS BY REGION/COMPLEXITY GROUPS*
($/Bbl of Crude Oil Throughput)

	PADD I		PADD II			PADD III			PADD IV	PADD V			U.S. Total
	I–S	I–C	II–S	II–LC	II–DC	III–S	III–LC	III–DC		V–S	V–COC	V–CC	
Operating Costs													
Direct Payroll & Payroll Related	1.36	0.86	0.38	0.76	0.64	0.49	0.81	0.63	0.64	0.36	0.49	0.87	0.70
Contract Maintenance Labor	0.08	0.32	§	0.09	0.14	0.08	0.20	0.13	0.11	0.04	§	0.26	0.17
Refinery Produced Fuels & Utilities	0.88	1.99	0.40	1.73	1.26	0.41	1.20	1.30	1.51	0.39	1.58	2.56	1.50
Refinery Purchased Fuels & Utilities	1.10	0.55	‡	0.64	0.72	0.56	0.89	0.89	0.42	0.56	‡	1.19	0.81
Catalyst & Chemicals	0.11	0.25	§	0.22	0.20	0.06	0.17	0.25	0.22	0.03	§	0.36	0.23
Antiknock Compounds	0.03	0.04	§	0.05	0.05	0.04	0.12	0.05	0.05	0.01	§	0.03	0.05
Maintenance Materials	0.19	0.33	0.12	0.23	0.17	0.15	0.22	0.19	0.16	0.05	0.13	0.22	0.20
Depreciation	0.43	0.43	0.21	0.25	0.28	0.53	0.32	0.41	0.21	0.19	0.25	0.49	0.37
Other Operating Expenses	0.52	0.53	0.41	0.58	0.30	0.31	0.32	0.57	0.45	0.61	0.95	0.90	0.54
Total Operating Costs	**4.74**	**5.36**	**1.69**	**4.58**	**3.80**	**2.67**	**4.29**	**4.44**	**3.80**	**2.28**	**4.07**	**6.92**	**4.60**
Nelson Complexity Factors†	6.58	10.51	2.11	8.40	9.24	5.15	9.68	10.69	6.77	2.67	7.29	10.23	9.41
Associated Crude Oil Charge Capacity (MB/CD)	359	1,235	36	729	2,433	351	1,610	5,207	456	443	462	1,992	15,313
No. of Refineries	12	11	4	10	22	18	15	31	14	22	6	16	181
Crude Oil Charge Capacity/ Refinery (MB/CD)	30	112	9	73	111	20	107	168	33	20	77	125	85

*The line item data are for calendar year 1984 and for geographic region/complexity groups. Not all of the 181 respondents to the 1985 NPC survey responded for operating costs, and the number of respondents varied on each line item, from 129 on antiknock compounds to 166 for direct payroll and related payroll.

†The Nelson Complexity Factors were calculated from facilities data from the 181 refiners responding to the 1985 NPC survey.

‡Refinery produced and purchased fuels and utilities were combined under the Produced Fuels and Utilities heading.

§Data withheld due to confidentiality requirements. Data included in total.

TABLE 33

NPC SURVEY DATA FOR 1984 ENERGY FUEL CONSUMPTION COSTS BY REGION/COMPLEXITY GROUPS

	PADD I		PADD II			PADD III			PADD IV	PADD V			U.S. Total
	I–S	I–C	II–S	II–LC	II–DC	III–S	III–LC	III–DC		V–S	V–COC	V–CC	
$/Bbl Crude Oil Throughput													
Cost of Refinery Produced Fuels and Utilities	0.88	1.99	0.40	1.73	1.26	0.41	1.20	1.30	1.51	0.39	1.58	2.56	1.50
Cost of Refinery Purchased Fuels and Utilities	1.10	0.55	*	0.64	0.72	0.56	0.89	0.89	0.42	0.56	*	1.19	0.81
Total Cost of Fuels and Utilities	**1.98**	**2.54**	**0.40**	**2.37**	**1.98**	**0.97**	**2.09**	**2.19**	**1.93**	**0.95**	**1.58**	**3.75**	**2.31**
MMBTU/Bbl Crude Oil Throughput													
Refinery Produced Fuels and Utilities	0.22	0.54	0.08	0.45	0.33	0.13	0.32	0.37	0.43	0.09	0.37	0.55	0.39
Refinery Purchased Fuels and Utilities	0.28	0.13	0.06	0.16	0.19	0.20	0.25	0.25	0.12	0.11	0.07	0.21	0.20
Total Fuels and Utilities	**0.50**	**0.67**	**0.14**	**0.61**	**0.52**	**0.33**	**0.57**	**0.62**	**0.55**	**0.20**	**0.44**	**0.76**	**0.59**
$/MMBTU													
Refinery Produced Fuels and Utilities	4.00	3.68	*	3.84	3.82	3.15	3.75	3.51	3.51	4.33	*	4.65	3.67
Refinery Purchased Fuels and Utilities	3.93	4.23	*	4.00	3.79	2.80	3.56	3.56	3.50	5.09	*	5.67	4.01
Total Fuels and Utilities	**3.96**	**3.79**	**2.85**	**2.89**	**3.81**	**2.94**	**3.67**	**3.53**	**3.51**	**4.75**	**3.59**	**4.93**	**3.92**

*Refinery produced and purchased fuels and utilities were combined under the Refinery Produced Fuels and Utilities heading.

TABLE 34

NPC SURVEY DATA FOR 1984 REFINERY ASSETS

	PADD I		PADD II			PADD III			PADD IV	PADD V			U.S. Total
	I–S	I–C	II–S	II–LC	II–DC	III–S	III–LC	III–DC		V–S	V–COC	V–CC	
Gross Fixed Assets (MM$)	421	3,510	39	1,107	4,551	631	3,413	15,589	739	387	1,029	6,581	37,997
Capacity (MB/CD)	261	1,165	36	734	2,253	313	1,564	4,702	463	300	414	1,765	13,970
No. of Refineries	11	11	3	10	20	16	13	29	14	19	5	15	166
Gross Fixed Assets (Dollars Per Barrel)	1,613	3,013	1,083	1,508	2,020	2,016	2,182	3,315	1,704	1,290	2,486	3,729	2,720
Approximate Replacement Cost (MM$)	1,410	10,666	70	4,351	12,574	931	9,078	27,175	2,562	846	2,934	16,402	89,000
Capacity (MB/CD)	254	1,165	36	734	2,253	313	1,564	4,247	463	258	414	1,736	13,436
No. of Refineries	10	11	3	10	20	16	13	28	14	18	5	14	162
Replacement Cost (Dollars Per Barrel)	5,552	9,155	1,944	5,928	5,581	2,974	5,804	6,399	5,533	3,279	7,087	9,448	6,624
Percentage of Replacement Cost over Gross Fixed Assets	244	204	79	293	176	48	166	93	225	154	185	153	144

ranged from a high of $4.93/MMBTUs in PADD V California conversion refineries down to a low of $2.85/MMBTUs for PADD II refineries without conversion.

Payroll and payroll-related costs were the next highest operating cost element, averaging $0.70/bbl for all respondents. PADD I refineries without conversion had almost double the national average of payroll and payroll-related costs for reporting refineries, at $1.36/bbl of crude oil. This could be due to the high percentage of complex lubricant refineries of relative low capacity in this conversion category. In general, payroll burden increased with the capacity to process residuum. However, the large PADD III deep conversion refineries with the highest complexity had lower payroll, at $0.63/bbl, than several low-conversion groups.

Contract maintenance costs among the several region/complexity breakouts ranged from $0.04/bbl to $0.32/bbl, with the national average being $0.17/bbl of crude oil. Many factors impact upon this cost element: refinery complexity, refinery size, proportion of maintenance performed by refinery employees, contract labor rates, refinery vintage, maintenance emphasis, etc.

There are obvious relationships, as expected, between refinery complexity and the cost of catalysts and chemicals, with a national average in 1984 of $0.23/bbl of crude oil and with extremes of $0.03/bbl for the nonconversion California refineries and $0.36/bbl for the conversion refineries in that state.

Antiknock compounds averaged no more than $0.05/bbl of crude oil except in the PADD III conversion refineries where costs averaged $0.12/bbl.

Maintenance material costs generally trend upward with complexity. This trend appears to be dampened somewhat by refinery size. Averages reported ranged between $0.05/bbl and $0.33/bbl among the regions, resulting in a $0.20/bbl crude oil average for the total U.S.

Depreciation averaged $0.37/bbl for all respondents. Vintage of installation, as well as economics of size and complexity, are significant factors impacting on this cost element.

Expense for "other" operations, those not specifically included in items previously listed, averaged $0.54/bbl for all refineries responding to the survey. The high was $0.95/bbl at PADD V conversion refineries outside California, the low was $0.30/bbl for PADD III deep conversion refineries.

Table 34 presents the data by the 12 region/complexity groups for gross (undepreciated) fixed assets within the refinery and approximate in-kind replacement costs (1984 year-end). The *gross fixed assets* were reported to be about $38 billion. Based on the 166 refinery respondents to this question, who have a combined capacity of 13,970 MB/CD, these assets would amount to $2,720/bbl of crude oil capacity. Fixed assets as a function of capacity ranged from a low of $1,083/bbl in PADD II refineries without conversion, to $3,729/bbl in PADD V conversion refineries in California. The *replacement costs* would be about $89 billion for the 162 respondents with a capacity of 13,436 MB/CD, or $6,624/bbl. Gross fixed assets as a percentage of replacement costs ranged from a low of 25 percent for PADD II low conversion refineries to a high of 68 percent for PADD III simple refineries, and should be primarily a reflection of age of the facilities.

CHAPTER TWO

Analysis of Oil Supply and Demand

INTRODUCTION

This chapter describes the process for developing the estimates of oil supply and demand used in the study. The main objective was to create a plausible range of supply/demand balances that would induce measurable economic, technological, and business stress on the world, and in particular, on the U.S. refining industry. Adherence to this objective was crucial to making the study as relevant as possible for policy development. Consequently, no "most likely" supply/demand balance was produced.

In early 1985, the National Petroleum Council developed the initial worldwide supply and demand cases for the study of U.S. refinery capability. The Council's efforts were tempered by historical perspective and the objective of creating measurable stress on the refining industry.

The initial cases used in this study start from an estimated oil products demand for the non-communist world of about 46 MMB/CD in 1986. By 1990, the low demand case has a demand for oil products of about 44 MMB/CD; the high demand case has a demand of about 53 MMB/CD (including about 2 MMB/CD of refinery fuel). All subsequent 1990 cases fall within these broad ranges. Details of the initial cases are found in Appendix F.

CASE METHODOLOGY

The methodology in the study consisted of three basic steps:

- Choose a high and a low oil demand case that would be plausible and place measurable stress on refining capacity.
- Use the EIA's oil supply/demand model to develop details of the U.S. and non-U.S. oil balances, as described below.
- Vary the U.S. and non-U.S. demand parameters by changing the ratio of light oils (gasoline, distillates, and others) to residual fuel, or the product mixes in the United States.

HISTORICAL PERSPECTIVE

The two major shocks in crude oil prices in the 1970s had a major impact on worldwide supply and demand and significantly altered petroleum trading patterns affecting the United States. Worldwide demand declined as petroleum prices rose. Crude oil supplies increased as new fields were more rapidly developed or came on stream in Alaska, Mexico, and the North Sea as a result of the economic incentive created by higher petroleum prices. The combination of reduced demand and transportation economics changed the crude oil supply picture of the

United States. Mexico, Canada, Venezuela, and the United Kingdom increased crude oil exports to the United States. As a result, Saudi Arabia, Algeria, Nigeria, and Indonesia became less significant suppliers. Long haul Organization of Petroleum Exporting Countries (OPEC) sources became less important as short haul non-OPEC sources came on stream. The details of the historical trends in imports and demand are found in Appendix G.

For this study, product imports into and exports from the United States have been classified by their functionality. Unfinished oils, because they require additional refinery processing, have been removed from the products category and treated as crude oil. Gasoline is defined as finished motor gasoline, finished aviation gasoline, motor gasoline blendstocks, and aviation gasoline blendstocks. Jet fuel/kerosene is defined as naphtha jet, kero jet, and kerosene. Distillate is defined as no. 2 fuel oil and diesel. Residual products are a combination of residual fuel oil and petroleum coke. Other is a combination of everything else: liquified petroleum gas (LPG), petrochemical feed, special naphtha, lubricants, waxes, asphalt, still gas, and miscellaneous.

As a result of the forces caused by the petroleum price increases during the 1970s, non-communist worldwide demand for petroleum products has fallen from a high of almost 51 MMB/CD in 1979 to about 44 MMB/CD in 1983 (Figure 9). This volume is net products delivered to consumers, i.e., refinery fuel is excluded. The reduction in demand comes primarily from conservation and substitution of other fuels for residuel fuels in the major industrialized countries. In spite of price increases, petroleum demand has continued to increase in the less developed countries.

As shown in Figure 10, demand has shifted toward lighter products. Demand for motor fuel has remained essentially constant worldwide, while the demand for home heating products, industrial feedstocks, and boiler fuel has accounted for 90 percent of the decline in demand. Residual fuels have dropped from 26 percent of the demand barrel in 1977 to 21 percent in 1983, the last year for which worldwide demand reports from EIA are available.

The pattern of product imports into the United States changed as residual fuel oil was priced out of power generation and industrial heating markets and as the world upgraded its ability to convert residuum to light products. In 1977, the United States had gross imports of 2.2 MMB/CD of finished petroleum products with residual fuels representing almost two-thirds of that volume. By 1985, gross finished product imports[3] had leveled to 1.5 MMB/CD, with residual fuels comprising only one-third of the total (Figure 11). Imports of finished gasoline and blendstocks rose from 217 MB/CD to 447 MB/CD during the same period.

The United States has become a significant exporter of finished products. As shown in Figure 12, product exports have reduced the United States' net dependence on finished product imports to approximately 1.0 MMB/CD in 1985. The increase in product exports is the result of a rebalancing of product demands. Major exports from the United States are high-sulfur residual oils and high-sulfur petroleum coke, which reduces net imports of residual-type fuels to 126 MB/CD by 1985. In 1985, the United States also exported 67 MB/CD of distillates. As a result, net motor fuel and distillate imports now comprise 60 percent of net product imports.

Figure 13 shows net product imports and exports by PADD in 1985. PADD I has remained the economic point of import for a full slate of products. Netting imports and exports for PADDs III and V shows them as net importers of a small amount of gasoline while becoming net exporters of significant volumes of high-sulfur residual fuels and a small but growing amount of distillate. PADD II imports about 100 MB/CD of LPG from Canada and maintains a small import/export balance in the other products. PADD IV has a small import balance with Canada for gasoline, distillate, and other.

Petroleum product import patterns have changed from 1977 through 1985 (Figure 14). Puerto Rico, the U.S. Virgin Islands, Venezuela, Indonesia, and Europe saw total exports to the United States drop by a half to two-thirds. Entrepot refining in the Caribbean virtually disappeared. Mexico, Brazil, Algeria, Romania, Saudi Arabia, and the People's Republic of China experienced increases. Product imports into the United States are detailed by country in Appendix G.

Product demand patterns vary around the world. Demand in the United States, for example, comprises one-third of the total worldwide demand, yet U.S. gasoline demand is one-half

[3]Unfinished oils are excluded from product imports to determine finished product imports.

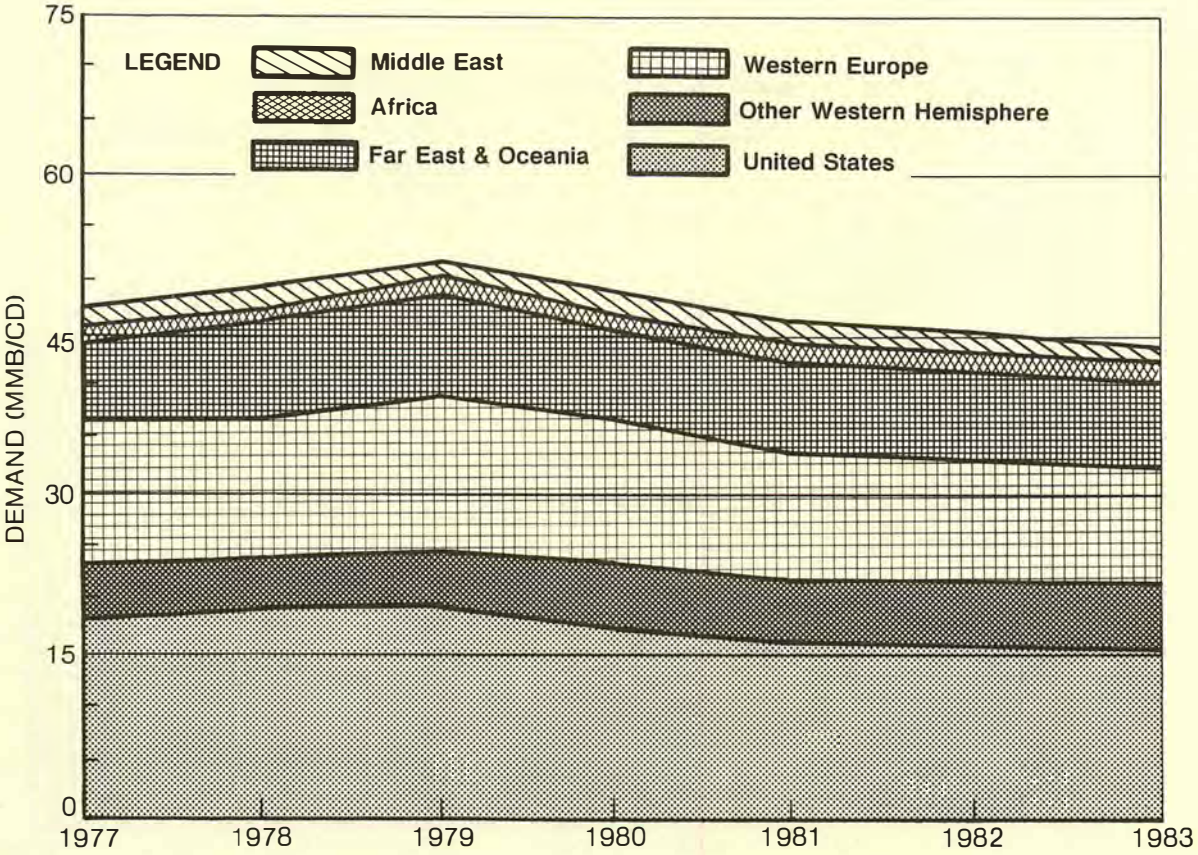


Figure 9. Non-Communist World Demand for Petroleum Products, by Region.

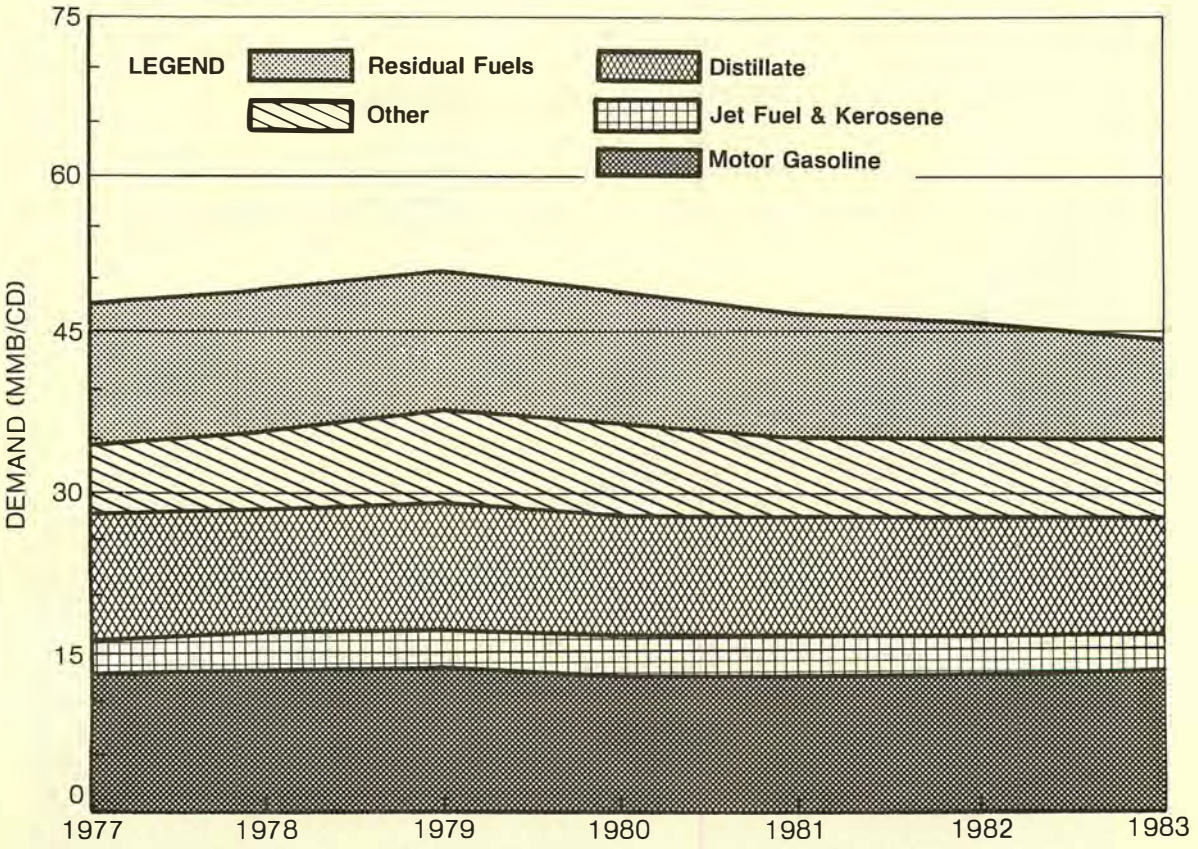


Figure 10. Non-Communist World Demand for Petroleum Products, by Product.

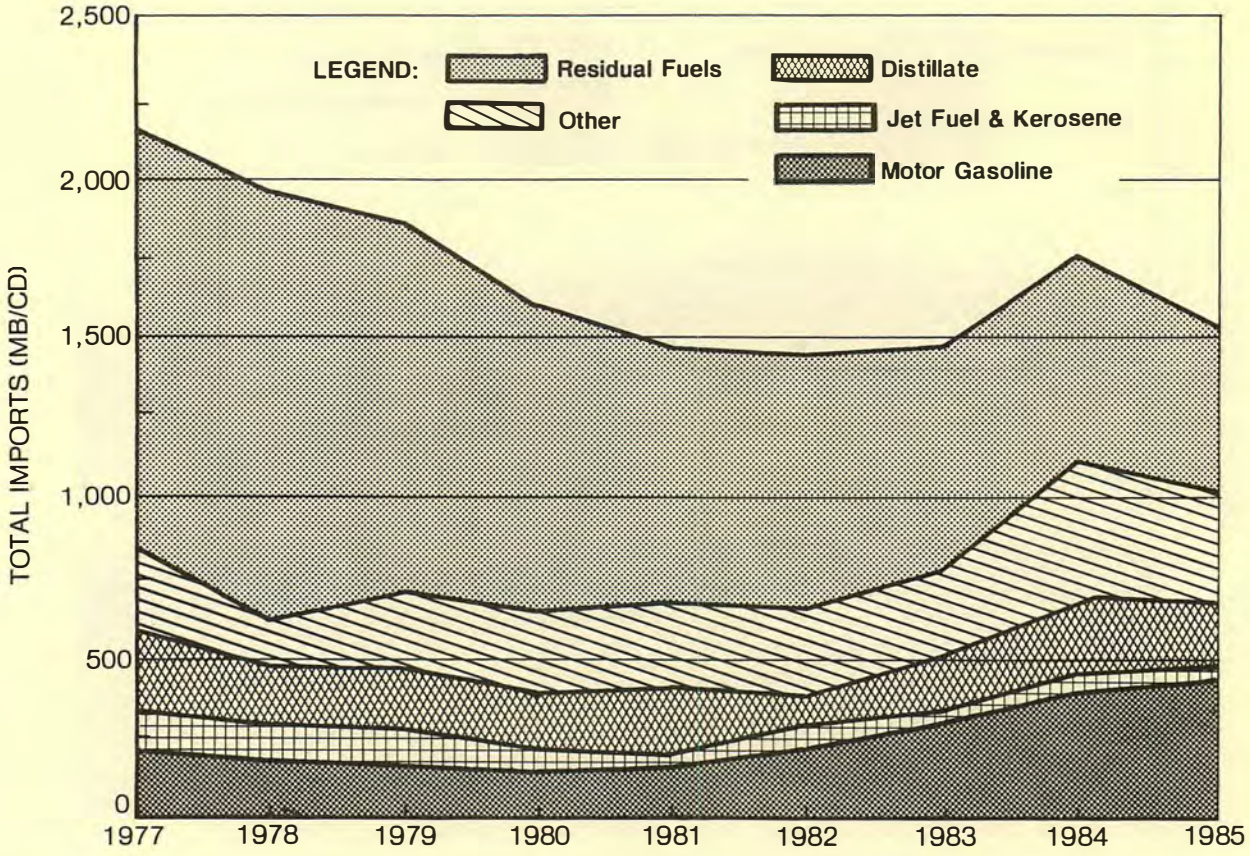


Figure 11. Total Finished Petroleum Product Imports into the United States.

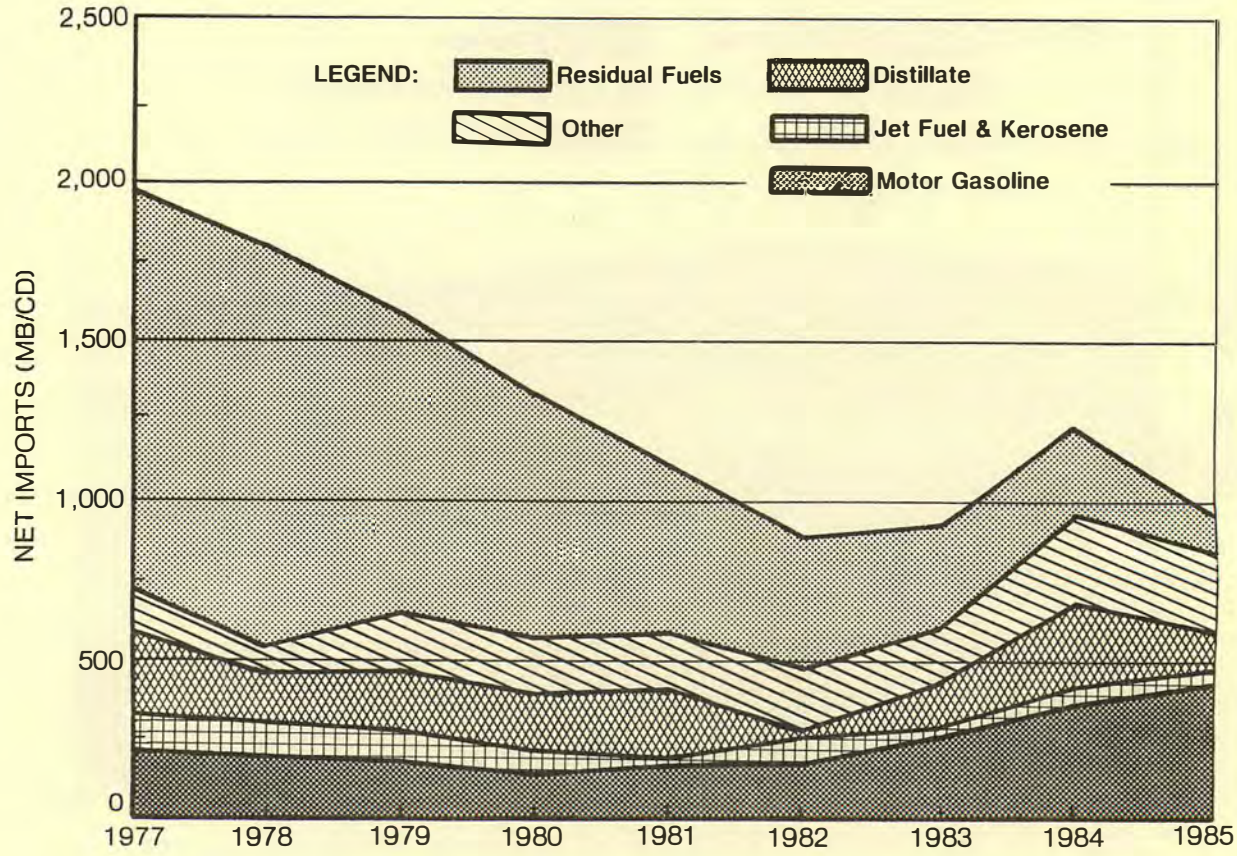


Figure 12. Net Finished Petroleum Product Imports into the United States.

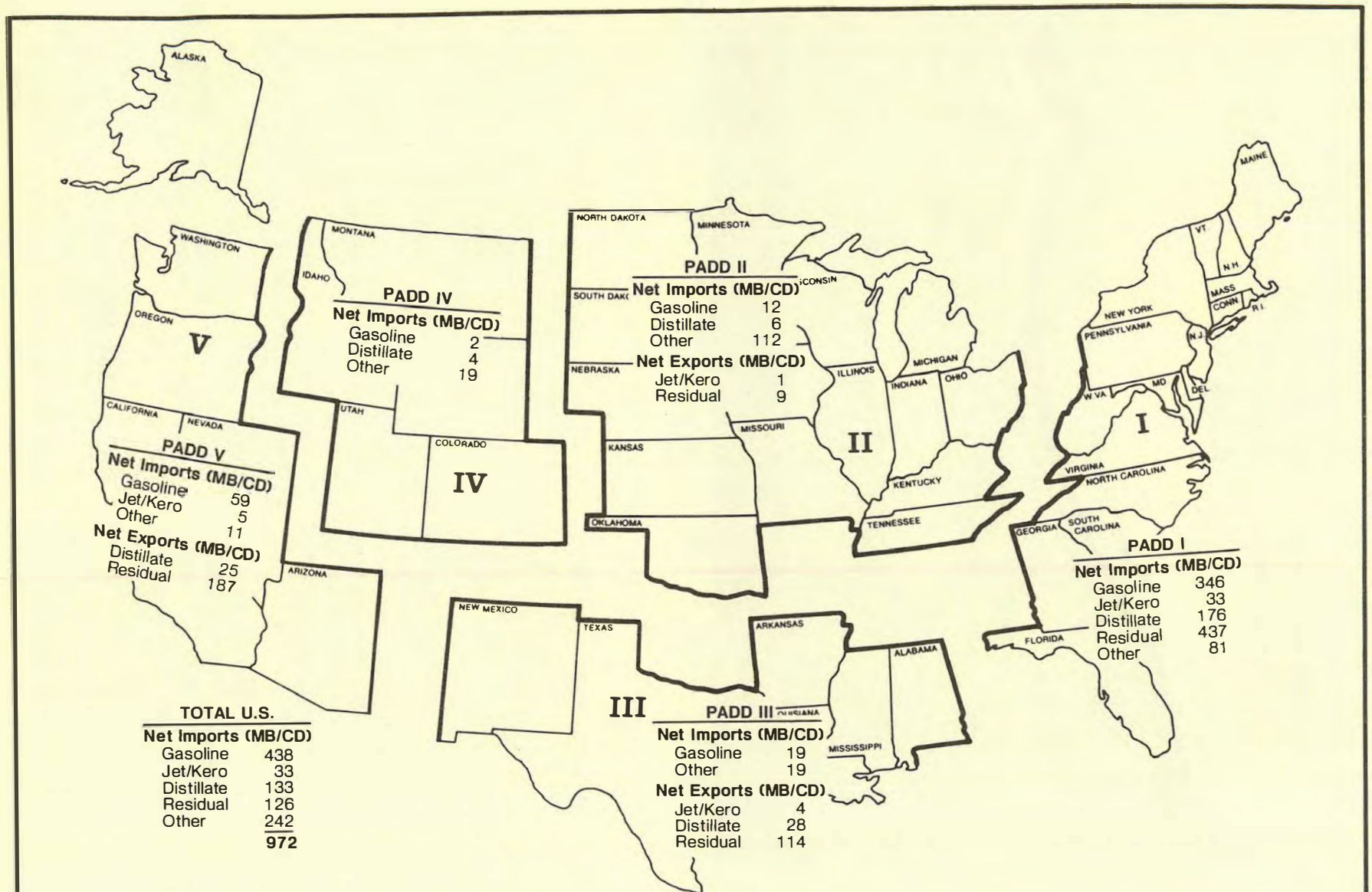


Figure 13. 1985 U.S. Product Import-Export Balance.

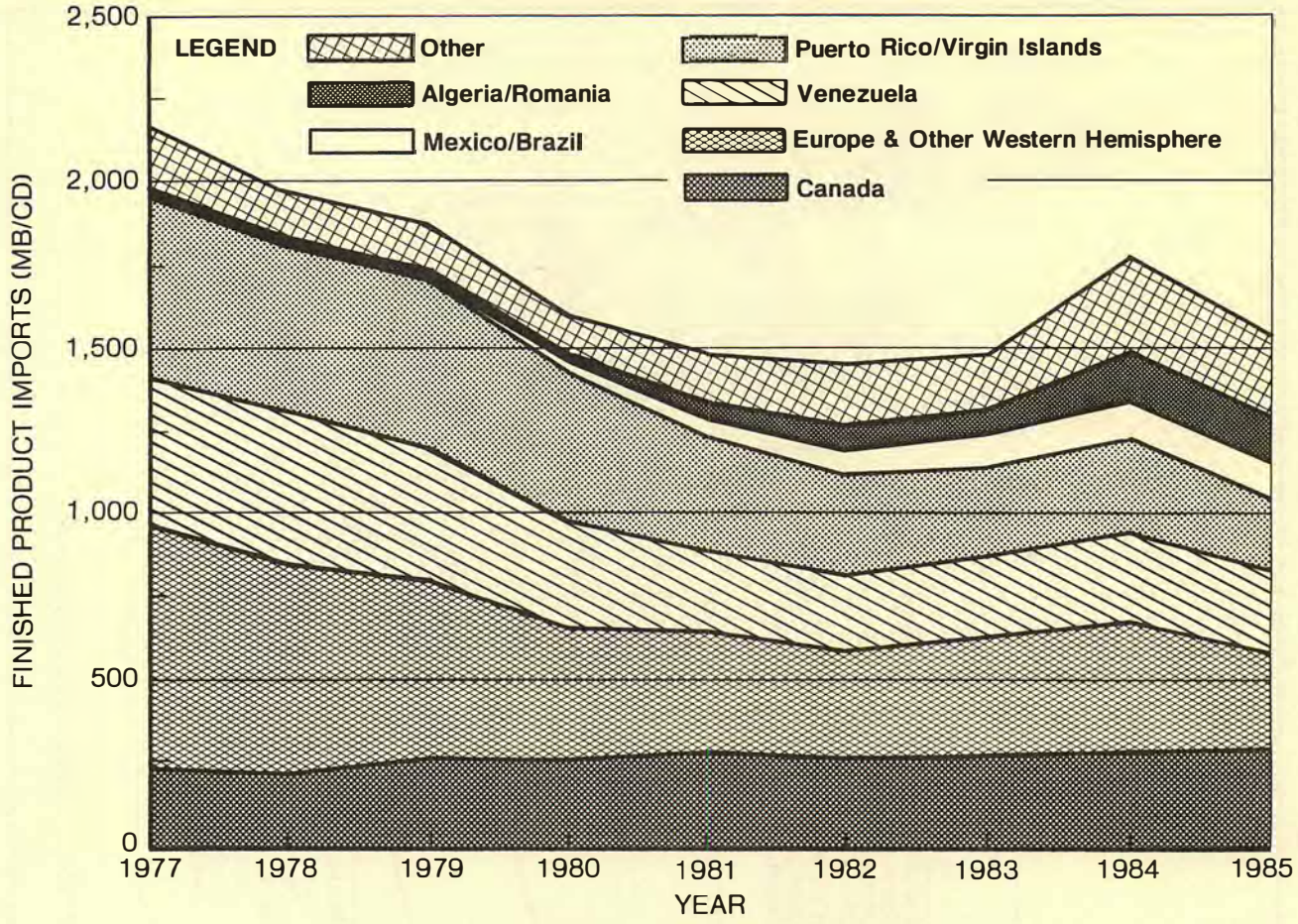


Figure 14. 1985 U.S. Finished Product Imports, by Source.

of total worldwide gasoline demand. In 1983 in the United States, residual fuel demand was only 10 percent of total demand; in the Far East, residual fuel represented over 30 percent of demand. For 1986, estimated U.S. gasoline demand is 46 percent of total U.S. demand, while in the rest of the world estimated gasoline demand is only 24 percent of total demand. On the other hand, U.S. residual fuel demand is estimated to be only 8 percent of total demand; worldwide residual fuel demand is estimated at 24 percent of the total. Demands for distillate and other products are about equal.

As intimated above in the discussion on product imports, the change in demand patterns has changed the direction of product flow around the world. Different countries have upgraded their refining capacity to convert residuum to lighter products, some for export and others to meet the changing demand within the country. The changes in demand pattern coupled with refinery improvements have created new geographic trade balances of gasolines, middle distillate, and fuel oil. For example, although European exports of distillate and residual fuel to the United States have dwindled, gasoline exports have doubled as cracking capacity has come on stream and hydroskimming capacity has been shut down. Venezuelan product exports to the United States have changed from 85 percent residual fuel in 1977 to 33 percent residual fuel in 1985. Venezuela's product exports to the United States changed as its Amuay Bay state-of-the-art U.S.-style deep conversion refinery came on stream. Some of the gasoline produced in Saudi Arabia's Yanbu refinery now comes to the United States. On the other hand, as the U.S. product demand has become lighter, refiners with topping and hydrocracking refineries around the world have ceased exporting to the United States.

INITIAL ASSUMPTIONS

The major assumptions driving the initial high and low cases were expected economic growth and the real output of specific industries.

- The low growth case assumes that trends in U.S. gross national product (GNP) between 1978 and 1983 and the conservation trends between 1979 and 1983 continue throughout the projection period. The high growth case assumes rapid growth between 1985 and 1990 before slowing somewhat after 1990 with little incremental conservation above that currently experienced.

- Growth rates in the real output for selected domestic energy-intensive industries critical to the projection, i.e., food, paper, chemical, stone/glass, and primary metals, were developed congruent with the GNP scenarios.

- For the international portion of the analysis, differential growth rates expressed in terms of real gross domestic product (GDP) were assumed for the Organization for Economic Cooperation and Development (OECD) and developing countries. The growth rate in developing countries was about 50 percent greater than the growth rate for the OECD. In the international analysis, OPEC production was not, however, allowed to exceed 30 MMB/CD.

Further detail is provided in Appendix F.

As in all analyses, certain clarifications of the results are necessary:

- The EIA model was used as a mechanical accounting tool to develop consistent supply/demand balances in the detail needed to support the modeling requirements for both the United States and the world. Thus, the economic and conservation assumptions that were input to achieve the desired NPC consensus demand results should not be considered representative of the National Petroleum Council's views on the overall environment necessary to achieve a low or high oil demand.

- While oil prices were not considered explicitly in the analysis, supply/demand estimates contained in the report are consistent with a wide range of oil prices.

- Both cases assume that leaded gasoline will be phased out by 1987.

- No supply side changes were included for non-OPEC, non-U.S. sources in either case. This does not imply that supply is not variable, but that such variability is not likely to be material to the analysis of refinery activity.

- The swing factor in the two cases is demand, driven by differing assumptions of economic growth and conservation/fuel substitution.

  The high case reflects strong demand growth that, when coupled with declining U.S. production, translates into significant increases in the requirement for OPEC oil, i.e., 30 MMB/CD by the early 1990s. It is important to note that this environment would initially be caused by a return to pre-1979 oil prices. As OPEC production approaches capacity, one would anticipate higher oil prices and a greater incentive to develop the more expensive worldwide petroleum and alternative energy supplies.

  The low case establishes an essentially flat total product demand after 1986. Increased demand for OPEC production comes only from declines in U.S. production and Centrally Planned Economies (CPE) exports, providing OPEC only slow relief for their revenue needs. It assumes that all members will cooperate and that the implied low levels of production (16.5 MMB/CD, or 19.1 MMB/CD including NGLs) will be met without any serious disruption of OPEC as an entity.

- U.S. imports will change to balance consumption with economic and political considerations, largely determining the split between crude oil and finished products. The split of imports developed were thus used only as a point of departure.

INITIAL CASE BALANCES

The results for the U.S. supply/demand balances are summarized in Table 35 and are detailed in Appendix F. In the high case, as domestic supply decreases, demand grows steadily over time, leading to increasing crude

oil and product imports. In the lower demand case, long term imports also increase, but at lower levels, again due to the decline in domestic production. Results of these cases are compared in Table 35 with the EIA base cases that were published as part of EIA's Annual Energy Outlook 1984 and 1985.

During the study, the competitive analysis of the U.S. vis-a-vis non-U.S. refineries was under consideration but not resolved until very late. Nonetheless, certain assumptions about net demands on refineries had to be made early in the study to begin the analysis of U.S. refinery capability. The preliminary assessment of the split of the imports shown in Table 35 between crude oil and products was made, and is shown in Table 36.

A simplifying premise for the initial pass at U.S. product import estimates was used: if world oil demands were high, non-U.S. refineries would be at high utilization rates and would have little product to export to the United States. Conversely, at low world oil demand, non-U.S. refineries would aggressively take increasing U.S. product market share to fill up their unused capacity. The objective of this premise was to give the maximum reasonable spread of demands on U.S. refineries between the high and low cases. Results of a consolidated worldwide supply/demand analysis are reported in Chapter Five. The U.S. import results from Chapter Five are more appropriate to use for analysis of refinery competitive position.

Further details of the initial high and low cases can be found in Appendix F. There are six separate sections.

Attachment 1:	U.S. Domestic High Case Balances
Attachment 2:	U.S. Domestic Low Case Balances
Attachment 3:	International High Case Balances
Attachment 4:	International Low Case Balances
Attachment 5:	Potential U.S. Product Import Cases
Attachment 6:	Assumptions, Definitions, and Notes

ALTERNATE CASES

In the final phase of the international competitiveness analysis, adjustments and interpretations were made to product demands to align them closer with current perceptions.

- Refinery consumption of residual fuel was netted out (about 2 MMB/CD worldwide).
- The resulting 1986 worldwide residual fuel demand was reduced to 8 MMB/CD, with a corresponding increase in light oils in each geographic area.
- Gasoline octane was changed from a constant octane pool, with changes in the ratio of grades depending on changes in demand, to a constant grade ratio.
- Distillate demand in the United States is all No. 2 fuel oil. Outside the United States, distillate has been broken down into No. 2 fuel oil and No. 4 fuel oil.
- Aromatics demand has been estimated to properly limit the worldwide octane pool.

A summary of the resulting demand is shown in Table 37. The extreme initial cases are actually listed under the Alternate Cases in Table 37 and in Chapter Five as the "1990 low demand high resid" and "1990 high demand high resid" cases.

During the final analysis of the comparative economics of U.S./non-U.S. refineries, it became apparent that assumptions about the light–heavy demand split were very important. For that reason, the initial cases for demand in 1990 were adjusted to create a light–heavy demand split similar to that developed for 1986. The modified cases then became the "reference cases" for understanding projected worldwide petroleum flows. To completely test the impact of the light–heavy demand split on refinery competitiveness, the worldwide demand for residual fuels in the 1990 low demand "reference case" was reduced by 1 MMB/CD with a corresponding increase in light product demand. This case is listed in Table 37 as the "1990 low demand low resid" case.

Finally, to develop the relationship between the light–heavy product split, U.S. imports, and U.S. refinery utilization, the light oil demands inside and outside the United States were varied parametrically by adding, in a geographically proportional way, light oil volumes. In one case, 3 MMB/CD of light oils were added to U.S. consumption in 1990; in the other, 3 MMB/CD were added to non-U.S. consumption in 1990. The resulting demands, shown in Table 38, are presented as percentages of total demand to make the differences in the light–heavy ratio more apparent.

TABLE 35

U.S. OIL BALANCE CASES
(MMB/CD)

	1990			1995		
	Demand*	Domestic Supply	Net Imports	Demand*	Domestic Supply	Net Imports
NPC Reference Cases						
High Case	17.7	10.0	7.9	19.5	7.8	11.8
Low Case	15.3	9.9	5.5	15.0	7.7	7.4
EIA Base Cases						
Base Case 1984	16.7	10.3	6.6	18.0	9.4	8.7
EIA Base Case 1985	16.1	10.3	5.8	16.6	8.8	7.8

*Includes about 2 MMB/CD of NGLs and processing gain.

TABLE 36

SUMMARY OF U.S. REFINERY REQUIREMENTS
(MMB/CD)

	Actual	High Case		Low Case	
	1985	1990	1995	1990	1995
Total Product Consumption*	15.7	17.7	19.5	15.3	15.0
Plus:					
Product Export & Losses	0.6	0.6	0.6	0.6	0.6
Less:					
Natural Gas Liquids	1.6	1.6	1.6	1.6	1.6
Product Imports	1.5	2.1	2.1	3.0	3.0
Equals:					
Net Product Demand On U.S. Refineries*	13.2	14.6	14.6	11.3	11.0

*Includes refinery fuel.

TABLE 37

SUMMARY OF PRODUCT DEMAND CASES*
(MMB/CD)

	U.S. Demands						World (Incl. U.S.) Demands						
	Gasoline†	No. 2	Jet	Other	Resid	Total	Gasoline	Dis-tillate‡	Jet	Other	Resid	Total	Gasoline Octane§
Reference Cases													
1986	7.0	2.9	1.2	2.8	1.3	15.2	13.7	11.4	3.8	6.8	8.0	43.7	84.3
1990 Low	6.2	3.1	1.3	2.8	1.3	14.7	12.5	11.5	3.9	6.8	7.7	42.4	84.0
1990 High	6.9	3.6	1.5	3.3	1.8	17.1	14.1	13.5	4.5	8.1	10.5	50.8	83.9
Alternate Cases													
1990 Low Demand Low Resid	6.4	3.2	1.3	2.8	0.9	14.6	12.9	11.8	4.1	6.8	6.8	42.4	84.0
1990 Low Demand High Resid¶	6.0	3.0	1.3	2.8	1.7	14.8	11.5	10.8	3.6	6.8	10.1	42.7	84.2
1990 High Demand High Resid¶	6.7	3.5	1.5	3.3	2.1	17.1	13.4	12.9	4.3	8.1	12.2	50.8	84.0
1990 Low Resid Higher U.S. Light Oils	7.9	3.9	1.7	2.8	1.3	17.6	14.2	12.4	4.3	6.8	7.8	45.4	84.5
1990 Low Resid Higher Non-U.S. Light Oils	6.2	3.1	1.3	2.8	1.3	14.7	13.6	13.0	4.4	6.8	7.8	45.4	83.7

*Detail data may not add to total due to independent rounding.
†U.S. gasoline clear pool octane held at 87.9.
‡Distillate = No. 2 + No. 4.
§Clear pool octane.
¶The "initial" extreme cases, as adjusted.

TABLE 38

SUMMARY OF PRODUCT DEMAND CASES*
(Percent)

	U.S. Demands				Rest of World Demand				Total Demand			
	Gasoline	Distillate†	Other	Resid	Gasoline	Distillate‡	Other	Resid	Gasoline	Distillate‡	Other	Resid
Reference Cases												
1986	46	27	18	9	24	39	14	24	31	35	16	18
1990 Low	42	30	19	9	23	40	14	23	29	36	16	18
1990 High	40	30	19	11	20	39	15	26	27	36	16	21
Alternate Cases												
1990 Low Demand Low Resid	44	31	19	6	23	41	14	21	30	38	16	16
1990 Low Demand High Resid§	41	29	19	11	20	36	14	30	27	34	16	24
1990 High Demand High Resid§	39	29	19	12	20	36	14	30	26	34	16	24
1990 Low Resid Higher U.S. Light Oils	45	32	16	7	23	40	14	23	31	37	15	17
1990 Low Resid Higher Non-U.S. Light Oils	42	30	19	9	24	42	13	21	30	38	15	17

*Detail percentages may not round to 100 due to independent rounding.
†Distillate = No. 2 + Jet.
‡Distillate = No. 2 + No. 4 + Jet.
§The "initial" extreme cases, as adjusted.

CHAPTER THREE

Capabilities of the Domestic Refining Industry

INTRODUCTION

This chapter assesses the capability of the U.S. domestic refining industry to meet the requirements of a range of scenarios in the 1984–1995 period. The scenarios considered by the study are not intended to be a forecast of this period, but rather are intended to impose conditions under which the U.S. refining system's ability to respond can be measured. The assessment assumes that appropriate economic conditions are in place, and the results provided herein are therefore primarily representative of physical limitations. These assessments primarily develop the response of the refining system to changes in demand or product specifications. While crude oil and product prices used were typical of the late 1984, early 1985 period, the lower crude oil and product prices being experienced in 1986 would not alter the conclusions contained in this chapter. All assessments were performed on an annual average basis reflecting shutdown and outage of process units in line with industry experience. At any time during the year when all process units in the industry are operating, production rates above those shown can be expected.

The major issues to be assessed by this analysis are the following:

- The capability of the domestic refining industry to meet the low and high supply/demand scenarios of the NPC study. The demand scenarios provided in Chapter Two do not describe maximum or minimum demands for any product but rather alternative economic scenarios that might adjust materially the demand for products from the refining industry.
- The capability of the domestic refining industry to maximize production of major light products at a given crude oil rate fully utilizing the conversion units.

The impacts of several related issues were also examined, including:

- Phasedown of lead in gasoline
- Reduction of motor gasoline vapor pressure
- Increase in motor gasoline octane
- Use of oxygenates in motor gasoline
- Deterioration of crude oil quality
- Other potential environmental constraints.

The assessment and conclusions contained in this chapter were derived from two principal sources: from the NPC's 1985 Survey of U.S. Petroleum Refineries, and from the use of mathematical models of the refining industry to test the industry's sensitivity to the issues addressed.

CONCLUSIONS

The principal conclusions of this chapter are as follows:

- In meeting current product demand mix and specifications, refiners have tended

to more fully utilize downstream conversion and octane-enhancement facilities than crude oil distillation capacity. Thus the measurement of refining capacity on the basis of crude oil distillation provides an overstatement of the remaining capability to meet light product demand, particularly motor gasoline.

- In the "low demand" scenario for 1988, refinery production capability was not stressed. There would be no need to operate the 1.4 million barrels per stream day (MMB/SD) of idle refinery capacity existing as of January 1, 1985. An additional 0.5 MMB/SD of capacity that was temporarily idle during the 1982–1985 period was also assumed to continue down in order to achieve a reasonable level of capacity utilization in the 80 percent range.
- The high demand case for 1988 postulates a refining capacity of approximately 15.7 MMB/CD (16.5 MMB/SD) operating at a utilization of about 85 percent. This capacity is attained by considering idle refineries to be available to meet demand requirements given appropriate economic incentives. The high ratio of fuel oil to gasoline demand, in this scenario, would result in under-utilization of residual conversion capacity.
- For the high demand case for 1988, which includes product imports at 1984 levels, the gasoline production capacity is adequate on an entire U.S. basis. However, the capability to meet required octane levels is stressed after complete lead phasedown. Potential environmental constraints not currently in place would restrict the ability to meet demand, require further capital investments, or cause further import of products.
- Motor gasoline manufacturing capability in 1988, estimated on an annual basis including planned additions and at crude oil rates of about 13 MMB/CD, are estimated as follows:

	MB/CD
Lead level at 0.1 gplg	6,700–6,800
1 psi lower RVP	6,550
1 psi lower RVP *and* increased pool octane of 0.6–0.7	6,300

- The 6.7–6.8 MMB/CD annual production capability represents only 5 percent potential above 1984–1985 annual production from refineries. The study indicates that PADD V refiners are currently operating at or near full gasoline manufacturing capability.
- At the 6.7–6.8 MMB/CD annual rate, gasoline production is estimated to be 7.0–7.4 million barrels per day (MMB/D) for portions of the year where downstream capacity is fully available for operation and is operated near capacity.
- Refineries are near octane limits in many areas in 1988 and could have some difficulty in achieving higher octanes or increased ratios of unleaded premium.
- Very little additional gasoline production could be accomplished by increases in crude oil rate above 13 MMB/CD. At this crude oil rate, downstream conversion units are fully utilized and octane-enhancing units are nearing full capability. Additional octane-enhancement capability can raise annual gasoline production to about 7.1 MMB/CD.
- The various demand cases studied for 1988 show that the industry can adjust to gradual changes in demand. Shortfalls in particular products (especially motor gasoline) can result if import levels decline or demand increases above those shown for the high demand case in Chapter Two.
- The refinery survey indicates that in response to the EPA's lead phasedown, the industry is adding, by 1988, about 18 isomerization units, totaling 156 MB/CD, 50 MB/CD of net additional alkylation unit capacity, and an additional amount of reformer capacity. Even with the addition of these facilities, 1988 motor gasoline manufacturing capability is estimated to be reduced by about 100 MB/CD due to the increased octane requirements of the gasoline pool.
- The source of the estimated 1.9 octane number [(R+M)/2] boost in average clear pool octane needed to replace the lead

removed from gasoline comes principally from the following:

Increased Reformer Feed and Severity	50%
Additional Isomerization Units	20%
Light Naphtha Rejection	20%
Increased Oxygenates	5%
Other (Primarily Alkylation)	5%
	100%

- The penalty for a 1 psi reduction in 1988 motor gasoline vapor pressure is estimated at about a 200 MB/CD reduction in gasoline production capability with a removal of about 130 MB/CD butane from gasoline. The operating cost is estimated to be $1 billion per year or about 1¢ per gallon of gasoline produced.
- PADDs II and III are expected to continue to be the primary users of oxygenates for gasoline blending stocks.
- Removing or reducing benzene content in gasoline is expensive and would result in storage and handling of benzene product in numerous new geographic areas. Additional facilities would be required to convert the benzene product to a different gasoline component and replace the loss in octane value caused by the reduction in benzene. Depending upon level of reduction, new investment could be $4 billion or more and add 2–3¢ or more per gallon to gasoline manufacturing cost.
- Technology exists to meet more stringent sulfur specifications in distillate fuels. Additional investment may be in the range of $1 billion to reach a level of 0.2 wt.% sulfur.

INDUSTRY CAPABILITY AND CAPACITY

The NPC obtained information concerning the capacity, capability, and configuration of the U.S. refining industry with the 1985 survey, as reported in Chapter One. This information provided a sound basis for analyzing and testing the industry's ability to conform to and meet several demand scenarios that might develop with time. The primary demand scenarios are fully described in Chapter Two and are referred to as the low demand case and the high demand case. A third scenario assessed the capability of the industry to produce motor gasoline and distillate at the crude oil charge rate of the high demand case.

The low refinery demand case postulated a steady increase in the import of product into the United States, resulting in refinery crude oil runs of about 11 MMB/CD in 1988, about 1 MMB/CD less than experienced during 1984 and 1985. The high demand case postulated product imports remaining essentially constant at the 1984 level, creating a requirement for crude oil runs in 1988 of about 13 MMB/CD. Thus, these cases provide a range of refinery demands of approximately 20 percent from the low to the high demand.

Broadly, both of these demand scenarios postulate a decline in motor gasoline demand from the levels produced during 1984 and 1985, thus reducing the stress on the industry to meet the requirements of the lead phasedown. Therefore, a third condition was established to determine the industry's flexibility to meet a demand mix of products where motor gasoline would increase. The results indicate that while the industry has some flexibility, the ability to produce additional motor gasoline is limited.

The analysis of the industry capability was performed using a set of refinery models developed to represent specific segments of the U.S. industry. These segments were selected for similarity in geographic location and/or complexity of operation. Methodology of model development is discussed more fully near the end of this chapter. The definition of each group is as follows:

I-S	PADD I no conversion
I-C	PADD I conversion
II-S	PADD II no conversion
II-LC	PADD II gas oil conversion
II-DC	PADD II deep conversion
III-S	PADD III no conversion
III-LC	PADD III gas oil conversion
III-DC	PADD III deep conversion
IV	PADD IV all refineries
V-S	PADD V no conversion
V-COC	PADD V conversion outside California
V-CC	PADD V conversion inside California
VCLA	PADD V conversion in L.A. Basin
Simple	Refineries without conversion in PADDs I, II, III, and V.

Refinery Capacity

Historically, refinery capacity has been reported and measured in terms of the rated and actual charge to crude oil distillation units. This measure provides a quick, easy method of measuring the operation of refineries and is realistic when all units are operated within the design parameters.

During the last five to ten years, both product demand and product mix have changed materially. Product supplied by domestic refineries peaked in 1978 at a level of 16.8 MMB/CD, declining gradually to about 13.7 MMB/CD during 1984 and 1985. While overall demand declined, the reduction in motor gasoline demand was more gradual and was accompanied by an increase in clear octane pool requirements resulting from the shift from leaded to unleaded grades of gasoline. Further pressure on refinery capability to meet octane requirements results from the recent EPA lead phasedown from 1.1 gplg to 0.10 gplg.

The response to these changing conditions by many refiners was to reduce the utilization of crude oil distillation capacity while maintaining the operation of downstream conversion and octane-enhancing units at or near their rated capacities. With the conditions present today, measurement of the crude oil distillation utilization severely overstates the capability of the industry to meet increases in demand for some products, particularly motor gasoline.

1988 Low Refinery Demand Case

The 1988 low demand case describes the capability of the domestic refining system in a scenario in which the system is operating at a level below 1984 operations. The capacity estimates used as a base in these models were established by reviewing the Department of Energy (DOE) list of refiners operating in 1985 with additions to capacity from public announcements or indicated by the refinery survey. Under these conditions, further shutdown of the most marginal refineries might be expected.

Table 39 provides the crude oil unit capacity and utilization expected to meet the 1988 low demand case. In practice, there would be some adjustment in the utilization rates from group to group. Table 40 shows the crude oil charge, product yield, and the expected utilization level of all the process plants as a percentage of their indicated calendar-day capacities.

On a total U.S. basis, refinery crude oil runs amount to 11.2 MMB/CD, consuming about 81 percent of premised calendar-day distillation capacity of 13.9 MMB/CD (14.6 MMB/SD). Run levels are about 0.8 MMB/CD less than those of 1984. For this case, the utilization of complex refineries' crude oil distillation averages 82 percent, while the operational level of simple refineries averages 65 percent.

Regionally, this scenario results in utilization of complex refineries ranging from 75 to 87 percent, while that of the nonconversion refineries ranges from 63 to 74 percent. These values fall within a traditional range and, depending upon economic conditions, further reduction of the system distillation capacity below that of the 13.9 MMB/CD level premised for this scenario should be minimal.

The U.S. product demand level for this illustrative case is about 0.5 MMB/CD less than that experienced in 1984. In accordance with the objective of the case to study the system capability at low levels, premised product imports are about 0.6 MMB/CD more than those of 1984, resulting in a decrease in product demand at domestic refineries of about 1.0 MMB/CD. A further change is premised for the product demand mix with the bulk of the decrease occurring in gasoline demand and only modest decreases in middle distillates and residual fuel oils. The demand for "other" (predominantly petrochemical feedstocks) increases somewhat.

As a result of this change in demand mix, the refinery catalytic cracking units in most of the individual models are utilized somewhat less in this case than during 1984. At this demand level for products, the catalytic cracking utilization ranges from 61 to 92 percent with an average of about 80 percent.

A concurrent result of the change in demand mix is to increase the use of hydrocracking to meet the higher proportion of kerosene jet fuel in the demand pool with reduced crude oil runs. Most of the regional hydrocracking capacity in the models is fully utilized.

At the higher percentage of residual fuel oil demand in the refinery product slate and the lower crude oil run level, the utilization of residual conversion units of the low demand case is much less than in 1984. Residual conversion units are operating at a significantly lower utilization rate than the companion distillation units in nearly all of the geographic models.

TABLE 39

CRUDE OIL UNIT CAPABILITIES AND UTILIZATIONS
1988 LOW DEMAND CASE RESULTS

Region / Complexity Group	Number of Refineries	Crude Capacity (MB/SD)	Crude Input (MB/CD)	Utilization* (%)
I-S	9	146	102	73.4
I-C	10	1,226	951	81.7
II-S	5	47	33	73.9
II-LC	8	656	499	80.1
II-DC	23	2,508	2,072	87.0
III-S	17	322	225	73.6
III-LC	12	1,381	999	76.1
III-DC	28	4,783	3,790	83.4
IV	18	566	425	79.0
V-S	25	485	289	62.7
V-COC	6	512	423	87.0
V-CC	16	1,963	1,393	74.7
U.S. Total	**177**	**14,595**	**11,201**	**80.8**
Subtotal by Type				
Simple	56	1,000	649	64.9
Conversion†	121	13,595	10,552	81.7

*Utilization of operable calendar day capacity assuming 95 percent stream factor.
†Includes two simple refineries in PADD IV with a capacity of 19 MB/SD.

Similarly, the combination of the less sophisticated product demand slate and lower demand level reduces the throughput requirement in all of the other process units. An exception is the use of C_5/C_6 isomerization units, which operate at high utilization rates in nearly all of the models as dictated by the increased octane requirements and lead phasedown. Also, to meet octane requirements, the reformers are operated at quite high severities averaging in excess of 98 RONC.

In summary, with the low demand and high imports, excess capacity exists in gas oil conversion, in residual conversion, and in lower quality crude oil processing for this case. Further reduction in total refining capacity to meet the demand levels for this scenario of low refinery demand would be minimal, since the level of utilization is within historical bounds. However, the consequences of the premised low demand and higher product imports could act to squeeze out the least efficient refiners in areas where product imports and transfers are logistically feasible.

1988 High Refinery Demand Case

The 1988 high demand case describes the capability of the domestic refining system in a scenario in which the system would be stressed beyond 1984–1985 operation levels and might test capability limits and could require additional investment. In developing unit capacities to meet this scenario, it was presumed that recently idled capacity of about 1.4 MMB/SD would restart and be available to meet the increased demands. As discussed later in this section, the premised demand and product specification levels for 1988

TABLE 40

REFINERY MATERIAL BALANCE AND PROCESS UNIT UTILIZATION
1988 LOW DEMAND CASE

	PADD I		PADD II			PADD III			PADD IV	PADD V			U.S. Total
	I–S	I–C	II–S	II–LC	II–DC	III–S	III–LC	III–DC		V–S	V–COC	V–CC	
Raw Materials (MB/CD)													
Sweet Crude	51	559	7	182	1,057	180	385	1,935	280	61	52	182	4,931
Light Crude>0.5% Sulfur	2	121	1	56	230	0	233	867	20	0	20	0	1,550
Heavy Crude>0.5% Sulfur	49	271	25	261	785	45	381	988	125	228	351	1,211	4,720
Total Crude	102	951	33	499	2,072	225	999	3,790	425	289	423	1,393	11,201
NGL, Naphtha, Reformate	0	17	0	13	47	19	67	133	1	4	(8)	7	300
Butanes	0	16	0	28	96	0	38	132	14	1	16	10	351
Vacuum Gas Oil	(6)	69	(6)	15	4	0	31	75	0	(32)	3	42	195
Other	1	4	0	(5)	8	3	(2)	18	(4)	2	4	22	51
Total Feedstocks	**97**	**1,057**	**27**	**550**	**2,227**	**247**	**1,133**	**4,148**	**436**	**264**	**438**	**1,474**	**12,098**
Products (MB/CD)													
Motor Gasoline													
Low Lead Regular	0	69	0	41	205	0	73	306	64	0	34	109	901
Unleaded Regular	7	336	2	199	846	50	312	1,130	134	37	97	373	3,523
Unleaded Premium	0	119	0	38	158	0	86	447	14	0	47	198	1,107
Total Gasoline	7	524	2	278	1,209	50	471	1,883	212	37	178	680	5,531
Aviation Gasoline	0	0	0	2	3	0	3	18	2	0	2	10	40
Jet & Kero	6	60	9	49	137	43	91	415	38	28	63	234	1,173
Distillate Fuel	23	248	6	93	520	50	228	901	107	65	92	210	2,543
Residual Fuel	5	93	4	25	41	25	134	189	15	62	84	191	868
Asphalt/Road Oil	36	55	3	60	81	20	50	42	32	49	1	21	450
Marketable Coke (FOE)	0	12	0	0	54	0	0	63	2	0	6	65	202
Other	17	11	2	21	82	46	119	414	8	14	6	34	774
LPG & Refinery Fuel	1	111	0	39	198	11	68	374	30	5	22	141	1,000
(Gain)/Loss	2	(57)	1	(17)	(98)	2	(31)	(151)	(10)	4	(16)	(112)	(483)
Total Products	**97**	**1,057**	**27**	**550**	**2,227**	**247**	**1,133**	**4,148**	**436**	**264**	**438**	**1,474**	**12,098**
Unit Utilization (%)*													
Crude — Atmospheric		81.7		80.1	87.0		76.1	83.4	79.0		87.0	74.7	79.1
— Vacuum		73.4		78.2	92.7		64.6	73.1	92.3		106.1	73.0	73.5
Catalytic Reforming		60.1		51.2	84.7		60.6	81.5	57.8		92.7†	61.9	72.8
RONC		98.4		93.7	97.2		97.0	98.8	97.7		99.2	98.0	97.1
Catalytic Cracking		84.8		80.2	92.3†		61.3	74.4	87.9		92.3†	88.6	80.8
Conversion		77.6		73.5	76.5		76.1	74.4	74.1		70.6	77.2	75.6
Hydrocracking		92.5†		91.8†	92.6†		91.3†	92.7†	91.8†		92.6†	92.6†	92.5†
Coking		48.7		—	79.5		—	56.9	31.3		53.1	71.3	64.5
Coke Make (FOE)		37.3		—	75.2		—	40.1	19.6		42.5	76.1	64.5
Alkylation		82.6		72.8	92.3		89.9	66.5	87.3		82.5	93.1†	79.6
Isomerization — C_4		0		0	0		92.6†	0	50.1		42.4	24.7	25.6
— C_5/C_6		33.0†		62.2	77.6		92.6†	92.4†	92.3†		0	92.4†	81.3

*Utilizations assume a 95 percent stream factor for crude oil units and a 92 percent stream factor for all other units.
†Limited at maximum throughput in model run.

can be adequately handled with reactivated capacity and at most a very modest investment.

Table 41 provides the crude oil unit capacity and utilization required to meet the 1988 high demand case. Table 42 shows the crude oil charge, product yield, and expected utilization level of all process plants as a percentage of their indicated calendar-day capacities.

In this case, domestic crude oil run requirements amount to 13.2 MMB/CD, equivalent to 84 percent of the premised calendar-day distillation capacity of 15.7 MMB/CD (16.5 MMB/SD). This operational level is about 1.2 MMB/CD, or about 10 percent higher than that of 1984. Conversion refineries operate at 84 percent of crude oil distillation capacity, up from 79 percent in 1984, while nonconversion refineries operate at 65 percent, up from 54 percent in 1984. The capacity estimates developed for the total system as well as those of the conversion and nonconversion refineries are virtually identical to those existing in the 1984 system. Utilization of regional model capacity in this scenario ranges from 73 percent to 91 percent for conversion refineries and from 48 percent to 76 percent for the nonconversion refineries.

On balance, the planned additions to the domestic system distillation capacity base of 1984 are adequate to meet the requirements of the high demand case and further investment is not likely

TABLE 41

CRUDE OIL UNIT CAPABILITIES AND UTILIZATIONS
1988 HIGH DEMAND CASE RESULTS

Region / Complexity Group	Number of Refineries	Crude Capacity (MB/SD)	Crude Input (MB/CD)	Utilization* (%)
I-S	11	371	170	48.2
I-C	10	1,296	1,071	87.0
II-S	7	66	47	75.0
II-LC	12	827	662	84.3
II-DC	24	2,623	2,263	90.8
III-S	21	375	269	75.5
III-LC	14	1,634	1,242	80.0
III-DC	32	5,487	4,678	89.7
IV	20	591	466	83.9
V-S	28	583	375	67.7
V-COC	6	512	433	89.0
V-CC	17	2,153	1,502	73.4
U.S. Total	**202**	**16,518**	**13,178**	**84.0**
VCLA	9	1,209	860	74.9
Subtotal by Type				
Simple	67	1,395	861	65.0
Conversion†	135	15,123	12,317	85.7

*Utilization of operable calendar day capacity assuming 95 percent stream factor.
†Includes two simple refineries in PADD IV with a capacity of 19 MB/SD.

TABLE 42

REFINERY MATERIAL BALANCE AND PROCESS UNIT UTILIZATION
1988 HIGH DEMAND CASE

	PADD I		PADD II			PADD III			PADD IV	PADD V			U.S. Total
	I-S	I-C	II-S	II-LC	II-DC	III-S	III-LC	III-DC		V-S	V-COC	V-CC	
Raw Materials (MB/CD)													
Sweet Crude	72	633	10	298	2,329	215	551	2,085	279	79	48	186	5,785
Light Crude>0.5% Sulfur	3	79	2	70	169	0	238	1,021	56	0	28	0	1,666
Heavy Crude>0.5% Sulfur	95	359	35	294	765	54	453	1,572	131	296	357	1,316	5,727
Total Crude	170	1,071	47	662	2,263	269	1,242	4,678	466	375	433	1,502	13,178
NGL, Naphtha, Reformate	0	16	0	12	42	23	59	120	1	6	(5)	6	280
Butanes	0	17	0	28	98	0	26	142	15	2	15	12	355
Vacuum Gas Oil	(10)	85	(8)	16	4	0	31	72	0	(42)	3	46	197
Other	1	4	0	(6)	13	3	(2)	33	(3)	2	4	27	76
Total Feedstocks	**161**	**1,193**	**39**	**712**	**2,420**	**295**	**1,356**	**5,045**	**479**	**343**	**450**	**1,593**	**14,086**
Products (MB/CD)													
Motor Gasoline													
Low Lead Regular	0	75	0	55	223	0	87	365	70	0	34	118	1,027
Unleaded Regular	12	367	3	262	915	61	372	1,331	148	50	97	402	4,020
Unleaded Premium	0	130	0	51	171	0	103	526	15	0	46	213	1,255
Total Gasoline	12	572	3	368	1,309	61	562	2,222	233	50	177	733	6,302
Aviation Gasoline	0	0	0	2	4	0	4	24	2	0	2	12	50
Jet & Kero	10	65	13	58	149	51	123	547	43	37	69	255	1,420
Distillate Fuel	39	259	9	120	563	60	252	1,072	119	84	95	225	2,897
Residual Fuel	8	108	6	34	44	29	170	264	18	81	91	207	1,060
Asphalt/Road Oil	61	58	5	75	83	24	58	49	33	63	1	23	533
Marketable Coke (FOE)	0	16	0	0	52	0	0	88	2	0	5	66	229
Other	27	49	2	22	100	55	139	472	8	17	3	34	928
LPG & Refinery Fuel	1	123	0	55	213	13	87	492	33	6	23	151	1,197
(Gain)/Loss	3	(57)	1	(22)	(97)	2	(39)	(185)	(12)	5	(16)	(113)	(530)
Total Products	**161**	**1,193**	**39**	**712**	**2,420**	**295**	**1,356**	**5,045**	**479**	**343**	**450**	**1,593**	**14,086**
Unit Utilization (%)*													
Crude — Atmospheric		87.0		84.3	90.8		80.0	89.7	83.0		89.0	73.4	84.0
— Vacuum		82.0		83.7	94.7		76.2	86.9	94.7		105.0	76.4	83.1
Catalytic Reforming		76.2		55.5	92.2†		81.9	85.6	68.4		92.7†	72.9	81.7
RONC		98.7		96.5	97.4		97.6	98.2	94.6		99.6	99.6	98.0
Catalytic Cracking		87.7		87.7	92.5†		72.7	81.6	90.3		92.3†	92.6†	85.4
Conversion		76.5		74.3	75.2		78.3	78.1	76.5		73.3	70.0	75.9
Hydrocracking		92.5†		93.8†	91.0†		91.3†	92.7†	91.7†		92.6†	92.6†	92.4
Coking		67.4		—	77.0		—	71.0	31.6		45.9	71.1	70.2
Coke Make (FOE)		51.7		—	72.9		—	52.1	21.5		36.7	75.6	60.0
Alkylation		86.9		71.2	92.6†		92.4†	71.3	92.6†		82.1	87.0	81.0
Isomerization — C_4		—		104.3†	0		92.8†	0	43.0		62.0	6.9	22.5
— C_5/C_6		33.0†		85.6†	87.1†		92.3†	92.4†	92.4†		92.4†	92.4†	85.5†

*Utilizations assume a 95 percent stream factor for crude oil units and a 92 percent stream factor for all other units.
†Limited at maximum throughput in model run.

to be required. Shutdowns of distillation capacity would be unlikely at this demand level.

Total product demand for this case is 16.8 MMB/CD, or about 1.1 MMB/CD (6.9 percent) more than that in 1984. Product imports are premised to be 2.0 MMB/CD, about the same as in 1984, resulting in refinery product demand of 14.6 MMB/CD. This is an increase of 0.9 MMB/CD (6.8 percent) from the 1984 level. As in the low demand case, the product demand mix changes from that of 1984, with a smaller proportion of motor gasoline and larger fractions of residual fuel oil, middle distillates, and "other" products. The refinery demand for motor gasoline drops from 6,450 MB/CD in 1984 to 6,300 MB/CD in this case, while demand for the remainder of the products increases. The bulk of the latter are simple distillation types of products, which tend to require less use of conversion equipment for their manufacture. As a result, conversion units on balance have some underutilized capacity.

The catalytic cracking units have modest amounts of slack capacity in most of the models, even in cases in which poorer quality feedstocks using disproportionate amounts of feed capacity were selected. Hydrocracking units are fully utilized in all models, with the capacity directed to manufacture the increased yields of kerosene jet fuel required by the demand pattern. Residual conversion units are considerably underutilized in all regions due to the premised demand mix and level. Similarly, minor amounts of slack capacity exist in the other process units. The octane-enhancing process units (low pressure catalytic reforming, C_5/C_6 isomerization) are again stressed by the conditions of this case and are at full utilization.

In summary, the indicated additions for 1988 together with the reactivation of some refineries appear to be adequate to meet the needs of this high demand scenario. Increased amounts of simple distillation products could be manufactured using the slack distillation capacity, and some additional light products could be made through the use of slack conversion unit capacity.

Optimum/Maximum Light Products

Recognizing that the postulated demand scenarios reduced motor gasoline demand and left some of the refinery conversion facilities under-utilized, it was deemed desirable to determine the limits of industry flexibility. Two cases were developed that permitted full utilization of the coking and cracking capacity at the crude oil charge level of the high demand case. In one of these, the product slate was limited to octane-enhancing capacity planned by 1988. In the other, the model was permitted to "build" additional reforming, alkylation, and C_5/C_6 isomerization capacity where economically viable. This additional capacity might be in the form of new processing units or might result from debottlenecking of existing units.

Table 43 shows that with the crude oil charge rate held constant, products and unit utilizations would result in increased light product manufacture in the high demand case. This mode of operation indicates that the industry has the capability to produce just over 6.7 MMB/CD of motor gasoline, approximately 7 percent above the high demand level and only 5 percent above 1984–1985 levels. Considering the nature of forecasts, and the tendency of modeling efforts to over-optimize, it is reasonable to conclude that the industry flexibility to meet higher annual gasoline demand is limited, particularly on a regional basis. This case indicates that PADD V refiners will experience difficulty in maintaining current levels of gasoline production meeting 1988 specifications. For a portion of the year, with high seasonal demand, these figures would suggest the industry might sustain rates in the 7.0–7.4 MMB/D range through shifts in processing scheme and by minimizing process unit outtages for maintenance.

Table 44 provides information on the industry capability with addition of some octane-enhancing equipment. This analysis indicates a requirement of about 40 thousand barrels per stream day (MB/SD) additional catalytic reforming, nearly 100 MB/SD additional alkylation and another 30 MB/SD C_5/C_6 isomerization beyond the recently announced 156 MB/SD of new capacity. Under these conditions, the industry could produce nearly 7.1 MMB/CD of motor gasoline, just 10 percent above the 1984–1985 actual demand levels. With the lead time required for new capacity, it is unlikely this level could be reached by 1988.

In summary, the various demand cases studied show that the industry can adjust to gradual changes in demand. Problems could result from increased demand for motor gasoline from domestic refineries early in the forecast period, and require a shift in gasoline imports above the 1985 level of nearly 400 MB/CD of gasoline.

TABLE 43

1988 SENSITIVITY TO OPTIMUM MAJOR PRODUCTS WITHOUT NEW FACILITIES CASE

	PADD I	PADD II		PADD III		PADD	PADD V			U.S.
	I–C	II–LC	II–DC	III–LC	III–DC	IV	V–COC	V–CC	Simple	Total
Raw Materials (MB/CD)										
Sweet Crude	788	401	1,270	751	2,285	279	48	186	376	6,384
Light Crude>0.5% Sulfur	57	99	181	177	1,265	56	28	0	5	1,868
Heavy Crude>0.5% Sulfur	226	162	812	314	1,128	131	357	1,316	480	4,926
Total Crude	1,071	662	2,263	1,242	4,678	466	433	1,502	861	13,178
Butanes	15	28	90	23	142	15	15	11	2	341
Vacuum Gas Oil	121	16	4	140	72	0	3	46	(60)	342
Other	20	6	55	57	153	(2)	(1)	33	35	356
Total Feedstocks	**1,227**	**712**	**2,412**	**1,462**	**5,045**	**479**	**450**	**1,592**	**838**	**14,217**
Products (MB/CD)										
Motor Gasoline										
Low Lead Regular	82	60	222	100	401	75	34	123	0	1,097
Unleaded Regular	404	285	909	429	1,462	160	97	420	126	4,292
Unleaded Premium	143	56	170	119	577	16	46	222	0	1,349
Total Motor Gasoline	629	401	1,301	648	2,440	251	177	765	126	6,738
Jet & Kero	74	56	157	139	580	38	74	257	85	1,460
Distillate Fuel	295	132	591	286	1,138	105	101	226	148	3,022
Residual Fuel	51	17	40	143	44	8	63	128	124	618
Asphalt/Road Oil	42	54	61	41	35	24	1	17	153	428
Marketable Coke (FOE)	21	0	65	0	118	7	10	86	0	307
Other	49	18	77	147	439	20	15	78	172	1,015
LPG & Refinery Fuel	129	57	226	107	473	40	27	157	19	1,235
(Gain)/Loss	(63)	(23)	(106)	(49)	(222)	(14)	(18)	(122)	11	(606)
Total Products	**1,227**	**712**	**2,412**	**1,462**	**5,045**	**479**	**450**	**1,592**	**838**	**14,217**
Unit Utilization (%)*										
Crude — Atmospheric	87.0	84.3	90.8	80.0	89.7	83.0	89.0	73.4	65.0	8.40
— Vacuum	82.0	83.7	94.7	76.2	86.9	94.7	105.0	76.4	52.0	83.1
Catalytic Reforming	92.3†	65.0	92.2†	92.6†	92.5†	82.4	92.7†	78.4	92.4†	88.4
RONC	99.7	97.0	97.7	98.9	98.6	94.7	99.6	99.8	98.0	98.5
Catalytic Cracking	92.3†	92.6†	92.5†	92.5†	92.3†	92.2†	92.3†	92.6†	—	92.4†
Conversion	78.1	75.1	74.9	79.6	78.6	75.8	75.0	70.0	—	76.6
Hydrocracking	92.5†	93.8†	91.0†	91.3†	92.7†	91.7†	92.6†	92.6†	85.0	92.4†
Coking	89.0	—	92.6†	—	90.7	92.1†	92.6†	92.4†	—	91.7
Coke Make (FOE)	68.1	—	90.6	—	69.4	69.2	73.0	98.2	—	79.9
Alkylation	91.3	71.2	92.6†	92.4†	77.3	92.6†	89.3	90.0	—	84.5
Isomerization — C_4	—	11.9	29.3	54.6	0	36.3	85.0	10.6	—	28.2
— C_5/C_6	33.0†	85.6†	87.1†	92.3†	92.4†	92.4†	92.4†	92.4†	92.4†	85.5†

*Utilizations assume a 95 percent stream factor for crude oil units and a 92 percent stream factor for all other units.
†Limited at maximum throughput in model run.

TABLE 44

1988 SENSITIVITY TO MAXIMUM MAJOR LIGHT PRODUCTS
WITH NEW FACILITIES CASE

	PADD I	PADD II		PADD III		PADD	PADD V			U.S.
	I–C	II–LC	II–DC	III–LC	III–DC	IV	V–COC	V–CC	Simple	Total
Raw Materials (MB/CD)										
Sweet Crude	777	395	1,270	885	2,185	279	48	186	376	6,401
Light Crude>0.5% Sulfur	50	104	181	151	1,345	56	28	0	5	1,920
Heavy Crude>0.5% Sulfur	244	163	812	206	1,148	131	357	1,316	480	4,857
Total Crude	1,071	662	2,263	1,242	4,678	466	433	1,502	861	13,178
Butanes	20	44	116	55	301	17	17	41	2	613
Vacuum Gas Oil	121	16	4	38	72	0	3	46	(60)	240
Other	20	6	55	57	153	(2)	(1)	33	35	356
Total Feedstocks	**1,232**	**728**	**2,438**	**1,392**	**5,204**	**481**	**452**	**1,622**	**838**	**14,387**
Products (MB/CD)										
Motor Gasoline										
Low Lead Regular	84	64	224	109	432	77	37	127	0	1,154
Unleaded Regular	410	303	920	465	1,575	163	106	433	126	4,501
Unleaded Premium	145	59	172	129	623	16	51	229	0	1,424
Total Motor Gasoline	639	426	1,316	703	2,630	256	194	789	126	7,079
Jet & Kero	71	57	158	123	559	37	62	257	85	1,409
Distillate Fuel	282	119	596	251	1,096	103	86	226	148	2,907
Residual Fuel	64	18	40	74	53	8	77	129	124	587
Asphalt/Road Oil	42	54	61	41	35	24	1	17	153	428
Marketable Coke (FOE)	22	0	65	0	118	7	10	86	0	308
Other	49	18	77	147	439	20	15	78	172	1,015
LPG & Refinery Fuel	128	58	226	95	475	40	25	158	19	1,224
(Gain)/Loss	(65)	(22)	(101)	(42)	(201)	(14)	(18)	(118)	11	(570)
Total Products	**1,232**	**728**	**2,438**	**1,392**	**5,204**	**481**	**452**	**1,622**	**838**	**14,387**
Unit Utilization (%)*										
Crude — Atmospheric	87.0	84.3	90.8	80.0	89.7	83.0	89.0	73.4	65.0	84.0
— Vacuum	82.0	83.7	94.7	76.2	86.9	94.7	105.0	76.4	52.0	83.1
Catalytic Reforming	87.5	71.9	92.3	92.3†	92.4†	83.7	92.6†	77.0	92.2†	89.3
RONC	98.7	96.5	97.4	97.6	98.2	94.6	99.6	99.6	98.0	98.0
Catalytic Cracking	92.3†	92.6†	92.5†	92.5†	92.3†	92.2†	92.3†	92.6†	—	92.4†
Conversion	76.5	74.3	75.2	78.3	78.1	76.5	73.3	70.0	—	75.9
Hydrocracking	92.5†	93.8†	91.0†	91.3†	92.7†	91.7†	92.6†	92.6†	85.0	92.4†
Coking	97.8†	—	92.6†	—	91.2	92.4†	92.6†	92.4†	—	92.0
Coke Make (FOE)	16.0	—	52.0	—	88.0	2.0	5.0	66.0	—	229.0
Alkylation	92.7†	84.8	92.6†	92.7†	92.3†	92.6†	91.2	92.2†	—	92.3
Isomerization — C_4	—	104.3	92.0†	92.8†	92.0	69.7	93.4	92.4	—	84.9
— C_5/C_6	47.7†	85.6†	87.1†	92.3†	92.4†	92.6†	92.4†	92.4†	92.4†	86.0†

*Utilizations assume a 95 percent stream factor for crude oil units and a 92 percent stream factor for all other units.
†Limited at maximum throughput in model run.

REFINER RESPONSE TO LEAD PHASEDOWN

In March 1985, the EPA finalized lead phasedown regulations, which restricted the lead in gasoline to 0.10 gplg effective January 1, 1986. However, refiners who "banked" lead by using less than the maximum allowable lead level in 1985 can use that lead in 1986 and 1987 (or sell to others) to ease the phasedown to 0.10 gplg. After December 31, 1987, the use of banked lead will not be allowed. Because 1988 will be the first year of a rigid 0.10 gplg lead standard, a comparison of survey data for the years 1984 and 1988 provides an aggregated projection of gasoline production, octane quality, process changes, and other requirements to meet perceived 1988 consumer demands and comply with lead phasedown. Table 45 summarizes the gasoline volumes by grade and quality for 1984 and 1988 as reported by respondents to the NPC survey.

Several observations can be made from the data in Table 45:

- At the grade mix assumed for 1988, the clear octane of the gasoline pool must increase about 1.9 octane numbers to meet the reduction of lead from 1.1 gplg in 1984 to 0.10 gplg in 1988.
- The average as-blended gasoline pool shows a minor reduction of 0.2 octane number.
- The industry expects individual grade octane levels in 1988 to remain about the same as in 1984.
- Projections of gasoline volumes and quality are based on no change in RVP specifications—a national annual average of 11.68 psi in both years.
- The grade ratio of leaded regular is expected to decline by more than one-half—from 38 percent to 16 percent of total production. Leaded premium will essentially disappear from the market.

TABLE 45

GASOLINE PRODUCTION REPORTED BY SURVEY RESPONDENTS

	U.S. Total					
	1984 Actual			1988 Projected		
	MB/CD	Octane	%	MB/CD	Octane	%
Unleaded Regular	2,870	(87.1)	45.5	4,000	(87.1)	62.2
Unleaded Intermediate	95	(89.3)	1.5	214	(89.2)	3.3
Unleaded Premium	887	(91.9)	14.1	1,170	(91.8)	18.2
Leaded Regular	2,413	(88.8)	38.2	1,050	(88.6)	16.3
Leaded Premium	45	(91.6)	0.7	1	(91.2)	—
Total	**6,310**	**(88.5)**	**100.0**	**6,435**	**(88.3)**	**100.0**
(R+M)/2 Clear*		86.2			88.1	
Lead (gplg)		1.06			0.10	
MMT (gplg) †		0.10			0.10	
RVP		11.68			11.68	
Memo: No. of Refineries						
Making Unleaded Regular		133			130	
Making Other Unleaded		110			124	
Making Leaded Regular		140			87	
Making Leaded Premium		16			3	
Using MMT		15			25	

*Calculated by removing estimated octane boost of lead content from leaded gasoline portion.
†gplg figures apply only to those gallons containing MMT.

- The number of refineries that expect to be making leaded regular declines from 140 to 87, a 38 percent reduction.
- The number of refineries planning to use MMT (methylcyclopentadienyl manganese tricarbonyl) in leaded gasoline increases somewhat from 15 to 25 refineries, about 30 percent of those refineries remaining in the leaded gasoline business.
- Respondents indicated a plan to increase gasoline production 2 percent net over the 1984-1988 period for domestic refineries.

Processing changes to compensate for the octane-enhancement qualities of lead can come from a number of sources. A review of the changes reported in the survey indicates that the principal steps taken by most respondents from 1984 to 1988 were (1) increased reformer severity and feed rate, (2) isomerization of low-octane C_5/C_6 stocks to improve their octane value, (3) increased production of high-octane alkylate, (4) diversion of low-octane C_5/C_6 stocks out of gasoline to other uses where practical, (5) reduced natural gasoline and condensate feedstocks to decrease the amount of low-octane C_5/C_6 entering the gasoline pool, and (6) increased use of oxygenates.

Table 46 summarizes the process changes that the respondents reported to accomplish the gasoline production levels shown in Table 45. Some of the key changes are as follows:

- *Reformers*
  - —Feed rates are increased by 331 MB/CD to 2,776 MB/CD.
  - —Average reformer severities are increased by 2.3 RONC.
  - —The 116 MB/CD decrease in capacity results from a combination of increased severity, conversion of some units to isomerization, and unit shutdowns and capacity increases that were not separately quantified in the survey.
- *C_5/C_6 Isomerization*
  - —156 MB/CD of isomerization capacity is added. Eighteen new units or conversions are indicated by 1988.
  - —Feed rates to new and existing units increase a total of 170 MB/CD.
  - —A reduction in average octane value of product probably reflecting an increase in proportion of once-through process design.
- *Alkylation Units*
  - —50 MB/CD net additional capacity is added.
  - —Alkylate production is increased 121 MB/CD.
- *Naphtha Rejection*
  - —About 80 MB/CD of additional unfinished naphtha is produced. Although not specifically noted in the survey, this is assumed to be low-octane light straight-run material. Essentially all of this increase occurs in PADD III.
  - —Low-octane field condensate and natural gasoline feedstocks are also reduced by about 80 MB/CD.
- *Oxygenates*
  - —Planned use of oxygenates at refineries increases from 25.7 MB/CD to 49.2 MB/CD, primarily ethanol and MTBE.

The survey results tend to point to two principal conclusions about lead phasedown.

First, although spare reformer and alkylation capacity appear to be available, *on average*, to boost octane in most areas, the capacity is not sufficient or in the right location to avoid the need for some refiners to build new facilities. A net increase of 18 isomerization units totaling 156 MB/CD, and 50 MB/CD of additional aklylation capacity have been projected by 1988. Some reformer capacity additions are also included, but are masked by the overall decrease in capacity due to severity increases and possible conversion of older units to C_5/C_6 isomerization.

Second, the source of the 1.9 (R+M)/2 clear pool octane boost to replace the lead removed comes principally from octane enhancement of paraffinic material, as shown below:

Increased Reformer Feed and Severity	50%
Additional Isomerization Units	20%
Light Naphtha Rejection	20%
Increased Oxygenates	5%
Other (Primarily Alkylation)	5%
	100%

The above estimates are based on an approximation of the weighted octane-barrel contribution of each of the changes shown in Table 46, compared to the total octane-barrel increase

TABLE 46

SELECTED PROCESS CHANGES REPORTED BY SURVEY RESPONDENTS GASOLINE LEAD PHASEDOWN — ACTUAL 1984 AND PROJECTED 1988

	U.S. Total (MB/CD)		
	Actual 1984	Projected 1988	Increase (Decrease)
Reformers			
Feed Capacity	3,364	3,248	(116)
Feed Rate	2,445	2,776	331
Octane (RONC)	94.8	97.1	2.3
C_5/C_6 Isomerization			
Feed Capacity	112	268	156
Feed Rate	58	228	170
No. of Refineries	9	27	18
Octane (RONC)	88.1	84.9	(3.2)
Alkylation Units			
Production Capacity	861	911	50
Production	630	751	121
Octane (RONC)	93.2	93.3	0.1
Naphtha Rejection			
Unfinished Naphtha	137	218	81
Field Condensate	62	42	(20)
Natural Gasoline	151	93	(58)
Total Rejection	—	—	**159**
Oxygenate Blending			
Ethanol	2.6	14.8	12.2
Methanol	3.0	5.0	2.0
TBA	7.7	5.5	(2.2)
MTBE	12.4	23.9	11.5
Total Oxygenates	**25.7**	**49.2**	**23.5**
No. of Refineries	29	39	10

required of 1.9 (R+M)/2 × 6,435 MB/CD (12.2 million octane-barrels per day).

Variation in this "U.S. average" response is readily apparent when Table 46 data are disaggregated into the nine modeling groups. These data are shown in Table 47.

Although some of the data are not available in order to protect confidentiality, some general observations can be made:

- PADD IV and PADD V refiners have the apparent ability to utilize and expect to rely on increased reformer severity and feed rates to compensate for lead phasedown to a much larger degree than refiners in other PADDs.
- PADD II refiners expect to place a greater dependence on C_5/C_6 isomerization to cope with low-octane light gasoline than other PADDs. Nine of the eighteen new isomerization units are in groups II-LC and II-DC.
- As would be expected, most of low-octane naphtha rejection is in PADD III, where alternative use as petrochemical feedstock is more viable.

TABLE 47

SELECTED PROCESS CHANGES BY REGION/COMPLEXITY GROUP

	Incremental Change — 1988 vs. 1984 Increase (Decrease)								
	I–C	II–LC	II–DC	III–LC	III–DC	IV	V–COC	V–CC	No Conversion
No. of Refineries*	11	9	22	14	30	13	6	14	16
Reformers									
Capacity (MB/CD)	(25.6)	(31.0)	(33.2)	(19.7)	25.5	(2.9)	3.0	(23.2)	‡
Feed Rate (MB/CD)	4.2	4.9	42.9	28.4	171.6	10.0	5.5	62.7	‡
Octane (RONC)	1.7	1.8	2.5	2.5	2.0	8.1	3.2	2.4	‡
C_5/C_6 Isomerization									
Capacity Additions (MB/CD)	‡	14.1	57.8	‡	39.0	‡	—	‡	‡
Feed Rate (MB/CD)	‡	10.5	61.7	‡	48.3	‡	—	‡	‡
No. of New Units	0	2	7	2	3	1	—	1	2
Alkylation Units (MB/CD)									
Capacity Additions	6.8	(6.0)	1.6	2.4	44.7	1.2	—	(1.0)	—
Alkylate Production	11.2	1.3	9.3	10.0	82.2	0.2	2.5	1.2	—
Naphtha Rejection (MB/CD)									
Unfinished Naphtha	5.8	—	—	(3.6)	80.0	—	‡	‡	‡
Natural Gas & Condensate	—	‡	17.5	14.4	23.5	(0.6)	—	5.1	‡
Total Rejection	5.8	‡	17.5	10.8	103.5	(0.6)	‡	5.1	‡
Oxygenate Blending									
Oxygenates (MB/CD)	‡	‡	6.4	1.6	8.4	—	—	*	‡
No. of Refineries†	4	3	6	6	14	0	0	2	4

*Refineries reporting gasoline production in 1988.
†Refineries reporting oxygenate use in 1988.
‡Data withheld to protect confidentiality.

- Oxygenate blending is expected to continue to be concentrated in PADDs II and III.
- The processing unit capacity additions are concentrated most heavily in PADDs II and III.
- Reformer additions were not separately identified in the survey. Capacity increases are apparent in groups III-DC and V-COC. Additions to capacity in other groups are masked by derating of feed rate due to higher severity or retirements from this service. Recent published information on announced reformer additions indicates that as many as 13 new projects, totaling approximately 170 MB/SD, may be in the engineering/construction phase. Most of this addition of capacity is in PADD III.

Even with the reported additions and changes to refinery octane-producing capability, the industry projects a lower maximum capability to produce motor gasoline meeting 1988 lead level requirements. In the survey, respondents were asked to report maximum capability at the 1988 lead level of 0.1 gplg as well as the 1.1 gplg lead level permissible at the time the survey was conducted. This latter comparison serves as an indication of the impact of lead phasedown on gasoline production capacity. Table 48 shows the relative effect of lead phasedown on this capacity as reported in the survey. The data in this table indicate a negative impact of about 100 MB/CD on gasoline production capability as a result of lead phasedown with facility additions indicated in the survey. This estimate is based on the data of those responding to this section of the survey (96 percent of 1988 planned production).

TABLE 48

RESPONSE TO SURVEY SECTION D GASOLINE MANUFACTURING CAPABILITY (MB/CD)

Respondents' Planned 1988 Gasoline Production	1988 Maximum Gasoline Capability	
	at 1.1 gplg	at 0.1 gplg
6,211	6,533	6,432

The cost of the new isomerization units is estimated in the range of $300 million. Construction costs for alkylation and reformer capacity additions have not been estimated since survey data provide only the net change resulting from additions and shutdowns.

GASOLINE PRODUCTION CAPABILITY

The assessment of U.S. refinery gasoline production capability contained in this chapter has been derived from two principal sources: from the NPC's 1985 survey, and from mathematical models of the refining industry updated and run for the NPC by Turner, Mason and Company. Portions of this chapter will use these model case studies to test some of the limitations and assessments of gasoline production capability that may or may not be apparent from survey results.

This section will focus primarily on the following aspects of gasoline production capability for 1988:

1. At production levels required by the low demand case.
2. At production levels required by the high demand case.
3. At optimum capability to produce light products.
4. Cases 2 and 3 above will be assessed under 3 scenarios:
   - Current octane levels
   - A reduction of 1 psi in RVP
   - A 1.0 octane number increase above current levels for *unleaded* grades only.

In addition, this section will deal with the estimated impacts created by the above premised constraints on process unit requirements, volume effects, and costs. In some cases, these impacts can be assessed from survey data. In others, the impacts are more subjective and will rely to a larger extent on refinery model results. In all of these cases, it is important to note that the impact may only represent an average for that group and will vary significantly for individual refineries.

Low Demand Case

The low demand case placed 1988 gasoline productions requirements on U.S. refineries at only 5,531 MB/CD, approximately 900 MB/CD, or 14 percent, below 1984 actual production. Survey data provided by respondents indicated a planned gasoline production level of 6,435

MB/CD for 1988 (Section C of the survey), with the processing unit additions required for the phasedown to 0.10 gplg in place and operating. It was readily apparent from this comparison that gasoline production capability would not be stressed at the low demand level and further testing of additional constraints was not warranted.

High Demand Case

The high demand case provided a 1988 gasoline production requirement from refiners of 6,302 MB/CD, still slightly below the respondents' projected production level of 6,435 MB/CD for 1988. Actual production of gasoline in 1984 and 1985 was 6,453 MB/CD and 6,419 MB/CD, respectively. The 6,302 MB/CD production level was tested using the model and the results confirmed the capability of this level of operation.

Optimum Gasoline Capability

The optimum capability case was undertaken to depict conditions that could more nearly replicate portions of the survey data contained in Section D and upon the industry projection for gasoline production in 1988. The model results show a yearly average gasoline volume of 6,738 MB/CD, slightly higher than the estimates provided by survey respondents.

The high level of refiner response to the 1985 survey questionnaire provides good support for reliance on survey data for certain portions of this report. The 1984 motor gasoline production data from the survey is quite consistent with data published in the DOE 1984 Petroleum Supply Annual. Motor gasoline produced by the survey respondents represented 97.8 percent of 1984 total gasoline production as shown in Table 49.

Table 50 compares the survey results and the model results for selected processing data at three levels of gasoline production:

- 1984 actual production as reported by the survey respondents vs. the 1984 calibration runs to validate the model.
- 1988 gasoline production as projected by the survey respondents vs. the 1988 model results for the high demand case.
- 1988 maximum gasoline capability as reported by survey respondents vs. the optimum light products case determined by the model. Assessment of this case will be addressed later in this section.

Given that the model is designed to represent a slightly larger refinery population (to include nonrespondents to the survey), several observations can be made with regard to key factors affecting gasoline capability:

- 1984 calibration of the model to NPC survey results is very close.
- 1988 model runs were set at slightly lower gasoline demands to concur with the NPC high demand forecast, but key process changes relate quite well to survey results for 1988.
- 1988 model crude oil runs were somewhat higher in the high demand case, to meet higher demands for distillate and residual fuels rather than gasoline.
- A smaller increase in reformer feed rate in the model is compensated for by higher severity.
- Isomerization, alkylation, naphtha rejection, and oxygenate use are consistent with survey results.

TABLE 49

1984 U.S. MOTOR GASOLINE PRODUCTION (MB/CD)

	Produced by Respondents to Survey	Actual U.S. Total DOE-PSA	Percentage of U.S Total in Survey
Unleaded	3,852	3,882	99.2
Leaded	2,458	2,571	95.6
Total Motor Gasoline	**6,310**	**6,453**	**97.8**

TABLE 50

COMPARISON OF TOTAL U.S. REFINERY GASOLINE PRODUCTION CASES
NPC SURVEY VS. MODEL RESULTS

	NPC Survey			Model		
	1984 Actual	1988 Projected	1988 Maximum Gasoline	1984 Calibration	1988 High Demand	1988 Optimum Products
No. of Refineries	179	172	N.A.	214	202	202
Crude Oil Rate (MB/CD)	11,643	12,420	N.A.	12,044	13,178	13,178
Gasoline Production (MB/CD)	6,310	6,435	6,656	6,453	6,302	6,738
Reformers						
Feed Rate (MB/CD)	2,445	2,776	N.A.	2,427	2,604	2,741
Octane (RONC)	94.8	97.1	N.A.	94.6	98.0	98.9
C_5/C_6 Isomerization						
Feed Rate (MB/CD)	58	228	N.A.	72	234*	234*
Alkylation						
Production (MB/CD)	630	751	N.A	595	725	756
Naphtha Rejection (MB/CD)						
Unfinished Naphtha	137	218	N.A.	98	199	93
Natural Gas & Condensate	213	135	N.A.	209	125	125
Oxygenates (MB/CD)	26	49	79	25	58	58
Average Octane [(R+M)/2]	88.5	88.3	88.2	88.5	88.3	88.3

*At maximum.

Gasoline Capability

Amplifying further on the subject of annual gasoline capability in the year 1988, Table 51 presents aggregations of responses by model group and for the U.S. total. The columns are not additive since data for the group of nonconversion refineries and most of PADD II low conversion refineries are not available in order to protect the confidentiality of individual respondents. The U.S. totals, however, were aggregated to include the responses from these groups as well as the groups for which data are shown.

Data in this table represent responses from refineries that represented 6,211 MB/CD of the 6,435 MB/CD total gasoline production projected by survey respondents for 1988. These refineries indicate a capability of increasing production to 6,432 MB/CD, an increase of 221 MB/CD, at essentially the same octane level and unleaded premium grade ratio. Factoring this increase up to include the nonrespondents, but without assuming any increase for that group, gives the following:

Capability from Table 51	6,432 MB/CD
Nonrespondents to I-D (6,435-6,211)	224 MB/CD
Est. Maximum Gasoline Capacity (Survey Basis)	6,656 MB/CD

This is slightly less than the 6,738 MB/CD developed from the modeling effort. This should be expected in recognition of the larger refinery population and higher crude oil charge rate included in the model results. The survey results also include minor discrepancies in refinery count.

Historical monthly data (Figure 15) indicate that refinery gasoline production has in fact reached a 6.7-6.8 MMB/CD level four months during the past two years and has exceeded 7 MMB/CD briefly this year. It should be noted, however, that these production levels were accomplished with higher gasoline lead content levels than will be permitted in 1988, and reflect short-term monthly production levels rather than an annual average.

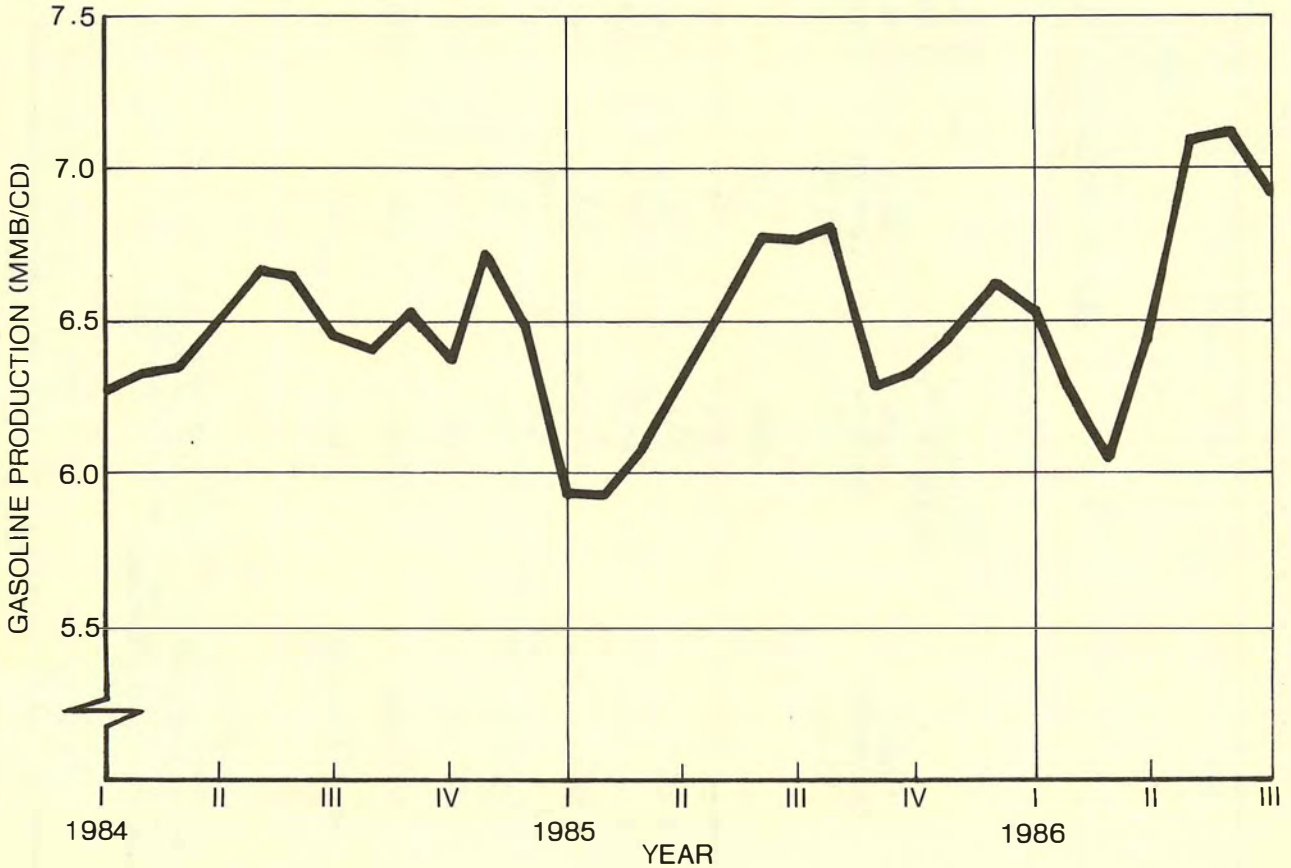


Figure 15. U.S. Refinery Gasoline Production.

TABLE 51

NPC SURVEY RESULTS
GASOLINE MANUFACTURING CAPABILITY
PROJECTED 1988

Region/ Complexity Group	Respondents to Survey Section C	Respondents to Survey Section D*					
		Maximum Gasoline† (1.1 gplg)			Maximum Gasoline† (0.1 gplg)		
	Total Gasoline (MB/CD)	Total Gasoline (MB/CD)	Premium Ratio‡ (%)	Average Octane (R+M)/2	Total Gasoline (MB/CD)	Premium Ratio (%)	Average Octane (R+M)/2
I-C	576	576	21.8	88.6	581	21.7	88.6
II-LC	307	§	§	§	§	§	§
II-DC	1,264	1,210	14.2	87.9	1,254	14.2	87.9
III-LC	632	598	20.6	88.0	642	17.9	88.0
III-DC	2,378	2,301	23.6	88.5	2,342	23.7	88.5
IV	207	181	6.1	86.0	210	10.9	86.1
V-COC	206	206	22.3	88.3	207	18.7	88.0
V-CC	788	788	22.1	88.6	815	21.1	88.4
U.S. Total	**6,435**	**6,211**	**21.9**	**88.2**	**6,432**	**20.0**	**88.2**
No. of Refineries	135	131			132		

*Data were not received from all NPC survey respondents.
†Survey requested maximum capability to produce unleaded gasoline.
‡Premium ratio expressed as percentage of total gasoline.
§Data withheld to protect confidentiality.

Taking all of these factors into consideration, a figure of 6.7–6.8 MMB/CD appears to be a reasonable assessment of U.S. 1988 annual gasoline production capability without further investment and at crude oil rates of approximately 13 MMB/CD. This capability represents an annual average and does not reflect seasonal or operational variations that might permit levels as high as 7.4 MMB/D during peak demand.

It should also be noted that the 6.7–6.8 MMB/CD figure assumes the average RVP specifications, octane levels, and grade ratios outlined in Table 45 for 1988. Gasoline production capability is sensitive to these factors and is addressed later in this chapter.

Table 52 provides the details of the model's material balance by group and indicates that numerous gasoline units are at maximum limits in a number of areas. One of the conclusions of this study then is that very little additional gasoline production could be accomplished by increases in crude oil rate above 13.2 MMB/CD. Additional conversion capacity and/or debottlenecking of existing units would likely be required to exceed the 6.7–6.8 MMB/CD capacity.

Maximum Light Products

Survey respondents were not requested to indicate their ability to increase gasoline production capability by adding facilities beyond those planned for 1988.

To estimate the capability of the industry to cope with a demand higher than the 6.7–6.8 MMB/CD average annual rate, an additional case was analyzed by the model. In this case, additional gasoline octane-enhancing facilities were allowed to be added over and above that reported for 1988 by survey results. The results of this case are shown in Table 53.

The model results indicate that it may be possible to increase annual average gasoline capability to about 7.1 MMB/CD (300 MB/CD increase) with a modest amount of new octane-enhancing facilities and debottlenecking. This capability is premised on the following:

- Butane feedstocks were increased about 27 MB/CD, and a minor shift of 70 MB/CD was made from heavy to light crude oils.
- Middle distillate production was reduced about 165 MB/CD.
- Debottlenecking or additions of octane-enhancement units comprising catalytic reforming, alkylation, and C_5/C_6 isomerization.

It should be recognized that the capacity additions represent a model-optimized minimum for each refinery group in the model. In actual practice, the increased production capability could be less, or facility additions greater, because of constraints on the capability of individual refiners.

Reid Vapor Pressure Effects

The effect of RVP reduction was estimated under three refining industry production premises: (A) 1988 high demand case, (B) 1988 high demand case plus one octane number increase for unleaded gasoline with leaded grade remaining constant, and (C) a 1988 optimum light product production case, using the models. The two projected high demand cases were compared at a constant crude oil and product rate. New capacities for octane-enhancement units were allowed to be added as necessary to compensate for the effect of RVP reduction although, in reality, construction lead time would be required. The difference in operating costs and capital charges are shown in Table 54.

The cost to the refining industry for a 1 lb. vapor pressure reduction in gasoline specification has been estimated to be $400–460 million annually in Cases A and B. The cost at the high end of this range occurs when increased octane requirements are combined with reduced RVP. Gasoline production required in the 1988 high demand cases (A and B) was about 6.3 MMB/CD, somewhat lower than actual 1984 refinery production. At this demand level the industry capacity has not been stressed and, thus, the modeling is prone toward over-optimization. Therefore, the full cost of RVP reduction is probably on the low side. In Case C (see Table 54) the models defined a base operation for the optimum production of light products before projecting the effect of an RVP reduction. The gasoline production in Case C was 6.7–6.8 MMB/CD before RVP reduction and represents the industry production limit without additional equipment. Meeting the reduced RVP required that 2 percent of the butane be removed from the motor gasoline pool. Since the ability to cope with the octane loss varied among the model groups, the loss in gasoline production capability shown in Table 55 ranged from 2.1 percent to 5.0 percent with an average of 2.8 percent, or approximately 200 MB/CD. The cost in this case

TABLE 52

1988 SENSITIVITY TO OPTIMUM MAJOR PRODUCTS WITHOUT NEW FACILITIES CASE

	PADD I	PADD II		PADD III		PADD IV	PADD V		Simple	U.S. Total
	I–C	II–LC	II–DC	III–LC	III–DC		V–COC	V–CC		
Raw Materials (MB/CD)										
Sweet Crude	788	401	1,270	751	2,285	279	48	186	376	6,384
Light Crude>0.5% Sulfur	57	99	181	177	1,265	56	28	0	5	1,868
Heavy Crude>0.5% Sulfur	226	162	812	314	1,128	131	357	1,316	480	4,926
Total Crude	1,071	662	2,263	1,242	4,678	466	433	1,502	861	13,178
Butanes	15	28	90	23	142	15	15	11	2	341
Vacuum Gas Oil	121	16	4	140	72	0	3	46	(60)	342
Other	20	6	55	57	153	(2)	(1)	33	35	356
Total Feedstocks	**1,227**	**712**	**2,412**	**1,462**	**5,045**	**479**	**450**	**1,592**	**838**	**14,217**
Products (MB/CD)										
Motor Gasoline										
Low Lead Regular	82	60	222	100	401	75	34	123	0	1,097
Unleaded Regular	404	285	909	429	1,462	160	97	420	126	4,292
Unleaded Premium	143	56	170	119	577	16	46	222	0	1,349
Total Motor Gasoline	629	401	1,301	648	2,440	251	177	765	126	6,738
Jet & Kero	74	56	157	139	580	38	74	257	85	1,460
Distillate Fuel	295	132	591	286	1,138	105	101	226	148	3,022
Residual Fuel	51	17	40	143	44	8	63	128	124	618
Asphalt/Road Oil	42	54	61	41	35	24	1	17	153	428
Marketable Coke (FOE)	21	0	65	0	118	7	10	86	0	307
Other	49	18	77	147	439	20	15	78	172	1,015
LPG & Refinery Fuel	129	57	226	107	473	40	27	157	19	1,235
(Gain)/Loss	(63)	(23)	(106)	(49)	(222)	(14)	(18)	(122)	11	(606)
Total Products	**1,227**	**712**	**2,412**	**1,462**	**5,045**	**479**	**450**	**1,592**	**838**	**14,217**
Unit Utilization (%)*										
Crude — Atmospheric	87.0	84.3	90.8	80.0	89.7	83.0	89.0	73.4	65.0	84.0
— Vacuum	82.0	83.7	94.7	76.2	86.9	94.7	105.0	76.4	52.0	83.1
Catalytic Reforming	92.3†	65.0	92.2†	92.6†	92.5†	82.4	92.7†	78.4	92.4†	88.4
RONC	99.7	97.0	97.7	98.9	98.6	94.7	99.6	99.8	98.0	98.5
Catalytic Cracking	92.3†	92.6†	92.5†	92.5†	92.3†	92.2†	92.3†	92.6†	—	92.4†
Conversion	78.1	75.1	74.9	79.6	78.6	75.8	75.0	70.0	—	76.6
Hydrocracking	92.5†	93.8†	91.0†	91.3†	92.7†	91.7†	92.6†	92.6†	85.0	92.4†
Coking	89.0	—	92.6†	—	90.7	92.1†	92.6†	92.4†	—	91.7
Coke Make (FOE)	68.1	—	90.6	—	69.4	69.2	73.0	98.2	—	79.9
Alkylation	91.3	71.2	92.6†	92.4†	77.3	92.6†	89.3	90.0	—	84.5
Isomerization — C_4	—	11.9	29.3	54.6	0	36.3	85.0	10.6	—	28.2
— C_5/C_6	33.0†	85.6†	87.1†	92.3†	92.4†	92.4†	92.4†	92.4†	92.4†	85.5†

*Utilizations assume a 95 percent stream factor for crude oil units and a 92 percent stream factor for all other units.
†Limited at maximum throughput in model run.

TABLE 53

1988 SENSITIVITY TO MAXIMUM MAJOR LIGHT PRODUCTS WITH NEW FACILITIES CASE

	PADD I	PADD II		PADD III		PADD	PADD V			U.S.
	I–C	II–LC	II–DC	III–LC	III–DC	IV	V–COC	V–CC	Simple	Total
Raw Materials (MB/CD)										
Sweet Crude	777	395	1,270	885	2,185	279	48	186	376	6,401
Light Crude >0.5% Sulfur	50	104	181	151	1,345	56	28	0	5	1,920
Heavy Crude >0.5% Sulfur	244	163	812	206	1,148	131	357	1,316	480	4,857
Total Crude	1,071	662	2,263	1,242	4,678	466	433	1,502	861	13,178
Butanes	20	44	116	55	301	17	17	41	2	613
Vacuum Gas Oil	121	16	4	38	72	0	3	46	(60)	240
Other	20	6	55	57	153	(2)	(1)	33	35	356
Total Feedstocks	**1,232**	**728**	**2,438**	**1,392**	**5,204**	**481**	**452**	**1,622**	**838**	**14,387**
Products (MB/CD)										
Motor Gasoline										
Low Lead Regular	84	64	224	109	432	77	37	127	0	1,154
Unleaded Regular	410	303	920	465	1,575	163	106	433	126	4,501
Unleaded Premium	145	59	172	129	623	16	51	229	0	1,424
Total Motor Gasoline	639	426	1,316	703	2,630	256	194	789	126	7,079
Jet & Kero	71	57	158	123	559	37	62	257	85	1,409
Distillate Fuel	282	119	596	251	1,096	103	86	226	148	2,907
Residual Fuel	64	18	40	74	53	8	77	129	124	587
Asphalt/Road Oil	42	54	61	41	35	24	1	17	153	428
Marketable Coke (FOE)	22	0	65	0	118	7	10	86	0	308
Other	49	18	77	147	439	20	15	78	172	1,015
LPG & Refinery Fuel	128	58	226	95	475	40	25	158	19	1,224
(Gain)/Loss	(65)	(22)	(101)	(42)	(201)	(14)	(18)	(118)	11	(570)
Total Products	**1,232**	**728**	**2,438**	**1,392**	**5,204**	**481**	**452**	**1,622**	**838**	**14,387**
Unit Utilization (%)*										
Crude — Atmospheric	87.0	84.3	90.8	80.0	89.7	83.0	89.0	73.4	65.0	84.0
— Vacuum	82.0	83.7	94.7	76.2	86.9	94.7	105.0	76.4	52.0	83.1
Catalytic Reforming	87.5	71.9	92.3	92.3†	92.4†	83.7	92.6†	77.0	92.2†	89.3
RONC	98.7	96.5	97.4	97.6	98.2	94.6	99.6	99.6	98.0	98.0
Catalytic Cracking	92.3†	92.6†	92.5†	92.5†	92.3†	92.2†	92.3†	92.6†	—	92.4†
Conversion	76.5	74.3	75.2	78.3	78.1	76.5	73.3	70.0	—	75.9
Hydrocracking	92.5†	93.8†	91.0†	91.3†	92.7†	91.7†	92.6†	92.6†	85.0	92.4†
Coking	97.8†	—	92.6†	—	91.2	92.4†	92.6†	92.4†	—	92.0
Coke Make (FOE)	16.0	—	52.0	—	88.0	2.0	5.0	66.0	—	229.0
Alkylation	92.7†	84.8	92.6†	92.7†	92.3†	92.6†	91.2	92.2†	—	92.3
Isomerization — C_4	—	104.3	92.0†	92.8†	92.0	69.7	93.4	92.4	—	84.9
— C_5/C_6	47.7†	85.6†	87.1†	92.3†	92.4†	92.6†	92.4†	92.4†	92.4†	86.0†

*Utilizations assume a 95 percent stream factor for crude oil units and a 92 percent stream factor for all other units.
†Limited at maximum throughput in model run.

TABLE 54

MODEL PROJECTION OF INDUSTRY COST
TO REDUCE UNLEADED GASOLINE RVP 1 PSI
1988 SCENARIOS

Case*	Region/ Complexity Group	Gasoline Reduction (%)	Butane Removed (%)	Facilities Added (MB/SD)			Incremental Cost	
				Catalytic Reforming	Alkylation	C_5/C_6 Isomerization	$MM/ Year	¢/bbl Gasoline
A	I-C	—	1.5	—	—	0.2	27	13
	II-LC	—	0.8	—	—	—	22	16
	II-DC	—	1.6†	34.1	—	—	96	20
	III-LC	—	2.0	—	1.8	—	46	23
	III-DC	—	—	—	—	—	99	12
	IV	—	2.0	—	0.7	0.9	28	33
	V-COC	—	1.4	3.5	—	—	18	28
	V-CC	—	1.5†	—	—	—	47	17
	Simple	3.2	2.1	—	—	—	17	37
	U.S. Total	**—**	**1.0†**	**37.6**	**2.5**	**1.1**	**400**	**17**
B	I-C	—	0.8	—	—	—	31	15
	II-LC	—	1.3	—	—	—	22	16
	II-DC	—	0.9†	22.1	—	—	106	22
	III-LC	—	1.9	11.5	0.2	(0.1)	53	27
	III-DC	—	—	24.5	—	(0.6)	123	16
	IV	—	2.1	—	0.2	1.0	30	36
	V-COC	—	1.3	3.7	—	0.6	19	30
	V-CC	—	0.4†	—	—	(8.3)	55	15
	Simple	1.7	—	—	—	—	17	39
	U.S. Total	**—**	**0.4†**	**61.8**	**0.4**	**(7.4)**	**457**	**20**
C	I-C	3.2	2.0	—	—	—	97	43
	II-LC	5.0	2.0	—	—	—	175	37
	II-DC	2.3	2.0†	—	—	—	60	42
	III-LC	2.3	2.0	—	—	—	388	44
	III-DC	3.0	2.0	—	—	—	117	50
	IV	3.2	2.0	—	—	—	39	43
	V-COC	2.8	2.0	—	—	—	25	39
	V-CC	2.1	2.0	—	—	—	83	30
	Simple	3.2	2.0	—	—	—	24	52
	U.S. Total	**2.8**	**2.0†**	**—**	**—**	**—**	**1,007**	**42**

*A — gasoline demand 6.3 MMB/CD.
B — gasoline demand 6.3 MMB/CD, unleaded (R+M)/2 increased 1 number.
C — gasoline production 6.7-6.8 MMB/CD.
†Includes $_nC_4$ isomerization feed changes.

was $1 billion, or more than double the cost in Case B. The cost of RVP reduction cannot be expressed as a single point estimate but is in fact a cost variable depending on the industry base operations. Since much of the rejected butane can be used only as fuel, the cost is sensitive to the price relationship of gasoline and fuel gas.

The survey response data are shown in Table 55 for PADD and refinery type. Butane in gasoline will be reduced about 2 percent with total gasoline declining 2.4-2.6 percent. These percentages agree quite well with the model projections in Case C. No significant change in the use of oxygenates was projected. Cost data were not requested in the survey.

The U.S. refining industry has the ability to produce a maximum of 6.5-6.6 MMB/CD of gasoline at a 1 lb. reduction in RVP, without

TABLE 55

SURVEY RESPONSE DATA
RVP EFFECT ON GASOLINE CAPACITY BY PADD AND CONVERSION GROUPS

Region / Complexity Group	Reid Vapor Pressure (psi)		Projected 1988		
				Reduction Due to Lower RVP	
	Standard	Reduced	Gasoline Capacity (MB/CD)	Gasoline Capacity (%)	Butane in Gasoline (%)
I-C	12.2	11.2	580	3.0	3.6
II-LC	12.2	11.2	*	*	*
II-DC†	12.4	11.4	1,190	4.4	2.5
III-LC	11.5	10.5	633	2.4	2.4
III-DC	11.5	10.5	2,342	2.0	2.4
IV	11.6	10.6	210	2.1	2.6
V-COC	13.0	11.8	208	3.1	3.3
V-CC	10.1	9.5	806	0.2	1.4
Simple	—	—	*	*	*
U.S. Total	**11.6**	**10.6**	**6,349**	**2.4†**	**2.2**

*Data withheld to protect confidentiality.
†Data adjusted to provide consistent respondent population at both levels of RVP.

adding capacity. This represents a decrease of about 200 MB/CD in production capability. The cost for RVP reduction is estimated to be $1 billion per year, or about 1¢ per gallon of gasoline produced. Individual refineries could incur costs significantly greater or less than this average figure. This cost estimate includes the cost of downgrading butane from gasoline to fuel value. The butane removed from gasoline (2 percent, or 132 MB/CD) represents a major share of the butane purchased from natural gas plant production. Some, if not all, refiners will forego these butane purchases and force additional volumes into the market. The cost to the industry to reduce RVP is estimated to be lower when gasoline demands are below maximum gasoline capacity.

The survey data showed no significant change in oxygenate use in gasoline as a result of reduced RVP. The evaluation of the RVP effect through model projections also held oxygenates constant. If more severe vapor pressure limits were imposed on the industry, the use of oxygenates, such as methyl and ethyl alcohol, could significantly decrease without separate consideration of their impact on vapor pressure limits.

Impact of Higher Octane Requirements

The second part to the question that addressed maximum gasoline production capability in the NPC survey requested refineries to increase the octane level one octane number [(R+M)/2] for each grade of unleaded gasoline meeting 1988 specifications while maintaining leaded octane constant and then restate their maximum gasoline capacity.

The response to this part of the survey was inconclusive. In several of the model groups, the respondents to the impact of increased octane were fewer in number than to the maximum gasoline capability. It is not known whether those refineries not responding could not accomplish the octane increase or did not have the data to respond. Therefore, the volume impact of increased octane cannot be measured from survey data. Model results, however, do address this issue.

Nevertheless, several observations can be made regarding the survey data shown in Table 56.

TABLE 56

NPC SURVEY RESULTS
MAXIMUM GASOLINE PRODUCTION CAPABILITY
PROJECTED 1988

Region/ Complexity Group	Maximum Gasoline Base Octanes			Maximum Gasoline Unleaded + 1.0 (R+M)/2			
	Total Gasoline* (MB/CD)	Premium Ratio (%)	Average Octane (R+M)/2	Total Gasoline* (MB/CD)	Premium Ratio (%)	Average Octane (R+M)/2	Octane Increase (R+M)/2
I-C	581 (11)	21.6	88.6	554 (11)	13.8	89.0	0.4
II-LC	† (9)	†	†	† (9)	†	†	†
II-DC	1,254 (22)	14.2	87.9	1,062 (22)	12.0	88.7	0.8
III-LC	642 (14)	17.9	88.0	639 (14)	12.1	88.6	0.6
III-DC	2,342 (30)	23.7	88.5	2,170 (29)	18.4	89.1	0.6
IV	210 (13)	10.9	86.1	208 (13)	4.2	86.7	0.6
V-COC	207 (6)	18.7	88.0	153 (5)	12.4	88.6	0.6
V-CC	815 (14)	21.1	88.4	750 (13)	15.5	89.0	0.6
U.S. Total‡	**6,432 (131)**	**20.0**	**88.2**	**5,920 (125)**	**14.7**	**88.8**	**0.6**
Associated Survey Volume	6,211			N.A.			

*Number of refiners responding are indicated in parentheses.
†Data withheld to protect confidentiality.
‡Includes simple refineries and II-LC.

- The refineries on average were not able to increase the unleaded grades one octane number without a substantial reduction in the percentage of unleaded premium produced. At a constant ratio of premium unleaded to regular unleaded, the total gasoline octane pool should increase about 0.8 since leaded regular approximates 15–20 percent of the gasoline pool. This occurred only in group II-DC where the premium ratio decreased very little.
- The average increase in the total U.S. gasoline pool of 0.6 octane represents a one octane number increase in unleaded grades but a decrease in premium ratio from 20 percent to 15 percent.
- The average increase of 0.6 octane can also be stated to represent a premium ratio increase from 18 percent to 30 percent if octanes remain constant at the levels shown in Table 45.

In modeling the industry, two sensitivity cases were prepared. In the first case, the high demand scenario (6.3 MMB/CD gasoline) and current RVP specifications, the industry would require additions to octane-producing capability in order to maintain a constant mix of gasolines. These were predominantly reforming (60 MB/CD) and isomerization (100 MB/CD) with an associated cost of 38¢ per octane barrel. The model tended to over-optimize in developing this solution with shared use of new capacity and other under-utilized capacity across each refining model. In practice, individual refinery requirements would tend to increase the need for new capacity. The second sensitivity case tested the optimum light products case at 1 psi lower RVP specification with and without the octane increase and without additional facilities beyond those planned by 1988. Results were as follows:

Gasoline Production @ 1 psi lower RVP	
Base Octanes	+1.0(R+M)/2 Unleaded Grades
6,548 MB/CD	6,299 MB/CD

The 250 MB/CD reduction due to octane increase was accompanied by reductions in premium ratio (similar to survey data) in order to accommodate the increase in octane. Table 57 compares the NPC survey and model results.

TABLE 57

COMPARISON OF NPC SURVEY AND MODEL RESULTS IMPACT OF OCTANE INCREASE — PROJECTED 1988 (Optimum Gasoline Cases)

	NPC Survey	Model*
Gasoline Capacity (MB/CD)		
At Base Octane	N.A.	6,548
At +1.0 Unleaded	N.A.	6,299
Volume Decrease	N.A.	249
Premium Ratio (%)		
At Base Octane	20.0	19.8
At +1.0 Unleaded	14.8	16.8
Increased Octane Reported		
I-C	0.3†	0.6†
II-LC	‡	0.9
II-DC	0.8	0.8
III-LC	0.6†	0.7†
III-DC	0.6†	0.5†
IV	0.6†	0.7
V-COC	0.6†	0.5†
V-CC	0.6†	0.8
Average Octane Increase	0.6	0.7

*Model case is at 1 psi lower RVP than NPC survey.
†Groups with indicated octane constraints and reduced premium ratios.
‡Data withheld to protect confidentiality.

Several refinery groups developed octane constraints in the model and were forced to reduce premium ratios. These groups include PADD I, PADD III, and PADD V outside California, as noted in Table 57, and correspond quite well with the groups showing lower octane potential in the NPC survey data.

On balance, the model results reflect a lesser problem in increasing octanes than the survey results, but both are reasonably comparable. This is within the accuracy of model results when recognizing the possibility for excess optimization.

TABLE 58

1988 MAXIMUM SENSITIVITY TO REDUCED GASOLINE VAPOR PRESSURE COMBINED WITH INCREASED GASOLINE OCTANES

	PADD I	PADD II		PADD III		PADD	PADD V			U.S.
	I–C	II–LC	II–DC	III–LC	III–DC	IV	V–COC	V–CC	Simple	Total
Total Costs (MM$/Yr)	263	404	111	1,079	321	60	77	208	74	2,597
RVP Costs (¢/bbl for 1 RVP reduction)	43	37	42	44	50	43	39	30	52	42
Octane Costs (¢/bbl for 1 octane number increase)	89	62	44	97	110	34	104	55	116	81
Raw Materials (MB/CD)										
Sweet Crude	733	411	1,427	751	2,232	279	48	186	376	6,443
Light Crude>0.5% Sulfur	59	91	150	186	915	56	28	0	5	1,490
Heavy Crude>0.5% Sulfur	279	160	686	305	1,531	131	357	1,316	480	5,245
Total Crude	1,071	662	2,263	1,242	4,678	466	433	1,502	861	13,178
NGL, Naphtha, Reformate	0	5	29	0	64	1	0	4	0	103
Butanes	16	28	98	21	142	14	15	11	2	347
Vacuum Gas Oil	121	16	4	119	72	0	3	46	(60)	321
Other	25	5	39	37	105	(2)	0	31	34	274
Total Feedstocks	**1,233**	**716**	**2,433**	**1,419**	**5,061**	**479**	**451**	**1,594**	**837**	**14,223**
Products (MB/CD)										
Motor Gasoline										
Low Lead Regular	75	57	205	89	379	71	32	118	0	1,026
Unleaded Regular	402	274	838	408	1,518	152	103	403	114	4,212
Unleaded Premium	98	54	157	80	411	15	33	213	0	1,061
Total Motor Gasoline	575	385	1,200	577	2,308	238	168	734	114	6,299
Jet & Kero	76	65	179	141	571	40	74	259	85	1,490
Distillate Fuel	304	134	676	289	1,120	109	101	228	148	3,109
Residual Fuel	86	16	35	147	113	8	66	128	124	723
Asphalt/Road Oil	42	54	61	41	35	24	1	17	153	428
Marketable Coke (FOE)	19	0	55	0	121	7	10	86	0	298
Other	49	18	77	154	477	20	15	78	180	1,068
LPG & Refinery Fuel	139	66	235	115	532	46	33	182	22	1,370
(Gain)/Loss	(57)	(22)	(85)	(45)	(216)	(13)	(17)	(118)	11	(562)
Total Products	**1,233**	**716**	**2,433**	**1,419**	**5,061**	**479**	**451**	**1,594**	**837**	**14,223**
Unit Utilization (%)*										
Crude — Atmospheric	87.0	84.3	90.8	80.0	89.7	83.0	89.0	73.4	65.0	84.0
— Vacuum	82.0	83.7	94.7	76.2	86.9	94.7	105.0	76.4	52.0	83.1
Catalytic Reforming	92.3†	68.7	92.2†	92.6†	92.5†	87.3	92.7†	90.3	92.4	90.4
RONC	98.7	96.5	97.4	97.6	98.2	94.6	99.6	99.6	98.0	98.0
Catalytic Cracking	92.3†	92.6†	92.5†	92.5†	92.3†	92.2†	92.3†	92.6†	—	92.4†
Conversion	76.5	74.3	75.2	78.3	78.1	76.5	73.3	70.0	—	75.9
Hydrocracking	92.5†	93.8†	91.0†	91.3†	92.7†	91.7†	92.6†	92.6†	85.0	92.4
Coking	82.4	—	81.1	—	92.3†	92.4†	92.1†	92.4†	—	89.6
Coke Make (FOE)	16.0	—	52.0	—	88.0	2.0	5.0	66.0	—	229.0
Alkylation	92.9†	73.7	92.6†	92.4†	78.8	92.6†	89.9	91.9†	—	85.7
Isomerization — C_4	—	104.3†	21.0	88.7	0	47.1	40.9	15.2	—	33.2
— C_5/C_6	34.4	85.6†	87.1†	92.3†	92.4†	92.4†	92.4†	92.4†	92.4†	85.5†

*Utilizations assume a 95 percent stream factor for crude oil units and a 92 percent stream factor for all other units.
†Limited at maximum throughput in model run.

The model results indicate the cost to be on average about 81¢ per octane-barrel with a range of 34¢ to $1.16 per octane-barrel, as noted in Table 58. These octane costs are at the more severe case of 1 psi lower RVP; however, the model constraints closely approach survey results, and costs, therefore, should be within this reasonable order-of-magnitude estimate.

In view of 1984–1985 gasoline production requirements of 6.4 MMB/CD, the flexibility of refiners to respond to potential increases in gasoline demand, further octane requirement, or RVP constraints appears limited without additions to octane-enhancement facilities.

Use of Oxygenates

Oxygenates can be very important octane enhancers to the small refiner lacking capital to invest in major process equipment. In addition, a large refiner could turn to oxygenates to fill an octane requirement prior to new process equipment being constructed and coming on stream. Oxygenates can also be important for a large refiner with an existing investment in a methanol or ethanol plant or a special incentive to produce MTBE. Ethanol blending has been of great interest to many refiners due to the tax subsidies it has received and therefore good profit potential. In certain situations oxygenates are the most economic alternative to lead as evidenced by their rapid growth over the last five years.

Various factors concerning the use of oxygenates are summarized below; a more complete analysis may be found in Appendix H.

OXYGENATE GROWTH

Table 59 presents the growth in oxygenate consumption through hydrocarbon fuel blends from 1981 through 1985, which has been reported in literature. This represents U.S. consumption and includes significant quantities blended outside refineries. The total consumption has grown from about 18 MB/CD in 1981 to 75 MB/CD in 1985, an increase of 325 percent. Continued growth will be dependent upon the cost of oxygenates relative to motor gasoline.

Ethanol has been the fastest growing of the oxygenates and accounts for 50 MB/CD in 1985, or 66 percent of the total. MTBE consumption has increased from 2 MB/CD in 1981 to about 8 MB/CD in 1985. Methanol consumption has increased from 1 MB/CD in 1981 to about 12 MB/CD in 1985. TBA (tertiary butyl alcohol) has limited production capability and, according to some estimates, consumption in motor fuel has declined over the last 5 years.

OXYGENATE USAGE RESTRICTIONS

The Clean Air Act states that no fuel or fuel additive may be introduced into commerce that is not "substantially similar" to any fuel or fuel additive used in the certification of any 1974 or later model year vehicle. In July 1981, the EPA defined "substantially similar" to include fuels blended with ethers or alcohols (except methanol) up to 2.0 wt.% oxygen. Methanol could be used as a de-icer up to 0.3 volume percent or up to 2.75 volume percent if blended with a cosolvent such as butanol or higher molecular

TABLE 59

OXYGENATE USE IN MOTOR FUEL (MB/CD)

	1981	1982	1983	1984	1985 (Est.)
TBA	8.5	7.8	7.2	6.5	5.9
MTBE	2.3	3.3	5.2	6.5	7.5
Methanol*	1.1	2.3	7.9	9.5	11.9
Ethanol	5.5	15.3	28.0	37.0	49.6
Total	**17.4**	**28.7**	**48.3**	**59.5**	**74.9**

*Includes Petrocoal, Oxinol, and Deicer.
Source: Information Resources Incorporated.

weight alcohol. Table 60 shows "substantially similar" fuels.

The Clean Air Act also provides for the EPA to waive the prohibition on new fuels or fuel additives that are not "substantially similar" if it can determine that the fuel or fuel additive will not cause failure of any vehicle emission control system. The EPA has granted waivers as shown in Table 61.

TABLE 60

"SUBSTANTIALLY SIMILAR" FUELS

Oxygenate	Maximum Volume %
Methanol	0.3
Ethanol	5.4
IPA	7.1
TBA	8.7
MTBE	11.0
50/50 Methanol/TBA	5.5

SURVEY RESULTS

The NPC's 1985 Survey of U.S. Petroleum Refineries included data on oxygenate usage. In Section C, refiners were asked to report actual oxygenate feedstocks used in 1984 and projected feedstock requirements in 1986 and 1988. Refiners responding to this portion of the survey reported gasoline production in 1984 of about 6,310 MB/CD, or about 97.8 percent of total U.S. gasoline production of 6,453 MB/CD. In Section D, refiners were asked to report gasoline manufacturing capabilities for 1985 through 1988 while maximizing unleaded volumes. They also reported gasoline manufacturing capabilities under the same conditions, but excluding all oxygenates.

Table 62 shows the survey response to actual oxygenate feedstocks required by refiners in 1984 and their projected requirements in 1986 and 1988. A total of 29 refiners reported requiring 25.8 MB/CD of oxygenates in 1984. In addition, the survey shows a 118 percent projected increase in oxygenate requirement from 1984 to 1986, to 56.4 MB/CD. In 1988, refiners are projecting a 12 percent decrease in oxygenate requirement from 1986, to 49.4 MB/CD.

TABLE 61

FUEL WAIVERS GRANTED BY EPA

	Oxygenate	Maximum Volume %	Maximum Oxygen Wt. %
Gasohol	Ethanol	10.0	3.7
Arconol	TBA	16.0	3.5
Oxinol 30	30% Methanol 70% TBA	7.8 3.4	3.5
Oxinol 50	50% Methanol 50% TBA	4.7 4.7	3.5
Petrocoal*	80% Methanol 20% TBA Proprietary Rust Inhibitor	12.0 3.0	5.9
DuPont	Methanol Cosolvent (Ethanol, Propanols, GTBA and/or Butanols)	5.0 2.5	3.7

*The EPA moved to revoke this waiver.

TABLE 62

1985 NPC SURVEY
OXYGENATE REQUIREMENTS

	Actual 1984		Projected 1986		Projected 1988	
	MB/CD	No. of Refiners*	MB/CD	No. of Refiners*	MB/CD	No. of Refiners*
Ethanol	2.7	10	13.9	15	14.9	16
Methanol	3.0	4	5.0	10	5.0	11
TBA	7.7	3	15.0	4	5.6	4
MTBE	12.4	15	22.5	13	24.0	14
Total†	**25.8**	**29**	**56.4**	**37**	**49.4**	**39**

*Number of refiners reporting feedstock requirement.
†Totals may not add due to independent rounding.

Table 63 presents a comparison of oxygenate feedstocks used for 1984 as reported in the NPC survey and the total usage estimated by Information Resources, Inc. The NPC survey includes those oxygenates blended at the refinery level, while the Information Resources data represent all U.S. consumption. As expected, total ethanol and methanol consumption is much higher, as reported by Information Resources. Due to storage and transportation problems, most ethanol and methanol are blended at the distribution terminal level rather than at refineries. Out of 37.0 MB/CD of ethanol consumption in 1984, only 2.7 MB/CD was blended at the refinery level.

TABLE 63

COMPARISON OF 1984 OXYGENATE USAGE (MB/CD)

	Information Resources	NPC Survey*	Difference
Ethanol	37.0	2.7	34.3
Methanol	9.5	3.0	6.5
TBA	6.5	7.7	(1.2)
MTBE	6.5	12.4	(5.9)
Total	**59.5**	**25.8**	**33.7**

*For refiners reporting usage.

Total methanol consumption was about 9.5 MB/CD, with about 3.0 MB/CD blended at refineries. MTBE usage was reported at 12.4 MB/CD by the survey, but only 6.5 MB/CD was reported by Information Resources. Since MTBE is largely captive for individual company gasoline pools, it appears likely that the Information Resources estimate is understated.

Table 64 summarizes oxygenate usage as projected by refiners while maximizing production of unleaded gasoline with leaded gasoline constrained at 0.10 gplg lead except for lead

TABLE 64

1985 NPC SURVEY
OXYGENATE USAGE
MAXIMUM UNLEADED GASOLINE PRODUCTION

	1985	1986	1988*	1988†
Ethanol	6.4	22.5	28.9	33.2
Methanol	1.9	1.9	3.2	3.0
TBA	5.7	4.5	4.5	4.7
MTBE	25.6	39.1	42.5	58.0
Total	**39.6**	**68.0**	**79.1**	**98.9**
Leaded Grade (gplg)	1.1	0.10	0.10	0.10

*Current octane, i.e. 87 (R+M)/2 for unleaded regular.
†Unleaded grades increased one octane number.

banking after January 1986. Refiners also projected their oxygenate usage with unleaded gasoline while meeting an increase of one road octane number in pool octane in unleaded gasoline.

As noted from the table, oxygenate usage to meet octane requirements is expected to increase steadily in the 1985–1988 period. In 1985, oxygenates were expected to represent about 0.6 percent of the gasoline pool, increasing to an expected level of 1.2 percent by 1988. This indicates that, while oxygenates are relatively expensive, some refiners find that they are an attractive alternate route to capital expenditure.

When asked to raise gasoline octane levels of the unleaded grades by one number, refiners required an increase of approximately 25 percent in the use of oxygenates to a level of approximately 100 MB/CD at the refinery level. It is interesting to note that this is four times the usage reported for 1984.

Table 65 provides respondents' views on the usage of oxygenates to maximize the production of unleaded grades of gasoline while meeting current specifications on all grades. It can be noted from this information that refiners in the Gulf Coast and the Midwest account for the majority of oxygenate usage for the years surveyed. In the short term, the largest increase in usage is expected for the Gulf Coast refiners, with a steady continuing growth in usage for the refiners in PADD II. The other significant usage, predominantly MTBE, can be found in PADD I, which will experience only nominal growth through the period of the survey.

In another section of the NPC survey, refiners were asked to report the impact of eliminating all oxygenates on gasoline production, assuming maximum unleaded production, 0.1 gplg effective January 1, 1986, and constant crude oil rates. They reported that disallowing oxygenates in 1986 could reduce gasoline production by up to 81 MB/CD, or 1.26 percent of total gasoline. Without oxygenates, 1988 gasoline production could reportedly fall by almost 100 MB/CD, or 1.55 percent.

Refiners reported that for 1985 operations they expected to use 40 MB/CD of oxygenates; elimination of this would reduce gasoline production capability 54 MB/CD, for a ratio of 1.4 barrels of gasoline to 1.0 barrel of oxygenate. Similarly for 1988, elimination of 79 MB/CD of oxygenates reduces gasoline production 100 MB/CD, for a ratio of 1.3 to 1.0. These changes indicate that the loss of the octane value of the oxygenates requires more severe operation of reformers and/or rejection of a low octane stream from the gasoline pool.

TABLE 65

1985 NPC SURVEY
PROJECTED USAGE OF OXYGENATES
BY PADD
MAXIMUM UNLEADED GASOLINE PRODUCTION
(MB/CD)

	1985	1986	1988
PADD I			
No Conversion	0	0	0
All Conversion	7.4	9.7	10.6
Subtotal	7.4	9.7	10.6
PADD II			
No Conversion	0	0	0
Gas Oil Conversion	*	3.3	5.0†
Deep Conversion	6.3	14.0	17.2
Subtotal	6.3	17.3	22.2
PADD III			
No Conversion	*	0.7	*
Gas Oil Conversion	5.2	5.4	6.3
Deep Conversion	13.5†	30.0	31.4
Subtotal	18.7	36.1	37.7
PADD IV	*	*	*
PADD V			
No Conversion	*	*	*
Outside California	*	*	*
Inside California	*	*	4.2
Subtotal	*	*	4.2
Unidentified	7.2	5.5	4.4
Total	**39.6**	**68.6**	**79.1**
Leaded Grade (gplg)	1.1	0.10	0.10

*Represents unidentified data.
†Constructed from partial data, therefore a minimum number.

MODEL RESULTS

The model assumption concerning oxygenates varied somewhat from survey data; however, none of the cases are on a completely identical basis. Table 66 compares applicable model and survey cases in terms of gasoline production and oxygenate usage. The 1988 high demand model case is most closely comparable

to the 1988 refiner projected survey case. Total gasoline production is 132 MB/CD higher under the survey case, with unleaded production 194 MB/CD higher and unleaded premium production 85 MB/CD lower. While gasoline production is higher under the survey case, oxygenate usage is 9 MB/CD lower. Oxygenate usage is 58 MB/CD under the model case and 49 MB/CD under the survey case.

The 1988 maximum unleaded production survey case shows higher unleaded and unleaded premium production and lower leaded production than the 1988 refiner projected case. Corresponding to this is an increase in oxygenate usage from 49 MB/CD to 79 MB/CD. The 1988 optimum major products model case shows a 436 MB/CD increase in gasoline production from the 1988 high demand model case, but no increase in oxygenate usage.

Further comparing the 1988 optimum major products model case to the 1988 maximum unleaded survey case shows that PADD III, Gulf Coast, has the greatest usage of oxygenates in both cases. The survey case shows usage of 37.7 MB/CD, while the model case assumes 33 MB/CD. The greatest discrepancy occurs in PADD II, Midwest, where the survey shows a project usage of 22.2 MB/CD, but the model assumption is only 10 MB/CD. The model case also assumes lower usage of oxygenates in PADDs I and V.

Combining the reduction in RVP with an increase in required octane of 1.0 (R+M)/2, the model showed a 439 MB/CD decrease in gasoline production. The increased octane also triggered a 74 percent increase in oxygenate consumption, from 58 MB/CD to 101 MB/CD. Two-thirds of the increased oxygenate consumption took place in only two categories, PADD II deep conversion and PADD III deep conversion, which were the two primary users of oxygenates under the base case. It is interesting to note that while octane costs are relatively high for PADD III deep conversion refineries at 97¢/octane number/barrel, they are relatively low for PADD II deep conversion refineries at 62¢/octane number/barrel. PADD III low conversion refineries have the highest octane cost at $1.10/octane number/barrel, but relatively no incremental oxygenates are consumed in the increased octane case. There seems to be little pattern between additional oxygenates required and octane cost, according to the model data.

Reduction of Benzene in Gasoline

BENZENE SURVEY RESULTS

Results from the 1985 NPC survey show that average benzene content of U.S. gasoline for 1984 and projected for 1988 are:

	Benzene Content (Volume %)			
	Unleaded Regular +Other Unleaded	Unleaded Premium	Total Leaded	Pool Average
1984 Typical	1.75	1.54	1.78	1.72
1988 Typical	1.82	1.77	1.79	1.81

These are for the 103 refiners that provided responses for both 1984 and 1988.

TABLE 66

COMPARISON OF GASOLINE PRODUCTION AND OXYGENATE USAGE MODEL VS. SURVEY (MB/CD)

	Model		Survey	
	1988 High Demand	1988 Optimum Major Products	1988 Projected	1988 Maximum Unleaded
Leaded Gasoline	1,027	1,097	1,051	812
Unleaded Gasoline	4,020	4,291	4,214	4,334
Unleaded Premium	1,255	1,350	1,170	1,259
Total	**6,302**	**6,738**	**6,435**	**6,432**
Oxygenates	58	58	49	79

IMPACT OF LEAD REDUCTION

The EPA's mandated lead phasedown required new or incremental octane sources to achieve the approximate 2-octane-number increase in the clear pool octane. The octane of benzene is about 10 (R+M)/2 octane numbers higher than average gasoline; thus benzene reduction would require additional octane sources.

As octane-generating capabilities are stretched to meet lead phasedown, catalytic reformers will be operating at high capacity and severity. Refiners are shifting reformer feedstocks and operating conditions to produce more high-octane reformate. Increasing the octane of reformate makes a modest increase in the benzene content of reformate. More importantly, shifting reformer feedstock to reform additional hydrocarbons with six carbon atoms (benzene has six carbon atoms) can significantly increase the benzene content of reformate—from 1 to 3 percent, for example. However, the benzene content of reformate seldom exceeds 5 percent unless the refiner is reforming a feed specifically tailored to produce benzene for chemical, not gasoline, markets.

REDUCING GASOLINE BENZENE CONTENT

Reducing the benzene content of gasoline, and the cost in doing so, is refinery-specific. The costs are influenced by factors such as refinery configuration and benzene distribution among refinery process streams. Direct capital costs of benzene removal are primarily a function of the volume and character of gasoline streams that must be processed to achieve a desired level of benzene reduction. Benzene is usually most concentrated in reformate. Other streams containing benzene include FCC gasoline, coker gasoline, light straight-run gasoline, and light hydrocracked gasoline. The benzene content of these gasoline components is typically 0.5 to 1 percent. Butane, alkylate, polymer gasoline, and isomerate are typically benzene-free. These components comprise in total about 20 percent of total gasoline.

Previous reports have shown a range of gasoline benzene contents of 0.2 to 4.0 percent. These values could be supported by the average reported by respondents. Even in a single refinery, gasoline benzene content varies from batch to batch and also from grade to grade, depending on the particular mix of refinery streams being blended.

Previous cost estimates have been based on the removal of benzene from reformate or from reformate and FCC gasoline. Benzene reduction in these process streams should result in producing a U.S. gasoline pool containing less than 1 percent benzene on an annual average basis. Controlling gasoline benzene content in ways other than by overall pool average over a long period places severe blending restrictions on the refiner. Refiners require blending flexibility to respond to normal variations in refinery operations. Using approaches other than overall long-time pool average (e.g., limiting the benzene content of each batch of gasoline produced to a fixed level) would result in much higher costs for benzene reduction.

DISPOSITION OF BENZENE REMOVED FROM GASOLINE

One method of reducing the benzene content of gasoline is to remove benzene from one or more of the process streams blended into gasoline. For many refiners, this may be the lowest cost method for reducing the benzene content of their gasolines. Disposition of the benzene removed from gasoline has not been studied. Even though benzene is one of the largest volume chemicals used and produced in the United States, the total volume of benzene in gasoline is considerably greater than the total demand for benzene as a chemical. Thus the impact on those who now produce benzene would be significant.

A viable method of coping with reducing benzene in gasoline postulates the combining of reformate and catalytic gasoline streams for concentrating the benzene by fractionation. The concentrated stream could be processed through an extraction unit for removal of most of the benzene. The removed benzene could then be hydrogenated to produce cyclohexane for return to the gasoline pool. This results in a significant reduction in pool octane, requiring additional octane-enhancement operation or use of oxygenates. Information presented in response to a survey of the California Air Resources Board indicates capital costs in the order of $600 per daily barrel of gasoline production to effectively limit benzene content of gasoline to about 1 percent in California. Extending this to the entire U.S. gasoline production would postulate new investment of about $4 billion, depending on the degree of reduction and the method of disposal of the benzene removed. Total cost of gasoline

manufacture would increase 2–3¢ or more per gallon when all factors are considered.

CONCLUSION

All refiners and all refineries are different. Costs and impacts of regulations to reduce the benzene content of gasoline would vary widely. Costs would depend on the degree of benzene reduction required and on the size and specific situation of the individual refiner.

Although the technology to reduce the benzene content of gasoline does exist, it is both difficult and expensive, requiring significant new investment out of proportion with investments currently being incurred to meet lead phasedown. The added burden on the refiner would result in higher cost from the refinery, thus impacting the competitive position of the U.S. refining industry. Control of imports of gasoline would also be extremely difficult and could result in less effective benzene control than might be expected.

SULFUR IN DISTILLATE FUEL

In the survey of the U.S. refining industry, respondents were asked to project the maximum quantities of very low sulfur distillate fuels (defined as 0.2 wt.% sulfur, except in the L.A. Basin, where it is defined as 0.05 wt.% sulfur) that they expect to be able to produce in 1988. They were also asked the extent to which additional facilities would be required to produce this level. The response to this question was quite good, with refineries possessing approximately 80 percent of the crude oil capacity responding.

The respondents indicated the capability to produce 2,071 MB/CD of distillate at the specifications for very low sulfur. Interpretation of the survey responses indicates that this task would require the addition of 457.8 MB/CD of hydrotreating capacity and 71.0 MB/CD of hydrorefining capacity. This would indicate an investment in excess of $750 million of new capital for the above capacity and associated sulfur removal, tankage, and hydrogen-generation facilities.

Analysis of the data indicates that the investment is not proportional throughout the United States. Projected operations in PADD I appear to meet the very low sulfur requirements with minor capital expenditure, because refiners there are configured to meet the very low sulfur specifications imposed in the northeast and have already incurred the economic penalty of meeting those specifications. But both PADD II and PADD III low conversion refiners indicate that having to meet a specification level of 0.2 wt.% sulfur would have a severe impact on them. These areas indicate a lower level of respondents than for the national average. The largest single producer of distillate fuels, PADD III deep conversion, reported the ability to meet the 0.2 wt.% sulfur specification with only modest additions to their refineries. However, the remaining conversion refineries in PADDs II and III would require more than 225 MB/CD of new hydrotreating/hydrorefining capacity to produce the approximately 650 MB/CD of distillate required. Adjusting for nonrespondents would add approximately 50 MB/CD of new capacity to the above figure. Similarly, the PADD V California conversion refineries reported that additions to hydrotreating capacity approaching 100 MB/CD would be required to meet the very low sulfur specifications. They reported production of distillate of slightly less than 200 MB/CD. Assuming similar capacity additions required for the nonrespondents, an additional 25-50 MB/CD of facilities would be required.

In summary, the U.S. refining industry possesses the technology to meet more stringent specifications on distillate fuels. In some portions of the United States, refiners are already faced with limits well below the national ASTM (American Society for Testing and Materials) specification. To meet the requirement of 0.2 wt.% sulfur (0.05 wt.% in the L.A. Basin) would require new hydrotreating/hydrorefining capacity in excess of 530 MB/CD and more probably in the range of 600–650 MB/CD, requiring an aggregate of $1 billion of new investment. Incurring investment of this magnitude and the concurrent costs of operating the new capacity would add about 3¢ per gallon to the ultimate consumer cost.

MODEL DEVELOPMENT

The assessment of refinery capability included the use of a mathematical model to aid in quantification of the several cases. To avoid as far as possible the over-optimization associated with the use of mathematical models, the industry was divided into five geographic regional refineries with several regions further split into several models representing levels of refining complexity in the particular region. This representation resulted in the use of eight linear

program models to simulate the more complex portions of the industry and four material balance simulations to portray the simple refineries in the industry. A supplementary model was also created to portray the L.A. Basin refineries in order to study that area's unique constraints.

The NPC survey results were used extensively for guidance and for determining some of the data base used for developing the industry models. However, the basis used for the model studies of industry capability assumed the actual 1984 operations reported to DOE (Petroleum Supply Annual) as a starting point, with appropriate NPC survey information used as a supplement. After validation, the 1984 base refinery model description was reconfigured to those of the forecast years, using survey data, published information, and judgement.

The decision to use mathematical models allowed the study to test, condition, and extend the aggregate data obtained from the survey. Its use provided the following advantages:

- Adjustment of the survey results to allow for refineries that did not respond, so as to represent the industry more fully
- Consistency to the mix of survey replies received from the individual refineries
- Orientation to analyze the demand and environmental issues
- The ability to judge the imposition of constraints on the total industry.

In assessing the various modeling alternatives, a consultant's model was selected for preparation of the analytical base. This selection had the advantages of being cost effective, of incorporating this segment of industry expertise, of starting with an up-to-date base, and of having a continuous availability of skilled personnel to run a familiar model while incorporating the expertise of the study participants. The model selected to assess refining capability was that of Turner, Mason and Company.

While the model provided invaluable quantification of the analyses, it was the study participants assigned to the problem who were responsible for the final assessment and conclusions.

The solution method selected for the model operation was a demand-driven mode with variables of capacity utilization, process unit severities, and limited crude oil selection. Crude oil and product prices were supplied to the model for the various cases. While these were considered in the solution, the results are relatively insensitive to price. No transportation optimizers were used in the modeling procedure. Instead, regional refinery demands and supplies were developed from the demand scenarios described in Chapter Two, using historical patterns and judgement, as discussed later in this chapter.

The distinction made between the low conversion and high conversion classifications was to classify deep conversion refineries as those that processed greater than 50 percent of the vacuum residuum into lighter products. Simple refineries are essentially specialty plants and topping units that can include naphtha reforming and hydrotreating but lack gas oil conversion units.

Process Unit Capacity

A capacity of each refinery process unit for the year 1984 was calculated by averaging the January 1 capacities provided in the DOE Petroleum Supply Annuals for 1984 and 1985 stream-day operable capacities. These data were supplemented with information obtained from the NPC survey and from the corresponding annual capacity information published by the *Oil & Gas Journal*. The final tabulation is given in Appendix I.

Separate estimates of capacity were made for the 1988 low and high cases. The high case capacity estimates are based on the 1985 DOE information published in the Petroleum Supply Annual, 1984, less published permanent shutdowns, plus announced facilities under construction by June 1985, restarts of capacity by June 1985, and the incremental capacity for January 1, 1988, reported to the NPC survey above the 1984 DOE capacity that exceeded the announced construction and restart quantities. These stream-day capacity estimates are summarized in Table 67.

The low case capacity estimates are based on the 1988 high case values less any refinery or partial refinery in the base volume that was shut down in the period from 1982 through June of 1985. This assumes that these units were marginal historically and would revert to this status in the low case scenario.

The stream-day capacities thus developed were adjusted for use in the models to calendar-day values by assuming a 95 percent stream factor for crude oil distillation units and a 92 percent stream factor for all other process units.

TABLE 67

REFINERY PROCESS UNIT CAPACITIES
1988 HIGH DEMAND CASE
(MB/SD)

	PADD I		PADD II			PADD III			PADD IV	PADD V			U.S. Total	VCLA*
	I-S	I-C	II-S	II-LC	II-DC	III-S	III-LC	III-DC		V-S	V-COC	V-CC		
Number of Refineries	11	10	7	12	24	21	14	32	20	28	6	17	202	9
Feedstock														
Crude — Atmospheric	371.0	1,296.0	65.8	826.8	2,623.4	374.8	1,633.9	5,487.5	590.6	583.2	512.0	2,152.8	16,517.8	1,209.4
Crude — Vacuum	180.3	602.4	8.6	327.7	985.3	107.5	673.9	2,287.8	199.2	171.5	194.0	1,187.8	6,926.0	620.0
Catalytic Cracking	—	574.3	—	286.0	998.5	—	521.8	1,951.8	190.9	—	114.5	577.0	5,214.8	352.0
Hydrocracking	4.4	74.0	—	44.5	113.4	—	30.0	367.7	10.9	—	65.5	353.2	1,063.6	138.7
Coking — Delayed	—	35.0	—	—	281.4	—	—	559.9	13.0	—	59.0	337.3	1,285.6	272.0
Coking — Fluid	—	54.0	—	—	—	—	—	49.0	16.5	—	—	86.5	206.0	—
Combined Coke	—	89.0	—	—	281.4	—	—	608.9	29.5	—	59.0	423.8	1,491.6	272.0
Combined Coke — FOE	—	33.5	—	—	78.0	—	—	184.9	11.0	—	14.9	95.2	417.5	66.8
Thermal Cracking	—	—	—	1.5	—	—	55.0	14.6	—	17.2	—	—	88.3	—
Visbreaking	—	13.0	—	—	6.6	—	22.5	43.5	—	5.0	—	45.8	136.4	33.8
Total Thermal Processing	—	13.0	—	1.5	6.6	—	77.5	58.1	—	22.2	—	45.8	224.7	33.8
Solvent Deasphalting	7.0	16.0	—	—	41.6	7.1	28.2	145.2	17.7	—	7.4	50.0	320.2	—
Catalytic Reforming														
Low Pressure	—	118.8	—	133.5	339.3	—	187.5	866.4	39.5	6.0	31.8	204.0	1,926.8	75.0
High Pressure	11.7	232.1	3.0	111.8	283.5	45.0	144.5	461.5	75.2	36.1	78.0	289.9	1,772.3	212.2
Total Reforming	11.7	350.9	3.0	245.3	622.8	45.0	332.0	1,327.9	114.7	42.1	109.8	493.9	3,699.1	287.2
Hydrotreating														
Naphtha	14.5	403.8	1.3	201.0	711.9	53.1	360.8	1,261.6	161.0	38.4	91.5	463.0	3,761.9	249.0
Distillate	1.3	343.0	—	117.4	326.6	12.0	382.5	1,142.0	67.0	16.4	76.0	315.9	2,800.1	134.5
Heavy Gas Oil	—	117.0	—	100.7	230.5	27.6	138.0	513.3	18.5	25.0	—	444.6	1,615.2	227.0†
Residuum	0.5	—	—	—	—	—	—	176.0	—	—	—	24.0	200.5	— †
Product Rate														
Alkylation	—	70.3	—	64.3	192.5	—	76.6	403.4	31.7	—	29.1	102.7	970.6	63.5
Polymerization	—	15.0	—	5.0	16.1	—	8.0	27.2	11.7	0.1	1.1	5.6	89.8	2.4
Isomerization — C_5/C_6	1.1	25.0	—	15.4	85.7	2.0	31.0	111.1	3.9	2.7	—	16.7	294.6	—
Isomerization — C_4	—	—	—	0.5	24.3	2.0	10.0	10.1	8.4	—	4.4	17.2	76.9	10.9
Hydrogen — MMCF/SD	5.0	96.0	—	—	159.0	8.8	71.0	858.0	27.0	—	107.8	923.0	2,255.6	433.0
Hydrogen, FOE — MB/SD	0.3	4.9	—	—	8.1	0.4	3.6	43.7	1.4	—	5.5	47.0	114.9	22.0
Asphalt	89.6	67.0	5.7	95.1	142.6	27.1	54.1	95.4	36.0	98.0	1.3	26.0	737.9	4.0
Lube	20.2	20.0	1.0	4.6	29.6	17.2	30.9	91.6	1.5	5.3	—	21.1	243.0	—
Acromatics	—	12.7	—	—	42.2	6.2	32.7	119.3	—	—	—	3.5	216.6	1.5
Hydrodealkylation	—	1.8	—	—	6.1	—	—	20.2	—	—	—	—	28.1	—

*L.A. Basin data included in V-CC column.
†Includes 24.0 MB/SD of residuum hydrodesulfurization in heavy gas oil service.

These calendar-day values are the basis for computing percentage utilization from the required capacity derived from model runs. To recognize historically achieved levels, account for unplanned shutdowns, and limit over-optimization, the utilization of all process units was limited to 92 percent of the calendar-day capacity (crude oil units 88 percent stream-day capacity, downstream units 85 percent stream-day capacity).

Capacities for critical process units were also adjusted within the individual model runs for feedstock quality and severity level of operation. Thus, in numerous instances, effective capacity is somewhat less than the illustrated name plate capacity.

The stream-day capacities for the entire United States used for the 1984 calibration and to meet the 1988 high and low demand cases are provided in Table 68.

Crude Oil Slates

Characterization of the domestic and foreign portions of the refinery crude oil slates was done through the use of the Turner, Mason and Company crude oil assay library.

For any given year, the volume of domestic crude oil available was that estimated in the supply/demand portion of the study. Domestic crude oil quality was estimated from DOE domestic production data by states, some gravity data on production, and NPC survey data. Allocation of domestic production to the individual models was estimated using the DOE data on crude oil movements last published in 1980, the NPC survey data regarding regional crude oil quality and consumption, and a recognition of the use of local crude oils in a given region. Appropriate assays were used to define each type of crude oil. The allocation process was iterated to obtain a satisfactory check by comparing the PADD regional aggregates with annualized crude oil run quality data from the DOE Monthly Petroleum Summary.

The volumes of imported crude oil for a given year were also supplied in the supply/demand portion of the study. For the 1984 case, imported crude oils were disaggregated into regional models from DOE data, which included classification by destination, by country of origin, and by crude oil properties of sulfur content and ^{0}API gravity.

Validation of Model vs. 1984 DOE Results

Calibration of the model was done by validating the output parameters versus the actual values provided by the 1984 DOE Petroleum Supply Annual and the results of the NPC survey.

An excellent comparison was obtained by several iterations of model runs (included in Appendix I). The resulting calibrated model provides the study not only with additional insight into 1984 operations, but also a good base for the forecast cases.

In summary, 1984 operations did not stress the refinery capability. The U.S. utilization of distillation capacity was 77 percent, conversion units utilization of capacity was in the low 80 percent range, and octane generation capacity utilization was in the low 70 percent range. Some regions did approach full utilization of their facilities, but, in general, the system had slack capacity available. Incremental octane costs based upon feedstock prices and variable operating costs ranged from $0.14/octane number/barrel to $0.29/octane number/barrel.

Dimensions of the Study

The following case studies, which appear in detail in Appendix I, were made in order to meet the objectives of the study. These studies are referenced as shown in Table 69. As may be noted in the listing in Table 69, the sensitivity issues are addressed in a 1988 framework and are studied in two different operational modes for the industry system.

The first series, Cases C and D plus the sensitivity cases (Cases E-1 through E-4), analyze the refining system capability in 1988 from the viewpoint created by the supply/demand scenarios of this study. For the sensitivity cases based on high demand, the model was permitted to add octane-enhancement and treating capacity required to overcome constraints. In these scenarios, the demand for gasoline decreases both in level and in percentage of total demand from those experienced in 1984–1985, while there is a corresponding increase in demand for middle distillate, residual fuel oil, and the "other" product category (a large growth in petrochemical feedstock is included in "other"). This shift in the demand pattern was perceived early on to not create stress on the capability limits for the system.

TABLE 68

ESTIMATED REFINERY PROCESS UNIT CAPACITIES
U.S. TOTAL 1984 AND 1988 CASES
(MB/SD)

	Calibration 1984 Average	1988 High Case	Changes 1988 High Less 1984 Average*	1988 Low Case	Changes 1988 Low Less 1988 High†
Number of Refineries	214	202	(12)	177	(25)
Feed Rate					
Crude — Atmospheric	16,539.5	16,517.8	(21.7)	14,595.4	(1,922.4)
Crude — Vacuum	6,943.7	6,926.0	(17.7)	6,480.0	(446.0)
Catalytic Cracking	5,242.7	5,214.8	(27.9)	4,887.2	(327.6)
Hydrocracking	997.0	1,063.6	66.6	1,057.6	(6.0)
Coking — Delayed	1,238.8	1,285.6	46.8	1,199.0	(86.6)
Coking — Fluid	164.9	206.0	41.1	206.0	0.0
Combined	1,403.7	1,491.6	87.9	1,405.0	(86.6)
Combined Coke, FOE	398.5	417.5	19.0	398.8	(18.7)
Thermal Cracking	90.6	88.3	(2.3)	86.8	(1.5)
Visbreaking	143.9	136.4	(7.5)	128.9	(7.5)
Total	234.5	224.7	(9.8)	215.7	(9.0)
Solvent Deasphalting	315.4	320.2	4.8	293.0	(27.2)
Catalytic Reforming					
Low Pressure	1,905.7	1,926.8	21.1	1,824.8	(102.0)
High Pressure	1,857.1	1,772.3	(84.8)	1,685.2	(87.1)
Total	3,762.8	3,699.1	(63.7)	3,510.0	(189.1)
Hydrotreating					
Naphtha	3,742.6	3,761.9	19.3	3,601.3	(160.6)
Distillate	2,790.6	2,800.1	9.5	2,721.6	(78.5)
Heavy Gas Oil	1,460.7	1,615.2	154.5	1,555.2	(60.0)
Residuum	280.3	200.5	(79.8)	200.5	0.0
Product Rate					
Alkylation	923.9	970.6	46.7	913.7	(56.9)
Polymerization	86.7	89.8	3.1	84.7	(5.1)
Isomerization — C_5/C_6	135.0	294.6	159.6	289.4	(5.2)
Isomerization — C_4	79.2	76.9	(2.3)	76.4	(0.5)
Hydrogen — MMCF/SD	2,206.4	2,255.6	49.2	2,227.6	(28.0)
Asphalt	767.8	737.9	(29.9)	640.9	(97.0)
Lube	240.5	243.0	2.5	242.0	(1.0)
Aromatics	211.3	216.6	5.3	210.2	(6.4)
Hydrodealkylation	30.1	28.1	(2.0)	28.1	0.0

*Decreased by permanent shutdowns and reductions in capacity. Increased by restarts, facilities under construction, plus incremental NPC capacity.

†Eliminates all marginal capacity. Includes idle operable capacity and all temporary shutdowns since 1981, both complete and partial refineries due to economic losses.

TABLE 69

REFINERY CAPABILITY CASE

Reference		Title
C	1988	Base Case, Low Demand
D	1988	Base Case, High Demand
E-1	1988	High Demand Sensitivity to Lower RVP
E-2	1988	High Demand Sensitivity to Higher Octane
E-3	1988	High Demand Sensitivity to No Use of Oxygenates
E-4	1988	High Demand Sensitivity to Combined Higher Octane and Lower RVP
E-5	1988	Maximum Light Product Manufacture with Incremental New Octane Generation Facilities
E-6	1988	Sensitivity to Higher Sulfur, Heavier Crude Oil Slate, Based on E-5
E-7	1988	Optimum Light Product Manufacture without New Facilities
E-8	1988	Sensitivity to Lower RVP, Based on E-7
E-9	1988	Sensitivity to Combined Higher Octane and Lower RVP, Based on E-7
F	1990	Base Case, Low Demand
G	1990	Base Case, High Demand
H	1995	Base Case, Low Demand
I	1995	Base Case, High Demand

Note: High Demand = High Refinery Demand Case.

Thus, to provide an alternative analysis of system capability, a second series of cases were developed in which conversion units were fully utilized with resultant increases in light product manufacture. Crude oil runs were maintained at the given supply/demand scenario. These are Cases E-5 through E-9. In Cases E-7 through E-9, the model was further constrained by not allowing any new octane generation facilities above those planned for 1988.

Preliminary studies indicated the system to have little sensitivity to the issues of gasoline specification and crude oil mix in the low demand cases. Therefore, these sensitivity cases were fully developed only for the high demand cases.

Full model runs were not made for the 1995 cases because preliminary calculations showed that light product demands of the basic supply/demand scenarios with declining requirement for motor gasoline could be met without additional conversion facilities. Therefore, full development would not provide any additional insight as to refinery capability. Similarly, full development of the sensitivity cases for 1990 was judged to be nonproductive.

Model input information and results are provided in more detail in Appendix I.

CHAPTER FOUR

Assessment of Worldwide Refining Capability

INTRODUCTION

During the study, the National Petroleum Council analyzed the world refining and transportation system in order to determine that system's ability to export petroleum product to the United States. This chapter summarizes the results of the analysis.

The data collected were incorporated into DOE's mathematical model of the world refining system in order to determine the impact of various supply/demand scenarios and social, political, and economic constraints. The data, collected initially in early 1985, have been constantly reviewed and revised.

Refining Overview

Table 70 presents a view of world crude oil refining capacity vs. the 1986 and 1990 NPC product demand cases. The capacity illustrated is a summary of that shown in Appendix J, Attachment 4. The demand figures include bunker fuel requirements. The growth in refining capability of the Arab Gulf is the major component of world increase from 1986 through 1990, 469 MB/CD, with the Saudi Arabian refinery at Rabigh accounting for 325 MB/CD. This is in addition to the 1.4 MMB/CD of crude oil distillation installed between 1980 and 1986. The other major increase in refining capacity is expected to be the Nigerian 150 MB/CD crude oil distillation unit at Port Harcourt, which is the major single part of the 250 MB/CD increase in capacity shown for the column labeled "Other Potential Exporters." At the present time, the Rabigh refinery is on hold for an indefinite time. However, for all scenarios it was assumed operable by 1990. The 1986–1990 Arab Gulf increases are more than offset by the projected 815 MB/D reduction of European distillation capacity. The Ministry of International Trade & Industry has announced a shutdown target of 700 MB/CD in Japan, which could result in a net reduction in total of 791 MB/CD in non-U.S. free-world crude oil distillation capacity.

The ratio of crude oil distillation capacity to total product demand (high case) between 1986 and 1990 is expected to decline due to increasing product demand and shutdown of crude oil distillation capacity, especially in Europe. In the Arab Gulf, crude oil capacity is about constant at 240 percent of high demand throughout the 1986 to 1988 time period. The 1990 high demand case indicates that Europe would be required to operate at 97 percent of calendar-day capacity to fulfill local product demand. Other potential product exporters and the rest of the world, on the same basis, are at about crude oil capacity.

Model Development and Analysis Overview

A simultaneous economic evaluation of the domestic and worldwide refining and logistic systems was conducted to address the issues of petroleum product imports and the potential impact of product imports on the domestic refining industry. The vehicle for this analysis was a

TABLE 70

FREE-WORLD CRUDE OIL PROCESSING CAPABILITY AND COMBINED PRODUCT DEMAND*
(MB/CD)

	Europe†	Arab Gulf‡	Other Potential Exporters§	United States	All Other Free World	Total Free World
1986 Crude Oil Distillation Capability	14,517	2,883	8,642	15,621	14,238	55,901
1986 Regional High Product Demand	11,800	1,119	7,178	16,530	10,523	47,150
1986 Regional Low Product Demand	11,370	1,072	6,918	16,010	10,158	45,528
1990 Crude Oil Capability¶	13,702	3,352	8,892	15,692	14,243	55,882
1990 Regional High Product Demand	13,259	1,462	7,958	17,900	12,619	53,198
1990 Regional Low Product Demand	10,930	1,189	7,110	15,600	10,001	44,829
1986-1990 Change in Crude Oil Refinery Capability	(815)	469	250	71	5	(20)
1986-1990 Change in Product Demand (High Cases)	1,459	343	780	1,370	2,096	6,048

* Total product demand from NPC supply/demand case scenario. These demands are gross product demand. In the analysis used, demands are net of refinery fuel and include bunkers.
† Finland, Iceland, Norway, Sweden, Belgium, Denmark, Netherlands, Luxembourg, West Germany, France, Austria, Switzerland, Portugal, Spain, Italy, Greece, Turkey, Ireland, and U.K.
‡ Iraq, Kuwait, Neutral Zone, Oman, Qatar, Saudia Arabia, South Yemen.
§ Indonesia, Caribbean, Algeria, Libya, Mexico, Gabon, Nigeria, Iran, Puerto Rico, Virgin Islands, Ecuador, Venezuela and other Americas, Bahrain, Egypt, Syria.
¶ 1990 crude oil capability was assumed to be equal to 1988.

mathematical model of the world's refining and transportation infrastructures, crude oil and gas liquids supply, and petroleum product demands. The mathematical model, referred to as the World Refining and Transportation Model (WR&T Model), was modified by the industry as part of the overall study. DOE provided assistance in the data handling, development of computer input and output protocols, and in the running of the cases necessary to complete the task. The WR&T Model utilized DOE's refinery and transportation modeling systems and is an extension of earlier work of DOE in creating separate, stand-alone representations of the U.S. and world refining systems. Documentation of the DOE models (PAL/REMS) is available from DOE.

Industry participants generated the detailed assumptions necessary to create an adequate representation of the oil market. The WR&T Model was configured to simulate two years—1986 and 1990. For 1990 refining operation, 1988 estimated refining capacity was used. The 1986 version was studied and calibrated to reflect the real world and to aid in interpreting the 1990 model results. The 1990 model was exercised with a number of scenarios, varying resource availabilities and costs, feedstock supply, and product demands. The results of those cases are illustrated in Chapter Five, "Comparative Position of the Domestic Refining Industry."

A team of industry experts was assembled to use the mathematical model, to modify its structure as appropriate, and to interpret the results of the various mathematical model solutions. As shown in Figure 16, the "model" was the combined result of the mathematical optimization plus the judgement of the industry team. It is important to note that the mathematical model results (the computer printouts) can be misleading unless interpreted by experts.

WORLD REFINING AND TRANSPORTATION CAPACITIES

World Refining Capacity

To facilitate data collection and to correspond to area modeling descriptions, the world was divided into refining regions. A complete list

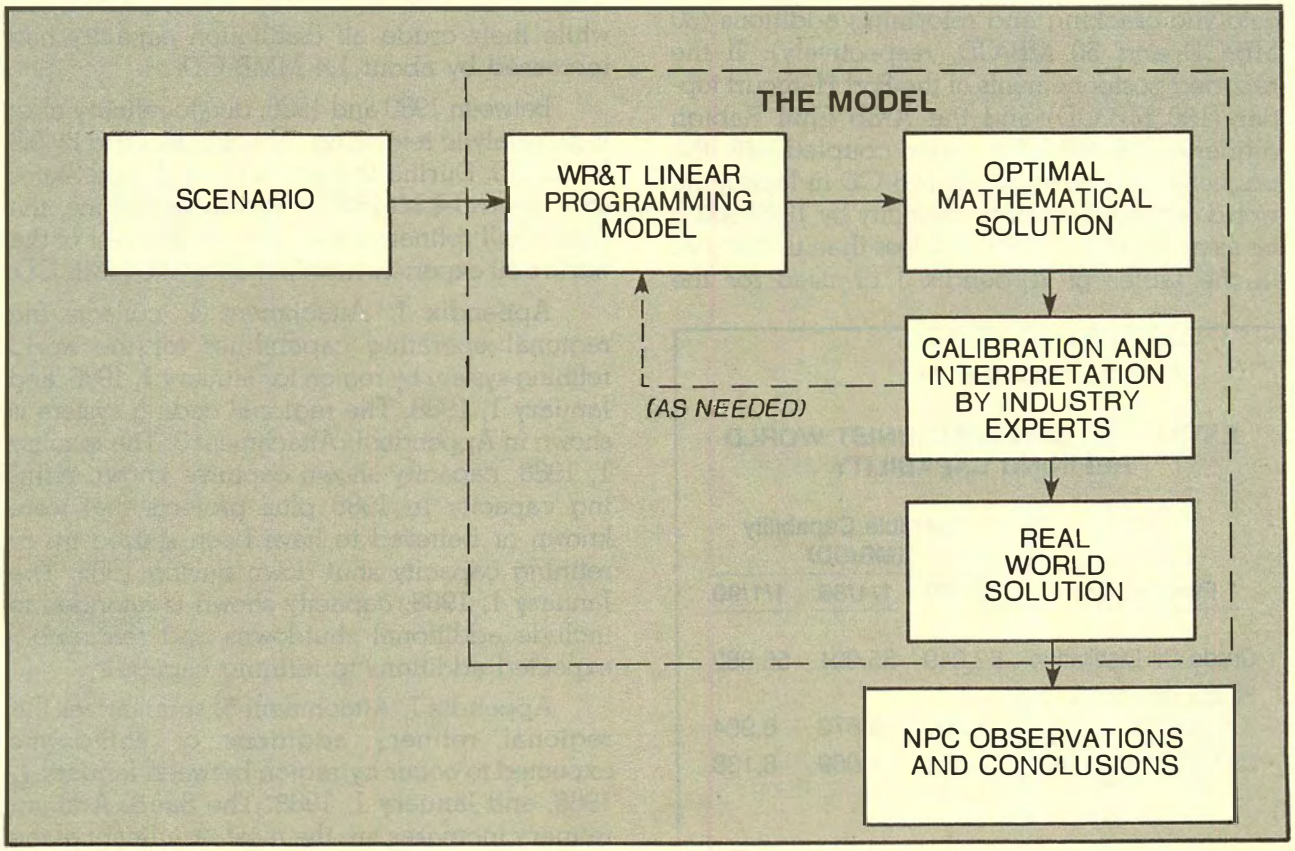


Figure 16. The Interpretation Process.

of this regionalization is included in Appendix J, Attachment 3. The rationale of the groupings of countries into regions included the highlighting of various regional activities, such as crude oil availability, refining upgrading characteristics, crude oil and product export potential, transportation issues, and trade practices.

Estimates of the total non-communist world crude oil distillation, FCC, and catalytic reforming (sum of quantity of high and low pressure) capability for the years under consideration are shown in Table 71. The world shut down a little over 6 MMB/CD of crude oil capacity and about 0.5 MMB/CD of catalytic reforming capacity between 1980 and 1986. It is believed that capacity peaked in 1981. The shutdown of crude oil distillation capacity includes entire hydroskimming refineries and crude oil units in other refineries. During the same period, additional upgrading capacity consisting of about 0.5 MMB/CD of fluid catalytic cracking was installed to accommodate a lighter product demand mix. The trend is expected to continue through the rest of the 1980s but at a much lower rate of change, with expected net elimination of 20 to 720 MB/CD of crude oil capacity and small catalytic cracking and reforming additions (30 MB/CD and 50 MB/CD, respectively). If the reported postponements of the Port Harcourt topper (150 MB/CD) and the Arab Gulf Rabigh refinery (325 MB/CD) occur, coupled with the projected shutdown of 700 MB/CD in Japan, the world crude oil refinery capacity by 1990 could be as much as 1.2 MMB/CD less than that shown in the tables of Appendix J or used for the high demand scenario analyses. For the low demand cases, the targeted Japanese shutdowns were reflected in the analysis. For all other scenarios, this capacity was assumed to be operable.

TABLE 71

ESTIMATED NON-COMMUNIST WORLD REFINING CAPABILITY

	Operable Capability (MB/CD)		
Process Unit	**1/1/80**	**1/1/86**	**1/1/90**
Crude Oil Distillation	62,049	55,901	55,882
Fluid Catalytic Cracking	8,301	8,873	8,904
Catalytic Reforming	8,562	8,089	8,138

Table 72 puts some geographic perspective on the change in refining capacity from 1980 through 1990. The major changes in crude oil capacity between 1980 and 1986 have consisted of a 5.4 MMB/CD reduction in European capacity and a 2+ MMB/CD reduction in the United States and the Caribbean, with a concurrent 1.4 MMB/CD increase in the Arab Gulf. Through the remainder of the 1980s, this shift in crude oil capacity is expected to continue in Europe and the Middle East with another 0.8 MMB/CD reduction in European capacity and a 0.5 MMB/CD increase in Arab Gulf capacity. U.S. crude oil distillation capacity, however, is not expected to change significantly.

There has been a significant increase in catalytic cracking in the world, thereby increasing gasoline production capability. While the rest of the free world installed about 0.8 MMB/CD catalytic cracking between 1980 and 1986, the U.S. capability declined about 0.3 MMB/CD. The Arab Gulf area accounted for 0.1 MMB/CD, while their crude oil distillation capacity had increased by about 1.4 MMB/CD.

Between 1980 and 1986, due to refinery closings, catalytic reforming capacity declined by 0.5 MMB/CD. During this period, the United States shut down 0.4 MMB/CD. At the same time, the Arab Gulf refineries and some of the rest of the world's oil exporters installed about 0.5 MMB/CD.

Appendix J, Attachment 4, collects the regional operating capabilities for the world refining system by region for January 1, 1986, and January 1, 1988. The regional coding system is shown in Appendix J, Attachment 3. The January 1, 1986, capacity shown captures known refining capacity in 1985 plus projects that were known or believed to have been started up or refining capacity shut down during 1985. The January 1, 1988, capacity shown is intended to include additional shutdowns and reasonably expected additions to refining capability.

Appendix J, Attachment 5, summarizes the regional refinery additions or shutdowns expected to occur by region between January 1, 1986, and January 1, 1988. The Saudi Arabian refinery increases are the most significant of the changes in refining capacity other than the

TABLE 72

REFINING CAPABILITY BY REGION*
(MMB/CD)

	Europe	Arab Gulf	Other Exporters	United States	All Other Free World	Total Non-Communist World
1980						
Crude Oil Distillation	19.9	1.5	8.5	17.8	14.3	62.0
Fluid Catalytic Cracking	1.0	0.0	0.7	5.0	1.6	8.3
Catalytic Reforming	2.5	0.1	0.5	3.7	1.7	8.5
1986 (Estimated)						
Crude Oil Distillation	14.5	2.9	8.6	15.6	14.2	55.8
Fluid Catalytic Cracking	1.6	0.1	0.8	4.8	1.6	8.9
Catalytic Reforming	2.1	0.3	0.8	3.4	1.5	8.1
Projected 1988/1990						
Crude Oil Distillation	13.7	3.4	8.9	15.7	14.2	55.9
Fluid Catalytic Cracking	1.6	0.1	0.8	4.8	1.7	9.0
Catalytic Reforming	2.0	0.3	0.8	3.4	1.6	8.1

*For region descriptions, see Table 70.

anticipated reduction of the European refining capacity in Italy, Spain/Portugal, West Germany, and France, which total 815 MB/CD of effective crude oil distillation capacity. Since this shuts down some entire refineries, the associated upgrading capacity is also eliminated.

The net expected change in refining capability between 1986 and 1988, excluding the United States, will better balance overall regional refining capability with a lighter product barrel by converting resid rather than crude oil to light product.

World Transportation Capacity

A description of the world petroleum transportation system was developed to support the modeling and analysis activities. The data gathered included capacity of major world pipelines, and capacity and operating characteristics of the crude oil and product marine fleet.

The world crude oil and product carriers (shown in Appendix J, Attachments 29 and 30) are estimated to have an inter-region product capacity totaling 26.5 million deadweight tons (MMDWT) for the world (excluding the United States) and 3 MMDWT for the U.S. Jones Act fleet in 1986. The world (non-U.S.) crude oil carriers have a total capacity of 251 MMDWT in 1986 and the U.S. crude oil carriers total 7 MMDWT. An across-the-board reduction in carrying capacity is expected, with the sole exception of world product carriers over 60 MDWT, where a 1 MMDWT increase is expected.

To ensure that the capacity of the combined fleet is not exceeded when modeling the high

demand cases, very large crude carrier (VLCC) product conversions and product new builds were simulated. Cost parameters are shown in Appendix J, Attachment 31.

The spot charter rate of these fleets, with appropriate adjustments for expected inflation and other increases in operating costs, is shown in Appendix J, Attachments 33 and 34. Spot charter rates were forecast by vessel size, cargo, and trip length.

Vessel speeds and other operating characteristics have been estimated and are shown in Appendix J, Attachment 28.

For the analysis, total world and U.S. marine costs are also assumed to include holding, losses, lightering, and insurance costs. Holding costs are estimated to be 8 percent per year, insurance at 2¢ per barrel, part cargo lightering at 40¢ per barrel plus 1½ days at world scale demmurage, and a terminaling cost at 15¢ per barrel.

In order to most realistically model the shipping activities, a number of port and operating restrictions were defined. Product and crude oil port assignments were made by region for world shipping activities and are shown in Appendix J, Attachment 23. Similarly, intra-U.S. voyages have been defined as to product, carrier type, and source and destination of trip (shown in Appendix J, Attachment 32). Specific details of port and operating restrictions to not allow the model, for example, to operate VLCCs or large product tankers out of the U.S. East Coast or to operate from U.S. ports to U.S. ports with other than U.S. tankers is shown in Appendix J, Attachment 35.

Aggregations of world pipeline capacities are shown in Appendix J, Attachment 24. The capacities shown in some cases combine more than one pipeline when the source and destination are similiar. The actual operating costs for most of the world pipelines were not available so the equivalent marine operating plus holding cost was set as a surrogate.

Aggregations of U.S. pipeline capacities are shown in Appendix J, Attachments 25 through 27, and are depicted on regional maps in Appendix J, Attachments 37 through 39. Pipelines have been specified as to source, destination, product type, and a maximum capacity. The tariff cost in addition to the variable portion of total cost have been provided to allow full and variable cost analyses.

MODELING OIL PRODUCT IMPORTS

The petroleum refining industry competes in a worldwide network of interdependent markets. Changes ripple through the system. For example, the British coal strike of 1984–1985 generated an increase in gasoline and distillate imports into the United States. The reduction in coal production precipitated an increase in the demand for heavy oil in England. The increase in refinery output needed to meet the heavy oil demand created a surplus of gasoline and other light products, some of which found its way to the United States. Hence, there was a strong (but unwitting) link between the coal market in England and the oil refining market in America.

Such market interconnections play a key role in allowing the competition in the refining industry. Locational advantages, shipping options, raw material quality, refinery size, product mix capability, product specifications, demand mix, taxes, and more combine to influence the relative economics of refining. Every refiner responds to the competitive pressures of this sophisticated international market.

The NPC study addresses a range of topics including the effects of U.S. environmental legislation on refinery equipment and the technical competitiveness of its U.S. refinery facilities, given changing policies and economic conditions in the rest of the world. The task was to develop information about the size, mix, and cost of product imports and the potential responses of domestic refiners to changes in the world market. The focus on facilities competitiveness, and the wide range of issues addressed, established the scope of the effort and the need to describe the principal market interactions. The following sections describe the general framework used to consider these issues.

Information Requirements

An analysis of refinery facilities competitiveness inevitably requires a degree of detail that goes beyond a description of the aggregate movements of crude oil and petroleum products. A modern refinery is a complex system of equipment. The output is a diverse mix of products, each with its own quality specifications. To make more of one (e.g., gasoline) inevitably means either making less of another (e.g., distillate), or at least changing the relative economics. The crude oil inputs to a refinery can span a similarly diverse range of quality specifications. Light

crude oils from Nigeria may compete with heavy crude oils from Venezuela in a refinery. Some refineries in California capitalize on the abundance of Alaskan oils and heavy sour crude oils. The flexible refineries in the Gulf Coast follow the changing economics of light and heavy crude oils.

Some of these refineries connect to markets through an integrated network of ships, pipelines, barges, and trucks. The relative transportation cost differentials contribute to the balancing of supply, demand, and price in the marketplace. Inevitably, the analysis of competition requires both a disaggregation by product type and by region of the country, or of the world. The regional and product detail must provide a manageable description of products supplied to the United States.

For purposes of the study of refining markets, there is a tension between finding an acceptable level of detail for describing the issues, and preserving a manageable framework for estimating the effects of different policies. A highly aggregated accounting might be easy to manipulate, but it would risk obscuring many of the most important problems. A detailed description of all refining products and relative economics, similar to those used within individual refineries, would overwhelm the analysis when extended to the breadth of the world market.

The tradeoff in regional and product detail should reflect the purposes of the analysis. In the case of a study of refinery competitiveness, the focus on regional facilities yields and costs, transportation differentials, and crude oil supply is more important than the detail of operations within individual refineries. Hence the analysis started with a relatively simple characterization of refinery operating costs in many regions of the world. Even with only a few key products and crude oil types, the focus on the relative ability of regions to deliver required products created the need for a tool that would manipulate a large amount of data within a consistent framework describing the basics of the refining market. The framework applied started with a model of the refining facilities and crude oil and product transportation operations.

Competition and Cost Minimization

In selecting the appropriate analytical framework, the nature of the market provided important clues. Although the petroleum product market responds to many pressures, the market does not move far from the dictates of the underlying costs and economics. If prices rise in Europe, product flows to Europe, driving down prices there and raising prices elsewhere, restoring the balance. The very extent of the complex interconnections in the refining system creates the unifying theme of a competitive market as the starting point for analysis.

If there is reasonable competition in the market, a familiar theory guides the organization of the data. Furthermore, a well developed and available set of tools opens the way for what would otherwise be an impossibly ambitious level of detail in the analysis. The basic theory relies on the common observation that a competitive market moves inexorably towards a least cost distribution of effort and resources. Individual refiners know well that cost minimization is a key to profitability. If a refinery is cheaper to operate, has better access to crude oil, or the alternative markets are less efficient, then a refiner can enter a market at a lower price and gain market share. If everyone operates from the same principle, then pockets of high cost attract attention and new entrants. Lower costs open windows for lower prices, and the balance returns. Free competition promotes cost minimization. Lower costs mean greater profits and an improved ability to compete in the market.

With each refiner working to optimize profits, the market as a whole moves towards lower cost refiners with access to crude oil and markets. In the refining system, this means that the selection of crude oils, refinery utilization, and logistics all adjust to minimize the overall cost of supplying the market with a given slate of petroleum products. Higher cost producers lose share and profits, and eventually leave the market. The market to an individual refiner may be a localized region, a few states, the nation, or the world. To the extent that the market is competitive, however, it adjusts to minimize the overall cost of meeting market demand. Free competition promotes cost minimization.

Knowing of the importance for cost minimization, refiners have developed many tools for finding the least cost way to run a refinery. These tools appear in the form of computer programs for calculating the least cost way to operate a refinery under a given set of constraints. The constraints include the technical limitations of the hardware, the availability of

crude oil and other inputs, and the product slate for the outputs. Given the details of the costs and engineering coefficients, refiners solve these problems every day.

The extension from a single refinery to a group of refineries—connected by a variety of transportation links—presents no major conceptual challenge. This is a familiar problem for any large refiner. Cost minimization is the essence of the task of balancing the logistics of moving crude oil and partially processed oil among a system of refineries in search of improved profitability. But the essential problem is the same: find the least cost mix of raw materials, operations, and transportation of both the raw material and the products that meet the engineering constraints and balance supply and demand.

Continuing along the same path established by the analysis of a system of refineries, a regional or international market falls within the framework of cost minimization. The same tools and techniques applied to either the study of individual refineries, or to the analysis of the logistics of a group of refineries, lend themselves to the description of the world market. Each extension to a broader market may require a compromise in detail. But given valid data and enough time, the least cost framework brings order to the analysis of this complex market.

Modeling for Insight

The computer models generate too many numbers, and the results are no better than the inputs. Hence, the analysis needs attention to quality control. Furthermore, despite the attractions of the competitive model and the computer programs for finding least cost solutions, other factors play important roles in the world refining market. Governments may support certain refineries to run at uneconomic levels, or special contract conditions may alter the economics in ways undetected by the world refining model. Whatever the reason, the least cost refining model provides no more than the starting point for the application of judgement. The final analysis depends upon the use of expertise in the search for insight.

The results reported in the study follow from this application of industry judgement. The computer model provided the accounting framework for organizing a vast array of data. The least cost solution provided an approximation of the competitive forces that would drive major trends in the market. And the industry judgement provided the real world constraints that would lead to deviations from the least cost solution. Each element complements the others. Without the use of judgement, the model would provide data but no understanding. Without the model, there would be little understanding of the message hidden in the data.

Refining Competition Model

The refining and transportation minimum cost model calculates the least cost solution for meeting a slate of product demands around the world. The Council began with a model developed for DOE and conducted an extensive effort to modify the DOE data base and to test the model. Major revisions left a model suited for the analysis of relative regional economies.

The NPC settled on a regional disaggregation with 31 world refining or product centers, 7 refining regions in the United States, 11 product types in trade, 25 export crude oil groupings, and many modes of product and crude oil transportation. The description of each refining center was approximate and included information on intermediate products, costs, and technical capabilities. The necessary aggregation of refining facilities and optimal use of transportation modes necessarily over-optimized the solution.

The models for the refinery regions summarize the more detailed economics within each region. Each of the refinery regions includes a range of possible modes of operation generated by a parallel analysis with individual refinery models. The data base for the refinery models includes estimates of world refining capability in 1984 and capacity expansions announced in 1985 covering the period through 1987.

The refining competition model requires as input the product demands, crude oil supplies, and transportation rates. The inputs utilize the reports of the several study groups devoted to more specialized study of each of these factors. Given the inputs, the model utilizes a linear program and is demand driven to find a solution that minimizes costs subject to the aggregate technical constraints. Other than the cost of the marginal barrel of crude oil, no product or crude oil prices are input or utilized by the model. The output includes product flow mix and relative product variable costs for further analysis.

Linear Programming Implementation

We can illustrate the analysis by describing the major categories of variables and their uses. In generating data to summarize possible supplies of product imports, let

- z: product imports and exports [$z_{product,\ region}$]
- x: intermediate activities [$x_{product,\ region}$]
- y: crude oil and product transportation [$y_{product,\ to,\ from}$]
- s: crude oil supply [$s_{crude\ oil\ type,\ region}$]
- p: product price vector
- v: crude oil price vector
- c: cost vector for intermediate activities
- t: cost vector for transportation
- d: demand for products [$d_{product,\ region}$].

The imports and exports of products (z) and crude oil (s) receive the greatest attention in our analysis. The intermediate activities (x) describe the utilization of distillation, cracking, partially refined products, purchased fuels and materials, and all other inputs and outputs of the refineries other than crude oil and petroleum products. The costs for each of these activities appear in the vector c. Combined, the c and x vectors represent a large amount of data.

The transportation economics (t) summarize the costs of each mode of transport, between each pair of possible shipment points, for each product. Given c, v, t, and d, our objective is to determine the corresponding vector [z, s] of imports, crude oil requirements, and associated economics. To incorporate political or other noneconomic constraints on the market, judgemental analysis provides additions to the technical limitations on aggregate flows. Hence, with c, v, t, and d, the least cost problem is:

$$\underset{x,y,s,z}{\text{Minimize}} \quad cx+ty+vs$$

Subject to:

$Ax+Bs = b$ refining constraints,

$Cz+Dx = d$ local demand constraints,

$Ez+Fs = y$ transport constraints,

where the matrices in A, B, C, D, E, and F represent the technology of refining and transportation in the model. The vector sets the limits on the utilization of certain refineries in regions where political constraints might override the simple economics of competition.

This simple summary of the model outlines the accounting structure of a significant amount of underlying detail. Appendix J lists the principal products covered, and displays the regions included in the analysis. The key to the analysis of competition is the network of transportation. Appendix J summarizes the principal modes of transportation allowed for crude oil and products among the regions.

In total, the model includes 60,000 variables and 3,600 constraints. This is one of the largest linear programming models ever constructed to study this problem. And this summary model utilizes as inputs the results of the individual regional refinery models, each of which includes about 600 variables and 300 constraints. These tools stretch the limits of the state of the art of formal analysis. These powerful tools may be an important product of this study, available for future analysis.

The powerful capabilities make the application of experienced judgement possible. The voluminous data generated make the use of judgement necessary. Separate sections of this report describe the application of these tools in the analysis of the U.S. refining industry.

World Refining and Transportation Model

The WR&T Model is a linear programming model of the world's refineries, petroleum transportation system, crude oil and gas liquids supply, and petroleum product demands. The WR&T Model calculates the least cost combination of refinery and transportation activities that exactly satisfies a fixed world petroleum product demand scenario.

Generating a solution to a particular scenario is a multi-step procedure (see Figure 17). The world's refinery capacity and configurations are aggregated regionally and/or by level of complexity. Estimates of the world's petroleum transportation capacities and costs are developed. Crude oil and gas liquids supply and product demand scenarios are generated.

A detailed refinery linear programming model is created, representing each particular region and/or complexity. Each refinery model is then used to create sets of extreme points representing possible refinery operations in the

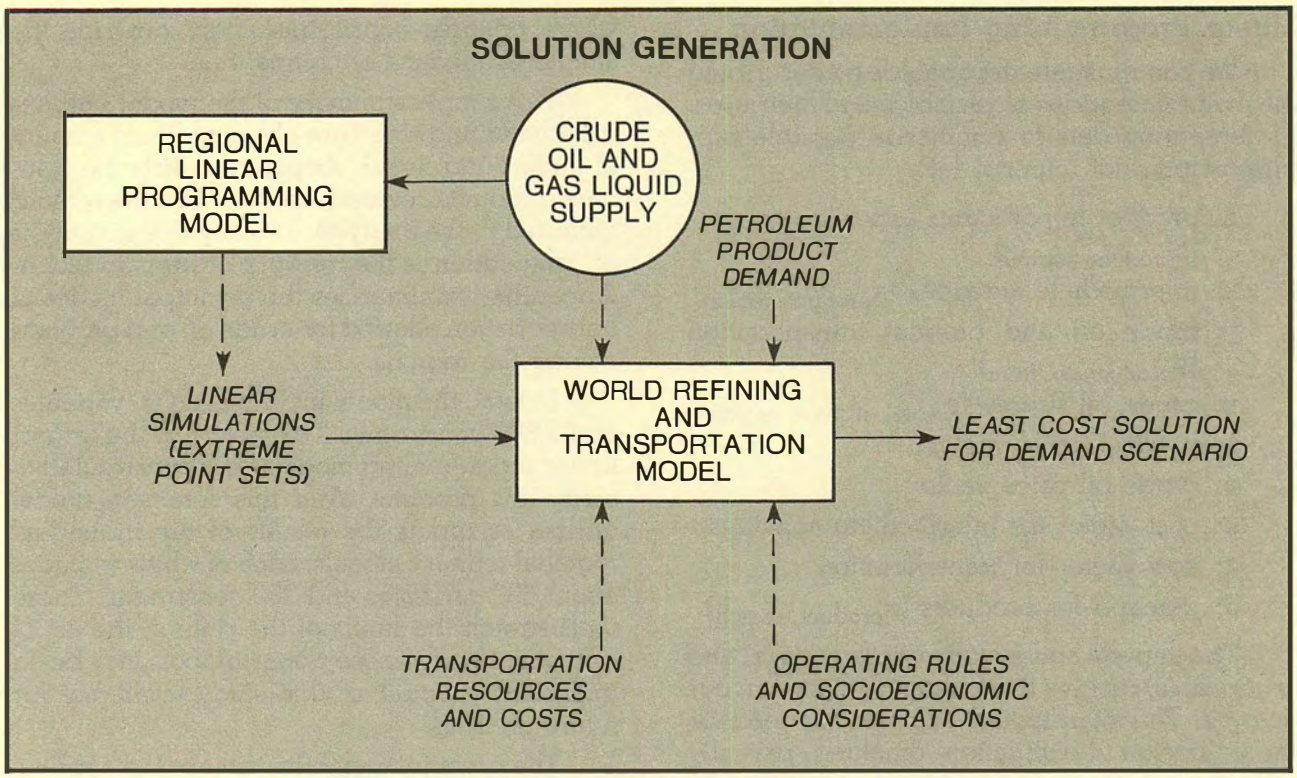


Figure 17. World Refining and Transportation Model.

region under differing feedstock and product price environments. Any other refinery operating scenario is simulated by allowing linear combinations of those extreme point sets. The collection of extreme point sets for each refinery representing a region is a linear simulation of that region.

Region extreme points are transferred to the WR&T Model. The model includes the regional simulations, transportation capacities and costs, supply/demand balances, and any appropriate operational constraint. The model selects the appropriate combination of refinery and transportation activities to satisfy the particular demand scenario under investigation.

In recognition of the non-economic and sociopolitical realities of the oil market, an additional set of constraints was assembled. These constraints included minimum or maximum regional refinery throughput levels and crude oil and/or product flow restrictions. Minimum refinery throughput volumes were estimated by considering each region's stated policy or past practice of refinery operations; crude oil production level; and size of the domestic product market. Minimums ranged from 20 percent for the Caribbean region to 65 percent for Europe to 75 percent for the Arab Gulf area. A complete listing of these constraints is included in Appendix J.

To evaluate the impact of these non-economic forces, oil market scenarios were evaluated that alternatively included or excluded these constraints.

For each scenario evaluated, the model provided detailed output showing refinery and process unit utilization and costs, transportation utilization and costs, crude oil and petroleum product flows, and crude oil and petroleum product marginal costs.

Refinery Models

The detailed refinery modeling system is a number of individual refinery process unit models. An aggregation of refineries, refinery process unit models—each with appropriate capacities, costs, and yields—are joined together to create a unique refinery model.

Industry refinery modeling and refinery operating experts conducted an extensive review of DOE's refinery modeling system. Individual process unit parameters and operating characteristics were either verified and accepted or modified to reflect industry standards. Complete regional U.S. refinery models were

validated with the data generated by the U.S. refinery capability model and with the data collected from the NPC's 1985 Survey of U.S. Petroleum Refineries.

Individual refinery models were created to represent 28 non-U.S. world regions. The degree of world aggregations was dictated by the availability of reliable data and by the desire to maintain a common basis with the earlier DOE work. The U.S. refinery system was represented by seven regional refinery models. The models were organized by PADD and by complexity. PADDs I, IV, and V were modeled with one refinery model each. PADDs II and III were modeled with two refinery models each, high and low complexity. The degree of U.S. refinery aggregation was determined by the amount of detail thought necessary to be compatible with the rest of the world modeling.

The regional refinery models were used to generate extreme point representations of refinery operations under various feedstock and product price scenarios. The extreme points were then incorporated into the WR&T Model as linear simulations of the world's refineries.

Refinery modeling experts selected 10 product price sets for use in generating extreme points sets. Each product price set and feedstock combination generated appropriate refinery product yields, costs, and process unit utilization at 40 and 80 percent of calendar-day crude oil distillation capacity. The set of extreme points generated at 40 percent utilization was used to simulate refinery throughput of between 0 and 50 percent of calendar-day capacity. The set of extreme points generated at 80 percent utilization was used to simulate refinery throughput greater than 50 percent of calendar-day capacity.

Extreme-point representations were created for a base feedstock slate for all regions (1983 historical slate per DOE for non-U.S. regions, and 1984 historical slate per DOE for U.S. regions). Except for those non-U.S. regions that refine only indigenous crude oil, additional feedstock slates were created by substituting 40 percent of the historical slate with 1 of 35 trade crude oils.

The WR&T Model contains more than 12,000 sets of extreme points, each set representing a combination of refinery operation level, feedstock slate, and product price environment. Linear combinations of extreme-point sets produced any refinery operating scenario required.

SUPPLY AND DEMAND

The analysis required greater product detail than that provided by the initial supply/demand cases. Additional items of demand, supply, product description, and crude oil type and allocation were developed. These items include:

- World Aromatics Demand (Appendix J, Attachment 15)
- World (Non-U.S.) Resid Demand (Appendix J, Attachment 18)
- World (Non-U.S.) Gasoline Octane Demand (Appendix J, Attachment 17)
- World (Non-U.S.) Distillate Demand (Appendix J, Attachment 19)
- Centrally Planned Economies Petroleum Exports (Appendix J, Attachment 21)
- World (non-OECD) LPG Demand (Appendix J, Attachment 16).

As summarized in Table 73, the principal growth in aromatics demand is expected to occur in the United States from 1986 to 1988, with the remainder of the growth to be from non-European rest-of-world countries, principally in the "Asia" and "other exporters" group. Due to the lack of availability of data on product type, all aromatic materials were grouped into one category.

TABLE 73

WORLD AROMATICS DEMAND SUMMARY*

	United States	Europe	Rest of World	Total
Demand (MB/CD)				
1986	142	178	203	523
1988	165	180	218	563
1990	167	183	237	586
Demand Growth (%/Yr)				
1986 - 1988	7.8	0.7	3.6	3.3
1988 - 1990	0.6	0.6	4.3	2.0

*For region descriptions, see Table 70.

For modeling purposes, the world's low sulfur residual fuel demand was estimated. The U.S. residual fuel demand estimate is contained in the NPC supply/demand case. Appendix J illustrates non-U.S. residual fuel demand assumptions.

Estimated world (non-U.S.) gasoline octane demands are shown in Appendix J, Attachment 17. They are shown as clear pool octane [(R+M)/2] and in general show patterns related to regional refinery upgrading capability and lead additive regulation. Europe in aggregate has the highest (non-U.S.) clear pool octane requirement, averaging 86.2, with West Germany, Austria, and Switzerland about 90. Europe without Region 9 (Greece and Turkey, which require 77 clear pool octane) has a clear pool octane of 87.4.

Puerto Rico, the Virgin Islands, and Japan have a demand requirement at 87 pool octane [(R+M)/2] while Canada, Australia, New Zealand, and the Carribbean demand about 85 octane. The rest of the world (excluding the United States) has varying lower demand requirements, ranging from a low of 68 in Bolivia, Brazil, and Colombia, to about 75 octane, the average for the rest. The octane requirements were developed from industry sources and are either 1985 requirements for the non-U.S. region or estimates of future demands. The U.S. demand was forecast for two grades, 87 and 92 octane unleaded. No increase in octane demands above these levels was assumed for the study period.

Supply/demand information was not available from industry sources for the Centrally Planned Economies, and refinery configurations and transportation modes and capacities were uncertain. Net import/export quantities (Appendix J, Attachment 21) were supplied by the CIA for the East Bloc (non-Soviet), the Soviet Union, and the Peoples Republic of China. We note a significant expected decrease in crude oil and product export from the Soviet Union, with a slight expected increase in combined export including gasoline from the Peoples Republic of China.

For modeling purposes it was necessary to distinguish between No. 2 and No. 4 fuel oil demand for non-U.S. locations. Appendix J, Attachment 19, shows the distribution of No. 2 and No. 4 fuel oil by region, where estimable.

TARIFF AND TRADE REGULATIONS

Included in Appendix J is Attachment 22, "Trade Measures Affecting Oil Products," prepared by the International Energy Agency, which outlines and details the known trade measures and tariffs in effect on petroleum. These issues have been consolidated so as to allow analysis of the potential overall effect of changes in various levels and types of restrictions. Additional restrictions to world trade were estimated. These included government-to-government arrangements, company practices, etc.

Import fees or custom duties are greater for the lighter products.

CHAPTER FIVE

Comparative Position of the Domestic Refining Industry

INTRODUCTION

By measuring the comparative position of U.S. refineries by capacity utilization (U.S. versus non-U.S.) and U.S. product imports, the following observations can be made. U.S. product import levels and refining throughput should be relatively stable at today's conditions if demand levels and patterns and political constraints in the world do not change significantly, even though world refining configurations will be changing. Rising U.S. and world demand increases U.S. refinery throughput and product imports. Changing demand patterns, in particular the mix of light and heavy products, both inside and outside the United States, will impact on the comparative position of U.S. refineries. The lighter the demand barrel, the lower the U.S. product import level and the higher the U.S. refinery throughput assuming constant overall demand. The converse is also true—the higher the residual fuel share of demand, the higher the U.S. product import level and the lower the U.S. refinery throughput assuming constant overall demand.

Any increases in the levels of product imports will land primarily in PADD I, but offsetting reductions in U.S. refinery utilization rates will take place primarily in PADD III, and to a lesser extent in PADD II. The refineries or parts of refineries that will be primarily affected are those whose product yields are not in line with the product demand mix in their own market.

Many variables have been examined for their effect on U.S. refinery operation. The only variables that equal the significance of the oil demand level and the percentage of residual fuel in the demand mix are the imposition of sociopolitical constraints and the imposition of product import tariffs. Analysis indicates that the effectiveness of a U.S. tariff depends directly on the reaction of the product exporting countries and other product importing countries.

SCENARIOS

In order to examine the competitiveness of U.S. refineries, a number of scenarios were tested using the model discussed in Chapter Four. To provide a standard to test against, reference cases were defined for two years—1986 and 1990. First, the operational conditions expected to prevail in 1986 were simulated. Then, two sets of conditions that could occur in 1990 were modeled reflecting the two most sensitive variables—the level of demand and the percentage of residual fuel in the demand mix. The first 1990 reference case has a lower level of world demand in 1990 than in 1986 (by 1 MMB/CD) and a percentage of residual fuel in the demand barrel about the same as in 1986 (residual fuel demand equal to about 18 percent of the total). The second 1990 reference case has a much higher level of demand in 1990 than in 1986 (by 7 MMB/CD), and a percentage of residual fuel in the demand that reflects a much heavier product barrel. (Residual

fuel demand equals 21 percent of the total, and is about 2.5 MMB/CD higher worldwide in 1990 than in 1986.)

Variations of these reference cases explored changes to product mix at various demand levels within limits indicated in the reference cases. Structural changes to today's political, social, and economic environment were also studied. A recap of the scenarios that were used in this analysis appears in Appendix J, Attachment 40.

THE REFERENCE CASES

In the model of the 1986 reference case, the U.S. refineries are operating at about 12 MMB/CD throughput, which is about an 80 percent utilization rate of operable calendar-day capacity (as defined in Chapter Three), compared to the worldwide average of about 72 percent. PADDs I and V operate at the highest rate allowed in the model, 92 percent, and spare crude oil distilling capacity is predominantly in PADDs II and III. Net product imports total about 1.5 MMB/CD, consisting of about 0.8 MMB/CD of gasoline/distillates,[4] 0.5 MMB/CD of residual fuel to PADD I, and 0.3 MMB/CD of other (LPG, chemical feed, etc.), predominantly to PADD III. About 0.2 MMB/CD of residual fuel is exported from PADD V. Most of the light oil imports come from South America and the Caribbean.

As shown in Table 74, compared to recent experience the model estimates of imports are slightly high and the 1986 model does not fit 1985 actual. However, the National Petroleum Council viewed the consistent mathematical treatment of the variables as sufficient for analyses of differences. Therefore, analyses of the cases were reported as differences, not as absolute volumes.

In the 1990 low demand reference case, world demand is down about 1.2 MMB/CD, or 3 percent, from the 1986 case but retains the same percentage of residual fuel in the demand. Under this scenario, it appears that the slackening demand will be absorbed nearly proportionally around the world by slowing refinery throughputs. However, average refinery throughputs in the United States do decrease more than in the rest of the world. This is primarily because the U.S. demands used in this scenario are down 0.7 MMB/CD of light products, while demand in the rest of the world is down 0.5 MMB/CD, with residual fuel more than half the decline. U.S. imports of gasoline and distillates increase 0.1 MMB/CD. Residual fuel exports from PADD V are up slightly and imports to PADD I down slightly, so the net residual fuel imports decline by about 0.2 MMB/CD.

TABLE 74

U.S. NET PRODUCT IMPORTS (MMB/CD)

	U.S. Demands		Imports	
	1985 Actual	1986 Model	1985 Actual	1986 Model
Gasoline/Distillate	11.0	11.1	0.6	0.8
Other	3.4	2.8	0.2	0.4
Residual Fuel				
PADD V	1.3	1.3	(0.2)	(0.2)
PADDs I-IV	—	—	0.5	0.5
U.S.			0.3	0.3
Total Demand	**15.7**	**15.2**		
Net Imports			**1.1**	**1.5**

Most of the decline in U.S. refinery utilization takes place in PADD III refineries. PADD II lower complexity refineries[5] also exhibit lower utilization rates.

The results from this case indicate that despite the changes to refining hardware expected over the next few years, both inside and outside the United States, minimal changes to U.S. imports are implied.

The 1990 high demand reference case presents a different picture. There is a substantial increase in world oil demand, +7 MMB/CD or 4 percent per annum over the four year period. The demand increase inside the United States is 3 percent per annum.

World residual fuel demand in this case is 2.5 MMB/CD higher than in the 1986 reference case, and represents 36 percent of the growth in demand. The world product barrel would be getting heavier in this case, reversing the trend experienced in recent years.

[4]Throughout this chapter, references to imports of gasoline and distillates are combined.

[5]The model, and this analysis, does not differentiate between lower complexity refineries and parts of refineries that behave like they are of lower complexity. The text is meant to indicate both.

Refiners around the world share the increases in demand, with worldwide utilization increasing to 85–86 percent both inside and outside the United States. The increase outside the United States is greater—it started from a much lower level and responded to faster growing demands. U.S. imports of gasoline and distillates change 0.1 MMB/CD. Imports of LPG, chemical feedstocks, and other streams increase 0.2 MMB/CD. Residual fuel imports to PADD I also increase about 0.2 MMB/CD. The increased refinery utilization in the United States is predominantly in PADD III refineries.

The analysis indicates that U.S. refineries can approximately maintain their present share of the gasoline/distillate demand increase, despite improvements to refining hardware outside the United States. This is true as long as worldwide product demands increase in the same pattern as in the high reference case and the sociopolitical constraints do not change. (Variations of this are discussed below.)

PERCENTAGE OF RESIDUAL FUEL IN THE DEMAND

The importance of the product mix must be understood. For that reason, a number of cases were examined that varied the percentage of residual fuel in the demand. In each case, the total demand in each geographic area was held constant, with residual fuel demand changes being allocated proportionally to the light oil demands.

The relationship between the percentage of residual fuel in the demand and U.S. light oil imports and refinery utilization is illustrated in Figure 18. The data for those lines come from taking the 1990 low demand reference case and varying the percentage of residual fuel in the demand. Increasing the residual fuel share of the barrel lowers the U.S. refinery utilization rate and increases the U.S. net imports. What appears to be happening is what was experienced during the 1983–1984 U.K. coal strike, when 300–500 MB/CD of additional residual fuel was consumed in power plants. The world refining system reacts by running more crude oil to produce the residual fuel. That generates more coproduct light oils, puts them in the market, and reduces the economic incentives to run conversion capacity. The United States has the largest high conversion refining system along with the highest light–heavy ratio of product demand. This results in refineries in PADD III and, to a lesser extent

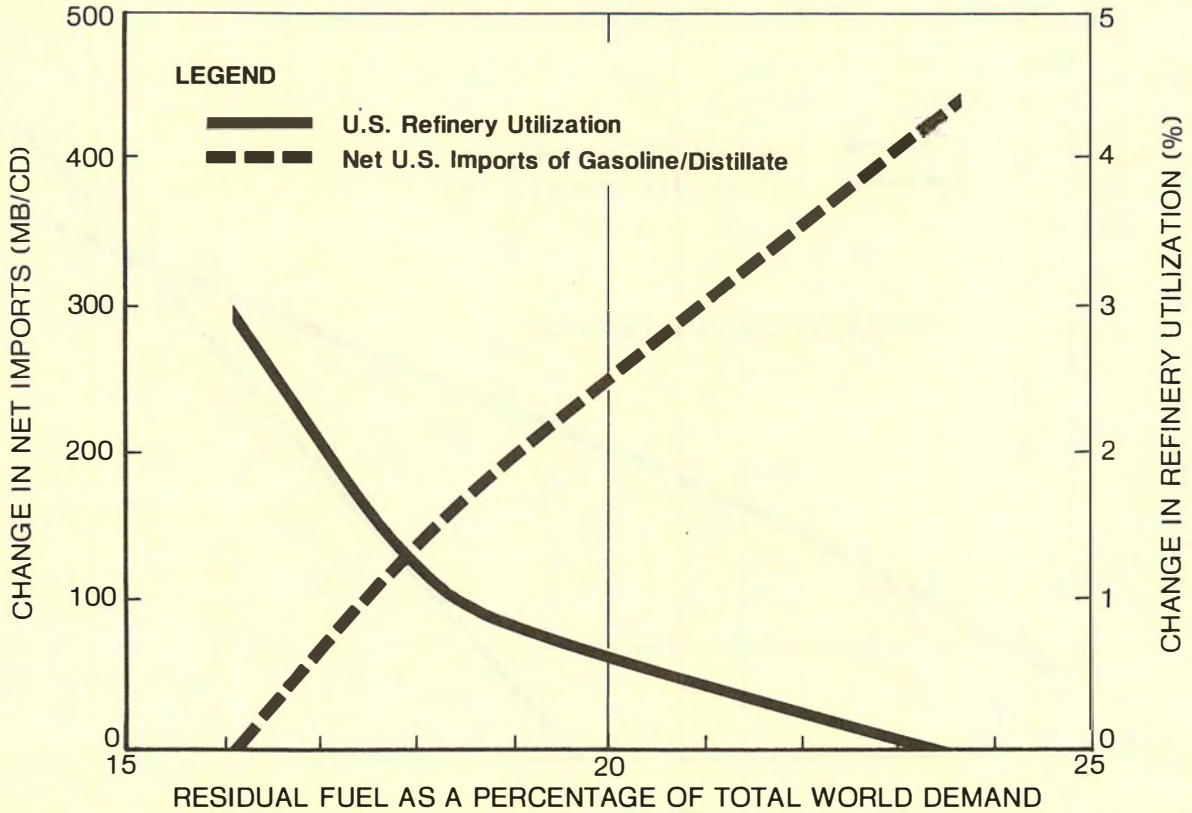


Figure 18. Effect of Residual Fuel Demand on 1990 Low Demand Case.

PADD II, remaining at lower throughputs while additional light oils are imported.

At higher levels of world oil demand, the same relationship holds true. This can be illustrated by plotting the world residual fuel demand against U.S. gasoline/distillate imports, but showing the two world oil demands in the case studies, as in Figure 19, which shows U.S. imports are higher in the low world oil demand case than the high case over most of the range. At the lower oil demand level, foreign refiners are producing coproduct light oils as residual fuel demands increase. In the higher oil demand case, foreign conversion capacity is filled, and coproduct light oils are needed to satisfy foreign demands. Consequently, light oil imbalances, available for export to the United States, do not occur until residual fuel is a higher percent of total oil demand.

SOCIAL AND POLITICAL CONSTRAINTS

There are many places around the world where free product trade and market economics do not determine the level or mode of refinery operations. For this reason, the model was used to test the effect of superimposing non-economic, social, and political constraints. A complete listing of the constraints tested appears in Appendix J. Of particular interest was the minimum throughput designated for a number of developing countries.

Cases with and without these constraints were examined using the 1986 model and a 1990 low demand model. Removing the refinery utilization minimum assumptions from the reference case increased U.S. refinery throughput 0.5 percent and decreased net imports 0.1 MMB/CD. The changes were not more pronounced because some non-U.S. refining areas had been operating at their economic level in the reference case. It was concluded that the specific local, political, and social constraints analyzed would not alter any of the other conclusions of the study about the United States, except those concerning the effectiveness of product import tariffs, as discussed below.

There has been interest in the impact on world product flows of the Middle East/North Africa refineries as they become operational. For this reason, a maximum refinery throughput case for the area was examined. Maximum throughputs for all refineries in Algeria, Libya, Egypt, Syria, Bahrain, Iran, Arab Gulf countries, Gabon, and Nigeria were tested. The case on

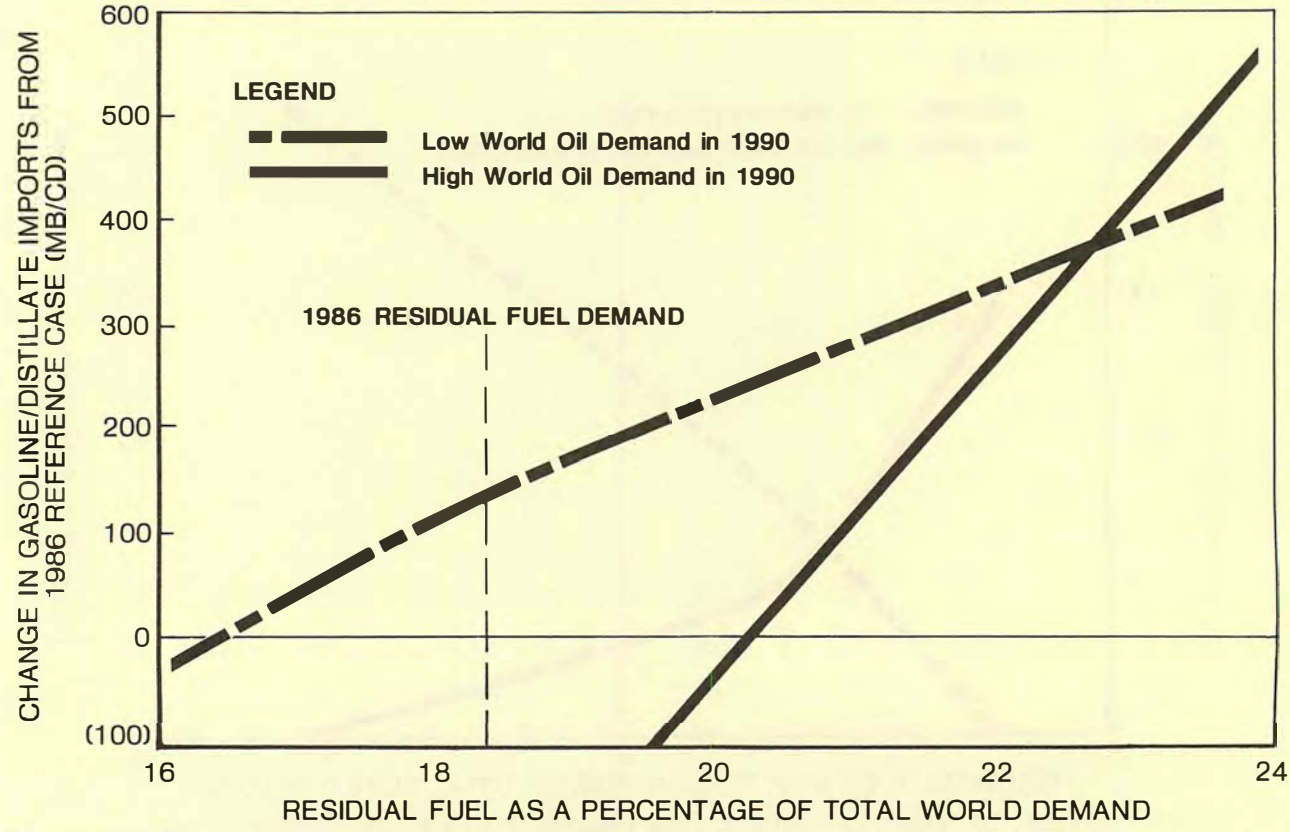


Figure 19. Effect of Worldwide Residual Fuel Demand on U.S. Gasoline and Distillate Imports.

which this constraint was levied had a low world oil demand (43 MMB/CD) and a high world residual fuel demand (10 MMB/CD).

Throughputs were increased 1 MMB/CD to simulate capacity utilization, and the model indicated:

- Middle East exports increase about 0.9 MMB/CD.
- Of that, about half goes to Europe and 0.3 MMB/CD goes to the Far East. The increases are in residual fuel, distillate, and other.
- About 0.2 MMB/CD of light products moves to the United States. Rebalancing of the world's supply patterns results in an additional 0.1 MMB/CD of light products moving to the United States from other sources. As a result of the 0.3 MMB/CD increase in U.S. light products imports, average U.S. refinery utilization declines about 2 percent, with the throughput decline predominantly in PADD III.
- It should be noted that all announced Middle East/North African refinery capacity expansions/additions are included in the study work. As of this writing, construction of one Middle East refinery, with a capacity of 0.3 MMB/CD, has been delayed.

It appears that if the Middle East refineries are arbitrarily run at high non-economic levels, most of the increased product will be absorbed by backing down free-market topping refineries in Europe and the Far East, but about 20 percent of the outturn comes to the United States as gasoline/distillates. Of course, the reaction of the non-U.S. importers could affect the volume of product that flows into the United States, particularly if protectionist barriers are erected.

U.S. TARIFFS

Because of the high interest level, protective tariffs on U.S. imports were studied with the model. Numerous variations could have been examined—light oils only, miscellaneous exemptions such as LPG or residual fuel, offsets for exports, exemptions for certain exporting countries, etc. To establish the principles, tariff increases, varying up to $5/bbl, on all U.S. product imports were used for the 1990 reference case as defined earlier in this chapter. A variation on this case examined whether there would be any different impact if refineries in the Middle East/North Africa were run at a maximum throughput. Finally, a case was examined where all minimum throughput constraints listed in Appendix J and included in the reference case were removed to determine if they had any impact on the effectiveness of a U.S. product tariff.

Figure 20 contrasts the results of these cases.

- Increasing tariffs under reference case conditions decreases U.S. imports. The maximum product tariff evaluated was $5/bbl (on all products). As can be seen in Figure 20, net U.S. product imports are eliminated by a $4/bbl increase in U.S. tariffs.
- When the same U.S. tariff test was applied to the case where reference case refinery minimum throughput constraints were removed, a $1/bbl tariff reduced product imports by 75 percent and a $2/bbl tariff completely eliminated net product imports. This is indicated by the bottom line in Figure 20.
- In the Middle East/North Africa refinery maximum throughput case, the tariff effect is less than in the other cases.
  - —As discussed in the previous section, Social and Political Constraints, this set of conditions increases U.S. product imports in the situation where no additional U.S. product tariffs are imposed. This results in U.S. product imports at about 116 percent of 1990 reference levels.
  - —Tariff increases of up to $3/bbl are effective in redistributing some U.S. imports to the rest of the world. Beyond this level, the curve essentially flattens, indicating that the exporting area is absorbing the U.S. tariff increase.

European tariff constraints were studied in relation to the reference case plot in Figure 20. The European Economic Community (EEC) imposes import tariffs on products from the United States, Canada, and communist bloc countries. The EEC does not impose tariffs on product imports from other free-world nations. If a $5/bbl tariff increase is applied to all European product imports, U.S. imports are higher by 0.4 MMB/CD. Imposing a $5/bbl tariff on U.S. product imports at the same time more than offsets the EEC tariff effect.

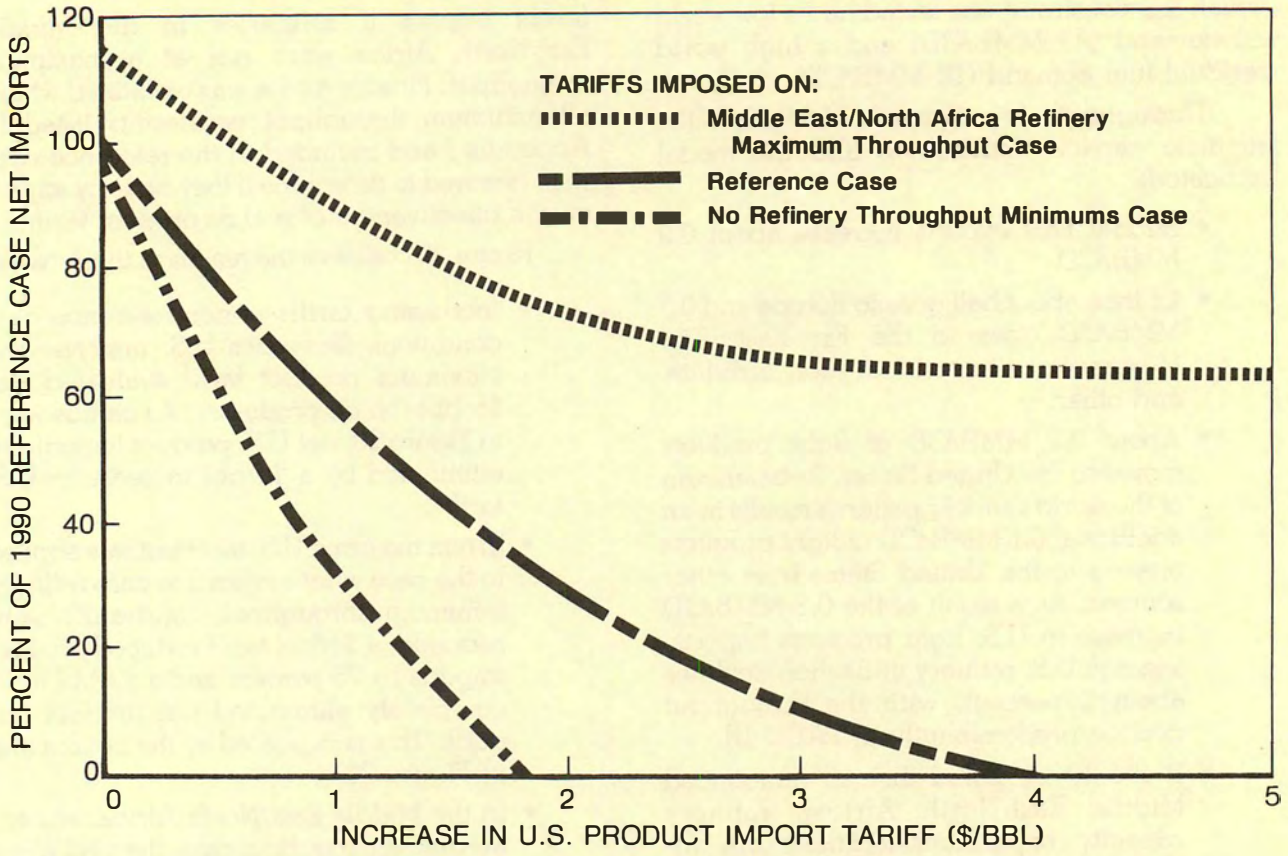


Figure 20. Impact of Sociopolitical Constraints on U.S. Tariff Effectiveness.

Finally a case was examined in which a $5/bbl tariff increase was applied to both crude oil and product imports into the United States. The model indicates that U.S. product imports increase 0.2 MMB/CD, all in heavy fuel oil from the reference case level with no tariff. U.S. exports, namely residual fuel from PADDs III and V and "other" from around the United States, are about $5 more expensive than from foreign refiners. So U.S. exports go to zero. The previously exported streams are either transported to other U.S. markets or converted to light oils. U.S. crude oil imports are reduced correspondingly.

What this rather narrowly focused analysis ignores is the external effects of the $5/bbl tariff on crude oil and products. For example, the U.S. demand for chemical feed is likely to drop because U.S. petrochemicals will probably be less attractive in other countries.

MIDDLE EAST REFINING

The keen interest in the refining capacity in the Middle East arises from the active construction program started several years ago. As detailed in Appendix J, nearly 2.0 MMB/CD of crude oil distilling capacity will have been added in this region over the 1982–1988 period. (Note: As mentioned earlier, construction of a Middle East refinery included in the model, which has a capacity of 0.3 MMB/CD, has been delayed.) The operations of these refineries were examined in detail in all the cases studied, with the following observations.

Middle East product exports to the rest of the world range from a low of 1.3 MMB/D in the 1986 reference case to a high of 3.1 MMB/D in the case where the Middle East refineries are run at maximum throughput. The distribution patterns are shown in Table 75.

Close examination of the two key variables identified above, world oil demand and the world percentage of residual fuel in the demand, indicates that the Middle East refineries play an important role in how the world behaves. In Figure 21, refinery utilization for the world and for the Middle East refineries are plotted against residual fuel as a percentage of total demand. Two relationships are evident:

- At the high world oil demand levels, the world refining system is working hard to

supply product demand. But the Middle East refineries appear to be at an economic disadvantage if residual fuel demands are at the lower end of the range.

- If economics alone are considered, at the lower world oil demand, the Middle East refineries swing with the percentage of residual fuel in world demand.

TABLE 75

PRODUCT EXPORTS FROM THE MIDDLE EAST (MMB/CD)

	1986 Reference Case				Middle East Utilization Forced at 90% (Low Demand/High Resid)			
Destination	Gasoline/ Distillate	Resid	Other	Total*	Gasoline/ Distillate	Resid	Other	Total*
United States	—	0.1	—	0.1	0.1	—	0.1	0.2
Europe	—	0.2	0.5	0.7	0.4	0.9	0.6	1.9
Far East	—	—	0.5	0.5	—	0.1	0.7	0.8
Other	0.1	—	—	0.1	0.2	—	—	0.2
	0.1	0.3	1.0	1.3	0.7	1.0	1.4	3.1

*Totals may not add due to independent rounding.

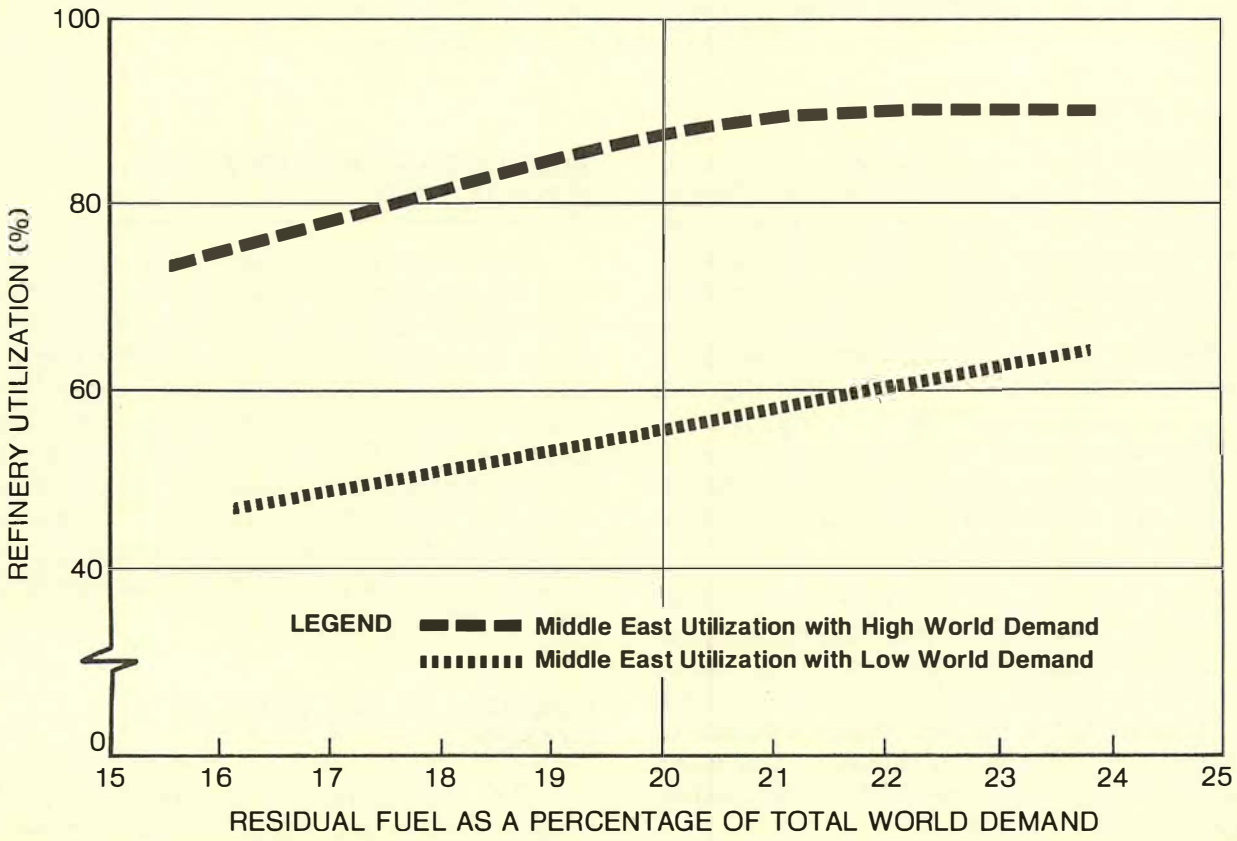


Figure 21. Impact of Residual Fuel Demand on Middle East Refinery Utilization.

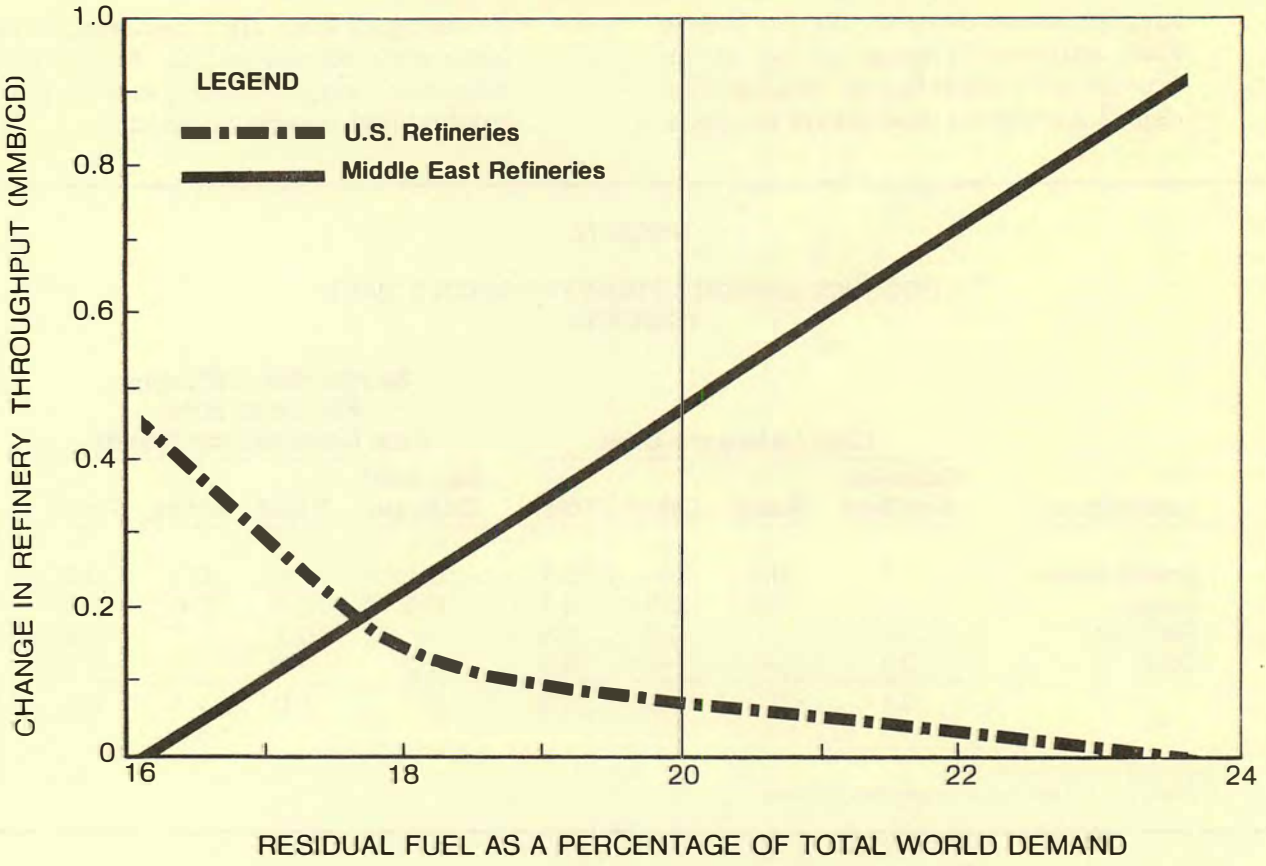


Figure 22. Impact of Residual Fuel Demand on Refinery Utilization (at 1990 Demand of 42 MMB/CD).

Figure 22 is also important. It plots the volume throughputs of U.S. and of Middle East refineries as a function of the residual fuel percentage of world demand (using the low demand case). It is apparent that as the percentage of residual fuel increases, the U.S. refiners lose throughput and the Middle East refiners gain. This is consistent with the fact that the U.S. refineries are higher conversion to light product facilities than are the Middle East refineries. It is notable, however, that the slopes are different —the loss in the United States is much less than the gain in the Middle East.

The Middle East refineries play an important role in providing incremental capacity for rapidly increasing oil demands. Their role at lower demand levels will be a function of the world oil demand mix, i.e., the percentage of residual fuel in the demand. Under conditions of a heavier demand barrel, Middle East product exports will be higher.

MIDDLE EAST/NORTH AFRICA NATURAL GAS

The contention that the availability of lower cost natural gas to Middle East/North Africa refineries could give an economic advantage to those exporters was examined. The reference cases all assumed that the marginal refinery fuel cost was crude oil value based. The model was used to examine the impact if Middle East/North Africa refinery fuel was about 15 percent of the reference case fuel cost. There was no impact because the Middle East/North Africa refineries make a substantial portion of their own fuel from the refining process.

FOREIGN VS. U.S. LIGHT OIL DEMANDS

The relationship of the percentage of residual fuel in the demand to U.S. product

imports was further dissected with another set of model analyses. Light oil demands were increased separately in the United States and then outside the United States. Either way, U.S. refinery utilization goes up. In the former case (Figure 23), foreign refiners get a share of the increase. Consequently, U.S. imports of gasoline/distillates increase at the same time utilization goes up.

If light oil demands increase outside the United States, foreign refiners give up shares of the U.S. market as they work harder to satisfy their own demands. U.S. imports of gasoline/distillates decline as refinery utilization goes up, as shown in Figure 24.

Thus a refinement of the percentage of residual fuel in the demand relationship to the U.S. refining industry is possible. It appears that the lighter the world's oil product barrel, the higher the U.S. refiner's throughput will be. The markets in which that light-heavy relationship changes (U.S. or foreign) determine whether U.S. imports increase or decrease along with increasing utilization.

MARINE TRANSPORTATION

The cost of shipping products to the United States is higher than shipping crude oil to the United States. There are several constraints in the marine transportation sector that could increase or decrease this relationship. The model was used to determine if changes could affect U.S. refinery operations. In one case, marine rates in 1990 were kept equal to the 1986 level; in the alternate case, they were allowed to escalate at 4–7 percent per year for crude oil, and 5–9 percent for products varying with tanker size. The escalation reflected continuing scrappage of older, obsolete tankers and marine rates approaching full capital recovery.

The variance in the two cases is minimal. As expected, with socioeconomic constraints imposed, the marine rate advantage for crude oil versus product movement (25–50¢/bbl for typical vessels and routes) was insufficient to significantly

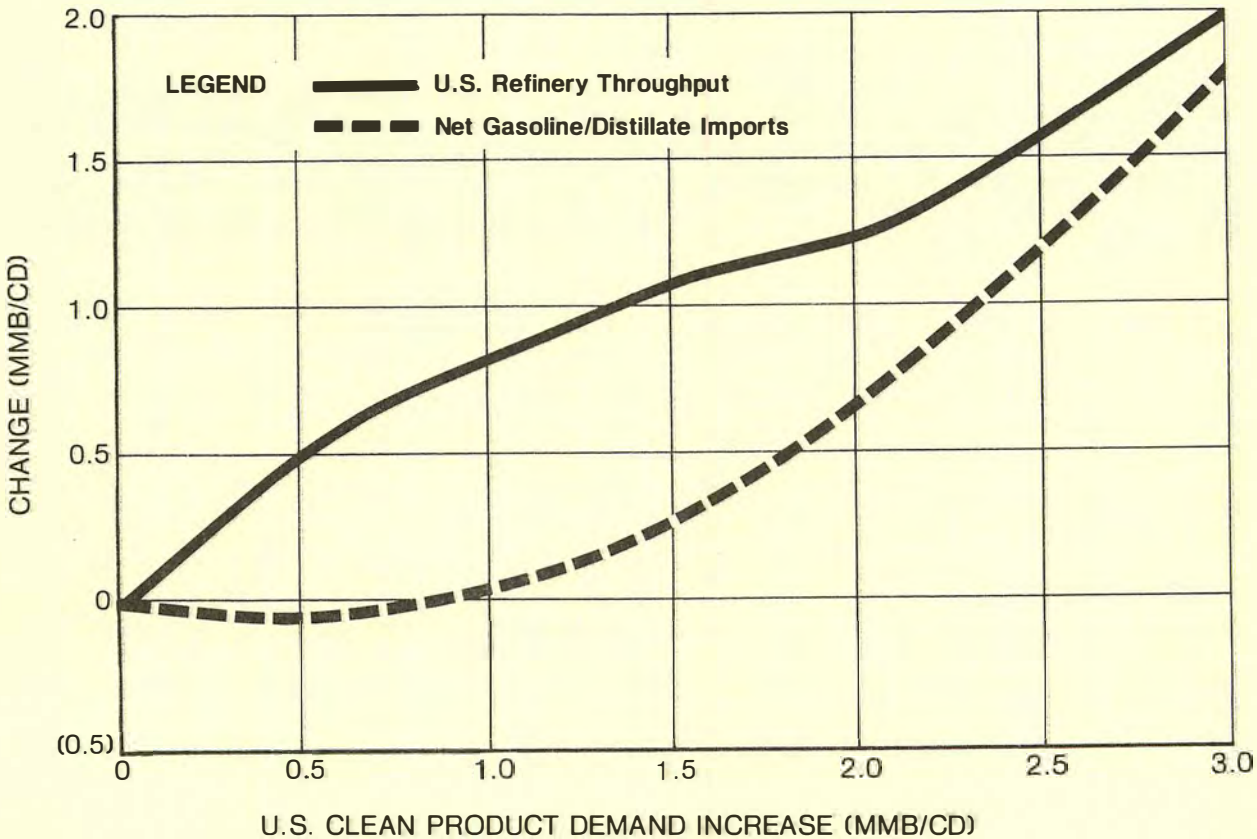


Figure 23. Effect of Increasing 1990 U.S. Clean Product Demands.

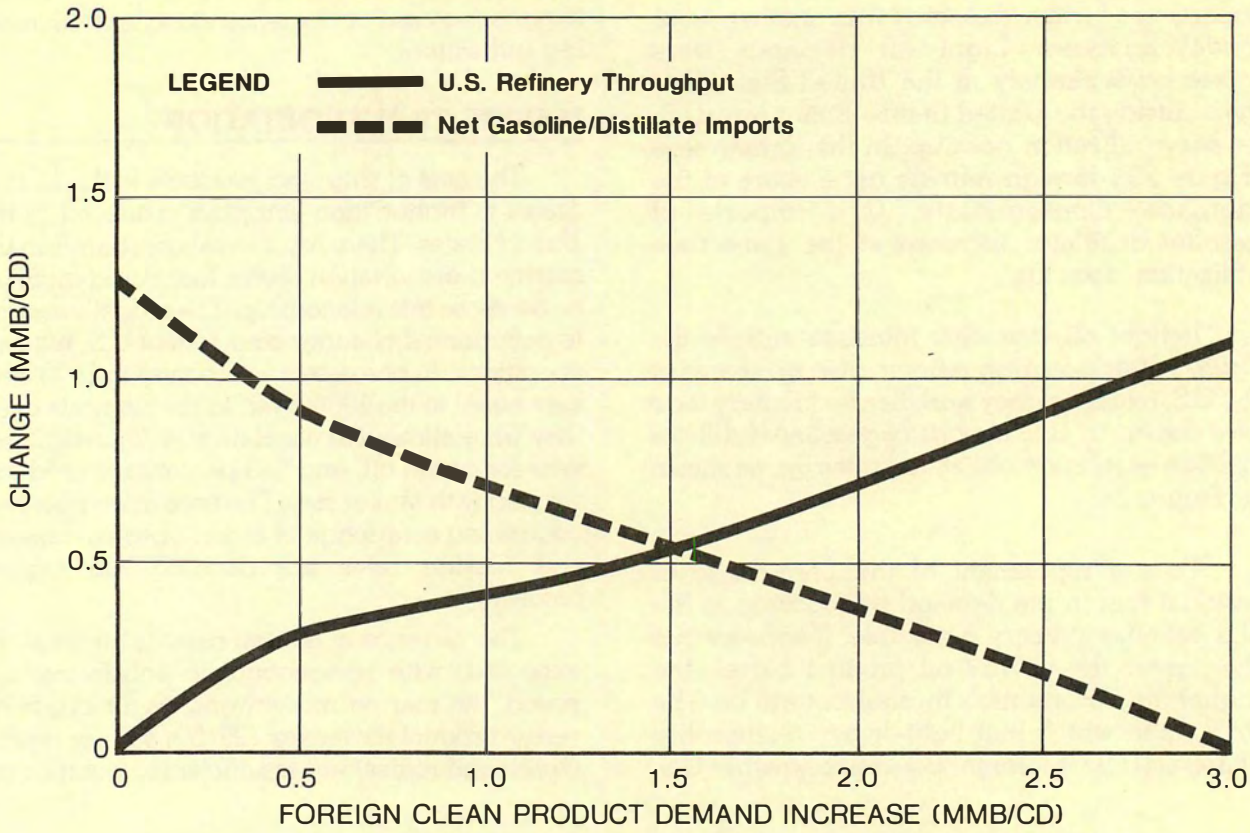


Figure 24. Effect of Increasing 1990 Foreign Clean Product Demands.

affect product imports vs. the 1990 reference case. U.S. product imports and U.S. refinery utilization rates were not measurably increased when marine rates were held equal to the 1986 level.

In conclusion, varying assumptions about marine rates and vessel availabilities over a given range, under assumed reference case socio-political constraints, has little tangible effect on expectations about U.S. refinery operations.

CHAPTER SIX

Other Issues

INTRODUCTION

There were a number of specific and independent issues that the National Petroleum Council was asked to review. These issues have been consolidated and addressed in this chapter.

Impact of Taxes and Tariffs on the Refining Industry

The impact of taxes and tariffs on the refining industry has been reviewed. The U.S. petroleum industry is already one of the most heavily taxed industries in the United States. The need to balance the federal budget must be resolved, but it should be done primarily by reducing federal expenses and not by imposing a variety of new taxes on the petroleum industry.

It was found that the U.S. tariffs on foreign products were substantially lower than the tariffs applied by foreign trading partners on U.S. exports. U.S. refiners would be more competitive in foreign markets if foreign tariffs were equal to the U.S. tariff. There are also a number of ambiguities in U.S. tariff classifications that should be corrected to avoid confusion and misinterpretation.

The NPC was unable to find any areas where foreign private-sector refiners had significant subsidies or tax advantages over U.S. refiners. In the case of government-owned refineries in producing nations, there is no way of determining the extent of subsidization from the raw material to the finished product. Product exporter nations that also export crude oil can artificially change the crude oil price they charge their refineries or other refineries in the world with whom they have processing arrangements relative to a fixed export crude oil price, thereby making their products more or less economic in the world market relative to refineries that purchase the same crude oil at the fixed export price. It has been assumed that these refineries will operate at a reasonable level and the exported products will be sold competitively at the highest net back price available on the free market worldwide. Although some of the recent refineries in the Middle East have been designed to produce a slightly lighter product slate, on the average the Middle East refineries produce a heavier product slate than a typical U.S. refinery. This yield structure tends to put more economic pressure on free-world, private-sector topping refineries than on free-world, private-sector cracking refineries.

Los Angeles Basin Refineries

The L.A. Basin refiners are subjected to the most severe environmental restrictions in the world. Product restrictions include 0.05 wt.% maximum sulfur on diesel, 0.03 wt.% maximum sulfur on gasoline, 9 lb. maximum RVP on summer gasoline, 30 maximum bromine number on gasoline, and a proposed benzene restriction on gasoline. Refinery emission controls include sulfur dioxide (SO_2) restrictions on FCC stack gases, nitrogen oxide (NO_x) limitations on heaters, boilers, and gas engines. They also face serious permitting hurdles on new construction.

All of these environmental restrictions on product quality and refinery operations add substantially to the cost of manufacturing products in the L.A. Basin. The L.A. Basin refining system was modeled to determine the impact of the more significant individual restrictions.

Since all refiners in the L.A. Basin must meet both the product quality and refinery environmental restrictions, it does not impact their relative competitiveness with each other. However, in the long term they will probably become less competitive with imports of products produced outside the L.A. Basin in refineries that have the ability to meet the L.A. product specifications, but do not have the L.A. Basin operating restrictions.

Regional Refineries

Regional refineries serve nearby markets and generally have a local source of raw material. DOE reported 104 refineries with a capacity of 2,650 MB/CD that could be considered regional. Although many of these refineries are small, about 30 percent of the capacity is in refineries with capacities above 50 MB/CD. These refiners serve local and specialty markets with minimal transportation costs on both crude oil and products. Each has its own niche and economic situation that cannot be addressed specifically. These refineries have suffered through the very low refinery margins of the restructuring period along with the rest of the U.S. refining industry. Since the U.S. refining industry restructuring is largely complete, most of the surviving regional refineries will probably continue to operate as long as their unique local competitive advantage continues.

IMPACT OF TAXES AND TARIFFS ON THE REFINING INDUSTRY

The U.S. petroleum industry already bears a heavier tax load than most U.S. industries. As a result of declining demand, lower margins, increasing foreign competition, and unequal taxation, a large number of U.S. refineries have been forced to shut down. Any new taxes on the refining industry could discourage the new investment required to keep existing U.S. refineries competitive with foreign product imports and result in further shutdowns. Additional shutdowns would adversely impact U.S. employment, state and federal tax receipts, and our foreign trade balance.

The present U.S. product tariffs were set in 1948 on a cents per gallon basis and currently are lower than EEC product tariffs that were originally set on an ad valorem basis. Furthermore, the EEC waives their product tariff from most of the rest of the world. The United States, Canada, and Soviet bloc nations are notable exceptions. EEC product imports from the United States must pay duty and compete with product imports from most other countries that pay no duty. On bilateral trade between the EEC and the United States, we are also at a disadvantage.

In addition, there are a number of classification anomalies that reduce the effective tariffs on some U.S. imports by reclassification. Furthermore, U.S. refiners must pay a $0.105/bbl tariff on crude oil imports, which is not levied by EEC countries on their imported crude oil.

It has not been possible to ascertain that U.S. refineries suffer significantly higher domestic tax burdens than other private-sector refineries, i.e., European or Asian entrepot refineries.

Petroleum Import Tariffs for Major Free-World Consuming Regions

U.S. and foreign tariff practices affecting petroleum products are of concern to the U.S. refining industry. Marked disparities between the United States and other nations in tariffs applied to petroleum product imports tend to disadvantage U.S. refiners on exporting regional surplus products that are out of balance with the regional demand.

An examination of existing petroleum import tariffs in the United States, the EEC, and Japan reveals that both of these major trading partners impose considerably higher tariffs on imports from the United States than the United States imposes on imports from them.

As shown in Table 76, both Europe and Japan have higher import duties than the United States. As noted earlier, the EEC waives the duties on imports from most other countries. While Japan has higher overall tariff levels, they apply to crude oil as well as products. The differential between gasoline and crude oil is similar in Japan and the United States, but the overall higher tariff level tends to discourage exports to Japan.

U.S. tariffs, administered on a cents-per-gallon basis rather than on an ad valorem basis,

TABLE 76

PETROLEUM IMPORT TARIFFS
[$/Barrel (Basis 1985 Product Values)]

	United States	EEC	Japan
Products			
Gasoline	0.525	1.66*	2.22
Naphtha	0.105	—	0.08
Heating Oil	0.105	1.13*	1.75
Fuel Oil	0.105	1.00*	1.40
Crude Oil	0.105	—	1.72
Gasoline–Crude Oil Tariff Differential	0.42	1.66*	0.50

*Applies only to imports from the United States, Canada, and most Soviet bloc countries because of waivers to all other nations.

are essentially the same tariffs agreed to in the original General Agreement on Tariffs and Trade, but the foreign tariffs have escalated with the value of petroleum products.

Within the EEC, the Common Customs Tariff specifies the duties on petroleum imports. Crude oil imports enter the EEC duty-free, as does petroleum for further processing (e.g., naphtha for feedstocks). Finished petroleum products are dutied at ad valorem rates ranging from 3.5 percent for heavy oils (gas and fuel oils) to 6 percent for light oils (gasolines) and medium oils (kerosenes). These higher tariffs are of concern to some U.S. refiners, who are exporting their products to Europe and could possibly increase their product exports to Europe if the EEC tariffs were lowered. Since the European refiners do not pay any tariff on imported crude oil, the U.S. refiner suffers a $0.105/bbl higher tariff on every barrel of foreign crude oil imported, and U.S. crude oil prices tend to equalize with foreign imports including the $0.105/bbl tariff.

The Japanese impose a petroleum tax on three classes of petroleum and petroleum products in addition to an import duty. These classes are indigenous and imported crude oil, indigenous and imported gaseous hydrocarbons, and imported petroleum products. While the Japanese duty on gasoline appears high relative to that in the United States, the differential between crude oil and gasoline tariffs is about the same. Although the Japanese government does not formally prohibit imports, de facto administrative restrictions prevented most product imports until recently. On the other hand, the lower Japanese tariff on naphtha relative to crude oil has resulted in the significant imports of naphtha for petrochemical feedstocks. Since Japan recently relaxed its import restrictions, there has been a substantial increase in middle distillate exports from the U.S. West Coast to Japan. Japan has also announced that they are considering removing export restrictions in the fall of 1986.

It is recognized that the U.S. refining system will never export a full spectrum of products. For instance, the United States is the world's largest gasoline market and is importing gasoline from both Europe and Asia. Europe and Asia have much higher demands for distillate and fuel oil, and the United States is now exporting distillates and fuel oil to these markets. If the U.S. and EEC tariffs are equalized as they relate to each other, the United States would tend to export more distillate and fuel oil. Although the magnitude of this change in the import–export balances cannot be quantified, directionally it would improve the overall trade balance of the United States.

In addition to the above-stated tariffs, there are several classification anomalies in the U.S. tariffs that result in uneven tariff treatment for many petroleum product imports.

- Diesel fuel is a motor fuel and as such is subject to the $0.525/bbl product tariff, but since diesel is normally fungible with heating oil some of it may be entering at the lower $0.105/bbl heating oil tariff. A similar situation applies to aviation jet fuel and kerosene.
- Motor fuel blendstock imports may have entered the United States classified as naphtha, unfinished oil, or chemical materials, to take advantage of the $0.105/bbl tariff or the even lower tariffs under the General System of Preferences.
- Aromatics such as chemical grade benzene and toluene can be imported as chemicals with no tariff.

- Ethanol from the Caribbean can be imported without paying the $0.60 tariff under the Caribbean Basin Initiative (CBI) even if it has only been dehydrated in the Caribbean. There is some question whether the processing complexity meets the CBI requirements for preferential duty treatment.
- Ethanol has been imported in high concentration with gasoline and paid only the $0.525/bbl gasoline tariff even though it still generates the $0.60/gallon excise tax credit. The government is considering steps to eliminate this practice but has not yet issued the implementing regulations.

Federal Taxes Affecting the Refining Industry

The oil refining industry is affected, to various degrees, by a number of different federal taxes on refiners and consumers of refined petroleum products. In addition to the corporate income tax, which applies to all corporations, other taxes, such as motor fuels excise taxes, and CERCLA (Superfund) taxes are applied to petroleum.

Current estimates of the burden imposed on the refining industry by federal corporate income taxes vary somewhat, but generally show that refiners face higher-than-average effective tax rates. According to the Joint Committee on Taxation, the average effective tax rate for the refining industry was 18.2 percent in 1982, versus 16.1 percent for the corporate sector as a whole. (More recent data from the Joint Committee on Taxation combine petroleum production and refining into a single industry, which also faces a tax rate higher than that for the corporate sector as a whole.)

Calculations of marginal effective tax rates, which measure the expected tax on an additional dollar of income, also show that the refining industry faces a higher-than-average tax burden. According to a paper entitled "Corporate Taxation in the U.S." by Alan Auerbach in *Brookings Papers on Economic Activity* (2:1983), the marginal effective tax rate for the "petroleum and coal products" industry, which is dominated by oil refining, was 33.2 percent in 1982. Only three industries (out of forty-four) faced higher rates.

Motor fuels excise taxes also have an impact on the refining industry, although in a less direct manner than corporate income taxes. These taxes are borne by purchasers of motor fuels in higher pump prices. However, consumers respond to these higher prices by reducing their demand for petroleum products. This reduction in demand reduces the economic viability of petroleum marketers, refiners, and, ultimately, producers. Recent legislative proposals to exclude excise tax payments to the federal government as a corporate expense would further increase motor fuel costs and put additional downward profit pressure on marketing and refining.

Superfund

The Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (CERCLA), better known as Superfund, imposes excise taxes on crude oil received at refineries, on imported petroleum products, and on certain chemical feedstocks. The Superfund crude oil tax, at a rate of 0.79¢/bbl, raised about $40 million per year. The petroleum industry is already bearing more than its share of Superfund expenses. Reauthorization and expansion of Superfund will likely occur in the near future.

As of October 9, 1986, when this report was adopted by the NPC, the Senate and the House of Representatives had passed a Superfund bill. Whether the President would sign the bill into law was unclear. This five year, $8.5 billion Superfund bill would greatly increase the taxation of the refining industry. The bill would raise the current 0.79¢/bbl tax on crude oil to 11.7¢/bbl on imported crude oil and products and 8.2¢/bbl on domestic crude oil. The increased tax rate would raise the Superfund oil tax burden from about $40 million per year to about $550 million per year. This bill would also contain a broad-based tax on all manufacturers.

Superfund provides funds to clean up old and abandoned waste sites. The 1984 Resource Conservation and Recovery Act (RCRA) provides for much more stringent regulations on existing and future refinery waste disposal. Although the administrative regulations have not yet been fully defined, they will substantially increase the cost of waste disposal. These increased costs, which are higher than imposed on foreign refineries, will reduce domestic refiners' competitive position vis a vis foreign refiners.

State and Local Taxes Affecting the Refining Industry

Direct state and local taxes other than excise taxes and unitary taxes do not impose as significant a burden on the refining industry as federal taxes. However, the nationwide trend in recent years has been toward significant rate increases in many types of state and local taxes. In addition to increases in traditional state real estate taxes, many states have imposed ad valorem taxes on inventories.

Other state taxes, although not imposed directly on the refining industry, do have considerable indirect effect on the industry. The most notable of these taxes are motor fuels excise taxes. These taxes, which range from 4¢ to 20.5¢ per gallon and average about 12¢ per gallon, are the major source of funds for the building and maintenance of state roads. Since January 1, 1982, 33 states have increased their gasoline excise tax rates. Fourteen states and the District of Columbia have switched to tax rates that rise and fall with the price of oil, the general price level, or highway maintenance costs. As is the case with federal motor fuels excise taxes, the reduction of demand for motor fuel that results from tax-caused price increases adversely affects the profitability of refiners and all other segments of the petroleum industry. These local taxes could adversely impact the competitive position of regional refiners.

A variety of other taxes has also been imposed by state and local governments. Rhode Island imposes taxes on wholesale petroleum product sales. These are essentially just hidden motor fuels excise taxes. Connecticut, New York, and Pennsylvania all impose taxes on the gross receipts of oil company operations. This type of tax encourages companies to locate operations in other states. However, in the future, companies will be reluctant to continue marginal operations in cities and states where the political climate makes enactment of such taxes possible.

Foreign Competition

The taxes and subsidies of foreign refiners were reviewed in regard to their ability to competitively export products to the U.S. market.

The OPEC refineries are an integral part of their crude oil exporting policy, and their operations may be based more on national political and economic objectives than on refining economics. Since most of these refineries have higher fuel oil yields than U.S. refineries, they have tended to put more pressure on free-world topping refineries than on free-world cracking units that have high gasoline yields. Exports from these refineries have contributed to the shutdown of private-sector topping refineries worldwide, particularly the entrepot refineries in the Caribbean, Europe, and Singapore. To date only a small portion of Eastern Hemisphere OPEC product exports have come to the United States, primarily in the form of gasoline from the one cracking refinery in Saudi Arabia. The OPEC cracking refinery in Amuay Bay, Venezuela, produces a high gasoline and distillate type U.S. product slate that moves directly to the U.S. East Coast.

The communist bloc countries export petroleum products to the western world including the United States. These exports may be justified more on generating hard currency and disposing of structural gasoline surpluses rather than on overall refining economics. Most of the product coming to the United States is gasoline.

In the case of product importer nations that are also crude oil importers, product import controls in the form of tariffs or volumetric quotas can be varied to the benefit or detriment of local refineries. Product exporter nations that also export crude oil can artificially change the crude oil price they charge their refineries or other refineries in the world with whom they have processing arrangements relative to a fixed export crude oil price, thereby making their products more or less economic in the world market relative to refineries that purchase the same crude oil at the fixed export price. Local tax and regulatory incentives or disincentives can be imposed on refineries that make local refinery output more or less economical.

Influence on U.S. domestic refining margins may occur if crude oil producers were to abandon the now widespread practice of selling crude oil under "net back" contracts, where the price is determined on the basis of a formula related to the market price for refined products in the areas where the crude oils are processed. These arrangements have provided some margin of protection to some refiners against the 1986 decline in crude oil prices during the period between purchase and refining, thereby shifting some risk from the refiner to the crude oil producer.

An analysis of the economic impact of increased volumes of light product imports into U.S. markets should recognize that such imports are predominantly into PADD I. The full economic impact cannot be measured simply by comparing the volumetric percentage of total imports against total U.S. demand. In PADD I, light product imports during 1985 represented 15 percent of total light product demand as compared to 6 percent nationwide. Domestic refiners, seeking to retain market share in PADD I, must compete against imports. This can affect the overall structure of prices in the market and have significant impact on refiner margins. The impact on refiner margins can be positive or negative depending on the nature of the worldwide supply/demand situation. Since some of the PADD I supply comes from PADD III, the PADD I effect is transferred to refiners in PADD III.

The private-sector refineries in the EEC appear to be at least as heavily taxed as in the United States, and do not appear to have any subsidies on exported products. They also face competition from duty free product imports from OPEC refineries. As the EEC refineries have installed cracking facilities, they have generated gasoline surpluses that are moving to the United States in increasing volumes. Japan, although nominally a free market, has restrained its imports by administrative procedures. Japan appears to be relaxing these restraints.

Many smaller consuming countries have protected refining systems. Many of these refineries are small and inefficient by today's refining standards, but their operations are protected for currency conservation, political, and security reasons by means of import restrictions, price controls, and/or nationalized operations. Since these refineries do not export to the United States or the rest of the world, they do not directly compete with the free-world refineries. However, these political restrictions limit the ability of free-world refiners to export into their markets.

Brazil has a unique situation where the national policy has increased ethanol use to more than 50 percent of the gasoline demand and generated a surplus of gasoline and alcohol. Brazil has become one of the larger gasoline and alcohol exporters to the United States.

Impact of Tax Reform Proposals

Since the refining industry has been marginally profitable, any further tax increase could result in further erosion. The refining industry is more severely impacted by tax increases than most industries because of its inability to shift the tax burden. U.S. petroleum product prices cannot be isolated from worldwide price competition.

Historically, the U.S. petroleum industry has paid a higher rate of taxes than the average of manufacturing industries. Today, in the face of increased competition from foreign refineries, the industry is once again faced with the threat of additional taxes. Any additional tax burden could reduce U.S. competitiveness in world markets and result in a further erosion to the domestic refining industry.

Additional taxes under consideration today that could affect refiners include increases in excise taxes and crude oil and/or product import fees. A crude oil import fee, without a similar levy on product imports, would have a severe impact on U.S. refiners. Increased crude oil costs would make it difficult for even the most efficient refiners to compete with imported petroleum products. For this reason, it would be essential that crude oil and petroleum product import fees be enacted in tandem. Such a combination would raise the cost of both crude oil and petroleum products, and impact other American companies, especially U.S. petrochemical companies. These companies would be less competitive in foreign markets, but they would also face increased foreign competition in domestic markets unless U.S. tariffs on chemical imports were increased. Although some of the increased import duties might be recovered through drawback claims, this procedure is limited to direct exports of products produced from foreign crude oil. It does not apply if petroleum products are sold to a U.S. manufacturer or if products produced from U.S. crude oil are exported.

LOS ANGELES BASIN REFINERIES

This section focuses on the special circumstances of Los Angeles area refineries. Issues to be covered are:

(1) Discussion of the unique environmental factors facing L.A. refiners:
- Product specifications
- Emissions standards
- Hurdles to process plant construction

(2) Modeling of L.A. refineries' production capability under various scenarios involving the above factors.

The net result of these special requirements for L.A. refiners is a high degree of continuing pressure on refinery economics to achieve regulatory compliance and, at the same time, continue to supply gasoline and other light products to a high fuel consumption area in the United States not closely linked with other refining centers.

In summary, the L.A. Basin refineries produced approximately 480 MB/CD of motor gasoline during the 1984–1985 period. This production rate included approximately 35 percent leaded grades at then-current specifications. The model runs were prepared to meet operational scenarios in 1988 meeting the 0.10 gplg lead standard with about 15 percent leaded grades and increased ratio of unleaded premium. All model runs indicated a reduced capability to the range of 440 MB/CD. In all cases, the emission limitations in the L.A. Basin were met through the use of desulfurization facilities; several model runs required capacity beyond that announced at this time.

Environmental Restrictions Unique to L.A. Basin Refineries

The meteorologic, geographic, and demographic conditions found in the L.A. Basin have led to and continue to result in air quality that fails to meet federal and/or state standards. Unique emission control regulations have been imposed by the South Coast Air Quality Management District (SCAQMD) on virtually all major source types, including petroleum refineries. The next five years will likely see continued efforts to implement additional emission control requirements to reduce existing refinery and fuels emission levels significantly. Most of these requirements have not been imposed anywhere else in the United States.

Emission reductions to be achieved through installation of refinery controls or petroleum product specification limitations are briefly discussed below.

PRODUCT SPECIFICATION LIMITATIONS

Diesel Fuel Sulfur Content. Diesel fuel manufactured by major refiners for sale in the "South Coast Control Area" must not exceed 0.05 wt.% sulfur. This generally requires expensive hydrofining. Small refiners will also be subject to this rule by the end of 1988 though they are partially or fully exempt from this requirement until that time. The sulfur specification for diesel fuel manufactured for sale in all California areas outside the SCAQMD is 0.50 wt.% maximum.

Gasoline Sulfur Content. The sulfur content of gasoline is limited to 300 parts per million (ppm), or 0.03 wt.% maximum, compared to the ASTM standard of 1,000 ppm.

Reid Vapor Pressure of Gasoline. The RVP is currently controlled from April 1 to October 31 at 9.0 psi RVP maximum. In most other areas of the country, RVP is permitted to vary from 10–11.5 psi, depending upon seasonal requirements adding to the gasoline octane pool.

Bromine Number of Gasoline. Motor gasoline manufactured in SCAQMD must not exceed a maximum allowable bromine number specification of 30. This specification limits the olefin content of gasoline to about 15 percent, thus adversely affecting refiners' ability to optimize their motor gasoline blending components' production and inventory. No other geographic area has a motor gasoline bromine number specification.

Benzene in Gasoline. California is considering putting a ceiling on or lowering the allowable benzene and/or aromatic content of gasoline fuel. Should the benzene/aromatic level be controlled, refineries may have to invest in benzene/aromatic removal/reprocessing facilities. The costs, impacts, and alternatives are discussed in Chapter Three relative to refinery capability.

REFINERY EMISSIONS CONTROLS

There are three rules that weigh heavily on the refining industry in Southern California.

FCC Units. After January 1, 1987, refinery FCC unit stack sulfur oxide (SO_x) emissions must achieve approximately a 54 percent reduction from current levels. The limit until January 1, 1987, is 130 kg SO_2 per 1,000 barrels of feed. After January 1, 1987, that limit drops to 60 kg SO_2 per 1,000 barrels of feed charged to the FCC.

Heaters and Boilers Starting in 1988. SCAQMD limits NO_x emissions from boiler and process heaters in petroleum refineries. By July 1, 1988, petroleum refiners must reduce NO_x emissions to 0.14 lb. of NO_x per million BTU of heat input for gas-fired boilers and process heaters over 40 MMBTU per hour, and to 0.308 lb. of NO_x per million BTU of heat input for liquid-fired boilers and process heaters over

40 MMBTU per hour. NO_x emissions from dual gas/liquid-fired boilers and process heaters must not exceed the weighted average of the individual gas and liquid firing limits. NO_x produced in an FCC unit regenerator are specified by SCAQMD to be from gaseous fuel and are also governed by this rule. Compliance with these specifications requires significant new investment by these refiners, adding to the cost of continued operation in the L.A. Basin.

Gas Engines. SCAQMD limits NO_x emission from rich-burn and lean-burn stationary internal combustion engines, thus requiring retrofitting with exhaust NO_x control. All rich-burn engines must eventually achieve 90 percent NO_x reduction or a maximum of 90 ppm NO_x emissions. As of December 31, 1985, all 500 horsepower (hp) and greater rich-burn stationary internal combustion engines were required to be retrofitted with exhaust NO_x control. By December 31, 1986, most (75 percent) of the 200 hp and greater rich-burn engines must have such control. And by 1995, all 50 hp and greater stationary internal combustion engines must be retrofitted with exhaust NO_x control.

Lean-burn engines must eventually achieve 80 percent NO_x reduction or a maximum of 150 ppm NO_x emissions. Most (80 percent) of the large engines (500 hp and over) were required to be in compliance by December 31, 1985, with smaller engines following on a timetable that brings all engines into compliance by December 31, 1994.

HURDLES TO PROCESS PLANT CONSTRUCTION

New process facilities to provide the processing needed to comply with these product and refinery regulations also must meet strict air quality controls.

SCAQMD rules have several requirements unique to the L.A. Basin:

- BACT (Best Available Control Technology) retrofit requirement on refinery modifications requiring a change in permit requirements.
- Offsets back to zero are required at thresholds below those required by the EPA. For example, the EPA requires offsets for a new source greater than 100 tons/year. Offsets for modifications resulting in a "significant increase" are defined as:

		Tons/Year	
		EPA	SCAQMD
NO_x	(Nitrogen oxides)	> 40	18
ROG	(Reactive organic gases)	> 40	14
SO_x	(Sulfur oxides)	> 40	27
TSP	(Total suspended particulates)	> 25	27
CO	(Carbon monoxide)	> 100	100

SCAQMD New Source Review (NSR) regulations may be revised to eliminate the use of emission "banks" for the emission offsetting of projects requiring SCAQMD permits.

One-half of existing emission banks will be available for offsets only after BACT retrofit is implemented for the entire facility.

Proposed regulations would also require counting and offsetting marine vessel and related outer continental shelf activities for NSR purposes.

In summary, product specifications and refinery emissions associated with Los Angeles area refinery combustion and processing sources are being, and will continue to be, controlled more stringently than in the rest of the United States. This difference requires incremental pollution control and process unit investment by the petroleum refining industry in the L.A. Basin. When also combined with more stringent construction permitting hurdles, the result is a formidable challenge for L.A. Basin refinery economics compared to refineries located in other areas of the United States and the world.

Model Results of L.A. Basin Refining Capability

To examine the impact of environmental regulations on the refining industry in the L.A. Basin, this study has considered the conversion refineries in this area separately. The NPC modeled these L.A. refineries, in aggregate, to consider the following cases:

1. A 1984 base case for calibration of the model and comparison with the NPC survey responses
2. A 1988 case meeting the NPC's estimate of the product demands (in the high

demand scenario) on the L.A. Basin refineries

3. A 1988 case as above with a 1 psi reduction (year-round) in the maximum RVP of gasoline
4. A 1988 case with the same total crude oil as case 2 above, where the production of light and heavy products is optimized based on a set of product values that favor the production of light products
5. A case like case 4 above with a 1 psi reduction (year-round) in the maximum RVP of gasoline
6. A 1988 case without any additional FCC feed hydrotreating capacity beyond that available in 1984
7. A 1988 case with high volume of California SJVH (San Joaquin Valley heavy) and California OCS (Outer Continental Shelf) crude oils run in the L.A. refineries.

These cases consider the impact of two environmental regulations, the L.A. Basin refinery's unique 1987 requirement for lower SO_x emissions from catalytic crackers (FCC units) and a possible lower vapor pressure gasoline requirement. The lower SO_x emissions were met in all cases, though some showed constraints requiring improved feed to the catalytic crackers.

The reduced SO_x emission from FCC stacks can most readily be achieved by reducing the sulfur content of the FCC feed. This is accomplished by hydrotreating the FCC feed, an expensive process requiring a high-pressure plant, hydrogen for desulfurization, satellite plants for removing hydrogen sulfide (H_2S) from the off-gas and for converting the H_2S into elemental sulfur, etc. The typical operating costs are roughly $1/bbl for utilities, labor, maintenance, etc., plus another $1/bbl for the hydrogen consumed, plus the cost of the capital required. An FCC feed hydrofiner complex, including the support plants, costs about $5,000 per barrel per stream day of capacity. Alternatives are to run low-sulfur crude oils so that the lower SO_x emission requirements can be met without hydrofining the FCC feed, or to provide facilities for scrubbing the flue gas to remove the sulfur oxides. Flue gas scrubbing creates other difficulties in disposal of the solid waste.

The model used in developing the following cases represents the conversion refineries in the L.A. Basin. Conversion refineries are those with vacuum gas oil conversion units such as catalytic crackers or hydrocrackers. Comparisons of the cases are presented in the following text and tables; the complete modeling results may be found in Appendix I.

CASE 1

Case 1 is a 1984 base case for calibration of the model and comparison with the NPC survey responses.

Both FCC and hydrocracking capacity are very heavily utilized in this case. The FCC conversion is comparatively low, 64 percent, reflecting the fact that the average quality of the FCC feed to L.A. Basin refineries is low, and the low-API gravity, high-nitrogen, low-hydrogen content feeds are difficult to crack (U.S. average FCC feed gravity = 24.7°API; L.A. Basin average = 21.7° API). Twenty-five percent of the FCC product (77 MB/CD) in L.A. Basin refineries is light cycle oil. Of this, 42 MB/CD is fed to hydrocrackers. The remainder is blended into products for use as cutter in fuel oil and with suitable hydrotreating into diesel fuel.

The average crude oil processed in L.A. Basin refineries is of much lower quality than that processed elsewhere in the United States.

	L.A. Basin Average	Total U.S. Average
API gravity (deg)	24.3	32.6
Wt.% sulfur	1.20	0.96
% 1,050 + °F resid	25.3	16.3
% sweet crude oil	11	51

A specification on the bromine number of gasoline is included in the model of the L.A. Basin refineries. The bromine number specification (maximum = 30) is intended to restrict the olefin content of gasoline and hence lower the emission of reactive hydrocarbons by evaporation. The bromine number is approximately twice the olefin content of the gasoline in percent.

The bromine number specification illustrates one of the limitations of this type of industry aggregated model. Since the model reflects the composite of L.A. Basin refineries, this does not appear to be an overly restrictive specification. However, for those refiners who make more than the average amount of gasoline by catalytic cracking (FCC gasoline has a 70 or higher bromine number), this specification may force

them to do additional costly processing. One such processing step for reducing the bromine number of a gasoline component is to hydrofine and then reform a portion of FCC gasoline. Indeed, three L.A. Basin refiners reported doing so in 1984. Over 17 MB/CD of FCC naphtha was reformed by L.A. Basin refiners; this volume corresponds to almost 10 percent of FCC conversion product and almost 10 percent of reformer feed.

The model results are in agreement with the NPC survey, as shown in Appendix I. The production of light products (except for propane and refinery fuel) and the product qualities were matched. The balance of the refinery production was also in agreement. Overall, the match between the survey and the model for the L.A. Basin refineries is very good, giving confidence in the modeling results when used and analyzed suitably.

CASE 2

Case 2 is a 1988 case meeting the NPC's high demand scenario in the L.A. Basin refineries. This case is compared to Case 1 in Table 77 and is used as the base case for comparisons in Tables 78 and 79. In the NPC high demand scenario, the demand for fuel oil has grown slightly, accompanied by demand growth for distillate and kerosene jet fuel, and significant decrease in motor gasoline demand from 1984 levels.

At the higher volume of fuel oil, the L.A. Basin refineries can meet the required volume of light products. However, both catalytic cracking and hydrocracking are fully utilized in this case. The FCC capacity is derated for the difficult feedstocks produced from the crude oils run by the L.A. Basin refineries. With the demand for heavier product, the coking capacity becomes under-utilized. Light ends processing equipment and reforming show some available capacity.

The FCC feed hydrotreating capacity is fully utilized to meet SCAQMD requirements on SO_2 emissions from FCC unit stacks. Two large FCC feed hydrofiner expansions announced in 1985, which do not appear to be included in the survey responses, were included in the FCC feed hydrotreating capacity available by 1988. The L.A. Basin refineries required FCC feed desulfurization capacity totaling 211 MB/CD to meet the SCAQMD requirements. This is nearly 100 MB/CD above the capacity currently in place.

Total crude oil run is up slightly from 1984 to 1988, but the average quality is little changed.

Starting January 1, 1985, highway diesel produced by large refiners for sale in the L.A. Basin must meet a 0.05 wt.% maximum sulfur specification. This applies to 90 plus percent of the L.A. Basin conversion refineries in this aggregation. The model increased the utilization of distillate hydrotreating capacity, to make 77 MB/CD of this product. Gasoline production is 8 percent lower than that in 1984. Bromine number specification is met. Reformer octane goes up to 99.2 from 96.4 to meet octane requirements with 0.10 gplg maximum.

CASE 3

Case 3 is a 1988 case based upon the NPC high demand base case above, with a 1 psi reduction (year-round) in the maximum RVP of gasoline. Table 78 compares this situation with the NPC high demand base case.

Since the base case, with gasoline demand lower than in the 1984–1985 period, provided some capacity in the octane-enhancement facilities, the model used this capacity. Additionally, the model fully utilizes the C_4 isomerization capacity available in one L.A. Basin refinery, creating an over-optimization that could only be realized by transfer of butane between refineries in the area. This permits better utilization of the alkylation capacity to cope with the RVP reduction without excessing butane from the refinery. The costs computed by the model equate to 16¢/bbl but do not reflect the true cost of accomplishing this task.

The results of this case, however, are over-optimized and are not representative of individual refinery impacts because most refineries are operating with light product facilities at, or near, full utilization. This is especially true in the summer months. A better measure of refinery impacts is represented by Case 5.

CASE 4

Case 4 is a case with the same total crude oil run as in the NPC high demand base case above, except that the production of light and heavy products is optimized based on a set of product values that favor the production of light products. A comparison of this case with the NPC high demand case is shown in Table 79.

This case increased the charge to the cokers up to their model capacity in order to optimize

TABLE 77

COMPARISON OF THE 1984 L.A. MODEL CALIBRATION WITH THE 1988 L.A. HIGH DEMAND CASE (MB/CD)

	1984 L.A. Model Calibration		1988 L.A. High Demand	
	Available	Utilized	Available	Utilized
Process Unit				
Crude Oil Distillation	1,170	841	1,149	861
Catalytic Cracking	325	305	324	287
Conversion (%)	—	64	—	70
Coking	255	226	250	192
Coke (MT/CD)	12.8	11.2	12.3	9.6
Catalytic Reforming	264	195	264	191
Octane (RONC)	—	96.4	—	99.2
Hydrotreating				
Distillate	126	62	124	114
Heavy Gasoil	117	108	209	211
Residuum	22	0		
Alkylation	58	41	58	49
Hydrocracking	133	130	128	118
Crude Oil & Other Feeds				
ANS — Medium Sulfur	316		316	
CA SJVH — High Sulfur	155		167	
CA OCS — High Sulfur	0		0	
Minas — Sweet	61		67	
Other — Sweet	45		44	
— High Sulfur	264		266	
Total Crude Oil	841		860	
Other Feeds	78		64	
Total	**919**		**924**	
Product				
Motor Gasoline	479		445	
Kerojet/Kerosene	92		108	
Distillate	136		155	
F.O. <1% Sulfur	9		5	
F.O. 1%-2% Sulfur	65		68	
F.O. >2% Sulfur	15		21	
Coke @ FOE	56		47	
Propane LPG	14		15	
Butane LPG	5		0	
Refinery Fuel	72		70	
Other	37		48	
Loss/ (Gain)	(61)		(58)	
Total Products	**919**		**924**	

TABLE 78

REDUCTION OF RVP IN THE L.A. HIGH DEMAND CASE (MB/CD)

	1988 L.A. High Demand		1988 L.A. High Demand with Reduced RVP	
	Available	**Utilized**	**Available**	**Utilized**
Process Unit				
Crude Oil Distillation	1,149	861	1,149	862
Catalytic Cracking	324	287	324	286
Conversion (%)	—	70	—	70
Coking	250	192	250	193
Coke (MT/CD)	12.3	9.6	12.3	9.4
Catalytic Reforming	264	191	264	197
Octane (RONC)	—	99.2	—	N/A
Hydrotreating				
Distillate	124	114	124	N/A
Heavy Gasoil / Residuum	209	211	209	N/A
Alkylation	58	49	58	54
Hydrocracking	128	118	128	N/A
Crude Oil & Other Feeds				
ANS — Medium Sulfur	316		318	
CA SJVH — High Sulfur	167		167	
CA OCS — High Sulfur	0		0	
Minas — Sweet	67		67	
Other — Sweet	44		44	
— High Sulfur	266		266	
Total Crude Oil	860		862	
Other Feeds	64		64	
Total	**924**		**926**	
Product				
Motor Gasoline	445		445	
Kerojet/Kerosene	108		108	
Distillate	155		155	
F.O. <1% Sulfur	5		5	
F.O. 1%-2% Sulfur	68		68	
F.O. >2% Sulfur	21		21	
Coke @ FOE	47		47	
Propane LPG	15		15	
Butane LPG	0		0	
Refinery Fuel	70		71	
Other	48		48	
Loss/ (Gain)	(58)		(57)	
Total Products	**924**		**924**	

TABLE 79

COMPARISON OF THE 1988 L.A. HIGH DEMAND CASE WITH THE 1988 L.A. OPTIMUM LIGHT PRODUCTS CASE (MB/CD)

	1988 L.A. High Demand		1988 L.A. Optimum Light Products	
	Available	**Utilized**	**Available**	**Utilized**
Process Unit				
Crude Oil Distillation	1,149	861	1,149	860
Catalytic Cracking	324	287	324	286
Conversion (%)	—	70	—	70
Coking	250	192	250	231
Coke (MT/CD)	12.3	9.6	12.3	10.6
Catalytic Reforming	264	191	264	187
Octane (RONC)	—	99.2	—	99.3
Hydrotreating				
Distillate	124	114	124	114
Heavy Gasoil / Residuum	209	211	209	211
Alkylation	58	49	58	49
Hydrocracking	128	118	128	N/A
Crude Oil & Other Feeds				
ANS — Medium Sulfur		316		314
CA SJVH — High Sulfur		167		167
CA OCS — High Sulfur		0		0
Minas — Sweet		67		69
Other — Sweet		44		44
— High Sulfur		266		266
Total Crude Oil		860		860
Other Feeds		64		63
Total		**924**		**923**
Product				
Motor Gasoline		445		440
Kerojet/Kerosene		108		119
Distillate		155		172
F.O. <1% Sulfur		5		4
F.O. 1%-2% Sulfur		68		50
F.O. >2% Sulfur		21		15
Coke @ FOE		47		54
Propane LPG		15		15
Butane LPG		0		0
Refinery Fuel		70		73
Other		48		42
Loss/ (Gain)		(58)		(61)
Total Products		**924**		**923**

light products and more closely match historical operations for this area. With cokers at maximum charge, more distillate was produced. The model was instructed to maintain the approximate 40:60 ratio of jet to distillate, resulting in a slight reduction (5 MB/CD) of motor gasoline production. Had jet production been held constant, the gasoline production would have increased about 5 MB/CD by reforming incremental heavy naphtha. Even so, the gasoline production of 445 MB/CD is almost 10 percent less than that produced in 1984–1985, before lead phasedown. In summary, this case replicates conditions faced by L.A. Basin refiners and indicates the strain placed on the industry to meet demand in the area.

CASE 5

Case 5 is a case like the 1988 optimized light product case above, with a 1 psi reduction (year-round) in the maximum RVP of gasoline. Table 80 compares this situation with the NPC optimized light product base case.

Light product processing facilities are fully utilized in the base case so there is no capacity available to cope with the reduced RVP without producing excess butane in the refinery. About 9 MB/CD of butane is sold as LPG. However, currently there is very little demand for such a product in the L.A. Basin. Butane is therefore given fuel value. When allocated to gasoline, the cost of producing gasoline goes up about 29¢/bbl, or $47 million per year. This cost is directly related to the assumed value of fuel gas and could increase if fuel gas prices decline relative to gasoline price.

Crude oil run is held constant in this case, so the loss of the butane blended to gasoline reduces gasoline volume equivalently, 9 MB/CD. There were no other significant changes between the base case and the reduced RVP case.

CASE 6

Case 6 is a 1988 case without additional FCC feed hydrotreating capacity beyond that available in 1984. See Table 81 for a comparison of this case with the 1988 optimized light products base case.

FCC feed hydrotreating capacity is down to 112 MB/CD, that available in 1984. In this case, a low sulfur crude oil, Minas from Indonesia, is imported and run in place of the domestic Alaskan North Slope (ANS) crude oil in order to meet the FCC SO_2 emission regulations. The Minas crude oil run is increased 190 MB/CD from 69 MB/CD in the optimized light product base case to 259 MB/CD in this case. The ANS crude oil run is down correspondingly from 314 MB/CD to 124 MB/CD, resulting in a net 190 MB/CD additional import of crude oil to the L.A. Basin.

Gas oil conversion capacity (FCC and hydrocracking) is fully utilized as is coker hydraulic capacity. Although reformer severity is up to 99.6, gasoline production is down because of the poor reformer quality of the Minas naphtha compared to ANS naphtha.

Although larger volumes of low sulfur fuel oil could be produced with this crude oil slate, the actual production of low sulfur fuel oil shown, 4 MB/CD, is only that required by local demand.

Since most of the FCC feed hydrotreating capacity additions announced for 1985 and later were not reported in the survey, the FCC feed hydrotreating capacity utilized in this case is in good agreement with the survey. However, the survey respondents did not switch to a lighter and lower sulfur crude oil slate between 1984 and 1988. In fact, they projected a heavier and higher sulfur crude oil slate for 1988. They also projected a lower utilization of their heavy gas oil (FCC feed) hydrotreating capacity (down from 96 MB/CD to 86 MB/CD). Since the survey did not ask for any emission or environmental data, it is not clear if the respondents considered meeting the FCC stack SO_2 limits in their projections.

CASE 7

Case 7 is a 1988 case with high volumes of California SJVH and California OCS crude oils run in the L.A. Basin refineries. See Table 82 for a comparison of this case with the 1988 optimized light products base case.

This case is based on large volumes of these heavy crude oils being pipelined to the L.A. Basin refineries via the proposed Southern California Pipeline System. This pipeline could deliver 200 MB/CD of California offshore crude oil (average API gravity less than 20°) and 130 MB/CD of SJVH crude oil (average API gravity about 13°) into the L.A. Basin. All of this California offshore crude oil is new production. Of the SJVH, one-half is assumed to be new production not previously refined in Los Angeles and one-half is assumed to be SJVH currently delivered to L.A. refineries by vessel. This additional heavy crude oil, 265 MB/CD, is processed in the L.A. basin refineries and the optimum volume of light products is produced from this crude oil slate.

TABLE 80

REDUCTION OF RVP IN THE 1988 L.A. OPTIMUM LIGHT PRODUCTS CASE (MB/CD)

	1988 L.A. Optimum Light Products		1988 L.A. Optimum Light Products with Reduced RVP	
	Available	**Utilized**	**Available**	**Utilized**
Process Unit				
Crude Oil Distillation	1,149	860	1,149	860
Catalytic Cracking	324	286	324	286
Conversion (%)	—	70	—	70
Coking	250	231	250	231
Coke (MT/CD)	12.3	10.6	12.3	10.6
Catalytic Reforming	264	187	264	188
Octane (RONC)	—	99.3	—	N/A
Hydrotreating				
Distillate	124	114	124	N/A
Heavy Gasoil / Residuum	209	211	209	N/A
Alkylation	58	49	58	49
Hydrocracking	128	N/A	128	N/A
Crude Oil & Other Feeds				
ANS — Medium Sulfur	314		314	
CA SJVH — High Sulfur	167		167	
CA OCS — High Sulfur	0		0	
Minas — Sweet	69		69	
Other — Sweet	44		44	
— High Sulfur	266		266	
Total Crude Oil	860		860	
Other Feeds	63		63	
Total	**923**		**923**	
Product				
Motor Gasoline	440		431	
Kerojet/Kerosene	119		119	
Distillate	172		172	
F.O. <1% Sulfur	4		4	
F.O. 1%-2% Sulfur	50		50	
F.O. >2% Sulfur	15		15	
Coke @ FOE	53		53	
Propane LPG	16		16	
Butane LPG	0		9	
Refinery Fuel	73		73	
Other	42		42	
Loss/ (Gain)	(61)		(61)	
Total Products	**923**		**923**	

TABLE 81

USE OF LOW SULFUR CRUDE OIL IN THE 1988 L.A. OPTIMUM LIGHT PRODUCTS CASE (MB/CD)

	1988 L.A. Optimum Light Products		1988 L.A. Optimum Light Products with Low Sulfur Crude	
	Available	Utilized	Available	Utilized
Process Unit				
Crude Oil Distillation	1,149	860	1,149	860
Catalytic Cracking	324	286	324	286
Conversion (%)	—	70	—	70
Coking	250	231	250	231
Coke (MT/CD)	12.3	10.6	12.3	10.4
Catalytic Reforming	264	187	264	185
Octane (RONC)	—	99.3	—	99.6
Hydrotreating				
Distillate	124	114	124	114
Heavy Gasoil / Residuum	209	211	122	112
Alkylation	58	49	58	48
Hydrocracking	128	N/A	128	N/A
Crude Oil & Other Feeds				
ANS — Medium Sulfur		314		124
CA SJVH — High Sulfur		167		167
CA OCS — High Sulfur		0		0
Minas — Sweet		69		259
Other — Sweet		44		44
— High Sulfur		266		266
Total Crude Oil		860		860
Other Feeds		63		63
Total		**923**		**923**
Product				
Motor Gasoline		440		434
Kerojet/Kerosene		119		118
Distillate		172		171
F.O. <1% Sulfur		4		4
F.O. 1%-2% Sulfur		50		56
F.O. >2% Sulfur		15		15
Coke @ FOE		53		52
Propane LPG		16		15
Butane LPG		0		0
Refinery Fuel		73		73
Other		42		42
Loss/ (Gain)		(61)		(59)
Total Products		**923**		**923**

TABLE 82

HIGH VOLUME CALIFORNIA CRUDE OIL IN THE 1988 L.A. OPTIMUM LIGHT PRODUCTS CASE (MB/CD)

	1988 L.A. Optimum Light Products		1988 L.A. Optimum Light Products with High Volume California Crude Oil	
	Available	Utilized	Available	Utilized
Process Unit				
Crude Oil Distillation	1,149	860	1,149	860
Catalytic Cracking	324	286	324	288
Conversion (%)	—	70	—	70
Coking	250	231	250	231
Coke (MT/CD)	12.3	10.6	12.3	11.5
Catalytic Reforming	264	187	264	199
Octane (RONC)	—	99.3	—	99.7
Hydrotreating				
Distillate	124	114	124	100
Heavy Gasoil / Residuum	209	211	209	219
Alkylation	58	49	58	51
Hydrocracking	128	N/A	128	N/A
Crude Oil & Other Feeds				
ANS — Medium Sulfur	314		51	
CA SJVH — High Sulfur	167		232	
CA OCS — High Sulfur	0		200	
Minas — Sweet	69		67	
Other — Sweet	44		44	
— High Sulfur	266		266	
Total Crude Oil	860		860	
Other Feeds	63		63	
Total	**923**		**923**	
Product				
Motor Gasoline	440		458	
Kerojet/Kerosene	119		77	
Distillate	172		110	
F.O. <1% Sulfur	4		4	
F.O. 1%-2% Sulfur	50		43	
F.O. >2% Sulfur	15		105	
Coke @ FOE	53		57	
Propane LPG	16		17	
Butane LPG	0		0	
Refinery Fuel	73		72	
Other	42		42	
Loss/ (Gain)	(61)		(62)	
Total Products	**923**		**923**	

Because more kerosene and distillate boiling range material is required for fuel oil cutter in this case, the amount of distillate desulfurization goes down. This happens in spite of the high sulfur content of the California OCS crude oil.

Compared with the 1988 optimum light product base case, this case produces 18 MB/CD more gasoline, 104 MB/CD less kerosene jet fuel plus diesel, and 83 MB/CD more fuel oil.

REGIONAL REFINERIES

With the shutdown of 120 refineries from January 1, 1981, through January 1, 1986, concern has been expressed that the regional refiner might be at a disadvantage and suffering disproportionately compared to the rest of the industry. As can be noted from Table 83, most of the shutdowns have been of "simple" or "low conversion" refineries.

About one-half of these shutdown plants came into operation during the 1970s to take advantage of the economic bias built into the price control regulations that were in effect during those years. Regional refiners represent approximately 20 percent of the simple refineries and 30 percent of the "low conversion" refineries shut down during the period. All of the regional "low conversion" refineries shut down during this period had been in operation more than 25 years. Table 83 provides a summary of these shutdowns.

TABLE 83

REFINERY SHUTDOWNS 1981–1985

	Simple	Low Conversion	High Conversion	Total
No. of Plants	91	20	9	120
Total Capacity (MB/CD)	1,099	821	706	2,626
Age (Years)				
0–5	30	0	0	30
5–10	24	0	1	25
10–15	2	1	0	3
Over 15	35	19	8	62

Regional refineries are characterized by geographically limited markets for raw materials or product distribution, or both, creating a high degree of dependence upon local market conditions. Primarily operating upon local raw materials to supply local markets, regional refineries possess a competitive economic advantage in transportation costs. They compete with other refineries in their region and with products imported to their markets from elsewhere, particularly from U.S. refining centers. Appendix K provides the classification, used for this study, of all U.S. refineries as: regional, located in a refining center, or other non-regional refineries.

Regional refineries play an important role in the U.S. petroleum industry, providing a local market for indigenous crude oil production and a supply of finished products to their region. Regional plants in many cases have design characteristics particularly appropriate to the petroleum produced in that region, allowing greater economic upgrading than would be possible in larger remote plants after commingling crude oils in pipeline transportation facilities. In addition to providing motor and distillate fuels, regional refineries provide other petroleum products to local markets that might otherwise be unavailable without significant transportation costs. Often located in small communities, regional refineries provide an important industrial base to communities that might otherwise be devoid of industry. Petroleum storage capabilities at regional plants provide an important buffer against seasonal product demand changes, reducing the peak load demands on the product transportation system. In general, regional refineries tend to decentralize and spread the U.S. refining capacity over a greater geographic area than would otherwise exist.

Survey Results

Response to the NPC's 1985 Survey of U.S. Petroleum Refineries was less complete for regional refineries than for refineries in general. Responses covered nearly 90 percent of the crude oil distillation capacity of regional refineries, with about 70 percent of the plants. A review of the respondent list indicates that many of the nonrespondents were from plants not operating at the time of the survey. A summary of survey response by PADD for regional refineries is shown in Table 84.

Competitive Position

Competitive position refers to relative costs of competitors in supplying products or services demanded by the marketplace. In this context,

TABLE 84

RESPONSE OF REGIONAL REFINERIES TO
1985 SURVEY OF U.S. PETROLEUM REFINERIES

	Total Regional Refineries		Respondent Refineries		Percent Responding	
	No. of Ref.	Capacity* (MB/CD)	No. of Ref.	Capacity* (MB/CD)	No. of Ref.	Capacity* (%)
PADD I	7	42.9	5	35.9	71	84
PADD II	21	799.2	16	744.7	76	93
PADD III	37	891.1	27	795.5	73	89
PADD IV	22	564.7	14	460.1	64	81
PADD V	17	352.0	11	287.6	65	82
U.S. Total	**104**	**2,650**	**73**	**2,324**	**70**	**88**

*Source: DOE, *Petroleum Supply Annual*, 1984.

the regional refinery enjoys several real economic advantages vis-a-vis its competitors. Processing local crude oils to supply local product markets provides a competitive advantage in transportation costs compared to shipping crude oils to distant refining centers and then shipping products back. Refineries of 50 MB/CD or greater were 30 percent of the total regional refinery capacity with several larger than 100 MB/CD. Located in the oil fields and generally designed to process indigenous production, regional refineries may have special processing capabilities that provide greater economic upgrading capabilities for the particular crude oils being processed than would be feasible after commingling such crude oils for shipment elsewhere. Also, since they can be designed for a specific crude oil mix, capital costs can be minimized. Proximity to the markets served may provide the regional refinery with a competitive advantage in identifying and supplying unusual local product demands and should provide an advantage in responding more rapidly to changing local market conditions.

Economies of scale available to larger refinery competitors partially offset the cost advantages of smaller regional refineries. Limited markets, for both raw materials and products, may be a more important disadvantage under rapidly changing conditions. The regional refinery has little access to alternative markets when local conditions decline, and in many instances is subject to competition from products imported to local markets from elsewhere whenever its markets become attractive. Profitability of the regional refinery is limited on the top side by the cost that competitors must bear to move products into regional markets and limited on the downside by the financial resources available to carry it through a decline. Other variables important to the continued economic operation of the regional refiner are refinery complexity, operating efficiency, and relative fuel costs. If the regional refinery is part of a total domestic manufacturing system operated by a large refiner, poor local market conditions may result in a decision to reduce fixed charges by replacing production from the regional plant with higher utilization rates at a larger remote plant. If operated by a small or independent refiner, the financial resources available to carry the refinery may be less than those of its competitors.

The transportation cost factors that provide the competitive advantage for regional refineries will vary for each geographic location. For example, the transportation advantage of the regional refineries located in Alaska, running Alaskan crude oil and supplying Alaskan markets, is undoubtedly greater than that of refineries in the San Joaquin Valley of California, who must compete with larger refineries only a few hundred miles away, or those regional refineries in the Midwest that face competition from Chicago and Gulf Coast refining centers.

While it is not possible for this study to predict the future economic health of regional

refiners in any specific geographic area, the following observations can be made:

- The restructuring of the U.S. refining industry is largely complete. Most of the marginal refineries, nationwide, have been shut down. Likewise, the shutdown of uneconomic regional refineries has probably taken place. Refineries that have weathered the thin margins of the early 1980s are likely to continue to survive. Most of the shutdowns occurred in 1981–1982.
- Additional closures will likely be scattered and be the result of one or more of the following:
  - —The need for high capital investment for regulatory or process requirements
  - —Rapid decline of local indigenous crude oil production
  - —Depressed local product demands
  - —Inequitable local taxation or regulatory impacts that nullify competitive advantage.

In summary, it should be recognized that refinery economics provide an average profit margin of 1¢ to 2¢ per gallon with unprofitable periods resulting from volatile market conditions. To the extent that costs cannot be fully covered in the marketplace, further attrition of some refineries, whether regional or otherwise, is a possibility. The success of each individual regional refiner depends upon efficiently refining locally available crude oil to match changing local product market conditions. The regional refiner continues to fulfill an economic need by performing the local refining-marketing function, providing jobs to smaller communities, and supplying specialty products (asphalts, LPG, solvents, lube oils) without high transportation costs.

APPENDICES

THE SECRETARY OF ENERGY
WASHINGTON, D.C. 20585

June 20, 1984

Mr. Robert A. Mosbacher
Chairman
National Petroleum Council
1625 K Street N.W.
Washington, D.C. 20006

Dear Mr. Mosbacher:

Since its inception, the National Petroleum Council has conducted numerous studies of the Nation's petroleum refining industry. The Council's latest such study was completed in 1980 and included analyses of oil supply and demand, refinery capability and flexibility, and competitive economics of various types of refinery operations. These analyses were based largely on 1978 data. Significant changes have taken place in both the domestic and foreign refining industries since that time.

Accordingly, I request the National Petroleum Council to undertake a new study of the factors affecting domestic refining in the 1985-1990 time frame. This study would update previous Council refining studies and evaluate future refinery operations and the industry's ability to meet demands for petroleum products. The study should examine capacity changes including announced closings, debottleneckings, and additions; and the projected role of small regional refineries. Related environmental and regulatory issues should be addressed as appropriate.

For the purpose of this study, I will designate J. Erich Evered, Administrator, Energy Information Administration, to represent me and to provide the necessary coordination between the Department of Energy and the National Petroleum Council.

Sincerely,

Donald Paul Hodel

DONALD PAUL HODEL

DESCRIPTION OF THE NATIONAL PETROLEUM COUNCIL

In May 1946, the President stated in a letter to the Secretary of the Interior that he had been impressed by the contribution made through government/industry cooperation to the success of the World War II petroleum program. He felt that it would be beneficial if this close relationship were to be continued and suggested that the Secretary of the Interior establish an industry organization to advise the Secretary on oil and natural gas matters.

Pursuant to this request, Interior Secretary J. A. Krug established the National Petroleum Council on June 18, 1946. In October 1977, the Department of Energy was established and the Council's functions were transferred to the new department.

The purpose of the NPC is solely to advise, inform, and make recommendations to the Secretary of Energy on any matter, requested by him, relating to petroleum or the petroleum industry. Matters that the Secretary of Energy would like to have considered by the Council are submitted as a request in the form of a letter outlining the nature and scope of the study. The request is then referred to the NPC Agenda Committee, which makes a recommendation to the Council. The Council reserves the right to decide whether or not it will consider any matter referred to it.

Examples of recent major studies undertaken by the NPC at the request of the Department of Energy include:

- *Materials and Manpower Requirements* (1979)
- *Petroleum Storage & Transportation Capacities* (1979)
- *Refinery Flexibility* (1979, 1980)
- *Unconventional Gas Sources* (1980)
- *Emergency Preparedness for Interruption of Petroleum Imports into the United States* (1981)
- *U.S. Arctic Oil & Gas* (1981)
- *Environmental Conservation—The Oil and Gas Industries* (1982)
- *Third World Petroleum Development: A Statement of Principles* (1982)
- *Petroleum Inventories and Storage Capacity* (1984)
- *Enhanced Oil Recovery* (1976, 1984)
- *The Strategic Petroleum Reserve* (1984)

The NPC does not concern itself with trade practices, nor does it engage in any of the usual trade association activities. The Council is subject to the provisions of the Federal Advisory Committee Act of 1972.

Members of the National Petroleum Council are appointed by the Secretary of Energy and represent all segments of petroleum interests. The NPC is headed by a Chairman and a Vice Chairman, who are elected by the Council. The Council is supported entirely by voluntary contributions from its members.

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APPENDIX B

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APPENDIX C

History and Fundamentals of Refining Operations

Note: Data for Appendix C are taken from the following National Petroleum Council reports: *Refinery Flexibility,* December 1980, Appendix D—History and Fundamentals of Refining Operations; *Environmental Conservation,* 1982, Chapter Three—Refining, Industry Operations.

HISTORY

The history of the refining industry has been one of many advancements in petroleum technology. Although equipment design has advanced greatly over the years, crude oil distillation remains today what it was in the early years—the separation of the different components (fractions) of crude oil based on their different boiling points. Most of the changes in petroleum refineries have been in the processing units that are used after the distillation, or separation, process. These changes were brought about because the distillation process could not produce enough high octane motor gasoline to meet market demand. The evolution of the industry was necessary to meet the demands of the marketplace, and the new developments of each period were based largely on scientific advances of the previous period.

The evolving market demand brought changes in petroleum product characteristics such as gasoline octane number and fuel oil sulfur content. These changes were made by developing downstream processes (those that occur after the initial separation process of the crude oil) to produce lighter products, such as gasoline, from heavy crude oil fractions by: cracking; combining highly volatile hydrocarbons to produce gasoline; rearranging the molecular structure of molecules to improve their physical characteristics; and treating crude oil fractions to remove contaminants such as sulfur, nitrogen, and arsenic.

In the early 1800s, the distillation of coal provided some of the products currently produced from crude oil, condensate, and natural gasoline. Between 1830 and 1858, use of illuminating and lubricating oils increased at a rate that exceeded their supply. Illuminating oil was the main item and was called "coal-oil." During this period a Pittsburgh druggist, Samuel Kier, inspired by the popularity of this product and by the coal-oil industry's distillation facilities, produced a substitute oil from "rock-oil" (crude oil). This product was also called coal-oil, but now is known as kerosene. The demand for this new product increased rapidly.

From the 1860s until 1920, refining operations were generally limited to crude oil distillation for the production of kerosene. The petroleum refining industry increased in processing capacity from 11,680 barrels per day in 1865 to 142,465 barrels per day in 1900. By 1960, capacity stood at 9.9 million barrels per day (MMB/D). Capacity nearly doubled over the next 20 years; by 1980 operating capacity was 18.0 MMB/D.[1]

Even though the number of refineries increased rapidly, the average capacity was low. For example, in 1918 there were 267 refineries with a total capacity of 1,200 thousand barrels per day (MB/D) or less than 4.5 MB/D per refinery. By 1940, the number had increased to 461 refineries in operation with a total capacity

[1]American Petroleum Institute, *Basic Petroleum Data Book,* September 1986.

of 4,200 MB/D, an average of 9.1 MB/D. As of January 1, 1986, the Department of Energy (DOE) reported in the Petroleum Supply Annual that 216 refineries were operable with a capacity of 15,459 MB/D, or an average of 76.2 MB/D.

GROWTH AND CHANGES IN REFINERY CONFIGURATION

The initial refining process separates crude oil into boiling range fractions. These fractions are then processed by cracking the large hydrocarbon molecules into smaller ones. The structure of some of these molecules is rearranged and others are joined in different combinations to provide the desired components for blending into finished products. This takes place in a number of refinery process units, each with a specific purpose, integrated into a processing sequence. The type and number of refinery process units in a given plant depend upon the type of crude oil to be processed, product requirements, and economic factors such as crude oil costs, product values, and availability and cost of utilities and equipment. The type and size of processing units thus vary greatly. Theoretically, any petroleum or petrochemical product can be manufactured from any type of crude oil. However, a refinery is designed based on the available crude oil and the market demand for products.

Equipment design and distillation techniques have changed considerably over the years, but crude oil distillation remains basically what it has always been—the separation of crude oil into discrete fractions having differing characteristics. These various fractions, or cuts, may by sold directly or may be further "refined" in other process units. The total products manufactured by a refinery for distribution are termed "the product slate."

Those components that "boil" and are recovered as an overhead stream, or as sidecuts, are referred to as "naphthas and distillates" and are further categorized by other physical properties. The bottom product from the crude oil distillation column contains materials that are too heavy to boil under the atmospheric pressure conditions of the crude oil unit. This bottom product has many names—"atmospheric resid," "residual oil," "topped crude," and "No. 6 fuel oil," among them.

Initially, kerosene and light distillates were considered the prime products. Gasoline had only nuisance value until the early 20th century, when the advent of the automobile and its internal combustion engine resulted in increased demand for gasoline. However, the quantities required were in approximate balance with the amount contained in the quantity of crude oil processed to meet the demand for the heavier distillates. Simultaneously, a growing market was developing for lubricating oils of better quality.

During World War I, military requirements necessitated rapid advancement in application and refinement of existing internal combustion engine technology. In the immediate post-war years, "spinoffs" from wartime technology led to design and production improvements in automotive manufacture that made automobile ownership generally more common. During this period, the typical U.S. refinery was small and simple in operation (see Figure C-1).

Within a short time, petroleum refiners were faced with the problem of shifting their product slate toward production of more, higher quality gasoline from a given barrel of crude oil than had previously been recovered by simple distillation processes. The conversion of heavier fractions to gasoline became necessary.

In the early 1920s, with the commercialization of the thermal cracking process, refiners found a satisfactory economic solution that was complemented by a substantial increase in domestic crude oil production (see Figure C-2). Thermal cracking is a severe form of thermal processing. It reduces the amount of heavy fuel oil produced by cracking, or fracturing, the molecules using the heaviest components present in crude oil to produce lighter, generally more valuable materials, such as gasoline and light fuel oils.

Acceptance of the new processing technique was immediate. From the standpoint of the automotive industry, the successful commercialization of the cracking process came none too soon. Apart from the problem of gasoline availability, gasoline quality had become troublesome. Engine knock had been identified as a severe fuel problem; gasoline from crude oil distillation units burned too fast and unevenly, affecting the efficiency of engine performance. Cracked gasoline was found to be of superior quality, as measured by the "octane rating," and demand soared for what was then considered to be a "premium" fuel from thermal crackers. The

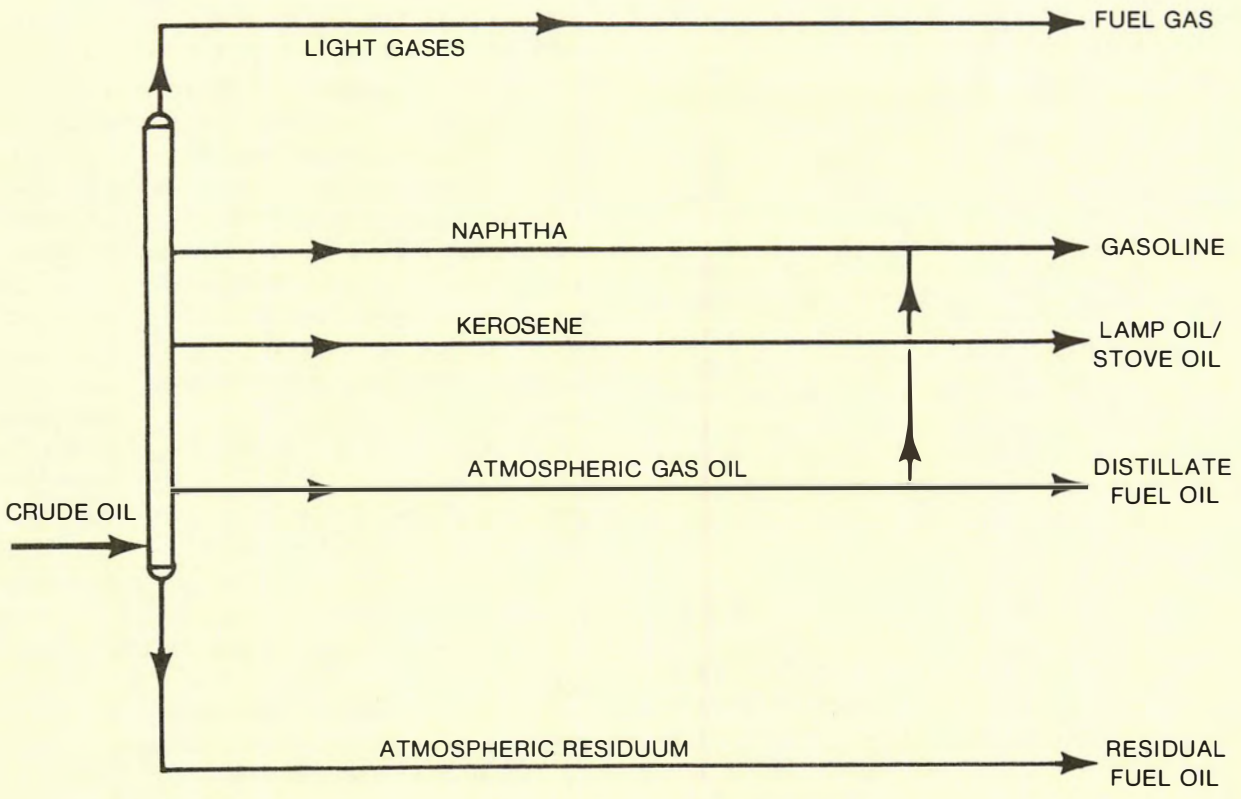


Figure C-1. Simplified Flow Chart of a U.S. Petroleum Refinery (circa 1915).

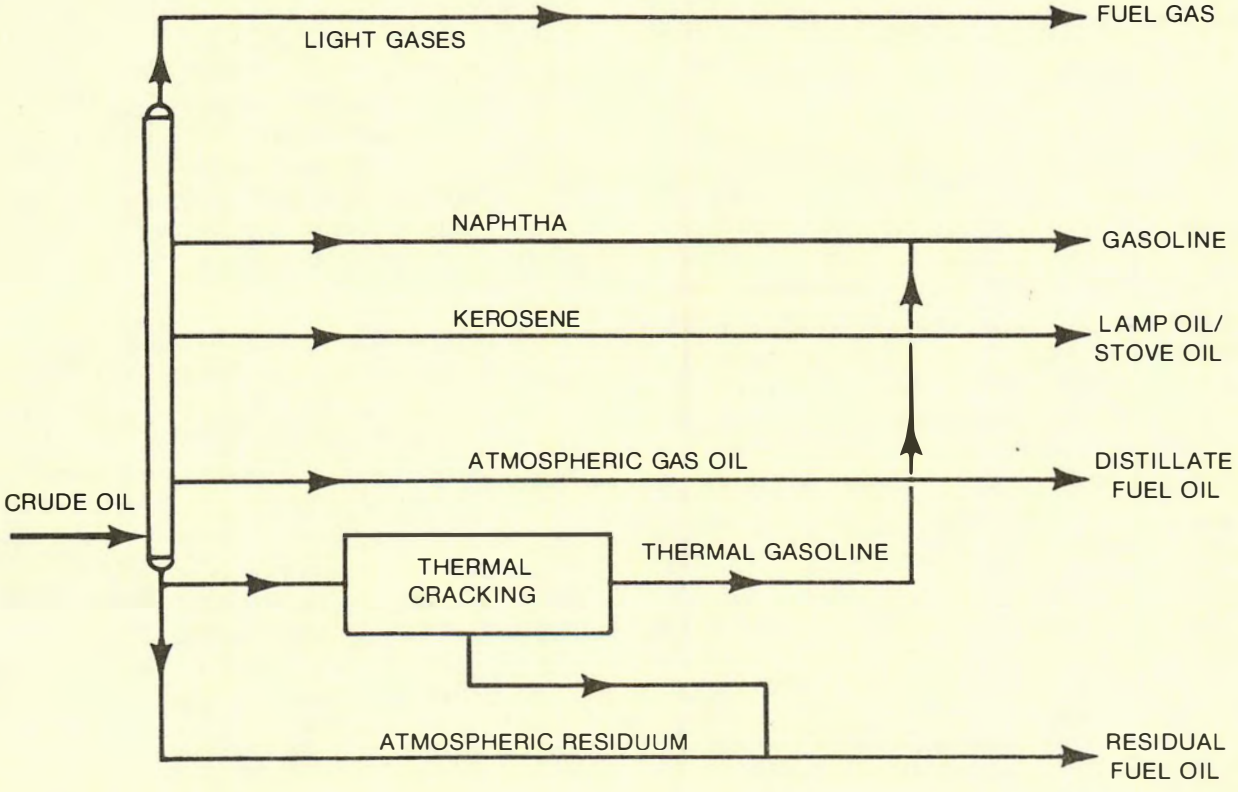


Figure C-2. Simplified Flow Chart of a U.S. Petroleum Refinery (circa 1920s).

thermal cracking process became a mainstay of the early refinery.

During the late 1920s and early 1930s, consumer demand required that the refining industry continue to shift from production of heavy distillates and fuel oils toward that of more higher quality gasoline (see Figure C-3).

A by-product of the previously commercialized thermal cracking process was a gaseous material, rich in a type of hydrocarbon known as "olefins." Olefins are typically produced in operations where a deficiency in hydrogen exists. They are reactive materials and can be made to form heavier, liquid materials. In the early days of thermal cracking, this olefin-rich gaseous co-product was used as a fuel gas or, in some cases, burned as a waste product.

To make economic use of these light thermal olefins, the catalytic condensation or polymerization process was developed. This processing technique utilizes a catalyst to provide the proper processing conditions under which light olefins will react selectively to yield a high octane gasoline. The overall efficiency of the operation was improved by "concentrating" the light olefins in a gas recovery plant prior to processing in the polymerization unit. This process was later applied to produce gasoline from suitable olefins recovered from other types of operations.

The yield of residual oil was reduced through application of improvements in vacuum distillation techniques and equipment design. As mentioned previously, the bottom product from the crude oil distillation column contains materials that will not distill at atmospheric pressure. When the atmospheric resid was fractionated under a vacuum, a distillate, referred to as vacuum gas oil, was recovered, which could be directed to thermal cracking to produce additional gasoline.

The refiner was able to cut more deeply into the crude oil and further reduce heavy fuel oil yields by applying the visbreaking and coking processes to the vacuum residuum, or pitch. Visbreaking is a mild form of thermal cracking that was, and still is, used primarily to reduce the viscosity of the vacuum residuum used in fuel oil.

Coking is a more severe type of thermal processing. In the coking unit, atmospheric or vacuum residuum is subjected to time–temperature conditions that, through a series of complex reactions, result in production of gas, gasoline, distillates, and petroleum coke.

During the early years of World War II, the U.S. government brought together the refining technologies to expedite the contribution of the petroleum industry to the war effort, particularly in the manufacture of badly needed high octane aviation fuel. Working in close collaboration, petroleum industry scientists and engineers immediately directed their broad knowledge and talents to the war effort. From the industry's laboratories and engineering departments came technology for the process of alkylation, isomerization, fixed bed cracking, thermofor catalytic cracking, and the most important of the heavy distillate conversion processes—fluid catalytic cracking (FCC) (see Figure C-4).

Fluid catalytic cracking converts virgin atmospheric and vacuum gas oils and heavy stocks derived from other refinery operations into high octane "cat" gasoline and light fuel oils called "cycle stocks." Olefin-rich light gases, which can be directed to polymerization or alkylation operations to produce gasoline, are coproducts. With proper design and selection of operating conditions and catalysts, yields and qualities of specific FCC products may be varied. Typically, yields of liquid products will exceed 75 to 80 volume percent of the FCC feed. The cracking reaction is accomplished in the presence of a catalyst at controlled conditions of temperature, pressure, and time. The term "fluid catalytic cracking" derives from the use of a catalyst consisting of small particles that, when aerated with a vapor, behave as a fluid. This fluidized catalyst will flow and is circulated within the system.

The alkylation process for motor fuel production catalytically combines light olefins, primarily mixtures of propylene and butylenes, with isobutane (a paraffinic hydrocarbon) to produce a fuel that is one of the highest quality components of a gasoline pool. The alkylate product has excellent antiknock properties and lead response. It is clean burning, has high unleaded and leaded Research and Motor octane ratings, and has an excellent aviation gasoline "performance" rating, as well. The alkylation takes place in the presence of a catalyst—hydrofluoric acid or sulfuric acid—under conditions selected to maximize alkylate yield and quality.

When considered together, the FCC and alkylation processes are of major importance in

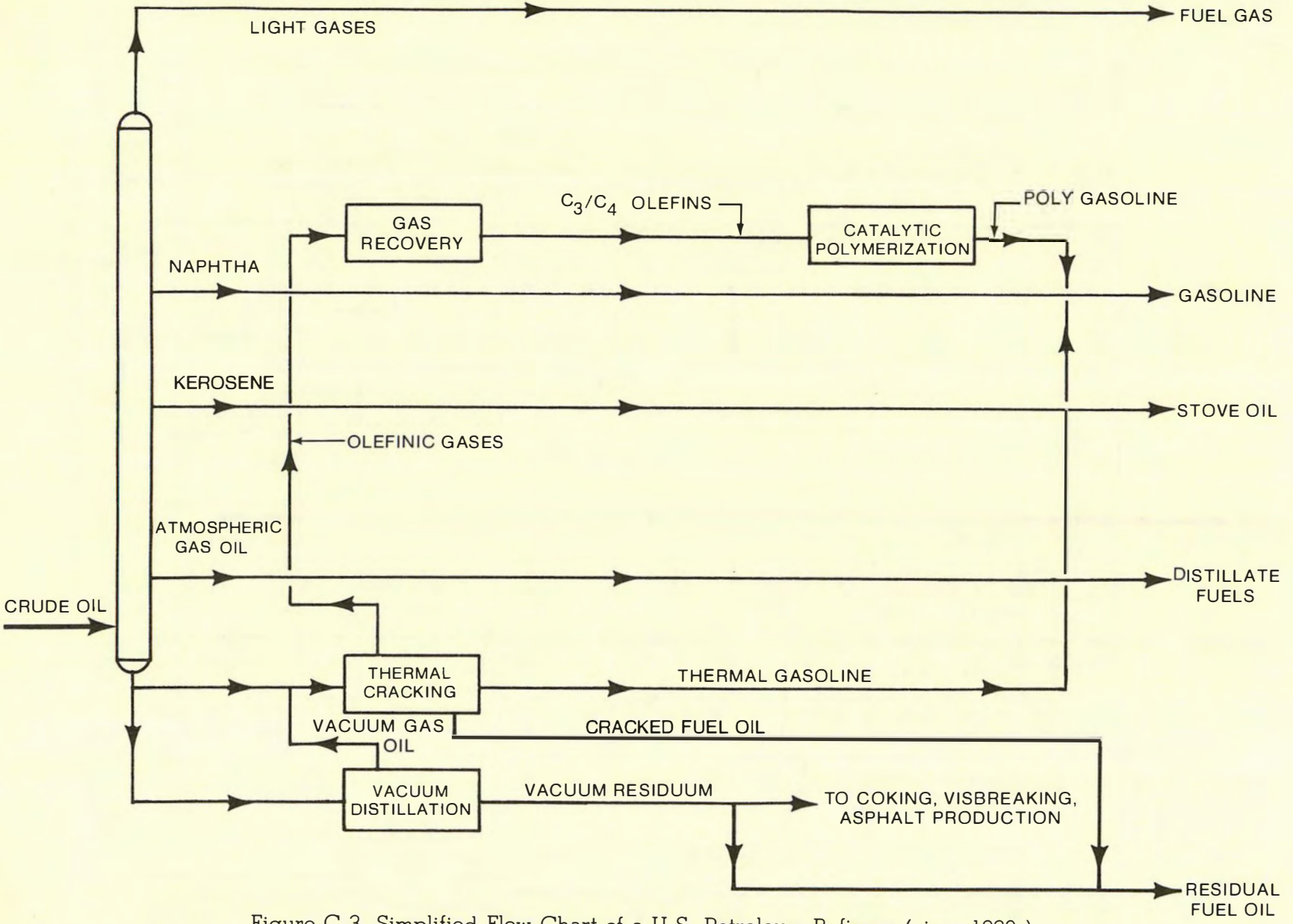


Figure C-3. Simplified Flow Chart of a U.S. Petroleum Refinery (circa 1930s).

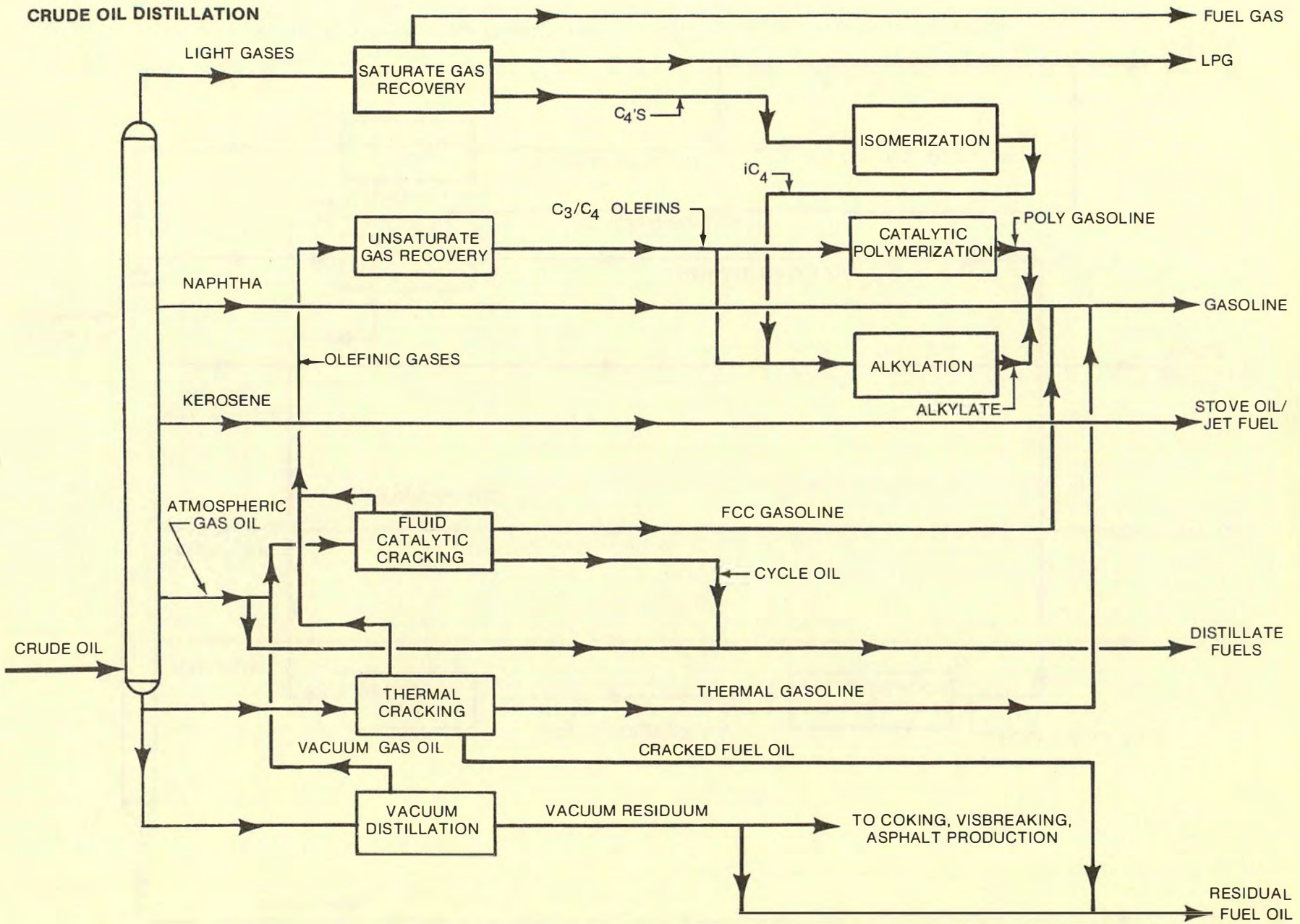


Figure C-4. Simplified Flow Chart of a U.S. Petroleum Refinery (circa 1940s).

the manufacture of quality gasoline. The overall gasoline yield of the two processes—the "cat" gasoline plus the alkylate produced from the FCC olefins—will typically exceed 90 volume percent of the FCC feed. Allowing for the blending of butane into the gasoline to meet volatility requirements, the overall yield approaches 100 volume percent. In other words, for each barrel of feedstock processed in the FCC unit, approximately one barrel of gasoline can be recovered from the combined FCC–alkylation operation. There is, of course, an additional yield of fuel oil from the FCC unit.

Isobutane is consumed in the alkylation process. The isomerization process was developed and added to the refinery components in order to produce isobutane from normal butane and, thus, supplement the isobutane recovered from the crude oil itself and from other processes.

After World War II, the availability of catalytically cracked gasolines and alkylate for motor fuel blending made refinery naphtha, with its low octane number, increasingly unattractive as a gasoline component. In the late 1940s, a radically different process was developed that utilized a catalyst containing platinum in petroleum refining for the first time. This process, known as catalytic reforming, revolutionized the art of converting low grade naphthas into high octane motor fuels.

Catalytic reforming is the octane generator and determinant in the gasoline-oriented refinery. The gasoline-range materials recovered from other operations, such as FCC, alkylation, hydrocracking, and polymerization, are of relatively fixed octane quality. The catalytic reforming process is capable of efficiently yielding gasoline products ranging in octane number from the low 80s to over 100 Research clear (unleaded). Unfortunately, as operating severity is increased to raise the octane number, gasoline yield decreases. On the basis of gasoline produced per unit of feedstock, typical yields can range from over 90 volume percent to 70 volume percent, respectively, for low to high octane operations. This process is also the major source of the hydrogen required for many of the operations employed in today's modern refineries.

Since processing over a platinum catalyst produces aromatics, such as benzene, toluene, and xylene, catalytic reforming quickly established itself as a processing base for development of an aromatic-based petrochemical industry.

With continuing emphasis on producing greater quantities of higher octane gasolines, it became necessary to upgrade other materials that were formerly used directly as gasoline components, such as thermal naphthas derived from thermal cracking, visbreaking, and coking operations, as well as refinery naphthas having more than modest amounts of sulfur and nitrogen. The contaminants present in these materials, however, were detrimental (poisonous) to the platinum-based catalyst used in the reforming process. Treatment of such stocks prior to catalytic reforming became a necessity.

With the development of the hydrotreating process in the mid-1950s, an efficient answer to this problem was provided. The process utilized hydrogen produced in the catalytic reformer itself to catalytically remove sulfur, nitrogen, and other reformer catalyst poisons. The yield of treated product from a hydrotreater generally approaches 100 volume percent. As catalytic reforming severity increased over the years, more active catalysts were developed and greater care was exercised to provide clean feedstocks for these operations. Thus, it became routine practice to hydrotreat reformer feeds for elimination of contaminants (see Figure C-5). The hydrotreating process was also used to desulfurize high-sulfur distillate fuels produced from high-sulfur crude oils.

In the latter part of the 1950s, improvements in the design and reliability of sulfuric and hydrofluoric alkylation process units resulted in the beginning of the phasing out of the catalytic polymerization process as a route to gasoline production. Polymerization technology, however, retained its importance as a refining tool in the production of a variety of compounds used in the petrochemical industry.

The use of chemical treating processes for odor improvement of gasoline and distillate, or for reduction of the sulfur content of light hydrocarbon streams, became widespread.

With the development of catalytic processing during the war years and early 1950s, thermal based operations became relegated to a position of lesser importance. Most thermal processing now is being used in the area of visbreaking and coking. The refining industry has passed from the thermal to the catalytic era.

In the late 1950s and early 1960s, rapid acceptance by the airlines of the turbine engine

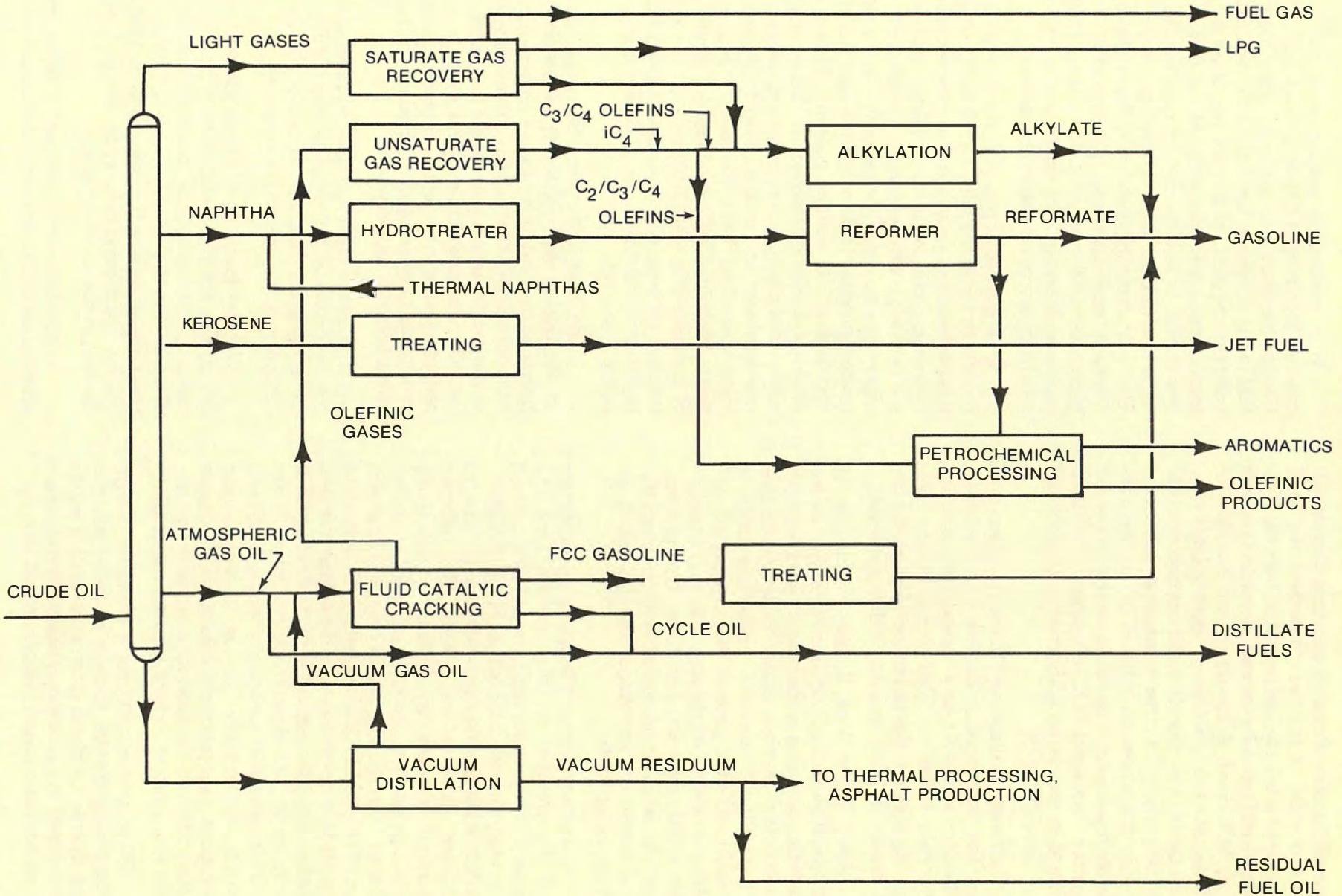


Figure C-5. Simplified Flow Chart of a U.S. Petroleum Refinery (circa 1950s).

resulted in a startling increase in jet fuel consumption. The petroleum industry was hard pressed to meet the demand. With the hydrocracking process in 1960, the refiner was provided with a tool for production of high quality jet fuel from materials otherwise unsuitable. Hydrocracking is a highly versatile process that can charge any fraction of crude oil to yield virtually any product lighter (lower boiling) and cleaner than the charge stock. The process can produce directly almost any material the refiner markets, such as liquified petroleum gas (LPG), light gasoline, turbine fuels, lubricating oils, and diesel and distillate fuels. It can also upgrade stocks for subsequent processing in other operations. With hydrocracking reactions, undesirable sulfur, nitrogen, and oxygen compounds are almost completely removed (see Figure C-6).

Hydrocracking flexibility permits ready adjustment of refinery production to whatever proportions are necessary for variations in seasonal, geographic, or marketing requirements.

Hydrocracking is a catalytic process and, as is hydrotreating, a hydrogen consumer. Total yield of liquid products, that is, gasoline and heavier materials, will exceed 100 volume percent of feed. The yield of specific products will depend on the application.

Hydrogen for hydrocracking and hydrotreating is most often supplied by catalytic reforming operations. Process selection and flow scheme in many instances have been dictated by "hydrogen balance" considerations. Where this has not been possible, supplementary hydrogen generation facilities have been installed.

The decade of the 1960s saw rapid growth in the production of petrochemicals, particularly in the area of light olefins. For example, U.S. domestic demand for ethylene tripled during the 1960–1970 period. A representative configuration of a refinery operating in the 1970s is presented in Figure C-7. Refinery operation in the 1980s is much the same as in the 1970s.

Lubricating oil manufacture is a highly specialized operation not included in most fuel refineries. The lubricating oil process generally starts with a heavy paraffinic gas oil (also known as a wax distillate) produced from the crude oil vacuum distillation unit, as shown in Figure C-8. The wax distillate is solvent extracted with furfural or n-methyl pyrolidone to remove the aromatic compounds. This processing step reduces the viscosity changes with increasing temperatures (viscosity index).

The refined oil is then dewaxed by the use of solvents such as methyl ethyl ketone and propane. The most recent process is to catalytically dewax the lube oil. The lube oil is generally finished today by hydrotreating, but in some instances the older clay treating process is used. The waxes produced by solvent dewaxing can be de-oiled to produce marketable paraffin wax.

During the latter part of the 1960s and continuing to the present, increasing emphasis has been placed on environmental considerations. Such concerns have affected the design of every process unit in the refinery. Proper handling of waste materials, such as contaminant-containing water, gas streams, and spent chemicals, has required creation of new and improved antipollution techniques.

The choice of refinery processes is based on the specific circumstances of each operation and is dependent on crude oil type, product slate, product quality requirements, and economic factors such as crude oil costs, product values, availability and cost of utilities, and availability of equipment and capital.

The characteristics of the crude oil feedstock are critical to process selection. There are hundreds of crude oils available on the world market today that vary widely in physical properties. Many crude oils from the Middle East tend to be high in sulfur content and of moderate metals content, both important factors to be considered if low sulfur–heavy fuel oils are the desired products. Some of the more readily available Middle East crude oils, such as those from Kuwait, have a poor naphtha component, which makes them less desirable for gasoline operations. Many Venezuelan crude oils, while moderate in sulfur, contain a high level of metals, which poisons catalysts. Some North African crude oils are low in sulfur and other contaminants but are waxy and, therefore, less suitable for production of lubricating oils.

As for product slate, in a gasoline oriented refinery, the yields of heavy oils will be minimized through the application of conversion processes. Fluid catalytic cracking would be utilized to crack the distillate products from resid conversion processes as well as virgin distillate materials, to yield gasoline and olefins for motor fuel alkylate production.

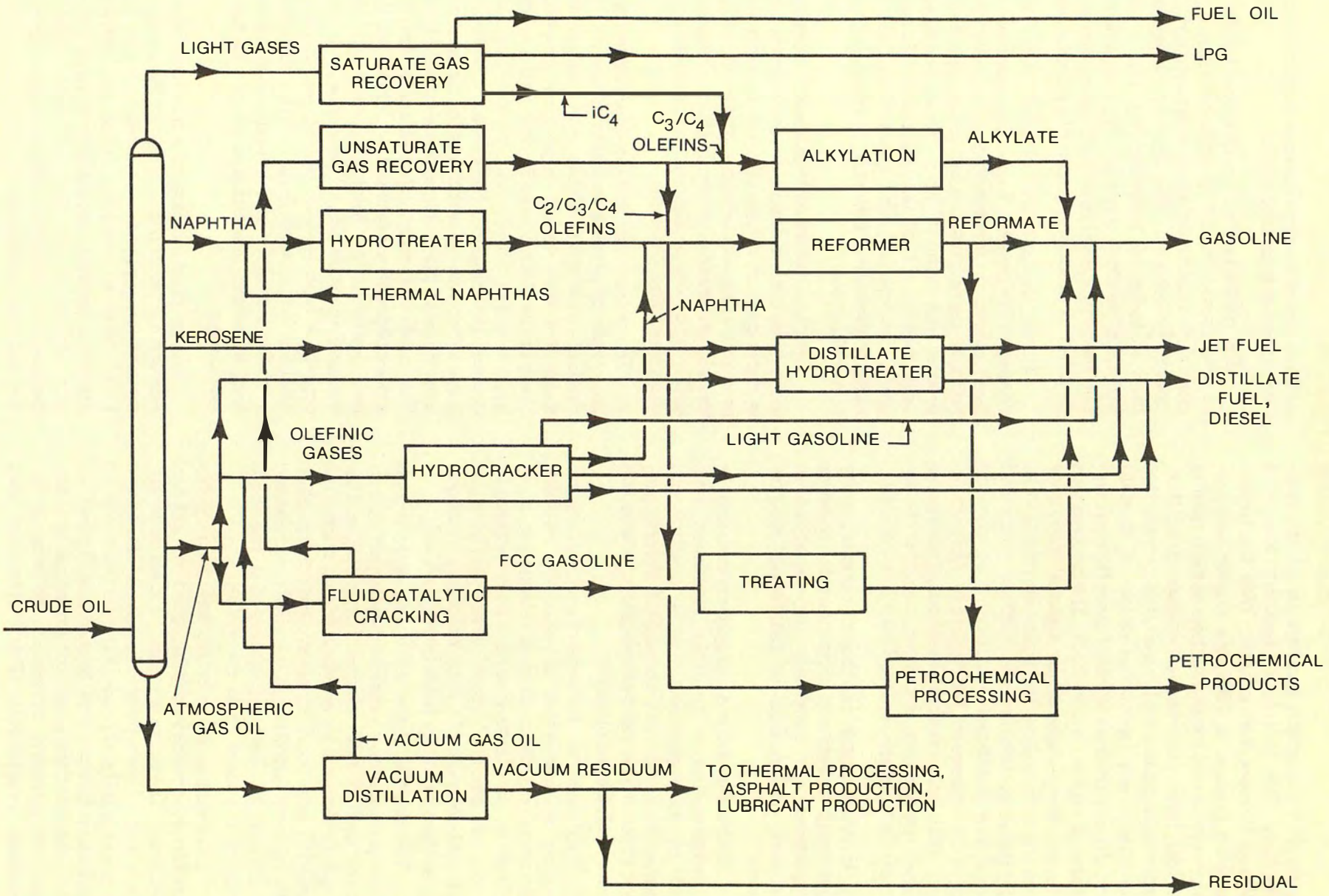


Figure C-6. Simplified Flow Chart of a U.S. Petroleum Refinery (circa 1960s).

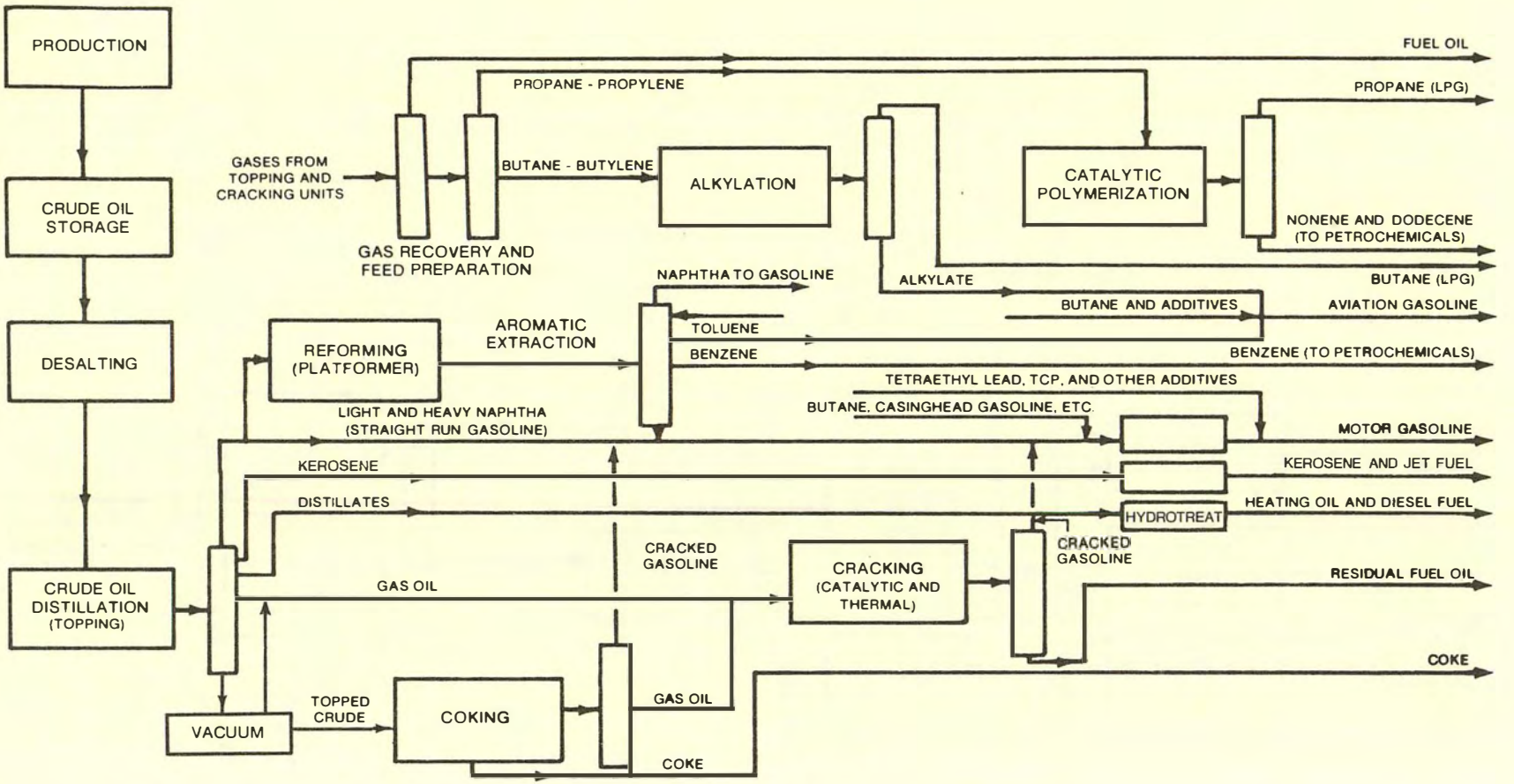


Figure C-7. Simplified Flow Chart of a Refinery (circa 1970s).

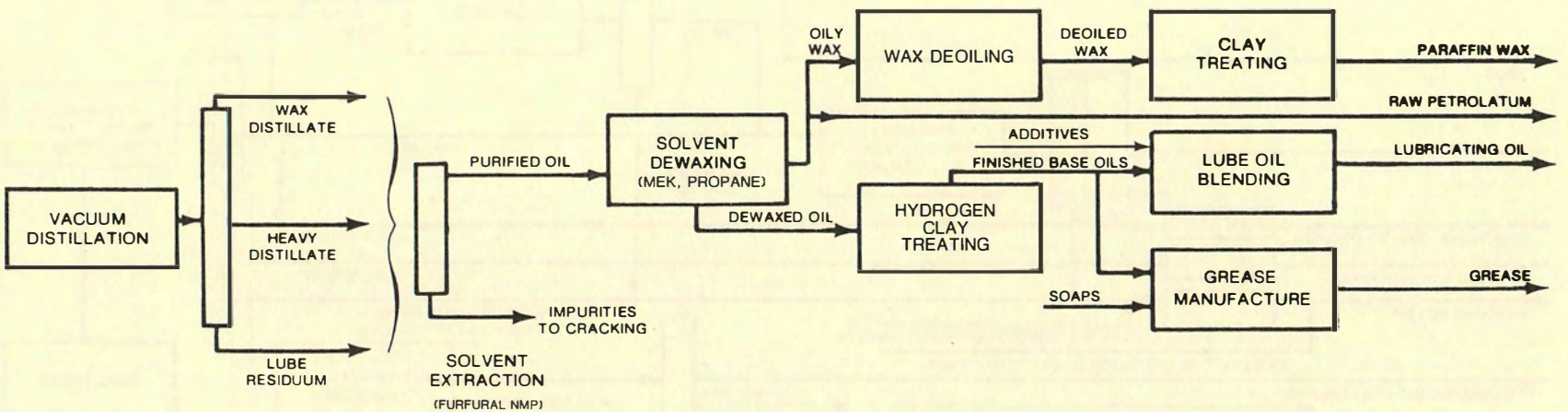


Figure C-8. Simplified Flow Chart of a Lubricating Oils Refinery.

In situations where quality distillates, such as turbine fuel, diesel and lube oils, and low-sulfur fuel oils are required, hydrogen refining concepts will apply, with hydrocracking and hydrodesulfurizing processes predominating.

The variability of marketing requirements and the potential uncertainty in crude oil supply require that processing flexibility be a major consideration in the design of today's modern petroleum refinery. The general result is an overall operation combining cracking and hydrogen refining capabilities.

REFINERY OPERATING UNITS

As of January 1, 1986, the U.S. refineries' crude oil input ranged from 350 barrels per day to 494,000 barrels per day. The simplest refineries "top" the crude oil and are usually limited to atmospheric distillation and, in some cases, vacuum distillation (Figure C-9). These plants produce only a few products, such as naphthas, distillates, residual fuels, and asphalts. More complex refineries have process units such as cracking, alkylation, reforming, isomerization, hydrotreating, and lubricant processing (Figure C-10), producing a wide range of products, including gasolines, low-sulfur fuel oils, lubricants, petrochemicals, and petrochemical feedstocks.

To better understand the operation of a refinery, the facilities can be divided into seven steps:

- *Separation of Crude Oil.* The most widely used methods for separating crude oil fractions by boiling point are atmospheric and vacuum distillation.
- *Conversion of Hydrocarbon Molecules.* Conversion processes, which change the size or structure of the hydrocarbon molecule, convert some of the crude oil fractions into higher value products. The most common conversion processes are cracking (thermal, catalytic, viscosity breaking, hydrocracking, and coking), combining (alkylation and polymerization), and rearranging (catalytic reforming and isomerization).

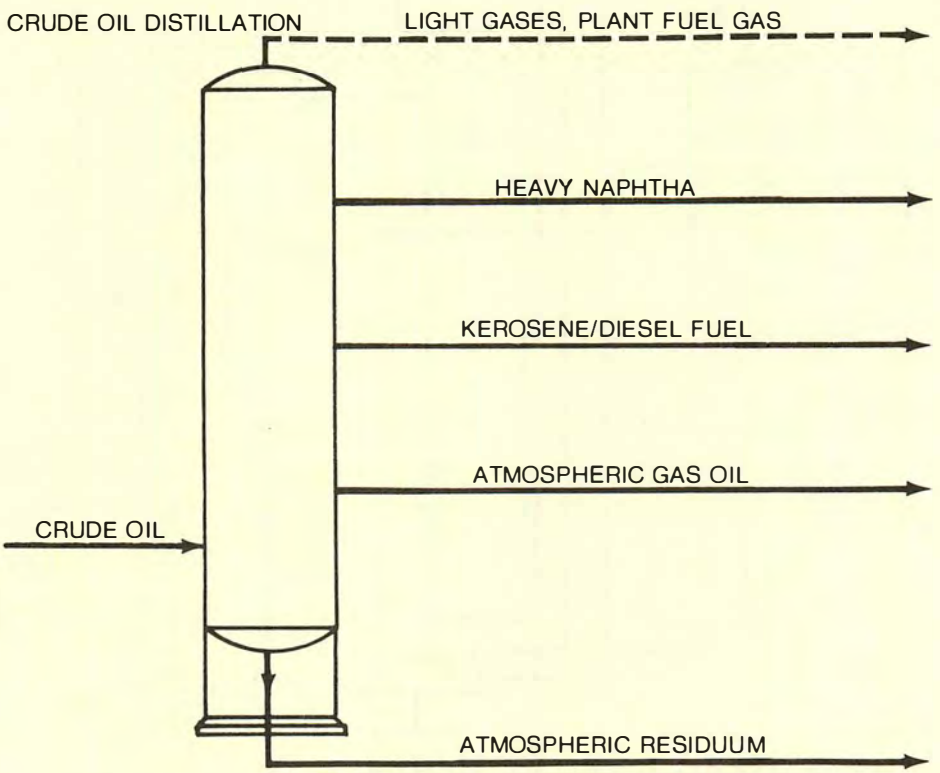


Figure C-9. Crude Oil Skimming or Topping Plant.

NOTE: The following legend applies to Figures C-9 through C-28.
——— HYDROCARBON - - - - - GASES

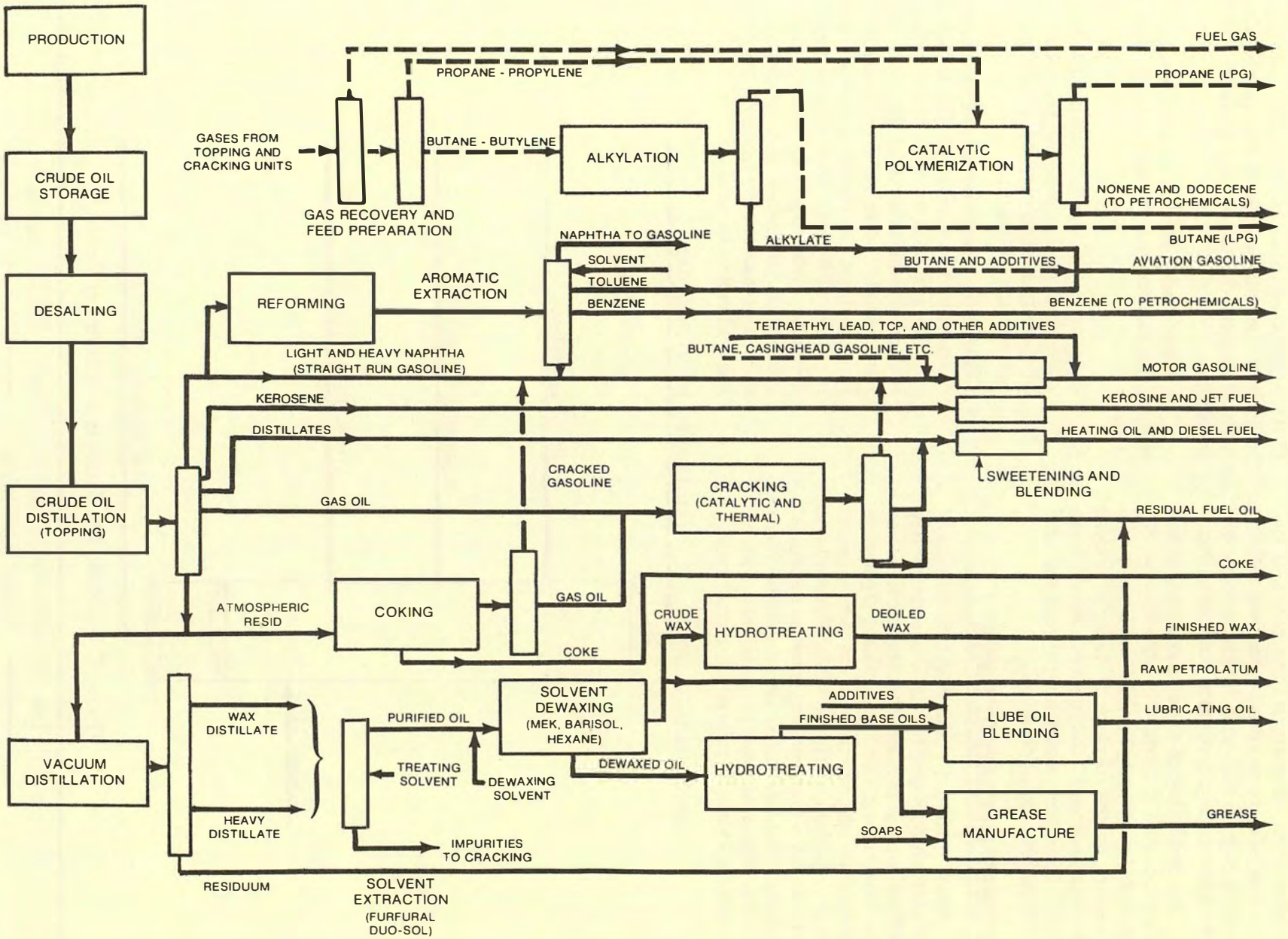


Figure C-10. Simplified Flow Chart of a Complex Refinery.

- *Treating Crude Oil Fractions.* Some of the original sulfur compounds are converted to hydrogen sulfide (H_2S), which can be separated and converted to elemental sulfur. Undesirable sulfur compounds are removed by treating processes such as hydrodesulfurizing and chemical treating.

- *Blending Hydrocarbon Products.* Most petroleum products are a blend of hydrocarbon fractions or components produced by various refinery processes. Motor gasoline is a blend of various gasoline blending stocks, including reformate, alkylate, straight-run naphtha, thermally and catalytically cracked gasoline, and necessary additives. The vast number of fuel oils, lubricants, and asphalt products are blends of refinery base stocks.

- *Auxiliary Operating Facilities.* A number of refinery units are used to maintain normal operating conditions. These units support processes such as hydrotreating, improve efficiency by allowing re-use of water and the use of sour gas as fuel, and help the refinery meet environmental standards. Included among the functions of auxiliary operating facilities are hydrogen production, light ends recovery, acid gas treating, sour water stripping, sulfur recovery, tail gas treating, and wastewater treatment.

- *Refinery Offsite Facilities.* Refinery offsite facilities are equipment and systems used to support refinery operations. These facilities include storage tanks, steam generating systems, flare and blowdown systems, cooling water systems, receiving and distribution systems, and refinery fire control systems. In addition, garages, maintenance shops, storehouses, laboratories, and necessary office buildings are considered offsite facilities.

- *Emission and Effluent Control.* Refineries generate air emissions, wastewater, solid waste, and noise, which must be controlled for efficient processing and environmental protection. The control of pollutants that can damage the environment is an important part of refinery operations.

Separation of Crude Oil

Following salt and water removal (desalting), crude oil is separated into the desired boiling range fractions by atmospheric and vacuum distillation.

DESALTER

The desalter is normally the starting point of the separation process. The crude oil is pumped from tankage, preheated by heat exchange with various product streams (fractions), and sent to the desalter. Desalting removes inorganic salts from crude oil so that these salts will not contribute to the fouling and corrosion of process equipment. The process also removes the soluble trace metals present in the water phase, which can poison downstream process catalysts. Chemicals and water are added to the crude oil, and oil/water separation occurs by gravity in the presence of a high voltage electrostatic field. This helps agglomerate the water droplets, which contain the salts, and separates the water from the oil. The oil is removed from the top of the desalter vessel, and the water and sludge are removed from the bottom. The water is then sent to the wastewater treatment plant.

ATMOSPHERIC DISTILLATION UNIT

Crude oil from the desalter is pumped to a furnace where the oil is further heated and fed to the atmospheric distillation unit. All petroleum distillation processes are fundamentally the same and require the following equipment: heat exchangers; furnaces or other heaters; a fractionating tower or column; condensers and coolers; pumps and connecting lines; storage and accumulator tanks; and instrumentation. In adapting these units of equipment, many factors must be considered. Among the most important are:

- Boiling range of the stocks
- Heat stability of the stocks
- Product specifications.

As shown in Figure C-11, the atmospheric distillation tower separates the crude oil into fractions having specific boiling point ranges. The fractions with the lowest boiling range are recovered as overhead streams and are either fuel gas, light naphtha, or straight-run gasoline. These fractions are used as reformer feedstocks, gasoline blending stocks, petrochemical

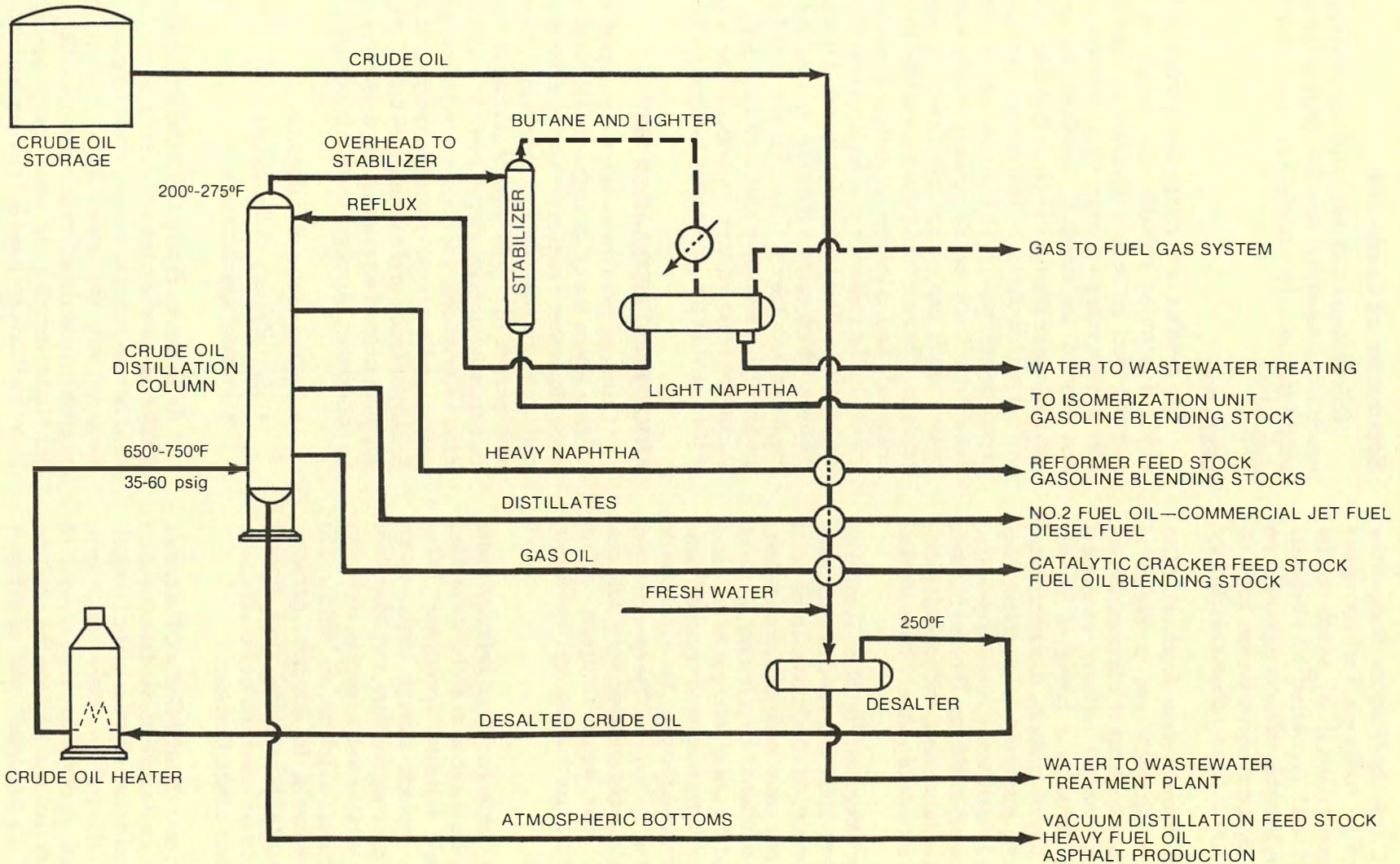


Figure C-11. Crude Oil Distillation Unit.

feedstocks, solvents, and LPGs. The intermediate boiling range fractions are gas oil, heavy naphtha, and distillates. These fractions are used to produce kerosene, diesel fuel, fuel oil, jet fuel, blending stocks, and catalytic cracker feedstocks. The high boiling point stream, or atmospheric bottoms, is used to produce No. 6 fuel oil, or to feed a vacuum distillation unit for the recovery of wax distillates for cracking or lube feedstocks.

VACUUM DISTILLATION UNIT

The charge stock for the vacuum distillation unit (Figure C-12) consists of heated atmospheric bottoms from the crude oil distillation unit. The vacuum can be produced by using steam ejectors or vacuum pumps. The equipment commonly used are two-stage steam-jet ejectors and surface condensors. At the reduced pressure, the oil vaporizes at a lower temperature, allowing the distillation to occur with a minimum of high-temperature cracking.

The product streams from the vacuum tower include light vacuum gas oil, heavy vacuum gas oil, and vacuum tower bottoms or residuum. These streams can be further processed depending upon the desired products. The vacuum gas oil may be sent to the catalytic cracker to produce gasoline blending stocks or it may be recovered for lube oil feedstocks. The vacuum bottoms may be used as fuel oil, used for the production of asphalt and lubricants, or sent to a coker for conversion to gasoline components, coke, and gas. If low-sulfur fuel oil is required, the vacuum bottoms may have to be desulfurized prior to blending.

Conversion of Hydrocarbon Molecules

Conversion processes change the size or structure of the hydrocarbon molecules, converting them into higher value products. The more common conversion processes are:

- Cracking processes (thermal cracking, coking, viscosity breaking, catalytic cracking, and hydrocracking)
- Combining processes (alkylation and polymerization)
- Rearranging processes (catalytic reforming and isomerization).

CRACKING PROCESSES

Cracking processes break large hydrocarbon molecules into smaller, lower-boiling-point molecules. During the process, some of the molecules combine (polymerize) to form larger

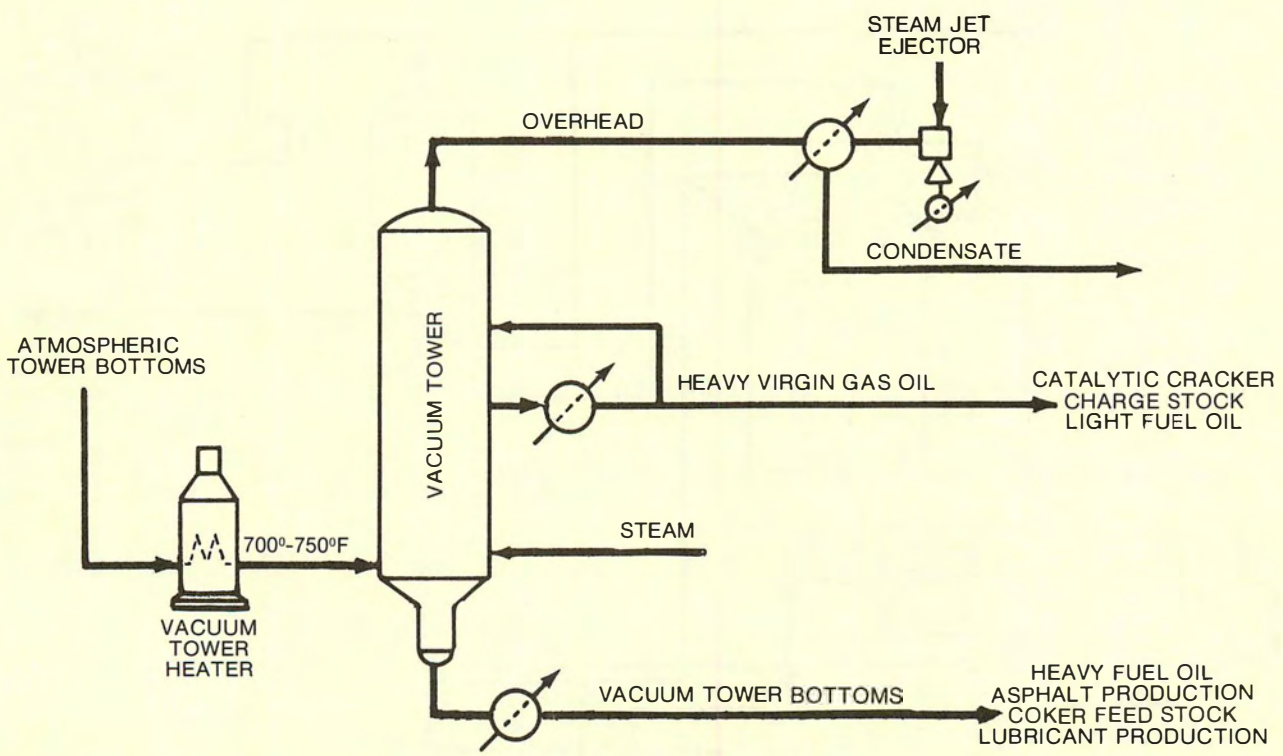


Figure C-12. Vacuum Distillation Unit.

molecules. The usual products of cracking are gaseous hydrocarbons, gasoline blending stocks, gas oil, fuel oil, and coke. Sour water generated during the process is sent to the sour water stripping unit. The off-gases from the fractionating column are treated by amine scrubbing, which removes the H_2S. The H_2S then is sent to the sulfur recovery unit.

Thermal Cracking. In the past, thermal cracking was accomplished solely by application of heat and pressure. The thermal cracking process was widely practiced during the 1920–1950 period. Today, thermal cracking is used mostly in only two of its more extreme forms, coking and viscosity breaking.

Coking. There are two coking processes that are employed extensively—delayed and fluid coking. Coking is accomplished at a high temperature and low pressure. It is a valuable process for upgrading heavy charge stock such as resids and very heavy crude oils to FCC feedstocks. In the coking unit, atmospheric bottoms or vacuum residuum are cracked to produce fuel gas, gasoline blending stocks, distillates, and petroleum coke. A delayed coking unit is shown in Figure C-13.

The coker charge is fed directly to the fractionator, where the feed combines with the heavy recycle oil from the coke drums. The combined feed is pumped to the coker furnace, where it is heated. This heating produces partial vaporization and mild cracking. The liquid/vapor mixture then enters the coke drum, where the liquid settles until it undergoes further cracking and is converted to hydrocarbon vapors and coke.

The coking unit typically has one or more pairs of coke drums. In normal operation one drum is in service while the other is being decoked. Decoking involves cooling the coke, and then cutting it from the drum with a high-pressure water drill. The coke and water drop from the drum into a pit where the coke dewaters, and the cutting water is recovered for re-use. The coke is loaded into transport vehicles or is stored offsite.

Fluid coking is a similar thermal cracking process, producing similar products, but fluid coking occurs in a fluid bed. This is a continuous process, unlike delayed coking.

In 1976, a new process, termed "flexicoking," was first used in Japan by the Toa Oil Company. The process is an adjunct to fluid cok-

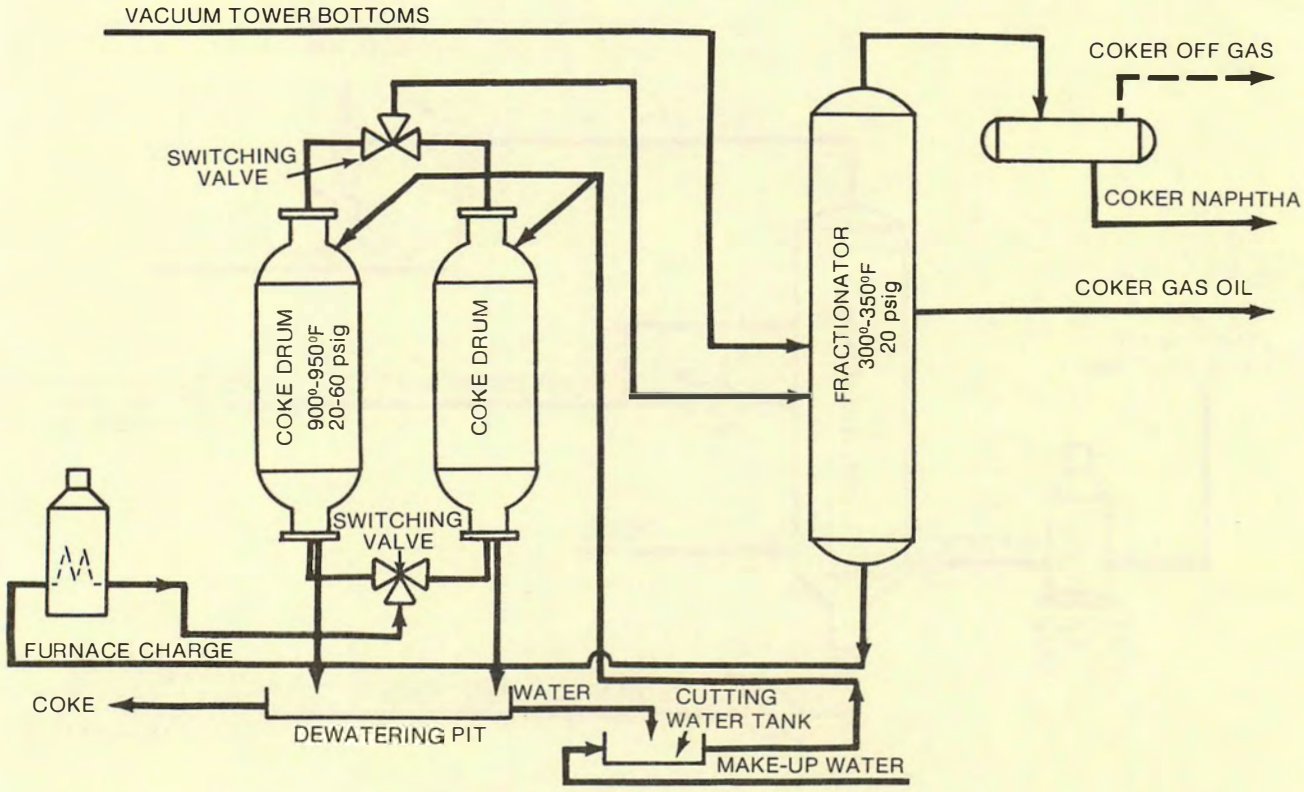


Figure C-13. Delayed Coking Unit.

ing and converts heavy, high-sulfur vacuum bottoms into petroleum products and fuel gas. Only a small quantity of ash or coke residue is produced.

Viscosity Breaking. Viscosity breaking, or visbreaking, is a mild form of thermal cracking that is used primarily to lower the viscosity of heavy fuel oil. The decomposition process is usually conducted at low cracking temperatures (860°F to 900°F). This process produces small amounts of gasoline blending stocks, gas oil, and a high yield of fuel oils.

Catalytic Cracking. Catalytic cracking uses a catalyst in combination with high temperatures to convert atmospheric and vacuum gas oils and stocks derived from other refinery operations into fuel gases, light gases, and gasoline and distillate fuel components. This process normally takes place in the fluid catalytic cracking unit (FCCU). Olefin-rich light gases are normally directed to alkylation or polymerization operations to produce high-octane gasoline blending stocks. Typically, yields of gasoline boiling range products will exceed 50 to 65 volume percent of the FCCU feed.

A typical FCCU is shown in Figure C-14. While there are numerous FCCU designs currently in use, they employ similar operating principles. The catalyst used in the process must be regenerated to remove coke that forms on its surface during the reaction. This is done in a separate regenerating vessel by passing air through the catalyst. The catalytic regeneration produces carbon monoxide (CO), sulfur oxides (SO_x), nitrogen oxides (NO_x), and particulates. Recent improvements in technology have minimized the formation of CO.

Hydrocracking. Hydrocracking differs from catalytic cracking in four distinct ways: hydrogen is utilized in the process; operating pressures are substantially higher; temperatures are somewhat lower; and a different type of catalyst is employed. The process has an advantage over catalytic cracking in that high-sulfur feedstocks are concurrently desulfurized. The yield of specific products will depend upon how the hydrocracking unit is operated. For example, yields of jet fuel plus diesel fuel equal to approximately 85 to 90 volume percent of feed can be achieved, with concurrent production of LPG and gasoline. The process produces high-quality gasoline and distillates and accepts a wide variety of feedstocks, including naphthas, gas oils, and heavy aromatic feedstocks. Hydrogen used for this process is generated by a hydrogen plant or is a by-product from the catalytic reformer. A typical two-stage hydrocracker is shown in Figure C-15.

Combining Processes. Combining processes join together small hydrogen-deficient molecules (olefins) that are recovered from thermal and catalytic cracking to produce more valuable gasoline blending stocks. Two processes, alkylation and polymerization, are normally utilized for combining the olefins with isobutane.

Alkylation. The alkylation process combines light olefins, primarily a mixture of propylene and butylenes, with isobutane to produce a blending stock that is one of the highest quality components of motor gasoline. The final product, called alkylate, has excellent antiknock properties. It is clean burning, has high Research and Motor method octane number ratings, and has excellent performance ratings. The union of the olefins and isobutane takes place in the presence of a catalyst, either hydrofluoric or sulfuric acid, under conditions selected to maximize product yield and quality.

The process utilizing hydrofluoric acid as the catalyst is shown in Figure C-16. The unit feed, consisting of C_3 and C_4 olefins and isobutane, is mixed with recycled acid and fed to the reactor–settler where the alkylation reaction takes place. The combined products are sent to a fractionator where the alkylate product is separated from the unreacted feed, catalysts that carry over, and propane and butane that was formed by the reaction. The product or alkylate may first be debutanized before being sent to storage for gasoline blending.

Construction materials for hydrofluoric acid alkylation units include plain carbon steel; some of the rundown lines, however, are constructed of Monel alloy. All unit lines are jacketed and connected to a "blowdown" or water spray pump so that gaseous acid will be caught if a break occurs. Much of the operation is by remote control; when the operator must approach the unit, face masks and rubberized clothing are worn.

The hydrofluoric acid alkylation unit includes a hydrofluoric acid regenerator, which continuously purifies a small side stream of the acid. The tar-like substance that is formed in the

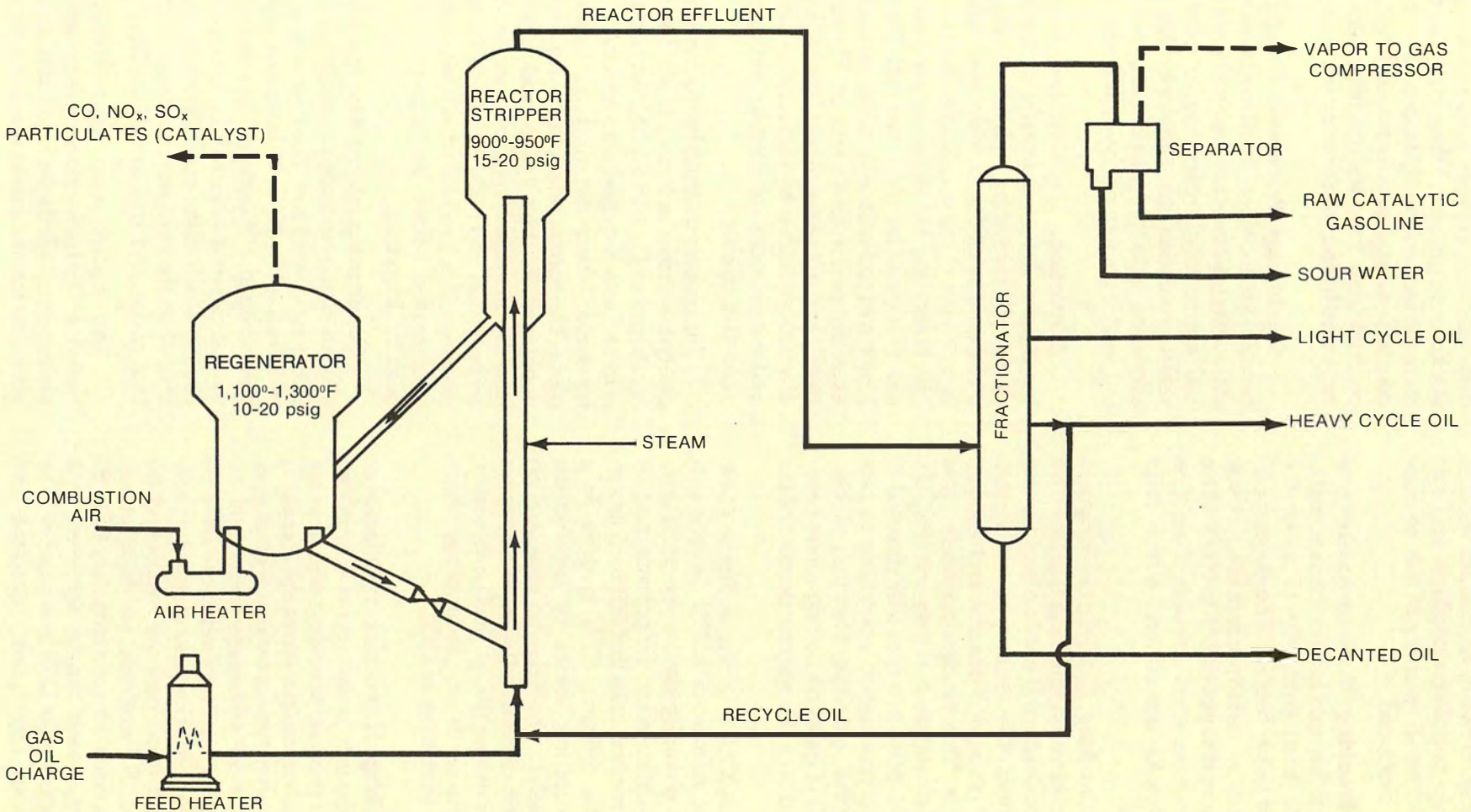


Figure C-14. Fluid Catalytic Cracking Unit.

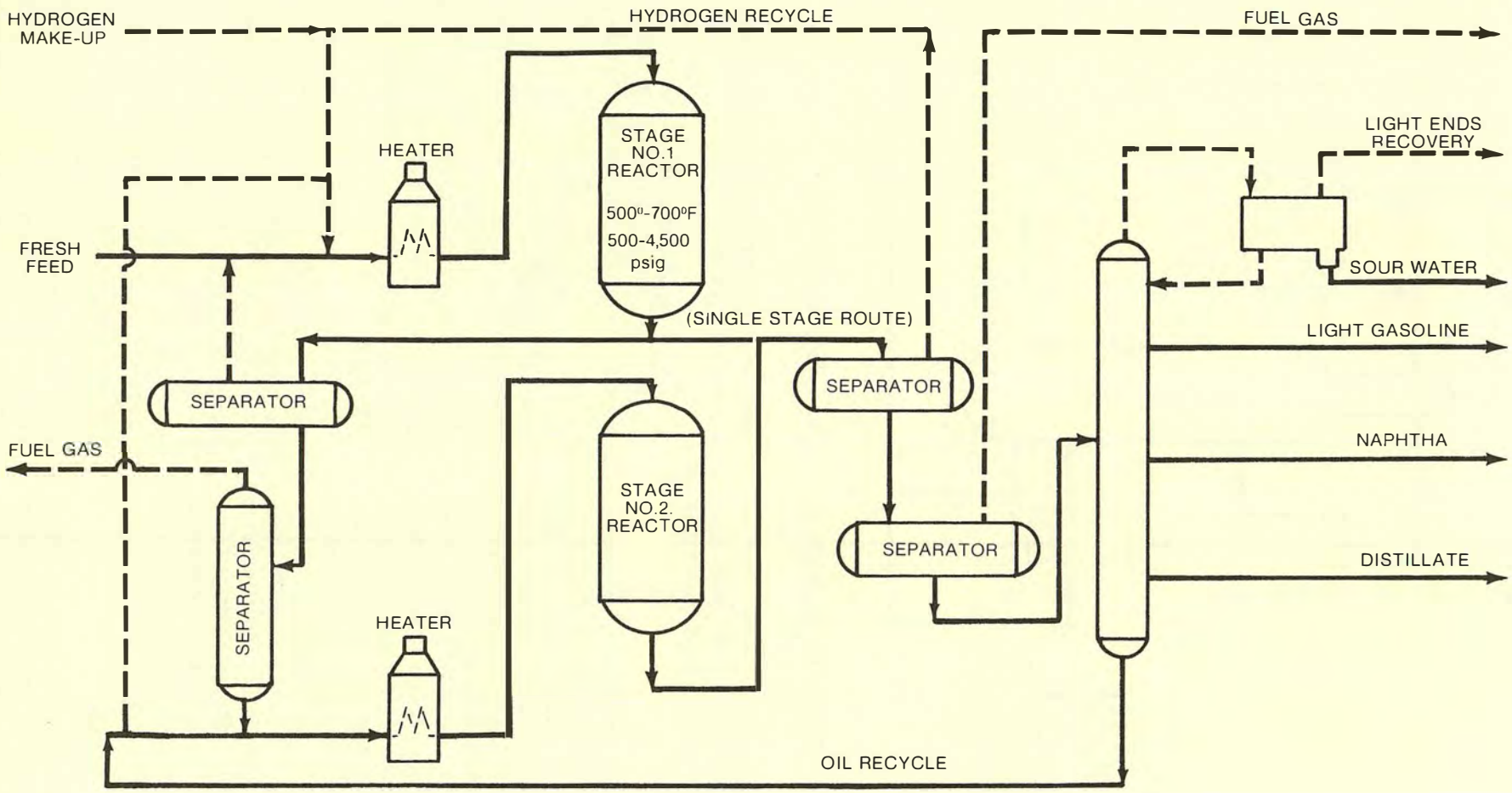


Figure C-15. Typical Two-Stage Hydrocracker Unit.

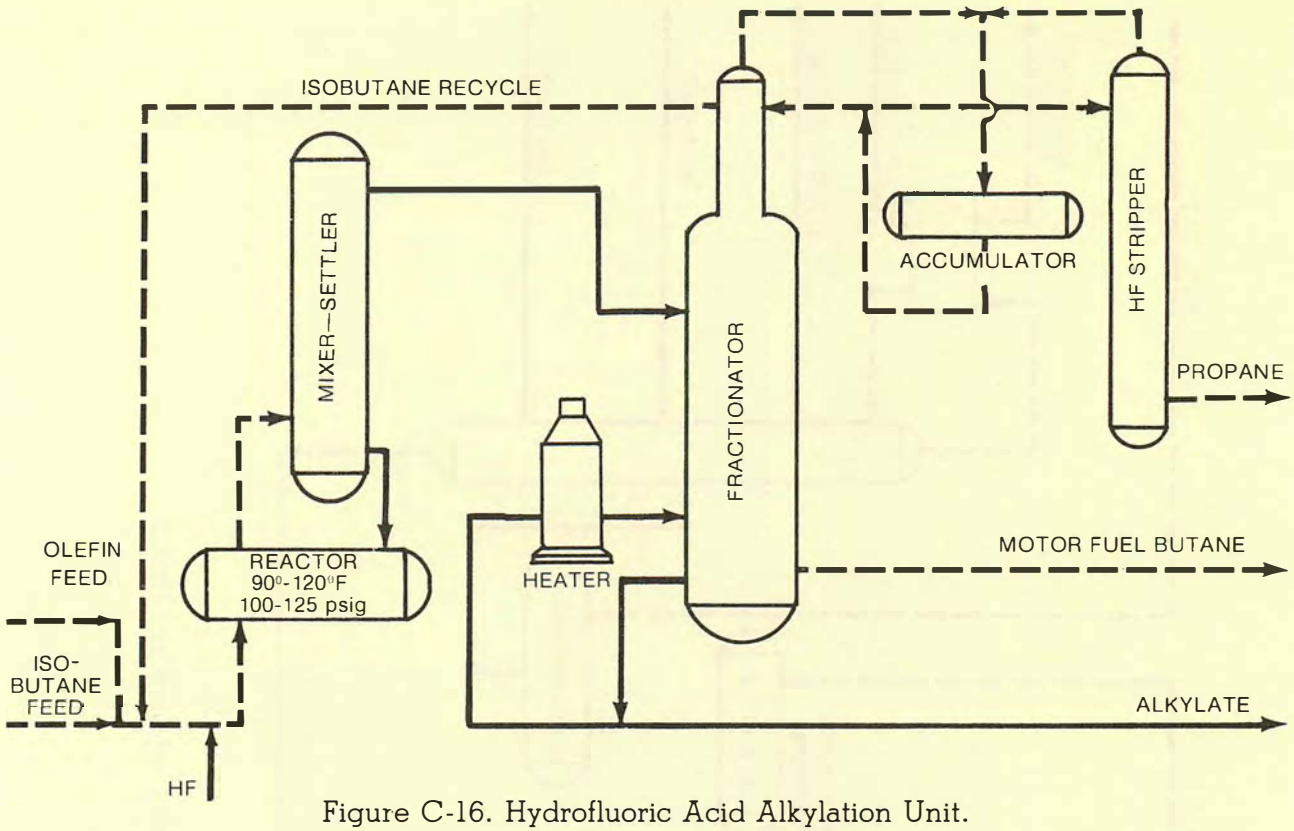


Figure C-16. Hydrofluoric Acid Alkylation Unit.

regenerator may be disposed of by incineration or neutralized with lime and handled as a solid waste. Also, the spent caustic from the unit is handled as solid waste.

Polymerization. Polymerization combines light olefins from thermal and FCC units to form hydrocarbons of higher molecular weight. Two molecules of isobutylene (C_4H_8) may be combined to form one molecule of di-isobutylene (C_8H_{16}). This product, formed by the union of two olefin molecules, is referred to as a dimer. That formed by three such molecules is known as a trimer. Two unlike olefins may also be combined, resulting in a product known as a copolymer. By-product gases are used to produce a wide variety of products ranging from gasoline blending stocks to solids that can be used as plasticizers. Polymerization of a mixture of propylene and butylene to produce a blending stock for gasoline is the most common polymerization operation. The most commonly used process employs phosphoric acid as a catalyst.

REARRANGING PROCESSES

Rearranging processes are those in which the molecule is changed to produce a product of different characteristics. The two most widely used rearranging processes are catalytic reforming and isomerization.

Catalytic Reforming. Catalytic reforming is a process used to upgrade low-octane naphthas to produce high-octane blending stocks or high yields of aromatic hydrocarbons for petrochemical feedstocks (i.e., benzene). The final product will depend on reactor temperature and pressure, the catalyst used, and the hydrogen recycle rate. Reforming catalysts contain platinum and are readily deactivated (poisoned) by sulfur and nitrogen, so the feedstock must be pretreated prior to being charged to the reforming unit.

Catalytic reforming is the octane number generator for most gasoline-oriented refineries. The gasoline blending stocks from other operations such as FCCU, alkylation, hydrocracking, and polymerization are of relatively fixed octane number quality. The catalytic reforming process is capable of efficiently yielding gasoline blending stocks within an octane number range from the low 80s to over 100 Research clear (unleaded). As operation severity is increased to raise the octane number, gasoline yield decreases. On the basis of the gasoline produced per unit of feedstock, typical yields can range

from 70 to over 90 volume percent for high- to low-octane-number operations. This process also generates hydrogen that is required for many of the operations employed in modern refineries.

A typical catalytic reforming unit is shown in Figure C-17. The naphtha feedstock is mixed with recycle hydrogen-rich gas, heated in a furnace, and fed to the first reactor. Because the reforming reaction requires heat (endothermic), the product must be reheated before entering the next reactor. This process typically is repeated in three subsequent reactors. The liquid product passes to a separator to remove the hydrogen-rich gas and then to a stabilizer for final separation of light gases and product. The reformate product then goes to storage for blending into gasoline. The light gases, consisting of mostly propane and butane, are sent to the light ends recovery unit.

The catalyst requires regeneration, which may be accomplished by utilizing a swing reactor, as shown in Figure C-17. As in hydrotreating and FCCU, coke deposited on the catalyst surface is burned off under controlled conditions.

Isomerization. Isomerization units are employed to convert n-butane, n-pentane, and n-hexane (low-octane, straight chain hydrocarbons) to high-octane, branched chain isomers.

Figure C-18 shows a typical light naphtha isomerization process. In this process, desulfurized pentane/hexane (C_5/C_6) mixtures are fed to the de-isopentanizers to remove the isopentane present in the feed. The n-pentane and n-hexane mixture is dried, mixed with organic chloride catalyst promoter and hydrogen, and fed to the reactor. The product is cooled and fed to a separator, where excess hydrogen is removed to be recycled. The product is then fed to a stabilizer to remove low-boiling light hydrocarbons. The stabilizer bottom products are used for gasoline blending stocks or may be further fractionated to remove unreacted n-pentane, n-butane, and n-hexane for recycling.

Treating Crude Oil Fractions

With continuing emphasis on producing greater yields of higher octane gasoline and low-sulfur fuel oil, it is necessary to upgrade materials that are used directly as gasoline components or blended into fuel oil. Components such as thermal naphthas derived from thermal cracking, visbreaking, and coking operations, as well as high-sulfur naphthas and distillates from crude oil distillation containing sulfur and nitrogen, require treating.

HYDRODESULFURIZATION

Hydrodesulfurization is a catalytic process used to remove sulfur, nitrogen, olefins, arsenic, and lead from liquid petroleum fractions. Typically, hydrodesulfurization units are employed before such processes as catalytic reforming because the process catalysts used in reforming become inactive if the feedstock contains these impurities. Hydrodesulfurization may be used prior to catalytic cracking to reduce the sulfur emissions from the regenerator and improve product yields. It may also be used to upgrade petroleum fractions into finished products such as kerosene, diesel fuel, and fuel oils.

Hydrodesulfurization processes are used on a wide range of feedstocks from naphtha to heavy residual oils. In general, the hydrodesulfurizing of cracked process streams requires greater quantities of hydrogen than does hydrodesulfurizing of virgin crude oil fractions.

In a typical hydrodesulfurizing process (Figure C-19), the feed is mixed with make-up hydrogen from the reformer or hydrogen manufacturing plant. The mixture is heated and fed to the catalyst reactor, where sulfur and nitrogen are converted into H_2S and ammonia (NH_3).

Product from the reactor goes to the high-pressure separator, where excess hydrogen is flashed off and returned to the reactor. The product then passes to the low-pressure separator where H_2S, NH_3, noncondensable hydrocarbon gases, and hydrogen are removed. The gases from the low-pressure separator are sent to the gas treating system to remove H_2S. The liquid product is then sent to the stabilizer where the remaining light material is stripped and is sent to the fuel gas treating system. The sour water generated during the process is sent to the sour water stripping unit.

CHEMICAL TREATING

The use of chemical treating to directly remove sulfur from petroleum fractions has declined as hydrodesulfurization has increased. Chemical treating processes are used, however, to remove such impurities as carbon dioxide (CO_2), oxidants, and various corrosive compounds from processing systems.

A variety of gasoline sweetening (mercaptan removal) processes are available. The most

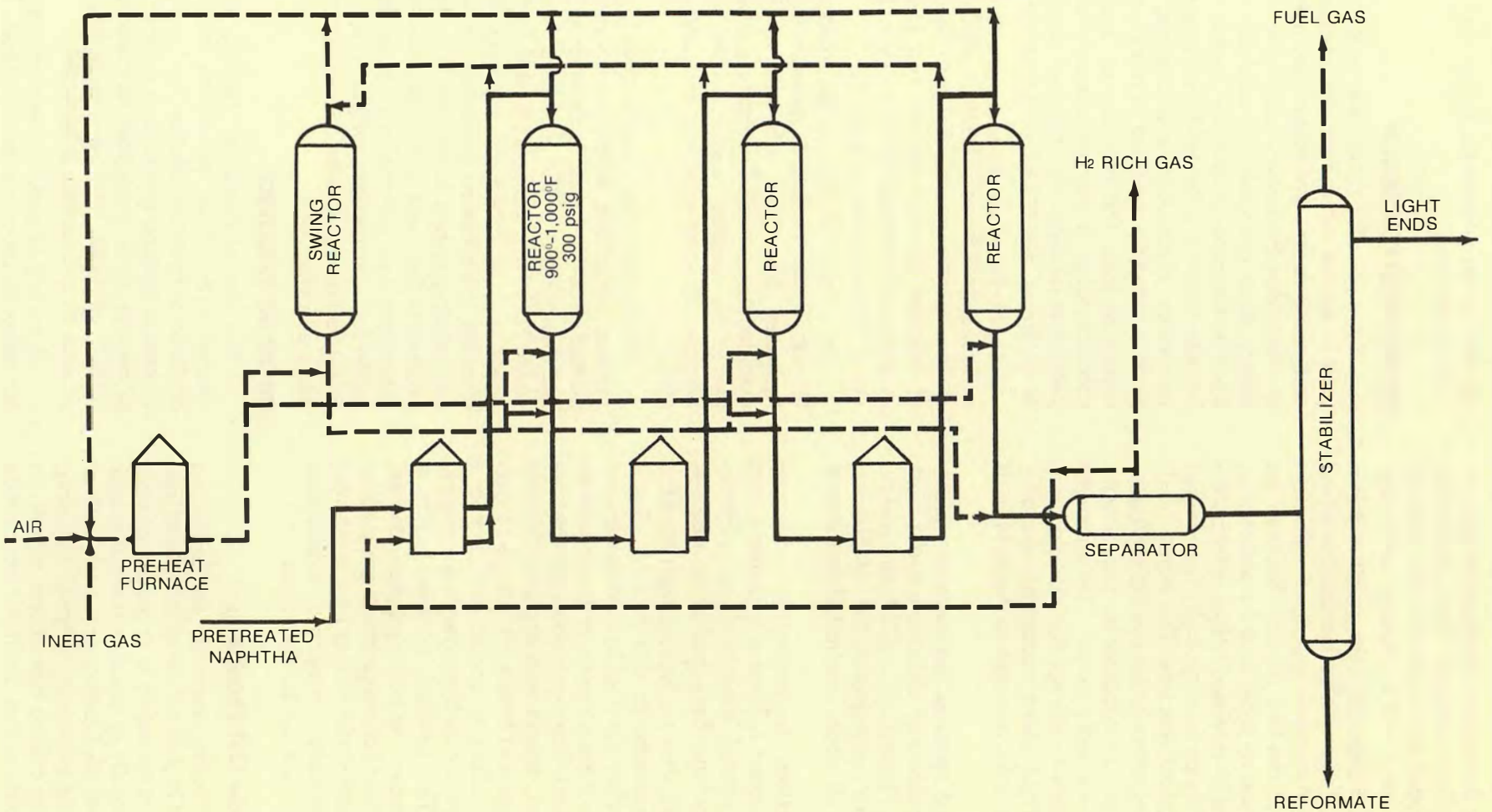


Figure C-17. Catalytic Reforming Unit.

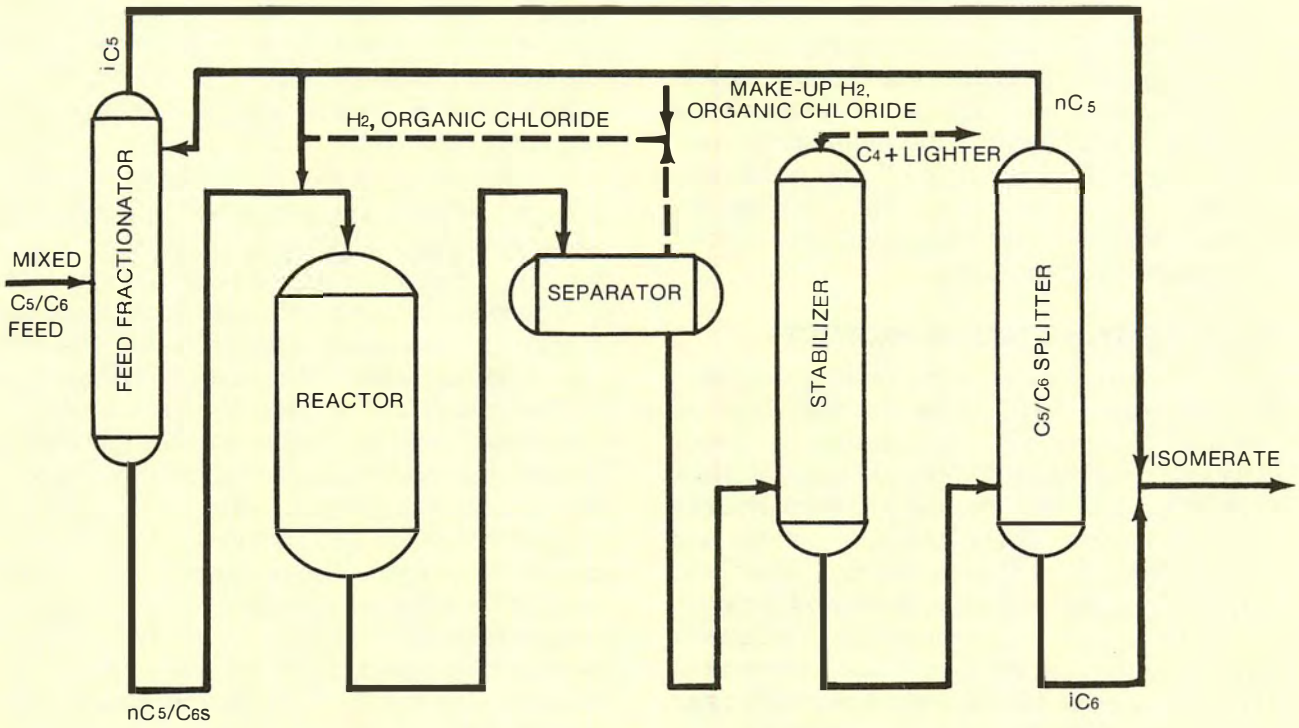


Figure C-18. Pentane/Hexane (C_5/C_6) Isomerization Unit.

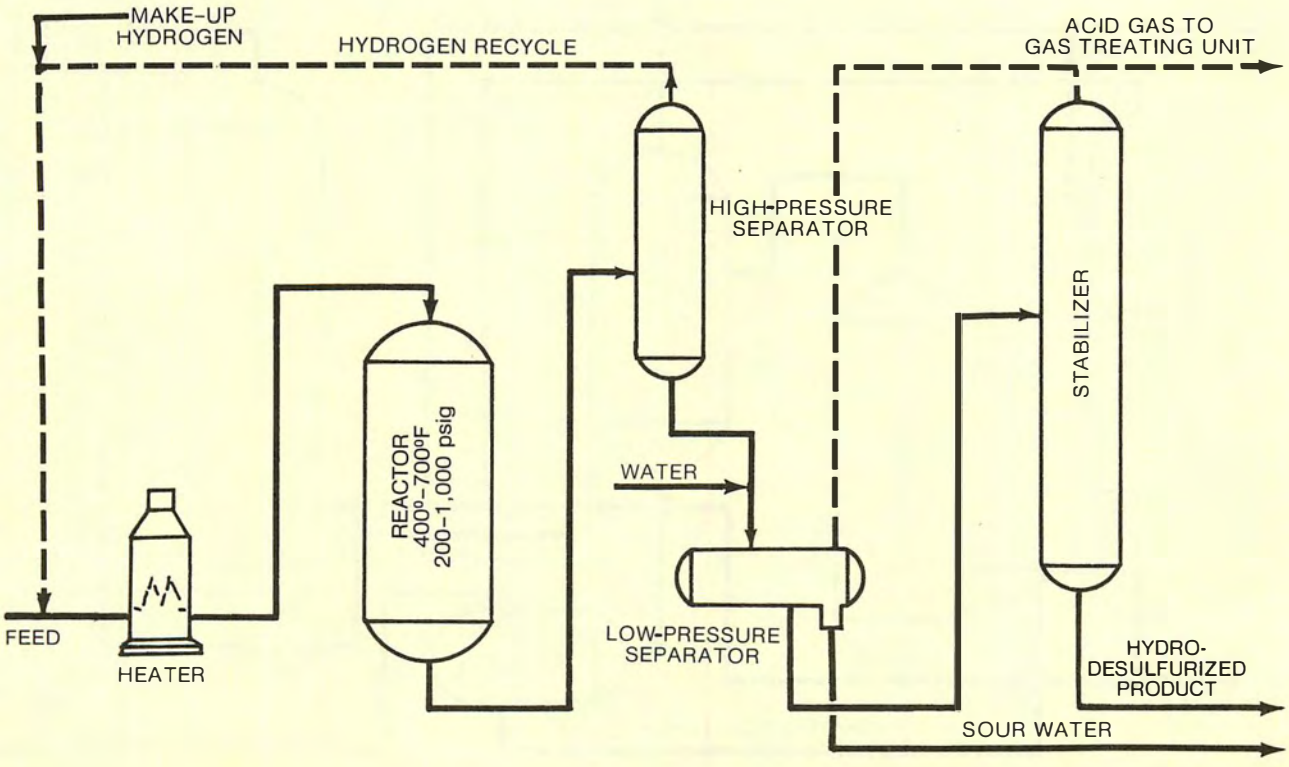


Figure C-19. Hydrodesulfurizing Unit.

widely used process employs sodium hydroxide with added catalysts or promoters (Figure C-20). The process converts the mercaptans to less objectional disulfides. The use of sweetening is primarily dependent upon the sulfur and/or mercaptan content of the crude oil, the sulfur specification of the gasoline, and whether the original feedstock had been hydrodesulfurized prior to catalytic cracking.

BLENDING HYDROCARBON PRODUCTS

The last major step in the refinery operation is the blending of various fractions into finished products. All grades of motor gasoline are blends of various fractions, including reformate, alkylate, straight-run gasoline, thermally and catalytically cracked gasoline, coker gasoline, butane, and necessary additives. Furnace oil and deisel fuels may be blends of virgin distillates and cycle oil. Jet fuels may be straight-run virgin distillates or include naphtha in the blend. The vast number of lubricating oils are blends of a relatively small number of refined based stocks plus additives to impart specific properties to most crankcase and specialty lubricants. In some cases these additives may total more than 15 to 20 percent of the finished lubricant. Asphalt is blended from select residual base stocks according to the application desired.

For example, in gasoline blending, the components or blending stocks from the process unit, such as butane, alkylate, isomerization stock, reformate, catalytic gasoline, naphtha or straight-run gasoline, coker gasoline, and additives, are blended to meet gasoline specifications. The mixing of the components is normally accomplished by automated in-line blending (Figure C-21). Gasoline blending components are fed into a system of proportional metering pumps and control valves to the gasoline header. The metering pumps ensure that each component is fed in the proper proportion. The components are mixed by the flow turbulence in the header and sent to a series of on-stream analyzers, which continually monitor the product for octane number and vapor pressure. The monitors automatically control the metering systems to ensure proper portions of each component.

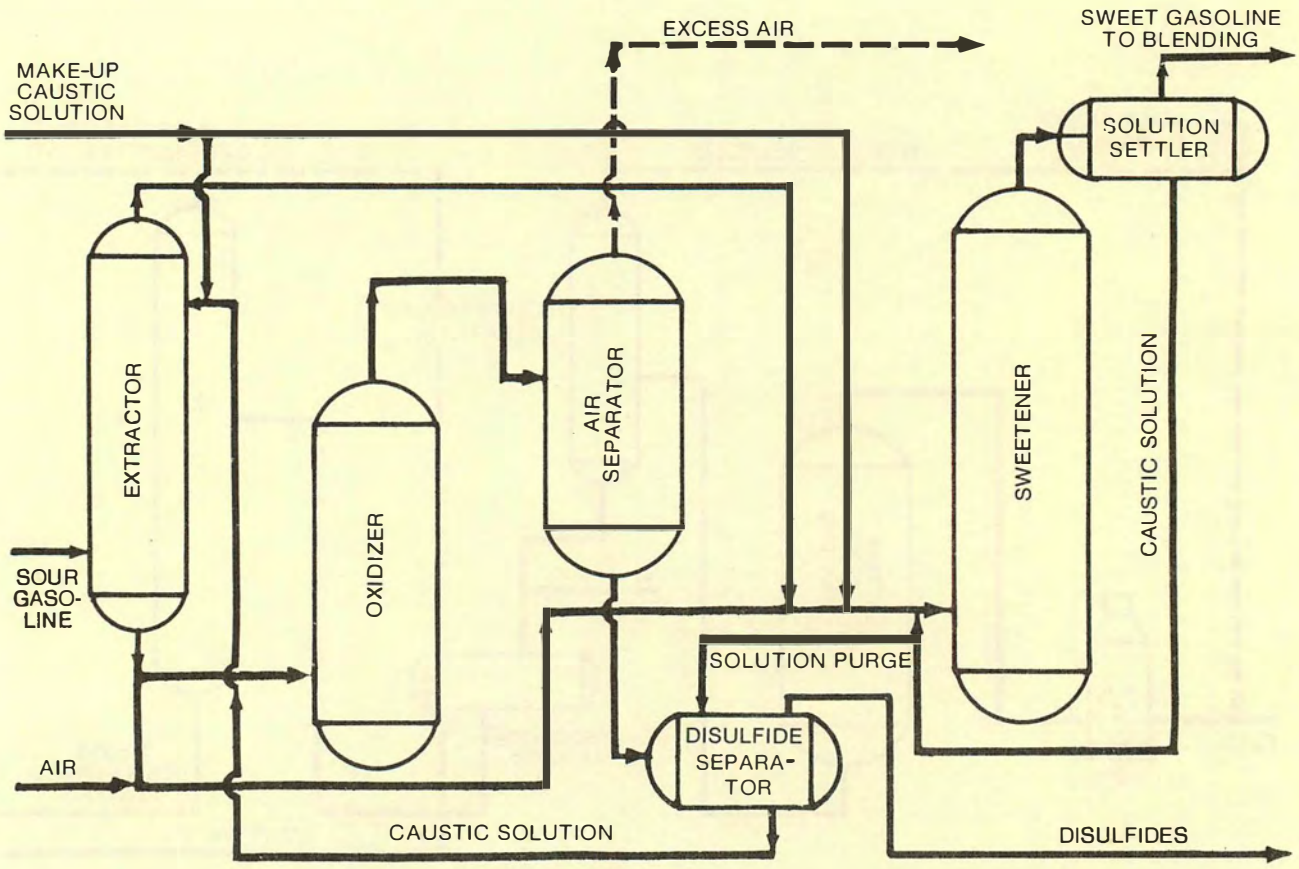


Figure C-20. Gasoline Sweetening Unit.

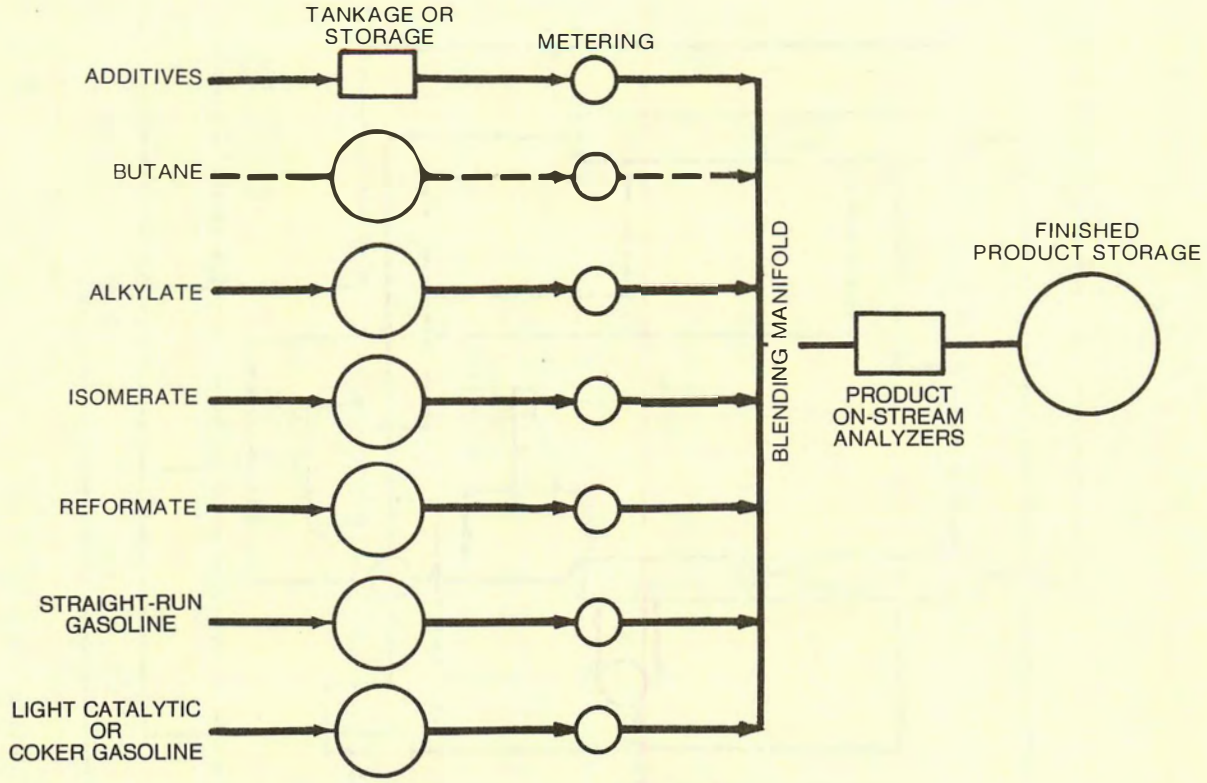


Figure C-21. Gasoline In-Line Blending System.

Auxiliary Operating Facilities

Auxiliary operating facilities are necessary to support process units requiring hydrogen, collect and treat gases for refinery fuels, control air emissions, meet water effluent standards, and re-use water.

HYDROGEN PRODUCTION UNIT

Hydrogen is required for a number of refining units, including hydrodesulfurization, hydrocracking, and isomerization. The primary source of hydrogen is the catalytic reforming process. Additional hydrogen may be produced by the steam reforming of available hydrocarbons such as methane, refinery fuel gases, propane, butane, or desulfurized light naphtha, or by the partial oxidation of heavier hydrocarbons.

The flow diagram for manufacturing hydrogen by the steam reforming process is shown in Figure C-22. The feed to the unit normally contains traces of sulfur, which are removed by absorption or activated carbon. The removal of the sulfur is necessary to avoid poisoning the process catalyst. The process employs two beds of activated carbon; while one bed is in use, the other is being regenerated. Upon completion of the regeneration, the sequence is reversed. Regeneration is accomplished by heating the carbon with steam to remove absorbed sulfur. The used steam is condensed and sent to the sour water stripper.

Desulfurized naphtha and natural gas are mixed with steam passed through catalyst-filled tubes in the reformers. The reformer gas containing hydrogen, CO, CO_2, and excess steam is passed through a shift converter where CO and steam are converted to hydrogen and CO_2. The CO_2-rich gas is scrubbed to remove practically all the CO_2, yielding 95-98 percent pure hydrogen.

In the manufacture of hydrogen by the partial oxidation process, the feed to the units is typically bottom products from the vacuum tower or heavy coker gas oil. This process avoids the necessity of using naphtha or other, more valuable hydrocarbons as hydrogen plant feedstock.

In the partial oxidation process, the residual oil is fed to a combustion chamber where it is partially burned in the presence of steam and oxygen. Gases leaving the combustion chamber are composed primarily of hydrogen and CO and have a temperature of 2,000°F to 2,800°F. The gases are then quenched with water and steam

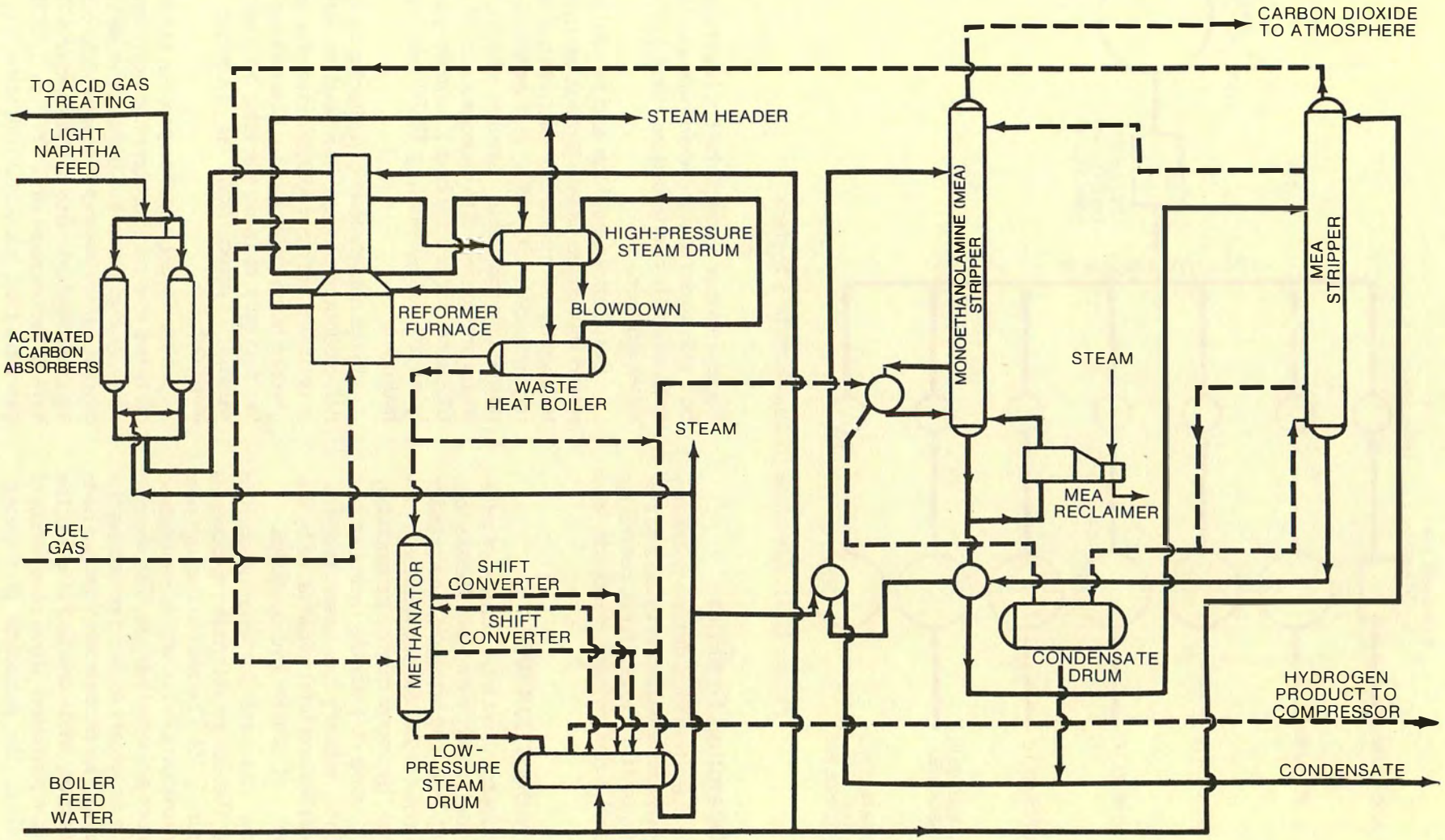


Figure C-22. Hydrogen Production Unit.

and fed to a shift converter for further conversion of the CO and steam to hydrogen. The gases are then purified by absorption and the hydrogen product is sent to storage or process units.

LIGHT ENDS RECOVERY UNIT

The term "light ends" refers to light hydrocarbon gases having four or fewer carbon atoms in the molecule. These include methane, ethane, propane, and butane. Included in this group are C_3 and C_4 olefins and isobutane. The purpose of this unit is to separate these gases for further use in product production or refining.

The flow diagram for the unit is shown in Figure C-23. The feed to this unit is desulfurized gases that have been collected from the various process units. The gases are first liquefied by compression and cooling, then sent to a surge drum to remove condensed moisture. The mixture is pumped to the de-ethanizer where methane and ethane are separated from the mixture and recovered for refinery fuel. The de-ethanized bottoms are sent to the de-propanizer, where propane and butanes are separated. These streams may be further processed to separate the olefins and isobutane from the propane and normal butane. The olefins and isobutane are used for alkylation unit feedstock. The propane is recovered for LPG and normal butane is sent to gasoline blending.

ACID GAS TREATING UNIT

H_2S and CO_2 are acid gases, and a fuel gas stream containing these compounds is called sour gas. Sour gas is produced during a number of refinery processes, including catalytic cracking and hydrotreating. Refinery-produced gas can be expected to be sour; it is sometimes necessary to treat the gas to remove H_2S before it can be used as a refinery fuel in order to comply with environmental standards.

Acid gas is typically removed by absorption in alkaline solution. A typical acid gas treating system is shown in Figure C-24. The alkaline material is chosen so that the chemical bond formed during absorption can be broken by heating to regenerate the solution. Absorption solutions containing acid gas are termed "rich" and the regenerated solutions are termed "lean." The fact that these solutions differ allows for several acid gas treating processes. The most widely used absorbents are monoethanol amine and diethanol amine. The processes differ only in the absorbents used.

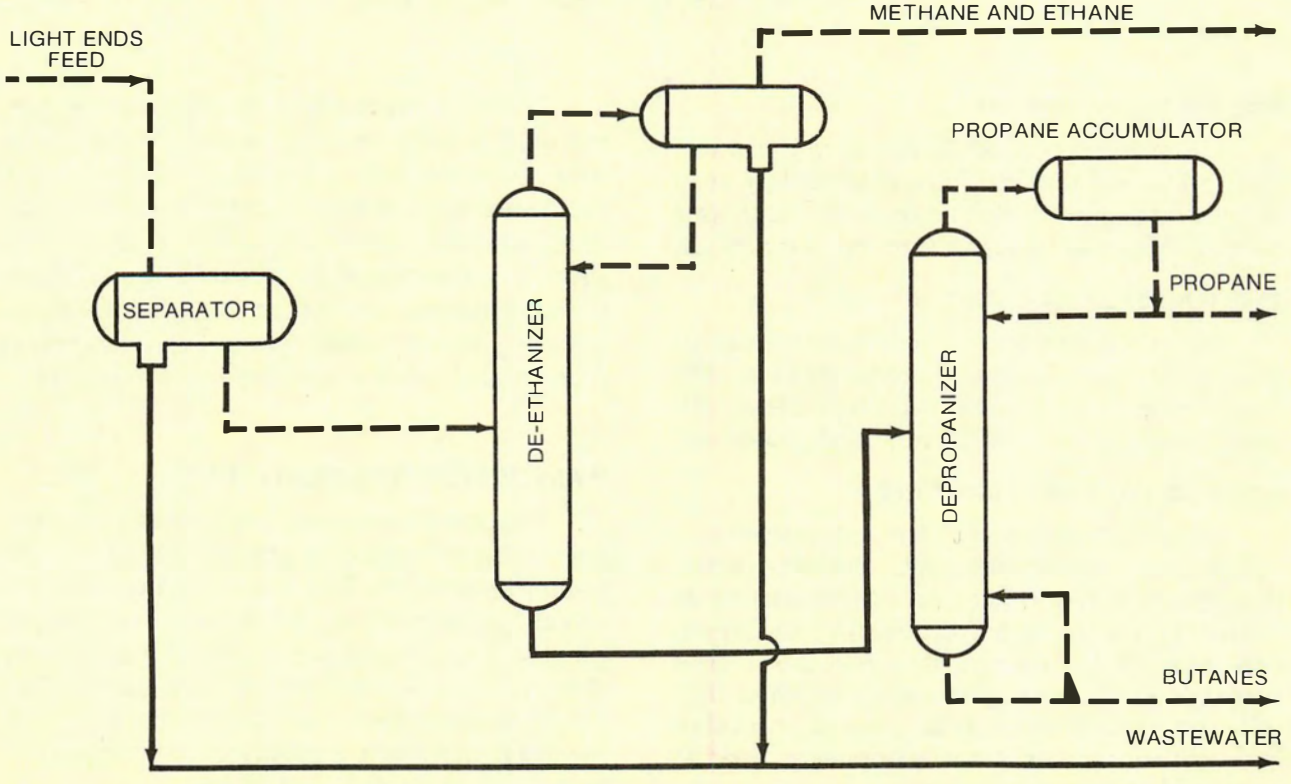


Figure C-23. Light Ends Recovery Unit.

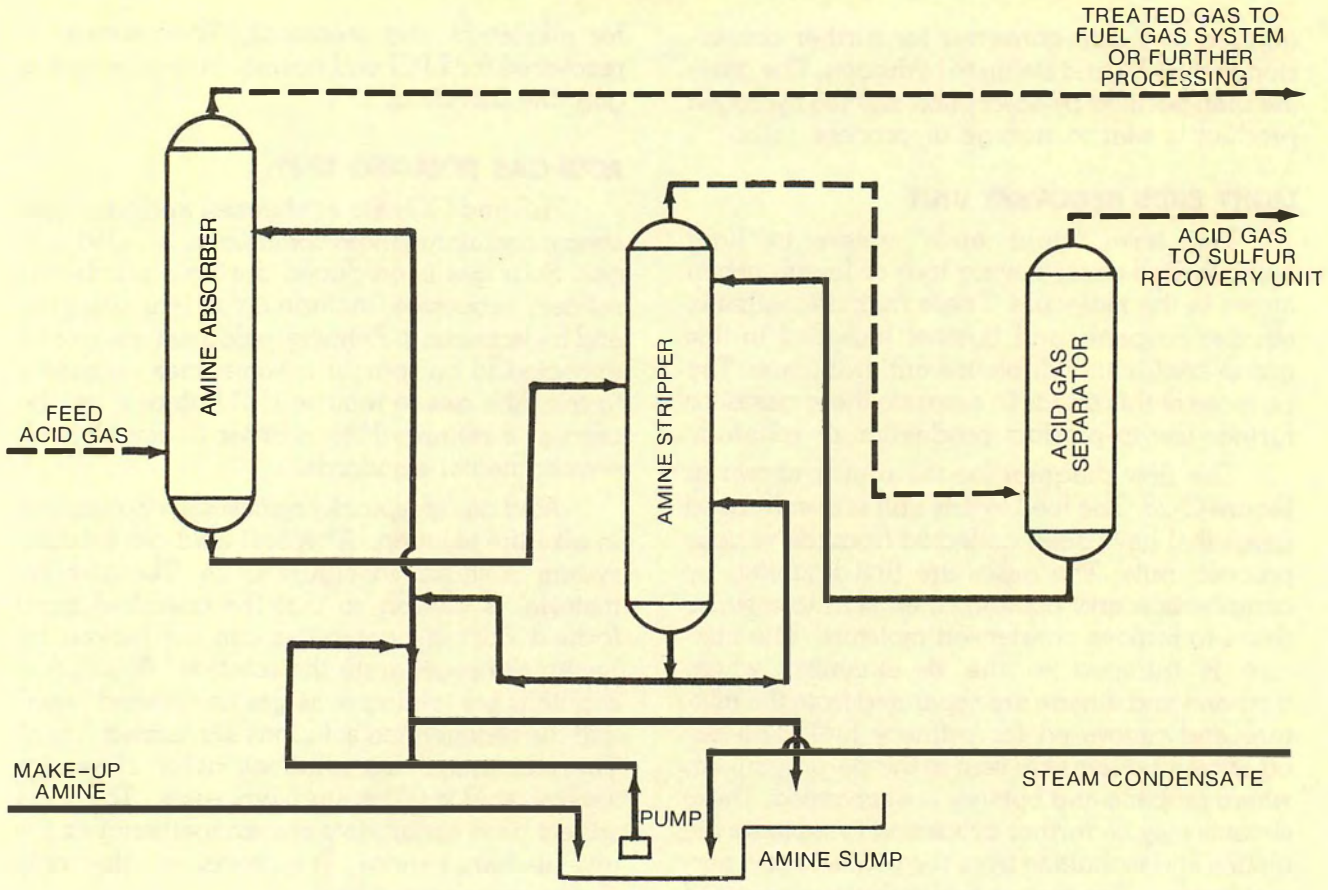


Figure C-24. Acid Gas Treating Unit.

SULFUR RECOVERY UNIT

The sulfur recovery plant is used to convert H_2S to elemental sulfur. The most widely used recovery system is the Claus process, which uses both thermal and catalytic conversion reactions.

TAIL GAS TREATING UNIT

Numerous processes are available to treat tail gas from the the Claus sulfur recovery unit. They include the Beavon-Stretford, Shell Claus Off-Gas Treatment, and Wellman-Lord processes.

SOUR WATER STRIPPING UNIT

Water containing sulfides and ammonia is called "sour water condensate." Refinery operations produce sour water from processes such as catalytic cracking and hydrotreating and whenever steam is condensed in the presence of gases containing H_2S. Sour water usually contains H_2S, NH_3, and small amounts of phenol and other hydrocarbons. Sour water stripping is used to reduce H_2S and NH_3 levels.

There are many different stripping methods, but most of them involve the downward flow of sour water through a trayed or packed tower while an ascending flow of stripping steam or gas removes the H_2S and NH_3. A typical sour water stripper is shown in Figure C-25. The acid gases from the process are sent to the sulfur recovery unit, stripped sour water goes to the desalter, and recovered oil goes to the slop oil recovery tank.

WASTEWATER TREATMENT UNIT

Treatment of refinery wastewater to remove contaminants typically involves a variety of treating processes. The proper treatment combined with in-plant source control of wastewater provides a quality effluent suitable for discharge. A typical wastewater treatment unit may contain an equalization basin, an API separator, slop oil recovery equipment, a dissolved air flotation unit, biological treatment, and filters.

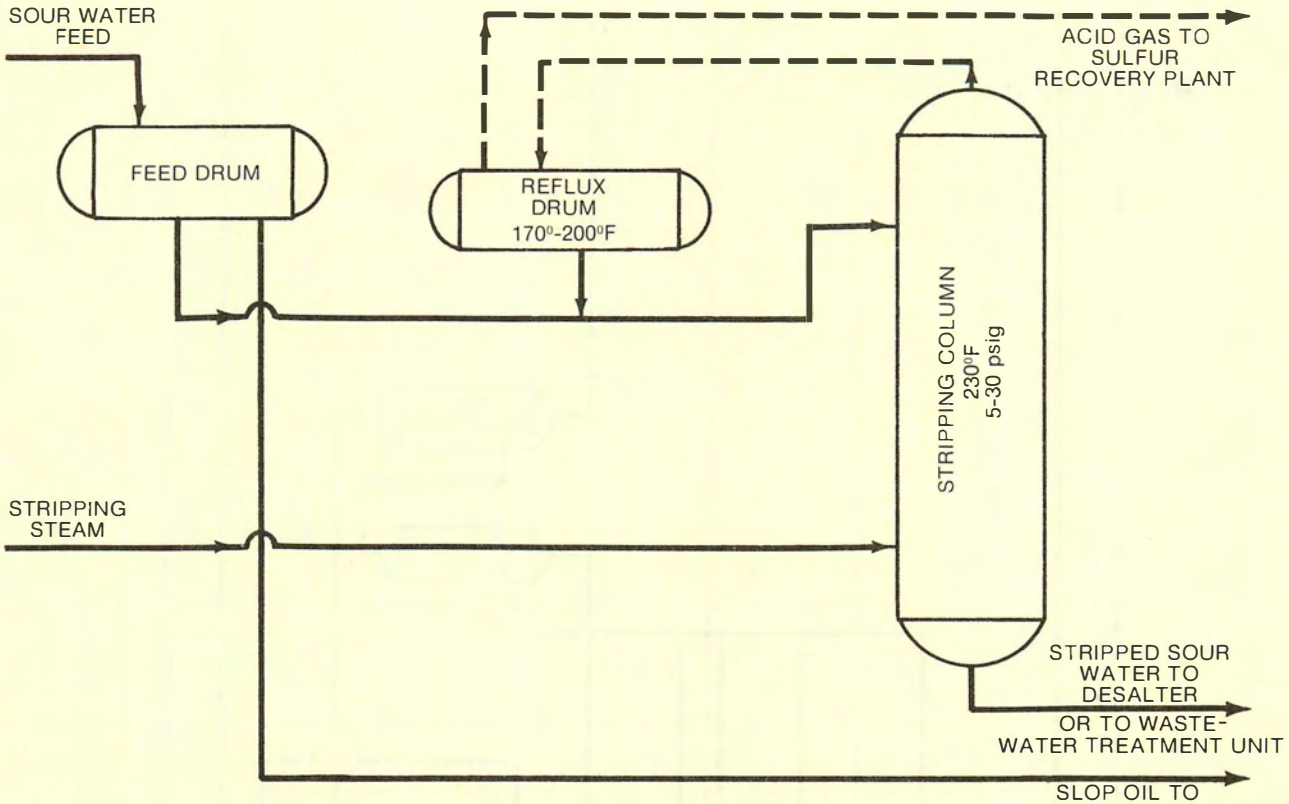


Figure C-25. Sour Water Stripping Unit.

Refinery Offsite Facilities

Although the offsite equipment and facilities do not enter directly into the operations of the various process units, they are critical to the operation of the refinery.

STORAGE TANKS

Tankage in a refinery is required for storage of crude oil and intermediate and finished products, in both liquified and gaseous forms. The requirement for tankage will vary, depending upon such factors as the storage levels for crude oil, the number of products and their storage levels, and the variety of blending and intermediate stocks.

Many tank designs are available for storage of liquid products and gases. The type of storage required will depend primarily upon the vapor pressure and pour point of the material. To minimize hydrocarbon emissions, products such as motor gasoline are stored in floating roof tanks. A number of tanks are equipped with steam coils and are insulated to store products such as highly viscous oils and asphalt. Products with low vapor pressure are stored in fixed roof tanks.

STEAM GENERATING SYSTEMS

Steam is needed for many of the refinery processes. These include steam distillation, steam stripping, steam-jet eductors for vacuum distillation, steam turbines for driving blowers and other equipment, steam reforming to produce hydrogen, and power generation.

Steam is provided to the refinery processes through either a closed loop or an open loop system. In the closed loop system, the steam generated yields its heat to the product process streams in heat exchangers by condensation. The steam condensate is then returned to the boiler. The open system uses steam for stripping in fractionating towers, for example, and the steam lost is made up by feedwater to the boiler.

Figure C-26 shows a typical steam generation system. Fresh make-up water is first treated by softening and de-ionization to achieve the desired feedwater quality. After treatment, the fresh water is preheated with the boiler blowdown and pumped to the de-aerator to remove dissolved oxygen. The treated make-up water is then mixed with the returned condensate and pumped to the boiler.

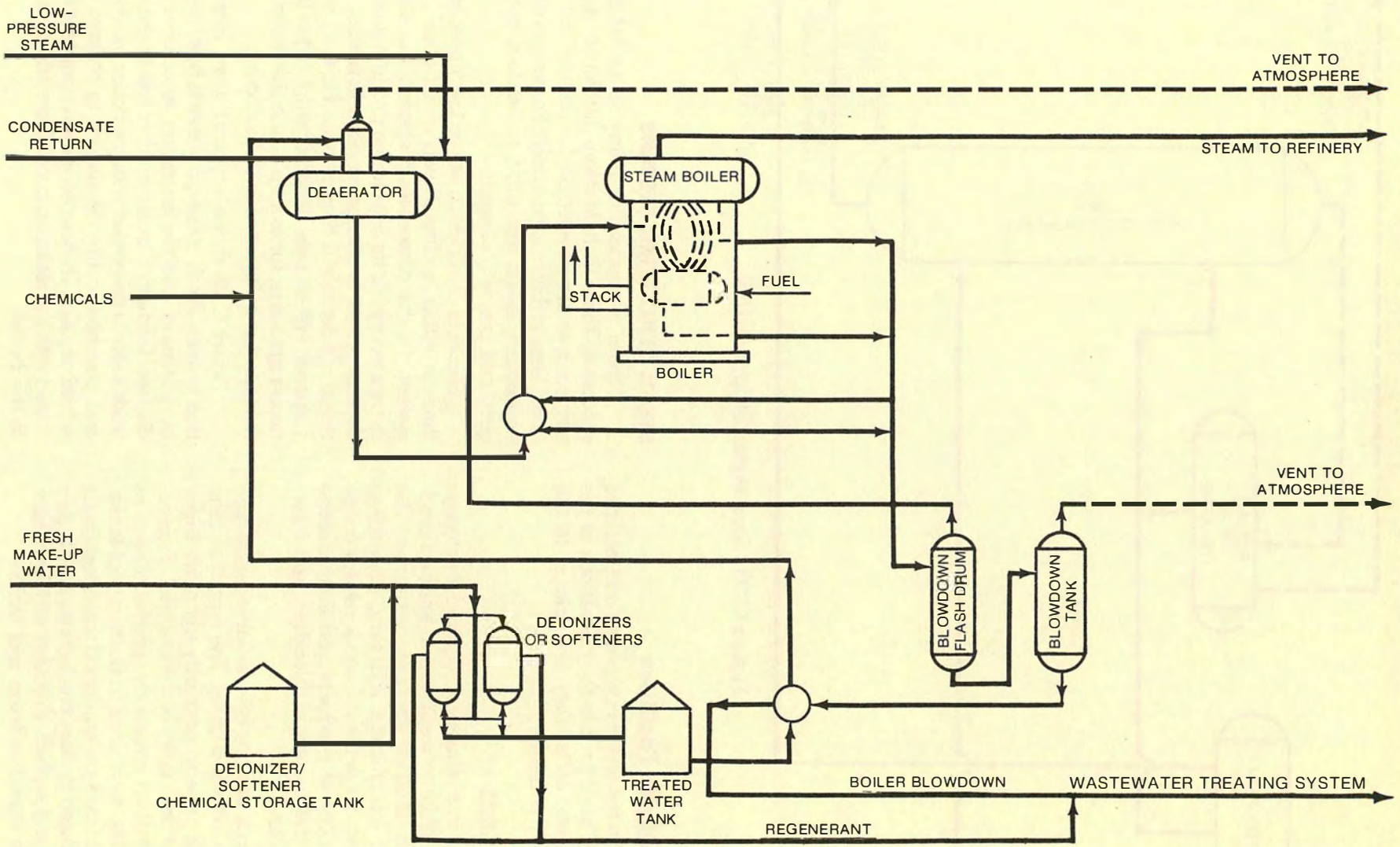


Figure C-26. Steam Generation System.

FLARE AND BLOWDOWN SYSTEMS

The flares are the main safety valves for the refinery operation. They safeguard personnel and protect the plant from damage during process unit upsets and plant emergency conditions, such as power failures and extreme pressure conditions in process units. To protect the refinery equipment from damage, and for operating safety, pressure relief valves are set below the design pressure of the equipment.

Basically, a flare system consists of piping to collect the gases, devices to remove entrained liquid, and a terminal burner operating in the open with no provision to recover heat or to treat the combustion products. As shown in Figure C-27, the system consists of the following elements:

- Flare header from the process units
- Knockout drums to remove and store condensable and entrained liquids
- Proprietary seal, drum, or purge gas to prevent flashback
- Flare stack to raise the burner to the desired height
- Gas pilots and an igniter
- Steam injection for smokeless flaring.

Under emergency conditions, the released hydrocarbons flow from the flare header to a knockout drum, where entrained liquids are separated. The vapors from the drum flow through a liquid seal to the flare and are burned. Steam is injected into the flare gas or flame to provide a smokeless exhaust. The liquid is pumped to the slop oil system for reprocessing. This system avoids the uncontrolled discharge of hydrocarbons to the wastewater treatment system, the release of hydrocarbon to the air, and the loss of valuable petroleum material.

Several types of flares are available, but all must operate safely and efficiently under widely varying conditions. The flow of waste gas can range from almost zero, when the only discharges are leakages from relief valves, to very large quantities in emergencies. Further, the required capacity of the flare varies with the crude oil throughput, the complexity of refining, and capacity of the recovery system.

Since it is difficult to design a single flare to handle efficiently such extreme variations in flow, many systems have two flares. One flare is designed to provide smokeless combustion for the normal flow, and the other is activated to handle excess flow resulting from an emergency. There

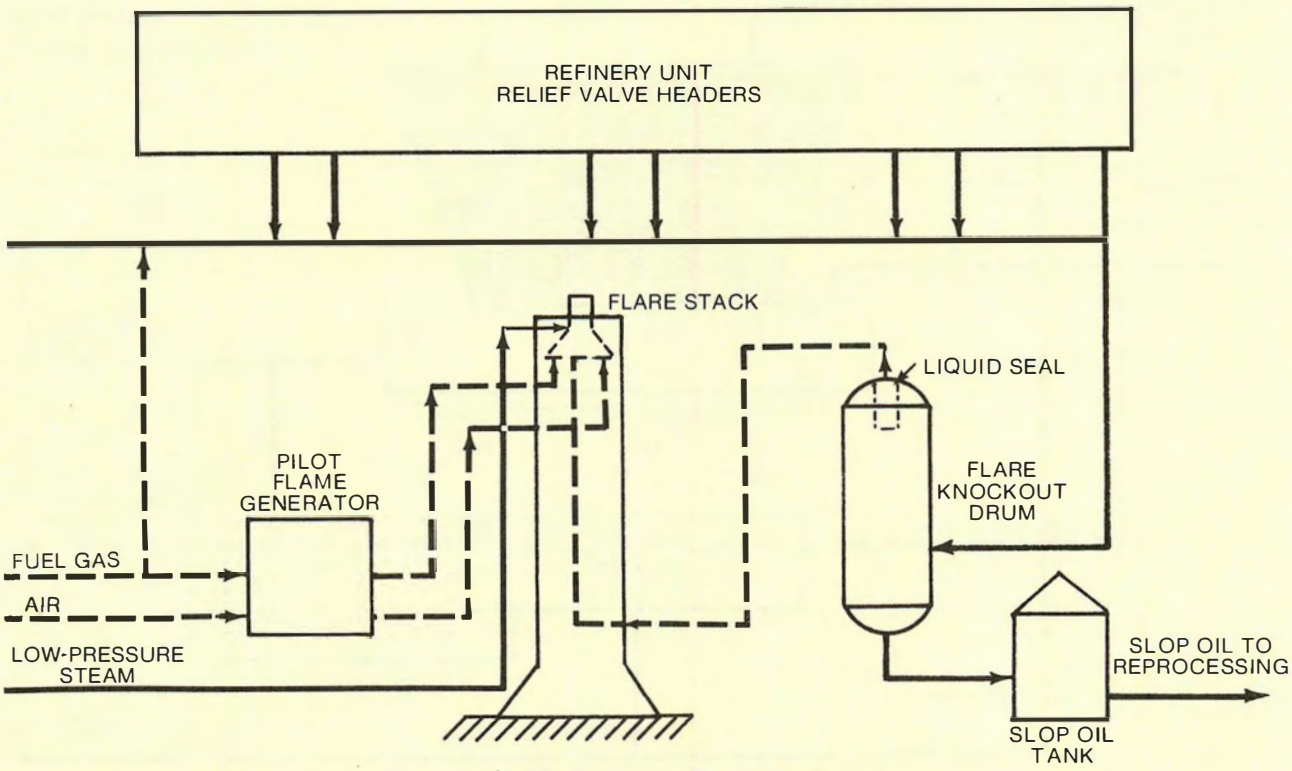


Figure C-27. Refinery Flare System.

also may be flares designed to serve single specialized units.

COOLING WATER SYSTEMS

Water is typically used for removing heat from the various product streams. Fans are employed, however, for air cooling in some refineries to reduce water requirements and effluent volume. Figure C-28 is an illustration of a typical water cooling system. Most systems are recirculating systems similar to the one shown in the diagram. Water from the cooling tower basin is circulated to heat exchangers, where it picks up heat and returns to the top of the cooling tower. The tower, which is open to the atmosphere, contains a wood or plastic packing, which provides the surface necessary to maintain high heat-transfer efficiency. Air is either forced or flows by natural convection countercurrent to water, and the water is cooled by evaporating a portion of the water.

RECEIVING AND DISTRIBUTION SYSTEMS

Receiving and distribution systems are a combination of pumps, pipelines, storage tanks, barges, tankers, tank cars, tank trucks, and loading and unloading facilities. These facilities are used to receive and collect materials, crude oil, and products, and to distribute final products to the consumer by pipeline to trucks, tank cars, barges, and tankers.

REFINERY FIRE CONTROL SYSTEMS

Most refineries are completely equipped and maintain trained personnel to fight a fire should one occur. The refinery fire water system is a separate system with designated storage, pumps, and piping. Process areas maintain permanent installed water spray devices called monitors, which provide virtually instantaneous fire-fighting capability. Sewer systems, particularly those in process areas, are designed with seals, covers, traps, fire baffles, etc., to prevent the spread of fire between areas. Refineries maintain a foam system, fire trucks, and other fire-fighting equipment. Appropriate training is an essential ingredient of fire protection.

CRUDE OIL CHARACTERISTICS

Crude oil is a substance comprised of a complex mixture of hydrocarbons, which are molecules consisting almost solely of carbon and hydrogen atoms in various arrangements. Crude

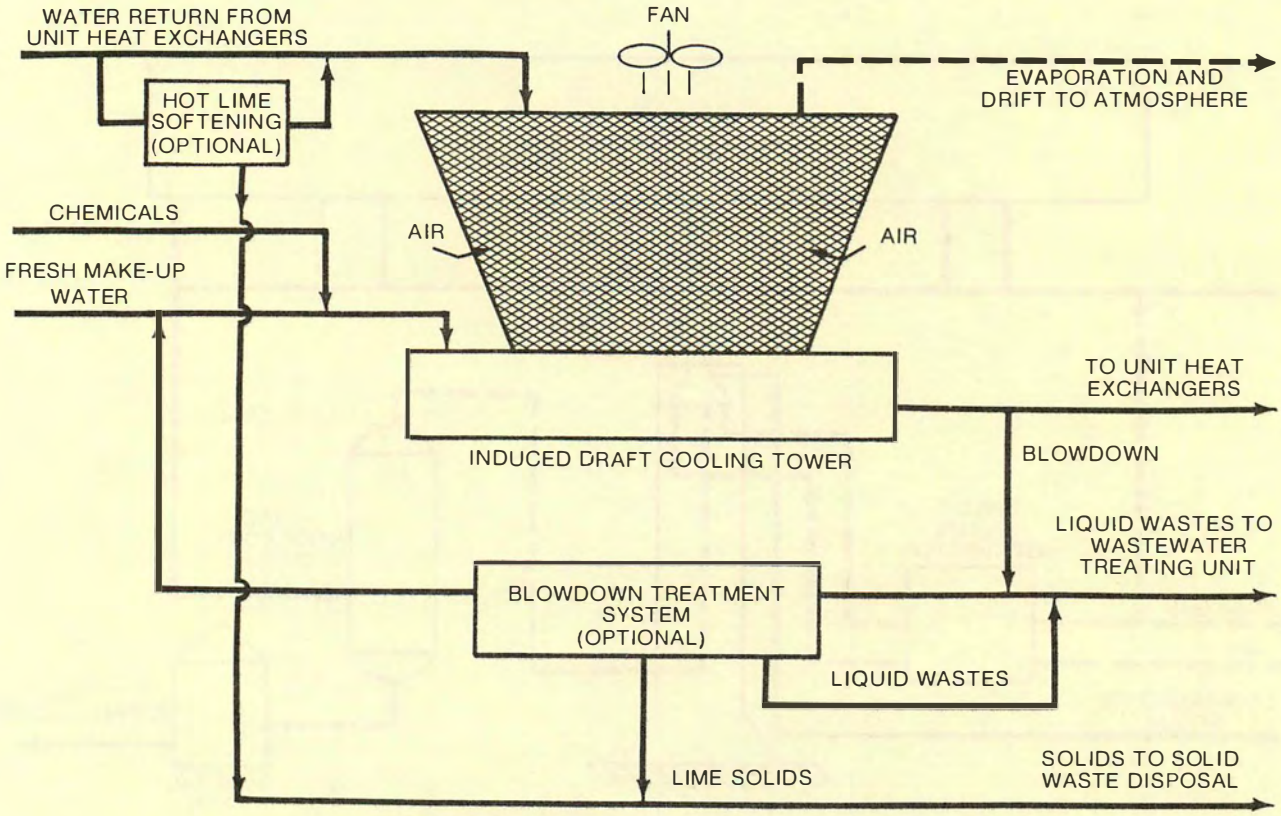


Figure C-28. Recirculating Water Cooling System.

oil contains thousands of different molecules of varying sizes, their size being determined by the number of carbon and hydrogen atoms aggregated together. As a result of the different sizes and configurations, the molecules boil at different temperatures. It can be assumed that most of the molecules boil between 100°F and something in excess of 1,500°F. Due to the complexity of the hydrocarbon mixtures, only a few of the smaller, lower boiling molecules can be identified. The characteristics and yields of a range of crude oils are presented in Table C-1.

Paraffinic-type crude oil is generally of high °API gravity and low in sulfur content, and contains a lesser amount of other contaminants such as metals and nitrogen. The straight-run gasoline derived from this type of crude oil is low in octane quality. The naphtha fraction is a poor reformer charge stock but an excellent SNG feedstock and cracking stock for olefins. The heavy naphtha and kerosene fractions give problems in meeting product freeze point specifications, and the diesel fuel fractions have problems in meeting pour point specifications. The residual fuel oils also have high pour points, and the asphalt quality is often poor. However, the heavy naphtha and kerosene have good smoke point characteristics, and the heavy naphtha, kerosene, and light gas oil have high cetane indices. The volumes of residuals are low and often can be cracked without too much penalty.

The physical properties of naphthenic crude oils vary widely between different producing fields. They are generally of low °API gravity, may be either high or low in sulfur content, and are often high in nitrogen and metals. The straight-run gasolines from this source are higher in octane but often of lesser volume. The naphtha is excellent reforming charge stock. The heavy naphtha has a poor smoke point and cetane index, and should be reformed. The kerosene and light gas oils have very poor cetane indices and are not suitable for domestic distillates. Pour points and freeze points of this latter fraction are very low. The residual fuel oil may be of high or low volume, high or low sulfur content, and high in metal content. The metals are corrosive to boiler tubes, and the use of high-sulfur fuel oils is becoming more restrictive. These crude oils are the source of naphthenic lubricating oils, and their asphalt quality is often good.

Intermediate-type crude oils are, as their name implies, somewhere in between the paraffinic- and naphthenic-type crude oils. These crude oils generally will fall in the medium to high gravity range. Sulfur content may fall between 0.1 and 2.5 wt.% sulfur. The distillate from these crude oils generally has pour point and cetane index characteristics suitable for burning oil and diesel fuel.

In addition to the paraffinic, naphthenic, and intermediate types of crude oils already discussed, there exist many combinations of these crude oils.

Crude oils are also classified as low-sulfur content (below 0.5 wt.% sulfur), intermediate-sulfur content (between 0.5 and 1.0 wt.% sulfur), and high-sulfur content (over 1.0 wt.% sulfur). In general, the definition of a sweet crude oil is one that does not contain hydrogen sulfide and has below 0.5 wt.% sulfur content, with only a minor portion of the sulfur content being present as mercaptans. Mercaptans (sulfur compounds) are the most malodorous contaminants of crude oil and petroleum products.

PRODUCT CHARACTERISTICS

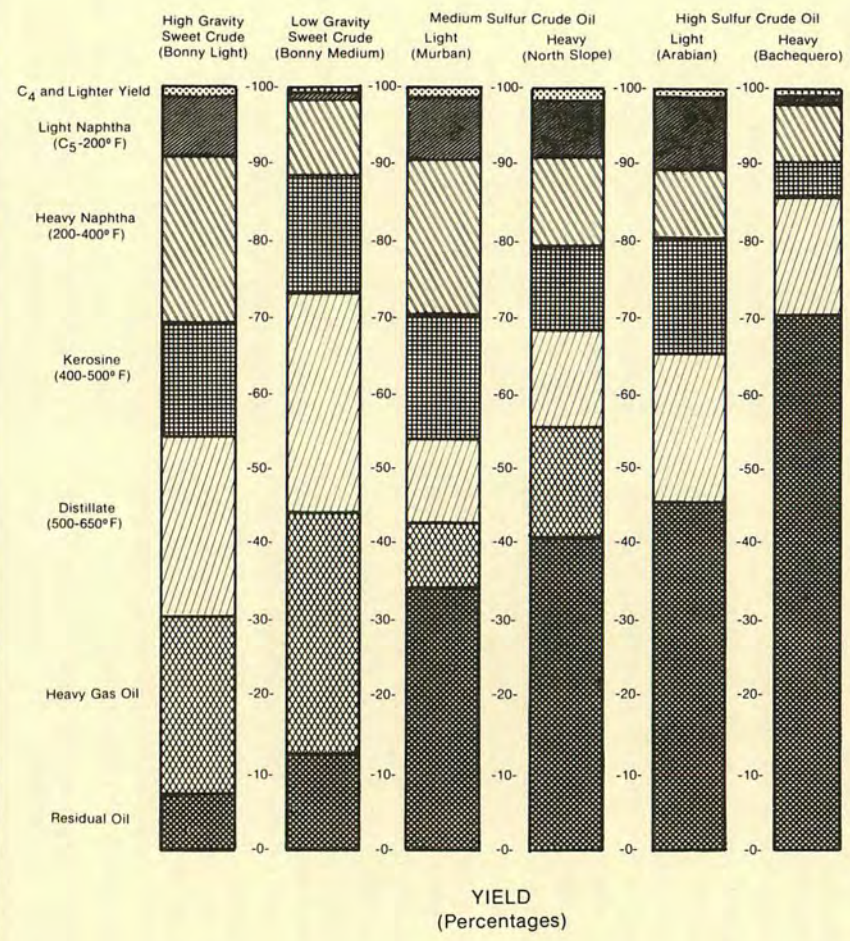
Motor Fuels

MOTOR GASOLINE

Since World War II, gasoline has changed in hydrocarbon composition and is now a product made by blending of refinery stock prepared by involved processes and special additives developed in extensive research programs. The most outstanding change in gasoline in recent years has been a vast improvement in antiknock quality. Since 1970 the compression ratio of automobiles has reduced the octane number requirement for motor gasoline to permit lead removal from gasoline. Subsequent to 1974, the octane number has remained virtually the same, but the unleaded pool octane has increased as lead has been removed. During this same period, the control of gasoline volatility has improved, contributing to better engine performance.

Federal air quality regulations limit the lead alkyl content of motor gasolines. Only one grade of unleaded gasoline was available for public use in mid-1974; however, unleaded gasolines constitute an increasing portion of gasoline consumption (increasing from 34 percent in 1978 to 65 percent in 1985). Production of these types of fuels is projected to increase. Such motor fuel characteristics as sulfur content, volatility, and boiling range may require further modifications to satisfy automotive performance and automobile pollution control needs.

TABLE C-1
CHARACTERISTICS AND YIELDS OF SELECTED CRUDE OILS



	High Gravity Sweet Crude (Bonny Light)	Low Gravity Sweet Crude (Bonny Medium)	Medium Sulfur Crude Oil		High Sulfur Crude Oil	
			Light (Murban)	Heavy (North Slope)	Light (Arabian)	Heavy (Bachequero)
Crude Oil						
Gravity (°API)	37.6	26.0	39.4	26.8	33.4	16.8
Sulfur (Wt.%)	0.13	0.23	0.74	1.0	1.80	2.40
Pour Point (°F)	5	<-5	+5	-5	-30	-10
Sulfur Range (Wt.%)	0-0.5	0-0.5	0.51-1.0	0.51-1.0	1.0+	1.0+
C_4 and Lighter Yield	2.2	0.7	1.8	1.8	1.7	0.4
Light Naphtha (C_5-200°F)						
Yield (Vol.%)	6.4	2.1	6.78	5.8	9.0	2.5
Gravity (°API)	79.9	79.2	82.2	68.3	78.5	65.0
Sulfur (Wt.%)	0.0002	0.001	0.012	0.01	0.024	—
Naphthenes (Vol.%)	21.5	24	—	30.0	10.4	51.9
Aromatics (Vol.%)	1.5	3	—	—	2.4	4.7
Paraffins (Vol.%)	77.0	73	—	48.8	87.2	43.4
Octane No. (RONC)	78	80	69	65	54.7	—
Heavy Naphtha (200-400°F)						
Yield (Vol.%)	22.0	8.7	21.2	12.6	8.4	6.0
Gravity (°API)	53.6	50.1	56.9	49.7	59.6	49.0
Sulfur (Wt.%)	0.003	0.01	0.013	0.02	0.027	—
Naphthenes (Vol.%)	55	58.5	20	56.4	18.2	58.5
Aromatics (Vol.%)	11	14.0	17	—	12.3	13.9
Paraffins (Vol.%)	34	27.5	63	43.6	69.5	27.6
Kerosene (400-500°F)						
Yield (Vol.%)	15.4	14.7	16.14	12.3	15.0	5.0
Gravity (°API)	40.2	34.4	45.4	37.4	38.5	36.4
Sulfur (Wt.%)	0.03	0.063	0.058	0.20	0.094	0.48
Pour Point (°F)	-70	<-70	—	—	—	-80
Distillate (500-650°F)						
Yield (Vol.%)	23.2	29.7	10.4	12.1	19.8	15.5
Gravity (°API)	33.2	27.5	37.8	31.3	37.1	—
Sulfur (Wt.%)	0.13	0.18	0.47	0.56	1.05	0.99
Cetane No.	51	40.0	54	47	—	—
Pour Point (°F)	20	-15	0	—	0	—
Viscosity (@ 100°F)	40.3 SUS	44.6 SUS	4.2 cSt	—	3.28 cSt	—
Heavy Gas Oil					*	*
Yield (Vol.%)	23.1	31.3	9.24	14.7		
Gravity (°API)	25.4	19.7	33.6	25.8		
Sulfur (Wt.%)	0.21	0.31	1.06	0.90		
Pour Point (°F)	105	80	41	55		
Viscosity (@ 210°F)	48.1 SUS	53.1 SUS	—	77 SUS 100°F		
Residual Fuel Oil						
Yield (Vol.%)	7.7	12.8	34.5	40.7	46.1	70.6
Gravity (°API)	11.8	10.1	22.6	13.0	17.6	—
Sulfur (Wt.%)	0.39	0.48	1.49	1.74	3.08	3.0
Pour Point (°F)	—	—	85	475	40	60
Viscosity (@ 210°F)	2,030 SUS	3,690 SUS	—	391 SUS	21 cSt	—
Total (%)	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**

*Data for Heavy Gas Oil included in Residual Fuel Oil.

DIESEL FUELS

Like gasoline, distillate fuels for use in automotive diesel engines have been improved during the past several years to meet requirements imposed by changes in engine design and operation. The most significant change in diesel fuels has been the use of hydrogen treating in refineries, primarily to reduce sulfur content. In addition, fuels have been gradually improved, resulting in decreased engine deposits, smoke, and odor. Railroad diesel fuels have not changed significantly as the large diesel engines used in railroad service operate satisfactorily on fuels with less exacting specifications.

The use of additives in diesel fuels has become more common to provide improvement such as lower pour points, ignition quality, and storage stability. Air pollution regulations have generated an increased interest in anti-smoking additives.

Aviation Fuels

AVIATION GASOLINE

Quality control is particularly important in aviation gasoline production. Other important quality factors are volatility, freezing point, heat of combustion, and oxidation stability. Quality control surveillance and close process control enable the industry to produce a uniform-quality premium product.

JET FUELS

Commercial kerosene was first used as a fuel in early development on jet aircraft, since it provided the necessary volatility and was a readily available commercial product of rather uniform characteristics. Jet fuels are exposed to both high and low temperatures in use; therefore, these fuels must have very low freezing points and must be stable when exposed to high temperatures. The JP-4 and JP-5 military jet fuels and equivalent commercial fuels have thermal stability properties satisfactory for operations up to speeds of Mach 2.

Industrial and Heating Fuels

LIQUIFIED PETROLEUM GAS

The extensive use of catalytic cracking and catalytic reforming processes and the growth in hydrocracking have resulted in large quantities of LPG in addition to the production from natural gas processing. Prior to the use of LPG in ethylene production, its major use was in household and industrial fuel, although LPG has long been used to a limited extent as a motor fuel.

DISTILLATE FUEL OIL

Distillate fuel oil can be defined as Nos. 1, 2, and 4 heating oils, diesel oil, and industrial distillates. Grade No. 2 fuel oil is the designation given to the heating or furnace oil most commonly used for domestic and small commercial space heating.

The period since World War II has seen marked changes in both the quality of home heating oils and the manufacturing techniques employed in producing them. Domestic heating oil should form no sediment in storage and leave no measurable quantity of ash or other deposits on burning. It should be fluid at storage conditions encountered during the winter months. The composition of the product must be controlled to assist in reducing smoke emission. Low sulfur content has become quite important. The fuel must have a light color, an attractive appearance, and an acceptable odor. It is these properties, along with sulfur removal, that have undergone the greatest changes in the past 20 years.

In the early 1950s, hydrogen treating was adopted as a means of reducing the sulfur and nitrogen compounds content of distillate fuel oil. Through the use of this process, carbon residue is reduced to less than 0.10 percent. Hydrogen-treated products are of excellent quality from the standpoint of a change in both color and sludge formation during storage.

RESIDUAL FUELS

Residual fuel oil can be defined as Nos. 5 and 6 heating oils, heavy diesel, heavy industrial, and Bunker C fuel oils. Typically, these fuels are used to provide steam and heat for industry and large buildings, to generate electricity, and to power ships.

Since World War II, refining processes in the United States have continued to favor the breaking up of the heavier residuum into lighter petroleum products until residual fuel amounts to less than 10 percent of the crude oil refined. The desulfurization of high-metal-content fuel oil and stack gas desulfurization has become widespread.

Other Petroleum Products

PETROCHEMICAL FEEDSTOCKS

Petrochemical feedstocks, such as benzene, toluene, xylene, ethane, and propane, are used in such diverse products as synthetic rubber, synthetic fibers, and plastics. Tremendous growth in the petrochemical industry over the last 10 years has resulted in many new and improved uses for petrochemicals.

LUBRICANTS

Lubricants fall generally into three categories: automotive oils, industrial oils, and greases. Engine oils, gear oil, and automatic transmission fluids are three major lubrication products used in automotive operations. These products function to lubricate, seal, cool, clean, protect, and cushion. Industrial oils are formulated to perform a broad range of functions under a variety of operating conditions. The major functions provided include lubrication, friction modification, heat transfer, dispersancy, and rust prevention. Greases are basically gels and are composed of lubricating oil in a semi-rigid network of gelling agents such as soaps, clays, and more recently, totally organic substances.

PETROLEUM SOLVENTS

A variety of petroleum solvents are produced, and critical specifications are largely a function of the end-product use. For example, rigid specifications are required for petroleum solvents used in the paint industry. These products must contain no materials that would discolor pigments and must possess low odor for interior paints. Control devices make it possible to maintain consistent product quality even under the most rigid specifications.

ASPHALT

The heaviest fractions of a great many crude oils include natural bitumens or asphaltenes and are generally called asphalt. Actually this material is the oldest product of petroleum and has been used throughout recorded history. However, new uses and new demands for asphalt are continually being developed. The industry has satisfied these demands by changing processing and types of crude oils and by improving storage, transportation, and blending facilities.

APPENDIX D

Aggregated Data from the NPC's 1985 Survey of U.S. Petroleum Refineries

The following data represent the aggregations of the responses from 181 U.S. refiners to the NPC's 1985 Survey of U.S. Petroleum Refineries. (This does not include refineries in the U.S. Virgin Islands, Puerto Rico, Guam, and the Hawaiian Foreign Trade Zone.) The aggregated data are presented as summations or averages as appropriate, e.g., process unit capacities, charge, and yield information are summations; octane, feedstock composition, and process energy production and consumption information are averages.

In most cases, a three line format is used to present data from each cell in the survey. This format permits presentation of data indicating the:

- Response
- Number of refineries for which responses were received for that cell
- Associated crude oil charge capacity of those refineries for which responses were received for that cell.

Care must be exercised when interpreting these data. When comparing two cells, bear in mind that different refineries with different crude oil charge capacities may be represented even where the number of refineries or associated crude oil charge capacity are the same. Also, in some cases, process unit utilizations may appear to be greater than 100 percent. Since capacity figures are given as of January 1, and utilization is the average of the entire year, this would indicate the addition of one or more units after January 1.

Separate aggregations for the 12 region/complexity groups, the Los Angeles Basin, and the offshore U.S. refineries are available from the NPC. An order form is included at the back of this report.

NATIONAL PETROLEUM COUNCIL
1985 SURVEY OF U.S. PETROLEUM REFINERIES
ALL U.S. RESPONDENTS*

PART I: CURRENT AND FIRMLY COMMITTED FACILITIES

January 1, 1985 Associated Crude Oil Charge Capacity (MB/CD)	15,313.8
Number of Respondent Refineries	181

*Does not include respondent refineries in the U.S. Virgin Islands, Puerto Rico, Guam, and the Hawaiian Foreign Trade Zone.

NATIONAL PETROLEUM COUNCIL
SURVEY OF U.S. PETROLEUM REFINERIES
* ALL U.S. RESPONDENTS *

SECTION A: PROCESS FACILITIES CAPABILITIES

GIVEN ANTICIPATED FEEDSTOCK QUALITIES, PROCESS OPERATING CONDITIONS, AND ENVIRONMENTAL CONSTRAINTS, LIST MAXIMUM OPERABLE PROCESS UNIT CAPACITIES AND OTHER SPECIFIED UNIT CAPABILITIES IN PLACE AS OF JANUARY 1,1984, OR UNDERWAY OR FIRMLY PLANNED FOR COMPLETION ON OR BEFORE JANUARY 1, 1986 AND JANUARY 1, 1988. ALSO REPORT ACTUAL UTILIZATION IN 1984 AND ESTIMATED UTILIZATION IN 1988.

	OPERABLE CAPACITIES *			CAPACITY UTILIZATION *	
	1/1/84	1/1/86	1/1/88	1984	1988
1. ATMOSPHERIC DISTILLATION	14,798.3	14,791.9	14,616.6	11,907.0	12,511.0
NO. REFINERIES	176	171	170	172	165
OTHER UNITS THAT NORMALLY CHARGE WHOLE CRUDE	90.6	110.8	85.8	44.7	60.6
NO. REFINERIES	7	7	6	7	7
2. VACUUM DISTILLATION	6,220.8	6,213.0	6,123.4	4,801.2	5,038.3
NO. REFINERIES	141	138	137	133	128
ASSOCIATED CRUDE CHARGE	13,809.0	13,805.5	13,545.5	13,596.7	13,202.1
3. CATALYTIC REFORMING					
CONTINUOUS REGENERATION					
CURRENT OR ANTICIPATED SEVERITY(RONC) (1)	97.02	97.78	98.00	96.96	98.48
NAPHTHA CHARGE CAPACITY	1,394.2	1,387.2	1,359.5	1,080.7	1,206.1
NO. REFINERIES	41	42	41	41	42
ASSOCIATED CRUDE CHARGE	7,051.8	7,088.4	6,850.2	7,051.8	6,850.2
MAXIMUM SEVERITY(RONC) (1)	100.48	100.58	100.56		
NAPHTHA CHARGE CAPACITY	1,246.5	1,258.8	1,241.8		
NO. REFINERIES	41	42	41		
ASSOCIATED CRUDE CHARGE	7,051.8	7,088.4	6,850.2		
FEEDSTOCK COMPOSITION, % NAPTHENES	35.26	35.08	34.90	35.19	34.93
FEEDSTOCK COMPOSITION, % AROMATICS	14.99	14.63	14.67	15.06	15.18
NO. REFINERIES	41	42	41	41	42
ASSOCIATED CRUDE CHARGE	7,051.8	7,088.4	6,850.2	7,051.8	6,850.2

* ALL UNITS IN MB/CD UNLESS OTHERWISE NOTED
(1) RONC OF C5+ (DEBUTANIZED) REFORMATE

NATIONAL PETROLEUM COUNCIL
SURVEY OF U.S. PETROLEUM REFINERIES
* ALL U.S. RESPONDENTS *

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	OPERABLE CAPACITIES *			CAPACITY UTILIZATION *	
	1/1/84	1/1/86	1/1/88	1984	1988
3. CATALYTIC REFORMING					
SEMI-REGENERATIVE					
CURRENT OR ANTICIPATED SEVERITY(RONC) (1)	93.64	95.72	95.76	93.10	96.05
NAPHTHA CHARGE CAPACITY	1,969.7	1,847.5	1,888.5	1,364.0	1,569.8
NO. REFINERIES	104	101	101	102	98
ASSOCIATED CRUDE CHARGE	9,569.1	9,242.7	9,269.7	9,312.4	8,968.9
MAXIMUM SEVERITY(RONC) (1)	97.56	97.88	97.88		
NAPHTHA CHARGE CAPACITY	1,800.0	1,728.2	1,752.6		
NO. REFINERIES	104	101	101		
ASSOCIATED CRUDE CHARGE	9,569.1	9,242.7	9,269.7		
FEEDSTOCK COMPOSITION, % NAPTHENES	37.62	37.35	37.48	37.62	38.02
FEEDSTOCK COMPOSITION, % AROMATICS	13.41	13.58	13.47	13.95	12.97
NO. REFINERIES	104	101	101	102	98
ASSOCIATED CRUDE CHARGE	9,569.1	9,242.7	9,269.7	9,312.4	8,968.9

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(1) RONC OF C5+ (DEBUTANIZED) REFORMATE

NATIONAL PETROLEUM COUNCIL
SURVEY OF U.S. PETROLEUM REFINERIES
* ALL U.S. RESPONDENTS *

SECTION A: PROCESS FACILITIES CAPABILITIES
GIVEN ANTICIPATED FEEDSTOCK QUALITIES, PROCESS OPERATING CONDITIONS, AND ENVIRONMENTAL CONSTRAINTS, LIST MAXIMUM OPERABLE PROCESS UNIT CAPACITIES AND OTHER SPECIFIED UNIT CAPABILITIES IN PLACE AS OF JANUARY 1,1984, OR UNDERWAY OR FIRMLY PLANNED FOR COMPLETION ON OR BEFORE JANUARY 1, 1986 AND JANUARY 1, 1988. ALSO REPORT ACTUAL UTILIZATION IN 1984 AND ESTIMATED UTILIZATION IN 1988.

	OPERABLE CAPACITIES *			CAPACITY UTILIZATION *	
	1/1/84	1/1/86	1/1/88	1984	1988
4. C4 ISOMERIZATION	59.4	54.5	54.5	32.8	38.5
NO. REFINERIES	19	17	17	16	14
ASSOCIATED CRUDE CHARGE	1,566.7	1,338.7	1,348.2	1,228.3	1,089.1
5. C5/C6 ISOMERIZATION	111.8	214.3	268.1	57.5	228.2
PRODUCT RONC	87.85	85.45	84.99	88.12	84.85
NO. REFINERIES	9	19	27	7	27
ASSOCIATED CRUDE CHARGE	1,451.2	3,037.2	3,802.7	1,284.1	3,802.7
6. CATALYTIC HYDROTREATING					
NAPHTHA	3,368.4	3,308.2	3,301.3	2,436.6	2,627.9
NO. REFINERIES	120	119	118	120	118
ASSOCIATED CRUDE CHARGE	12,723.5	12,729.7	12,539.9	12,723.5	12,495.8
KEROSENE	901.8	865.9	867.7	564.0	557.5
NO. REFINERIES	47	45	45	46	43
ASSOCIATED CRUDE CHARGE	6,939.6	6,926.3	6,886.8	6,559.5	6,704.2
DISTILLATE	1,617.5	1,621.9	1,601.7	1,076.5	1,195.5
NO. REFINERIES	79	80	78	78	74
ASSOCIATED CRUDE CHARGE	10,246.1	10,400.0	10,114.8	10,264.8	9,706.6
HEAVY GAS OIL	1,431.5	1,524.9	1,525.5	1,113.8	1,229.9
NO. REFINERIES	50	53	52	49	47
ASSOCIATED CRUDE CHARGE	6,664.8	7,191.4	6,987.9	6,793.6	6,460.0
ATMOSPHERIC RESID	240.4	240.7	179.7	211.5	154.8
NO. REFINERIES	6	6	5	6	5
ASSOCIATED CRUDE CHARGE	985.4	985.4	491.4	985.4	491.4
VACUUM RESIDUUM	0.0	.	.	0.0	.
NO. REFINERIES	0	1	1	0	1
ASSOCIATED CRUDE CHARGE	0.0	.	.	0.0	.

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NATIONAL PETROLEUM COUNCIL
SURVEY OF U.S. PETROLEUM REFINERIES
* ALL U.S. RESPONDENTS *

SECTION A: PROCESS FACILITIES CAPABILITIES
GIVEN ANTICIPATED FEEDSTOCK QUALITIES, PROCESS OPERATING CONDITIONS, AND ENVIRONMENTAL CONSTRAINTS, LIST MAXIMUM OPERABLE PROCESS UNIT CAPACITIES AND OTHER SPECIFIED UNIT CAPABILITIES IN PLACE AS OF JANUARY 1,1984, OR UNDERWAY OR FIRMLY PLANNED FOR COMPLETION ON OR BEFORE JANUARY 1, 1986 AND JANUARY 1, 1988. ALSC REPORT ACTUAL UTILIZATION IN 1984 AND ESTIMATED UTILIZATION IN 1988.

	OPERABLE CAPACITIES *			CAPACITY UTILIZATION *	
	1/1/84	1/1/86	1/1/88	1984	1988
7. CATALYTIC CRACKING					
FRESH FEED RATE	4,905.2	4,934.5	4,911.9	4,103.5	4,359.0
NO. REFINERIES	116	115	114	116	114
ASSOCIATED CRUDE CHARGE	13,474.1	13,483.2	13,280.2	13,474.1	13,236.1
FRESH FEED COMPOSITION					
VIRGIN GAS OILS, VOL. %	70.39	70.54	70.44	70.22	71.56
NO. REFINERIES	107	106	105	108	106
ASSOCIATED CRUDE CHARGE	13,113.4	13,122.5	12,919.5	13,157.5	12,919.5
THERMAL GAS OIL, VOL. %	10.23	10.44	10.19	10.20	10.50
NO. REFINERIES	47	47	46	47	47
ASSOCIATED CRUDE CHARGE	7,664.5	7,775.6	7,539.4	7,528.5	7,534.4
ATMOSPHERIC RESID, VOL. %	9.31	8.71	8.58	9.33	7.67
NO. REFINERIES	37	33	32	39	32
ASSOCIATED CRUDE CHARGE	3,717.7	3,330.0	3,140.5	3,871.2	2,996.6
DEASPHALTED OIL, VOL. %	1.88	2.14	2.35	1.92	2.26
NO. REFINERIES	22	23	24	22	22
ASSOCIATED CRUDE CHARGE	2,438.0	2,555.5	2,676.8	2,438.0	2,033.1
VACUUM RESID, VOL. %	2.46	2.39	2.50	2.58	2.79
NO. REFINERIES	20	21	22	22	23
ASSOCIATED CRUDE CHARGE	2,771.7	2,931.9	3,167.7	2,899.8	3,201.8
OTHER FRESH FEED, VOL. %	5.72	5.82	5.94	5.71	5.09
NO. REFINERIES	35	34	33	38	31
ASSOCIATED CRUDE CHARGE	5,992.7	6,105.4	5,910.3	6,206.1	5,621.2
FEEDSTOCK QUALITY					
API GRAVITY	24.74	24.55	24.65	24.70	24.52
NO. REFINERIES	116	115	114	116	114
ASSOCIATED CRUDE CHARGE	13,474.1	13,483.2	13,280.2	13,474.1	13,236.1
CONRADSON CARBON WT %	1.11	1.10	1.12	0.84	0.86
NO. REFINERIES	116	115	114	116	114
ASSOCIATED CRUDE CHARGE	13,474.1	13,483.2	13,280.2	13,474.1	13,236.1

* ALL UNITS IN MB/CD UNLESS OTHERWISE NOTED

NATIONAL PETROLEUM COUNCIL
SURVEY OF U.S. PETROLEUM REFINERIES
* ALL U.S. RESPONDENTS *

SECTION A: PROCESS FACILITIES CAPABILITIES
GIVEN ANTICIPATED FEEDSTOCK QUALITIES, PROCESS OPERATING CONDITIONS, AND ENVIRONMENTAL CONSTRAINTS, LIST MAXIMUM OPERABLE PROCESS UNIT CAPACITIES AND OTHER SPECIFIED UNIT CAPABILITIES IN PLACE AS OF JANUARY 1,1984, OR UNDERWAY OR FIRMLY PLANNED FOR COMPLETION ON OR BEFORE JANUARY 1, 1986 AND JANUARY 1, 1988. ALSO REPORT ACTUAL UTILIZATION IN 1984 AND ESTIMATED UTILIZATION IN 1988.

	OPERABLE CAPACITIES *			CAPACITY UTILIZATION *	
	1/1/84	1/1/86	1/1/88	1984	1988
7. CATALYTIC CRACKING (CONTINUED)					
PRODUCT YIELDS					
FUEL GAS, FOE VOL. %	4.93	4.90	4.85	5.05	5.01
NO. REFINERIES	112	112	111	112	111
ASSOCIATED CRUDE CHARGE	13,242.7	13,306.8	13,108.8	13,242.7	13,064.7
C3/C4 VOL % RECOVERED	23.11	23.34	23.50	22.97	23.24
NO. REFINERIES	116	115	114	116	114
ASSOCIATED CRUDE CHARGE	13,474.1	13,483.2	13,280.2	13,474.1	13,236.1
NAPHTHA, C5 -430 F, VOL %	56.63	56.75	56.70	56.40	56.56
NO. REFINERIES	116	115	114	116	114
ASSOCIATED CRUDE CHARGE	13,474.1	13,483.2	13,280.2	13,474.1	13,236.1
CYCLE OIL 430-630 F VOL %	20.93	20.20	20.16	20.96	20.11
NO. REFINERIES	116	115	114	116	114
ASSOCIATED CRUDE CHARGE	13,474.1	13,483.2	13,280.2	13,474.1	13,236.1
DECANT OIL VOL %	6.41	6.32	6.32	6.41	6.34
NO. REFINERIES	116	115	114	116	114
ASSOCIATED CRUDE CHARGE	13,474.1	13,483.2	13,280.2	13,474.1	13,236.1
COKE WT %	5.42	5.40	5.42	5.50	5.44
NO. REFINERIES	115	113	112	116	112
ASSOCIATED CRUDE CHARGE	13,209.4	13,359.7	13,156.7	13,474.1	13,112.6
CARBON BURNING CAPACITY	3,715.1	3,761.9	3,726.2	3,421.5	3,475.7
NO. REFINERIES	116	115	114	116	114
ASSOCIATED CRUDE CHARGE	13,474.1	13,483.2	13,280.2	13,474.1	13,236.1
RONC OF C5 +, NAPHTHA	91.21	91.32	91.37	91.25	91.41
NO. REFINERIES	116	115	114	116	114
ASSOCIATED CRUDE CHARGE	13,474.1	13,483.2	13,280.2	13,474.1	13,236.1
MONC OF C5 +, NAPHTHA	79.99	80.00	80.03	80.21	80.20
NO. REFINERIES	116	115	114	116	114
ASSOCIATED CRUDE CHARGE	13,474.1	13,483.2	13,280.2	13,474.1	13,236.1

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NATIONAL PETROLEUM COUNCIL
SURVEY OF U.S. PETROLEUM REFINERIES
* ALL U.S. RESPONDENTS *

SECTION A: PROCESS FACILITIES CAPABILITIES
GIVEN ANTICIPATED FEEDSTOCK QUALITIES, PROCESS OPERATING CONDITIONS, AND ENVIRONMENTAL CONSTRAINTS, LIST MAXIMUM OPERABLE PROCESS UNIT CAPACITIES AND OTHER SPECIFIED UNIT CAPABILITIES IN PLACE AS OF JANUARY 1,1984, OR UNDERWAY OR FIRMLY PLANNED FOR COMPLETION ON OR BEFORE JANUARY 1, 1986 AND JANUARY 1, 1988. ALSO REPORT ACTUAL UTILIZATION IN 1984 AND ESTIMATED UTILIZATION IN 1988.

	OPERABLE CAPACITIES *			CAPACITY UTILIZATION *	
	1/1/84	1/1/86	1/1/88	1984	1988
7. CATALYTIC CRACKING (CONTINUED)					
FRESH FEED HYDROTREATING					
VIRGIN GAS OILS, VOL. %	22.89	22.91	24.17	22.80	25.75
NO. REFINERIES	39	38	38	40	39
ASSOCIATED CRUDE CHARGE	6,732.6	6,767.5	6,719.1	6,846.6	6,719.1
THERMAL GAS OILS, VOL. %	22.65	25.17	25.93	20.67	25.78
NO. REFINERIES	21	22	22	21	21
ASSOCIATED CRUDE CHARGE	4,192.9	4,351.9	4,343.7	4,056.9	4,049.6
ATMOSPHERIC RESID, VOL. %	5.87	5.84	5.87	5.47	5.53
NO. REFINERIES	6	6	6	6	5
ASSOCIATED CRUDE CHARGE	1,188.1	1,183.1	1,089.1	1,188.1	844.1
DEASPHALTED OIL, VOL. %	.	5.05	5.07	.	5.09
NO. REFINERIES	2	4	4	2	4
ASSOCIATED CRUDE CHARGE	.	736.0	643.0	.	643.0
VACUUM RESID, VOL. %	2.27	2.26	2.27	2.17	3.49
NO. REFINERIES	3	3	3	3	4
ASSOCIATED CRUDE CHARGE	550.0	550.0	550.0	550.0	795.0
OTHER FRESH FEED, VOL %	5.20	6.38	6.48	7.01	8.53
NO. REFINERIES	10	11	11	10	9
ASSOCIATED CRUDE CHARGE	2,006.3	2,340.3	2,358.8	2,079.7	2,143.1

* ALL UNITS IN MB/CD UNLESS OTHERWISE NOTED

NATIONAL PETROLEUM COUNCIL
SURVEY OF U.S. PETROLEUM REFINERIES
* ALL U.S. RESPONDENTS *

SECTION A: PROCESS FACILITIES CAPABILITIES

GIVEN ANTICIPATED FEEDSTOCK QUALITIES, PROCESS OPERATING CONDITIONS, AND ENVIRONMENTAL CONSTRAINTS, LIST MAXIMUM OPERABLE PROCESS UNIT CAPACITIES AND OTHER SPECIFIED UNIT CAPABILITIES IN PLACE AS OF JANUARY 1,1984, OR UNDERWAY OR FIRMLY PLANNED FOR COMPLETION ON OR BEFORE JANUARY 1, 1986 AND JANUARY 1, 1988. ALSO REPORT ACTUAL UTILIZATION IN 1984 AND ESTIMATED UTILIZATION IN 1988.

	OPERABLE CAPACITIES *			CAPACITY UTILIZATION *	
	1/1/84	1/1/86	1/1/88	1984	1988
8. ALKYLATION, HYDROFLUORIC					
C5+ DEBUTANIZED PRODUCT FROM BUTYLENE	290.4	297.7	321.6	212.8	250.6
NO. REFINERIES	55	55	56	55	55
ASSOCIATED CRUDE CHARGE	4,974.3	5,058.5	5,462.3	4,974.3	5,418.2
C5+ DEBUTANIZED PRODUCT FROM PROPYLENE	122.5	128.2	128.7	83.4	112.5
NO. REFINERIES	38	38	38	39	40
ASSOCIATED CRUDE CHARGE	3,392.9	3,437.1	3,425.9	3,567.0	4,015.0
C5+ DEBUTANIZED PRODUCT, TOTAL	413.0	426.0	450.3	296.2	363.2
NO. OF REFINERIES	55	55	56	55	55
ASSOCIATED CRUDE CHARGE	4,974.3	5,058.5	5,462.3	4,974.3	5,418.2
RONC OF DEBUTANIZED PRODUCT	92.69	92.76	92.78	92.66	92.82
NO. REFINERIES	55	55	56	55	55
ASSOCIATED CRUDE CHARGE	4,974.3	5,058.5	5,462.3	4,974.3	5,418.2
MONC OF DEBUTANIZED PRODUCT	90.75	90.83	90.79	90.81	90.77
NO. REFINERIES	55	55	56	55	55
ASSOCIATED CRUDE CHARGE	4,974.3	5,058.5	5,462.3	4,974.3	5,418.2
8. ALKYLATION, SULFURIC					
C5+ DEBUTANIZED PRODUCT FROM BUTYLENE	378.3	378.7	389.2	288.0	333.8
NO. REFINERIES	53	52	52	53	52
ASSOCIATED CRUDE CHARGE	8,032.4	7,947.3	7,760.5	8,032.4	7,760.5
C5+ DEBUTANIZED PRODUCT FROM PROPYLENE	69.6	69.0	71.5	45.9	54.0
NO. REFINERIES	26	24	24	26	24
ASSOCIATED CRUDE CHARGE	2,833.2	2,697.8	2,570.8	2,833.2	2,570.8
C5+ DEBUTANIZED PRODUCT, TOTAL	448.0	447.8	460.7	334.0	387.9
NO. OF REFINERIES	53	52	52	53	52
ASSOCIATED CRUDE CHARGE	8,032.4	7,947.3	7,760.5	8,032.4	7,760.5
RONC OF DEBUTANIZED PRODUCT	93.70	93.65	93.65	93.74	93.75
NO. REFINERIES	53	52	52	53	52
ASSOCIATED CRUDE CHARGE	8,032.4	7,947.3	7,760.5	8,032.4	7,760.5
MONC OF DEBUTANIZED PRODUCT	91.36	91.27	91.28	91.38	91.35
NO. REFINERIES	53	52	52	53	52
ASSOCIATED CRUDE CHARGE	8,032.4	7,947.3	7,760.5	8,032.4	7,760.5

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NATIONAL PETROLEUM COUNCIL
SURVEY OF U.S. PETROLEUM REFINERIES
* ALL U.S. RESPONDENTS *

SECTION A: PROCESS FACILITIES CAPABILITIES

GIVEN ANTICIPATED FEEDSTOCK QUALITIES, PROCESS OPERATING CONDITIONS, AND ENVIRONMENTAL CONSTRAINTS, LIST MAXIMUM OPERABLE PROCESS UNIT CAPACITIES AND OTHER SPECIFIED UNIT CAPABILITIES IN PLACE AS OF JANUARY 1,1984, OR UNDERWAY OR FIRMLY PLANNED FOR COMPLETION ON OR BEFORE JANUARY 1, 1986 AND JANUARY 1, 1988. ALSO REPORT ACTUAL UTILIZATION IN 1984 AND ESTIMATED UTILIZATION IN 1988.

	OPERABLE CAPACITIES *			CAPACITY UTILIZATION *	
	1/1/84	1/1/86	1/1/88	1984	1988
9. POLYMERIZATION					
C5+ PRODUCT FROM BUTYLENE	8.3	6.8	6.8	4.0	4.2
NO. REFINERIES	14	13	13	13	11
ASSOCIATED CRUDE CHARGE	780.5	733.5	733.5	730.5	511.0
C5+ PRODUCT FROM PROPYLENE	57.4	58.2	58.1	36.2	44.8
NO. REFINERIES	29	28	28	29	28
ASSOCIATED CRUDE CHARGE	2,910.2	2,493.1	2,495.6	2,910.2	2,495.6
TOTAL DEBUTANIZED PRODUCT	65.8	65.1	65.0	40.3	49.0
NO. OF REFINERIES	33	31	31	32	30
ASSOCIATED CRUDE CHARGE	3,062.6	2,595.5	2,598.0	3,012.6	2,532.0
RONC	95.70	95.79	95.77	95.57	95.86
NO. REFINERIES	33	31	31	32	30
ASSOCIATED CRUDE CHARGE	3,062.6	2,595.5	2,598.0	3,012.6	2,532.0
MONC	82.42	82.46	82.46	82.38	82.42
NO. REFINERIES	33	31	31	32	30
ASSOCIATED CRUDE CHARGE	3,062.6	2,595.5	2,598.0	3,012.6	2,532.0

* ALL UNITS IN MB/CD UNLESS OTHERWISE NOTED

NATIONAL PETROLEUM COUNCIL
SURVEY OF U.S. PETROLEUM REFINERIES
* ALL U.S. RESPONDENTS *

SECTION A: PROCESS FACILITIES CAPABILITIES
GIVEN ANTICIPATED FEEDSTOCK QUALITIES, PROCESS OPERATING CONDITIONS, AND ENVIRONMENTAL CONSTRAINTS, LIST MAXIMUM OPERABLE PROCESS UNIT CAPACITIES AND OTHER SPECIFIED UNIT CAPABILITIES IN PLACE AS OF JANUARY 1,1984, OR UNDERWAY OR FIRMLY PLANNED FOR COMPLETION ON OR BEFORE JANUARY 1, 1986 AND JANUARY 1, 1988. ALSO REPORT ACTUAL UTILIZATION IN 1984 AND ESTIMATED UTILIZATION IN 1988.

	OPERABLE CAPACITIES *			CAPACITY UTILIZATION *	
	1/1/84	1/1/86	1/1/88	1984	1988
10. CATALYTIC HYDROCRACKING					
FEED RATE	854.6	961.2	925.4	722.7	929.6
NO. REFINERIES	35	35	34	34	36
ASSOCIATED CRUDE CHARGE	6,409.9	6,467.3	6,142.0	6,322.4	6,360.0
FEED COMPOSITION					
VIRGIN GAS OILS, VOL %	56.73	51.59	53.04	59.08	51.38
NO. REFINERIES	33	32	31	32	33
ASSOCIATED CRUDE CHARGE	6,146.4	5,978.8	5,653.5	6,058.9	5,871.5
CYCLE OIL, VOL %	28.21	26.43	24.30	26.67	27.09
NO. REFINERIES	27	26	24	27	26
ASSOCIATED CRUDE CHARGE	5,395.4	5,164.6	4,689.6	5,395.4	4,907.6
THERMAL GAS OIL, VOL %	.	.	.	.	.
NO. REFINERIES	14	13	13	14	13
ASSOCIATED CRUDE CHARGE	.	.	.	.	.
DEASPHALTED OIL, VOL %	.	.	.	.	.
NO. REFINERIES	2	2	2	2	2
ASSOCIATED CRUDE CHARGE	.	.	.	.	.
ATMOSPHERIC RESID, VOL %	0.00	0.00	0.00	0.00	0.00
NO. REFINERIES	0	0	0	0	0
ASSOCIATED CRUDE CHARGE	0.0	0.0	0.0	0.0	0.0
VACUUM RESID, VOL %	0.00	8.50	8.70	0.00	8.26
NO. REFINERIES	0	3	3	0	3
ASSOCIATED CRUDE CHARGE	0.0	680.6	680.6	0.0	680.6
FEED COMPOSITION TOTALS	100.00	100.00	100.00	100.00	100.00

* ALL UNITS IN MB/CD UNLESS OTHERWISE NOTED

NATIONAL PETROLEUM COUNCIL
SURVEY OF U.S. PETROLEUM REFINERIES
* ALL U.S. RESPONDENTS *

SECTION A: PROCESS FACILITIES CAPABILITIES
GIVEN ANTICIPATED FEEDSTOCK QUALITIES, PROCESS OPERATING CONDITIONS, AND ENVIRONMENTAL CONSTRAINTS, LIST MAXIMUM OPERABLE PROCESS UNIT CAPACITIES AND OTHER SPECIFIED UNIT CAPABILITIES IN PLACE AS OF JANUARY 1,1984, OR UNDERWAY OR FIRMLY PLANNED FOR COMPLETION ON OR BEFORE JANUARY 1, 1986 AND JANUARY 1, 1988. ALSO REPORT ACTUAL UTILIZATION IN 1984 AND ESTIMATED UTILIZATION IN 1988.

	OPERABLE CAPACITIES *			CAPACITY UTILIZATION *	
	1/1/84	1/1/86	1/1/88	1984	1988
10. CATALYTIC HYDROCRACKING (CONTINUED)					
PRODUCT YIELDS					
FUEL GAS FOE, VOL %	3.44	2.65	2.50	3.50	2.53
NO. REFINERIES	30	30	30	29	31
ASSOCIATED CRUDE CHARGE	6,047.9	6,077.3	5,887.0	5,960.4	6,105.0
C3/C4 VOL % RECOVERED	16.70	15.11	15.10	17.22	14.98
NO. REFINERIES	33	33	32	32	34
ASSOCIATED CRUDE CHARGE	6,348.9	6,382.8	6,057.5	6,261.4	6,275.5
C5 + NAPHTHA VOL %	75.13	66.63	64.92	73.74	63.60
NO. REFINERIES	34	34	33	33	35
ASSOCIATED CRUDE CHARGE	6,361.4	6,395.3	6,070.0	6,273.9	6,288.0
KEROSENE DISTILLATE VOL %	14.10	12.19	12.71	13.47	12.36
NO. REFINERIES	17	16	17	16	17
ASSOCIATED CRUDE CHARGE	3,195.4	2,934.0	3,055.7	3,107.9	3,055.7
700 F EP DISTILLATE VOL %	4.58	6.76	7.35	6.62	9.54
NO. REFINERIES	12	15	15	12	15
ASSOCIATED CRUDE CHARGE	2,329.7	2,993.2	2,901.2	2,460.2	2,869.2
700 F + GAS OIL VOL %	8.63	15.86	16.52	8.04	16.11
NO. REFINERIES	6	9	9	6	9
ASSOCIATED CRUDE CHARGE	1,041.5	1,896.5	1,740.5	1,041.5	1,740.5
PRODUCT YIELDS TOTALS	122.58	119.21	119.11	122.59	119.12
H2 CONSUMPTION SCF/BBL	2098.6	2018.3	1920.2	2041.3	1906.4
NO. REFINERIES	34	34	33	33	35
ASSOCIATED CRUDE CHARGE	6,361.4	6,395.3	6,070.0	6,273.9	6,288.0

* ALL UNITS IN MB/CD UNLESS OTHERWISE NOTED

NATIONAL PETROLEUM COUNCIL
SURVEY OF U.S. PETROLEUM REFINERIES
* ALL U.S. RESPONDENTS *

SECTION A: PROCESS FACILITIES CAPABILITIES
GIVEN ANTICIPATED FEEDSTOCK QUALITIES, PROCESS OPERATING CONDITIONS, AND ENVIRONMENTAL CONSTRAINTS, LIST MAXIMUM OPERABLE PROCESS UNIT CAPACITIES AND OTHER SPECIFIED UNIT CAPABILITIES IN PLACE AS OF JANUARY 1,1984, OR UNDERWAY OR FIRMLY PLANNED FOR COMPLETION ON OR BEFORE JANUARY 1, 1986 AND JANUARY 1, 1988. ALSO REPORT ACTUAL UTILIZATION IN 1984 AND ESTIMATED UTILIZATION IN 1988.

	OPERABLE CAPACITIES *			CAPACITY UTILIZATION *	
	1/1/84	1/1/86	1/1/88	1984	1988
11. THERMAL PROCESSING					
FLEXICOKER AND FLUID COKER					
FEED RATE	157.7	161.2	149.2	120.0	158.2
NO. REFINERIES	7	7	7	7	8
ASSOCIATED CRUDE CHARGE	648.4	667.0	932.0	648.4	932.0
FRESH FEED COMPOSITION					
ATMOSPHERIC GAS OIL, VOL %	0.00	0.00	0.00	0.00	0.00
NO. REFINERIES	0	0	0	0	0
ASSOCIATED CRUDE CHARGE	0.0	0.0	0.0	0.0	0.0
VACUUM GAS OIL, VOL %	0.00	0.00	0.00	0.00	0.00
NO. REFINERIES	0	0	0	0	0
ASSOCIATED CRUDE CHARGE	0.0	0.0	0.0	0.0	0.0
ATMOSPHERIC RESID, VOL %	0.00	0.00	.	0.00	.
NO. REFINERIES	0	0	1	0	1
ASSOCIATED CRUDE CHARGE	0.0	0.0	.	0.0	.
VACUUM RESID, VOL %	.	.	80.67	.	83.67
NO. REFINERIES	7	7	6	7	7
ASSOCIATED CRUDE CHARGE	.	.	532.0	.	532.0
CRACKED STOCK, VOL %	.	.	.	.	.
NO. REFINERIES	1	1	1	2	1
ASSOCIATED CRUDE CHARGE	.	.	.	.	.
TOTAL FRESH FEED COMP	100.00	100.00	100.00	100.00	100.00

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NATIONAL PETROLEUM COUNCIL
SURVEY OF U.S. PETROLEUM REFINERIES
* ALL U.S. RESPONDENTS *

SECTION A: PROCESS FACILITIES CAPABILITIES

GIVEN ANTICIPATED FEEDSTOCK QUALITIES, PROCESS OPERATING CONDITIONS, AND ENVIRONMENTAL CONSTRAINTS, LIST MAXIMUM OPERABLE PROCESS UNIT CAPACITIES AND OTHER SPECIFIED UNIT CAPABILITIES IN PLACE AS OF JANUARY 1,1984, OR UNDERWAY OR FIRMLY PLANNED FOR COMPLETION ON OR BEFORE JANUARY 1, 1986 AND JANUARY 1, 1988. ALSO REPORT ACTUAL UTILIZATION IN 1984 AND ESTIMATED UTILIZATION IN 1988.

	OPERABLE CAPACITIES *			CAPACITY UTILIZATION *	
	1/1/84	1/1/86	1/1/88	1984	1988
11. THERMAL PROCESSING (CONTINUED)					
FLEXICOKER AND FLUID COKER					
COKE MAKE, ST/CD	5505	5625	4425	5200	5549
NO. REFINERIES	7	7	6	7	7
ASSOCIATED CRUDE CHARGE	648.4	667.0	532.0	648.4	532.0
COKE QUALITIES, SULFUR WT %	4.27	4.20	4.80	4.26	4.12
NO. REFINERIES	7	7	6	7	7
ASSOCIATED CRUDE CHARGE	648.4	667.0	532.0	648.4	532.0
COKE QUALITIES, TOTAL METALS	1949.6	1900	1303.4	2034.4	1921.2
NO. REFINERIES	6	6	5	6	6
ASSOCIATED CRUDE CHARGE	557.0	557.0	422.0	557.0	422.0
FRESH FEED HYDROTREATING					
ATMOSPHERIC GAS OIL	0.00	0.00	0.00	0.00	0.00
NO. REFINERIES	0	0	0	0	0
ASSOCIATED CRUDE CHARGE	0.0	0.0	0.0	0.0	0.0
VACUUM GAS OIL	0.00	0.00	0.00	0.00	0.00
NO. REFINERIES	0	0	0	0	0
ASSOCIATED CRUDE CHARGE	0.0	0.0	0.0	0.0	0.0
ATMOSPHERIC RESID	0.00	0.00	0.00	0.00	0.00
NO. REFINERIES	0	0	0	0	0
ASSOCIATED CRUDE CHARGE	0.0	0.0	0.0	0.0	0.0
CRACKED STOCK	0.00	0.00	0.00	0.00	0.00
NO. REFINERIES	0	0	0	0	0
ASSOCIATED CRUDE CHARGE	0.0	0.0	0.0	0.0	0.0

* ALL UNITS IN MB/CD UNLESS OTHERWISE NOTED

NATIONAL PETROLEUM COUNCIL
SURVEY OF U.S. PETROLEUM REFINERIES
* ALL U.S. RESPONDENTS *

SECTION A: PROCESS FACILITIES CAPABILITIES
GIVEN ANTICIPATED FEEDSTOCK QUALITIES, PROCESS OPERATING CONDITIONS, AND ENVIRONMENTAL CONSTRAINTS, LIST MAXIMUM OPERABLE PROCESS UNIT CAPACITIES AND OTHER SPECIFIED UNIT CAPABILITIES IN PLACE AS OF JANUARY 1,1984, OR UNDERWAY OR FIRMLY PLANNED FOR COMPLETION ON OR BEFORE JANUARY 1, 1986 AND JANUARY 1, 1988. ALSO REPORT ACTUAL UTILIZATION IN 1984 AND ESTIMATED UTILIZATION IN 1988.

	OPERABLE CAPACITIES *			CAPACITY UTILIZATION *	
	1/1/84	1/1/86	1/1/88	1984	1988
11. THERMAL PROCESSING (CONTINUED)					
VISBREAKER AND THERMAL CRACKER					
FEED RATE	145.5	137.7	137.7	82.7	86.7
NO. REFINERIES	13	12	12	12	11
ASSOCIATED CRUDE CHARGE	1,391.1	1,266.1	1,266.1	1,371.1	1,246.1
FRESH FEED COMPOSITION					
ATMOSPHERIC GAS OIL, VOL %	.	.	.	.	.
NO. REFINERIES	1	1	1	2	1
ASSOCIATED CRUDE CHARGE	.	.	.	.	.
VACUUM GAS OIL, VOL %	0.00	0.00	0.00	.	0.00
NO. REFINERIES	0	0	0	1	0
ASSOCIATED CRUDE CHARGE	0.0	0.0	0.0	.	0.0
ATMOSPHERIC RESID, VOL %	0.00	0.00	0.00	0.00	0.00
NO. REFINERIES	0	0	0	0	0
ASSOCIATED CRUDE CHARGE	0.0	0.0	0.0	0.0	0.0
VACUUM RESID, VOL %	91.91	91.46	91.46	93.26	86.90
NO. REFINERIES	11	10	10	10	9
ASSOCIATED CRUDE CHARGE	1,177.7	1,052.7	1,052.7	1,157.7	1,032.7
CRACKED STOCK, VOL %	.	.	.	6.05	.
NO. REFINERIES	2	2	2	3	3
ASSOCIATED CRUDE CHARGE	.	.	.	463.4	.
TOTAL FRESH FEED COMP	100.00	100.00	100.00	100.00	100.00

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NATIONAL PETROLEUM COUNCIL
SURVEY OF U.S. PETROLEUM REFINERIES
* ALL U.S. RESPONDENTS *

SECTION A: PROCESS FACILITIES CAPABILITIES

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	OPERABLE CAPACITIES *			CAPACITY UTILIZATION *	
	1/1/84	1/1/86	1/1/88	1984	1988
11. THERMAL PROCESSING (CONTINUED)					
VISBREAKER AND THERMAL CRACKER					
COKE MAKE, ST/CD	0	0	0	0	0
NO. REFINERIES	0	0	0	0	0
ASSOCIATED CRUDE CHARGE	0.0	0.0	0.0	0.0	0.0
COKE QUALITIES, SULFUR WT %	0.00	0.00	0.00	0.00	0.00
NO. REFINERIES	0	0	0	0	0
ASSOCIATED CRUDE CHARGE	0.0	0.0	0.0	0.0	0.0
COKE QUALITIES, TOTAL METALS	0.00	0.00	0.00	0.00	0.00
NO. REFINERIES	0	0	0	0	0
ASSOCIATED CRUDE CHARGE	0.0	0.0	0.0	0.0	0.0
FRESH FEED HYDROTREATING					
ATMOSPHERIC GAS OIL	0.00	0.00	0.00	0.00	0.00
NO. REFINERIES	0	0	0	0	0
ASSOCIATED CRUDE CHARGE	0.0	0.0	0.0	0.0	0.0
VACUUM GAS OIL	0.00	0.00	0.00	0.00	0.00
NO. REFINERIES	0	0	0	0	0
ASSOCIATED CRUDE CHARGE	0.0	0.0	0.0	0.0	0.0
ATMOSPHERIC RESID	0.00	0.00	0.00	0.00	0.00
NO. REFINERIES	0	0	0	0	0
ASSOCIATED CRUDE CHARGE	0.0	0.0	0.0	0.0	0.0
CRACKED STOCK	0.00	0.00	0.00	0.00	0.00
NO. REFINERIES	0	0	0	0	0
ASSOCIATED CRUDE CHARGE	0.0	0.0	0.0	0.0	0.0

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NATIONAL PETROLEUM COUNCIL
SURVEY OF U.S. PETROLEUM REFINERIES
* ALL U.S. RESPONDENTS *

SECTION A: PROCESS FACILITIES CAPABILITIES
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	OPERABLE CAPACITIES *			CAPACITY UTILIZATION *	
	1/1/84	1/1/86	1/1/88	1984	1988
11. THERMAL PROCESSING (CONTINUED)					
DELAYED COKER					
FEED RATE	1,133.3	1,185.5	1,190.1	981.6	1,057.8
NO. REFINERIES	43	43	43	44	42
ASSOCIATED CRUDE CHARGE	6,627.6	6,727.1	6,779.6	6,705.6	6,735.5
FRESH FEED COMPOSITION					
ATMOSPHERIC GAS OIL, VOL %	.	.	.	.	.
NO. REFINERIES	2	2	2	2	2
ASSOCIATED CRUDE CHARGE	.	.	.	.	.
VACUUM GAS OIL, VOL %	.	.	.	.	0.00
NO. REFINERIES	1	1	1	1	0
ASSOCIATED CRUDE CHARGE	.	.	.	.	0.0
ATMOSPHERIC RESID, VOL %	4.34	3.89	3.87	5.31	.
NO. REFINERIES	4	3	3	4	3
ASSOCIATED CRUDE CHARGE	182.0	156.0	156.0	182.0	.
VACUUM RESID, VOL %	91.33	91.47	91.52	90.46	90.52
NO. REFINERIES	40	41	41	41	40
ASSOCIATED CRUDE CHARGE	6,515.6	6,650.1	6,702.6	6,593.6	6,658.5
CRACKED STOCK, VOL %	3.43	3.83	3.80	3.28	4.17
NO. REFINERIES	13	16	16	14	16
ASSOCIATED CRUDE CHARGE	1,682.1	2,175.8	2,241.5	1,796.1	2,241.5
TOTAL FRESH FEED COMP	100.00	100.00	100.00	99.99	100.00

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NATIONAL PETROLEUM COUNCIL
SURVEY OF U.S. PETROLEUM REFINERIES
* ALL U.S. RESPONDENTS *

SECTION A: PROCESS FACILITIES CAPABILITIES
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	OPERABLE CAPACITIES *			CAPACITY UTILIZATION *	
	1/1/84	1/1/86	1/1/88	1984	1988
11. THERMAL PROCESSING (CONTINUED)					
DELAYED COKER					
COKE MAKE, ST/CD	55299	58120	59181	49986	54037
NO. REFINERIES	43	43	43	44	42
ASSOCIATED CRUDE CHARGE	6,627.6	6,727.1	6,779.6	6,705.6	6,735.5
COKE QUALITIES, SULFUR WT %	3.26	3.26	3.44	3.30	3.46
NO. REFINERIES	43	43	43	44	42
ASSOCIATED CRUDE CHARGE	6,627.6	6,727.1	6,779.6	6,705.6	6,735.5
COKE QUALITIES, TOTAL METALS	996.42	992.11	1072.1	993.85	1036.1
NO. REFINERIES	43	43	43	44	42
ASSOCIATED CRUDE CHARGE	6,627.6	6,727.1	6,779.6	6,705.6	6,735.5
FRESH FEED HYDROTREATING					
ATMOSPHERIC GAS OIL	0.00	0.00	0.00	0.00	0.00
NO. REFINERIES	0	0	0	0	0
ASSOCIATED CRUDE CHARGE	0.0	0.0	0.0	0.0	0.0
VACUUM GAS OIL	.	.	.	.	.
NO. REFINERIES	1	1	1	1	1
ASSOCIATED CRUDE CHARGE	.	.	.	.	.
ATMOSPHERIC RESID	0.00	0.00	0.00	0.00	0.00
NO. REFINERIES	0	0	0	0	0
ASSOCIATED CRUDE CHARGE	0.0	0.0	0.0	0.0	0.0
CRACKED STOCK	0.00	.	.	0.00	.
NO. REFINERIES	0	2	1	0	1
ASSOCIATED CRUDE CHARGE	0.0	.	.	0.0	.

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NATIONAL PETROLEUM COUNCIL
SURVEY OF U.S. PETROLEUM REFINERIES
* ALL U.S. RESPONDENTS *

SECTION A: PROCESS FACILITIES CAPABILITIES
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	OPERABLE CAPACITIES *			CAPACITY UTILIZATION *	
	1/1/84	1/1/86	1/1/88	1984	1988
12. LUBE OILS MANUFACTURE	228.2	229.8	229.6	176.9	207.7
NO. REFINERIES	32	31	31	31	31
ASSOCIATED CRUDE CHARGE	5,247.9	5,166.1	5,030.9	5,241.1	5,030.9
13. PETROCHEMICALS					
AROMATICS UNITS					
CHARGE TO					
SOLVENT EXTRACTION	512.7	543.4	543.4	426.4	471.2
NO. REFINERIES	29	29	29	29	29
ASSOCIATED CRUDE CHARGE	5,206.4	5,354.0	5,340.8	5,206.4	5,340.8
HYDRODEALKYLATION	27.5	36.3	36.3	16.7	25.9
NO. REFINERIES	8	9	9	8	8
ASSOCIATED CRUDE CHARGE	1,455.5	1,659.5	1,646.3	1,455.5	1,546.3
PRODUCTS					
BENZENE	60.0	65.9	66.0	41.2	48.3
NO. REFINERIES	24	24	24	22	21
ASSOCIATED CRUDE CHARGE	3,854.4	4,047.0	4,033.8	3,441.0	3,493.4
TOLUENE	42.4	40.8	40.7	29.2	30.2
NO. REFINERIES	20	19	19	18	15
ASSOCIATED CRUDE CHARGE	2,960.3	2,975.9	2,962.7	2,353.4	2,091.0
XYLENE	49.8	47.2	47.2	45.9	48.4
NO. REFINERIES	16	15	15	17	14
ASSOCIATED CRUDE CHARGE	2,702.8	2,707.4	2,707.4	2,971.8	2,664.4
MTBE	6.4	12.7	13.5	3.9	13.9
NO. REFINERIES	3	7	8	4	8
ASSOCIATED CRUDE CHARGE	410.0	937.6	987.1	485.0	987.1
14. SOLVENT DEASPHALTING					
FEED RATE	329.1	336.9	327.4	215.3	270.5
NO. REFINERIES	37	37	36	34	33
ASSOCIATED CRUDE CHARGE	4,827.5	4,779.8	4,437.7	4,422.0	3,851.9
DEASPHALTED OIL, VOL % FEED	55.65	55.47	55.63	54.38	56.47
NO. REFINERIES	36	36	35	33	32
ASSOCIATED CRUDE CHARGE	4,657.5	4,609.8	4,267.7	4,252.0	3,681.9
SDA RESID, VOL % FEED	40.70	40.97	40.70	44.46	42.57
NO. REFINERIES	36	36	35	33	32
ASSOCIATED CRUDE CHARGE	4,657.5	4,609.8	4,267.7	4,252.0	3,681.9

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NATIONAL PETROLEUM COUNCIL
SURVEY OF U.S. PETROLEUM REFINERIES
* ALL U.S. RESPONDENTS *

SECTION A: PROCESS FACILITIES CAPABILITIES
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	OPERABLE CAPACITIES *			CAPACITY UTILIZATION *	
	1/1/84	1/1/86	1/1/88	1984	1988
15. HYDROGEN GENERATION OR UPGRADING TO 90+%					
REFORMING, LPG	161.2	121.2	121.2	134.5	107.0
NO. REFINERIES	4	3	3	4	3
ASSOCIATED CRUDE CHARGE	752.6	627.6	614.4	752.6	614.4
REFORMING, METHANE	1,015.0	1,357.1	1,282.1	808.0	996.0
NO. REFINERIES	22	28	27	23	24
ASSOCIATED CRUDE CHARGE	3,100.0	3,917.0	3,761.0	3,092.0	3,058.5
REFORMING, NAPHTHA	0.0	0.0	0.0	0.0	0.0
NO. REFINERIES	0	0	0	0	0
ASSOCIATED CRUDE CHARGE	0.0	0.0	0.0	0.0	0.0
REFORMING, MIXED	487.3	404.1	415.1	304.1	382.0
NO. REFINERIES	11	10	10	10	11
ASSOCIATED CRUDE CHARGE	1,778.2	1,688.6	1,654.3	1,686.8	1,904.3
PARTIAL OXIDATION	.	.	.	.	.
NO. REFINERIES	1	2	2	1	2
ASSOCIATED CRUDE CHARGE	.	.	.	.	.
PURIFICATION	157.8	174.5	174.5	132.6	154.8
NO. REFINERIES	6	10	10	6	9
ASSOCIATED CRUDE CHARGE	1,187.9	2,550.5	2,415.3	1,187.9	2,015.3
16. SULFUR RECOVERY, LT/CO	15836.3	17417.3	17760.3	7895.0	10909.3
NO. REFINERIES	99	101	100	97	97
ASSOCIATED CRUDE CHARGE	12,440.8	12,638.5	12,435.5	12,345.3	12,254.1
17. REFORMING OF CAT NAPHTHA	78.5	87.5	95.1	55.6	83.5
NO. REFINERIES	10	15	17	9	17
ASSOCIATED CRUDE CHARGE	1,710.2	2,669.6	2,918.5	1,626.2	3,211.5
18. REFORMING CAPACITY TO BTX EXTRACT	785.8	798.2	792.9	719.3	744.4
NO. REFINERIES	30	31	31	31	31
ASSOCIATED CRUDE CHARGE	5,835.4	6,001.0	5,893.8	5,883.9	5,893.8

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NATIONAL PETROLEUM COUNCIL
SURVEY OF U.S. PETROLEUM REFINERIES
* ALL U.S. RESPONDENTS *

SECTION B: 1984 GROSS PROCESS ENERGY PRODUCTION AND CONSUMPTION

	FUEL (1)		POWER (2)		STEAM (3)	
	PRODUCED	CONSUMED	PRODUCED	CONSUMED	PRODUCED	CONSUMED
1. CRUDE DISTILLATION	0.010	0.073	.	0.603	0.026	0.057
NO. REFINERIES	64	127	1	118	36	110
CRUDE CHARGE CAPACTIY	6,003.8	12,417.2	.	11,792.7	3,827.3	11,845.0
2. VACUUM DISTILLATION	0.004	0.033	0.000	0.243	0.134	0.144
NO. REFINERIES	6	74	0	67	31	57
ASSOCIATED CRUDE CHARGE	398.2	6,174.2	0.0	5,586.6	2,865.5	4,631.4
3. REFORMING	0.125	0.248	0.000	2.597	0.045	0.031
NO. REFINERIES	70	99	0	91	69	73
ASSOCIATED CRUDE CHARGE	7,024.6	11,695.3	0.0	11,167.3	9,429.4	9,243.5
4. C4 ISOMERIZATION	0.016	0.022	0.000	1.611	0.000	0.145
NO. REFINERIES	4	7	0	12	0	13
ASSOCIATED CRUDE CHARGE	558.3	530.5	0.0	1,203.4	0.0	1,208.8
5. C5/C6 ISOMERIZATION	0.016	0.080	0.000	2.421	.	0.174
NO. REFINERIES	4	6	0	6	1	4
ASSOCIATED CRUDE CHARGE	862.4	1,020.4	0.0	1,020.4	.	739.9
6. CATALYTIC HYDROTREATING						
REFORM NAPHTHA	0.010	0.047	0.000	0.570	0.003	0.008
NO. REFINERIES	28	70	0	63	8	35
ASSOCIATED CRUDE CHARGE	2,653.8	7,278.8	0.0	6,698.6	895.0	4,227.4
KEROSENE	0.005	0.039	.	0.655	0.001	0.009
NO. REFINERIES	8	26	1	24	4	20
ASSOCIATED CRUDE CHARGE	1,036.4	4,600.6	.	4,240.6	709.3	3,226.6
DISTILLATE	0.022	0.035	0.000	1.104	0.204	0.115
NO. REFINERIES	24	52	0	48	16	38
ASSOCIATED CRUDE CHARGE	3,226.0	7,899.1	0.0	7,435.1	2,190.4	5,862.6
HEAVY GAS OIL	0.018	0.033	0.000	1.605	0.005	0.015
NO. REFINERIES	11	31	0	30	11	24
ASSOCIATED CRUDE CHARGE	1,572.0	5,415.7	0.0	5,375.7	2,262.2	4,595.2
ATMOSPHERIC RESID	0.054	0.055	0.000	4.305	0.026	0.033
NO. REFINERIES	3	6	0	6	5	6
ASSOCIATED CRUDE CHARGE	290.7	985.4	0.0	985.4	969.7	985.4
VACUUM RESID	0.000	.	0.000	.	0.000	0.000
NO. REFINERIES	0	2	0	1	0	0
ASSOCIATED CRUDE CHARGE	0.0	.	0.0	.	0.0	0.0

(1) FUEL EXPRESSED AS MMBTU/BBL OF FEED OR PRODUCT UNLESS OTHERWISE INDICATED
(2) POWER EXPRESSED AS KWHR/BBL OF FEED OR PRODUCT UNLESS OTHERWISE INDICATED
(3) STEAM EXPRESSED AS MLBS/BBL OF FEED OR PRODUCT UNLESS OTHERWISE INDICATED

NATIONAL PETROLEUM COUNCIL
SURVEY OF U.S. PETROLEUM REFINERIES
* ALL U.S. RESPONDENTS *

SECTION B: 1984 GROSS PROCESS ENERGY PRODUCTION AND CONSUMPTION

	FUEL (1)		POWER (2)		STEAM (3)	
	PRODUCED	CONSUMED	PRODUCED	CONSUMED	PRODUCED	CONSUMED
7. CATALYTIC CRACKING	0.235	0.223	0.055	1.932	0.082	0.071
NO. REFINERIES	64	86	5	82	72	77
ASSOCIATED CRUDE CHARGE	6,980.8	11,158.8	517.7	10,777.1	9,274.4	10,270.7
8. ALKYLATION	0.035	0.101	0.000	4.058	0.016	0.162
NO. REFINERIES	22	51	0	77	11	72
ASSOCIATED CRUDE CHARGE	3,177.9	6,453.4	0.0	9,812.1	1,596.0	9,381.2
9. POLYMERIZATION	0.126	0.008	0.000	1.990	0.021	0.132
NO. REFINERIES	8	6	0	16	5	11
ASSOCIATED CRUDE CHARGE	1,112.1	1,124.5	0.0	1,886.9	559.3	1,366.1
DIMERIZATION	0.000	.	0.000	2.045	0.000	0.054
NO. REFINERIES	0	2	0	5	0	5
ASSOCIATED CRUDE CHARGE	0.0	.	0.0	532.5	0.0	532.5
11. CATALYTIC HYDROCRACKING	0.130	0.240	0.000	7.201	0.023	0.038
NO. REFINERIES	14	30	0	29	12	26
ASSOCIATED CRUDE CHARGE	2,439.3	5,904.9	0.0	5,584.9	2,439.4	5,094.9
12. THERMAL PROCESSING	0.396	0.197	0.000	2.196	0.034	0.062
NO. REFINERIES	27	45	0	43	28	39
ASSOCIATED CRUDE CHARGE	3,556.4	7,062.9	0.0	6,513.5	4,649.6	6,405.1
13. LUBE OIL MANUFACTURE	0.028	0.226	0.000	7.024	0.015	0.206
NO. REFINERIES	3	26	0	26	5	26
ASSOCIATED CRUDE CHARGE	689.3	4,207.8	0.0	4,257.8	1,231.7	4,372.4
14. PETROCHEMICALS						
BTX	0.051	0.084	0.000	3.452	0.011	0.156
NO. REFINERIES	5	20	0	25	5	23
ASSOCIATED CRUDE CHARGE	1,187.5	3,562.1	0.0	4,586.1	1,130.5	4,236.4
OTHERS	0.000	0.000	0.000	0.000	0.000	0.000
NO. REFINERIES	6	13	0	17	3	17
ASSOCIATED CRUDE CHARGE	993.3	2,300.3	0.0	2,773.9	491.0	2,773.9
15. HYDROGEN GENERATION (4)	0.058	3.204	0.000	112.327	0.081	0.354
NO. REFINERIES	8	27	0	27	21	23
ASSOCIATED CRUDE CHARGE	1,226.5	4,407.9	0.0	4,473.9	3,571.4	3,468.9

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(2) POWER EXPRESSED AS KWHR/BBL OF FEED OR PRODUCT UNLESS OTHERWISE INDICATED
(3) STEAM EXPRESSED AS MLBS/BBL OF FEED OR PRODUCT UNLESS OTHERWISE INDICATED
(4) UTILITY COMODITIES EXPRESSED AS UNITS/MCF

NATIONAL PETROLEUM COUNCIL
SURVEY OF U.S. PETROLEUM REFINERIES
* ALL U.S. RESPONDENTS *

SECTION B: 1984 GROSS PROCESS ENERGY PRODUCTION AND CONSUMPTION

	FUEL (1)		POWER (2)		STEAM (3)	
	PRODUCED	CONSUMED	PRODUCED	CONSUMED	PRODUCED	CONSUMED
16. SOLVENT DEASPHALTING	0.022	0.041	0.000	2.037	0.003	0.122
NO. REFINERIES	3	24	0	23	3	24
ASSOCIATED CRUDE CHARGE	102.4	2,624.0	0.0	2,830.3	518.4	3,140.3
17. SULFUR RECOVERY (5)	0.153	2.853	0.000	113.884	47.792	65.242
NO. REFINERIES	4	72	0	64	51	60
ASSOCIATED CRUDE CHARGE	737.4	9,970.6	0.0	8,774.6	6,590.2	8,271.7
18. OUTSIDE PROCESS (6)	0.017	0.103	0.798	1.185	0.544	0.126
NO. REFINERIES	17	90	14	78	72	73
ASSOCIATED CRUDE CHARGE	2,218.4	9,956.1	2,962.0	8,752.9	8,002.0	8,139.8
19. OVERALL REFINERY	0.300	0.514	0.833	6.127	0.194	0.554
NO. REFINERIES	102	172	20	163	88	136
ASSOCIATED CRUDE CHARGE	9,420.6	14,664.6	3,503.4	14,203.7	9,270.5	11,480.4

PLANNED ENERGY CONSERVATION SAVINGS RELATIVE TO JANUARY 1,1984

JANUARY 1, 1988 (MMBTU/BBL CRUDE)	5.258
NO. REFINERIES	93
ASSOCIATED CRUDE CHARGE	10,216.1

1988 OVERALL REFINERY ENERGY CONSUMPTION

FUEL (MMBTU/BBL)	0.521
NO. REFINERIES	170
ASSOCIATED CRUDE CHARGE	14,578.0
POWER (KWHR/BBL)	6.081
NO. REFINERIES	161
ASSOCIATED CRUDE CHARGE	14,096.0
STEAM (MLBS/BBL)	6.601
NO. REFINERIES	131
ASSOCIATED CRUDE CHARGE	11,035.7

(1) FUEL EXPRESSED AS MMBTU/BBL OF FEED OR PRODUCT UNLESS OTHERWISE INDICATED
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(3) STEAM EXPRESSED AS MLBS/BBL OF FEED OR PRODUCT UNLESS OTHERWISE INDICATED
(4) UTILITY COMODITIES EXPRESSED AS UNITS/MCF
(5) (INCLUDING TAIL GAS CLEANUP) UTILITY COMODITIES EXPRESSED AS UNITS PER LT
(6) (OUTSIDE PROCESS BATTERY LIMITS) UTILITY COMODITIES EXPRESSED AS UNITS PER BBL OF CRUDE

NATIONAL PETROLEUM COUNCIL
1985 SURVEY OF U.S. PETROLEUM REFINERIES
ALL U.S. RESPONDENTS

Part I
Section C: Crude Oil and Other Feedstock; Product Yield

Actual calendar 1984 and projected calendar 1986 and 1988 crude oil and other feed and blending stocks. Crude oils are identified by the types shown below.

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

Typical qualities of high sulfur crude oil

HIGH SULFUR-LIGHT

Crude Oil Stream	Gravity °API	Sulfur Wt. %	1,050 + °F Bottoms Yield Vol. %
Domestic			
East Mississippi	32-36	1.0-1.4	8-11
Carpentira Mix, Cal.	28-29	1.1-1.4	15-20
Montana Sour	31-34	1.0-1.3	8-14
West Texas Sour	25-36	1.0-2.0	10-15
Foreign			
Arabian-Light	32-36	1.5-1.8	11-14
Iranian-Light	32-35	1.3-1.6	11-14
Qatar	40-43	1.0-1.3	5- 8
Kirkuk, Iraq	35-37	1.8-2.0	11-14

HIGH SULFUR-LIGHT

Crude Oil Stream	Gravity °API	Sulfur Wt. %	1,050 + °F Bottoms Yield Vol. %
Domestic			
Hawkins/Talco, Tex.	20-29	2.0-3.5	25-35
HEY Heavy, Miss.	20-25	3.0-4.0	27-31
San Joaquin Valley, Ca.	13-25	1.0-1.5	15-30
Wilmington, Ca.	15-21	1.4-2.2	21-32
Wyoming Sour	20-28	2.0-3.5	15-27
Foreign			
Arabian-Heavy	27-29	2.5-3.0	25-28
Iranian-Heavy	30-32	1.4-1.7	17-20
Tia Juana, Venez	25-27	1.4-1.6	23-25
Bachaquero, Venez	16-21	2.0-2.5	30-40
Laqunillas, Venez	11-18	2.0-3.0	35-45

NOTE: Alaskan North Slope Crude Oil is classified as Medium Sulfur-Heavy.

NATIONAL PETROLEUM COUNCIL
SURVEY OF U.S. PETROLEUM REFINERIES
* ALL U.S. RESPONDENTS *

SECTION C: CRUDE OIL
LIST ACTUAL 1984 AND PROJECTED CALENDAR 1986 AND 1988 CRUDE OIL

	ACTUAL 1984				PROJECTED 1986				PROJECTED 1988			
CRUDE OIL	MB/CD	API	% S	%RESID	MB/CD	API	% S	%RESID	MB/CD	API	% S	%RESID
DOMESTIC												
SWEET CRUDE OIL	4,389.8	38.5	0.27	9.3	4,291.4	38.6	0.27	9.1	4,156.0	38.7	0.28	9.2
NO. OF REFINERIES	105				102				101			
ASSOC. CRUDE CHARGE	10,168.4				10,241.5				9,839.8			
MEDIUM SULFUR CRUDE OIL												
MEDIUM SULFUR LIGHT	232.9	35.0	0.63	10.0	197.7	34.5	0.62	10.4	207.2	34.3	0.63	10.6
NO. OF REFINERIES	21				19				18			
ASSOC. CRUDE CHARGE	2,768.4				2,591.1				2,092.6			
MEDIUM SULFUR HEAVY	1,537.9	27.0	0.99	22.0	1,740.4	26.6	0.99	22.1	1,655.0	26.6	0.99	22.0
NO. OF REFINERIES	53				48				47			
ASSOC. CRUDE CHARGE	6,592.9				6,785.3				6,304.0			
HIGH SULFUR CRUDE OIL												
HIGH SULFUR LIGHT	826.3	32.6	1.68	13.0	875.2	32.5	1.72	12.9	945.5	32.3	1.74	12.8
NO. OF REFINERIES	30				24				25			
ASSOC. CRUDE CHARGE	4,726.1				3,810.7				3,717.5			
HIGH SULFUR HEAVY	1,574.3	22.9	1.87	27.7	1,891.3	23.4	1.79	26.5	1,952.6	23.0	1.93	27.1
NO. OF REFINERIES	68				63				63			
ASSOC. CRUDE CHARGE	7,344.1				6,935.3				6,720.8			
DOMESTIC SUB-TOTAL	8,561.4	32.9	0.84	15.3	8,996.1	32.4	0.88	15.7	8,916.4	32.3	0.94	15.9
NO. OF REFINERIES	164				155				154			
ASSOC. CRUDE CHARGE	14,085.3				13,775.7				13,152.7			
FOREIGN												
SWEET CRUDE OIL	1,493.8	37.6	0.18	11.5	1,545.6	36.7	0.19	12.0	1,585.3	36.4	0.20	12.0
NO. OF REFINERIES	61				45				43			
ASSOC. CRUDE CHARGE	9,637.5				7,025.1				6,560.8			
MEDIUM SULFUR CRUDE OIL												
MEDIUM SULFUR LIGHT	63.2	38.4	0.71	8.7	47.6	38.4	0.71	8.0	43.4	38.8	0.72	7.9
NO. OF REFINERIES	15				6				6			
ASSOC. CRUDE CHARGE	3,010.3				517.6				517.6			
MEDIUM SULFUR HEAVY	117.5	30.7	0.90	26.3	79.6	32.8	0.87	26.6	97.4	32.4	0.88	25.6
NO. OF REFINERIES	17				7				7			
ASSOC. CRUDE CHARGE	3,779.4				1,158.9				764.9			

NATIONAL PETROLEUM COUNCIL
SURVEY OF U.S. PETROLEUM REFINERIES
* ALL U.S. RESPONDENTS *

SECTION C: CRUDE OIL
LIST ACTUAL 1984 AND PROJECTED CALENDAR 1986 AND 1988 CRUDE OIL

	ACTUAL 1984				PROJECTED 1986				PROJECTED 1988			
CRUDE OIL	MB/CD	API	% S	%RESID	MB/CD	API	% S	%RESID	MB/CD	API	% S	%RESID
FOREIGN, CONTINUED												
HIGH SULFUR CRUDE OIL												
HIGH SULFUR LIGHT	246.1	30.3	1.75	11.7	311.6	30.8	1.71	11.6	263.6	30.2	1.74	11.1
NO. OF REFINERIES	16				12				11			
ASSOC. CRUDE CHARGE	3,421.9				1,730.3				1,593.3			
HIGH SULFUR HEAVY	1,160.4	23.8	2.70	29.6	1,310.5	22.9	2.66	30.7	1,513.4	23.7	2.64	29.9
NO. OF REFINERIES	40				41				43			
ASSOC. CRUDE CHARGE	6,607.0				6,649.0				6,682.1			
FOREIGN SUB-TOTAL	3,081.2	31.6	1.29	18.9	3,295.1	30.6	1.34	19.7	3,503.2	30.3	1.39	20.0
NO. OF REFINERIES	82				72				73			
ASSOC. CRUDE CHARGE	11,441.1				10,402.1				10,237.4			
COMBINED DOMESTIC AND FOREIGN												
SWEET CRUDE OIL	5,883.7	38.3	0.25	9.9	5,837.0	38.1	0.25	9.9	5,741.3	38.1	0.26	10.0
NO. OF REFINERIES	129				118				117			
ASSOC. CRUDE CHARGE	12,905.9				12,291.5				11,981.5			
MEDIUM SULFUR CRUDE OIL												
MEDIUM SULFUR LIGHT	296.1	35.7	0.65	9.8	245.3	35.3	0.64	10.0	250.6	35.1	0.64	10.1
NO. OF REFINERIES	31				24				24			
ASSOC. CRUDE CHARGE	4,384.3				3,066.7				2,610.2			
MEDIUM SULFUR HEAVY	1,655.4	27.2	0.98	22.3	1,820.0	26.9	0.98	22.3	1,752.4	26.9	0.98	22.2
NO. OF REFINERIES	59				49				48			
ASSOC. CRUDE CHARGE	8,186.8				6,875.3				6,394.0			
HIGH SULFUR CRUDE OIL												
HIGH SULFUR LIGHT	1,072.5	32.1	1.69	12.7	1,186.9	32.0	1.72	12.6	1,209.1	31.8	1.74	12.4
NO. OF REFINERIES	35				33				33			
ASSOC. CRUDE CHARGE	5,408.1				4,978.0				4,747.8			
HIGH SULFUR HEAVY	2,734.7	23.3	2.22	28.5	3,201.8	23.2	2.14	28.2	3,466.0	23.3	2.24	28.3
NO. OF REFINERIES	85				84				86			
ASSOC. CRUDE CHARGE	9,128.7				9,033.9				8,999.7			
TOTAL, ALL GRADES	11,642.7	32.6	0.96	16.3	12,291.3	31.9	1.00	16.8	12,419.6	31.7	1.06	17.0
NO. OF REFINERIES	173				167				168			
ASSOC. CRUDE CHARGE	14,639.4				14,610.9				14,424.6			

NATIONAL PETROLEUM COUNCIL
SURVEY OF U.S. PETROLEUM REFINERIES
* ALL U.S. RESPONDENTS *

SECTION C: OTHER FEEDSTOCKS
LIST ACTUAL 1984 AND PROJECTED CALENDAR 1986 AND 1988 FEEDSTOCKS AND BLENDING STOCKS OTHER THAN CRUDE OIL

	ACTUAL 1984 *	PROJECTED 1986 *	PROJECTED 1988 *
UNFINISHED BLENDSTOCKS OF DOMESTIC ORIGIN			
C3,C4 OLEFINS	43.7	34.3	31.4
NO. OF REFINERIES	28	15	14
ASSOCIATED CRUDE CHARGE	4,194.2	2,232.1	1,924.9
NAPHTHA	112.7	120.8	146.7
NO. OF REFINERIES	50	27	28
ASSOCIATED CRUDE CHARGE	7,185.2	4,404.9	4,359.7
DISTILLATE	32.9	44.5	42.3
NO. OF REFINERIES	24	11	11
ASSOCIATED CRUDE CHARGE	3,067.5	1,075.4	1,136.1
GAS OIL	283.5	348.7	320.5
NO. OF REFINERIES	73	43	43
ASSOCIATED CRUDE CHARGE	8,938.4	4,367.8	4,342.3
ATMOS RESID	15.2	.	.
NO. OF REFINERIES	16	5	5
ASSOCIATED CRUDE CHARGE	1,897.8	.	.
VACUM RESID	15.2	22.1	22.1
NO. OF REFINERIES	14	6	7
ASSOCIATED CRUDE CHARGE	2,053.9	708.7	719.2
LUBESTOCK INTERMEDIATE	0.8	.	.
NO. OF REFINERIES	5	2	2
ASSOCIATED CRUDE CHARGE	746.3	.	.
RESID FEEDSTOCK	41.9	84.9	81.5
NO. OF REFINERIES	15	12	11
ASSOCIATED CRUDE CHARGE	2,332.9	2,205.9	2,137.6
TOTAL UNFINISHED BLENDSTOCK DOMESTIC	546.3	658.3	648.0
NO. OF REFINERIES	103	70	71
ASSOCIATED CRUDE CHARGE	11,361.3	8,166.8	8,184.8
UNFINISHED BLENDSTOCKS OF FOREIGN ORIGIN			
C3,C4 OLEFINS	0.8	0.0	0.0
NO. OF REFINERIES	4	0	0
ASSOCIATED CRUDE CHARGE	749.5	0.0	0.0
NAPHTHA	14.3	.	22.3
NO. OF REFINERIES	6	4	4
ASSOCIATED CRUDE CHARGE	1,004.0	.	464.6

* ALL UNITS IN MB/CD UNLESS OTHERWISE NOTED

NATIONAL PETROLEUM COUNCIL
SURVEY OF U.S. PETROLEUM REFINERIES
* ALL U.S. RESPONDENTS *

SECTION C: OTHER FEEDSTOCKS
LIST ACTUAL 1984 AND PROJECTED CALENDAR 1986 AND 1988 FEEDSTOCKS AND BLENDING STOCKS OTHER THAN CRUDE OIL

	ACTUAL 1984 *	PROJECTED 1986 *	PROJECTED 1988 *
DISTILLATE	.	0.0	.
NO. OF REFINERIES	1	0	1
ASSOCIATED CRUDE CHARGE	.	0.0	.
GAS OIL	57.7	23.2	64.2
NO. OF REFINERIES	8	4	5
ASSOCIATED CRUDE CHARGE	1,411.0	841.0	936.0
ATMOS RESID	107.9	115.3	84.3
NO. OF REFINERIES	8	5	4
ASSOCIATED CRUDE CHARGE	1,431.2	946.1	846.1
VACUM RESID	8.0	0.0	0.0
NO. OF REFINERIES	3	0	0
ASSOCIATED CRUDE CHARGE	541.1	0.0	0.0
LUBESTOCK INTERMEDIATE	.	.	.
NO. OF REFINERIES	2	1	1
ASSOCIATED CRUDE CHARGE	.	.	.
RESID FEEDSTOCK	0.0	0.0	0.0
NO. OF REFINERIES	0	0	0
ASSOCIATED CRUDE CHARGE	0.0	0.0	0.0
TOTAL UNFINISHED BLENDSTOCK			
FOREIGN	193.9	161.0	195.0
NO. OF REFINERIES	22	12	12
ASSOCIATED CRUDE CHARGE	3,417.5	1,623.6	1,618.6
FIELD CONDENSATE	62.1	39.9	42.0
NO. OF REFINERIES	30	21	21
ASSOCIATED CRUDE CHARGE	3,673.5	2,360.8	2,363.3
FIELD NATURAL GASOLINE	151.1	105.1	92.8
NO. OF REFINERIES	66	44	43
ASSOCIATED CRUDE CHARGE	7,583.3	4,877.7	4,596.3
NATURAL GAS, FOE	263.3	271.2	271.0
NO. OF REFINERIES	119	112	111
ASSOCIATED CRUDE CHARGE	12,312.1	11,804.5	11,386.6
HYDROGEN, FOE	1.3	1.4	1.4
NO. OF REFINERIES	22	21	21
ASSOCIATED CRUDE CHARGE	4,327.0	4,172.8	4,117.5

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NATIONAL PETROLEUM COUNCIL
SURVEY OF U.S. PETROLEUM REFINERIES
* ALL U.S. RESPONDENTS *

SECTION C: OTHER FEEDSTOCKS
LIST ACTUAL 1984 AND PROJECTED CALENDAR 1986 AND 1988 FEEDSTOCKS AND BLENDING STOCKS OTHER THAN CRUDE OIL

	ACTUAL 1984 *	PROJECTED 1986 *	PROJECTED 1988 *
PROPANE	18.2	10.0	.
NO. OF REFINERIES	8	3	2
ASSOCIATED CRUDE CHARGE	1,351.2	239.2	.
ISOBUTANE	118.3	126.2	124.0
NO. OF REFINERIES	80	68	64
ASSOCIATED CRUDE CHARGE	9,834.3	7,319.8	6,433.5
BUTANE	183.5	186.0	189.6
NO. OF REFINERIES	100	90	90
ASSOCIATED CRUDE CHARGE	10,896.4	9,101.0	9,321.3
OXYGENATES:			
ETHYL ALCOHOL	2.6	13.9	14.8
NO. OF REFINERIES	10	15	16
ASSOCIATED CRUDE CHARGE	562.2	1,305.2	1,331.6
METHYL ALCOHOL	3.0	5.0	5.0
NO. OF REFINERIES	4	10	11
ASSOCIATED CRUDE CHARGE	535.0	1,189.6	1,211.2
TBA	7.7	15.0	5.5
NO. OF REFINERIES	3	4	4
ASSOCIATED CRUDE CHARGE	418.0	670.0	464.1
MTBE	12.4	22.4	23.9
NO. OF REFINERIES	15	13	14
ASSOCIATED CRUDE CHARGE	2,509.6	2,545.5	2,651.9
TOTAL OXYGENATES	25.8	56.4	49.4
NO. OF REFINERIES	29	37	39
ASSOCIATED CRUDE CHARGE	3,606.8	4,690.3	4,825.6
OTHER BLENDSTOCKS OF DOMESTIC ORIGIN:			
GASOLINE STOCK	106.2	82.8	82.8
RONC (R+M)/2	89.00	91.01	90.66
NO. OF REFINERIES	39	24	23
ASSOCIATED CRUDE CHARGE	5,210.8	3,368.5	2,941.4
DISTILLATE	24.8	5.1	8.0
WT. % SULFUR	0.12	0.15	0.26
NO. OF REFINERIES	15	4	5
ASSOCIATED CRUDE CHARGE	2,139.6	451.6	646.6

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NATIONAL PETROLEUM COUNCIL
SURVEY OF U.S. PETROLEUM REFINERIES
* ALL U.S. RESPONDENTS *

SECTION C: OTHER FEEDSTOCKS
LIST ACTUAL 1984 AND PROJECTED CALENDAR 1986 AND 1988 FEEDSTOCKS AND BLENDING STOCKS OTHER THAN CRUDE OIL

	ACTUAL 1984 *	PROJECTED 1986 *	PROJECTED 1988 *
HEAVY FUEL OIL	41.1	21.5	18.6
WT. % SULFUR	1.13	1.23	1.36
NO. OF REFINERIES	12	5	5
ASSOCIATED CRUDE CHARGE	1,631.7	482.2	454.2
TOTAL BLENDSTOCKS DOMESTIC	172.2	109.5	109.5
NO. OF REFINERIES	47	27	28
ASSOCIATED CRUDE CHARGE	6,372.4	4,013.5	3,795.0
OTHER BLENDSTOCKS OF FOREIGN ORIGIN:			
GASOLINE STOCK	.	.	.
RONC (R+M)/2	.	.	.
NO. OF REFINERIES	2	2	2
ASSOCIATED CRUDE CHARGE	.	.	.
DISTILLATE	.	.	.
WT. % SULFUR	.	.	.
NO. OF REFINERIES	2	1	1
ASSOCIATED CRUDE CHARGE	.	.	.
HEAVY FUEL OIL	.	.	.
WT. % SULFUR	.	.	.
NO. OF REFINERIES	1	1	1
ASSOCIATED CRUDE CHARGE	.	.	.
TOTAL BLENDSTOCKS FOREIGN	9.8	10.2	10.2
NO. OF REFINERIES	4	3	3
ASSOCIATED CRUDE CHARGE	616.4	516.4	516.4
OTHER FEEDSTOCKS	90.9	59.2	59.5
NO. OF REFINERIES	50	36	36
ASSOCIATED CRUDE CHARGE	6,781.7	4,943.4	5,237.2
TOTAL FEEDSTOCKS	13,480.3	14,087.3	14,227.9
NO. OF REFINERIES	174	170	171
ASSOCIATED CRUDE CHARGE	14,790.4	14,768.6	14,582.3

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NATIONAL PETROLEUM COUNCIL
SURVEY OF U.S. PETROLEUM REFINERIES
* ALL U.S. RESPONDENTS *

SECTION C: PRODUCT YIELD
LIST PRODUCT YIELDS FOR CRUDE OIL AND OTHER FEEDSTOCK SLATES

	ACTUAL 1984 *	PROJECTED 1986 *	PROJECTED 1988 *
LPG	270.9	285.5	296.5
NO. OF REFINERIES	111	106	107
ASSOCIATED CRUDE CHARGE	12,307.0	11,922.1	11,913.3
UNLEADED REGULAR	2,869.5	3,666.0	4,000.2
OCTANE, (R+M)/2	87.11	87.05	87.05
NO. OF REFINERIES	133	131	130
ASSOCIATED CRUDE CHARGE	14,050.9	14,044.5	13,715.7
UNLEADED INTERMEDIATE	94.7	108.3	213.6
OCTANE, (R+M)/2	89.30	89.30	89.17
NO. OF REFINERIES	8	10	22
ASSOCIATED CRUDE CHARGE	716.6	770.1	1,894.8
UNLEADED PREMIUM	887.3	1,073.8	1,169.8
OCTANE, (R+M)/2	91.86	91.85	91.84
NO. OF REFINERIES	102	100	102
ASSOCIATED CRUDE CHARGE	12,593.7	12,271.2	12,318.2
LEADED REGULAR	2,413.0	1,516.4	1,049.9
OCTANE, (R+M)/2	88.76	88.56	88.64
NO. OF REFINERIES	140	114	87
ASSOCIATED CRUDE CHARGE	14,143.6	12,081.6	9,524.5
LEADED PREMIUM	44.9	43.2	0.8
OCTANE, (R+M)/2	91.55	90.03	91.24
NO. OF REFINERIES	16	7	3
ASSOCIATED CRUDE CHARGE	1,009.4	455.7	97.4
AVIATION GASOLINE	27.7	32.0	31.7
NO. OF REFINERIES	29	26	26
ASSOCIATED CRUDE CHARGE	4,726.6	4,404.3	4,334.8
GASOLINE TOTALS	6,337.3	6,440.0	6,466.3
NO. OF REFINERIES	142	136	135
ASSOCIATED CRUDE CHARGE	14,252.1	14,246.9	14,002.3
JET FUEL:			
NAPHTHA	190.0	203.5	211.4
NO. OF REFINERIES	56	49	51
ASSOCIATED CRUDE CHARGE	5,261.6	4,887.6	5,401.8
KEROSENE	981.5	1,098.4	1,116.5
% SULFUR	0.11	0.13	0.14
NO. OF REFINERIES	101	95	95
ASSOCIATED CRUDE CHARGE	12,110.8	11,964.2	11,896.2

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NATIONAL PETROLEUM COUNCIL
SURVEY OF U.S. PETROLEUM REFINERIES
* ALL U.S. RESPONDENTS *

SECTION C: PRODUCT YIELD
LIST PRODUCT YIELDS FOR CRUDE OIL AND OTHER FEEDSTOCK SLATES

	ACTUAL 1984 *	PROJECTED 1986 *	PROJECTED 1988 *
KEROSENE & NO.1	94.9	95.9	95.5
NO. OF REFINERIES	75	65	65
ASSOCIATED CRUDE CHARGE	7,036.5	6,541.9	6,933.3
DIESEL:			
VERY LOW SULFUR	241.9	291.7	310.9
% SULFUR	0.17	0.19	0.18
NO. OF REFINERIES	32	31	31
ASSOCIATED CRUDE CHARGE	2,183.9	2,314.3	2,383.5
OTHER SULFUR	785.7	814.9	820.6
% SULFUR	0.34	0.34	0.35
NO. OF REFINERIES	76	72	72
ASSOCIATED CRUDE CHARGE	7,399.5	7,518.8	7,311.3
DISTILLATE NO. 2	1,474.4	1,533.8	1,525.4
% SULFUR	0.27	0.29	0.29
NO. OF REFINERIES	93	88	88
ASSOCIATED CRUDE CHARGE	10,026.5	9,392.8	9,299.7
NO. 4 FUEL OIL	6.3	18.8	18.1
NO. OF REFINERIES	17	15	14
ASSOCIATED CRUDE CHARGE	903.9	674.5	537.5
NO. 5 & 6 FUEL OIL:			
0-0.3 % SULFUR	42.6	35.7	34.9
NO. OF REFINERIES	12	11	10
ASSOCIATED CRUDE CHARGE	578.4	496.3	273.3
0.3-0.7 % SULFUR	76.1	73.3	71.6
NO. OF REFINERIES	20	20	20
ASSOCIATED CRUDE CHARGE	1,845.6	1,716.8	1,553.8
0.7-1.0 % SULFUR	109.9	121.4	121.9
NO. OF REFINERIES	37	26	24
ASSOCIATED CRUDE CHARGE	5,390.0	2,948.1	2,653.2
1-2.0 % SULFUR	302.3	302.6	319.4
NO. OF REFINERIES	64	54	52
ASSOCIATED CRUDE CHARGE	6,906.6	6,015.1	5,595.6
> 2.0 % SULFUR	296.8	260.5	232.6
NO. OF REFINERIES	48	36	37
ASSOCIATED CRUDE CHARGE	6,722.1	4,323.8	4,312.5

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NATIONAL PETROLEUM COUNCIL
SURVEY OF U.S. PETROLEUM REFINERIES
* ALL U.S. RESPONDENTS *

SECTION C: PRODUCT YIELD
LIST PRODUCT YIELDS FOR CRUDE OIL AND OTHER FEEDSTOCK SLATES

	ACTUAL 1984 *	PROJECTED 1986 *	PROJECTED 1988 *
FUEL OIL TOTALS	834.3	812.6	798.8
NO. OF REFINERIES	142	126	123
ASSOCIATED CRUDE CHARGE	13,036.2	11,627.8	10,925.1
ASPHALT & ROAD OIL	339.8	369.1	386.1
NO. OF REFINERIES	77	74	75
ASSOCIATED CRUDE CHARGE	6,921.9	6,061.2	5,988.5

REPORT ACTUAL AND ANTICIPATED LEAD AND MMT CONTENT AND RVP LEVELS

LEAD CONTENT (GM/GAL)			
LEADED REGULAR	1.06	0.21	0.1
NO. OF REFINERIES	139	119	
ASSOCIATED CRUDE CHARGE	14,123.8	13,017.2	
LEADED PREMIUM	1.27	0.19	0.1
NO. OF REFINERIES	14	14	
ASSOCIATED CRUDE CHARGE	792.4	1,096.9	
MMT CONTENT (GM/GAL)			
LEADED REGULAR	0.10	0.12	0.10
NO. OF REFINERIES	15	29	25
ASSOCIATED CRUDE CHARGE	2,403.2	4,681.1	3,611.9
LEADED PREMIUM	0.06	.	.
NO. OF REFINERIES	4	1	1
ASSOCIATED CRUDE CHARGE	208.7	.	.
RVP ALL GASOLINE (AVG. PSI)	11.68	11.68	11.68
NO. OF REFINERIES	139	134	133
ASSOCIATED CRUDE CHARGE	14,161.8	14,134.9	13,890.3

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NATIONAL PETROLEUM COUNCIL
SURVEY OF U.S. PETROLEUM REFINERIES
* ALL U.S. RESPONDENTS *

SECTION C: PRODUCT YIELD
LIST PRODUCT YIELDS FOR CRUDE OIL AND OTHER FEEDSTOCK SLATES

	ACTUAL 1984 *	PROJECTED 1986 *	PROJECTED 1988 *
FINISHED LUBRICANTS:			
PARAFFINIC	105.1	131.8	135.3
NO. OF REFINERIES	24	24	24
ASSOCIATED CRUDE CHARGE	4,658.7	4,576.5	4,441.3
NAPHTHENIC	41.8	43.5	48.3
NO. OF REFINERIES	15	14	14
ASSOCIATED CRUDE CHARGE	2,555.2	2,496.2	2,361.0
TOTAL LUBES	147.0	175.3	183.7
NO. OF REFINERIES	31	30	30
ASSOCIATED CRUDE CHARGE	4,870.7	4,786.7	4,651.5
WAX (ALL GRADES), ST/CD	4555.0	5059.0	5192.0
NO. OF REFINERIES	19	18	18
ASSOCIATED CRUDE CHARGE	3,554.8	3,259.2	3,137.2
BENZENE	27.5	38.1	38.7
NO. OF REFINERIES	18	20	20
ASSOCIATED CRUDE CHARGE	3,239.3	3,477.6	3,477.6
TOLUENE	48.9	49.5	54.0
NO. OF REFINERIES	23	16	17
ASSOCIATED CRUDE CHARGE	3,789.3	2,761.9	2,853.9
XYLENE	53.9	57.7	54.8
NO. OF REFINERIES	19	14	15
ASSOCIATED CRUDE CHARGE	3,311.8	2,667.4	2,818.4
OTHER SPECIALTIES & PETROCHEMICALS	208.7	235.8	231.6
NO. OF REFINERIES	49	42	41
ASSOCIATED CRUDE CHARGE	7,128.8	6,779.8	6,478.3
UNFINISHED OILS:			
C3,C4 OLEFINS	66.6	55.6	54.4
NO. OF REFINERIES	22	15	16
ASSOCIATED CRUDE CHARGE	3,368.1	2,406.9	2,645.7
NAPHTHA	137.0	184.9	217.9
NO. OF REFINERIES	59	40	40
ASSOCIATED CRUDE CHARGE	6,322.2	4,949.8	4,664.1

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NATIONAL PETROLEUM COUNCIL
SURVEY OF U.S. PETROLEUM REFINERIES
* ALL U.S. RESPONDENTS *

SECTION C: PRODUCT YIELD
LIST PRODUCT YIELDS FOR CRUDE OIL AND OTHER FEEDSTOCK SLATES

	ACTUAL 1984 *	PROJECTED 1986 *	PROJECTED 1988 *
DISTILLATE	85.8	82.0	83.4
NO. OF REFINERIES	35	19	18
ASSOCIATED CRUDE CHARGE	4,341.8	1,857.2	1,401.2
GAS OIL	249.0	207.6	223.8
NO. OF REFINERIES	56	32	32
ASSOCIATED CRUDE CHARGE	7,600.1	3,685.1	3,763.8
ATMOSPHERIC RESID	40.7	25.7	26.2
NO. OF REFINERIES	20	9	9
ASSOCIATED CRUDE CHARGE	1,541.4	241.3	241.3
VACUUM RESID	35.2	34.8	36.6
NO. OF REFINERIES	23	10	11
ASSOCIATED CRUDE CHARGE	3,324.5	1,075.7	1,131.7
LUBESTOCK INTERMEDIATES	19.6	12.3	12.3
NO. OF REFINERIES	9	4	4
ASSOCIATED CRUDE CHARGE	1,952.1	512.3	512.3
TOTAL UNFINISHED OILS	634.2	603.1	654.9
NO. OF REFINERIES	101	75	76
ASSOCIATED CRUDE CHARGE	11,178.3	8,644.6	8,420.1
SULFUR, LT/CD	7568.0	8459.0	9319.0
NO. OF REFINERIES	89	89	90
ASSOCIATED CRUDE CHARGE	12,129.9	11,817.5	11,840.3
PRODUCT COKE, ST/CD			
FUEL GRADE	31673.0	30778.0	29507.0
NO. OF REFINERIES	33	26	24
ASSOCIATED CRUDE CHARGE	5,395.2	4,492.8	4,195.0
METALLURGICAL GRADE	19192.0	20382.0	20117.0
NO. OF REFINERIES	24	19	18
ASSOCIATED CRUDE CHARGE	3,700.0	2,835.6	2,814.3
NEEDLE GRADE	-	-	-
NO. OF REFINERIES	2	2	2
ASSOCIATED CRUDE CHARGE	-	-	-

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NATIONAL PETROLEUM COUNCIL
SURVEY OF U.S. PETROLEUM REFINERIES
* ALL U.S. RESPONDENTS *

SECTION C: PRODUCT YIELD
LIST PRODUCT YIELDS FOR CRUDE OIL AND OTHER FEEDSTOCK SLATES

	ACTUAL 1984 *	PROJECTED 1986 *	PROJECTED 1988 *
PRODUCT COKE, UNSPECIFIED	.	.	.
NO. OF REFINERIES	4	5	6
ASSOCIATED CRUDE CHARGE	.	.	.
TOTAL PRODUCT COKE	55722.0	58156.0	56751.0
NO. OF REFINERIES	50	47	46
ASSOCIATED CRUDE CHARGE	7,365.7	7,253.5	7,491.0
MISCELLANEOUS OTHER PRODUCTS	164.7	138.6	143.8
NO. OF REFINERIES	46	43	44
ASSOCIATED CRUDE CHARGE	6,535.0	5,650.7	5,771.0
BLEND STOCKS TO OTHER REFINERS:			
GASOLINE	16.2	13.8	14.9
RONC	95.91		
NO. OF REFINERIES	9	7	6
ASSOCIATED CRUDE CHARGE	1,401.4	1,229.0	811.0
DISTILLATE	8.7	11.5	18.0
SULFUR WT. %	0.35		
NO. OF REFINERIES	4	6	7
ASSOCIATED CRUDE CHARGE	161.9	354.9	368.9
HEAVY FUEL OIL	18.1	17.5	12.1
SULFUR WT. %	1.59		
NO. OF REFINERIES	6	5	4
ASSOCIATED CRUDE CHARGE	1,024.6	859.6	694.3
TOTAL BLEND STOCKS	43.1	42.9	45.2
NO. OF REFINERIES	15	16	15
ASSOCIATED CRUDE CHARGE	2,049.9	2,295.5	1,726.2
REFINERY FUEL CONSUMED, FOE			
CRUDE OIL(FUEL)	.	.	.
NO. OF REFINERIES	2	2	2
ASSOCIATED CRUDE CHARGE	.	.	.
FUEL OILS:			
DISTILLATE	2.5	1.0	0.5
NO. OF REFINERIES	16	9	8
ASSOCIATED CRUDE CHARGE	2,198.8	855.1	765.1
RESID	61.6	62.7	60.8
PERCENT SULFUR	1.46	1.52	1.54
NO. OF REFINERIES	75	70	69
ASSOCIATED CRUDE CHARGE	5,974.0	5,654.9	5,513.4

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NATIONAL PETROLEUM COUNCIL
SURVEY OF U.S. PETROLEUM REFINERIES
* ALL U.S. RESPONDENTS *

SECTION C: PRODUCT YIELD
LIST PRODUCT YIELDS FOR CRUDE OIL AND OTHER FEEDSTOCK SLATES

	ACTUAL 1984 *	PROJECTED 1986 *	PROJECTED 1988 *
LIQUIFIED PETROLEUM GASES	23.8	28.2	25.6
NO. OF REFINERIES	46	32	32
ASSOCIATED CRUDE CHARGE	5,442.8	3,791.0	3,798.7
NATURAL GAS	197.4	209.3	203.6
NO. OF REFINERIES	112	108	106
ASSOCIATED CRUDE CHARGE	10,695.9	10,527.4	10,195.2
BY-PRODUCT GAS	482.8	509.8	509.7
NO. OF REFINERIES	140	137	136
ASSOCIATED CRUDE CHARGE	13,569.1	13,597.9	13,304.6
PETROLEUM COKE:			
MARKETABLE	8.3	11.7	11.8
NO. OF REFINERIES	5	6	6
ASSOCIATED CRUDE CHARGE	482.5	700.5	565.5
CATALYST	158.1	157.4	158.9
NO. OF REFINERIES	92	88	88
ASSOCIATED CRUDE CHARGE	11,009.4	10,467.1	10,269.1
OTHER	29.4	30.9	32.7
NO. OF REFINERIES	9	8	8
ASSOCIATED CRUDE CHARGE	1,117.0	716.0	716.0
TOTAL REFINERY FUEL	997.4	1,061.1	1,053.8
NO. OF REFINERIES	172	168	169
ASSOCIATED CRUDE CHARGE	14,764.7	14,742.9	14,556.6
CHANGE IN INVENTORY OF			
BLENDSTOCK:			
LIQUIFIED PETROLEUM GAS	8.6	.	.
NO. OF REFINERIES	21	2	2
ASSOCIATED CRUDE CHARGE	2,920.8	.	.
NAPHTHA	2.6	0.2	0.2
NO. OF REFINERIES	49	5	5
ASSOCIATED CRUDE CHARGE	6,004.3	789.0	789.0

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NATIONAL PETROLEUM COUNCIL
SURVEY OF U.S. PETROLEUM REFINERIES
* ALL U.S. RESPONDENTS *

SECTION C: PRODUCT YIELD
LIST PRODUCT YIELDS FOR CRUDE OIL AND OTHER FEEDSTOCK SLATES

	ACTUAL 1984 *	PROJECTED 1986 *	PROJECTED 1988 *
GAS BLENDSTOCKS	-12.3	.	1.5
NO. OF REFINERIES	47	2	3
ASSOCIATED CRUDE CHARGE	5,701.6	.	209.0
KEROSENE,TURBINE FUEL, DISTILLATE	44.6	.	.
NO. OF REFINERIES	43	2	2
ASSOCIATED CRUDE CHARGE	5,057.3	.	.
HEAVY FUEL OIL	-5.0	-1.4	1.0
NO. OF REFINERIES	38	6	3
ASSOCIATED CRUDE CHARGE	5,291.9	1,159.0	409.0
OTHERS	5.3	0.9	0.3
NO. OF REFINERIES	46	11	8
ASSOCIATED CRUDE CHARGE	5,828.9	1,777.9	949.7
TOTAL CHANGE IN INVENTORY	43.9	6.8	10.0
NO. OF REFINERIES	72	14	11
ASSOCIATED CRUDE CHARGE	8,314.8	2,110.7	1,138.7
TOTAL PRODUCTS	13,920.8	14,355.1	14,499.3
NO. OF REFINERIES	174	170	171
ASSOCIATED CRUDE CHARGE	14,790.4	14,768.6	14,582.3

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NATIONAL PETROLEUM COUNCIL
SURVEY OF U.S. PETROLEUM REFINERIES
* ALL U.S. RESPONDENTS *

SECTION C: CRUDE OIL AND OTHER FEEDSTOCK, PRODUCT YIELD

UNDER PRESENTLY KNOWN ENVIRONMENTAL CONSTRAINTS, WHAT WILL BE, IN 1988 THE MAXIMUM AMOUNT OF CRUDE OIL OVER 0.5 WT. % SULFUR THAT COULD BE SUBSTITUTED FOR CRUDE OIL OF 0.5% OR LESS, AS REPORTED FOR 1988 FOR PROCESSING IN FACILITIES REPORTED, WHILE MAINTAINING CURRENT PRODUCT QUALITY. (REPORT MAXIMUM SUBSTITUTION OF EACH GRADE OF CRUDE OIL INDEPENDENT OF THE OTHER THREE GRADES.)

	MB/CD SUBST. FOR SWEET CRUDE	WT. %S IN SUBST. CRUDE	MB/CD DROPPED OUT
CRUDE OIL SUBSTITUTED			
MEDIUM SULFUR CRUDE OIL:			
MEDIUM SULFUR-LIGHT	1,128.2	0.80	1,130.2
NO. OF REFINERIES	40	40	40
ASSOCIATED CRUDE CHARGE	5,323.4	5,323.4	5,323.4
MEDIUM SULFUR-HEAVY	825.2	0.95	867.4
NO. OF REFINERIES	36	36	36
ASSOCIATED CRUDE CHARGE	5,280.7	5,280.7	5,280.7
HIGH SULFUR CRUDE OIL:			
HIGH SULFUR-LIGHT	880.2	1.92	891.0
NO. OF REFINERIES	34	34	34
ASSOCIATED CRUDE CHARGE	4,762.2	4,762.2	4,762.2
HIGH SULFUR-HEAVY	795.3	2.40	852.1
NO. OF REFINERIES	36	36	36
ASSOCIATED CRUDE CHARGE	5,011.4	5,011.4	5,011.4
ASSOCIATED CRUDE CHARGE FOR ANY SUBSTITUTION		6,459.3	

ASSUMING MAXIMUM SUBSTITUTIONS OF CRUDE OIL AS SET FORTH ABOVE, REPORT ASSOCIATED ADJUSTED YIELD FOR EACH CRUDE OIL SUBSTITUTION INDEPENDENTLY OF OTHER CRUDE OIL GRADE SUBSTITUTIONS. (THE QUANTITIES SHOWN FOR EACH PRODUCT WILL NOT BE ADDITIVE BETWEEN GRADES.)

CRUDE OIL SUBSTITUTED	TOTAL GASOLINE	DIESEL	DIST IL NO. 2	HEAVY FUEL OIL	COKE (ST/D)
MEDIUM SULFUR CRUDE OIL:					
MEDIUM SULFUR-LIGHT	-28.2	0.6	-18.0	38.6	1429.0
NO. OF REFINERIES	22	13	13	19	6
ASSOCIATED CRUDE CHARGE	3,149.3	1,663.8	1,903.2	2,532.4	1,298.5
MEDIUM SULFUR-HEAVY	-62.8	-17.1	-25.3	62.8	1554.0
NO. OF REFINERIES	28	11	14	27	7
ASSOCIATED CRUDE CHARGE	3,946.3	1,156.6	2,184.0	3,875.3	1,435.5
HIGH SULFUR CRUDE OIL:					
HIGH SULFUR-LIGHT	-33.0	-8.8	-27.2	48.3	1339.0
NO. OF REFINERIES	24	13	9	19	6
ASSOCIATED CRUDE CHARGE	3,255.3	1,827.8	1,476.0	2,674.7	1,099.5
HIGH SULFUR-HEAVY	-76.2	-25.8	-47.3	89.8	2158.0
NO. OF REFINERIES	26	15	15	24	8
ASSOCIATED CRUDE CHARGE	3,496.6	1,895.1	2,115.8	3,305.6	1,282.5

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NATIONAL PETROLEUM COUNCIL
SURVEY OF U.S. PETROLEUM REFINERIES
* ALL U.S. RESPONDENTS *

SECTION C: CRUDE OIL AND OTHER FEEDSTOCK, PRODUCT YIELD

ENVIRONMENTAL CONSTRAINTS EXPECTED TO RESTRICT ABILITY TO PROCESS HIGH SULFUR CRUDE OILS

	1986	1988
SULFUR CONTENT OF PRODUCTS		
NO. OF REFINERIES	104	89
ASSOCIATED CRUDE CHARGE	9,082.8	7,489.1
SULFUR CONTENT OF REFIN FUELS		
NO. OF REFINERIES	57	45
ASSOCIATED CRUDE CHARGE	4,753.0	3,083.2
AIR EMISSIONS		
NO. OF REFINERIES	61	55
ASSOCIATED CRUDE CHARGE	5,871.8	4,850.2
EFFLUENT WATER QUALITY		
NO. OF REFINERIES	17	18
ASSOCIATED CRUDE CHARGE	1,566.6	1,600.8
OTHERS (E.G. METALLURGY)		
NO. OF REFINERIES	57	59
ASSOCIATED CRUDE CHARGE	4,883.7	5,229.4

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NATIONAL PETROLEUM COUNCIL
SURVEY OF U.S. PETROLEUM REFINERIES
* ALL U.S. RESPONDENTS *

SECTION D: IMPACT OF LEAD PHASE DOWN

1. GASOLINE MANUFACTURING CAPABILITIES WHILE MAXIMIZING UNLEADED GRADE VOLUMES, UNDER LEAD USE REGULATIONS APPLICABLE ON DATE OF SURVEY, I.E. LEAD CONTENT NOT TO EXCEEED 1.1 GM/GAL LEADED FUEL BLEND

	REGULAR UNLEADED GAS		OTHER UNLEADED GAS		LEADED GAS POOL		LEAD CONTENT	TOTAL GASOLINE
	(R+M)/2	MB/CD	(R+M)/2	MB/CD	(R+M)/2	MB/CD	GM/GAL	MB/CD
JANUARY 1, 1985	86.89	3,726.9	91.84	1,183.7	88.70	1,489.3	1.1	6,399.9
NO. OF REFINERIES		131		97		103		
JANUARY 1, 1986	87.07	4,014.7	91.78	1,222.6	88.69	1,283.3	1.1	6,520.7
NO. OF REFINERIES		131		102		92		
CRUDE CHARGE CAPACITY		14,081.1		12,494.0		10,088.6		
JANUARY 1, 1987	87.07	4,110.2	91.78	1,251.8	88.71	1,219.2	1.1	6,581.4
NO. OF REFINERIES		131		102		90		
JANUARY 1, 1988	87.06	4,097.0	91.78	1,304.7	88.71	1,131.2	1.1	6,533.0
NO. OF REFINERIES		131		103		85		
CRUDE CHARGE CAPACITY		13,878.1		12,368.0		9,205.0		
ASSOCIATED VOLUMES OF GASOLINE FROM SECTION C (MB/CD)								
1986		3,660.1		1,122.8		1,193.9		5,976.9
NO. OF REFINERIES		128		97		85		
1988		3,996.2		1,356.7		864.5		6,217.5
NO. OF REFINERIES		128		100		65		

PLANNED USE OF OXYGENATES, VOL. % OF TOTAL GASOLINE

	EOH	MTBE	MOH	TBA	TOTAL
JANUARY 1, 1985	0.10	0.36	0.03	0.09	0.59
NO. OF REFINERIES	8	15	3	3	
JANUARY 1, 1986	0.16	0.37	0.06	0.09	0.67
NO. OF REFINERIES	14	16	5	3	
CRUDE CHARGE CAPACITY	761.2	2,687.3	298.3	404.1	
JANUARY 1, 1987	0.23	0.38	0.06	0.09	0.75
NO. OF REFINERIES	14	16	5	3	
JANUARY 1, 1988	0.24	0.38	0.07	0.09	0.78
NO. OF REFINERIES	14	16	5	3	
CRUDE CHARGE CAPACITY	761.2	2,674.1	321.6	404.1	

NATIONAL PETROLEUM COUNCIL
SURVEY OF U.S. PETROLEUM REFINERIES
ALL U.S. RESPONDENTS

PART I - SECTIONS D, E, and F
GASOLINE MANUFACTURING CAPABILITIES

Maximum capabilities to manufacture unleaded gasolines, with crude oil rates not in excess of those projected in preceding Section C, current gasoline specifications (except as noted below), and taking into account normal seasonal factors, are reported for the several situations set forth below to show the impacts of constraints on leaded gasoline antiknock content, oxygenate use, and vapor pressure. Qualities and quantities of the remaining leaded gasoline pools are also reported.

The quantity of leaded fuels manufactured and the acquisition, sales or other external disposition of gasoline blend stocks other than oxygenates by any refinery was not to exceed the amount reported earlier in Section C of this survey. Ratios of volumes of regular unleaded gasolines to other unleaded gasolines was maintained at levels presently anticipated for dates investigated.

Gasoline Specifications

Section D-1: Base Case under lead regulations applicable on date of survey; i.e., not to exceed 1.1 gram/gallon leaded fuel blend.

Section D-2: Lead use under new regulation pending at time of survey; i.e., not to exceed 0.1 gram/gallon leaded gasoline after January 1, 1986. For 1988, unleaded gasoline capability was reported for both current octane specifications and with (R+M)/2 increased by 1.0 unit.

Section E: Elimination of use of oxygenates from all gasoline combined with limiting lead use to not exceed 0.1 gram/gallon in leaded grades after January 1, 1986.

Section F: Reid Vapor Pressure (RVP) of all gasoline was limited to 1.0 psi less than current ASTM specifications, or to 9.0 psi, whichever was greater, combined with limiting lead use to not exceed 0.1 gram/gallon in leaded grades after January 1, 1986.

NATIONAL PETROLEUM COUNCIL
SURVEY OF U.S. PETROLEUM REFINERIES
* ALL U.S. RESPONDENTS *

SECTION D: IMPACT OF LEAD PHASE DOWN

2. GASOLINE MANUFACTURING CAPABILITIES WHILE MAXIMIZING UNLEADED GRADE VOLUMES, UNDER NEW LEAD REGULATIONS PENDING ON DATE OF SURVEY, I.E. LEAD CONTENT NOT TO EXCEEED 0.1 GM/GAL LEADED FUEL BLEND AFTER JANUARY 1, 1986. FOR 1988 REPORT UNLEADED GASOLINE MAXIMUM CAPABILITY AT BOTH CURRENT (R+M)/2 QUALITY AND FOR AN INCREASE OF 1.0 OVER CURRENT QUALITY

	REGULAR UNLEADED GAS		OTHER UNLEADED GAS		LEADED GAS POOL		LEAD CONTENT	TOTAL GASOLINE
	(R+M)/2	MB/CD	(R+M)/2	MB/CD	(R+M)/2	MB/CD	GM/GAL	MB/CD
JANUARY 1, 1985	87.09	3,742.7	91.84	1,174.3	88.69	1,475.2	1.1	6,392.2
NO. OF REFINERIES		131		96		102		
JANUARY 1, 1986	87.06	4,168.9	91.62	1,182.2	88.59	1,064.0	0.1	6,415.1
NO. OF REFINERIES		130		103		74		
CRUDE CHARGE CAPACITY		14,002.1		12,555.4		8,934.1		
JANUARY 1, 1987	87.05	4,248.6	91.57	1,257.6	88.61	959.9	0.1	6,466.2
NO. OF REFINERIES		130		103		71		
JANUARY 1, 1988	87.06	4,334.0	91.65	1,285.7	88.63	811.9	0.1	6,431.7
NO. OF REFINERIES		131		104		62		
CRUDE CHARGE CAPACITY		13,878.1		12,430.4		7,562.6		
JANUARY 1, 1988	88.06	4,290.2	92.64	873.3	88.66	756.6	0.1	5,920.2
NO. OF REFINERIES		125		88		58		
CRUDE CHARGE CAPACITY		13,071.1		10,761.3		7,113.6		
ASSOCIATED VOLUMES OF GASOLINE FROM SECTION C (MB/CD)								
1986		3,660.1		1,154.4		1,102.0		5,916.6
NO. OF REFINERIES		128		99		73		
1988		3,996.2		1,360.3		853.9		6,210.5
NO. OF REFINERIES		128		102		61		

PLANNED USE OF OXYGENATES, VOL. % OF TOTAL GASOLINE

	EOH	MTBE	MOH	TBA	TOTAL
JANUARY 1, 1985	0.10	0.40	0.03	0.09	0.62
NO. OF REFINERIES	7	17	3	3	
JANUARY 1, 1986	0.35	0.61	0.03	0.07	1.07
NO. OF REFINERIES	19	23	4	3	
CRUDE CHARGE CAPACITY	1,275.4	3,918.1	215.8	404.1	
JANUARY 1, 1987	0.42	0.64	0.03	0.07	1.17
NO. OF REFINERIES	18	23	4	3	
JANUARY 1, 1988	0.45	0.66	0.05	0.07	1.23
NO. OF REFINERIES	19	24	4	3	
CRUDE CHARGE CAPACITY	1,275.4	4,027.0	236.6	404.1	
JANUARY 1, 1988	0.56	0.98	0.05	0.08	1.67
NO. OF REFINERIES	19	24	4	3	
CRUDE CHARGE CAPACITY	1,275.4	4,027.0	236.6	404.1	

NATIONAL PETROLEUM COUNCIL
SURVEY OF U.S. PETROLEUM REFINERIES
* ALL U.S. RESPONDENTS *

SECTION E: IMPACT OF LIMITATION ON THE USE OF OXYGENATES
GASOLINE MANUFACTURING CAPABILITIES WHILE MAXIMIZING UNLEADED GRADE VOLUMES, WITH USE OF OXYGENATES ELIMINATED, AND UNDER NEW REGULATIONS PENDING ON DATE OF SURVEY, I.E. LEAD CONTENT NOT TO EXCEED 0.1 GRAMS/GALLON AFTER JANUARY 1, 1986

	REGULAR UNLEADED GAS		OTHER UNLEADED GAS		LEADED GAS POOL		LEAD CONTENT	TOTAL GASOLINE
	(R+M)/2	MB/CD	(R+M)/2	MB/CD	(R+M)/2	MB/CD	GM/GAL	MB/CD
JANUARY 1, 1985	87.09	3,709.4	91.84	1,158.3	88.69	1,469.8	0.1	6,337.7
NO. OF REFINERIES		131		94		103		
JANUARY 1, 1986	87.06	4,161.6	91.61	1,112.6	88.60	1,059.9	0.1	6,334.3
NO. OF REFINERIES		131		96		76		
CRUDE CHARGE CAPACITY		14,008.8		11,938.2		9,020.9		
JANUARY 1, 1987	87.06	4,242.1	91.55	1,178.1	88.61	968.8	0.1	6,389.1
NO. OF REFINERIES		131		98		73		
JANUARY 1, 1988	87.06	4,320.8	91.64	1,187.9	88.66	823.3	0.1	6,332.1
NO. OF REFINERIES		132		99		64		
CRUDE CHARGE CAPACITY		13,884.8		12,252.7		7,649.4		
ASSOCIATED VOLUMES OF GASOLINE FROM SECTION C (MB/CD)								
1986		3,661.1		1,126.9		1,111.2		5,899.2
NO. OF REFINERIES		129		93		75		
1988		3,997.2		1,345.4		855.1		6,197.7
NO. OF REFINERIES		129		98		62		

NATIONAL PETROLEUM COUNCIL
SURVEY OF U.S. PETROLEUM REFINERIES
* ALL U.S. RESPONDENTS *

SECTION F: IMPACT OF LIMITATION ON VAPOR PRESSURE
GASOLINE MANUFACTURING CAPABILITIES WHILE MAXIMIZING UNLEADED GRADE VOLUMES, WITH REID VAPOR PRESSURE (RVP) REDUCED TO 1.0 PSI UNDER CURRENT ASTM SPECIFICATIONS, OR TO 9.0 PSI (WHICHEVER IS GREATER) COMBINED WITH LIMITING LEAD USE, I.E. LEAD CONTENT NOT TO EXCEED 0.1 GM/GAL LEADED FUEL BLEND

	REGULAR UNLEADED			OTHER UNLEADED		
	RVP	(R+M)/2	MB/CD	RVP	(R+M)/2	MB/CD
CALENDAR 1985						
CURRENT	11.68	87.09	3,705.1	11.56	91.83	1,181.3
NO. OF REFINERIES			131			97
REDUCED	10.70	87.09	3,532.7	10.59	91.84	1,152.1
NO. OF REFINERIES			130			96
CALENDAR 1986						
CURRENT	11.70	87.06	4,093.1	11.58	91.65	1,160.2
NO. OF REFINERIES			130			100
ASSOCIATED CRUDE CHARGE			13,857.8			12,235.9
REDUCED	10.71	87.06	3,956.1	10.63	91.67	1,148.7
NO. OF REFINERIES			129			99
ASSOCIATED CRUDE CHARGE			13,720.8			12,098.9
CALENDAR 1987						
CURRENT	11.69	87.07	4,134.3	11.55	91.59	1,237.5
NO. OF REFINERIES			129			101
REDUCED	10.70	87.07	3,976.4	10.59	91.61	1,221.7
NO. OF REFINERIES			128			100
CALENDAR 1988						
CURRENT	11.67	87.07	4,241.5	11.60	91.68	1,267.2
NO. OF REFINERIES			130			103
ASSOCIATED CRUDE CHARGE			13,680.8			12,264.9
REDUCED	10.68	87.08	4,095.1	10.68	91.70	1,251.4
NO. OF REFINERIES			129			102
ASSOCIATED CRUDE CHARGE			13,543.8			12,127.9

NATIONAL PETROLEUM COUNCIL
SURVEY OF U.S. PETROLEUM REFINERIES
* ALL U.S. RESPONDENTS *

SECTION F: IMPACT OF LIMITATION ON VAPOR PRESSURE
GASOLINE MANUFACTURING CAPABILITIES WHILE MAXIMIZING UNLEADED GRADE VOLUMES, WITH REID VAPOR PRESSURE (RVP) REDUCED TO 1.0 PSI UNDER CURRENT ASTM SPECIFICATIONS, OR TO 9.0 PSI (WHICHEVER IS GREATER) COMBINED WITH LIMITING LEAD USE, I.E. LEAD CONTENT NOT TO EXCEED 0.1 GM/GAL LEADED FUEL BLEND

	LEADED			PLANNED USE OF OXYGENATES				
	RVP	(R+M)/2	MB/CD	EOH	MTBE	MOH	TBA	TOTAL
CALENDAR 1985								
CURRENT	11.66	88.65	1,486.1	0.11	0.38	.	.	0.61
NO. OF REFINERIES			103	8	17	2	3	
REDUCED	10.65	88.67	1,422.8	0.12	0.43	.	.	0.66
NO. OF REFINERIES			101	9	18	2	3	
CALENDAR 1986								
CURRENT	11.54	88.57	1,078.5	0.35	0.57	.	.	1.17
NO. OF REFINERIES			75	18	22	2	5	
ASSOCIATED CRUDE CHARGE			8,939.6	1,254.2	3,830.6	.	.	
REDUCED	10.54	88.61	993.6	0.38	0.52	.	.	1.15
NO. OF REFINERIES			73	18	21	2	5	
ASSOCIATED CRUDE CHARGE			8,702.6	1,265.4	3,146.7	.	.	
CALENDAR 1987								
CURRENT	11.57	88.54	1,011.9	0.42	0.50	.	.	1.02
NO. OF REFINERIES			73	17	20	2	4	
REDUCED	10.56	88.57	935.9	0.47	0.66	.	.	1.24
NO. OF REFINERIES			71	18	23	2	4	
CALENDAR 1988								
CURRENT	11.66	88.54	840.4	0.45	0.62	0.04	0.07	1.19
NO. OF REFINERIES			64	19	23	3	3	
ASSOCIATED CRUDE CHARGE			7,621.1	1,302.2	3,939.5	171.6	404.1	
REDUCED	10.63	88.57	784.5	0.48	0.67	0.04	0.07	1.26
NO. OF REFINERIES			62	19	23	3	3	
ASSOCIATED CRUDE CHARGE			7,384.1	1,313.4	3,836.9	171.6	404.1	

NATIONAL PETROLEUM COUNCIL
SURVEY OF U.S. PETROLEUM REFINERIES
* ALL U.S. RESPONDENTS *

SECTION F: IMPACT OF LIMITATION ON VAPOR PRESSURE
GASOLINE MANUFACTURING CAPABILITIES WHILE MAXIMIZING UNLEADED GRADE VOLUMES, WITH REID VAPOR PRESSURE (RVP) REDUCED TO 1.0 PSI UNDER CURRENT ASTM SPECIFICATIONS, OR TO 9.0 PSI (WHICHEVER IS GREATER) COMBINED WITH LIMITING LEAD USE, I.E. LEAD CONTENT NOT TO EXCEED 0.1 GM/GAL LEADED FUEL BLEND

	EXCESS BUTANES (B/CD)	REDUCED BUTANES (B/CD)	REDUCTION IN PURCHASES OF BUTANES (B/CD)
CALENDAR 1985			
CURRENT	6365	754	7119
NO. OF REFINERIES	8	3	
REDUCED	68983	73148	142131
NO. OF REFINERIES	66	91	
CALENDAR 1986			
CURRENT	.	.	6829
NO. OF REFINERIES	8	2	
ASSOCIATED CRUDE CHARGE	.	.	
REDUCED	70778	78619	149397
NO. OF REFINERIES	63	92	
ASSOCIATED CRUDE CHARGE	7,184.9	10,255.5	
CALENDAR 1987			
CURRENT	.	.	8760
NO. OF REFINERIES	8	1	
REDUCED	73644	79079	152723
NO. OF REFINERIES	65	91	
CALENDAR 1988			
CURRENT	.	.	8760
NO. OF REFINERIES	8	2	
ASSOCIATED CRUDE CHARGE	.	.	
REDUCED	74897	79349	154246
NO. OF REFINERIES	64	92	
ASSOCIATED CRUDE CHARGE	7,578.5	9,920.2	

NATIONAL PETROLEUM COUNCIL
SURVEY OF U.S. PETROLEUM REFINERIES

* ALL U.S. RESPONDENTS *

SECTION G: BENZENE IN GASOLINE

1984 TYPICAL AND PROJECTED 1988 TYPICAL BENZENE CONTENT OF MOTOR GASOLINE, GIVEN FACILITIES EXISTING OR FIRMLY COMMITTED, QUANTITIES OF GASOLINE ANTICIPATED IN SECTION C, AND CURRENT (R+M)/2 SPECIFICATIONS

	UNLEADED			LEADED	
	REGULAR	PREMIUM	OTHER	REGULAR	PREMIUM
BENZENE					
1984 TYPICAL, VOL %	2.08	2.49	1.68	1.90	1.62
ASSOC. GAS VOLUME (MB/CD)	2,464.5	814.8	36.9	2,080.4	38.1
TOTAL BENZENE (MB/CD)	51.2	20.2	0.6	39.4	0.6
NO. OF REFINERIES	106	83	10	108	14
ASSOC. CRUDE CHARGE (MB/CD)	12,270.3	11,253.6	979.0	12,020.9	1,030.2
1988 TYPICAL, VOL %	1.82	1.76	1.54	1.79	1.53
ASSOC. GAS VOLUME (MB/CD)	3,082.0	915.2	94.8	680.7	0.5
TOTAL BENZENE (MB/CD)	56.1	16.1	1.4	12.2	0.0
NO. OF REFINERIES	97	80	16	72	7
ASSOC. CRUDE CHARGE (MB/CD)	10,512.9	9,869.0	1,270.9	8,314.7	457.4

SECTION H: SULFUR CONTENT LIMITATIONS ON DISTILLATES

1. REPORT MAXIMUM VOLUME OF VERY LOW SULFUR DISTILLATE THAT CAN BE PRODUCED IN 1988 WITH COMMITTED OR PLANNED FACILITIES AND ANTICIPATED CRUDE SLATES

	MAXIMUM WT %SULFUR	DISTILLATE (MB/CD)	NO. OF REFINERIES	ASSOCIATED CRUDE CHARGE (MB/CD)
LA BASIN TRANSPORTATION DIESEL	0.05	206.93	16	1,670.0
DISTILLATE IN OTHER REGIONS	0.2	1863.738	101	10,070.2

2. ADDED FACILITIES REQUIRED TO REDUCE SULFUR CONTENT TO 0.2 WT. %

	ADDITIONAL CAPACITY	NO. OF REFINERIES	ASSOCIATED CRUDE CHARGE (MB/CD)
DISTILLATE HYDROTREATING (MB/CD)	457.8	45	3,402.7
HYDROCRACKING (MB/CD)	.	1	.
HYDROREFINING (MB/CD)	71.0	4	233.7
HYDROGEN GENERATION (MMCF/CD)	201.96	15	1,225.5
SULFUR RECOVERY (LT/CD)	2348.6	20	1,010.0
TANKAGE (MBBL)	1274	15	764.0

NATIONAL PETROLEUM COUNCIL
1985 SURVEY OF U.S. PETROLEUM REFINERIES
ALL U.S. RESPONDENTS*

PART II: OPERATIONAL COSTS

January 1, 1985 Associated Crude Oil Charge Capacity (MB/CD)	14,651.4
Number of Respondent Refineries	168

*Does not include respondent refineries in the U.S. Virgin Islands, Puerto Rico, Guam, and the Hawaiian Foreign Trade Zone.

NATIONAL PETROLEUM COUNCIL
SURVEY OF U.S. PETROLEUM REFINERIES

* ALL U.S. RESPONDENTS *

PART II, SECTION A: OPERATIONAL EXPENSES
1984 OPERATING EXPENSES FOR THE CATEGORIES LISTED BELOW (ALL COSTS LIMITED TO OPERATIONS AND FACILITIES INSIDE THE REFINERY FENCE)

	$/BBL CRUDE OIL THROUGHPUT	$/MMBTU	MMBTU/BBL CRUDE OIL THROUGHPUT	NO. OF REFINERIES	ASSOCIATED CRUDE CHARGE (MB/CD)
1. DIRECT PAYROLL & PAYROLL RELATED (1)	$0.70			166	14,289.7
2. CONTRACT MAINTENANCE LABOR	$0.17			147	13,891.6
3. REFINERY PRODUCED FUEL & UTILITIES (2)	$1.50			148	14,030.3
			0.39	155	14,104.3
		$3.67		152	14,062.8
4. PURCHASED FUEL AND UTILITIES (3)	$0.81			157	14,082.1
			0.20	165	14,248.2
		$4.01		162	14,118.8
5. CATALYSTS AND CHEMICALS	$0.23			149	14,101.5
6. ANTIKNOCK COMPOUNDS	$0.05			129	13,525.0
7. MAINTENANCE MATERIALS	$0.20			162	14,243.5
8. DEPRECIATION	$0.37			163	14,188.3
9. OTHER OPERATING EXPENSES (4)	$0.54			160	14,199.3
TOTAL	$4.60				

SECTION B: 1984 CRUDE OIL COSTS
DELIVERED COST AND TRANSPORTATION COST WITHIN THE U.S. FOR CRUDE OIL PROCESSED AT THE REFINERY

	VOLUME MB/CD	DELIVERED COST $/BBL	TRANSPORT COST $/BBL
DOMESTIC CRUDE	7,925.6	$27.82	$0.48
NO. OF REFINERIES	158	156	88
ASSOC. CRUDE CHARGE (MB/CD)	13,876.8	13,590.6	6,221.3
IMPORTED CRUDE	2,500.0	$27.63	$0.14
NO. OF REFINERIES	75	75	26
ASSOC. CRUDE CHARGE (MB/CD)	11,045.0	10,812.5	3,230.6

SECTION C: REFINERY ASSETS (5)

	MM$	NO. OF REFINERIES	ASSOCIATED CRUDE CHARGE (MB/CD)
GROSS FIXED ASSETS	$37,997.39	166	13,969.7
APPROX REPLACEMENT COST	$89,099.63	162	13,436.9

(1) OPERATIONS, MAINTENANCE, BLENDING, PUMPING, LABORATORY AND OTHER DIRECT LABOR AND SUPERVISION
(2) USE 10,000 BTU/KILOWATT HOUR TO CONVERT FUEL TO ELECTRICITY
(3) IN CALCULATING UNIT FUEL, USE ACTUAL EXPENSE FOR PURCHASED ENERGY, AND THE LOCAL INCREMENTAL PURCHASE/SALE PRICE FOR SELF-PRODUCED ENERGY
(4) INCLUDING FIXED AND ALLOCATED EXPENSES
(5) WITHIN THE REFINERY FENCE

APPENDIX E

Questionnaire for the NPC's 1985 Survey of U.S. Petroleum Refineries

NATIONAL PETROLEUM COUNCIL

1985 SURVEY OF U.S. PETROLEUM REFINERIES

Part I: Current and Firmly Committed Facilities

and

Part II: Operational Costs

Please return this booklet, when completed, to:

Thomas R. Janson
Arthur Young & Company
1025 Connecticut Avenue, N.W.
Washington, D.C. 20036

NATIONAL PETROLEUM COUNCIL

1985 Survey of U.S. Petroleum Refineries

General Instructions

As outlined in the cover letter to your Chief Executive Officer, the National Petroleum Council is conducting a study of refinery capability for the Secretary of Energy.

In order to analyze refinery capability and flexibility to meet future product demand, the Council is surveying all U.S. refineries for historical, current, and projected operations, selected operational costs for each refinery, and possible future facilities requirements. The Council is surveying all domestic refineries with operable capacity as of January 1, 1984, *including those refineries that ceased operations during 1984.* All refineries that were not operable as of January 1, 1984, but became operable during 1984, or are planned to be operable prior to January 1, 1988, are also to be included in this survey.

Overview of the Survey

The Council requests that the attached questionnaire, in two parts, be completed for each refinery and returned to the Washington, D.C., office of Arthur Young & Company, by March 22, 1985.

Part I surveys each refinery's current and projected operations for those facilities that are in place or are firmly committed for installation prior to January 1, 1988. Part II surveys selected operational costs for each refinery.

The Council requests that refineries respond with the best, most reasonable data that can be provided within the time frame allowed for completion of the survey.

Data Tabulation and Confidentiality

The public accounting firm of Arthur Young & Company has been retained by the National Petroleum Council to tabulate the refinery survey data and provide aggregated data to the U.S. Petroleum Refining study participants and NPC staff. Individual company data from the survey will be held strictly confidential and will not be released to government, study participants, or NPC staff representatives. Ray W. Whitson, a private consultant, will assist Arthur Young & Company in reviewing the questionnaires, and will be available in the event of any difficulties in questionnaire interpretation. Mr. Whitson will have access to individual questionnaires only after they have been coded and refinery identification has been removed. Mr. Whitson has agreed not to divulge any confidential information he may receive while assisting Arthur Young & Company.

The accounting firm will release the aggregated data to NPC study participants only when sufficient data are available to permit aggregation in a manner which would not disclose an individual refinery's operations. Once the aggregated data have been formally accepted by the study participants, all individual refinery reports will be destroyed.

Mailing Instructions

The completed questionnaire should be mailed under confidential cover to the attention of:

Thomas R. Janson
Arthur Young & Company
1025 Connecticut Avenue, N.W.
Washington, D.C. 20036

Refinery Contacts

Companies are requested to identify a corporate-level contact for the survey by February 18, 1985, and send a memo to Thomas R. Janson, Arthur Young & Company, and John W. Rauber, Jr., National Petroleum Council, containing this individual's name and telephone number.

Jointly Owned Refineries

In the case of jointly owned refineries, the operating company should complete the survey questionnaire.

Conclusion

It is hoped that you will return completed survey forms not later than March 22, 1985. This will enable the NPC study groups to conduct their analyses and respond to the Secretary of Energy on a timely basis.

If there are any questions in completing the questionnaire, contact John W. Rauber, Jr., National Petroleum Council, (202) 393-6100, or Ray W. Whitson, Arthur & Young Company, (202) 828-7000.

Explanation of Purposes for Specific Information Requested

To the extent practical, the NPC study will rely directly upon aggregated responses to this survey to develop the refinery capability and flexibility assessments requested by the Secretary of Energy. The most reliable and complete data base is that supplied by individual refiners with due consideration being given to known constraints at each refinery location.

For other parts of the study it appears appropriate to use mathematical models of the industry, segmented by geographic area, refinery complexity, and size range. The survey results, combined with the judgements of the industry experts on the NPC study groups, will provide the necessary basis for ensuring that any models used are valid representations and do not overstate industry capability or flexibility.

Part I, Section A: Process Facilities Capabilities

The 1984 capabilities and utilization data requested in this section, when coupled with raw material and product information from Section C, will help permit base line validation of industry models. Portions will be cross checked with DOE-supplied information for consistency.

The capability data for 1986 and 1988 are needed (1) to assess the industry capability in the 1985–1990 time frame and (2) to update the models previously validated with 1984 information. Estimates of process unit utilization in 1988 will serve to check the reasonableness of operations projected under various scenarios.

The 1986 capacity data will reveal near-term changes in refining capabilities and are considered necessary for review of the interim ability of refiners to respond to proposed regulatory changes which, if adopted, would greatly reduce allowed use of lead antiknocks in gasoline.

Part I, Section B: Process Energy Production and Consumption

Recognizing that energy conservation measures may have resulted in current unit energy balances that differ significantly from design or published data, actual process unit energy balance data for 1984 will be used in the industry segment models. Note that Section B.2 will provide information concerning further energy conservation efforts through January 1, 1988.

Part I, Section C: Crude Oil and Other Feedstock; Product Yield

Projections by domestic refiners of their anticipated product yields and feedstock requirements in 1986 and 1988 will be considered along with worldwide and domestic supply/demand balances in preparing the requested assessment of the industry in the 1985–1990 time frame. The 1984 data will tie to other DOE-supplied information and assist in validating models used for impact studies.

Section C.3 results will determine the flexibility of the industry to adjust to lower quality crude slates in the event that changes in planned crude supplies were to occur.

Part I, Section D: Gasoline Manufacturing Capabilities

This section is intended to reflect the impact of proposed new lead phasedown regulations upon domestic gasoline manufacturing capabilities in the 1985 to 1988 time frame. The capability to produce unleaded gasolines while limiting lead in leaded grades at the proposed 0.1 gram per gallon level will be compared to the capability at the current 1.1 gram per gallon lead limit in leaded grades. Data are requested for each of these years since the blending capability may be changing as new octane generating facilities are brought on line.

Supplemental information requested for 1988 defines further limitations in unleaded gasoline production capabilities that would result if the industry were required to raise the road octane specification of the fuels by 1.0 number.

Part I, Sections E and F: Impacts of Limitations on the Use of Oxygenates and on Vapor Pressure

Potential regulations that would adversely impact gasoline manufacturing capacity include any new limitations upon the use of oxygenates and upon vapor pressure. These sections request data showing gasoline manufacturing capability without the use of oxygenates, or with the restriction of vapor pressure (to 1.0 psi less than current ASTM specifications or to 9.0 psi, whichever is greater). In all instances, this information is to be reported with lead limited to 0.1 grams per gallon in leaded grades.

Part I, Section G: Benzene in Gasoline

It is planned to assess the impact of limiting benzene content in gasoline in this NPC study. However, survey respondents are only requested to provide base line data on their 1984 actual and 1988 anticipated

typical benzene content of various gasoline grades. Inasmuch as any significant reduction in benzene content in gasoline, if at all practicable, would necessitate many major changes and additions to facilities, the study group believes this restriction is best investigated apart from the survey.

Part I, Section H: Sulfur Content Limitations on Distillates

Los Angeles basin refiners were recently required to limit sulfur in transportation diesel fuel to 0.05 weight percent. It has been proposed that refiners elsewhere should be required to limit sulfur in all diesel fuel and distillate heating fuel to not more than 0.2 weight percent. The intent of this section is to determine the impact of such existing and proposed environmental regulations on the industry.

Part II: Operational Costs

In requesting this study, the Secretary of Energy was interested in an assessment of the impact of competitive changes and structural shifts that might occur in the domestic refining industry in the 1985–1990 time frame. This section requests base line cost data, which will help project future manufacturing and transportation costs for different segments of the industry.

Detailed Instructions and Definitions

General

- Even if the refinery was declared inoperable during 1984, report data for 1984 operations.
- Report data only on those lines that are applicable to your operation. If there is no data for a specific line, leave the line blank. Do not enter zero (0).
- Where footnotes request additional information, enter data in spaces provided.

Part I, Section A: Process Facilities Capabilities

Operable Capacity

Operable capacity is defined as the sum of that capacity in operation at the beginning of a given period, that not in operation nor under repair but which can be placed in operation within 30 days, and that not in operation but under active repair that can be completed within 90 days. Unless otherwise specified, capacity data in this survey is requested in barrels per calendar day.

Barrels Per Calendar Day (B/CD)

Barrels per calendar day is defined in this survey as the maximum number of barrels of input that can be processed, or product that can be yielded, during a twenty-four hour period, after making allowance for the following limitations:

- The types and grades of inputs to be processed.
- The types and grades of products expected to be manufactured.
- The reduction of capacity for scheduled downtime such as routine inspection, mechanical problems, maintenance, repairs, and turnaround.
- The reduction of capacity for unscheduled downtime such as mechanical problems, repairs, and slowdowns.

Multiple Units

Individual process unit information is requested when the refinery has more than one of the following units:

- Catalytic Reforming
- Catalytic Hydrotreating
- Catalytic Cracking
- Alkylation
- Catalytic Hydrocracking
- Thermal Processing.

If the refinery has fewer units than there are spaces provided for these process facilities, leave the unused spaces for units blank. Do not enter zero (0).

Data requested under the column "Capacity Utilization" for 1984 should be average for 1984 and will be used for validation. The data for 1988 should be the reasonable projection.

Part I, Section B: Process Energy Production and Consumption

For question B.2, provide planned savings in overall refinery energy consumption (MMBTU/bbl crude oil) between January 1, 1984 and January 1, 1986, and between January 1, 1984 and January 1, 1988.

Part I, Section C: Crude Oil and Other Feedstocks; Product Yields

The following represent factors for converting to FOE B/CD for associated fuels:

- Fuel Oil Equivalent (FOE) = 6,300,000 BTUs/bbl
- Crude Oil—Average for one barrel = 5,800,000 BTU = 0.92 bbl of FOE
- Natural Gas—MMCF = 162 barrels of FOE
- By-product Gas—MMCF = 162 barrels of FOE (based on natural gas; could vary with hydrocarbon composition.)
- Coke—One short ton (ST) = 4.6 barrels of FOE
- Coal—Average for one short ton (ST) = 3.6 barrels of FOE

Part I, Sections D, E, and F

Proposed lead content standard refers to that proposed by EPA in *Regulation of Fuels and Fuel Additives; Lead Phase Down,* 49 FR 150.

Refinery Survey Acronyms & Abbreviations

NOTE: The abbreviations below refer to the way in which they are used in this survey.

API—American Petroleum Institute
AS—Asphalt
ASTM—American Society for Testing and Materials
B/CD—Barrels Per Calendar Day
BTUs—British Thermal Units
BTX—Benzene, Toluene, Xylene
C_3—Propane
C_3 + C_4 Olefins—Propylene and Butylene Olefins
C_4—Butane
C_5 + —Pentane
C_6—Hexane
DC—Delayed Coker
EP—End Point
°F—Degrees Fahrenheit
FC—Fluid Coker
FCC—Fluid Catalytic Cracker
FOE—Fuel Oil Equivalent
FX—Flexicoker
gm/gal—Grams Per Gallon
H_2—Hydrogen
HF—Hydrofluoric Acid
HFO—Heavy Fuel Oil
IC_4—Iso-Butane
KWHr/bbl—Kilowatt Hours Per Barrel
lbs/hr—Pounds Per Hour
LPG—Liquified Petroleum Gas
LT—Long Tons (2,240 lbs)
LT/CD—Long Tons Per Calendar Day
LU—Lube Oil Feedstock
M—Motor Octane Number
MB—Thousand Barrels
MCF—Thousand Cubic Feet
ME—Methane
Mlbs/bbl—Thousand Pounds of Steam Per Barrel
MM—Million
MMBTU—Million British Thermal Units
MMCF—Million Cubic Feet
MMCF/CD—Million Cubic Feet Per Calendar Day
MMT—Methylcyclopentadienyl Manganese Tricarbonyl (Gasoline Additive)
MOH—Methyl Alcohol
MONC—Motor Octane Number Clear (no lead)
MSCF/CD—Thousand Stantard Cubic Feet Per Calendar Day
MTBE—Methyl Tertiary Butyl Ether
MX—Mixed
N—Naphtha
NC_4—Normal Butane
Ni—Nickel
ppm—Parts Per Million
R—Research Octane Number
RONC—Research Octane Number Clear (no lead)
(R + M)/2—Road Octane Number
S—Sulfur
ST—Short Ton (2,000 lbs.)
ST/CD—Short Tons Per Calendar Day

NATIONAL PETROLEUM COUNCIL
1985 SURVEY OF U.S. PETROLEUM REFINERIES

INDIVIDUAL REFINERY REPORT

PART I: CURRENT AND FIRMLY COMMITTED FACILITIES

REFINERY IDENTIFICATION SHEET

Company: _____

Refinery Name: _____

State, Territory,
or Hawaiian Free Trade Zone: _____

Refinery Point
of Contact: _____
(NAME)

_____
(PHONE NUMBER)

NATIONAL PETROLEUM COUNCIL
1985 SURVEY OF U.S. PETROLEUM REFINERIES

INDIVIDUAL REFINERY REPORT

PART I: CURRENT AND FIRMLY COMMITTED FACILITIES (INSTALLATION PRIOR TO JANUARY 1, 1988)

Survey Due Date: March 22, 1985

Code Number[1] _____

General Refinery Information

1. Indicate location of this refinery by state, or Guam, Puerto Rico, Virgin Islands, or Hawaiian Free Trade Zone _____

2. If refinery is outside the 50 states, indicate which PADD(s) you are currently or anticipate supplying petroleum products. PADD(s) _____

3. Total charge capacity for crude oil distillation as reported to the Energy Information Administration on Form EIA-820 as of January 1, 1985. _____ Barrels per calendar day (B/CD)

4. If there are questions, contact John W. Rauber, Jr., National Petroleum Council, (202) 393-6100, or Ray W. Whitson, Arthur Young & Company, (202) 828-7000.

[1]This entry, and other NPC Code spaces on subsequent pages, will be entered by the accounting firm for Data Tabulation purposes.

PART I

Code Number _____

SECTION A: PROCESS FACILITIES CAPABILITIES

Given anticipated feedstock and product qualities, process operating conditions, and environmental constraints, list maximum operable process unit capacities and other specified unit capabilities in place as of January 1, 1984, or underway or firmly planned for completion on or before January 1, 1986 and January 1, 1988. Also report actual utilization in 1984 and estimated utilization in 1988.

	OPERABLE CAPACITIES, B/CD			CAPACITY UTILIZATION, B/CD	
	JAN. 1, 1984	JAN. 1, 1986	JAN. 1, 1988	1984	1988
1. Crude Oil Charge Atmospheric Distillation,[1] _____					
Other Units That Normally Charge Whole Crude					
2. Vacuum Distillation Feed Rate,[1] _____					
3. Catalytic Reforming, Unit No.1,[2] _____ (a and b are not additive) a. Current or Anticipated Severity (RONC)[3,4]					
Associated Charge Capacity					
b. Maximum Severity (RONC)					
Associated Charge Capacity					
c. Feedstock Composition,[5] _____					
3. Catalytic Reforming, Unit No. 2,[2] _____ (a and b are not additive) a. Current or Anticipated Severity (RONC)[3,4]					
Associated Charge Capacity					
b. Maximum Severity (RONC)					
Associated Charge Capacity					
c. Feedstock Composition,[5] _____					
3. Catalytic Reforming, Unit No. 3,[2] _____ (a and b are not additive) a. Current or Anticipated Severity (RONC)[3,4]					
Associated Charge Capacity					
b. Maximum Severity (RONC)					
Associated Charge Capacity					
c. Feedstock Composition,[5] _____					
4. C_4 Isomerization Product IC_4 Capacity					
5. C_5/C_6 Isomerization Product Capacity					
Product RONC					
6. Catalytic Hydrotreating, Unit No.1[6] Naphtha					
Kerosene					
Distillate					
Heavy Gas Oil					
Atmospheric Resid					
Vacuum Residuum					

[1]Indicate number of units.
[2]Enter C for continuous regeneration or S for semi-regenerative.
[3]RONC of C_5+ (debutanized) reformate.
[4]Anticipated refers to years 1986 and 1988 operable capacities.
[5]Enter Vol. % naphthenes/Vol. % aromatics for which capacities are reported.
[6]For multipurpose hydrotreaters, report capacities on the basis of normal distribution of feedstocks. Where there are multiple units performing one service (i.e., hydrotreating naphtha) report combined capacities as a single unit. For each multipurpose hydrotreater, these capacities for the several feedstocks are additive.

SECTION A: PROCESS FACILITIES CAPABILITIES (Cont.)

Given anticipated feedstock and product qualities, process operating conditions, and environmental constraints, list maximum operable process unit capacities and other specified unit capabilities in place as of January 1, 1984, or underway or firmly planned for completion on or before January 1, 1986 and January 1, 1988. Also report actual utilization in 1984 and estimated utilization in 1988.

	OPERABLE CAPACITIES*			CAPACITY UTILIZATION*	
	JAN. 1, 1984	JAN. 1, 1986	JAN. 1, 1988	1984	1988
6. Catalytic Hydrotreating, Unit No. 2[6] Naphtha					
Kerosene					
Distillate					
Heavy Gas Oil					
Atmospheric Resid					
Vacuum Residuum					
6. Catalytic Hydrotreating, Unit No. 3[6] Naphtha					
Kerosene					
Distillate					
Heavy Gas Oil					
Atmospheric Resid					
Vacuum Residuum					
7. Catalytic Cracking, Unit No. 1 Fresh Feed Rate, B/CD					
Fresh Feed Composition: Virgin Gas Oils, Vol.%					
Thermal Gas Oil, Vol.%					
Atmospheric Resid, Vol.%					
Deasphalted Oil, Vol.%					
Vacuum Resid, Vol.%					
Other Fresh Feed, Vol.%					
Feedstock Quality: °API Gravity					
Conradson Carbon, wt.%[7]					
Product Yields: Fuel Gas, FOE Vol.%					
C_3/C_4, Vol.% Recovered					
Naphtha, C_5-430°F, Vol.%					
Cycle Oil, 430°-630°F, Vol.%					
Decant Oil, Vol.%					
Coke, wt.%					
Carbon Burning Capacity, lb/hr					
RONC of C_5+ (Laboratory Debutanized)					
Naphtha Product					
MONC of C_5+ (Laboratory Debutanized)					
Naphtha Product					
Fresh Feed Hydrotreating (enter % hydrotreated): Virgin Gas Oils					
Thermal Gas Oils					
Atmospheric Resid					
Deasphalted Oil					
Vacuum Resid					
Other Fresh Feed					

*Responses to line item No. 6 should be reported in B/CD; for other line items, report in units indicated.

[6]For multipurpose hydrotreaters, report capacities on the basis of normal distribution of feedstocks. Where there are multiple units performing one service (i.e., hydrotreating naphtha) report combined capacities as a single unit. For each multipurpose hydrotreater, these capacities for the several feedstocks are additive.

[7]If carbon residue determined by alternate method, convert to equivalent Conradson Carbon.

PART I

Code Number _____

SECTION A: PROCESS FACILITIES CAPABILITIES (Cont.)

Given anticipated feedstock and product qualities, process operating conditions, and environmental constraints, list maximum operable process unit capacities and other specified unit capabilities in place as of January 1, 1984, or underway or firmly planned for completion on or before January 1, 1986 and January 1, 1988. Also report actual utilization in 1984 and estimated utilization in 1988.

	OPERABLE CAPACITIES			CAPACITY UTILIZATION	
	JAN. 1, 1984	JAN. 1, 1986	JAN. 1, 1988	1984	1988
7. Catalytic Cracking, Unit No. 2 Fresh Feed Rate, B/CD					
Fresh Feed Composition: Virgin Gas Oils, Vol.%					
Thermal Gas Oil, Vol.%					
Atmospheric Resid, Vol.%					
Deasphalted Oil, Vol.%					
Vacuum Resid, Vol.%					
Other Fresh Feed, Vol.%					
Feedstock Quality: °API Gravity					
Conradson Carbon, wt.%[7]					
Product Yields: Fuel Gas, FOE Vol.%					
C_3/C_4, Vol.% Recovered					
Naphtha, C_5-430°F, Vol.%					
Cycle Oil, 430°-630°F, Vol.%					
Decant Oil, Vol.%					
Coke, wt.%					
Carbon Burning Capacity, lb/hr					
RONC of C_5+ (Laboratory Debutanized)					
Naphtha Product					
MONC of C_5+ (Laboratory Debutanized)					
Naphtha Product					
Fresh Feed Hydrotreating (enter % hydrotreated): Virgin Gas Oils					
Thermal Gas Oils					
Atmospheric Resid					
Deasphalted Oil					
Vacuum Resid					
Other Fresh Feed					

[7]If carbon residue determined by alternate method, convert to equivalent Conradson Carbon.

Code Number _____

SECTION A: PROCESS FACILITIES CAPABILITIES (Cont.)

Given anticipated feedstock and product qualities, process operating conditions, and environmental constraints, list maximum operable process unit capacities and other specified unit capabilities in place as of January 1, 1984, or underway or firmly planned for completion on or before January 1, 1986 and January 1, 1988. Also report actual utilization in 1984 and estimated utilization in 1988.

	OPERABLE CAPACITIES*			CAPACITY UTILIZATION*	
	JAN. 1, 1984	JAN. 1, 1986	JAN. 1, 1988	1984	1988
7. Catalytic Cracking, Unit No. 3 Fresh Feed Rate, B/CD					
Fresh Feed Composition: Virgin Gas Oils, Vol.%					
Thermal Gas Oil, Vol.%					
Atmospheric Resid, Vol.%					
Deasphalted Oil, Vol.%					
Vacuum Resid, Vol.%					
Other Fresh Feed, Vol.%					
Feedstock Quality: °API Gravity					
Conradson Carbon, wt.%[7]					
Product Yields: Fuel Gas, FOE Vol.%					
C_3/C_4, Vol.% Recovered					
Naphtha, C_5-430°F, Vol.%					
Cycle Oil, 430°-630°F, Vol.%					
Decant Oil, Vol.%					
Coke, wt.%					
Carbon Burning Capacity, lb/hr					
RONC of C_5+ (Laboratory Debutanized)					
Naphtha Product					
MONC of C_5+ (Laboratory Debutanized)					
Naphtha Product					
Fresh Feed Hydrotreating (enter % hydrotreated): Virgin Gas Oils					
Thermal Gas Oils					
Atmospheric Resid					
Deasphalted Oil					
Vacuum Resid					
Other Fresh Feed					
8. Alkylation, Unit No. 1 C_5+ Debutanized Product Volume from Butylene					
C_5+ Debutanized Product Volume from Propylene					
RONC of Debutanized Product					
MONC of Debutanized Product					
Process Type,[8] _____					
8. Alkylation, Unit No. 2 C_5+ Debutanized Product Volume from Butylene					
C_5+ Debutanized Product Volume from Propylene					
RONC of Debutanized Product					
MONC of Debutanized Product					
Process Type,[8] _____					

*Responses to line item No. 8 should be reported in B/CD; for other line items, report in units indicated.

[7]If carbon residue determined by alternate method, convert to equivalent Conradson Carbon.

[8]Enter HF (for hydrofluoric) or SU (for sulfuric acid) catalyst.

PART I

Code Number _____

SECTION A: PROCESS FACILITIES CAPABILITIES (Cont.)

Given anticipated feedstock and product qualities, process operating conditions, and environmental constraints, list maximum operable process unit capacities and other specified unit capabilities in place as of January 1, 1984, or underway or firmly planned for completion on or before January 1, 1986 and January 1, 1988. Also report actual utilization in 1984 and estimated utilization in 1988.

	OPERABLE CAPACITIES*			CAPACITY UTILIZATION*	
	JAN. 1, 1984	JAN. 1, 1986	JAN. 1, 1988	1984	1988
9. Polymerization					
Type of Unit,[9] _____					
Debutanized Product Volume from Butylene					
Debutanized Product Volume from Propylene					
RONC of Debutanized Product					
MONC of Debutanized Product					
Feed Type,[10] _____					
10. Catalytic Hydrocracking, Unit No. 1					
Feed Composition: Virgin Gas Oils, Vol.%					
Cycle Oil, Vol.%					
Thermal Gas Oil, Vol.%					
Deasphalted Oil, Vol.%					
Atmospheric Resid, Vol.%					
Vacuum Resid, Vol.%					
Product Yields, Vol.% Fresh Feed: Fuel Gas, FOE Vol. %					
C_3/C_4, Vol. % Recovered					
C_5+ Naphtha, Vol.%					
Kerosene Distillate, Vol.%					
700°F EP Distillate, Vol.%					
700°F+ Gas Oil, Vol.%					
H_2 Consumption, SCF/bbl					
10. Catalytic Hydrocracking, Unit No. 2					
Feed Composition: Virgin Gas Oils, Vol.%					
Cycle Oil, Vol.%					
Thermal Gas Oil, Vol.%					
Deasphalted Oil, Vol.%					
Atmospheric Resid, Vol.%					
Vacuum Resid, Vol.%					
Product Yields, Vol.% Fresh Feed: Fuel Gas, FOE Vol. %					
C_3/C_4, Vol. % Recovered					
C_5+ Naphtha, Vol.%					
Kerosene Distillate, Vol.%					
700°F EP Distillate, Vol.%					
700°F+ Gas Oil, Vol.%					
H_2 Consumption, SCF/bbl					

*Responses to line item No. 9 should be reported in B/CD; for other line items, report in units indicated.

[9]Enter PA for phosphoric acid, D for dimersol.

[10]Enter C_3 for propylene, C_4 for butylene, and MX for mixed olefin feedstock.

PART I Code Number _____

SECTION A: PROCESS FACILITIES CAPABILITIES (Cont.)

Given anticipated feedstock and product qualities, process operating conditions, and environmental constraints, list maximum operable process unit capacities and other specified unit capabilities in place as of January 1, 1984, or underway or firmly planned for completion on or before January 1, 1986 and January 1, 1988. Also report actual utilization in 1984 and estimated utilization in 1988.

	OPERABLE CAPACITIES			CAPACITY UTILIZATION	
	JAN. 1, 1984	JAN. 1, 1986	JAN. 1, 1988	1984	1988
11. Thermal Processing, Unit No. 1 Feed Rate, B/CD					
Unit Type,[11] _____					
Fresh Feed Composition: Atmospheric Gas Oil, Vol.%					
Vacuum Gas Oil, Vol.%					
Atmospheric Resid Vol.%					
Vacuum Resid, Vol.%					
Cracked Stock, Vol.%					
Coke Make, ST/CD[12]					
Coke Qualities: Sulfur, wt.%					
Total Metals Ni + V, ppm					
Fresh Feed Hydrotreating (enter % hydrotreated):					
Atmospheric Gas Oil					
Vacuum Gas Oil					
Atmospheric Resid					
Cracked Stock					
11. Thermal Processing, Unit No. 2 Feed Rate, B/CD					
Unit Type,[11] _____					
Fresh Feed Composition: Atmospheric Gas Oil, Vol.%					
Vacuum Gas Oil, Vol.%					
Atmospheric Resid, Vol.%					
Vacuum Resid, Vol.%					
Cracked Stock, Vol.%					
Coke Make, ST/CD[12]					
Coke Qualities: Sulfur, wt.%					
Total Metals Ni + V, ppm					
Fresh Feed Hydrotreating (enter % hydrotreated): Atmospheric Gas Oil					
Vacuum Gas Oil					
Atmospheric Resid					
Cracked Stock					

[11]Enter TC for thermal cracker, VB for visbreaker, DC for delayed coker, FC for fluid coker, FX for flexicoker, TD for thermal demetallization.
[12]Where applicable.

PART I Code Number _____

SECTION A: PROCESS FACILITIES CAPABILITIES (Cont.)

Given anticipated feedstock and product qualities, process operating conditions, and environmental constraints, list maximum operable process unit capacities and other specified unit capabilities in place as of January 1, 1984, or underway or firmly planned for completion on or before January 1, 1986 and January 1, 1988. Also report actual utilization in 1984 and estimated utilization in 1988.

	OPERABLE CAPACITIES*			CAPACITY UTILIZATION*	
	JAN. 1, 1984	JAN. 1, 1986	JAN. 1, 1988	1984	1988
12. Lube Oils Manufacture Product Volumes,[13] _____					
13. Petrochemicals Aromatics Units					
Charge: to solvent extraction					
to hydrodealkylation					
Products: Benzene					
Toluene					
Xylene					
Methyl Tertiary Butyl Ether (MTBE)					
14. Solvent Deasphalting Fresh Feed Rate, B/CD					
Deasphalted Oil, Vol.% Fresh Feed,[14] _____					
SDA Residuum, Vol.% Fresh Feed,[15] _____					
15. Hydrogen (Generation of or upgrading to 90+% Purity, MSCF/CD Product),[13] _____					
Steam hydrocarbon reforming[16]	( )	( )	( )	( )	( )
Partial oxidation					
Purification of low H_2 content streams					
16. Sulfur Recovery,[17] LT/CD (includes recovered non-elemental sulfur),[13] _____					
17. Amount of Reforming Capacity in Section A.3. Used to Process Cat Naphtha					
18. Amount of Reforming Feed Capacity in Section A.3. Used to Produce Reformate for BTX Extraction Feedstock					

*Responses to line items Nos. 12, 13, 17 and 18 should be reported in B/CD; for other line items, report in units indicated.

[13]Indicate number of units.

[14]Indicate use of deasphalted oil for FC if for FCC feedstock, or LU if for lube oil feedstock, or if for both, enter % for each use.

[15]Indicate use of SDA residuum for AS if routed to asphalt, or HF if blended into HFO.

[16]Show in parentheses for each year the type of feed utilized or anticipated: Enter LPG for liquified petroleum gas, ME for methane, N for naphtha, or MX for mixed.

[17]Report sulfur that is recovered from the refinery's feedstocks. Include any recovery that may be accomplished off premises (e.g., an adjacent chemical plant).

PART I Code Number _____

SECTION B: PROCESS ENERGY PRODUCTION AND CONSUMPTION

1. Enter gross production under (P) and gross consumption under (C), for 1984 unit energy production and consumption. Where multiple units are used, give weighted average.

	FUEL[1]		POWER[2]		STEAM[3]	
	P	C	P	C	P	C
1. Crude Distillation						
2. Vacuum Distillation						
3. Reforming						
4. C_4 Isomerization						
5. C_5/C_6 Isomerization						
6. Catalytic Hydrotreating Reforming Naphtha						
Other Naphtha						
Kerosene						
Distillate						
Heavy Gas Oil						
Atmospheric Resid						
Vacuum Resid						
7. Catalytic Cracking						
8. Alkylation						
9. Polymerization						
10. Dimerization						
11. Catalytic Hydrocracking						
12. Thermal Processing						
13. Lube Oil Manufacture						
14. Petrochemicals BTX						
Others, specify						
15. Hydrogen Generation[4]						
16. Solvent Deasphalting						
17. Sulfur Recovery, (include Tail Gas Cleanup)[5]						
18. Outside Process Battery Limits[6]						
19. Overall Refinery						

2. Report planned energy conservation savings anticipated for the years indicated, relative to January 1, 1984.

a. 1/1/86 _____ MMBTU/bbl crude

b. 1/1/88 _____ MMBTU/bbl crude

3. Given 1988 projections in Sections A and C, estimate 1988 overall refinery energy consumption.

Fuel: _____ MMBTU/bbl

Power: _____ KWHr/bbl

Steam: _____ Mlbs/bbl

[1]Unless otherwise indicated, express fuel as MMBTU/bbl, of feed or of product, coinciding with basis for unit capacity, including coke on catalyst where applicable.

[2]Unless otherwise indicated, express power as KWHr/bbl, of feed or of product, coinciding with basis for unit capacity.

[3]Unless otherwise indicated, express steam as Mlbs/bbl, of feed or of product, coinciding with basis for unit capacity.

[4]Express utility comodities as units per MCF.

[5]Express utility comodities as units per LT.

[6]Express utility comodities as units per barrel of crude.

PART I

Code Number _____

SECTION C: CRUDE OIL AND OTHER FEEDSTOCK; PRODUCT YIELD

1. List actual calendar 1984 and projected calendar 1986 and 1988 crude oil and other feed and blending stocks. Crude oils should be identified by the types shown below. (See Attachment I at the end of Section C for classification of selected specific crude oils.)

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

	ACTUAL 1984				PROJECTED 1986				PROJECTED 1988			
	B/CD	°API	%S	%RESID[1]	B/CD	°API	%S	%RESID[1]	B/CD	°API	%S	%RESID[1]
Crude Oil												
Domestic:												
Sweet Crude Oil												
Medium Sulfur Crude Oil												
Medium Sulfur—Light												
Medium Sulfur—Heavy												
High Sulfur Crude Oil												
High Sulfur—Light												
High Sulfur—Heavy												
Foreign:												
Sweet Crude Oil												
Medium Sulfur Crude Oil												
Medium Sulfur—Light												
Medium Sulfur—Heavy												
High Sulfur Crude Oil												
High Sulfur—Light												
High Sulfur—Heavy												
Total:												
Sweet Crude Oil												
Medium Sulfur Crude Oil												
Medium Sulfur—Light												
Medium Sulfur—Heavy												
High Sulfur Crude Oil												
High Sulfur—Light												
High Sulfur—Heavy												

[1]Express as Vol.% of resid in crude oil over 1050°F boiling range.

PART I Code Number _____

SECTION C: CRUDE OIL AND OTHER FEEDSTOCK; PRODUCT YIELD (Cont.)

	ACTUAL 1984 B/CD	PROJECTED 1986 B/CD	PROJECTED 1988 B/CD
Other Feedstocks			
Unfinished Stocks of Domestic Origin:[2]			
C_3, C_4 Olefins			
Naphtha			
Distillate			
Gas Oil			
Atmospheric Resid			
Vacuum Resid			
Lubestock Intermediates			
Resid Feedstock			
Unfinished Stocks of Foreign Origin:[2]			
C_3, C_4 Olefins			
Naphtha			
Distillate			
Gas Oil			
Atmospheric Resid			
Vacuum Resid			
Lubestock Intermediates			
Resid Feedstock			
Field Condensate			
Field Natural Gasoline			
Natural Gas, MMCF/CD[3]			
Hydrogen, MMCF/CD			
Propane			
Isobutane			
Butane			
Oxygenates:			
Ethyl Alcohol			
Methyl Alcohol			
Tertiary Butyl Alcohol			
Methyl Tertiary Butyl Ether			
Other Blend Stocks of Domestic Origin:[4]			
Gasoline Stocks (Specify RONC)	( )	( )	( )
Distillate (Specify Sulfur, wt. %)	( )	( )	( )
Heavy Fuel Oil (Specify Sulfur, wt. %)	( )	( )	( )
Other Blend Stocks of Foreign Origin:[4]			
Gasoline Stocks (Specify RONC)	( )	( )	( )
Distillate (Specify Sulfur, wt. %)	( )	( )	( )
Heavy Fuel Oil (Specify Sulfur, wt. %)	( )	( )	( )
Specify Other Feedstocks:			
Total Feedstocks			

[2]Stocks to be further processed in your refinery.
[3]Includes purchases of both process feedstock and refinery fuel.
[4]Stocks only for blending into finished products. Report RONC and wt. % sulfur in parentheses.

PART I

Code Number _____

SECTION C: CRUDE OIL AND OTHER FEEDSTOCK; PRODUCT YIELD (Cont.)

2. List product yields for crude oil and other feedstock slates shown in Section C.1 above.

	ACTUAL 1984 B/CD	PROJECTED 1986 B/CD	PROJECTED 1988 B/CD
LPG			
Unleaded Regular[5]	( )	( )	( )
Unleaded Intermediate[5]	( )	( )	( )
Unleaded Premium[5]	( )	( )	( )
Leaded Regular[5,6]	( )	( )	( )
Leaded Premium[5,6]	( )	( )	( )
Aviation Gasoline			
Jet Fuel: Naphtha Base			
Kerosene Base[7]	( )	( )	( )
Kerosene & No. 1 Heating Oil			
Diesel: very low sulfur[7]	( )	( )	( )
other sulfur[7]	( )	( )	( )
Distillate No. 2[8]	( )	( )	( )
No. 4 Fuel Oil			
No. 5 & 6 Fuel Oil: (0.0-0.3%S)			
(0.3-0.7%S)			
(0.7-1.0%S)			
(1.0-2.0%S)			
(>2.0% S)			
Asphalt and Road Oils			

[5]Enter Road Octane number, (R+M)/2, in parentheses.

[6]Report actual and anticipated lead and MMT content and RVP levels for 1984, 1986, and 1988 (lead content of 0.1 gm/gal in 1988 is provided):

	ACTUAL 1984	PROJECTED 1986	PROJECTED 1988
Lead Content (gm/gal): Leaded Regular			0.1
Leaded Premium			0.1
MMT Content (gm/gal): Leaded Regular			
Leaded Premium			
RVP Level (yr. avg. psi): all gasoline			

[7]Enter wt. % sulfur in parentheses.

[8]Enter wt. % sulfur average in parentheses.

PART I Code Number _____

SECTION C: CRUDE OIL AND OTHER FEEDSTOCK; PRODUCT YIELD (Cont.)

	ACTUAL 1984 B/CD	PROJECTED 1986 B/CD	PROJECTED 1988 B/CD
Finished Lubricants: Paraffinic			
Naphthenic			
Wax (all grades), ST/CD			
Benzene			
Toluene			
Xylene			
Other Specialties & Petrochemicals			
Unfinished Oils: C_3, C_4 Olefins			
Naphtha			
Distillate			
Gas Oil			
Atmospheric Resid			
Vacuum Resid			
Lubestock Intermediates			
Sulfur, LT/CD (include non-elementary sulfur equivalent in sulfuric acid)			
Product Coke, ST/CD			
Fuel Grade			
Metallurgical Grade			
Needle			
Miscellaneous (other products)			
Blending stocks that go to other refiners: Gasoline (specify RONC)			
Distillate (specify sulfur)			
Heavy Fuel Oil (specify sulfur)			
Refinery Fuel Consumed, FOE B/CD[9]			
Crude Oil Used as Fuel			
Fuel Oils: Distillate			
Residual[10]	( )	( )	( )
Liquified Petroleum Gases			
Natural Gas			
By-product Gases			
Petroleum coke: Marketable			
Catalyst			
Coal			
Other			
Changes in inventories of intermediates and unfinished blendstocks: Liquified Petroleum Gases			
Naphtha			
Gasoline Blendstocks			
Kerosene, Turbine Fuel, and Distillates			
Heavy Fuel Oil			
Others			
Total Products (Ex-wax, sulfur, & coke)			

[9]Use conversion table provided in instructions to convert to FOE.
[10]Enter wt. % sulfur in parentheses.

PART I Code Number _____

SECTION C: CRUDE OIL AND OTHER FEEDSTOCK; PRODUCT YIELD (Cont.)

3. **Under presently known environmental contraints, what will be, in 1988, the maximum amount of crude oil over 0.5 wt.% sulfur content that could be substituted for crude oil of 0.5 wt.% or less, as reported for 1988 in Section C.1 for processing in facilities reported in Section A, while maintaining current product quality. (Report maximum substitution of each grade of crude oil for 0.5 wt. % sulfur or less independent of the other three grades. In other words, the quantities for the four grades are not additive.)**

CRUDE OIL SUBSTITUTED	B/CD SUBSTITUTE FOR SWEET CRUDE	WT. % OF SULFUR IN SUBSTITUTE CRUDE	B/CD SWEET CRUDE DROPPED OUT
Medium Sulfur Crude Oil: Medium Sulfur—Light			
Medium Sulfur—Heavy			
High Sulfur Crude Oil: High Sulfur—Light			
High Sulfur—Heavy			

4. **Assuming maximum substitutions of crude oil of over 0.5 wt.% sulfur content as set forth in 3. above, report associated adjusted yield projections for principal products. Report adjusted yield for each crude oil substitution independently of other crude oil grade substitutions. In other words, the quantities shown for each product will not be additive between substituted grades.**

CRUDE OIL SUBSTITUTED	1988 ADJUSTED REFINERY YIELD PROJECTION, B/CD				
	TOTAL GASOLINE	DIESEL	DISTILLATE NO. 2	HEAVY FUEL OIL	COKE (ST/D)
Medium Sulfur Crude Oil: Medium Sulfur—Light					
Medium Sulfur—Heavy					
High Sulfur Crude Oil: High Sulfur—Light					
High Sulfur—Heavy					

5. **Which environmental or other constraints, if any, will restrict your ability in 1986 and 1988 to process high sulfur crude oils? *Check applicable items.*** (✓)

	1986	1988
Sulfur Content of Products		
Sulfur Content of Refinery Fuels		
Air Emissions		
Effluent Water Quality		
Others (e.g., Metallurgy)		

ATTACHMENT I

Typical Qualities of High Sulfur Crude Oils

HIGH SULFUR—LIGHT

Crude Stream	Gravity °API	Sulfur Wt. %	1,050+ °F Bottoms Yield Vol. %
Domestic			
East Mississippi	32-36	1.0-1.4	8-11
Carpentria Mix, Cal.	28-29	1.1-1.4	15-20
Montana Sour	31-34	1.0-1.3	8-14
West Texas Sour	25-36	1.0-2.0	10-15
Foreign			
Arabian—Light	32-36	1.5-1.8	11-14
Iranian—Light	32-35	1.3-1.6	11-14
Qatar	40-43	1.0-1.3	5-8
Kirkuk, Iraq	35-37	1.8-2.0	11-14
Typical Crude	**25-40**	**1.0-2.0**	**8-15**

HIGH SULFUR—HEAVY

Crude Stream	Gravity °API	Sulfur Wt. %	1,050+ °F Bottoms Yield Vol. %
Domestic			
Hawkins/Talco, Tex.	20-29	2.0-3.5	25-35
HEY Heavy, Miss.	20-25	3.0-4.0	27-31
San Joaquin Valley, Ca.	13-25	1.0-1.5	15-30
Wilmington, Ca.	15-21	1.4-2.2	21-32
Wyoming Sour	20-28	2.0-3.5	15-27
Foreign			
Arabian—Heavy	27-29	2.5-3.0	25-28
Iranian—Heavy	30-32	1.4-1.7	17-20
Tia Juana, Venez.	25-27	1.4-1.6	23-25
Bachaquero, Venez.	16-21	2.0-2.5	30-40
Lagunillas, Venez.	11-18	2.0-3.0	35-45
Typical Crude	**13-29**	**1.0-4.0**	**16-40**

NOTE: Alaskan North Slope Crude Oil is classified as Medium Sulfur—Heavy.

PART I

Code Number _____

SECTION F: IMPACT OF LIMITATION ON VAPOR PRESSURE

Indicate the impact of limiting Reid Vapor Pressure (RVP) on all gasolines to 1.0 psi less than current ASTM specifications, or to 9.0 psi, whichever is greater, while reporting your maximum capability for blending unleaded gasoline. In reporting capability to make unleaded gasoline: 1) The leaded gasoline pool should be blended to meet current product specifications (other than RVP and lead content); 2) The amount reported as leaded fuel should not exceed the level reported in Section C.2; and 3) The sales or other external dispositions of normal gasoline blendstocks, other than butane, shall not be increased.

YEAR	REGULAR UNLEADED GASOLINE			OTHER UNLEADED GASOLINE		
	REPORT RVP	INDICATE QUALITY, CURRENT (R+M)/2[2]	QUANTITY, B/CD[3,4]	REPORT RVP	INDICATE QUALITY, CURRENT (R+M)/2[2]	QUANTITY, B/CD[3,4]
Calendar 1985	current			current		
	reduced[1]			reduced[1]		
Calendar 1986	current			current		
	reduced[1]			reduced[1]		
Calendar 1987	current			current		
	reduced[1]			reduced[1]		
Calendar 1988	current			current		
	reduced[1]			reduced[1]		

YEAR	LEADED GASOLINE POOL				PLANNED USE OF OXYGENATES, VOL.% OF TOTAL GASOLINE				EXCESS, BUTANES,[5] B/CD	REDUCTION IN PURCHASES OF BUTANE, B/CD
	REPORT RVP	INDICATE QUALITY, CURRENT (R+M)/2[2]	QUANTITY B/CD[3]	LEAD CONTENT, GM/GAL	EOH	MTBE	MOH	TBA		
Calendar 1985	current			1.1						
	reduced[1]			1.1						
Calendar 1986	current			0.1						
	reduced[1]			0.1						
Calendar 1987	current			0.1						
	reduced[1]			0.1						
Calendar 1988	current			0.1						
	reduced[1]			0.1						

[1]For limitations set forth above.

[2]R = Research Octane Number; M = Motor Octane Number; (R+M)/2 = Road Octane Number. Indicate current road octane number. Values should be consistent with those used in Section D.

[3]These quantities are not vertically additive.

[4]The ratios of volumes of regular unleaded gasoline to other unleaded gasoline should be those presently anticipated for the dates shown.

[5]Excess butanes defined as in-plant production which cannot be used internally for product manufacture, blending, or fuel with existing or planned facilities.

NOTE: Assume lead content restrictions as proposed in *Regulation of Fuels and Fuel Additives; Lead Phase Down*, 49 FR 150 (maximum lead content of 0.1 gm/gal as of January 1, 1986).

PART I

SECTION G: BENZENE IN GASOLINE

With facilities existing or firmly committed, for *quantities* of gasoline anticipated in Section C.2, and for current gasoline (R + M)/2 specifications, what is your 1984 typical and projected 1988 typical benzene content of motor gasoline?

	UNLEADED REGULAR	UNLEADED PREMIUM	UNLEADED OTHER	LEADED REGULAR	LEADED PREMIUM
Benzene Content, Vol.% 1984 typical					
1988 typical					

SECTION H: SULFUR CONTENT LIMITATIONS ON DISTILLATES

1. **Report the maximum volume of very low sulfur distillate that can be produced in 1988 with committed or planned facilities and ancitipated crude slates.**

PRODUCT	MAXIMUM WT. % SULFUR	MB/CD
LA Basin Transportation Diesel	0.05	
Distillate Heating Oil in All Other Geographic Regions	0.2	

2. **Based on projected 1988 crude oil slates, identify the added refining facilities capacity which would be required to reduce the sulfur content of anticipated distillate volumes to 0.2 wt.%. (For refineries in the LA Basin, use 0.05 wt.% sulfur content).**

Distilled Hydrotreating		B/CD
Hydrocracking		B/CD
Hydrorefining		B/CD
Hydrogen Generation		MMCF/CD
Sulfur Recovery & Tail Gas Cleanup		LT/CD
Tankage		Mbbl

PART I Code Number _____

SECTION D: GASOLINE MANUFACTURING CAPABILITIES

1. Current Lead Regulations[1]

For the years 1985, 1986, 1987, and 1988, indicate your maximum capability to make unleaded gasoline, with crude rates not to exceed those currently projected and taking into account normal seasonal factors, and report qualities and quantities of the remaining leaded gasoline pool. In reporting capability to make unleaded gasoline: 1) The leaded gasoline pool should be blended to meet current product specifications and comply with current lead regulations; 2) The amount reported as leaded fuel should not exceed the level reported in Section C.2; and 3) The acquisitions, sales, or other external dispositions of gasoline blendstocks other than oxygenates shall not be increased above the levels reported in Section C.2.

YEAR	REGULAR UNLEADED GASOLINE		OTHER UNLEADED GASOLINE		LEADED GASOLINE POOL			PLANNED USE OF OXYGENATES, VOL.% OF TOTAL GASOLINE			
	INDICATE QUALITY, CURRENT (R+M)/2[2]	QUANTITY B/CD[3,4]	INDICATE QUALITY, CURRENT (R+M)/2[2]	QUANTITY B/CD[3,4]	INDICATE QUALITY, CURRENT (R+M)/2[2]	QUANTITY B/CD[3]	LEAD CONTENT GM/GAL	EOH	MTBE	MOH	TBA
Jan 1, 1985							1.1				
Jan 1, 1986							1.1				
Jan 1, 1987							1.1				
Jan 1, 1988							1.1				

2. Proposed New Lead Standard[5]

For the years 1985, 1986, 1987, and 1988, indicate your maximum capability to make unleaded gasoline, with crude rates not to exceed those currently projected and taking into account normal seasonal factors, and report qualities and quantities of the remaining gasoline pool. Note that, for 1988, the maximum capability for making unleaded gasoline should be reported both at current (R + M)/2 quality and at an increase of 1.0 over current (R + M)/2 quality. In reporting capability to make unleaded gasoline: 1) The leaded gasoline pool should be blended to meet current product specifications, with the exception of lead content, which should be limited to the proposed level of 0.1 gm/gal as of January 1, 1986; 2) The amount reported as leaded fuel should not exceed the level reported in Section C.2; and 3) The acquisitions, sales, or other external dispositions of normal gasoline blendstocks other than oxygenates shall not be increased above the levels reported in Section C.2.

YEAR	REGULAR UNLEADED GASOLINE		OTHER UNLEADED GASOLINE		LEADED GASOLINE POOL			PLANNED USE OF OXYGENATES, VOL.% OF TOTAL GASOLINE			
	INDICATE QUALITY, CURRENT (R+M)/2[2]	QUANTITY B/CD[3,4]	INDICATE QUALITY, CURRENT (R+M)/2[2]	QUANTITY B/CD[3,4]	INDICATE QUALITY, CURRENT (R+M)/2[2]	QUANTITY B/CD[3]	LEAD CONTENT GM/GAL	EOH	MTBE	MOH	TBA
Jan 1, 1985							1.1				
Jan 1, 1986							0.1				
Jan 1, 1987							0.1				
Jan 1, 1988[6]							0.1				
Jan 1, 1988[6]							0.1				

[1]Maximum lead content of 1.1 gm/gal for period January 1, 1985—January 1, 1988.
[2]R = Research Octane Number; M = Motor Octane Number; (R+M)/2 = Road Octane Number. Indicate current road octane number.
[3]These quantities are not vertically additive.
[4]The ratios of volumes of regular unleaded gasoline to other unleaded gasoline should be those presently anticipated for the dates shown.
[5]As proposed in *Regulation of Fuels and Fuel Additives; Lead Phase Down,* 49 FR 150 (maximum lead content of 0.1 gm/gal as of January 1, 1986).
[6]For 1988 unleaded grades, indicate current road octane number, and an increase of 1.0 over current road octane number; for 1988 leaded grade, use current only.

PART I Code Number _____

SECTION E: IMPACT OF LIMITATION ON THE USE OF OXYGENATES

Indicate the impact of elimination of the use of oxygenates in all gasolines while reporting your maximum capability for blending unleaded gasoline, with crude rates not to exceed those currently projected, under the proposed restriction of lead content in gasoline to 0.1 gm/gal as of January 1, 1986. In reporting capability to make unleaded gasoline: 1) The leaded gasoline pool should, with the exception of lead content, be blended to meet current product specifications; 2) The amount reported as leaded fuel should not exceed the level reported in Section C.2; and 3) The acquisitions, sales, or other external dispositions of normal gasoline blendstocks other that oxygenates shall not be increased above the levels reported in Section C.2. Note: if you plan no use of oxygenates, the gasoline volumes reported in Section E should correspond to volumes shown in Section D.

YEAR	REGULAR UNLEADED GASOLINE		OTHER UNLEADED GASOLINE		LEADED GASOLINE POOL		
	INDICATE QUALITY, CURRENT (R+M)/2[1]	QUANTITY B/CD[2,3]	INDICATE QUALITY, CURRENT (R+M)/2[1]	QUANTITY B/CD[2,3]	INDICATE QUALITY, CURRENT (R+M)/2[1]	QUANTITY B/CD[2]	LEAD CONTENT GM/GAL
Jan 1, 1985							1.1
Jan 1, 1986							0.1
Jan 1, 1987							0.1
Jan 1, 1988							0.1

[1]R = Research Octane Number; M = Motor Octane Number; (R+M)/2 = Road Octane Number. Indicate current road octane number.
[2]These quantities are not vertically additive.
[3]The ratios of volumes of regular unleaded gasoline to other unleaded gasoline should be those presently anticipated for the dates shown.

NATIONAL PETROLEUM COUNCIL
1985 SURVEY OF U.S. PETROLEUM REFINERIES

INDIVIDUAL REFINERY REPORT

PART II: OPERATIONAL COSTS

REFINERY IDENTIFICATION SHEET

Company: _____

Refinery Name: _____

State, Territory,
or Hawaiian Free Trade Zone: _____

Refinery Point
of Contact: _____
(NAME)

_____
(PHONE NUMBER)

NATIONAL PETROLEUM COUNCIL
1985 SURVEY OF U.S. PETROLEUM REFINERIES

INDIVIDUAL REFINERY REPORT

PART II: OPERATIONAL COSTS

Survey Due Date: March 22, 1985

Code Number[1] _____

General Refinery Information

1. Indicate location of this refinery by state, or Guam, Puerto Rico, Virgin Islands, or Hawaiian Free Trade Zone _____

2. If refinery is outside the 50 states, indicate which PADD(s) you are currently or anticipate supplying petroleum products. PADD(s) _____

3. Total charge capacity for crude oil distillation as reported to the Energy Information Administration on Form EIA-820 as of January 1, 1985. _____ Barrels per calendar day (B/CD)

4. If there are questions, contact John W. Rauber, Jr., National Petroleum Council, (202) 393-6100, or Ray W. Whitson, Arthur Young & Company, (202) 828-7000.

[1]This entry, and other NPC Code columns on subsequent pages, will be entered by the accounting firm for Data Tabulation purposes.

PART II Code Number _____

SECTION A: OPERATIONAL EXPENSES

For calendar year 1984, what were the operating expenses for the refinery for the categories listed below? (Limit all costs to operations and facilities inside the refinery fence.)

1. Direct Payroll and Payroll Related[1] _____ $/bbl Crude Oil Throughput.

2. Contract Maintenance Labor _____ $/bbl Crude Oil Throughput.

3. Refinery Produced Fuel and Utilities. Report total energy consumption including fluid coker and catalytic cracking unit, carbon monoxide and coke burned, electric power generated, and steam produced.[2]
   _____ MMBTU consumed/bbl Crude Oil Throughput.
   _____ $/MMBTU weighted average energy unit expenses.[3]

4. Purchased Fuel and Utilities (include electric power procured and steam purchased):
   _____ MMBTU consumed/bbl Crude Oil Throughput.
   unit expenses.[3]
   _____ $/MMBTU weighted average energy

5. Catalysts and Chemicals: _____ $/bbl Crude Oil Throughput.
6. Antiknock Compounds: _____ $/bbl Crude Oil Throughput.
7. Maintenance Materials: _____ $/bbl Crude Oil Throughput.
8. Depreciation: _____ $/bbl Crude Oil Throughput.
9. Other Operating Expenses Not Reported Above: _____ $/bbl Crude Oil Throughput.[4]

SECTION B: 1984 CRUDE OIL COSTS

Report the delivered cost and the transportation cost within the U.S. for crude oil processed at this refinery in 1984.

	VOLUME, B/CD	DELIVERED CRUDE COST, $/BARREL	U.S. TRANSPORTATION COST, $/BARREL
Domestic Crude Oil			
Imported Crude Oil			

SECTION C: REFINERY ASSETS[5]

1. Gross (undepreciated) fixed assets in this refinery: _____ MM$.

2. Approximate in-kind replacement cost (1984 year end): _____ MM$.

[1]Operations, Maintenance, Blending, Pumping, Laboratory, and other *direct* labor and supervision.
[2]Use 10,000 BTU's/kilowatt hour to convert fuel to electricity.
[3]In calculating unit fuel, use (1) actual expense for purchased energy, and (2) the local incremental purchase/sale price for self-produced energy.
[4]Include fixed and allocated expenses.
[5]Within the refinery fence.

APPENDIX F

Initial Supply/Demand Cases and Assumptions

This appendix presents the initial petroleum supply/demand balances developed for this study. These balances were developed for the United States and the non-communist world for the 1985–1995 period. The objective of this analysis was two-fold: first, to provide a likely range of oil supply and demand over this time period and, second, to provide a range of cases that would induce economic, structural, and engineering stress in the refinery system. This approach was used to make the study as relevant as possible for policy development, while at the same time presenting a reasonable range of likely supply and demand futures.

The analysis consists of two cases, the "NPC high demand case" and the "NPC low demand case." These cases are characterized by high and low petroleum demand, respectively. The two cases were developed to illustrate a reasonable range of uncertainty surrounding petroleum supply, demand, and imports, not to represent extreme boundary situations. Mechanically, the Energy Information Administration (EIA) model was adjusted using NPC assumptions to reflect this uncertainty. The remainder of this appendix will discuss the assumptions key to the analysis, caveats about the results, and the results themselves.

KEY ASSUMPTIONS

Before presenting the actual assumptions used in the analysis, it is important to re-emphasize that these assumptions were not chosen in order to capture within the range all of the uncertainty about future economic growth or world oil prices (i.e., boundary cases), but to produce a range of energy balances that were found to represent reasonable expectations of uncertainty against which policy alternatives can be examined.

The major assumptions driving this analysis were expected economic growth and the real output of specific industries.

- The low growth case assumes that trends in U.S. gross national product (GNP) between 1978 and 1983 and the conservation trends between 1979 and 1983 continue throughout the projection period. The high growth case assumes rapid growth between 1985 and 1990 before slowing somewhat after 1990 with little incremental conservation above that currently experienced. (See Attachment 6, Table 6-1.)
- Growth rates in the real output for selected domestic energy-intensive industries critical to our forecast, i.e., food, paper, chemicals, stone/glass, and primary metals, were developed congruent with the GNP scenarios. (See Attachment 6, Table 6-2.)
- For the international portion of the analysis, differential growth rates expressed in terms of real gross domestic product (GDP) were assumed for the Organization for Economic Cooperation and

Development (OECD) and developing countries. (See Attachment 6, Table 6-3.) In the international analysis, the Organization of Petroleum Exporting Countries (OPEC) production was not, however, allowed to exceed 30 million barrels per day (MMB/D).

CAVEATS

As in all analyses, certain clarifications of the results are necessary:

- The EIA model was used as a mechanical accounting tool to develop consistent, detailed supply/demand balances needed to support the Council's initial case requirements. Thus the economic and conservation assumptions that were input to achieve the desired consensus demand results should not be considered representative of the NPC's views on the overall environment necessary to achieve a low or high oil demand.

- Both cases assume that leaded gasoline will be phased out by 1987.

- No supply side changes are included for non-OPEC, non-U.S. sources in either case. This does not imply that supply is not variable, but that such variability is not likely to be material to the analysis.

- The swing factor in the two cases is demand, driven by differing assumptions of economic growth and conservation/fuel substitution.

  The high case reflects strong demand growth that, when coupled with declining non-OPEC production, translates into significant increases in the requirement for OPEC oil, i.e., 30 MMB/D by the early 1990s. It is important to recognize that this healthy environment would imply higher oil prices and a greater incentive to develop alternative energy supplies as OPEC production approaches capacity.

  The low demand case captures only nominal demand increases and therefore provides only slow relief for OPEC's revenue needs. It assumes that all members will cooperate and that the implied low levels of production (16.5 MMB/D or 19.1 MMB/D, including NGLs) will be met without any serious disruption of OPEC as an entity.

- U.S. imports will change to balance consumption with economic and political considerations, largely determining the split between crude oil and finished products. A worldwide surplus supply situation would tend to increase the penetration of the U.S. market by offshore refiners, while a tighter worldwide supply/demand balance would result in fewer inroads by foreign refiners. No changes in current import regulations were assumed. The split of imports developed should thus be used only as a point of departure.

RESULTS

The results of the domestic analysis, detailed in Attachments 1 and 2, are summarized in Table F-1. In the high demand case, as domestic supply decreases, demand grows steadily over time, leading to increasing imports. In the low demand case, long-term imports also increase, but at lower levels, again due to the decline in domestic production. Results of these cases are compared in Table F-1 with the EIA base cases, which were prepared as part of EIA's Annual Energy Outlook 1984 and 1985.

Given these implied product levels, Table F-2 presents the estimated net product demanded from U.S. refineries for the two cases. Current net product demand from U.S. refineries (excluding imports) is about 15 MMB/D (including NGLs). High consumption is combined with low product imports to yield 18 MMB/D of refinery demand in 1995 in the NPC high demand case. Similarly, a low consumption case is combined with high imports to give about 13 MMB/D of U.S. refinery requirements in 1995 for the NPC low demand case. This leaves a 5 MMB/D range of uncertainty in U.S. refining requirements in 1995.

The results of the corresponding international analysis are presented in Attachments 3 and 4 and summarized in Table F-3.

A more detailed examination of the product import levels from the domestic analysis, presented in Attachment 5 and highlighted in Table F-4, suggests that in the low demand case

foreign refineries could succeed in increasing their share of overall U.S. product demand from the 12 percent level held in 1983–1984 to 20 percent by 1990.

Notable changes on a geographic basis in the low demand case could be the potential loss by 1990 of most of the leaded and unleaded gasoline markets in the Northeast to foreign refineries, as well as part of that same market in the South Atlantic states, and much of the middle distillate market down the entire East Coast. In the higher demand case, however, foreign refineries' share of the various regional U.S. product markets remains roughly at 1983–1984 levels through 1995.

Attachment 6 presents more detailed assumptions, definitions, and other notes pertinent to interpreting the results.

TABLE F-1

SUMMARY OF DOMESTIC ANALYSIS RESULTS
(MMB/D)

	1990			1995		
	Demand*	Supply	Net Imports	Demand*	Supply	Net Imports
NPC High	17.7	10.0	7.9	19.5	7.8	11.8
NPC Low	15.3	9.9	5.5	15.0	7.7	7.4
EIA Base Case 1984†	16.7	10.3	6.6	18.0	9.4	8.7
EIA Base Case 1985†	16.1	10.3	5.8	16.6	8.8	7.8

*Includes about 2 MMB/D of NGLs and processing gain.
†Shows higher supply since prices were allowed to rise.

TABLE F-2

SUMMARY OF U.S. REFINERY REQUIREMENTS
(MMB/D)

	High Case			Low Case		
	1985	1990	1995	1985	1990	1995
Total Product Consumption	16.2	17.7	19.5	16.0	15.3	15.0
Product Exports & Losses	0.6	0.6	0.6	0.6	0.6	0.6
Product Imports	2.0	2.1	2.1	2.0	3.0	3.0
Net Product Demanded from U.S. Refineries	**14.8**	**16.2**	**18.0**	**14.6**	**12.9**	**12.6**

TABLE F-3

SUMMARY OF INTERNATIONAL ANALYSIS
(MMB/D)

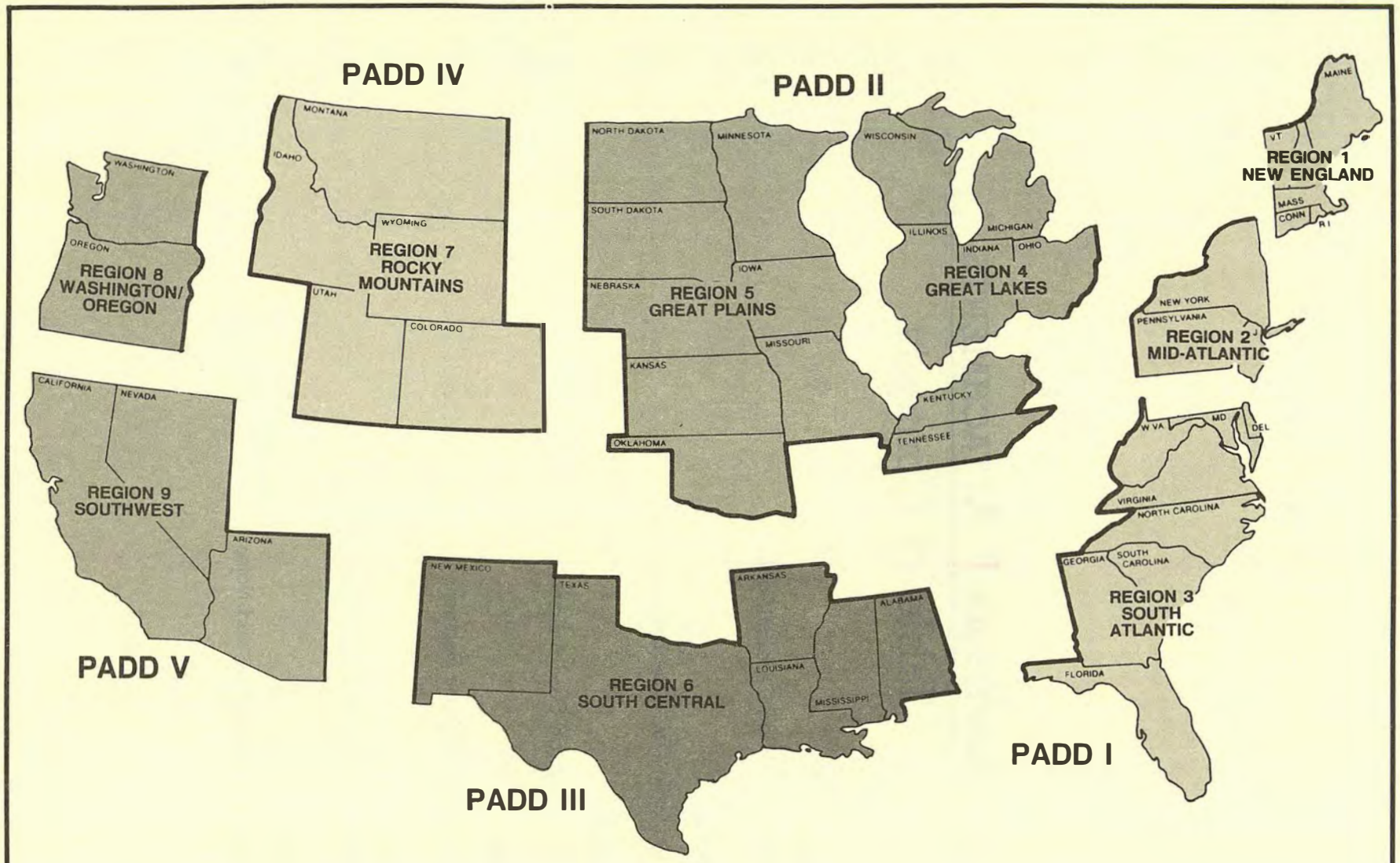
	High Case			Low Case		
	1985	1990	1995	1985	1990	1995
Production*						
Total Free World	46.5	53.3	54.4	46.5	44.9	44.6
OPEC Production	19.1	26.6	30.0	19.1	18.2	20.2
U.S. Production	11.1	10.0	7.8	11.1	9.9	7.7

*Includes NGLs and processing gain.

TABLE F-4

SUMMARY OF PRODUCT IMPORTS SHARE
(MMB/D, except where noted)

			High Case		Low Case	
	1983	1984	1990	1995	1990	1995
U.S. Demand	15.2	15.8	17.7	19.5	15.3	15.0
Imports						
Crude Oil	3.3	3.2	6.6	10.5	3.3	6.3
Products	1.7	2.0	2.1	2.1	3.0	3.0
Total	5.0	5.2	8.7	12.6	6.3	8.2
Product Exports	0.7	0.7	0.6	0.6	0.6	0.6
Natural Gas Liquids	1.6	1.6	1.6	1.6	1.6	1.6
Net Demand on Refineries	12.6	12.9	14.6	11.4	11.3	11.0
Product Imports As Percentage of Demand	11.0%	13.0%	12.0%	11.0%	20.0%	20.0%



NOTE: Region 10 includes Alaska, Hawaii, and Guam.

Regions Used in Domestic Analysis.

APPENDIX F ATTACHMENTS

Table of Contents

Attachment 1

U.S. Domestic High Case Balances F-8

Attachment 2

U.S. Domestic Low Case Balances F-22

Attachment 3

International High Case Balances F-36

Attachment 4

International Low Case Balances F-52

Attachment 5

Potential U.S. Product Import Cases F-67

Attachment 6

Assumptions, Definitions, and Notes F-73

ATTACHMENT 1

U.S. Domestic High Case Balances

Summary of Total U.S. Petroleum Supply and Distribution Balance--High Demand Case*
(Million Barrels per Day)

	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Production													
Crude Oil	8.69	8.76	8.86	8.65	8.49	8.26	7.99	7.80	7.26	6.76	6.25	5.77	5.37
Alaska North Slope	1.65	1.67	1.70	1.76	1.92	1.92	1.92	1.97	1.72	1.49	1.31	1.14	1.00
Subarctic	7.04	7.08	7.15	6.89	6.57	6.34	6.06	5.82	5.54	5.27	4.94	4.64	4.37
Natural Gas Plant Liquids	1.56	1.61	1.64	1.52	1.59	1.60	1.58	1.56	1.55	1.53	1.50	1.46	1.45
Other Domestic	.05	.05	.05	.05	.05	.05	.07	.09	.14	.19	.25	.30	.36
Processing Gain	.49	.55	.54	.51	.52	.53	.54	.56	.57	.57	.58	.59	.62
Total Production	10.79	10.97	11.09	10.73	10.66	10.45	10.18	10.01	9.52	9.06	8.58	8.13	7.79
Total Imports (including SPR)	5.05	5.70	5.88	6.44	6.81	7.35	7.99	8.08	9.19	9.90	10.61	11.40	12.59
Total Exports	.74	.67	.62	.78	.78	.78	.78	.78	.78	.78	.78	.78	.78
Net Imports (including SPR)	4.31	5.03	5.26	5.66	6.03	6.56	7.21	7.89	8.41	9.11	9.83	10.61	11.81
Primary Stock Changes													
Net Withdrawals	.25	.04	.00	-.01	-.06	-.07	-.09	-.04	-.04	-.04	-.04	-.05	-.10
SPR Fill Rate Additions (-)	-.23	-.18	-.14	-.14	-.14	-.14	-.14	-.14	.00	.00	.00	.00	.00
Total Primary Supply	15.11	15.86	16.20	16.23	16.48	16.80	17.17	17.67	17.89	18.13	18.37	18.69	19.50
Refined Petroleum Products													
Motor Gasoline	6.62	6.70	6.81	6.65	6.56	6.50	6.50	6.54	6.52	6.51	6.52	6.53	6.55
Aviation Gasoline	.03	.04	.04	.05	.05	.05	.05	.06	.06	.06	.06	.06	.06
Jet Fuel	1.05	1.15	1.17	1.23	1.29	1.35	1.40	1.46	1.48	1.50	1.52	1.53	1.54
Kerosene	.13	.11	.10	.11	.11	.12	.12	.12	.12	.12	.12	.12	.12
Distillate Fuel	2.69	2.87	2.86	2.91	3.02	3.13	3.26	3.40	3.51	3.60	3.68	3.78	3.91
Residual Fuel	1.42	1.46	1.45	1.42	1.47	1.55	1.62	1.75	1.82	1.91	2.00	2.16	2.76
Liquid Petroleum Gas	1.49	1.36	1.43	1.45	1.47	1.48	1.49	1.51	1.49	1.48	1.46	1.44	1.42
Petrochemical Feedstocks	.42	.68	.74	.79	.84	.90	.96	1.02	1.05	1.08	1.12	1.15	1.18
Other Petroleum Products	1.37	1.50	1.60	1.64	1.67	1.72	1.76	1.81	1.34	1.87	1.90	1.93	1.96
Total Product Supplied	15.21	15.86	16.20	16.23	16.43	16.80	17.17	17.67	17.89	18.13	18.37	18.69	19.50

*Tables 1-11 provide petroleum product supplied details for total U.S. and the 10 NPC regions, respectively. Table 12 provides crude oil (including lease condensate) details for the 10 NPC regions.

Table 1. Petroleum Product Supplied in the United States
Consumption in Million Barrels per Day

Fuel Category	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995
Motor Gasoline												
Leaded	3.170	2.984	2.794	2.631	2.428	2.245	1.027	0.000	0.000	0.000	0.000	0.000
Unleaded	2.767	2.925	3.039	3.229	3.466	3.711	4.584	5.362	5.334	5.349	5.418	5.565
Premium	0.660	0.679	0.706	0.762	0.804	0.851	1.039	1.195	1.171	1.154	1.126	0.982
Total of All Types	6.597	6.587	6.539	6.622	6.698	6.807	6.650	6.556	6.505	6.503	6.544	6.547
Distillate Fuel												
Heating Oil	0.861	0.754	0.700	0.670	0.705	0.686	0.716	0.747	0.773	0.799	0.822	0.823
Highway Diesel	0.975	1.013	0.975	0.993	1.045	1.044	1.076	1.115	1.162	1.217	1.281	1.609
Other Uses	1.038	1.061	0.996	1.027	1.119	1.124	1.114	1.154	1.197	1.239	1.294	1.476
Total of All Types	2.874	2.829	2.671	2.690	2.869	2.855	2.906	3.016	3.132	3.255	3.398	3.907
Jet Fuel												
Naphtha-Type	0.209	0.197	0.213	0.220	0.224	0.229	0.235	0.240	0.246	0.252	0.258	0.290
Kerosene-Type	0.862	0.810	0.799	0.826	0.924	0.938	0.995	1.054	1.102	1.152	1.201	1.248
Total of All Types	1.070	1.007	1.013	1.046	1.148	1.167	1.230	1.294	1.348	1.404	1.459	1.538
Residual Fuel												
0.00 to 0.30% Sulfur	0.489	0.402	0.339	0.286	0.291	0.289	0.281	0.291	0.307	0.322	0.348	0.574
0.31 to 1.00% Sulfur	0.674	0.558	0.457	0.379	0.389	0.386	0.379	0.393	0.413	0.433	0.466	0.735
Over 1.00% Sulfur	1.352	1.127	0.920	0.757	0.779	0.774	0.760	0.790	0.830	0.870	0.934	1.453
Total of All Types	2.515	2.088	1.716	1.421	1.458	1.450	1.420	1.474	1.550	1.624	1.748	2.762
Liquefied Petroleum Gas												
Total of All Types	1.473	1.466	1.499	1.509	1.361	1.432	1.445	1.466	1.480	1.495	1.510	1.421
Other Petroleum												
Total of All Types	2.573	2.081	1.857	1.943	2.328	2.488	2.579	2.676	2.785	2.892	3.009	3.323
Petroleum Product Supplied												
Total of All Types	17.103	16.058	15.296	15.231	15.862	16.199	16.230	16.482	16.800	17.173	17.668	19.498

Table 2. Petroleum Product Supplied in NPC 1 (New England)
Consumption in Million Barrels per Day

Fuel Category	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995
Motor Gasoline												
Leaded	0.154	0.145	0.137	0.129	0.119	0.110	0.050	0.000	0.000	0.000	0.000	0.000
Unleaded	0.134	0.143	0.149	0.159	0.170	0.182	0.224	0.262	0.260	0.260	0.263	0.268
Premium	0.032	0.033	0.035	0.037	0.039	0.042	0.051	0.058	0.057	0.056	0.055	0.047
Total of All Types	0.320	0.321	0.320	0.325	0.328	0.333	0.325	0.320	0.317	0.317	0.318	0.315
Distillate Fuel												
Heating Oil	0.181	0.156	0.147	0.142	0.148	0.144	0.150	0.156	0.160	0.165	0.169	0.166
Highway Diesel	0.023	0.022	0.027	0.027	0.029	0.029	0.030	0.031	0.032	0.033	0.035	0.044
Other Uses	0.031	0.025	0.027	0.048	0.051	0.051	0.050	0.051	0.053	0.054	0.055	0.062
Total of All Types	0.234	0.203	0.201	0.217	0.228	0.224	0.230	0.238	0.245	0.252	0.260	0.273
Jet Fuel												
Naphtha-Type	0.004	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.004	0.004
Kerosene-Type	0.034	0.030	0.027	0.028	0.031	0.032	0.034	0.035	0.037	0.038	0.040	0.042
Total of All Types	0.038	0.033	0.030	0.031	0.034	0.035	0.037	0.039	0.040	0.042	0.044	0.046
Residual Fuel												
0.00 to 0.30% Sulfur	0.069	0.061	0.058	0.052	0.051	0.052	0.049	0.050	0.053	0.056	0.061	0.117
0.31 to 1.00% Sulfur	0.072	0.063	0.061	0.054	0.054	0.054	0.051	0.052	0.055	0.058	0.064	0.121
Over 1.00% Sulfur	0.134	0.118	0.113	0.101	0.100	0.100	0.095	0.097	0.103	0.108	0.119	0.226
Total of All Types	0.276	0.242	0.232	0.208	0.205	0.205	0.194	0.199	0.211	0.222	0.244	0.464
Liquefied Petroleum Gas												
Total of All Types	0.018	0.018	0.019	0.019	0.017	0.017	0.017	0.018	0.018	0.018	0.018	0.016
Other Petroleum												
Total of All Types	0.044	0.032	0.028	0.034	0.039	0.039	0.039	0.040	0.042	0.043	0.044	0.046
Petroleum Product Supplied												
Total of All Types	0.930	0.849	0.830	0.834	0.851	0.853	0.842	0.854	0.873	0.893	0.927	1.161

Table 3. Petroleum Product Supplied in NPC 2 (Mid Atlantic)
Consumption in Million Barrels per Day

Fuel Category	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995
Motor Gasoline												
Leaded	0.406	0.380	0.357	0.337	0.311	0.287	0.131	0.000	0.000	0.000	0.000	0.000
Unleaded	0.354	0.373	0.389	0.413	0.444	0.475	0.586	0.685	0.681	0.683	0.691	0.707
Premium	0.084	0.086	0.090	0.098	0.103	0.109	0.133	0.153	0.150	0.147	0.144	0.125
Total of All Types	0.844	0.839	0.837	0.848	0.857	0.871	0.850	0.838	0.831	0.830	0.835	0.832
Distillate Fuel												
Heating Oil	0.325	0.295	0.266	0.255	0.268	0.260	0.271	0.282	0.292	0.301	0.309	0.307
Highway Diesel	0.086	0.076	0.077	0.078	0.082	0.082	0.085	0.088	0.091	0.096	0.101	0.127
Other Uses	0.121	0.108	0.098	0.134	0.144	0.145	0.141	0.145	0.150	0.155	0.162	0.192
Total of All Types	0.532	0.480	0.441	0.467	0.494	0.487	0.497	0.515	0.533	0.551	0.572	0.626
Jet Fuel												
Naphtha-Type	0.015	0.014	0.013	0.013	0.013	0.014	0.014	0.014	0.015	0.015	0.015	0.017
Kerosene-Type	0.136	0.130	0.118	0.122	0.135	0.137	0.145	0.153	0.159	0.166	0.173	0.181
Total of All Types	0.150	0.144	0.131	0.135	0.148	0.151	0.159	0.167	0.174	0.181	0.188	0.198
Residual Fuel												
0.00 to 0.30% Sulfur	0.141	0.113	0.103	0.088	0.089	0.088	0.085	0.088	0.093	0.097	0.106	0.183
0.31 to 1.00% Sulfur	0.146	0.117	0.108	0.091	0.092	0.092	0.089	0.091	0.096	0.101	0.110	0.190
Over 1.00% Sulfur	0.273	0.218	0.201	0.170	0.172	0.171	0.165	0.170	0.180	0.189	0.205	0.355
Total of All Types	0.560	0.448	0.412	0.349	0.352	0.350	0.339	0.349	0.369	0.387	0.420	0.728
Liquefied Petroleum Gas												
Total of All Types	0.056	0.052	0.050	0.049	0.044	0.046	0.046	0.047	0.047	0.048	0.048	0.044
Other Petroleum												
Total of All Types	0.242	0.209	0.192	0.199	0.236	0.253	0.262	0.273	0.284	0.295	0.307	0.337
Petroleum Product Supplied												
Total of All Types	2.384	2.172	2.061	2.046	2.132	2.158	2.154	2.189	2.238	2.292	2.370	2.766

Table 4. Petroleum Product Supplied in NPC 3 (South Atlantic)
Consumption in Million Barrels per Day

Fuel Category	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995
Motor Gasoline												
Leaded	0.539	0.512	0.484	0.457	0.421	0.389	0.178	0.000	0.000	0.000	0.000	0.000
Unleaded	0.470	0.502	0.527	0.561	0.601	0.643	0.793	0.927	0.921	0.922	0.932	0.949
Premium	0.112	0.117	0.122	0.132	0.139	0.147	0.180	0.206	0.202	0.199	0.194	0.168
Total of All Types	1.122	1.131	1.133	1.150	1.162	1.180	1.151	1.133	1.123	1.120	1.126	1.117
Distillate Fuel												
Heating Oil	0.110	0.090	0.076	0.073	0.077	0.075	0.078	0.081	0.084	0.086	0.089	0.088
Highway Diesel	0.143	0.152	0.145	0.148	0.156	0.156	0.161	0.166	0.173	0.182	0.191	0.240
Other Uses	0.148	0.132	0.112	0.105	0.116	0.115	0.112	0.115	0.121	0.125	0.133	0.168
Total of All Types	0.401	0.374	0.333	0.326	0.349	0.346	0.350	0.362	0.378	0.393	0.413	0.497
Jet Fuel												
Naphtha-Type	0.021	0.020	0.020	0.020	0.021	0.021	0.022	0.022	0.023	0.023	0.024	0.027
Kerosene-Type	0.195	0.187	0.183	0.189	0.209	0.212	0.225	0.237	0.247	0.258	0.268	0.281
Total of All Types	0.216	0.208	0.203	0.209	0.230	0.234	0.246	0.259	0.270	0.281	0.292	0.308
Residual Fuel												
0.00 to 0.30% Sulfur	0.123	0.100	0.076	0.066	0.065	0.065	0.062	0.063	0.067	0.070	0.077	0.145
0.31 to 1.00% Sulfur	0.128	0.104	0.079	0.068	0.068	0.068	0.064	0.066	0.069	0.073	0.080	0.150
Over 1.00% Sulfur	0.239	0.194	0.147	0.128	0.126	0.126	0.119	0.122	0.129	0.136	0.149	0.281
Total of All Types	0.491	0.398	0.301	0.262	0.259	0.259	0.245	0.251	0.265	0.278	0.305	0.576
Liquefied Petroleum Gas												
Total of All Types	0.113	0.099	0.091	0.089	0.079	0.082	0.083	0.084	0.085	0.085	0.085	0.077
Other Petroleum												
Total of All Types	0.215	0.161	0.149	0.162	0.196	0.209	0.216	0.225	0.235	0.243	0.251	0.268
Petroleum Product Supplied												
Total of All Types	2.558	2.371	2.210	2.198	2.274	2.308	2.291	2.315	2.354	2.400	2.471	2.842

Table 5. Petroleum Product Supplied in NPC 4 (Great Lakes)
Consumption in Million Barrels per Day

Fuel Category	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995
Motor Gasoline												
Leaded	0.565	0.521	0.471	0.443	0.409	0.378	0.173	0.000	0.000	0.000	0.000	0.000
Unleaded	0.493	0.511	0.512	0.544	0.584	0.625	0.772	0.904	0.899	0.902	0.914	0.941
Premium	0.118	0.118	0.119	0.128	0.135	0.143	0.175	0.201	0.197	0.195	0.190	0.166
Total of All Types	1.176	1.150	1.101	1.115	1.128	1.146	1.120	1.105	1.097	1.097	1.104	1.107
Distillate Fuel												
Heating Oil	0.124	0.107	0.097	0.093	0.097	0.095	0.099	0.103	0.107	0.110	0.113	0.113
Highway Diesel	0.169	0.163	0.154	0.157	0.165	0.165	0.170	0.176	0.184	0.192	0.203	0.254
Other Uses	0.163	0.158	0.147	0.148	0.162	0.163	0.161	0.166	0.173	0.179	0.187	0.217
Total of All Types	0.456	0.428	0.398	0.398	0.425	0.423	0.430	0.446	0.463	0.482	0.503	0.585
Jet Fuel												
Naphtha-Type	0.018	0.016	0.017	0.017	0.017	0.018	0.018	0.019	0.019	0.020	0.020	0.023
Kerosene-Type	0.087	0.077	0.078	0.080	0.090	0.091	0.096	0.102	0.106	0.111	0.116	0.121
Total of All Types	0.105	0.094	0.094	0.098	0.107	0.109	0.115	0.121	0.126	0.131	0.136	0.143
Residual Fuel												
0.00 to 0.30% Sulfur	0.030	0.020	0.014	0.012	0.012	0.013	0.012	0.013	0.014	0.014	0.015	0.022
0.31 to 1.00% Sulfur	0.054	0.036	0.025	0.022	0.022	0.023	0.022	0.023	0.024	0.025	0.027	0.040
Over 1.00% Sulfur	0.094	0.062	0.043	0.038	0.039	0.040	0.039	0.040	0.042	0.044	0.047	0.070
Total of All Types	0.178	0.118	0.081	0.072	0.074	0.075	0.073	0.076	0.080	0.084	0.090	0.132
Liquefied Petroleum Gas												
Total of All Types	0.284	0.251	0.240	0.241	0.217	0.228	0.230	0.233	0.235	0.237	0.240	0.225
Other Petroleum												
Total of All Types	0.452	0.320	0.280	0.291	0.355	0.382	0.396	0.411	0.428	0.444	0.461	0.506
Petroleum Product Supplied												
Total of All Types	2.650	2.360	2.194	2.214	2.305	2.362	2.364	2.392	2.428	2.474	2.534	2.698

Table 6. Petroleum Product Supplied in NPC 5 (Great Plains)
Consumption in Million Barrels per Day

Fuel Category	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995
Motor Gasoline												
Leaded	0.451	0.423	0.397	0.372	0.344	0.319	0.146	0.000	0.000	0.000	0.000	0.000
Unleaded	0.394	0.414	0.432	0.456	0.491	0.527	0.653	0.767	0.766	0.771	0.785	0.824
Premium	0.094	0.096	0.100	0.108	0.114	0.121	0.148	0.171	0.168	0.166	0.163	0.145
Total of All Types	0.938	0.933	0.929	0.935	0.949	0.967	0.948	0.938	0.934	0.938	0.948	0.969
Distillate Fuel												
Heating Oil	0.060	0.047	0.050	0.048	0.050	0.049	0.051	0.053	0.055	0.057	0.059	0.059
Highway Diesel	0.167	0.162	0.170	0.173	0.183	0.182	0.188	0.195	0.203	0.213	0.224	0.281
Other Uses	0.175	0.170	0.175	0.171	0.186	0.187	0.187	0.194	0.201	0.209	0.217	0.240
Total of All Types	0.401	0.379	0.395	0.392	0.419	0.419	0.426	0.442	0.459	0.478	0.500	0.580
Jet Fuel												
Naphtha-Type	0.015	0.014	0.013	0.013	0.014	0.014	0.014	0.015	0.015	0.015	0.016	0.018
Kerosene-Type	0.071	0.064	0.061	0.063	0.070	0.072	0.076	0.080	0.084	0.088	0.091	0.095
Total of All Types	0.086	0.078	0.074	0.077	0.084	0.086	0.090	0.095	0.099	0.103	0.107	0.113
Residual Fuel												
0.00 to 0.30% Sulfur	0.005	0.004	0.004	0.003	0.003	0.003	0.003	0.003	0.004	0.004	0.004	0.005
0.31 to 1.00% Sulfur	0.009	0.006	0.006	0.005	0.006	0.006	0.006	0.006	0.006	0.007	0.007	0.008
Over 1.00% Sulfur	0.016	0.011	0.011	0.009	0.010	0.010	0.010	0.011	0.011	0.012	0.012	0.014
Total of All Types	0.030	0.021	0.021	0.018	0.019	0.019	0.020	0.021	0.021	0.022	0.023	0.027
Liquefied Petroleum Gas												
Total of All Types	0.183	0.149	0.182	0.178	0.159	0.166	0.167	0.170	0.171	0.172	0.173	0.159
Other Petroleum												
Total of All Types	0.332	0.270	0.220	0.238	0.287	0.308	0.319	0.332	0.345	0.358	0.372	0.407
Petroleum Product Supplied												
Total of All Types	1.970	1.831	1.821	1.838	1.918	1.964	1.970	1.997	2.030	2.071	2.123	2.255

Table 7. Petroleum Product Supplied in NPC 6 (South Central)
Consumption in Million Barrels per Day

Fuel Category	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995
Motor Gasoline												
Leaded	0.451	0.432	0.414	0.390	0.360	0.333	0.152	0.000	0.000	0.000	0.000	0.000
Unleaded	0.394	0.423	0.450	0.479	0.514	0.550	0.678	0.793	0.788	0.789	0.798	0.814
Premium	0.094	0.098	0.105	0.113	0.119	0.126	0.154	0.177	0.173	0.170	0.166	0.144
Total of All Types	0.939	0.954	0.969	0.983	0.993	1.009	0.984	0.969	0.960	0.959	0.964	0.958
Distillate Fuel												
Heating Oil	0.012	0.017	0.018	0.016	0.018	0.018	0.019	0.020	0.022	0.023	0.024	0.027
Highway Diesel	0.183	0.233	0.212	0.216	0.227	0.227	0.234	0.242	0.253	0.265	0.278	0.350
Other Uses	0.184	0.258	0.235	0.225	0.246	0.248	0.248	0.258	0.268	0.277	0.289	0.316
Total of All Types	0.379	0.508	0.465	0.457	0.491	0.493	0.501	0.521	0.542	0.565	0.592	0.693
Jet Fuel												
Naphtha-Type	0.068	0.066	0.087	0.090	0.091	0.093	0.096	0.098	0.100	0.103	0.105	0.118
Kerosene-Type	0.063	0.061	0.079	0.082	0.097	0.098	0.106	0.114	0.121	0.128	0.134	0.134
Total of All Types	0.131	0.127	0.166	0.171	0.188	0.191	0.202	0.212	0.221	0.230	0.239	0.252
Residual Fuel												
0.00 to 0.30% Sulfur	0.075	0.066	0.057	0.043	0.047	0.046	0.048	0.051	0.053	0.055	0.058	0.065
0.31 to 1.00% Sulfur	0.111	0.099	0.085	0.065	0.070	0.069	0.071	0.076	0.079	0.083	0.087	0.097
Over 1.00% Sulfur	0.248	0.221	0.189	0.144	0.157	0.155	0.159	0.168	0.176	0.184	0.193	0.217
Total of All Types	0.434	0.387	0.331	0.252	0.274	0.271	0.278	0.294	0.307	0.322	0.338	0.380
Liquefied Petroleum Gas												
Total of All Types	0.720	0.806	0.820	0.841	0.764	0.809	0.816	0.829	0.838	0.848	0.859	0.820
Other Petroleum												
Total of All Types	0.850	0.703	0.645	0.666	0.790	0.840	0.872	0.905	0.942	0.979	1.022	1.145
Petroleum Product Supplied												
Total of All Types	3.452	3.484	3.396	3.370	3.500	3.612	3.653	3.730	3.810	3.904	4.013	4.248

Table 8. Petroleum Product Supplied in NPC 7 (Rocky Mountains)
Consumption in Million Barrels per Day

Fuel Category	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995
Motor Gasoline												
Leaded	0.105	0.099	0.093	0.088	0.081	0.075	0.034	0.000	0.000	0.000	0.000	0.000
Unleaded	0.092	0.097	0.102	0.108	0.116	0.124	0.154	0.180	0.180	0.181	0.184	0.192
Premium	0.022	0.023	0.024	0.025	0.027	0.028	0.035	0.040	0.040	0.039	0.038	0.034
Total of All Types	0.219	0.219	0.219	0.221	0.224	0.228	0.223	0.221	0.219	0.220	0.222	0.226
Distillate Fuel												
Heating Oil	0.010	0.005	0.007	0.006	0.007	0.006	0.007	0.007	0.008	0.008	0.008	0.009
Highway Diesel	0.052	0.044	0.043	0.044	0.046	0.046	0.047	0.049	0.051	0.054	0.057	0.071
Other Uses	0.065	0.058	0.052	0.051	0.056	0.056	0.056	0.059	0.061	0.063	0.065	0.071
Total of All Types	0.126	0.108	0.102	0.101	0.108	0.109	0.111	0.115	0.120	0.125	0.130	0.151
Jet Fuel												
Naphtha-Type	0.005	0.005	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.007	0.007	0.008
Kerosene-Type	0.021	0.022	0.023	0.023	0.026	0.026	0.028	0.030	0.031	0.032	0.034	0.035
Total of All Types	0.027	0.028	0.028	0.029	0.032	0.032	0.034	0.036	0.037	0.039	0.040	0.043
Residual Fuel												
0.00 to 0.30% Sulfur	0.005	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
0.31 to 1.00% Sulfur	0.009	0.004	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.004	0.004	0.004
Over 1.00% Sulfur	0.019	0.009	0.007	0.006	0.006	0.006	0.006	0.007	0.007	0.007	0.008	0.008
Total of All Types	0.033	0.016	0.012	0.010	0.011	0.011	0.011	0.012	0.012	0.013	0.013	0.015
Liquefied Petroleum Gas												
Total of All Types	0.027	0.025	0.031	0.030	0.026	0.027	0.027	0.028	0.028	0.028	0.028	0.025
Other Petroleum												
Total of All Types	0.084	0.065	0.057	0.060	0.072	0.078	0.080	0.083	0.087	0.090	0.094	0.103
Petroleum Product Supplied												
Total of All Types	0.516	0.461	0.447	0.450	0.473	0.485	0.487	0.494	0.503	0.515	0.528	0.563

Table 9. Petroleum Product Supplied in NPC 8 (Washington/Oregon)
Consumption in Million Barrels per Day

Fuel Category	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995
Motor Gasoline												
Leaded	0.096	0.090	0.084	0.079	0.073	0.067	0.031	0.000	0.000	0.000	0.000	0.000
Unleaded	0.084	0.088	0.091	0.097	0.104	0.111	0.137	0.161	0.160	0.160	0.162	0.166
Premium	0.020	0.021	0.021	0.023	0.024	0.026	0.031	0.036	0.035	0.035	0.034	0.029
Total of All Types	0.200	0.199	0.196	0.199	0.201	0.204	0.199	0.196	0.195	0.195	0.196	0.195
Distillate Fuel												
Heating Oil	0.023	0.020	0.023	0.022	0.023	0.022	0.023	0.025	0.025	0.026	0.027	0.028
Highway Diesel	0.037	0.039	0.035	0.036	0.038	0.038	0.039	0.040	0.042	0.044	0.046	0.058
Other Uses	0.036	0.034	0.033	0.034	0.036	0.036	0.037	0.038	0.039	0.041	0.042	0.043
Total of All Types	0.096	0.093	0.091	0.092	0.097	0.097	0.099	0.103	0.107	0.111	0.116	0.129
Jet Fuel												
Naphtha-Type	0.008	0.007	0.008	0.008	0.008	0.008	0.009	0.009	0.009	0.009	0.010	0.011
Kerosene-Type	0.032	0.030	0.032	0.033	0.037	0.038	0.040	0.042	0.044	0.046	0.048	0.050
Total of All Types	0.040	0.038	0.040	0.041	0.045	0.046	0.049	0.051	0.053	0.056	0.058	0.061
Residual Fuel												
0.00 to 0.30% Sulfur	0.005	0.005	0.005	0.004	0.004	0.004	0.004	0.005	0.005	0.005	0.005	0.006
0.31 to 1.00% Sulfur	0.017	0.017	0.018	0.014	0.015	0.015	0.016	0.017	0.017	0.018	0.019	0.021
Over 1.00% Sulfur	0.038	0.040	0.042	0.032	0.035	0.035	0.036	0.038	0.040	0.042	0.044	0.048
Total of All Types	0.060	0.062	0.066	0.051	0.055	0.055	0.056	0.060	0.062	0.065	0.068	0.075
Liquefied Petroleum Gas												
Total of All Types	0.008	0.008	0.008	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.006
Other Petroleum												
Total of All Types	0.056	0.055	0.048	0.051	0.061	0.065	0.067	0.069	0.071	0.074	0.077	0.085
Petroleum Product Supplied												
Total of All Types	0.460	0.455	0.449	0.441	0.466	0.473	0.477	0.486	0.496	0.507	0.521	0.551

Table 10. Petroleum Product Supplied in NPC 9 (Southwest)
Consumption in Million Barrels per Day

Fuel Category	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995
Motor Gasoline												
Leaded	0.372	0.351	0.329	0.311	0.286	0.265	0.121	0.000	0.000	0.000	0.000	0.000
Unleaded	0.325	0.344	0.358	0.381	0.409	0.437	0.540	0.631	0.6_7	0.628	0.635	0.649
Premium	0.077	0.080	0.083	0.090	0.095	0.100	0.122	0.141	0.138	0.135	0.132	0.115
Total of All Types	0.774	0.776	0.771	0.782	0.790	0.802	0.783	0.771	0.765	0.764	0.768	0.764
Distillate Fuel												
Heating Oil	0.013	0.012	0.013	0.012	0.013	0.013	0.014	0.015	0.015	0.016	0.017	0.019
Highway Diesel	0.086	0.091	0.083	0.084	0.088	0.088	0.091	0.094	0.098	0.103	0.109	0.136
Other Uses	0.085	0.087	0.087	0.083	0.091	0.092	0.091	0.094	0.098	0.102	0.107	0.122
Total of All Types	0.184	0.190	0.183	0.179	0.193	0.193	0.196	0.203	0.212	0.221	0.232	0.277
Jet Fuel												
Naphtha-Type	0.031	0.029	0.027	0.028	0.029	0.029	0.030	0.031	0.032	0.032	0.033	0.037
Kerosene-Type	0.127	0.118	0.112	0.116	0.130	0.132	0.139	0.148	0.154	0.161	0.168	0.175
Total of All Types	0.158	0.147	0.140	0.144	0.158	0.161	0.170	0.178	0.186	0.194	0.201	0.212
Residual Fuel												
0.00 to 0.30% Sulfur	0.024	0.021	0.014	0.011	0.011	0.011	0.011	0.011	0.012	0.012	0.013	0.020
0.31 to 1.00% Sulfur	0.086	0.075	0.049	0.038	0.039	0.039	0.038	0.040	0.042	0.044	0.046	0.069
Over 1.00% Sulfur	0.196	0.171	0.113	0.086	0.090	0.088	0.088	0.091	0.096	0.100	0.107	0.157
Total of All Types	0.306	0.267	0.177	0.135	0.141	0.138	0.137	0.142	0.149	0.156	0.166	0.246
Liquefied Petroleum Gas												
Total of All Types	0.055	0.049	0.050	0.046	0.041	0.043	0.043	0.044	0.044	0.044	0.045	0.041
Other Petroleum												
Total of All Types	0.252	0.225	0.203	0.205	0.246	0.266	0.276	0.286	0.297	0.310	0.323	0.359
Petroleum Product Supplied												
Total of All Types	1.729	1.653	1.523	1.491	1.569	1.603	1.605	1.626	1.653	1.689	1.735	1.900

Table 11. Petroleum Product Supplied in NPC 10 (Alaska/Hawaii/Guam)
Consumption in Million Barrels per Day

Fuel Category	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995
Motor Gasoline												
Leaded	0.031	0.030	0.028	0.026	0.024	0.022	0.010	0.000	0.000	0.000	0.000	0.000
Unleaded	0.027	0.029	0.030	0.032	0.034	0.037	0.045	0.053	0.053	0.053	0.053	0.055
Premium	0.007	0.007	0.007	0.008	0.008	0.008	0.010	0.012	0.012	0.011	0.011	0.010
Total of All Types	0.065	0.065	0.065	0.066	0.066	0.068	0.066	0.065	0.064	0.064	0.065	0.064
Distillate Fuel												
Heating Oil	0.004	0.004	0.004	0.004	0.005	0.004	0.005	0.005	0.005	0.006	0.006	0.007
Highway Diesel	0.030	0.031	0.029	0.029	0.031	0.031	0.032	0.033	0.034	0.036	0.038	0.047
Other Uses	0.030	0.030	0.030	0.029	0.031	0.032	0.031	0.033	0.034	0.035	0.037	0.042
Total of All Types	0.064	0.066	0.063	0.062	0.067	0.067	0.068	0.070	0.073	0.077	0.080	0.096
Jet Fuel												
Naphtha-Type	0.024	0.022	0.021	0.022	0.022	0.022	0.023	0.024	0.024	0.025	0.025	0.028
Kerosene-Type	0.097	0.090	0.086	0.089	0.099	0.100	0.107	0.113	0.118	0.123	0.128	0.134
Total of All Types	0.120	0.112	0.107	0.110	0.121	0.123	0.130	0.136	0.142	0.148	0.154	0.162
Residual Fuel												
0.00 to 0.30% Sulfur	0.012	0.010	0.007	0.005	0.005	0.005	0.005	0.005	0.006	0.006	0.006	0.009
0.31 to 1.00% Sulfur	0.041	0.036	0.024	0.018	0.019	0.019	0.019	0.019	0.020	0.021	0.023	0.033
Over 1.00% Sulfur	0.095	0.083	0.055	0.042	0.044	0.043	0.043	0.044	0.046	0.048	0.052	0.076
Total of All Types	0.148	0.129	0.086	0.065	0.068	0.067	0.066	0.069	0.072	0.076	0.081	0.119
Liquefied Petroleum Gas												
Total of All Types	0.009	0.008	0.008	0.008	0.007	0.007	0.007	0.007	0.007	0.008	0.008	0.007
Other Petroleum												
Total of All Types	0.046	0.041	0.037	0.037	0.045	0.049	0.050	0.052	0.054	0.057	0.059	0.066
Petroleum Product Supplied												
Total of All Types	0.453	0.422	0.366	0.348	0.374	0.380	0.387	0.400	0.414	0.428	0.446	0.514

Table 12. Production of Crude Oil (including Lease Condensate) by NPC Region
Production in Million Barrels per Day

NPC Regions	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995
NPC 1: New England	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
NPC 2: Mid Atlantic	0.012	0.012	0.012	0.012	0.012	0.011	0.010	0.010	0.010	0.011	0.013
NPC 3: South Atlantic	0.073	0.062	0.059	0.057	0.055	0.053	0.050	0.048	0.047	0.048	0.049
NPC 4: Great Lakes	0.195	0.197	0.194	0.190	0.183	0.168	0.157	0.155	0.159	0.173	0.214
NPC 5: Great Plains	0.729	0.739	0.709	0.681	0.642	0.580	0.521	0.470	0.425	0.389	0.247
NPC 6: South Central	4.561	4.378	4.357	4.322	4.390	4.275	4.090	3.916	3.654	3.444	2.352
NPC 7: Rocky Mountains	0.534	0.527	0.511	0.501	0.488	0.454	0.423	0.413	0.421	0.447	0.568
NPC 8: Washington/Oregon ...	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
NPC 9: Southwest.....	0.854	1.033	1.130	1.258	1.329	1.329	1.323	1.336	1.343	1.354	1.163
NPC 10: Alaska/Hawaii/Guam ..	1.613	1.701	1.717	1.735	1.762	1.784	1.920	1.917	1.930	1.933	0.762
Total United States	8.572	8.649	8.688	8.756	8.860	8.653	8.494	8.264	7.988	7.800	5.368

ATTACHMENT 2

U.S. Domestic Low Case Balances

Summary of Total U.S. Petroleum Supply and Disposition Balance--Low Demand Case*
(Million Barrels per Day)

	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Production													
Crude Oil	8.69	8.76	8.86	8.65	8.49	8.26	7.99	7.80	7.26	6.76	6.25	5.77	5.37
Alaska North Slope	1.65	1.67	1.70	1.76	1.92	1.92	1.92	1.97	1.72	1.49	1.31	1.14	1.00
Subarctic	7.04	7.08	7.15	6.89	6.57	6.34	6.06	5.82	5.54	5.27	4.94	4.64	4.37
Natural Gas Plant Liquids	1.56	1.61	1.64	1.52	1.59	1.60	1.58	1.56	1.55	1.53	1.50	1.46	1.45
Other Domestic	.05	.05	.05	.05	.05	.05	.07	.09	.14	.19	.25	.30	.36
Processing Gain	.49	.55	.54	.50	.49	.49	.48	.48	.48	.48	.48	.48	.48
Total Production	10.79	10.97	11.09	10.72	10.63	10.40	10.12	9.93	9.44	8.96	8.47	8.01	7.65
Total Imports (including SPR)	5.05	5.70	5.73	5.87	5.84	5.90	6.09	6.28	6.55	6.97	7.39	7.82	8.17
Total Exports	.74	.67	.62	.78	.78	.78	.78	.78	.78	.78	.78	.78	.78
Net Imports (including SPR)	4.31	5.03	5.11	5.08	5.06	5.11	5.31	5.49	5.77	6.18	6.60	7.04	7.39
Primary Stock Changes													
Net Withdrawals	.25	.04	.00	.05	.01	.02	.01	.00	.01	.01	.01	.01	.01
SPR Fill Rate Additions (-)	-.23	-.18	-.14	-.14	-.14	-.14	-.14	-.14	.00	.00	.00	.00	.00
Total Primary Supply	15.11	15.86	16.05	15.71	15.55	15.39	15.30	15.28	15.22	15.16	15.09	15.06	15.04
Refined Petroleum Products													
Motor Gasoline	6.62	6.70	6.74	6.48	6.28	6.10	5.97	5.87	5.77	5.68	5.61	5.54	5.48
Aviation Gasoline	.03	.04	.04	.04	.04	.04	.04	.04	.04	.04	.04	.04	.04
Jet Fuel	1.05	1.15	1.16	1.19	1.21	1.22	1.23	1.23	1.22	1.22	1.21	1.19	1.18
Kerosene	.13	.11	.10	.10	.10	.10	.10	.10	.10	.10	.10	.10	.10
Distillate Fuel	2.69	2.87	2.83	2.81	2.85	2.86	2.89	2.92	2.94	2.95	2.97	2.98	3.01
Residual Fuel	1.42	1.46	1.44	1.36	1.33	1.32	1.31	1.35	1.38	1.40	1.41	1.46	1.50
Liquid Petroleum Gas	1.49	1.36	1.42	1.41	1.41	1.40	1.40	1.39	1.37	1.35	1.33	1.31	1.29
Petrochemical Feedstocks	.41	.68	.73	.75	.78	.80	.82	.85	.86	.88	.89	.91	.92
Other Petroleum Products	1.37	1.50	1.59	1.57	1.55	1.54	1.53	1.53	1.53	1.53	1.53	1.53	1.53
Total Product Supplied	15.21	15.86	16.05	15.71	15.55	15.39	15.30	15.28	15.22	15.16	15.09	15.06	15.04

*Tables 1-11 provide petroleum product supplied details for total U.S. and the 10 NPC regions, respectively. Table 12 provides crude oil (including lease condensate) details for the 10 NPC regions.

Table 1. Petroleum Product Supplied in the United States
Consumption in Million Barrels per Day

Fuel Category	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995
Motor Gasoline												
Leaded	3.170	2.984	2.794	2.631	2.428	2.224	1.000	0.000	0.000	0.000	0.000	0.000
Unleaded	2.767	2.925	3.039	3.229	3.466	3.676	4.465	5.133	5.004	4.910	4.859	4.654
Premium	0.660	0.679	0.706	0.762	0.804	0.843	1.013	1.143	1.099	1.059	1.009	0.821
Total of All Types	6.597	6.587	6.539	6.622	6.698	6.743	6.478	6.276	6.103	5.969	5.868	5.475
Distillate Fuel												
Heating Oil	0.861	0.754	0.700	0.670	0.705	0.690	0.706	0.722	0.729	0.735	0.739	0.699
Highway Diesel	0.975	1.013	0.975	0.993	1.044	1.046	1.059	1.074	1.093	1.114	1.137	1.276
Other Uses	1.038	1.061	0.996	1.027	1.119	1.093	1.048	1.050	1.042	1.043	1.046	1.032
Total of All Types	2.874	2.829	2.671	2.690	2.869	2.828	2.813	2.846	2.864	2.892	2.922	3.007
Jet Fuel												
Naphtha-Type	0.209	0.197	0.213	0.220	0.224	0.229	0.235	0.240	0.246	0.252	0.258	0.290
Kerosene-Type	0.862	0.810	0.799	0.826	0.924	0.927	0.950	0.974	0.972	0.974	0.972	0.888
Total of All Types	1.070	1.007	1.013	1.046	1.148	1.156	1.185	1.214	1.218	1.226	1.230	1.178
Residual Fuel												
0.00 to 0.30% Sulfur	0.489	0.402	0.339	0.286	0.291	0.288	0.269	0.263	0.259	0.258	0.266	0.301
0.31 to 1.00% Sulfur	0.674	0.558	0.457	0.379	0.389	0.384	0.361	0.355	0.351	0.349	0.359	0.400
Over 1.00% Sulfur	1.352	1.127	0.920	0.757	0.779	0.770	0.726	0.713	0.705	0.702	0.722	0.800
Total of All Types	2.515	2.088	1.716	1.421	1.458	1.442	1.356	1.330	1.315	1.309	1.347	1.502
Liquefied Petroleum Gas												
Total of All Types	1.473	1.466	1.499	1.509	1.361	1.418	1.409	1.409	1.402	1.398	1.394	1.289
Other Petroleum												
Total of All Types	2.573	2.081	1.857	1.943	2.328	2.464	2.465	2.477	2.491	2.503	2.523	2.591
Petroleum Product Supplied												
Total of All Types	17.103	16.058	15.296	15.231	15.862	16.051	15.706	15.552	15.393	15.297	15.284	15.042

Table 2. Petroleum Product Supplied in NPC 1 (New England)
Consumption in Million Barrels per Day

Fuel Category	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995
Motor Gasoline												
Leaded	0.154	0.145	0.137	0.129	0.119	0.109	0.049	0.000	0.000	0.000	0.000	0.000
Unleaded	0.134	0.143	0.149	0.159	0.170	0.180	0.219	0.251	0.244	0.239	0.236	0.224
Premium	0.032	0.033	0.035	0.037	0.039	0.041	0.050	0.056	0.054	0.052	0.049	0.040
Total of All Types	0.320	0.321	0.320	0.325	0.328	0.330	0.317	0.307	0.298	0.291	0.285	0.264
Distillate Fuel												
Heating Oil	0.181	0.156	0.147	0.142	0.148	0.145	0.148	0.150	0.151	0.152	0.152	0.142
Highway Diesel	0.023	0.022	0.027	0.027	0.029	0.029	0.029	0.030	0.030	0.031	0.031	0.035
Other Uses	0.031	0.025	0.027	0.048	0.051	0.050	0.049	0.049	0.048	0.048	0.048	0.048
Total of All Types	0.234	0.203	0.201	0.217	0.228	0.223	0.225	0.229	0.230	0.231	0.232	0.225
Jet Fuel												
Naphtha-Type	0.004	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.004	0.004
Kerosene-Type	0.034	0.030	0.027	0.028	0.031	0.031	0.032	0.033	0.033	0.033	0.033	0.031
Total of All Types	0.038	0.033	0.030	0.031	0.034	0.035	0.035	0.036	0.036	0.037	0.037	0.035
Residual Fuel												
0.00 to 0.30% Sulfur	0.069	0.061	0.058	0.052	0.051	0.051	0.046	0.045	0.044	0.043	0.045	0.054
0.31 to 1.00% Sulfur	0.072	0.063	0.061	0.054	0.054	0.053	0.048	0.046	0.046	0.045	0.047	0.056
Over 1.00% Sulfur	0.134	0.118	0.113	0.101	0.100	0.100	0.090	0.087	0.085	0.084	0.088	0.105
Total of All Types	0.276	0.242	0.232	0.208	0.205	0.204	0.185	0.178	0.175	0.172	0.180	0.216
Liquefied Petroleum Gas												
Total of All Types	0.018	0.018	0.019	0.019	0.017	0.018	0.017	0.017	0.017	0.017	0.017	0.015
Other Petroleum												
Total of All Types	0.044	0.032	0.028	0.034	0.039	0.038	0.037	0.036	0.036	0.035	0.035	0.033
Petroleum Product Supplied												
Total of All Types	0.930	0.849	0.830	0.834	0.851	0.849	0.817	0.803	0.792	0.783	0.786	0.788

Table 3. Petroleum Product Supplied in NPC 2 (Mid Atlantic)
Consumption in Million Barrels per Day

Fuel Category	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995
Motor Gasoline												
Leaded	0.406	0.380	0.357	0.337	0.311	0.285	0.128	0.000	0.000	0.000	0.000	0.000
Unleaded	0.354	0.373	0.389	0.413	0.444	0.470	0.571	0.656	0.639	0.627	0.620	0.591
Premium	0.084	0.086	0.090	0.098	0.103	0.108	0.130	0.146	0.140	0.135	0.129	0.104
Total of All Types	0.844	0.839	0.837	0.848	0.857	0.863	0.829	0.802	0.780	0.762	0.748	0.696
Distillate Fuel												
Heating Oil	0.325	0.295	0.266	0.255	0.268	0.261	0.267	0.273	0.275	0.277	0.278	0.261
Highway Diesel	0.086	0.076	0.077	0.078	0.082	0.082	0.083	0.085	0.086	0.088	0.089	0.100
Other Uses	0.121	0.108	0.098	0.134	0.144	0.141	0.135	0.135	0.134	0.134	0.134	0.134
Total of All Types	0.532	0.480	0.441	0.467	0.493	0.485	0.485	0.492	0.495	0.499	0.502	0.496
Jet Fuel												
Naphtha-Type	0.015	0.014	0.013	0.013	0.013	0.014	0.014	0.014	0.015	0.015	0.015	0.017
Kerosene-Type	0.136	0.130	0.118	0.122	0.135	0.135	0.139	0.142	0.142	0.143	0.143	0.135
Total of All Types	0.150	0.144	0.131	0.135	0.148	0.149	0.153	0.157	0.157	0.158	0.159	0.152
Residual Fuel												
0.00 to 0.30% Sulfur	0.141	0.113	0.103	0.088	0.089	0.088	0.082	0.080	0.079	0.078	0.081	0.094
0.31 to 1.00% Sulfur	0.146	0.117	0.108	0.091	0.092	0.091	0.085	0.083	0.082	0.081	0.084	0.098
Over 1.00% Sulfur	0.273	0.218	0.201	0.170	0.172	0.170	0.158	0.155	0.153	0.152	0.157	0.182
Total of All Types	0.560	0.448	0.412	0.349	0.352	0.349	0.325	0.317	0.314	0.312	0.323	0.373
Liquefied Petroleum Gas												
Total of All Types	0.056	0.052	0.050	0.049	0.044	0.046	0.046	0.046	0.046	0.046	0.045	0.041
Other Petroleum												
Total of All Types	0.242	0.209	0.192	0.199	0.236	0.251	0.251	0.252	0.254	0.255	0.257	0.263
Petroleum Product Supplied												
Total of All Types	2.384	2.172	2.061	2.046	2.131	2.143	2.088	2.066	2.045	2.031	2.034	2.021

Table 4. Petroleum Product Supplied in NPC 3 (South Atlantic)
Consumption in Million Barrels per Day

Fuel Category	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995
Motor Gasoline												
Leaded	0.539	0.512	0.484	0.457	0.421	0.386	0.173	0.000	0.000	0.000	0.000	0.000
Unleaded	0.470	0.502	0.527	0.561	0.601	0.637	0.773	0.888	0.864	0.846	0.836	0.794
Premium	0.112	0.117	0.122	0.132	0.139	0.146	0.175	0.198	0.190	0.183	0.174	0.140
Total of All Types	1.122	1.131	1.133	1.150	1.162	1.169	1.122	1.085	1.054	1.029	1.010	0.934
Distillate Fuel												
Heating Oil	0.110	0.090	0.076	0.073	0.077	0.075	0.077	0.078	0.079	0.079	0.080	0.075
Highway Diesel	0.143	0.152	0.145	0.148	0.156	0.156	0.158	0.160	0.163	0.166	0.170	0.190
Other Uses	0.148	0.132	0.112	0.105	0.116	0.113	0.105	0.105	0.104	0.104	0.104	0.104
Total of All Types	0.401	0.374	0.333	0.326	0.349	0.344	0.340	0.343	0.346	0.349	0.353	0.369
Jet Fuel												
Naphtha-Type	0.021	0.020	0.020	0.020	0.021	0.021	0.022	0.022	0.023	0.023	0.024	0.027
Kerosene-Type	0.195	0.187	0.183	0.189	0.209	0.210	0.216	0.221	0.221	0.222	0.222	0.209
Total of All Types	0.216	0.208	0.203	0.209	0.230	0.231	0.237	0.243	0.244	0.245	0.246	0.236
Residual Fuel												
0.00 to 0.30% Sulfur	0.123	0.100	0.076	0.066	0.065	0.065	0.059	0.056	0.055	0.054	0.056	0.067
0.31 to 1.00% Sulfur	0.128	0.104	0.079	0.068	0.068	0.067	0.061	0.059	0.057	0.056	0.059	0.070
Over 1.00% Sulfur	0.239	0.194	0.147	0.128	0.126	0.125	0.114	0.109	0.107	0.105	0.109	0.130
Total of All Types	0.491	0.398	0.301	0.262	0.259	0.257	0.233	0.224	0.219	0.216	0.224	0.267
Liquefied Petroleum Gas												
Total of All Types	0.113	0.099	0.091	0.089	0.079	0.084	0.084	0.084	0.083	0.082	0.082	0.073
Other Petroleum												
Total of All Types	0.215	0.161	0.149	0.162	0.196	0.206	0.206	0.205	0.206	0.205	0.204	0.200
Petroleum Product Supplied												
Total of All Types	2.558	2.371	2.210	2.198	2.274	2.291	2.222	2.185	2.151	2.127	2.120	2.079

Table 5. Petroleum Product Supplied in NPC 4 (Great Lakes)
Consumption in Million Barrels per Day

Fuel Category	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995
Motor Gasoline												
Leaded	0.565	0.521	0.471	0.443	0.409	0.375	0.168	0.000	0.000	0.000	0.000	0.000
Unleaded	0.493	0.511	0.512	0.544	0.584	0.619	0.752	0.865	0.844	0.828	0.820	0.787
Premium	0.118	0.118	0.119	0.128	0.135	0.142	0.171	0.193	0.185	0.179	0.170	0.139
Total of All Types	1.176	1.150	1.101	1.115	1.128	1.135	1.091	1.058	1.029	1.007	0.990	0.926
Distillate Fuel												
Heating Oil	0.124	0.107	0.097	0.093	0.097	0.095	0.098	0.100	0.101	0.101	0.102	0.096
Highway Diesel	0.169	0.163	0.154	0.157	0.165	0.165	0.167	0.170	0.173	0.176	0.180	0.202
Other Uses	0.163	0.158	0.147	0.148	0.162	0.158	0.151	0.151	0.150	0.150	0.151	0.149
Total of All Types	0.456	0.428	0.398	0.398	0.425	0.419	0.416	0.421	0.423	0.428	0.432	0.447
Jet Fuel												
Naphtha-Type	0.018	0.016	0.017	0.017	0.017	0.018	0.018	0.019	0.019	0.020	0.020	0.023
Kerosene-Type	0.087	0.077	0.078	0.080	0.090	0.090	0.092	0.094	0.094	0.095	0.095	0.087
Total of All Types	0.105	0.094	0.094	0.098	0.107	0.108	0.110	0.113	0.114	0.114	0.115	0.110
Residual Fuel												
0.00 to 0.30% Sulfur	0.030	0.020	0.014	0.012	0.013	0.012	0.012	0.012	0.011	0.011	0.012	0.013
0.31 to 1.00% Sulfur	0.054	0.036	0.025	0.022	0.022	0.022	0.021	0.021	0.020	0.020	0.021	0.023
Over 1.00% Sulfur	0.094	0.062	0.043	0.038	0.039	0.039	0.036	0.036	0.035	0.035	0.036	0.040
Total of All Types	0.178	0.118	0.081	0.072	0.074	0.074	0.069	0.068	0.067	0.067	0.069	0.076
Liquefied Petroleum Gas												
Total of All Types	0.284	0.251	0.240	0.241	0.217	0.226	0.225	0.225	0.224	0.223	0.222	0.205
Other Petroleum												
Total of All Types	0.452	0.320	0.280	0.291	0.355	0.378	0.377	0.379	0.381	0.382	0.384	0.391
Petroleum Product Supplied												
Total of All Types	2.650	2.360	2.194	2.214	2.305	2.340	2.289	2.263	2.237	2.220	2.212	2.154

Table 6. Petroleum Product Supplied in NPC 5 (Great Plains)
Consumption in Million Barrels per Day

Fuel Category	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995
Motor Gasoline												
Leaded	0.451	0.423	0.397	0.372	0.344	0.316	0.142	0.000	0.000	0.000	0.000	0.000
Unleaded	0.394	0.414	0.432	0.456	0.491	0.522	0.635	0.733	0.718	0.707	0.703	0.689
Premium	0.094	0.096	0.100	0.108	0.114	0.120	0.144	0.163	0.158	0.153	0.146	0.122
Total of All Types	0.938	0.933	0.929	0.935	0.949	0.957	0.922	0.897	0.875	0.860	0.849	0.810
Distillate Fuel												
Heating Oil	0.060	0.047	0.050	0.048	0.050	0.049	0.050	0.051	0.052	0.052	0.053	0.050
Highway Diesel	0.167	0.162	0.170	0.173	0.183	0.183	0.185	0.188	0.191	0.195	0.199	0.223
Other Uses	0.175	0.170	0.175	0.171	0.186	0.181	0.175	0.176	0.174	0.175	0.175	0.172
Total of All Types	0.401	0.379	0.395	0.392	0.419	0.413	0.410	0.415	0.417	0.422	0.426	0.444
Jet Fuel												
Naphtha-Type	0.015	0.014	0.013	0.013	0.014	0.014	0.014	0.015	0.015	0.015	0.016	0.018
Kerosene-Type	0.071	0.064	0.061	0.063	0.070	0.071	0.073	0.074	0.074	0.074	0.074	0.069
Total of All Types	0.086	0.078	0.074	0.077	0.084	0.085	0.087	0.089	0.089	0.090	0.090	0.086
Residual Fuel												
0.00 to 0.30% Sulfur	0.005	0.004	0.004	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
0.31 to 1.00% Sulfur	0.009	0.006	0.006	0.005	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006
Over 1.00% Sulfur	0.016	0.011	0.011	0.009	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010
Total of All Types	0.030	0.021	0.021	0.018	0.019	0.019	0.018	0.018	0.018	0.019	0.019	0.019
Liquefied Petroleum Gas												
Total of All Types	0.183	0.149	0.182	0.178	0.159	0.167	0.167	0.167	0.166	0.165	0.164	0.148
Other Petroleum												
Total of All Types	0.332	0.270	0.220	0.238	0.287	0.305	0.305	0.306	0.307	0.308	0.310	0.314
Petroleum Product Supplied												
Total of All Types	1.970	1.831	1.821	1.838	1.918	1.946	1.910	1.892	1.873	1.862	1.858	1.822

Table 7. Petroleum Product Supplied in NPC 6 (South Central)
Consumption in Million Barrels per Day

Fuel Category	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995
Motor Gasoline												
Leaded	0.451	0.432	0.414	0.390	0.360	0.330	0.148	0.000	0.000	0.000	0.000	0.000
Unleaded	0.394	0.423	0.450	0.479	0.514	0.545	0.661	0.759	0.739	0.724	0.716	0.681
Premium	0.094	0.098	0.105	0.113	0.119	0.125	0.150	0.169	0.162	0.156	0.149	0.120
Total of All Types	0.939	0.954	0.969	0.983	0.993	0.999	0.959	0.928	0.901	0.880	0.864	0.801
Distillate Fuel												
Heating Oil	0.012	0.017	0.018	0.016	0.018	0.018	0.019	0.020	0.020	0.021	0.022	0.023
Highway Diesel	0.183	0.233	0.212	0.216	0.227	0.227	0.230	0.233	0.238	0.242	0.247	0.277
Other Uses	0.184	0.258	0.235	0.225	0.246	0.240	0.232	0.233	0.231	0.231	0.232	0.227
Total of All Types	0.379	0.508	0.465	0.457	0.491	0.485	0.481	0.486	0.489	0.494	0.501	0.528
Jet Fuel												
Naphtha-Type	0.068	0.066	0.087	0.090	0.091	0.093	0.095	0.098	0.100	0.102	0.105	0.118
Kerosene-Type	0.063	0.061	0.079	0.082	0.097	0.096	0.099	0.101	0.099	0.098	0.097	0.075
Total of All Types	0.131	0.127	0.166	0.171	0.188	0.189	0.194	0.199	0.200	0.201	0.202	0.193
Residual Fuel												
0.00 to 0.30% Sulfur	0.075	0.066	0.057	0.043	0.047	0.046	0.046	0.046	0.046	0.046	0.047	0.048
0.31 to 1.00% Sulfur	0.111	0.099	0.085	0.065	0.070	0.069	0.068	0.069	0.069	0.069	0.070	0.071
Over 1.00% Sulfur	0.248	0.221	0.189	0.144	0.157	0.154	0.152	0.153	0.153	0.154	0.156	0.158
Total of All Types	0.434	0.387	0.331	0.252	0.274	0.269	0.266	0.268	0.268	0.270	0.274	0.277
Liquefied Petroleum Gas												
Total of All Types	0.720	0.806	0.820	0.841	0.765	0.792	0.785	0.785	0.782	0.782	0.781	0.733
Other Petroleum												
Total of All Types	0.850	0.703	0.645	0.666	0.791	0.832	0.832	0.840	0.847	0.854	0.865	0.906
Petroleum Product Supplied												
Total of All Types	3.452	3.484	3.396	3.370	3.501	3.565	3.517	3.506	3.487	3.481	3.486	3.438

Table 8. Petroleum Product Supplied in NPC 7 (Rocky Mountains)
Consumption in Million Barrels per Day

Fuel Category	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995
Motor Gasoline												
Leaded	0.105	0.099	0.093	0.088	0.081	0.074	0.033	0.000	0.000	0.000	0.000	0.000
Unleaded	0.092	0.097	0.102	0.108	0.116	0.123	0.150	0.172	0.169	0.166	0.165	0.161
Premium	0.022	0.023	0.024	0.025	0.027	0.028	0.034	0.038	0.037	0.036	0.034	0.028
Total of All Types	0.219	0.219	0.219	0.221	0.224	0.225	0.217	0.211	0.206	0.202	0.199	0.189
Distillate Fuel												
Heating Oil	0.010	0.005	0.007	0.006	0.007	0.006	0.007	0.007	0.007	0.007	0.007	0.007
Highway Diesel	0.052	0.044	0.043	0.044	0.046	0.046	0.047	0.047	0.048	0.049	0.050	0.056
Other Uses	0.065	0.058	0.052	0.051	0.056	0.054	0.053	0.053	0.053	0.053	0.053	0.052
Total of All Types	0.126	0.108	0.102	0.101	0.108	0.107	0.106	0.107	0.108	0.109	0.110	0.116
Jet Fuel												
Naphtha-Type	0.005	0.005	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.007	0.007	0.008
Kerosene-Type	0.021	0.022	0.023	0.023	0.026	0.026	0.027	0.027	0.027	0.027	0.027	0.025
Total of All Types	0.027	0.028	0.028	0.029	0.032	0.032	0.033	0.034	0.034	0.034	0.034	0.033
Residual Fuel												
0.00 to 0.30% Sulfur	0.005	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
0.31 to 1.00% Sulfur	0.009	0.004	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
Over 1.00% Sulfur	0.019	0.009	0.007	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006
Total of All Types	0.033	0.016	0.012	0.010	0.011	0.011	0.010	0.011	0.010	0.011	0.011	0.011
Liquefied Petroleum Gas												
Total of All Types	0.027	0.025	0.031	0.030	0.026	0.028	0.028	0.028	0.028	0.027	0.027	0.024
Other Petroleum												
Total of All Types	0.084	0.065	0.057	0.060	0.072	0.077	0.077	0.077	0.078	0.078	0.079	0.080
Petroleum Product Supplied												
Total of All Types	0.516	0.461	0.447	0.450	0.473	0.480	0.471	0.467	0.463	0.461	0.460	0.453

Table 9. Petroleum Product Supplied in NPC 8 (Washington/Oregon)
Consumption in Million Barrels per Day

Fuel Category	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995
Motor Gasoline												
Leaded	0.096	0.090	0.084	0.079	0.073	0.067	0.030	0.000	0.000	0.000	0.000	0.000
Unleaded	0.084	0.088	0.091	0.097	0.104	0.110	0.134	0.154	0.150	0.147	0.145	0.139
Premium	0.020	0.021	0.021	0.023	0.024	0.025	0.030	0.034	0.033	0.032	0.030	0.024
Total of All Types	0.200	0.199	0.196	0.199	0.201	0.202	0.194	0.188	0.183	0.179	0.176	0.163
Distillate Fuel												
Heating Oil	0.023	0.020	0.023	0.022	0.023	0.023	0.023	0.024	0.024	0.024	0.024	0.023
Highway Diesel	0.037	0.039	0.035	0.036	0.038	0.038	0.038	0.039	0.040	0.040	0.041	0.046
Other Uses	0.036	0.034	0.033	0.034	0.036	0.035	0.035	0.035	0.035	0.035	0.035	0.034
Total of All Types	0.096	0.093	0.091	0.092	0.097	0.096	0.096	0.098	0.098	0.099	0.100	0.103
Jet Fuel												
Naphtha-Type	0.008	0.007	0.008	0.008	0.008	0.008	0.009	0.009	0.009	0.009	0.010	0.011
Kerosene-Type	0.032	0.030	0.032	0.033	0.037	0.037	0.038	0.039	0.039	0.039	0.039	0.036
Total of All Types	0.040	0.038	0.040	0.041	0.045	0.046	0.047	0.048	0.048	0.049	0.049	0.047
Residual Fuel												
0.00 to 0.30% Sulfur	0.005	0.005	0.005	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004
0.31 to 1.00% Sulfur	0.017	0.017	0.018	0.014	0.015	0.015	0.015	0.015	0.015	0.015	0.015	0.015
Over 1.00% Sulfur	0.038	0.040	0.042	0.032	0.035	0.035	0.034	0.035	0.034	0.035	0.035	0.035
Total of All Types	0.060	0.062	0.066	0.051	0.055	0.054	0.054	0.054	0.054	0.054	0.055	0.055
Liquefied Petroleum Gas												
Total of All Types	0.008	0.008	0.008	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.006
Other Petroleum												
Total of All Types	0.056	0.055	0.048	0.051	0.061	0.064	0.064	0.064	0.064	0.064	0.065	0.066
Petroleum Product Supplied												
Total of All Types	0.460	0.455	0.449	0.441	0.466	0.469	0.462	0.458	0.454	0.452	0.451	0.440

Table 10. Petroleum Product Supplied in NPC 9 (Southwest)
Consumption in Million Barrels per Day

Fuel Category	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995
Motor Gasoline												
Leaded	0.372	0.351	0.329	0.311	0.286	0.262	0.118	0.000	0.000	0.000	0.000	0.000
Unleaded	0.325	0.344	0.358	0.381	0.409	0.433	0.526	0.604	0.588	0.577	0.570	0.543
Premium	0.077	0.080	0.083	0.090	0.095	0.099	0.119	0.135	0.129	0.124	0.118	0.096
Total of All Types	0.774	0.776	0.771	0.782	0.790	0.795	0.763	0.739	0.718	0.701	0.688	0.639
Distillate Fuel												
Heating Oil	0.013	0.012	0.013	0.012	0.013	0.013	0.014	0.014	0.015	0.015	0.015	0.016
Highway Diesel	0.086	0.091	0.083	0.084	0.088	0.089	0.090	0.091	0.093	0.094	0.096	0.108
Other Uses	0.085	0.087	0.087	0.083	0.091	0.089	0.085	0.085	0.084	0.084	0.085	0.083
Total of All Types	0.184	0.190	0.183	0.179	0.193	0.190	0.188	0.190	0.191	0.194	0.196	0.207
Jet Fuel												
Naphtha-Type	0.031	0.029	0.027	0.028	0.029	0.029	0.030	0.031	0.032	0.032	0.033	0.037
Kerosene-Type	0.127	0.118	0.112	0.116	0.130	0.130	0.133	0.137	0.136	0.137	0.137	0.125
Total of All Types	0.158	0.147	0.140	0.144	0.158	0.159	0.163	0.167	0.168	0.169	0.170	0.162
Residual Fuel												
0.00 to 0.30% Sulfur	0.024	0.021	0.014	0.011	0.011	0.011	0.010	0.010	0.010	0.010	0.010	0.011
0.31 to 1.00% Sulfur	0.086	0.075	0.049	0.038	0.039	0.039	0.037	0.036	0.036	0.036	0.036	0.039
Over 1.00% Sulfur	0.196	0.171	0.113	0.086	0.090	0.088	0.085	0.083	0.082	0.082	0.083	0.090
Total of All Types	0.306	0.267	0.177	0.135	0.141	0.138	0.132	0.130	0.128	0.127	0.130	0.140
Liquefied Petroleum Gas												
Total of All Types	0.055	0.049	0.050	0.046	0.041	0.043	0.043	0.043	0.043	0.042	0.042	0.038
Other Petroleum												
Total of All Types	0.252	0.225	0.203	0.205	0.246	0.264	0.266	0.268	0.269	0.272	0.275	0.285
Petroleum Product Supplied												
Total of All Types	1.729	1.653	1.523	1.491	1.568	1.590	1.556	1.537	1.517	1.506	1.501	1.471

Table 11. Petroleum Product Supplied in NPC 10 (Alaska/Hawaii/Guam) Consumption in Million Barrels per Day

Fuel Category	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995
Motor Gasoline												
Leaded	0.031	0.030	0.028	0.026	0.024	0.022	0.010	0.000	0.000	0.000	0.000	0.000
Unleaded	0.027	0.029	0.030	0.032	0.034	0.036	0.044	0.051	0.050	0.049	0.048	0.046
Premium	0.007	0.007	0.007	0.008	0.008	0.008	0.010	0.011	0.011	0.010	0.010	0.008
Total of All Types	0.065	0.065	0.065	0.066	0.066	0.067	0.064	0.062	0.060	0.059	0.058	0.054
Distillate Fuel												
Heating Oil	0.004	0.004	0.004	0.004	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005
Highway Diesel	0.030	0.031	0.029	0.029	0.031	0.031	0.031	0.031	0.032	0.033	0.033	0.037
Other Uses	0.030	0.030	0.030	0.029	0.031	0.031	0.029	0.029	0.029	0.029	0.029	0.029
Total of All Types	0.064	0.066	0.063	0.062	0.067	0.066	0.065	0.066	0.066	0.067	0.068	0.072
Jet Fuel												
Naphtha-Type	0.024	0.022	0.021	0.022	0.022	0.022	0.023	0.024	0.024	0.025	0.025	0.028
Kerosene-Type	0.097	0.090	0.086	0.089	0.099	0.099	0.102	0.104	0.104	0.104	0.104	0.096
Total of All Types	0.120	0.112	0.107	0.110	0.121	0.122	0.125	0.128	0.128	0.129	0.130	0.124
Residual Fuel												
0.00 to 0.30% Sulfur	0.012	0.010	0.007	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005
0.31 to 1.00% Sulfur	0.041	0.036	0.024	0.018	0.019	0.019	0.018	0.018	0.017	0.017	0.018	0.019
Over 1.00% Sulfur	0.095	0.083	0.055	0.042	0.044	0.043	0.041	0.040	0.040	0.040	0.040	0.043
Total of All Types	0.148	0.129	0.086	0.065	0.068	0.067	0.064	0.063	0.062	0.062	0.063	0.068
Liquefied Petroleum Gas												
Total of All Types	0.009	0.008	0.008	0.008	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.006
Other Petroleum												
Total of All Types	0.046	0.041	0.037	0.037	0.045	0.048	0.049	0.049	0.049	0.050	0.050	0.052
Petroleum Product Supplied												
Total of All Types	0.453	0.422	0.366	0.348	0.374	0.377	0.374	0.375	0.373	0.374	0.376	0.376

Table 12. Production of Crude Oil (including Lease Condensate) by NPC Region
Production in Million Barrels per Day

NPC Regions	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995
NPC 1: New England	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
NPC 2: Mid Atlantic	0.012	0.012	0.012	0.012	0.012	0.011	0.009	0.008	0.008	0.007	0.006
NPC 3: South Atlantic	0.073	0.062	0.059	0.057	0.055	0.052	0.048	0.046	0.046	0.046	0.043
NPC 4: Great Lakes	0.195	0.197	0.194	0.190	0.183	0.166	0.148	0.134	0.122	0.113	0.097
NPC 5: Great Plains	0.729	0.739	0.709	0.681	0.646	0.590	0.534	0.485	0.440	0.398	0.216
NPC 6: South Central.....	4.561	4.378	4.357	4.322	4.375	4.236	4.035	3.882	3.670	3.496	2.593
NPC 7: Rocky Mountains	0.534	0.527	0.511	0.501	0.491	0.461	0.430	0.405	0.383	0.368	0.280
NPC 8: Washington/Oregon ...	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
NPC 9: Southwest.....	0.854	1.033	1.130	1.258	1.338	1.333	1.322	1.342	1.362	1.369	1.005
NPC 10: Alaska/Hawaii/Guam ..	1.613	1.701	1.717	1.735	1.761	1.805	1.967	1.961	1.957	2.003	1.128
Total United States	8.572	8.649	8.688	8.756	8.860	8.653	8.494	8.264	7.988	7.800	5.368

ATTACHMENT 3

International High Case Balances

WORLD PETROLEUM SUPPLY AND DEMAND SUMMARY
HIGH DEMAND CASE--1979-1995

	1979	1980	1981	1982	1983	1984	1985	1986	1987
WORLD OIL PRICE									
1984 CIF $	29.60	42.42	42.29	36.11	30.39	29.02	27.92	27.31	26.71
CONSUMPTION (MMB/D)									
UNITED STATES A/	18.91	17.50	16.45	15.69	15.51	16.18	16.08	16.53	16.78
CANADA	1.86	1.95	1.84	1.62	1.49	1.48	1.49	1.48	1.49
JAPAN	5.48	4.96	4.85	4.55	4.37	4.60	4.47	4.45	4.47
WESTERN EUROPE	14.72	13.51	12.47	12.09	11.81	11.92	11.89	11.80	11.85
OPEC	2.50	2.65	2.96	3.23	3.30	3.37	3.46	3.65	3.84
OTHER COUNTRIES	8.90	9.01	8.86	9.10	8.71	8.75	8.90	8.94	9.17
TOTAL FREE WORLD	52.37	49.57	47.42	46.28	45.19	46.29	46.30	46.85	47.60
PRODUCTION (MMB/D)									
UNITED STATES	10.71	10.81	10.74	10.78	10.79	10.98	11.08	10.73	10.66
CANADA	1.58	1.76	1.61	1.71	1.78	1.73	1.72	1.74	1.76
WESTERN EUROPE	2.40	2.56	2.90	3.14	3.83	4.09	4.18	4.13	4.08
OPEC	31.86	27.75	23.61	19.85	18.55	19.07	19.11	19.99	20.82
OTHER COUNTRIES	5.80	6.27	6.87	7.61	7.93	8.52	8.59	8.86	9.13
CPE NET EXPORTS	1.10	1.24	1.47	1.68	1.94	1.94	1.84	1.70	1.50
TOTAL FREE WORLD	53.44	50.39	47.20	44.77	44.82	46.33	46.53	47.14	47.95
NET UNITED STATES IMPORTS (MMB/D)									
50 STATE AREA	7.97	6.37	5.39	4.30	4.27	5.04	4.85	5.65	6.02
U. S. TERRITORIES	0.40	0.44	0.39	0.39	0.28	0.30	0.30	0.30	0.30
TOTAL UNITED STATES	8.37	6.81	5.78	4.69	4.55	5.34	5.15	5.95	6.33
NET STOCK ADDITIONS (MMB/D)									
U. S. STRATEGIC	0.07	0.05	0.34	0.17	0.23	0.18	0.14	0.14	0.14
U. S. COMMERCIAL	0.10	0.10	-0.18	-0.32	-0.25	-0.04	0.01	0.01	0.06
FOREIGN	0.90	0.67	-0.38	-1.37	-0.35	-0.10	0.08	0.15	0.15
TOTAL NET ADDITIONS	1.07	0.82	-0.22	-1.51	-0.37	0.04	0.23	0.30	0.35

A/ INCLUDES U. S. TERRITORIES.

WORLD PETROLEUM SUPPLY AND DEMAND SUMMARY
HIGH DEMAND CASE--1979-1995 (Continued)

	1988	1989	1990	1991	1992	1993	1994	1995
WORLD OIL PRICE								
1984 CIF $	26.13	25.56	25.00	25.93	26.89	27.89	28.93	30.00
CONSUMPTION (MMB/D)								
A/								
UNITED STATES	17.11	17.49	17.99	18.22	18.47	18.71	19.04	19.86
CANADA	1.52	1.57	1.64	1.68	1.72	1.69	1.66	1.59
JAPAN	4.57	4.72	4.91	5.05	5.18	5.07	4.94	4.75
WESTERN EUROPE	12.15	12.64	13.26	13.62	13.94	13.63	13.25	12.74
OPEC	4.04	4.26	4.48	4.72	4.97	5.01	5.05	5.03
OTHER COUNTRIES	9.62	10.15	10.71	10.98	11.21	10.97	10.70	10.32
TOTAL FREE WORLD	49.02	50.83	53.00	54.27	55.48	55.08	54.64	54.30
PRODUCTION (MMB/D)								
UNITED STATES	10.45	10.18	10.01	9.52	9.06	8.58	8.13	7.79
CANADA	1.78	1.80	1.82	1.81	1.80	1.79	1.78	1.77
WESTERN EUROPE	4.02	3.97	3.92	3.82	3.72	3.63	3.54	3.45
OPEC	22.39	24.40	26.57	28.18	29.90	29.99	30.01	30.00
OTHER COUNTRIES	9.42	9.71	10.01	10.18	10.36	10.54	10.73	10.93
CPE NET EXPORTS	1.30	1.10	1.00	0.90	0.80	0.70	0.60	0.50
TOTAL FREE WORLD	49.36	51.16	53.34	54.42	55.64	55.22	54.79	54.45
NET UNITED STATES IMPORTS (MMB/D)								
50 STATE AREA	6.55	7.18	7.85	8.42	9.12	9.83	10.61	11.76
U. S. TERRITORIES	0.31	0.32	0.32	0.33	0.34	0.34	0.35	0.36
TOTAL UNITED STATES	6.86	7.50	8.18	8.75	9.46	10.18	10.96	12.12
NET STOCK ADDITIONS (MMB/D)								
U. S. STRATEGIC	0.14	0.14	0.14					
U. S. COMMERCIAL	0.06	0.05	0.05	0.05	0.05	0.04	0.05	0.05
FOREIGN	0.15	0.15	0.15	0.10	0.10	0.10	0.10	0.10
TOTAL NET ADDITIONS	0.35	0.34	0.34	0.15	0.15	0.14	0.15	0.15

A/ INCLUDES U. S. TERRITORIES.

INTERNATIONAL OIL PRODUCT CODES

(DS)	Distillates	Diesel Oil
(GA)	Gasoline	Aviation and Motor Gasoline
(JF)	Jet Fuel	Jet Fuel and Kerosene
(LG)	Liquefied Petroleum Gases	Same
(OT)	Other	Refinery Gas, Naphtha, Other
(RS)	Residual	Residual Fuel Oil
(OL)	(OL)	Residual in certain LOC's
(UT)		Oil consumed by utilities
(TO)		Total--sum of above
(BU)		Bunkers--already included in residual amount and in total amount

INTERNATIONAL REGION CODES

Regions	Code
East Coast	E
Gulf Coast	G
West Coast	W
Puerto Rico/Virgin Islands, Guam, Hawaiian Foreign Trade Zone	U
Canada	C
Japan	J
Australia/New Zealand	A
Norway/Sweden/Finland	1
United Kingdom/Ireland	2
Benelux/Denmark	3
West Germany	4
France	5
Austria/Switzerland	6
Spain/Portugal	7
Italy	8
Greece/Turkey	9
Venezuela/Ecuador	V
Libya/Algeria	L
Nigeria/Gabon	N
Indonesia	I
Iran	R
Iraq/Kuwait/Qatar/Saudi Arabia/UAE	P
Caribbean	K
Mexico	M
Bolivia/Peru	B
Egypt/Syria/Bahrain	Q
Angola/Zaire/Congo	O
Tunisia/Brunei/Penin Malaysia/Singapore	Y
Other Latin America	S
Other Africa	F
Other Asia	X

SAS
OIL CONSUMPTION IN THE MARKET ECONOMIES
SCENARIO: NPC85 MID WORLD OIL PRICE, HIGH ECONOMIC GROWTH
YEARS: 1982, 1983, AND 1984
THOUSAND BARRELS PER DAY

YEAR=82

NUM	CODE	REGION	DS	GA	JF	LG	OT	RS	OL	UT	TO	BU
1	E	EC	0	0	0	0	0	0	0	0	0	0
2	G	GC	0	0	0	0	0	0	0	0	0	0
3	W	WC	0	0	0	0	0	0	0	0	0	0
4	U	R1	18	90	20	0	169	0	94	0	390	21
5	C	CA	399	577	90	28	310	180	0	35	1620	12
6	J	JA	729	625	443	445	727	528	0	1052	4550	149
7	A	AN	152	308	53	22	93	77	0	26	732	19
8	1	NF	274	145	32	13	111	184	0	35	793	26
9	2	UI	357	468	140	60	231	276	0	166	1697	48
10	3	BD	340	187	53	96	227	367	0	105	1375	217
11	4	WG	957	535	67	68	361	283	0	66	2338	51
12	5	FR	677	419	52	100	307	282	0	94	1931	56
13	6	AS	167	122	19	7	51	64	0	21	450	0
14	7	SP	243	148	84	82	178	253	0	161	1149	37
15	8	IT	472	282	46	70	209	335	0	380	1794	75
16	9	GT	155	80	36	30	46	156	0	61	563	15
17	V	R2	108	198	28	0	62	126	0	0	522	21
18	L	R3	87	56	18	0	45	0	61	0	267	20
19	N	R4	56	99	36	0	11	0	37	0	239	4
20	I	R5	160	71	156	0	17	0	75	0	479	6
21	R	R6	292	80	106	0	27	170	0	0	675	18
22	P	R7	373	193	115	0	69	296	0	0	1047	133
23	K	R8	27	10	12	0	6	178	0	0	234	72
24	M	R9	230	366	66	0	379	338	0	0	1379	9
25	B	R10	33	37	26	0	17	0	28	0	142	3
26	Q	R11	179	94	101	0	67	0	314	0	756	72
27	O	R12	16	8	7	0	2	0	18	0	52	10
28	Y	R13	125	48	23	0	13	252	0	0	461	141
29	S	R14	651	518	121	0	313	0	582	0	2185	110
30	F	R15	230	172	65	0	49	0	209	0	725	121
31	X	R16	746	206	299	0	294	0	888	0	2433	86

SAS
OIL CONSUMPTION IN THE MARKET ECONOMIES
SCENARIO: NPC85 MID WORLD OIL PRICE, HIGH ECONOMIC GROWTH
YEARS: 1982, 1983, AND 1984
THOUSAND BARRELS PER DAY

YEAR=83

NUM	CODE	REGION	DS	GA	JF	LG	OT	RS	OL	UT	TO	BU
1	E	EC	0	0	0	0	0	0	0	0	0	0
2	G	GC	0	0	0	0	0	0	0	0	0	0
3	W	WC	0	0	0	0	0	0	0	0	0	0
4	U	R1	12	64	14	0	121	0	67	0	280	15
5	C	CA	369	520	82	27	297	163	0	33	1490	11
6	J	JA	707	594	424	438	709	517	0	982	4370	153
7	A	AN	142	285	49	23	90	71	0	22	682	19
8	1	NF	272	143	31	13	112	185	0	36	792	26
9	2	UI	346	456	140	61	238	261	0	149	1653	48
10	3	BD	325	182	53	97	230	358	0	99	1345	215
11	4	WG	900	524	68	69	354	262	0	67	2245	50
12	5	FR	659	413	52	101	309	268	0	83	1887	56
13	6	AS	159	120	18	7	51	62	0	19	437	0
14	7	SP	242	147	82	81	181	251	0	141	1126	37
15	8	IT	456	279	44	71	204	319	0	389	1763	74
16	9	GT	155	79	35	30	46	158	0	60	564	15
17	V	R2	108	199	28	0	63	127	0	0	523	21
18	L	R3	91	59	19	0	46	0	63	0	278	21
19	N	R4	55	96	35	0	11	0	36	0	232	4
20	I	R5	171	76	167	0	19	0	80	0	512	6
21	R	R6	318	87	115	0	29	185	0	0	734	20
22	P	R7	364	188	112	0	68	289	0	0	1020	130
23	K	R8	26	10	12	0	6	171	0	0	224	69
24	M	R9	212	337	61	0	349	311	0	0	1271	9
25	B	R10	28	31	23	0	15	0	25	0	121	3
26	Q	R11	175	91	98	0	65	0	305	0	733	70
27	O	R12	16	8	7	0	2	0	18	0	50	10
28	Y	R13	127	49	24	0	14	258	0	0	472	144
29	S	R14	607	483	113	0	292	0	543	0	2039	102
30	F	R15	219	164	62	0	46	0	199	0	688	115
31	X	R16	746	206	299	0	294	0	886	0	2431	86

SAS
OIL CONSUMPTION IN THE MARKET ECONOMIES
SCENARIO: NPC85 MID WORLD OIL PRICE, HIGH ECONOMIC GROWTH
YEARS: 1982, 1983, AND 1984
THOUSAND BARRELS PER DAY

YEAR=84

NUM	CODE	REGION	DS	GA	JF	LG	OT	RS	OL	UT	TO	BU
1	E	EC	0	0	0	0	0	0	0	0	0	0
2	G	GC	0	0	0	0	0	0	0	0	0	0
3	W	WC	0	0	0	0	0	0	0	0	0	0
4	U	R1	15	76	17	0	142	0	79	0	330	17
5	C	CA	370	505	82	27	302	163	0	32	1480	11
6	J	JA	749	615	446	471	762	569	0	988	4600	175
7	A	AN	139	274	45	22	92	68	0	19	659	18
8	1	NF	282	145	32	15	116	195	0	38	823	28
9	2	UI	347	459	145	63	249	258	0	138	1657	49
10	3	BD	324	182	54	100	240	370	0	95	1365	226
11	4	WG	883	528	71	71	360	257	0	69	2238	51
12	5	FR	661	417	53	104	319	265	0	75	1893	57
13	6	AS	158	121	18	7	52	63	0	18	438	0
14	7	SP	247	149	84	83	187	258	0	127	1134	38
15	8	IT	456	283	45	74	207	322	0	404	1791	77
16	9	GT	159	79	36	31	47	167	0	60	580	15
17	V	R2	106	194	28	0	61	123	0	0	511	21
18	L	R3	96	62	20	0	49	0	68	0	295	22
19	N	R4	54	96	35	0	11	0	36	0	231	4
20	I	R5	178	79	174	0	18	0	83	0	533	7
21	R	R6	332	90	120	0	30	193	0	0	767	21
22	P	R7	369	191	114	0	69	292	0	0	1033	132
23	K	R8	26	10	12	0	6	168	0	0	220	68
24	M	R9	214	339	61	0	352	312	0	0	1278	9
25	B	R10	27	30	21	0	14	0	23	0	117	3
26	Q	R11	174	92	99	0	65	0	305	0	734	70
27	O	R12	15	8	7	0	2	0	17	0	50	10
28	Y	R13	135	52	25	0	14	273	0	0	501	153
29	S	R14	598	476	111	0	288	0	534	0	2008	101
30	F	R15	218	164	62	0	46	0	198	0	688	115
31	X	R16	766	212	307	0	302	0	909	0	2495	88

SAS
OIL CONSUMPTION IN THE MARKET ECONOMIES
SCENARIO: NPC85 MID WORLD OIL PRICE, HIGH ECONOMIC GROWTH
YEARS: 1985, 1986, AND 1987
THOUSAND BARRELS PER DAY

YEAR=85

NUM	CODE	REGION	DS	GA	JF	LG	OT	RS	OL	UT	TO	BU
1	E	EC	0	0	0	0	0	0	0	0	0	0
2	G	GC	0	0	0	0	0	0	0	0	0	0
3	W	WC	0	0	0	0	0	0	0	0	0	0
4	U	R1	14	69	15	0	130	0	72	0	300	16
5	C	CA	377	498	83	27	308	164	0	32	1490	11
6	J	JA	734	588	435	465	756	576	0	917	4470	180
7	A	AN	139	267	44	23	92	68	0	16	649	18
8	1	NF	286	144	31	16	116	201	0	39	834	29
9	2	UI	342	454	146	64	256	254	0	125	1640	49
10	3	BD	319	180	56	101	246	374	0	89	1365	230
11	4	WG	865	526	73	72	363	253	0	69	2220	52
12	5	FR	655	413	55	104	326	262	0	66	1880	58
13	6	AS	157	120	19	7	53	62	0	17	434	0
14	7	SP	248	149	85	82	190	262	0	112	1128	38
15	8	IT	449	282	46	76	209	325	0	411	1800	78
16	9	GT	162	78	37	31	48	173	0	59	589	15
17	V	R2	108	197	28	0	62	125	0	0	520	21
18	L	R3	100	64	21	0	52	0	70	0	306	23
19	N	R4	56	100	36	0	11	0	37	0	240	4
20	I	R5	184	82	180	0	19	0	86	0	552	7
21	R	R6	345	94	125	0	32	201	0	0	797	21
22	P	R7	372	192	115	0	69	295	0	0	1044	133
23	K	R8	25	10	12	0	6	165	0	0	217	66
24	M	R9	220	349	63	0	361	321	0	0	1314	9
25	B	R10	28	31	22	0	14	0	24	0	118	3
26	Q	R11	175	92	99	0	65	0	305	0	734	70
27	O	R12	15	8	7	0	2	0	17	0	50	10
28	Y	R13	142	55	27	0	15	287	0	0	525	160
29	S	R14	610	486	113	0	293	0	545	0	2047	103
30	F	R15	221	166	62	0	46	0	199	0	695	116
31	X	R16	784	217	314	0	308	0	929	0	2551	90

SAS
OIL CONSUMPTION IN THE MARKET ECONOMIES
SCENARIO: NPC85 MID WORLD OIL PRICE, HIGH ECONOMIC GROWTH
YEARS: 1985, 1986, AND 1987
THOUSAND BARRELS PER DAY

YEAR=86

NUM	CODE	REGION	DS	GA	JF	LG	OT	RS	OL	UT	TO	BU
1	E	EC	0	0	0	0	0	0	0	0	0	0
2	G	GC	0	0	0	0	0	0	0	0	0	0
3	W	WC	0	0	0	0	0	0	0	0	0	0
4	U	R1	13	69	15	0	130	0	72	0	300	16
5	C	CA	378	487	84	27	308	165	0	31	1480	11
6	J	JA	739	582	436	467	762	605	0	859	4450	186
7	A	AN	135	256	43	23	90	67	0	13	626	18
8	1	NF	289	143	32	16	117	208	0	40	845	30
9	2	UI	336	447	148	64	257	249	0	113	1613	49
10	3	BD	313	176	55	100	248	377	0	83	1353	233
11	4	WG	846	521	74	74	361	249	0	68	2192	52
12	5	FR	649	409	55	105	329	260	0	57	1864	57
13	6	AS	154	119	18	7	52	63	0	16	429	0
14	7	SP	248	148	84	82	190	265	0	99	1115	38
15	8	IT	442	281	47	77	209	326	0	415	1796	79
16	9	GT	163	78	37	31	48	178	0	58	593	15
17	V	R2	111	204	29	0	64	130	0	0	538	22
18	L	R3	105	68	22	0	54	0	74	0	324	24
19	N	R4	59	104	38	0	11	0	39	0	252	4
20	I	R5	195	87	190	0	21	0	92	0	584	7
21	R	R6	361	99	131	0	33	210	0	0	834	22
22	P	R7	399	206	123	0	74	316	0	0	1119	142
23	K	R8	26	9	11	0	6	166	0	0	217	67
24	M	R9	223	354	64	0	367	326	0	0	1333	9
25	B	R10	28	31	22	0	15	0	24	0	118	3
26	Q	R11	176	92	99	0	65	0	307	0	739	70
27	O	R12	16	7	6	0	2	0	18	0	50	10
28	Y	R13	146	55	28	0	16	294	0	0	538	164
29	S	R14	613	488	114	0	295	0	547	0	2057	103
30	F	R15	220	166	62	0	46	0	199	0	693	116
31	X	R16	789	217	317	0	310	0	934	0	2568	91

SAS
OIL CONSUMPTION IN THE MARKET ECONOMIES
SCENARIO: NPC85 MID WORLD OIL PRICE, HIGH ECONOMIC GROWTH
YEARS: 1985, 1986, AND 1987
THOUSAND BARRELS PER DAY

YEAR=87

NUM	CODE	REGION	DS	GA	JF	LG	OT	RS	OL	UT	TO	BU
1	E	EC	0	0	0	0	0	0	0	0	0	0
2	G	GC	0	0	0	0	0	0	0	0	0	0
3	W	WC	0	0	0	0	0	0	0	0	0	0
4	U	R1	14	69	16	0	130	0	72	0	300	16
5	C	CA	385	482	86	27	312	168	0	31	1490	11
6	J	JA	749	582	441	473	775	644	0	807	4470	196
7	A	AN	136	252	42	23	90	68	0	11	622	17
8	1	NF	295	144	32	17	116	216	0	41	861	32
9	2	UI	333	444	150	64	262	249	0	103	1605	49
10	3	BD	312	175	58	100	254	387	0	78	1364	240
11	4	WG	839	520	75	74	363	250	0	68	2190	52
12	5	FR	651	409	57	106	336	265	0	50	1873	57
13	6	AS	154	118	18	7	52	63	0	15	428	0
14	7	SP	250	148	84	82	191	271	0	87	1112	38
15	8	IT	439	280	49	79	212	334	0	418	1812	81
16	9	GT	165	79	38	32	49	186	0	57	605	15
17	V	R2	115	211	30	0	66	134	0	0	556	22
18	L	R3	111	72	23	0	57	0	78	0	341	26
19	N	R4	62	109	40	0	12	0	41	0	263	4
20	I	R5	205	91	200	0	22	0	96	0	615	8
21	R	R6	377	104	136	0	35	219	0	0	871	23
22	P	R7	426	221	131	0	79	339	0	0	1195	152
23	K	R8	26	10	12	0	5	170	0	0	223	68
24	M	R9	230	368	66	0	380	338	0	0	1381	9
25	B	R10	29	32	23	0	15	0	25	0	122	3
26	Q	R11	180	95	102	0	67	0	314	0	757	72
27	O	R12	15	8	7	0	2	0	17	0	51	10
28	Y	R13	152	58	28	0	15	308	0	0	562	171
29	S	R14	629	501	116	0	302	0	562	0	2110	106
30	F	R15	224	168	63	0	47	0	203	0	705	117
31	X	R16	811	224	326	0	319	0	958	0	2636	93

SAS
OIL CONSUMPTION IN THE MARKET ECONOMIES
SCENARIO: NPC85 MID WORLD OIL PRICE, HIGH ECONOMIC GROWTH
YEARS: 1988, 1989, AND 1990
THOUSAND BARRELS PER DAY

YEAR=88

NUM	CODE	REGION	DS	GA	JF	LG	OT	RS	OL	UT	TO	BU
1	E	EC	0	0	0	0	0	0	0	0	0	0
2	G	GC	0	0	0	0	0	0	0	0	0	0
3	W	WC	0	0	0	0	0	0	0	0	0	0
4	U	R1	13	69	15	0	130	0	72	0	300	16
5	C	CA	397	484	89	28	316	176	0	30	1520	11
6	J	JA	769	590	453	485	805	705	0	763	4570	210
7	A	AN	138	255	43	24	91	72	0	9	633	17
8	1	NF	306	148	33	17	118	232	0	42	895	33
9	2	UI	338	450	155	66	270	255	0	95	1629	49
10	3	BD	320	178	60	101	261	410	0	75	1405	256
11	4	WG	854	531	79	77	372	260	0	68	2241	54
12	5	FR	669	417	59	109	346	279	0	44	1923	57
13	6	AS	158	121	18	7	54	66	0	14	438	0
14	7	SP	254	151	85	83	194	284	0	79	1129	38
15	8	IT	444	286	51	82	220	354	0	426	1863	86
16	9	GT	170	81	39	34	50	196	0	57	627	15
17	V	R2	119	217	31	0	68	139	0	0	573	23
18	L	R3	117	75	24	0	61	0	81	0	359	27
19	N	R4	64	114	42	0	13	0	43	0	275	5
20	I	R5	216	96	210	0	23	0	101	0	647	8
21	R	R6	393	107	143	0	36	229	0	0	908	24
22	P	R7	455	236	141	0	84	361	0	0	1278	163
23	K	R8	27	10	12	0	5	177	0	0	234	72
24	M	R9	244	388	70	0	402	358	0	0	1464	10
25	B	R10	30	33	24	0	15	0	25	0	128	3
26	Q	R11	189	99	107	0	71	0	330	0	795	76
27	O	R12	16	8	7	0	2	0	19	0	52	10
28	Y	R13	163	62	31	0	17	329	0	0	602	183
29	S	R14	659	524	122	0	318	0	589	0	2211	111
30	F	R15	233	175	66	0	49	0	211	0	733	122
31	X	R16	852	234	342	0	335	0	1006	0	2769	98

SAS
OIL CONSUMPTION IN THE MARKET ECONOMIES
SCENARIO: NPC85 MID WORLD OIL PRICE, HIGH ECONOMIC GROWTH
YEARS: 1988, 1989, AND 1990
THOUSAND BARRELS PER DAY

YEAR=89

NUM	CODE	REGION	DS	GA	JF	LG	OT	RS	OL	UT	TO	BU
1	E	EC	0	0	0	0	0	0	0	0	0	0
2	G	GC	0	0	0	0	0	0	0	0	0	0
3	W	WC	0	0	0	0	0	0	0	0	0	0
4	U	R1	13	69	15	0	130	0	72	0	300	16
5	C	CA	415	495	94	28	322	186	0	30	1570	11
6	J	JA	800	607	470	499	844	772	0	728	4720	223
7	A	AN	144	263	45	25	94	78	0	8	656	17
8	1	NF	323	153	33	19	120	250	0	44	941	35
9	2	UI	349	462	162	68	280	266	0	90	1677	50
10	3	BD	335	185	65	106	274	439	0	72	1476	274
11	4	WG	883	549	82	80	383	273	0	69	2320	56
12	5	FR	700	433	62	113	361	299	0	39	2008	58
13	6	AS	164	125	20	7	55	69	0	14	454	0
14	7	SP	262	155	88	87	199	303	0	72	1167	40
15	8	IT	456	296	55	85	231	379	0	439	1941	91
16	9	GT	178	84	42	34	52	209	0	58	658	16
17	V	R2	123	225	32	0	70	143	0	0	593	24
18	L	R3	124	79	26	0	63	0	86	0	378	29
19	N	R4	67	119	44	0	13	0	45	0	287	5
20	I	R5	228	101	223	0	24	0	107	0	683	9
21	R	R6	410	113	149	0	39	240	0	0	949	26
22	P	R7	488	253	151	0	90	387	0	0	1369	174
23	K	R8	29	11	13	0	6	187	0	0	246	76
24	M	R9	260	413	75	0	429	382	0	0	1558	10
25	B	R10	32	35	25	0	16	0	26	0	135	3
26	Q	R11	199	105	112	0	74	0	348	0	837	80
27	O	R12	17	8	7	0	2	0	19	0	55	11
28	Y	R13	175	67	33	0	18	354	0	0	646	197
29	S	R14	694	552	128	0	335	0	621	0	2329	116
30	F	R15	243	182	68	0	52	0	220	0	766	127
31	X	R16	899	247	361	0	354	0	1062	0	2922	103

SAS
OIL CONSUMPTION IN THE MARKET ECONOMIES
SCENARIO: NPC85 MID WORLD OIL PRICE, HIGH ECONOMIC GROWTH
YEARS: 1988, 1989, AND 1990
THOUSAND BARRELS PER DAY

YEAR=90

NUM	CODE	REGION	DS	GA	JF	LG	OT	RS	OL	UT	TO	BU
1	E	EC	0	0	0	0	0	0	0	0	0	0
2	G	GC	0	0	0	0	0	0	0	0	0	0
3	W	WC	0	0	0	0	0	0	0	0	0	0
4	U	R1	13	69	15	0	130	0	72	0	300	16
5	C	CA	439	514	99	29	331	199	0	30	1640	11
6	J	JA	837	629	492	518	889	843	0	702	4910	236
7	A	AN	150	272	47	26	96	83	0	7	681	17
8	1	NF	343	162	36	19	123	269	0	47	999	37
9	2	UI	364	483	170	71	292	282	0	87	1749	51
10	3	BD	353	195	66	109	284	463	0	71	1541	286
11	4	WG	924	575	87	85	398	287	0	71	2427	58
12	5	FR	739	455	66	119	375	320	0	35	2110	60
13	6	AS	172	131	20	7	57	74	0	13	475	0
14	7	SP	275	164	92	91	207	323	0	67	1220	41
15	8	IT	476	310	59	90	244	407	0	458	2043	95
16	9	GT	187	89	44	36	55	224	0	60	695	16
17	V	R2	126	232	33	0	73	148	0	0	611	25
18	L	R3	130	84	27	0	68	0	91	0	398	30
19	N	R4	70	124	45	0	14	0	46	0	300	5
20	I	R5	240	107	234	0	26	0	112	0	719	9
21	R	R6	428	117	155	0	39	249	0	0	989	27
22	P	R7	522	270	161	0	97	414	0	0	1462	186
23	K	R8	30	11	14	0	6	197	0	0	258	80
24	M	R9	276	440	80	0	456	406	0	0	1658	11
25	B	R10	34	37	27	0	17	0	28	0	142	3
26	Q	R11	210	110	118	0	79	0	367	0	882	84
27	O	R12	18	9	8	0	2	0	20	0	58	11
28	Y	R13	187	72	36	0	20	379	0	0	694	211
29	S	R14	731	582	135	0	352	0	655	0	2454	123
30	F	R15	254	190	71	0	54	0	231	0	800	134
31	X	R16	949	261	381	0	373	0	1120	0	3083	109

SAS
OIL CONSUMPTION IN THE MARKET ECONOMIES
SCENARIO: NPC85 MID WORLD OIL PRICE, HIGH ECONOMIC GROWTH
YEAR: 1995
THOUSAND BARRELS PER DAY

YEAR=95

NUM	CODE	REGION	DS	GA	JF	LG	OT	RS	OL	UT	TO	BU
1	E	EC	0	0	0	0	0	0	0	0	0	0
2	G	GC	0	0	0	0	0	0	0	0	0	0
3	W	WC	0	0	0	0	0	0	0	0	0	0
4	U	R1	16	83	18	0	156	0	87	0	360	19
5	C	CA	442	485	102	27	301	210	0	23	1590	9
6	J	JA	827	603	481	501	891	976	0	471	4750	253
7	A	AN	136	242	44	23	81	86	0	3	612	13
8	1	NF	340	158	34	18	109	288	0	47	993	40
9	2	UI	340	452	167	65	276	282	0	65	1646	44
10	3	BD	350	188	66	101	271	463	0	52	1491	276
11	4	WG	863	544	83	80	362	282	0	61	2275	52
12	5	FR	722	439	66	112	358	340	0	16	2052	52
13	6	AS	166	126	19	8	51	75	0	10	456	0
14	7	SP	257	158	85	85	189	340	0	39	1153	36
15	8	IT	441	296	65	87	237	434	0	423	1984	92
16	9	GT	180	90	43	35	51	235	0	55	691	14
17	V	R2	133	244	35	0	77	156	0	0	644	26
18	L	R3	145	94	30	0	75	0	101	0	447	34
19	N	R4	77	137	49	0	15	0	51	0	330	5
20	I	R5	275	121	268	0	29	0	129	0	821	10
21	R	R6	473	130	171	0	43	275	0	0	1093	29
22	P	R7	605	313	186	0	112	480	0	0	1695	216
23	K	R8	28	10	12	0	6	180	0	0	235	72
24	M	R9	274	435	78	0	452	401	0	0	1641	11
25	B	R10	32	35	25	0	16	0	27	0	135	3
26	Q	R11	200	105	112	0	75	0	348	0	839	80
27	O	R12	16	8	7	0	2	0	18	0	52	10
28	Y	R13	196	76	37	0	20	396	0	0	724	220
29	S	R14	688	548	128	0	331	0	616	0	2311	116
30	F	R15	216	163	61	0	46	0	196	0	682	114
31	X	R16	954	261	384	0	374	0	1115	0	3088	108

Oil Supply Projections

International NPC High Case

Region Name	Production (Thousands of Barrels Per Day)						
	1985	1986	1987	1988	1989	1990	1995
Puerto Rico/Virgin Islands	0	0	0	0	0	0	0
Canada	1720	1740	1760	1780	1800	1820	1770
Japan	10	11	13	15	17	20	31
Australia/New Zealand	565	560	556	551	546	542	513
Scandinavia	847	854	882	910	939	970	971
United Kingdom/Ireland	2647	2603	2520	2432	2349	2264	1897
Benelux/Denmark	152	149	150	150	151	152	129
West Germany	143	140	141	141	142	143	121
France	106	104	105	105	105	106	90
Austria/Switzerland	29	28	29	29	29	29	25
Spain/Portugal	80	79	79	79	80	80	68
Italy	99	97	98	98	98	99	84
Greece/Turkey	77	76	76	76	77	77	65
Venezuela/Ecuador	2000	2007	2068	2183	2331	2400	2300
Libya/Algeria	2100	2112	2222	2430	2696	2850	3100
Nigeria/Gabon	1660	1811	1881	1933	1969	2100	2100
Indonesia	1460	1600	1519	1492	1446	1500	1400
Iran	2400	2411	2508	2693	2929	3250	3500
Persian Gulf (Arab OPEC)	9490	10049	10622	11659	13029	14470	17600
Non-U.S. Caribbean	197	201	204	209	214	219	232
Mexico	3012	3160	3303	3457	3610	3769	4169
Bolivia/Brazil/Colombia/Peru	808	823	838	857	876	896	952
Egypt/Syria/Bahrain	997	990	986	981	975	971	856
Angola/Congo/Zaire	221	237	254	270	287	304	430
Other Exporters of Petroleum	789	806	823	841	860	878	908
Other Americas	721	735	749	765	782	800	850
Other Africa	451	485	519	554	588	622	889
Other Asia	819	852	885	920	955	989	1100
Net Exports from CPE's	1840	1700	1500	1300	1100	1000	500

Note: Numbers include crude oil, natural gas liquids, shale oil, synthetics from coal, alcohol, and refinery processing gains.

ATTACHMENT 4

International Low Case Balances

WORLD PETROLEUM SUPPLY AND DEMAND SUMMARY
LOW DEMAND CASE--1979-1995

	1979	1980	1981	1982	1983	1984	1985	1986	1987
WORLD OIL PRICE									
1984 CIF $	29.60	42.42	42.29	36.11	30.39	29.02	27.92	27.31	26.71
CONSUMPTION (MMB/D)									
UNITED STATES A/	18.91	17.50	16.45	15.69	15.51	16.18	16.08	16.01	15.85
CANADA	1.86	1.95	1.84	1.62	1.49	1.48	1.49	1.43	1.38
JAPAN	5.48	4.96	4.85	4.55	4.37	4.60	4.47	4.30	4.17
WESTERN EUROPE	14.72	13.51	12.47	12.09	11.81	11.92	11.89	11.37	10.99
OPEC	2.50	2.65	2.96	3.23	3.30	3.37	3.46	3.50	3.54
OTHER COUNTRIES	8.90	9.01	8.86	9.10	8.71	8.75	8.90	8.62	8.53
TOTAL FREE WORLD	52.37	49.57	47.42	46.28	45.19	46.29	46.30	45.24	44.47
PRODUCTION (MMB/D)									
UNITED STATES	10.71	10.81	10.74	10.78	10.79	10.98	11.08	10.72	10.63
CANADA	1.58	1.76	1.61	1.71	1.78	1.73	1.72	1.74	1.76
WESTERN EUROPE	2.40	2.56	2.90	3.14	3.83	4.09	4.18	4.13	4.08
OPEC	31.86	27.75	23.61	19.85	18.55	19.07	19.11	18.38	17.72
OTHER COUNTRIES	5.80	6.27	6.87	7.61	7.93	8.52	8.59	8.86	9.13
CPE NET EXPORTS	1.10	1.24	1.47	1.68	1.94	1.94	1.84	1.70	1.50
TOTAL FREE WORLD	53.44	50.39	47.20	44.77	44.82	46.33	46.53	45.53	44.82
NET UNITED STATES IMPORTS (MMB/D)									
50 STATE AREA	7.97	6.37	5.39	4.30	4.27	5.04	4.85	5.14	5.12
U. S. TERRITORIES	0.40	0.44	0.39	0.39	0.28	0.30	0.30	0.30	0.30
TOTAL UNITED STATES	8.37	6.81	5.78	4.69	4.55	5.34	5.15	5.44	5.43
NET STOCK ADDITIONS (MMB/D)									
U. S. STRATEGIC	0.07	0.05	0.34	0.17	0.23	0.18	0.14	0.14	0.14
U. S. COMMERCIAL	0.10	0.10	-0.18	-0.32	-0.25	-0.04	0.01	0.01	0.06
FOREIGN	0.90	0.67	-0.38	-1.37	-0.35	-0.10	0.08	0.15	0.15
TOTAL NET ADDITIONS	1.07	0.82	-0.22	-1.51	-0.37	0.04	0.23	0.30	0.35

A/ INCLUDES U. S. TERRITORIES.

WORLD PETROLEUM SUPPLY AND DEMAND SUMMARY
LOW DEMAND CASE--1979-1995 (Continued)

	1988	1989	1990	1991	1992	1993	1994	1995
WORLD OIL PRICE								
1984 CIF $	26.13	25.56	25.00	25.93	26.89	27.89	28.93	30.00
CONSUMPTION (MMB/D)								
UNITED STATES A/	15.70	15.62	15.60	15.55	15.50	15.43	15.41	15.40
CANADA	1.36	1.36	1.37	1.37	1.37	1.39	1.37	1.37
JAPAN	4.12	4.10	4.11	4.13	4.15	4.20	4.13	4.10
WESTERN EUROPE	10.85	10.84	10.93	10.94	10.93	11.04	10.79	10.68
OPEC	3.58	3.61	3.64	3.73	3.83	3.97	4.01	4.11
OTHER COUNTRIES	8.62	8.75	8.88	8.89	8.86	8.97	8.80	8.75
TOTAL FREE WORLD	44.23	44.28	44.53	44.62	44.63	45.01	44.51	44.41
PRODUCTION (MMB/D)								
UNITED STATES	10.40	10.12	9.93	9.44	8.96	8.47	8.01	7.65
CANADA	1.78	1.80	1.82	1.81	1.80	1.79	1.78	1.77
WESTERN EUROPE	4.02	3.97	3.92	3.82	3.72	3.63	3.54	3.45
OPEC	17.65	17.91	18.18	18.62	19.15	20.03	20.01	20.25
OTHER COUNTRIES	9.42	9.71	10.01	10.18	10.36	10.54	10.73	10.93
CPE NET EXPORTS	1.30	1.10	1.00	0.90	0.80	0.70	0.60	0.50
TOTAL FREE WORLD	44.57	44.62	44.87	44.77	44.78	45.15	44.66	44.56
NET UNITED STATES IMPORTS (MMB/D)								
50 STATE AREA	5.19	5.37	5.54	5.83	6.25	6.66	7.10	7.44
U. S. TERRITORIES	0.31	0.32	0.32	0.33	0.34	0.34	0.35	0.36
TOTAL UNITED STATES	5.50	5.69	5.87	6.16	6.59	7.01	7.45	7.80
NET STOCK ADDITIONS (MMB/D)								
U. S. STRATEGIC	0.14	0.14	0.14					
U. S. COMMERCIAL	0.06	0.05	0.05	0.05	0.05	0.04	0.05	0.05
FOREIGN	0.15	0.15	0.15	0.10	0.10	0.10	0.10	0.10
TOTAL NET ADDITIONS	0.35	0.34	0.34	0.15	0.15	0.14	0.15	0.15

A/ INCLUDES U. S. TERRITORIES.

INTERNATIONAL OIL PRODUCT CODES

(DS)	Distillates	Diesel Oil
(GA)	Gasoline	Aviation and Motor Gasoline
(JF)	Jet Fuel	Jet Fuel and Kerosene
(LG)	Liquefied Petroleum Gases	Same
(OT)	Other	Refinery Gas, Naphtha, Other
(RS)	Residual	Residual Fuel Oil
(OL)	(OL)	Residual in certain LOC's
(UT)		Oil consumed by utilities
(TO)		Total--sum of above
(BU)		Bunkers--already included in residual amount and in total amount

INTERNATIONAL REGION CODES

Regions	Code
East Coast	E
Gulf Coast	G
West Coast	W
Puerto Rico/Virgin Islands, Guam, Hawaiian Foreign Trade Zone	U
Canada	C
Japan	J
Australia/New Zealand	A
Norway/Sweden/Finland	1
United Kingdom/Ireland	2
Benelux/Denmark	3
West Germany	4
France	5
Austria/Switzerland	6
Spain/Portugal	7
Italy	8
Greece/Turkey	9
Venezuela/Ecuador	V
Libya/Algeria	L
Nigeria/Gabon	N
Indonesia	I
Iran	R
Iraq/Kuwait/Qatar/Saudi Arabia/UAE	P
Caribbean	K
Mexico	M
Bolivia/Peru	B
Egypt/Syria/Bahrain	Q
Angola/Zaire/Congo	O
Tunisia/Brunei/Penin Malaysia/Singapore	Y
Other Latin America	S
Other Africa	F
Other Asia	X

SAS
OIL CONSUMPTION IN THE MARKET ECONOMIES
SCENARIO: NPC85 MID WORLD OIL PRICE, LOW ECONOMIC GROWTH
YEARS: 1982, 1983, AND 1984
THOUSAND BARRELS PER DAY

YEAR=82

NUM	CODE	REGION	DS	GA	JF	LG	OT	RS	OL	UT	TO	BU
1	E	EC	0	0	0	0	0	0	0	0	0	0
2	G	GC	0	0	0	0	0	0	0	0	0	0
3	W	WC	0	0	0	0	0	0	0	0	0	0
4	U	R1	18	90	20	0	169	0	94	0	390	21
5	C	CA	399	577	90	28	310	180	0	35	1620	12
6	J	JA	729	625	443	445	727	528	0	1052	4550	149
7	A	AN	152	308	53	22	93	77	0	26	732	19
8	1	NF	274	145	32	13	111	184	0	35	793	26
9	2	UI	357	468	140	60	231	276	0	166	1697	48
10	3	BD	340	187	53	96	227	367	0	105	1375	217
11	4	WG	957	535	67	68	361	283	0	66	2338	51
12	5	FR	677	419	52	100	307	282	0	94	1931	56
13	6	AS	167	122	19	7	51	64	0	21	450	0
14	7	SP	243	148	84	82	178	253	0	161	1149	37
15	8	IT	472	282	46	70	209	335	0	380	1794	75
16	9	GT	155	80	36	30	46	156	0	61	563	15
17	V	R2	108	198	28	0	62	126	0	0	522	21
18	L	R3	87	56	18	0	45	0	61	0	267	20
19	N	R4	56	99	36	0	11	0	37	0	239	4
20	I	R5	160	71	156	0	17	0	75	0	479	6
21	R	R6	292	80	106	0	27	170	0	0	675	18
22	P	R7	373	193	115	0	69	296	0	0	1047	133
23	K	R8	27	10	12	0	6	178	0	0	234	72
24	M	R9	230	366	66	0	379	338	0	0	1379	9
25	B	R10	33	37	26	0	17	0	28	0	142	3
26	Q	R11	179	94	101	0	67	0	314	0	756	72
27	O	R12	16	8	7	0	2	0	18	0	52	10
28	Y	R13	125	48	23	0	13	252	0	0	461	141
29	S	R14	651	518	121	0	313	0	582	0	2185	110
30	F	R15	230	172	65	0	49	0	209	0	725	121
31	X	R16	746	206	299	0	294	0	888	0	2433	86

SAS
OIL CONSUMPTION IN THE MARKET ECONOMIES
SCENARIO: NPC85 MID WORLD OIL PRICE, LOW ECONOMIC GROWTH
YEARS: 1982, 1983, AND 1984
THOUSAND BARRELS PER DAY

YEAR=83

NUM	CODE	REGION	DS	GA	JF	LG	OT	RS	OL	UT	TO	BU
1	E	EC	0	0	0	0	0	0	0	0	0	0
2	G	GC	0	0	0	0	0	0	0	0	0	0
3	W	WC	0	0	0	0	0	0	0	0	0	0
4	U	R1	12	64	14	0	121	0	67	0	280	15
5	C	CA	369	520	82	27	297	163	0	33	1490	11
6	J	JA	707	594	424	438	709	517	0	982	4370	153
7	A	AN	142	285	49	23	90	71	0	22	682	19
8	1	NF	272	143	31	13	112	185	0	36	792	26
9	2	UI	346	456	140	61	238	261	0	149	1653	48
10	3	BD	325	182	53	97	230	358	0	99	1345	215
11	4	WG	900	524	68	69	354	262	0	67	2245	50
12	5	FR	659	413	52	101	309	268	0	83	1887	56
13	6	AS	159	120	18	7	51	62	0	19	437	0
14	7	SP	242	147	82	81	181	251	0	141	1126	37
15	8	IT	456	279	44	71	204	319	0	389	1763	74
16	9	GT	155	79	35	30	46	158	0	60	564	15
17	V	R2	108	199	28	0	63	127	0	0	523	21
18	L	R3	91	59	19	0	46	0	63	0	278	21
19	N	R4	55	96	35	0	11	0	36	0	232	4
20	I	R5	171	76	167	0	19	0	80	0	512	6
21	R	R6	318	87	115	0	29	185	0	0	734	20
22	P	R7	364	188	112	0	68	289	0	0	1020	130
23	K	R8	26	10	12	0	6	171	0	0	224	69
24	M	R9	212	337	61	0	349	311	0	0	1271	9
25	B	R10	28	31	23	0	15	0	25	0	121	3
26	Q	R11	175	91	98	0	65	0	305	0	733	70
27	O	R12	16	8	7	0	2	0	18	0	50	10
28	Y	R13	127	49	24	0	14	258	0	0	472	144
29	S	R14	607	483	113	0	292	0	543	0	2039	102
30	F	R15	219	164	62	0	46	0	199	0	688	115
31	X	R16	746	206	299	0	294	0	886	0	2431	86

SAS
OIL CONSUMPTION IN THE MARKET ECONOMIES
SCENARIO: NPC85 MID WORLD OIL PRICE, LOW ECONOMIC GROWTH
YEARS: 1982, 1983, AND 1984
THOUSAND BARRELS PER DAY

YEAR=84

NUM	CODE	REGION	DS	GA	JF	LG	OT	RS	OL	UT	TO	BU
1	E	EC	0	0	0	0	0	0	0	0	0	0
2	G	GC	0	0	0	0	0	0	0	0	0	0
3	W	WC	0	0	0	0	0	0	0	0	0	0
4	U	R1	14	69	15	0	130	0	72	0	300	16
5	C	CA	370	505	82	27	302	163	0	32	1480	11
6	J	JA	749	615	446	471	762	569	0	988	4600	175
7	A	AN	139	274	45	22	92	68	0	19	659	18
8	1	NF	282	145	32	15	116	195	0	38	823	28
9	2	UI	347	459	145	63	249	258	0	138	1657	49
10	3	BD	324	182	54	100	240	370	0	95	1365	226
11	4	WG	883	528	71	71	360	257	0	69	2238	51
12	5	FR	661	417	53	104	319	265	0	75	1893	57
13	6	AS	158	121	18	7	52	63	0	18	438	0
14	7	SP	247	149	84	83	187	258	0	127	1134	38
15	8	IT	456	283	45	74	207	322	0	404	1791	77
16	9	GT	159	79	36	31	47	167	0	60	580	15
17	V	R2	106	194	28	0	61	123	0	0	511	21
18	L	R3	96	62	20	0	49	0	68	0	295	22
19	N	R4	54	96	35	0	11	0	36	0	231	4
20	I	R5	178	79	174	0	18	0	83	0	533	7
21	R	R6	332	90	120	0	30	193	0	0	767	21
22	P	R7	369	191	114	0	69	292	0	0	1033	132
23	K	R8	26	10	12	0	6	168	0	0	220	68
24	M	R9	214	339	61	0	352	312	0	0	1278	9
25	B	R10	27	30	21	0	14	0	23	0	117	3
26	Q	R11	174	92	99	0	65	0	305	0	734	70
27	O	R12	15	8	7	0	2	0	17	0	50	10
28	Y	R13	135	52	25	0	14	273	0	0	501	153
29	S	R14	598	476	111	0	288	0	534	0	2008	101
30	F	R15	218	164	62	0	46	0	198	0	688	115
31	X	R16	766	212	307	0	302	0	909	0	2495	88

SAS
OIL CONSUMPTION IN THE MARKET ECONOMIES
SCENARIO: NPC85 MID WORLD OIL PRICE, LOW ECONOMIC GROWTH
YEARS: 1985, 1986, AND 1987
THOUSAND BARRELS PER DAY

YEAR=85

NUM	CODE	REGION	DS	GA	JF	LG	OT	RS	OL	UT	TO	BU
1	E	EC	0	0	0	0	0	0	0	0	0	0
2	G	GC	0	0	0	0	0	0	0	0	0	0
3	W	WC	0	0	0	0	0	0	0	0	0	0
4	U	R1	13	69	15	0	130	0	72	0	300	16
5	C	CA	376	498	84	27	308	164	0	32	1490	11
6	J	JA	734	589	435	464	756	570	0	922	4470	177
7	A	AN	140	270	45	23	92	68	0	16	653	18
8	1	NF	285	145	31	17	117	199	0	39	834	28
9	2	UI	343	455	146	64	255	253	0	126	1643	50
10	3	BD	317	179	56	101	245	369	0	90	1357	226
11	4	WG	865	528	73	73	363	252	0	69	2222	52
12	5	FR	655	415	54	105	325	260	0	66	1880	58
13	6	AS	157	120	18	7	53	61	0	17	433	0
14	7	SP	249	149	84	83	190	261	0	113	1129	38
15	8	IT	451	283	46	77	209	323	0	414	1803	78
16	9	GT	162	78	36	31	49	173	0	60	589	16
17	V	R2	107	197	27	0	62	126	0	0	520	21
18	L	R3	99	64	20	0	52	0	70	0	306	23
19	N	R4	57	99	36	0	11	0	38	0	240	4
20	I	R5	185	82	180	0	19	0	86	0	553	7
21	R	R6	345	94	126	0	32	201	0	0	798	21
22	P	R7	372	193	115	0	69	295	0	0	1043	133
23	K	R8	25	10	12	0	6	165	0	0	216	67
24	M	R9	219	349	63	0	361	322	0	0	1314	9
25	B	R10	28	30	21	0	15	0	23	0	117	3
26	Q	R11	175	92	99	0	65	0	305	0	734	70
27	O	R12	16	8	7	0	2	0	17	0	50	10
28	Y	R13	143	54	27	0	16	287	0	0	526	160
29	S	R14	610	486	112	0	294	0	544	0	2046	103
30	F	R15	220	166	62	0	47	0	200	0	694	115
31	X	R16	783	216	314	0	307	0	927	0	2549	90

SAS
OIL CONSUMPTION IN THE MARKET ECONOMIES
SCENARIO: NPC85 MID WORLD OIL PRICE, LOW ECONOMIC GROWTH
YEARS: 1985, 1986, AND 1987
THOUSAND BARRELS PER DAY

YEAR=86

NUM	CODE	REGION	DS	GA	JF	LG	OT	RS	OL	UT	TO	BU
1	E	EC	0	0	0	0	0	0	0	0	0	0
2	G	GC	0	0	0	0	0	0	0	0	0	0
3	W	WC	0	0	0	0	0	0	0	0	0	0
4	U	R1	14	69	15	0	130	0	72	0	300	16
5	C	CA	364	472	80	26	298	158	0	31	1430	11
6	J	JA	714	566	422	451	734	570	0	841	4300	175
7	A	AN	131	250	41	22	88	64	0	13	608	17
8	1	NF	278	139	30	16	113	195	0	39	811	28
9	2	UI	325	433	141	62	246	237	0	110	1555	48
10	3	BD	301	170	54	98	236	354	0	82	1296	218
11	4	WG	815	505	71	71	349	236	0	67	2115	50
12	5	FR	625	397	53	101	314	246	0	56	1792	56
13	6	AS	148	116	17	7	51	59	0	16	414	0
14	7	SP	240	142	81	80	183	252	0	96	1076	37
15	8	IT	429	272	45	74	202	309	0	405	1737	75
16	9	GT	158	75	36	30	47	170	0	57	574	15
17	V	R2	106	196	28	0	61	124	0	0	516	21
18	L	R3	101	65	21	0	52	0	71	0	310	24
19	N	R4	56	100	36	0	11	0	37	0	241	4
20	I	R5	187	83	182	0	21	0	88	0	559	7
21	R	R6	346	95	126	0	32	201	0	0	801	22
22	P	R7	382	198	118	0	70	303	0	0	1072	137
23	K	R8	25	9	11	0	5	160	0	0	209	64
24	M	R9	215	342	61	0	353	315	0	0	1287	8
25	B	R10	26	29	21	0	14	0	23	0	114	3
26	Q	R11	169	89	96	0	63	0	296	0	712	68
27	O	R12	15	7	6	0	2	0	16	0	48	9
28	Y	R13	141	54	26	0	15	284	0	0	520	158
29	S	R14	591	471	110	0	284	0	528	0	1983	99
30	F	R15	212	159	59	0	45	0	193	0	667	111
31	X	R16	759	209	305	0	298	0	900	0	2471	88

SAS
OIL CONSUMPTION IN THE MARKET ECONOMIES
SCENARIO: NPC85 MID WORLD OIL PRICE, LOW ECONOMIC GROWTH
YEARS: 1985, 1986, AND 1987
THOUSAND BARRELS PER DAY

YEAR=87

NUM	CODE	REGION	DS	GA	JF	LG	OT	RS	OL	UT	TO	BU
1	E	EC	0	0	0	0	0	0	0	0	0	0
2	G	GC	0	0	0	0	0	0	0	0	0	0
3	W	WC	0	0	0	0	0	0	0	0	0	0
4	U	R1	13	69	15	0	130	0	72	0	300	16
5	C	CA	353	449	78	25	290	154	0	29	1380	11
6	J	JA	699	547	413	440	719	580	0	771	4170	176
7	A	AN	127	239	39	22	85	63	0	11	587	17
8	1	NF	270	135	29	16	110	193	0	39	791	27
9	2	UI	312	416	137	60	241	227	0	98	1490	47
10	3	BD	288	164	52	95	232	348	0	74	1253	215
11	4	WG	777	488	70	69	339	226	0	64	2033	48
12	5	FR	604	383	52	99	309	239	0	48	1734	54
13	6	AS	142	111	16	7	49	56	0	14	396	0
14	7	SP	234	138	79	78	178	248	0	83	1037	36
15	8	IT	412	264	44	74	197	304	0	398	1692	75
16	9	GT	155	73	35	30	46	171	0	55	564	15
17	V	R2	106	194	28	0	60	123	0	0	511	21
18	L	R3	102	66	21	0	53	0	72	0	314	24
19	N	R4	56	100	36	0	11	0	37	0	243	4
20	I	R5	189	84	184	0	20	0	89	0	567	7
21	R	R6	347	95	126	0	32	202	0	0	802	21
22	P	R7	393	204	121	0	73	313	0	0	1103	140
23	K	R8	25	9	11	0	5	158	0	0	207	63
24	M	R9	215	342	61	0	353	315	0	0	1286	9
25	B	R10	26	29	21	0	14	0	23	0	112	3
26	Q	R11	167	88	95	0	62	0	293	0	705	67
27	O	R12	15	7	6	0	2	0	17	0	47	10
28	Y	R13	142	54	26	0	15	286	0	0	524	160
29	S	R14	585	466	108	0	281	0	522	0	1961	98
30	F	R15	208	156	59	0	44	0	188	0	655	109
31	X	R16	751	207	302	0	295	0	890	0	2445	87

SAS
OIL CONSUMPTION IN THE MARKET ECONOMIES
SCENARIO: NPC85 MID WORLD OIL PRICE, LOW ECONOMIC GROWTH
YEARS: 1988, 1989, AND 1990
THOUSAND BARRELS PER DAY

YEAR=88

NUM	CODE	REGION	DS	GA	JF	LG	OT	RS	OL	UT	TO	BU
1	E	EC	0	0	0	0	0	0	0	0	0	0
2	G	GC	0	0	0	0	0	0	0	0	0	0
3	W	WC	0	0	0	0	0	0	0	0	0	0
4	U	R1	14	69	16	0	130	0	72	0	300	16
5	C	CA	351	437	78	25	286	155	0	28	1360	10
6	J	JA	695	539	410	436	722	606	0	713	4120	180
7	A	AN	126	234	37	22	84	64	0	9	576	16
8	1	NF	272	133	29	16	108	198	0	39	795	28
9	2	UI	304	406	136	59	239	223	0	88	1455	45
10	3	BD	283	161	52	93	229	351	0	69	1238	219
11	4	WG	761	479	69	68	335	225	0	63	2000	49
12	5	FR	598	376	52	98	308	240	0	41	1712	53
13	6	AS	141	110	17	7	48	56	0	13	392	0
14	7	SP	231	135	78	76	175	249	0	73	1017	35
15	8	IT	403	260	45	73	197	307	0	394	1678	76
16	9	GT	154	72	35	29	45	173	0	53	563	14
17	V	R2	105	193	27	0	60	122	0	0	507	20
18	L	R3	104	67	21	0	53	0	73	0	318	24
19	N	R4	57	101	37	0	11	0	38	0	243	4
20	I	R5	192	85	186	0	20	0	89	0	573	7
21	R	R6	348	96	126	0	32	203	0	0	804	21
22	P	R7	404	209	124	0	75	321	0	0	1134	144
23	K	R8	25	9	11	0	5	159	0	0	208	64
24	M	R9	219	349	63	0	360	321	0	0	1313	9
25	B	R10	26	29	21	0	14	0	23	0	114	3
26	Q	R11	169	88	95	0	63	0	296	0	712	68
27	O	R12	14	8	7	0	2	0	16	0	47	9
28	Y	R13	146	56	27	0	16	296	0	0	541	164
29	S	R14	590	469	110	0	285	0	527	0	1981	99
30	F	R15	208	156	59	0	44	0	189	0	655	110
31	X	R16	759	209	305	0	298	0	899	0	2472	88

SAS
OIL CONSUMPTION IN THE MARKET ECONOMIES
SCENARIO: NPC85 MID WORLD OIL PRICE, LOW ECONOMIC GROWTH
YEARS: 1988, 1989, AND 1990
THOUSAND BARRELS PER DAY

YEAR=89

NUM	CODE	REGION	DS	GA	JF	LG	OT	RS	OL	UT	TO	BU
1	E	EC	0	0	0	0	0	0	0	0	0	0
2	G	GC	0	0	0	0	0	0	0	0	0	0
3	W	WC	0	0	0	0	0	0	0	0	0	0
4	U	R1	14	69	15	0	130	0	72	0	300	16
5	C	CA	355	433	79	25	283	158	0	27	1360	10
6	J	JA	696	534	411	434	728	634	0	664	4100	183
7	A	AN	126	232	37	22	82	66	0	7	573	16
8	1	NF	274	133	29	16	107	203	0	39	800	29
9	2	UI	302	404	136	59	237	222	0	81	1441	45
10	3	BD	283	160	53	93	231	360	0	65	1244	224
11	4	WG	754	477	69	68	334	223	0	62	1987	49
12	5	FR	600	376	52	98	308	245	0	35	1715	52
13	6	AS	140	108	17	7	49	57	0	12	390	0
14	7	SP	231	136	78	76	174	252	0	65	1010	35
15	8	IT	400	258	46	74	199	314	0	394	1685	78
16	9	GT	155	72	36	30	45	178	0	52	567	14
17	V	R2	104	190	27	0	59	121	0	0	502	20
18	L	R3	105	67	22	0	55	0	74	0	321	24
19	N	R4	57	101	37	0	12	0	38	0	243	4
20	I	R5	193	86	188	0	21	0	91	0	579	7
21	R	R6	347	95	127	0	32	202	0	0	804	22
22	P	R7	414	214	127	0	76	328	0	0	1161	147
23	K	R8	25	9	11	0	5	161	0	0	211	65
24	M	R9	225	357	64	0	370	330	0	0	1347	9
25	B	R10	27	30	22	0	14	0	23	0	115	2
26	Q	R11	172	90	97	0	64	0	300	0	722	69
27	O	R12	15	7	7	0	2	0	17	0	47	9
28	Y	R13	151	58	28	0	16	305	0	0	559	170
29	S	R14	598	476	111	0	288	0	535	0	2008	101
30	F	R15	209	157	59	0	44	0	190	0	659	110
31	X	R16	771	212	310	0	303	0	913	0	2508	89

SAS
OIL CONSUMPTION IN THE MARKET ECONOMIES
SCENARIO: NPC85 MID WORLD OIL PRICE, LOW ECONOMIC GROWTH
YEARS: 1988, 1989, AND 1990
THOUSAND BARRELS PER DAY

YEAR=90

NUM	CODE	REGION	DS	GA	JF	LG	OT	RS	OL	UT	TO	BU
1	E	EC	0	0	0	0	0	0	0	0	0	0
2	G	GC	0	0	0	0	0	0	0	0	0	0
3	W	WC	0	0	0	0	0	0	0	0	0	0
4	U	R1	13	69	15	0	130	0	72	0	300	16
5	C	CA	359	435	80	25	282	162	0	26	1370	10
6	J	JA	701	536	415	433	739	661	0	625	4110	185
7	A	AN	126	231	37	22	81	68	0	6	573	15
8	1	NF	280	135	30	16	107	209	0	41	816	29
9	2	UI	302	406	137	59	238	224	0	76	1441	45
10	3	BD	288	162	53	93	229	361	0	62	1248	224
11	4	WG	757	481	69	69	336	225	0	62	1999	50
12	5	FR	608	380	52	99	308	249	0	31	1727	52
13	6	AS	141	110	17	7	49	58	0	12	393	0
14	7	SP	233	137	78	77	175	259	0	59	1017	36
15	8	IT	402	261	47	75	202	322	0	400	1709	79
16	9	GT	158	74	36	31	46	182	0	53	580	14
17	V	R2	102	188	27	0	59	120	0	0	497	20
18	L	R3	106	68	22	0	55	0	74	0	324	24
19	N	R4	57	101	36	0	11	0	37	0	243	4
20	I	R5	195	87	190	0	21	0	91	0	584	7
21	R	R6	347	95	126	0	32	202	0	0	803	22
22	P	R7	425	220	131	0	79	337	0	0	1189	151
23	K	R8	25	9	11	0	6	163	0	0	213	66
24	M	R9	230	366	66	0	379	338	0	0	1378	9
25	B	R10	28	30	22	0	15	0	23	0	116	2
26	Q	R11	174	91	98	0	65	0	305	0	733	70
27	O	R12	15	7	7	0	2	0	17	0	47	9
28	Y	R13	156	60	29	0	16	316	0	0	578	176
29	S	R14	606	482	112	0	292	0	542	0	2035	102
30	F	R15	210	158	59	0	44	0	191	0	662	111
31	X	R16	782	215	313	0	308	0	926	0	2544	90

SAS
OIL CONSUMPTION IN THE MARKET ECONOMIES
SCENARIO: NPC85 MID WORLD OIL PRICE, LOW ECONOMIC GROWTH
YEAR: 1995
THOUSAND BARRELS PER DAY

YEAR=95

NUM	CODE	REGION	DS	GA	JF	LG	OT	RS	OL	UT	TO	BU
1	E	EC	0	0	0	0	0	0	0	0	0	0
2	G	GC	0	0	0	0	0	0	0	0	0	0
3	W	WC	0	0	0	0	0	0	0	0	0	0
4	U	R1	18	92	21	0	173	0	97	0	400	21
5	C	CA	369	426	81	25	272	175	0	23	1370	9
6	J	JA	715	534	427	434	762	765	0	463	4100	200
7	A	AN	116	209	34	20	72	68	0	2	521	13
8	1	NF	280	133	30	16	100	218	0	44	820	29
9	2	UI	289	389	133	57	227	218	0	62	1375	42
10	3	BD	285	157	52	88	223	351	0	49	1206	211
11	4	WG	714	463	67	66	317	215	0	57	1900	46
12	5	FR	601	373	52	97	301	259	0	15	1699	49
13	6	AS	139	107	17	6	46	58	0	10	382	0
14	7	SP	228	135	75	75	169	273	0	37	992	33
15	8	IT	389	258	50	74	202	342	0	400	1714	78
16	9	GT	158	75	36	30	45	197	0	52	593	13
17	V	R2	108	199	28	0	62	127	0	0	525	21
18	L	R3	119	76	25	0	62	0	83	0	365	27
19	N	R4	63	112	40	0	12	0	42	0	269	4
20	I	R5	224	99	219	0	24	0	106	0	671	8
21	R	R6	386	106	140	0	35	225	0	0	893	24
22	P	R7	495	256	153	0	92	393	0	0	1387	176
23	K	R8	23	9	10	0	5	152	0	0	199	61
24	M	R9	234	372	67	0	386	343	0	0	1401	10
25	B	R10	27	29	21	0	14	0	23	0	112	3
26	Q	R11	170	89	96	0	63	0	296	0	714	68
27	O	R12	14	7	6	0	2	0	15	0	44	9
28	Y	R13	167	64	31	0	18	338	0	0	620	188
29	S	R14	584	465	109	0	282	0	523	0	1963	98
30	F	R15	183	137	51	0	39	0	166	0	576	96
31	X	R16	801	220	322	0	314	0	942	0	2600	92

Oil Supply Projections

International NPC Low Case

Region Name	Production (Thousands of Barrels Per Day)						
	1985	1986	1987	1988	1989	1990	1995
Puerto Rico/Virgin Islands	0	0	0	0	0	0	0
Canada	1720	1740	1760	1780	1800	1820	1770
Japan	10	11	13	15	17	20	31
Australia/New Zealand	565	560	556	551	546	542	513
Scandinavia	847	854	882	910	939	970	971
United Kingdom/Ireland	2647	2603	2520	2432	2349	2264	1897
Benelux/Denmark	152	149	150	150	151	152	129
West Germany	143	140	141	141	142	143	121
France	106	104	105	105	105	106	90
Austria/Switzerland	29	28	29	29	29	29	25
Spain/Portugal	80	79	79	79	80	80	68
Italy	99	97	98	98	98	99	84
Greece/Turkey	77	76	76	76	77	77	65
Venezuela/Ecuador	2000	1950	1905	1841	1812	1725	1592
Libya/Algeria	2100	2010	1929	1866	1837	1756	1823
Nigeria/Gabon	1660	1600	1546	1490	1461	1381	1359
Indonesia	1460	1450	1441	1324	1232	1024	962
Iran	2400	2310	2229	2188	2187	2156	2289
Persian Gulf (Arab OPEC)	9490	9060	8670	8941	9381	10138	12225
Non-U.S. Caribbean	197	201	204	209	214	219	232
Mexico	3012	3160	3303	3457	3610	3769	4169
Bolivia/Brazil/Colombia/Peru	808	823	838	857	876	896	952
Egypt/Syria/Bahrain	997	990	986	981	975	971	856
Angola/Congo/Zaire	221	237	254	270	287	304	430
Other Exporters of Petroleum	789	806	823	841	860	878	908
Other Americas	721	735	749	765	782	800	850
Other Africa	451	485	519	554	588	622	889
Other Asia	819	852	885	920	955	989	1100
Net Exports from CPE's	1840	1700	1500	1300	1100	1000	500

Note: Numbers include crude oil, natural gas liquids, shale oil, synthetics from coal, alcohol, and refinery processing gains.

ATTACHMENT 5

Potential U.S. Product Import Cases

The following assumptions and procedures were used to generate the petroleum imports profiles for the NPC cases.

LOW ECONOMIC GROWTH CASE

In this case, worldwide product demand and refinery utilization are so low that competition for the incremental barrel is intense. It was assumed that foreign refiners succeed in increasing their share of U.S. product demand from the 12 percent level in 1983–1984 to 20 percent by 1990, maintaining that level to 1995.

Table 5-1 shows that the implied product import level goes from 2.0 MMB/D in 1984 to 3.0 MMB/D in 1990 and 1995. The net demand on refineries (defined as U.S. product demand, minus product imports, plus product exports, minus natural gas liquids) declines from 12.9 MMB/D in 1984 to 11.3 MMB/D in 1990 and 11.0 MMB/D in 1995.

The regional distribution of the imports is bounded by geographic location and indigenous consumer demand. The preferred destinations are Mid-Atlantic, New England, South Atlantic, South Central, and the Southwest Coast. Table 5-2 shows the distribution of product imports in 1984. Table 5-3 shows the share of each local product market held by foreign refiners in 1984.

Table 5-4 shows a plausible distribution of the 3 MMB/D product imports in 1990. Table 5-5 shows the share of market by foreign refiners implied by Table 5-4 and the NPC low economic case demands. (Where there is an asterisk, the volume of imports was small, and did not change from 1984 to 1990.)

Notable changes were the increase in gasoline in the Northeast to capture most of the leaded and unleaded regular gasoline market, somewhat less so in the South Atlantic. Middle distillates increase somewhat on the East Coast as well.

The only other changes are a small increase of gasoline imports (+30 MB/D) in California. Market share is still only 2 percent or less.

For 1995, inasmuch as the volume of imports in 1995 is equal to the 1990 level (Table 5-1), the distribution over the nine regions is set equal to that of 1990, as shown in Table 5-4. In this case, leaded gasoline demand goes to zero by 1987.

HIGH ECONOMIC GROWTH CASE

Worldwide product demands and refinery utilization grow in this case, which may mean that refiners will need new hardware by 1990 to meet these new requirements. It is reasonable to assume that the foreign refiners' share of the U.S. product market will remain in the 11–13 percent range experienced in the 1983–1984 period. Therefore, allowing for only minor rounding, imports in 1990 and 1995 remain within 0.1 MMB/D of the 1984 level of 2.0 MMB/D. To be expedient, the level of imports in 1990 and 1995, as well as their geographic and product distribution in those years, is assumed to be equal to the 1984 imports shown in Table 5-2. Nonetheless, as seen in Table 5-1, increasing consumer demands cause net demand on refineries to increase from 12.9 MMB/D in 1984 to 14.6 MMB/D in 1990 and to 16.4 MMB/D in 1995.

TABLE 5-1

SUMMARY OF PRODUCT IMPORT SHARE
(MMB/D, except where noted)

			High Case		Low Case	
	1983	1984	1990	1995	1990	1995
U.S. Demand	15.2	15.8	17.7	19.5	15.3	15.0
Imports						
Crude Oil	3.3	3.2	6.6	10.5	3.3	5.2
Products	1.7	2.0	2.1	2.1	3.0	3.0
Total Imports	5.0	5.2	8.7	12.6	6.3	8.2
Product Exports	0.7	0.7	0.6	0.6	0.6	0.6
Natural Gas Liquids	1.6	1.6	1.6	1.6	1.6	1.6
Net Demand on Refineries	12.6	12.9	14.6	16.4	11.3	11.0
Product Imports As Percentage of Demand	11.0%	13.0%	12.0%	11.0%	20.0%	20.0%

Net Demand = U.S. Demand – Product Imports + Product Exports – NGLs.
Product Imports % = Products Imports ÷ U.S. Demand.

TABLE 5-2

U.S. PRODUCT IMPORTS: 1984
(MMB/D)

	New England	Mid-Atlantic	South Atlantic	Great Lakes	Great Plains	South Central	Rocky Mountain	Washington/ Oregon	South-West	U.S. Total
Motor Gasoline										
Leaded	15	95	14	1	1	10	2	3	7	150
Unleaded	23	94	11	1	0	10	0	2	11	152
Premium	0	0	0	0	0	0	0	0	0	0
Distillate	78	139	36	6	2	13	4	1	7	286
Jet Fuel	2	36	10	0	4	0	1	5	6	58
Residual Fuel										
<0.3%	19	185	14	1	0	46	0	1	1	267
0.3–1.0%	12	78	26	2	0	9	0	0	7	134
>1.0%	68	113	76	1	1	14	0	0	5	278
LPG	10	16	1	103	19	11	6	6	1	173
Other	8	128	22	24	4	251	3	18	30	491
Total	**235**	**886**	**210**	**140**	**28**	**367**	**15**	**31**	**73**	**1,990**

TABLE 5-3

IMPORT SHARE OF MARKET: 1984
(Percent)

	New England	Mid-Atlantic	South Atlantic	Great Lakes	Great Plains	South Central	Rocky Mountain	Washington/ Oregon	South-West
Motor Gasoline									
Leaded	13	31	4	*	*	3	*	*	2
Unleaded	14	22	2	*	*	2	*	*	2
Premium	0	0	0	0	0	0	0	0	2
Distillate	34	28	10	*	*	3	*	*	2
Jet Fuel	6	24	4	*	*	2	*	*	1
Residual Fuel									
<0.3%	37	100	21	*	*	100	*	*	*
0.3-1.0%	22	85	39	*	*	13	*	*	*
>1.0%	67	65	61	*	*	10	*	*	*
LPG	59	36	1	47	12	1	*	*	*
Other	21	54	11	7	*	32	*	*	10

*Negligible.

TABLE 5-4

U.S. PRODUCT IMPORTS: 1990
NPC LOW ECONOMIC CASE
(MMB/D)

	New England	Mid-Atlantic	South Atlantic	Great Lakes	Great Plains	South Central	Rocky Mountain	Washington/ Oregon	South-West	U.S. Total
Motor Gasoline										
Leaded	0	0	0	0	0	0	0	0	0	0
Unleaded	186	495	210	2	0	20	2	5	40	968
Premium	0	0	0	0	0	0	0	0	0	0
Distillate	100	251	36	6	2	13	4	1	7	420
Jet Fuel	12	138	40	4	4	0	1	5	6	211
Residual Fuel										
<0.3%	30	81	14	1	0	46	0	1	1	174
0.3–1.0%	30	75	26	2	0	9	0	0	7	147
>1.0%	60	140	70	1	1	14	0	0	5	291
LPG	10	16	0	103	19	11	6	6	1	172
Other	8	200	22	24	4	251	3	18	30	560
Total	**436**	**1,397**	**418**	**143**	**30**	**364**	**16**	**36**	**105**	**2,945**

TABLE 5-5

IMPORT SHARE OF MARKET: 1990
NPC LOW ECONOMIC CASE
(Percent)

	New England	Mid-Atlantic	South Atlantic	Great Lakes	Great Plains	South Central	Rocky Mountain	Washington/ Oregon	South-West
Motor Gasoline									
Leaded	*	*	*	*	*	*	*	*	*
Unleaded	80	80	25	*	*	*	*	*	8
Premium	*	*	*	*	*	*	*	*	*
Distillate	43	50	*	*	*	*	*	*	*
Jet Fuel	33	75	15	*	*	*	*	*	*
Residual Fuel									
<0.3%	67	100	*	*	*	*	*	*	*
0.3-1.0%	67	90	*	*	*	*	*	*	*
>1.0%	56	90	*	*	*	*	*	*	*
LPG	*	*	*	*	*	*	*	*	*
Other	20	75	*	*	*	*	*	*	*

*Volume in 1990 set equal to volume in 1984.

ATTACHMENT 6

Assumptions, Definitions, and Notes

ECONOMIC GROWTH

Tables 6-1, 6-2, and 6-3 contain the specific economic growth and real industrial output assumptions used to generate the NPC cases, both domestic and foreign. The conservation reductions noted in these tables represent the percent reduction in petroleum demand from the January 1985 EIA case results, using the NPC economic growth and world oil price assumptions. Therefore, these implied reductions—necessary to limit OPEC production to 30 MMB/D—represent additional conservation over and above that used in the 1984 EIA base case, and are included here for comparison.

CONSUMPTION AND PRODUCTION TABLES

Within each case, a number of assumptions relative to the construction of the consumption and production tables were necessary. Key assumptions include:

- *Regional Sharing.* Regional sharing of all fuels is based upon EIA's State Energy Data System (SEDS) actual consumption in 1980, 1981, and 1982. All years subsequent to 1982 use the 1982 shares. Therefore, regional consumption may not agree with the actual consumption in 1983. The regional sharing is done by using 6 EIA Intermediate Future Forecasting System (IFFS) sectors and 15 IFFS petroleum fuels, so the actual shares may change over time depending upon the relative growth of the sectors and fuels.
- *Motor Gasoline.* The motor gasoline consumption from the IFFS is divided into the premium, leaded, and unleaded categories, which are based upon data provided by the study participants. The shares are the same in each NPC region. The shares are such that the consumption of leaded gasoline falls to 1 MMB/D in 1986 and to 0 in 1987 and beyond. The shares for unleaded and premium are the same relative to each other as they were in the original runs, when there was leaded gasoline consumption through 1995.
- *Distillate.* Residential and commercial sector distillate consumption from IFFS is added for heating oil consumption. The transportation model forecast for highway versus non-highway diesel consumption is used to translate transportation sector consumption from IFFS into highway consumption. (The 1983 share is used in 1980, 1981, and 1982, so the split may not agree with the actual amount in those years.) Non-highway transportation, industrial, refinery, and electric utility sector consumptions are added for the "other" category. This general procedure was modified so that the resulting consumption of heating oil and highway diesel in 1983 agrees with consumption in those

TABLE 6-1

DOMESTIC PETROLEUM ANALYSIS ASSUMPTIONS
(Percent)

Case	Economic Growth*		Conservation Reductions†	
	1985-1990	1990-1985	1990	1995
NPC Low Case	1.3	1.3	7	14
NPC High Case	3.9	2.9	0	3.5
EIA Base Case	3.1	2.3	0	0

*Compound annual growth rates for real GNP.
†Percent reduction in that year from the corresponding EIA case.

TABLE 6-2

REAL INDUSTRIAL OUTPUT ASSUMPTIONS: ENERGY-INTENSIVE INDUSTRIES
(Average Annual Rate of Growth-Percent)

Industry	1985-1990		1990-1995	
	High	Low	High	Low
Food (SIC 20)	2.4	1.4	2.7	1.8
Paper (SIC 26)	3.7	0.9	3.2	2.2
Chemicals (SIC 28)	4.4	1.9	3.4	2.5
Stone, Clay, Glass (SIC 32)	4.6	0.9	2.2	1.1
Primary Metals (SIC 33)	5.5	−1.4	1.5	0.2

categories from the 1983 Petroleum Supply Annual (PSA). The differences between the original values and the values in the 1983 PSA are carried on out throughout the forecast to 1995 as benchmarks. The totals for distillate consumption from the IFFS for 1983 through 1995 are retained, so any difference is accounted for in the "other" category.

- *Residual.* Shares for the three types of residual fuel by sulfur content, in each NPC region in 1983, were calculated using several tables from the 1983 PSA. Using the 1983 shares, residual fuel is apportioned into the three types from the total value in each NPC region. Therefore, the residual types in 1980, 1981, and 1982 may not agree with the actual.
- *Jet Fuel.* Shares for the two types of jet fuel (naphtha and kerosene type) in each NPC region in 1983 were calculated using the 1983 PSA. Using the 1983 shares, jet fuel is apportioned into the two types from the total value in each NPC region in 1980 through 1983. Therefore, the types in 1980, 1981, and 1982 may not agree with the actual amount. In all years after 1983, naphtha-type jet fuel grows at a 2.38 percent annual rate, and all the remaining jet fuel is put into the kerosene-type category.
- *Production.* Forecasts of crude oil production shares for the NPC regions were

TABLE 6-3

INTERNATIONAL PETROLEUM ANALYSIS ASSUMPTIONS
(Percent)

Case	Economic Growth*		Conservation Reductions†	
	1985-1990	1990-1985	1990	1995
NPC Low Case				
Total OECD	1.9	1.7	0	0
Developing Countries	3.1	3.3	0	0
Total Free World	2.1	2.1	0	0
NPC High Case				
Total OECD	3.3	3.1	0	13‡
Developing Countries	4.5	4.7	0	13
Total Free World	3.5	3.5	0	13
EIA Base Case				
Total OECD	2.6	2.4	NA	NA
Developing Countries	3.8	4.0	NA	NA
Total Free World	2.8	2.8	NA	NA

*Compound annual growth rates for real GNP.
†Percent reduction in that year from the corresponding EIA case.
‡Conservation was exogenously determined in order to limit OPEC production to 30 MMB/D.

determined using a combination of the EIA's PROLOG model forecasts for a variety of production sources and the 1983 PSA. The regional forecasts of shares were used to apportion the national levels IFFS forecasts for crude oil production.

- *New Regions.* Originally, there were nine NPC regions. A tenth NPC region was added that split region nine into two regions. One resulting region, region nine, retained California, Nevada, and Arizona while the other resulting region, region ten, included Alaska, Hawaii, and Guam. The extra region is added after all the other consumption and production calculations have already been made.
- *Consumption Sharing.* The region nine consumptions, by fuel type, were apportioned into the new regions nine and ten based upon the 1982 SEDS state level consumptions for each of the fuels (Guam was not included). The same fuel shares were used for all of the various subcategories of each of the fuels, and the same fuel shares were used in all of the forecast years.
- *Production Sharing.* The old region nine sources of production in each forecast year were apportioned into the new regions nine and ten based upon their original estimated shares of Alaska production versus West Coast and Outer Continental Shelf production. Separate shares were used in each forecast year and separate shares were used for low and high macroeconomics.
- *Names.* The definition of liquefied petroleum gas is the SEDS and IFFS definition, not the EIA's Short Term Energy Outlook definition.

INTERNATIONAL OIL PRODUCT CODES

(DS)	Distillates	Diesel Oil
(GA)	Gasoline	Aviation and Motor Gasoline
(JF)	Jet Fuel	Jet Fuel and Kerosene
(LG)	Liquefied Petroleum Gases	Same
(OT)	Other	Refinery Gas, Naphtha, Other
(RS)	Residual	Residual Fuel Oil
(OL)	(OL)	Residual in certain LOC's
(UT)		Oil consumed by utilities
(TO)		Total — sum of above
(BU)		Bunkers — already included in residual amount and in total amount

INTERNATIONAL REGION CODES

Regions	Code
East Coast	E
Gulf Coast	G
West Coast	W
Puerto Rico /Virgin Islands, Guam, Hawaiian Foreign Trade Zone	U
Canada	C
Japan	J
Australia /New Zealand	A
Norway /Sweden /Finland	1
United Kingdom /Ireland	2
Benelux /Denmark	3
West Germany	4
France	5
Austria /Switzerland	6
Spain /Portugal	7
Italy	8
Greece /Turkey	9
Venezuela /Ecuador	V
Libya /Algeria	L
Nigeria /Gabon	N
Indonesia	I
Iran	R
Iraq /Kuwait /Qatar /Saudi Arabia /UAE	P
Caribbean	K
Mexico	M
Bolivia /Peru	B
Egypt /Syria /Bahrain	Q
Angola /Zaire /Congo	O
Tunisia /Brunei /Penin Malaysia /Singapore	Y
Other Latin America	S
Other Africa	F
Other Asia	X

APPENDIX G

Trends in U.S. Petroleum Imports

TRENDS IN U.S. PETROLEUM IMPORTS

Data contained in this appendix include:

- U.S. imports and exports of crude oil and petroleum products by PADD region and the total U.S.
- Trends in imports by source
- Total U.S. exports of crude oil and petroleum products
- Finished product demand by region.

CALCULATION OF NET PRODUCT IMPORTS BY PADD
Source: Petroleum Supply Annual 1985

PADD I

PRODUCT	IMPORTS MBPY	EXPORTS MBPY	NET IMPORTS MBPY	NET IMPORTS MB/CD
Crude Oil	354,631	9	354,622	972
LPG	8,900	476	8,424	23
Pentanes Plus	5,593		5,593	15
Other & Alcohol	0		0	0
Unfinished Oils	23,527		23,527	64
Mogas Blendstocks	17,513		17,513	48
Avgas Blendstocks	0		0	0
Finished Mogas	108,835	207	108,628	298
Finished Avgas	0		0	0
Naphtha Jet	2,598	106	2,492	7
Kero Jet	8,004		8,004	22
Kerosene	1,598	58	1,540	4
Distillate	64,576	347	64,229	176
Residual Fuel	163,779	436	163,343	448
Petrochem Feed	965	886	79	0
Special Naphtha	4,263	47	4,216	12
Lubricants	3,069	1,566	1,503	4
Waxes	162	53	109	0
Petroleum Coke	0	3,907	(3,907)	(11)
Asphalt	9,568	15	9,553	26
Still Gas	0	0	0	0
Miscellaneous	236	190	46	0
	777,817	8,303	769,514	2,108
Crude & Unfinished	378,158	9	378,149	1,036
Gasoline	126,348	207	126,141	346
Jet + Kero	12,200	164	12,036	33
Distillate	64,576	347	64,229	176
Residuals	163,779	4,343	159,436	437
Other	32,756	3,233	29,523	81
Total Fin Product	399,659	8,294	391,365	1,072
Total Imports	777,817	8,303	769,514	2,108

Gasoline = Mogas & Avgas blendstocks, Other & alcohol, Finished Mogas & Avgas
Jet + Kero = Naphtha Jet, Kero Jet, and Kerosene
Distillate = Distillate
Residuals = Residual Fuel and Petroleum Coke
Other = LPG, Petrochem Feed, Special Naphtha, Waxes, Lubricants, Asphalt, Still Gas, Miscellaneous

CALCULATION OF NET PRODUCT IMPORTS BY PADD
Source: Petroleum Supply Annual 1985

PADD II

PRODUCT	IMPORTS MBPY	EXPORTS MBPY	NET IMPORTS MBPY	NET IMPORTS MB/CD
Crude Oil	132,062	7,514	124,548	341
LPG	43,394	3,542	39,852	109
Pentanes Plus	125	617	(492)	(1)
Other & Alcohol	0	0	0	0
Unfinished Oils	2,731	0	2,731	7
Mogas Blendstocks	135	0	135	0
Avgas Blendstocks	0	0	0	0
Finished Mogas	4,327	46	4,281	12
Finished Avgas	0	0	0	0
Naphtha Jet	97	211	(114)	(0)
Kero Jet	1	97	(96)	(0)
Kerosene	0	3	(3)	(0)
Distillate	2,652	425	2,227	6
Residual Fuel	907	0	907	2
Petrochem Feed	152	565	(413)	(1)
Special Naphtha	1,585	178	1,407	4
Lubricants	180	188	(8)	(0)
Waxes	95	16	79	0
Petroleum Coke	0	4,369	(4,369)	(12)
Asphalt	403	32	371	1
Still Gas	0	0	0	0
Miscellaneous	231	19	212	1
	189,077	17,822	171,255	469
Crude & Unfinished	134,793	7,514	127,279	349
Gasoline	4,462	46	4,416	12
Jet + Kero	98	311	(213)	(1)
Distillate	2,652	425	2,227	6
Residuals	907	4,369	(3,462)	(9)
Other	46,165	5,157	41,008	112
Total Fin Product	54,284	10,308	43,976	120
Total Imports	189,077	17,822	171,255	469

Gasoline = Mogas & Avgas blendstocks, Other & alcohol, Finished Mogas & Avgas
Jet + Kero = Naphtha Jet, Kero Jet, and Kerosene
Distillate = Distillate
Residuals = Residual Fuel and Petroleum Coke
Other = LPG, Petrochem Feed, Special Naphtha, Waxes, Lubricants, Asphalt, Still Gas, Miscellaneous

CALCULATION OF NET PRODUCT IMPORTS BY PADD
Source: Petroleum Supply Annual 1985

PADD III

PRODUCT	IMPORTS MBPY	EXPORTS MBPY	NET IMPORTS MBPY	NET IMPORTS MB/CD
Crude Oil	603,043	0	603,043	1,652
LPG	6,552	16,708	(10,156)	(28)
Pentanes Plus	10,666	0	10,666	29
Other & Alcohol	0	0	0	0
Unfinished Oils	88,865	0	88,865	243
Mogas Blendstocks	2,220	0	2,220	6
Avgas Blendstocks	0	0	0	0
Finished Mogas	7,353	2,666	4,687	13
Finished Avgas	0	0	0	0
Naphtha Jet	243	145	98	0
Kero Jet	89	2,968	(2,879)	(8)
Kerosene	1,180	39	1,141	3
Distillate	855	11,095	(10,240)	(28)
Residual Fuel	16,579	25,492	(8,913)	(24)
Petrochem Feed	7,213	4,500	2,713	7
Special Naphtha	5,302	163	5,139	14
Lubricants	745	3,283	(2,538)	(7)
Waxes	201	222	(21)	(0)
Petroleum Coke	0	32,852	(32,852)	(90)
Asphalt	941	15	926	3
Still Gas	0	0	0	0
Miscellaneous	367	101	266	1
	752,414	100,249	652,165	1,787
Crude & Unfinished	691,908	0	691,908	1,896
Gasoline	9,573	2,666	6,907	19
Jet + Kero	1,512	3,152	(1,640)	(4)
Distillate	855	11,095	(10,240)	(28)
Residuals	16,579	58,344	(41,765)	(114)
Other	31,987	24,992	6,995	19
Total Fin Product	60,506	100,249	(39,743)	(109)
Total Imports	752,414	100,249	652,165	1,787

Gasoline = Mogas & Avgas blendstocks, Other & alcohol, Finished Mogas & Avgas
Jet + Kero = Naphtha Jet, Kero Jet, and Kerosene
Distillate = Distillate
Residuals = Residual Fuel and Petroleum Coke
Other = LPG, Petrochem Feed, Special Naphtha, Waxes, Lubricants, Asphalt, Still Gas, Miscellaneous

CALCULATION OF NET PRODUCT IMPORTS BY PADD
Source: Petroleum Supply Annual 1985

PADD IV

PRODUCT	IMPORTS MBPY	EXPORTS MBPY	NET IMPORTS MBPY	NET IMPORTS MB/CD
Crude Oil	14,056	0	14,056	39
LPG	5,419	9	5,410	15
Pentanes Plus	1,462	0	1,462	4
Other & Alcohol	0	0	0	0
Unfinished Oils	0	0	0	0
Mogas Blendstocks	0	0	0	0
Avgas Blendstocks	0	0	0	0
Finished Mogas	792	5	787	2
Finished Avgas	0	0	0	0
Naphtha Jet	0	0	0	0
Kero Jet	0	0	0	0
Kerosene	0	0	0	0
Distillate	1,363	1	1,362	4
Residual Fuel	131	0	131	0
Petrochem Feed	0	6	(6)	(0)
Special Naphtha	5	9	(4)	(0)
Lubricants	1	20	(19)	(0)
Waxes	5	0	5	0
Petroleum Coke	0	0	0	0
Asphalt	10	6	4	0
Still Gas	0	0	0	0
Miscellaneous	2	1	1	0
	23,246	57	23,189	64
Crude & Unfinished	14,056	0	14,056	39
Gasoline	792	5	787	2
Jet + Kero	0	0	0	0
Distillate	1,363	1	1,362	4
Residuals	131	0	131	0
Other	6,904	51	6,853	19
Total Fin Product	9,190	57	9,133	25
Total Imports	23,246	57	23,189	64

Gasoline = Mogas & Avgas blendstocks, Other & alcohol, Finished Mogas & Avgas
Jet + Kero = Naphtha Jet, Kero Jet, and Kerosene
Distillate = Distillate
Residuals = Residual Fuel and Petroleum Coke
Other = LPG, Petrochem Feed, Special Naphtha, Waxes, Lubricants, Asphalt, Still Gas, Miscellaneous

CALCULATION OF NET PRODUCT IMPORTS BY PADD
Source: Petroleum Supply Annual 1985

PADD V

PRODUCT	IMPORTS MBPY	EXPORTS MBPY	NET IMPORTS MBPY	NET IMPORTS MB/CD
Crude Oil	64,505	66,990	(2,485)	(7)
LPG	3,825	2,039	1,786	5
Pentanes Plus	0	0	0	0
Other & Alcohol	0	0	0	0
Unfinished Oils	856	0	856	2
Mogas Blendstocks	4,479	0	4,479	12
Avgas Blendstocks	0	0	0	0
Finished Mogas	17,647	550	17,097	47
Finished Avgas	6	0	6	0
Naphtha Jet	243	58	185	1
Kero Jet	2,917	1,296	1,621	4
Kerosene	19	0	19	0
Distillate	3,643	12,729	(9,086)	(25)
Residual Fuel	4,888	46,132	(41,244)	(113)
Petrochem Feed	237	1,149	(912)	(2)
Special Naphtha	788	33	755	2
Lubricants	633	453	180	0
Waxes	51	79	(28)	(0)
Petroleum Coke	0	27,033	(27,033)	(74)
Asphalt	2,020	45	1,975	5
Still Gas	0	0	0	0
Miscellaneous	196	47	149	0
	106,953	158,633	(51,680)	(142)
Crude & Unfinished	65,361	66,990	(1,629)	(4)
Gasoline	22,132	550	21,582	59
Jet + Kero	3,179	1,354	1,825	5
Distillate	3,643	12,729	(9,086)	(25)
Residuals	4,888	73,165	(68,277)	(187)
Other	7,750	3,845	3,905	11
Total Fin Product	41,592	91,643	(50,051)	(137)
Total Imports	106,953	158,633	(51,680)	(142)

Gasoline = Mogas & Avgas blendstocks, Other & alcohol, Finished Mogas & Avgas
Jet + Kero = Naphtha Jet, Kero Jet, and Kerosene
Distillate = Distillate
Residuals = Residual Fuel and Petroleum Coke
Other = LPG, Petrochem Feed, Special Naphtha, Waxes, Lubricants, Asphalt, Still Gas, Miscellaneous

CALCULATION OF NET PRODUCT IMPORTS BY PADD
Source: Petroleum Supply Annual 1985

TOTAL U.S.

PRODUCT	IMPORTS MBPY	EXPORTS MBPY	NET IMPORTS MBPY	NET IMPORTS MB/CD
Crude Oil	1,168,297	74,513	1,093,784	2,997
LPG	68,091	22,773	45,318	124
Pentanes Plus	17,846	617	17,229	47
Other & Alcohol	0	0	0	0
Unfinished Oils	115,979	0	115,979	318
Mogas Blendstocks	24,347	0	24,347	67
Avgas Blendstocks	0	0	0	0
Finished Mogas	138,954	3,474	135,480	371
Finished Avgas	6	0	6	0
Naphtha Jet	3,180	520	2,660	7
Kero Jet	11,011	4,361	6,650	18
Kerosene	2,797	101	2,696	7
Distillate	73,089	24,597	48,492	133
Residual Fuel	186,284	72,060	114,224	313
Petrochem Feed	8,566	7,108	1,458	4
Special Naphtha	11,944	430	11,514	32
Lubricants	4,628	5,510	(882)	(2)
Waxes	514	370	144	0
Petroleum Coke	0	68,161	(68,161)	(187)
Asphalt	12,942	114	12,828	35
Still Gas	0	0	0	0
Miscellaneous	1,031	359	672	2
	1,849,506	285,068	1,564,438	4,286
Crude & Unfinished	1,284,276	74,513	1,209,763	3,314
Gasoline	163,307	3,474	159,833	438
Jet + Kero	16,988	4,982	12,006	33
Distillate	73,089	24,597	48,492	133
Residuals	186,284	140,221	46,063	126
Other	125,562	37,281	88,281	242
Total Fin Product	565,230	210,555	354,675	972
Total Imports	1,849,506	285,068	1,564,438	4,286

Gasoline = Mogas & Avgas blendstocks, Other & alcohol, Finished Mogas & Avgas
Jet + Kero = Naphtha Jet, Kero Jet, and Kerosene
Distillate = Distillate
Residuals = Residual Fuel and Petroleum Coke
Other = LPG, Petrochem Feed, Special Naphtha, Waxes, Lubricants, Asphalt, Still Gas, Miscellaneous

CALCULATION OF NET PRODUCT IMPORTS
FOR THE FIRST SIX MONTHS OF 1986

Source: Petroleum Supply Monthly, June 1986

TOTAL U.S. PRODUCT	IMPORTS MBPY	EXPORTS MBPY	NET IMPORTS MBPY	NET IMPORTS MB/CD
Crude Oil	656,746	29,102	627,644	3,468
LPG	38,055	8,011	30,044	166
Pentanes Plus	4,111	420	3,691	20
Other & Alcohol	0	0	0	0
Unfinished Oils	44,123	0	44,123	244
Mogas Blendstocks	11,772	0	11,772	65
Avgas Blendstocks	13	0	13	0
Finished Mogas	56,492	0	56,492	312
Finished Avgas	6	0	6	0
Naphtha Jet	1,143	204	939	5
Kero Jet	6,866	2,933	3,933	22
Kerosene	1,328	120	1,208	7
Distillate	33,833	22,923	10,910	60
Residual Fuel	109,743	26,499	83,244	460
Petrochem Feed	15,562	3,951	11,611	64
Special Naphtha	2,580	125	2,455	14
Lubricants	2,202	3,590	(1,388)	(8)
Waxes	203	239	(36)	(0)
Petroleum Coke	0	39,833	(39,833)	(220)
Asphalt	4,484	94	4,390	24
Still Gas	0	0	0	0
Miscellaneous	763	322	441	2
	990,025	138,366	851,659	4,705
Crude & Unfinished	700,869	29,102	671,767	3,711
Gasoline	68,283	0	68,283	377
Jet + Kero	9,337	3,257	6,080	34
Distillate	33,833	22,923	10,910	60
Residuals	109,743	66,332	43,411	240
Other	67,960	16,752	51,208	283
Total Fin Product	289,156	109,264	179,892	994
Total Imports	990,025	138,366	851,659	4,705

Gasoline = Mogas & Avgas blendstocks, Other & alcohol, Finished Mogas & Avgas
Jet + Kero = Naphtha Jet, Kero Jet, and Kerosene
Distillate = Distillate
Residuals = Residual Fuel and Petroleum Coke
Other = LPG, Petrochem Feed, Special Naphtha, Waxes, Lubricants, Asphalt, Still Gas, Miscellaneous

U.S. FINISHED PETROLEUM PRODUCT IMPORTS BY SOURCE COUNTRY

Units: MB/CD

PUERTO RICO / VIRGIN ISLANDS

	1977	1978	1979	1980	1981	1982	1983	1984	1985
Gaso	132	118	114	98	82	78	69	62	36
Jet/Kero	37	26	26	30	14	23	14	30	18
Dist	130	125	119	113	83	59	51	54	39
Other	12	9	13	33	11	20	6	10	19
Resids	239	222	237	179	147	123	118	134	103
	550	500	509	453	337	303	258	290	215

VENEZUELA

	1977	1978	1979	1980	1981	1982	1983	1984	1985
Gaso	6	5	5	2	1	8	41	59	53
Jet/Kero	2	7	2	4	6	8	9	14	10
Dist	26	14	4	1	16	5	35	67	75
Other	26	13	19	12	7	10	8	11	25
Resids	378	422	363	309	216	204	154	118	84
	438	461	393	328	246	235	247	269	247

CANADA

	1977	1978	1979	1980	1981	1982	1983	1984	1985
Gaso	12	21	17	14	17	20	26	20	40
Jet/Kero	3	5	1	1	0	0	1	1	2
Dist	5	3	6	0	14	10	29	33	38
Other	157	120	192	200	212	208	181	199	182
Resids	58	69	49	39	39	24	27	25	29
	235	218	265	254	282	262	264	278	291

MEXICO / BRAZIL

	1977	1978	1979	1980	1981	1982	1983	1984	1985
Gaso	1	0	0	0	0	10	27	50	45
Jet/Kero	0	0	1	0	0	1	2	3	2
Dist	0	0	0	1	1	1	6	7	12
Other	1	1	1	15	20	18	19	12	17
Resids	1	1	1	13	40	39	40	39	37
	3	2	3	29	61	69	94	111	113

EUROPE AND OTHER WESTERN COUNTRIES

	1977	1978	1979	1980	1981	1982	1983	1984	1985
Gaso	42	31	31	12	27	39	48	70	90
Jet/Kero	32	35	35	46	23	8	9	16	2
Dist	76	21	51	23	41	10	33	58	15
Other	23	9	13	5	10	7	36	41	30
Resids	549	526	402	308	257	253	238	201	151
	722	622	532	394	358	317	364	386	288

ALGERIA / ROMANIA

	1977	1978	1979	1980	1981	1982	1983	1984	1985
Gaso	4	0	0	0	6	6	22	34	30
Jet/Kero	0	1	0	0	0	1	0	1	0
Dist	1	0	0	0	5	1	11	20	6
Other	3	1	7	0	2	5	8	59	48
Resids	23	26	20	32	42	72	50	59	57
	31	28	27	32	55	85	91	173	141

SAUDI ARABIA

	1977	1978	1979	1980	1981	1982	1983	1984	1985
Gaso	1	0	0	0	1	2	1	4	29
Jet/Kero	0	0	0	0	0	0	0	0	0
Dist	0	0	0	0	0	0	0	0	0
Other	6	2	7	4	14	16	4	6	2
Resids	1	0	0	0	0	2	6	3	3
	8	2	7	4	15	20	11	13	34

PEOPLES REPUBLIC OF CHINA

	1977	1978	1979	1980	1981	1982	1983	1984	1985
Gaso	0	0	0	0	16	28	26	27	20
Jet/Kero	0	0	0	0	0	0	0	0	0
Dist	0	0	0	0	0	0	0	0	1
Other	0	0	0	0	0	1	0	1	0
Resids	0	0	0	0	0	0	0	0	0
	0	0	0	0	16	29	26	28	21

INDONESIA

	1977	1978	1979	1980	1981	1982	1983	1984	1985
Gaso							5	4	0
Jet/Kero	1	4	3	3	0	0	1	1	0
Dist	2	4	6	2	2	3	1	1	0
Other	3	8	6	3	3	4	2	9	1
Resids	24	19	21	20	31	9	14	16	0
	30	35	36	28	36	16	23	31	1

OTHER NON WEST

	1977	1978	1979	1980	1981	1982	1983	1984	1985
Gaso	20	15	13	14	31	48	29	51	99
Jet/Kero	19	19	19	7	1	2	5	8	9
Dist	10	6	7	3	11	5	8	32	13
Other	11	1	8	10	9	13	16	24	20
Resids	87	70	55	40	28	50	53	87	48
	147	111	102	74	80	118	111	202	189

TOTAL FINISHED PRODUCT IMPORTS INTO U.S.

	1977	1978	1979	1980	1981	1982	1983	1984	1985
Gaso	217	190	181	140	181	239	294	382	442
Jet/Kero	94	97	87	90	45	41	40	74	45
Dist	250	173	193	142	173	93	174	272	199
Other	242	165	266	282	289	301	281	372	343
Resids	1359	1355	1151	939	800	776	699	681	512
	2162	1980	1878	1593	1488	1450	1488	1781	1541

FINISHED PRODUCT EXPORTS FROM U.S.

	1977	1978	1979	1980	1981	1982	1983	1984	1985
Gaso	2	1	0	1	2	20	10	6	10
Jet/Kero	2	2	1	1	2	6	7	9	14
Dist	1	3	3	3	5	74	64	51	67
Other	78	74	77	81	101	112	114	90	102
Resids	109	124	155	170	257	366	380	384	384
	192	204	236	256	367	578	575	540	577

NET FINISHED PETROLEUM PRODUCT IMPORTS INTO THE U.S.

	1977	1978	1979	1980	1981	1982	1983	1984	1985
Gaso	215	189	181	139	179	219	284	376	432
Jet/Kero	92	95	86	89	43	35	33	65	31
Dist	249	170	190	139	168	19	110	221	132
Other	164	91	189	201	188	189	167	282	241
Resids	1250	1231	996	769	543	410	319	297	128
	1970	1776	1642	1337	1121	872	913	1241	964

IMPORTS OF FINISHED GASOLINE AND GASOLINE BLENDSTOCKS

	1977	1978	1979	1980	1981	1982	1983	1984	1985
PR/VI	132	118	114	98	82	78	69	62	36
Venezuela	6	5	5	2	1	8	41	59	53
Canada	12	21	17	14	17	20	26	20	40
Mex/Brazi	1	0	0	0	0	10	27	50	45
Eur & OW	42	31	31	12	27	39	48	70	90
Alg/Rom	4	0	0	0	6	6	22	34	30
Saudi Ara	1	0	0	0	1	2	1	4	29
China	0	0	0	0	16	28	26	27	20
Indonesia							5	4	0
Oth Non W	20	15	13	14	31	48	29	51	99
Total	218	190	180	140	181	239	294	381	442

IMPORTS OF JET FUEL AND KEROSENE

	1977	1978	1979	1980	1981	1982	1983	1984	1985
PR/VI	37	26	26	30	14	23	14	30	18
Venezuela	2	7	2	4	6	8	9	14	10
Canada	3	5	1	1	0	0	1	1	2
Mex/Brazi	0	0	1	0	0	1	2	3	2
Eur & OW	32	35	35	46	23	8	9	16	2
Alg/Rom	0	1	0	0	0	1	0	1	0
Saudi Ara	0	0	0	0	0	0	0	0	0
China	0	0	0	0	0	0	0	0	0
Indonesia	1	4	3	3	0	0	0	1	1
Oth Non W	19	19	19	7	1	2	5	8	9
Total	94	97	87	91	44	43	40	74	44

IMPORTS OF DISTILLATE

	1977	1978	1979	1980	1981	1982	1983	1984	1985
PR/VI	130	125	119	113	83	59	51	54	39
Venezuela	26	14	4	1	16	5	35	67	75
Canada	5	3	6	0	14	10	29	33	38
Mex/Brazi	0	0	0	1	1	1	6	7	12
Eur & OW	76	21	51	23	41	10	33	58	15
Alg/Rom	1	0	0	0	5	1	11	20	6
Saudi Ara	0	0	0	0	0	0	0	0	0
China	0	0	0	0	0	0	0	0	1
Indonesia	2	4	6	2	2	3	1	1	0
Oth Non W	10	6	7	3	11	5	8	32	13
Total	250	173	193	143	173	94	174	272	199

U.S. IMPORTS OF RESIDUAL PRODUCTS

	1977	1978	1979	1980	1981	1982	1983	1984	1985
PR/VI	239	222	237	179	147	123	118	134	103
Venezuela	378	422	363	309	216	204	154	118	84
Canada	58	69	49	39	39	24	27	25	29
Mex/Brazi	1	1	1	13	40	39	40	39	37
Eur & OW	549	526	402	308	257	253	238	201	151
Alg/Rom	23	26	20	32	42	72	50	59	57
Saudi Ara	1	0	0	0	0	2	6	3	3
China	0	0	0	0	0	0	0	0	0
Indonesia	24	19	21	20	31	9	14	16	0
Oth Non W	87	70	55	40	28	50	53	87	48
Total	1360	1355	1148	940	800	776	700	682	512

U.S. IMPORTS OF OTHER FINISHED PRODUCTS

	1977	1978	1979	1980	1981	1982	1983	1984	1985
PR/VI	12	9	13	33	11	20	6	10	19
Venezuela	26	13	19	12	7	10	8	11	25
Canada	157	120	192	200	212	208	181	199	182
Mex/Brazi	1	1	1	15	20	18	19	12	17
Eur & OW	23	9	13	5	10	7	36	41	30
Alg/Rom	3	1	7	0	2	5	8	59	48
Saudi Ara	6	2	7	4	14	16	4	6	2
China	0	0	0	0	0	1	0	1	0
Indonesia	3	8	6	3	3	4	2	9	1
Oth Non W	11	1	8	10	9	13	16	24	20
Total	242	164	266	282	288	302	280	372	344

TOTAL U.S. EXPORTS OF CRUDE OIL AND UNFINISHED OIL
(Thousand Barrels)

	1977	1978	1979	1980	1981	1982	1983	1984	1985
Western Countries									
Belgium & Luxembourg	0	0	0	0	0	0	0	0	0
Canada	16,460	28,761	26,079	30,567	16,440	13,083	6,781	5,784	7,523
France	0	0	0	0	0	0	0	0	0
Italy	0	0	0	0	0	0	0	0	0
Mexico	0	0	0	0	0	0	0	0	0
Netherlands	0	0	0	0	0	0	0	0	0
Netherlands Antilles	0	0	0	0	0	0	0	0	0
Puerto Rico	329	13,840	0	25,098	19,858	26,278	10,552	7,916	8,822
Spain	0	0	0	0	0	0	0	0	0
Virgin Islands	1,466	15,127	0	47,239	45,246	41,355	35,879	41,582	46,197
Other Western*	(s)	0	59,628	2,030	1,615	5,563	6,736	10,951	11,971
Subtotal§	18,255	57,728	85,707	104,934	83,159	86,279	59,948	66,233	74,513
Non-Western Countries									
Japan	0	0	0	0	0	0	0	0	(s)
Republic of Korea	0	0	0	0	0	0	0	0	0
Other Non-Western	0	0	0	0	0	0	0	0	0
Subtotal§	0	0	0	0	0	0	0	0	(s)
Total§	18,255	57,728	85,707	104,934	83,166	86,279	59,948	66,233	74,513

*Made up entirely of the Hawaiian Foreign Trade Zone.
§Total may not equal sum of components due to independent rounding.
(s) = less than 500 barrels.

TOTAL U.S. EXPORTS OF MOTOR GASOLINE AND BLENDING STOCKS
(Thousand Barrels)

	1977	1978	1979	1980	1981	1982	1983	1984	1985
Western Countries									
Belgium & Luxembourg	(s)	0	0	0	0	(s)	(s)	(s)	(s)
Canada	24	17	6	8	186	127	1,832	488	830
France	(s)	0	(s)	1	2	1	(s)	1	(s)
Italy	1	0	0	0	0	0	0	0	0
Mexico	115	46	52	181	415	5,668	54	50	26
Netherlands	(s)	0	0	0	0	0	0	0	9
Netherlands Antilles	0	0	(s)	0	0	0	275	87	0
Puerto Rico	174	0	2	1	(s)	996	1	2	3
Spain	0	0	0	0	0	0	0	0	0
Virgin Islands	247	232	0	0	0	0	0	0	0
Other Western	8	10	10	7	10	253	1,122	695	2,094
Subtotal*	569	305	70	198	613	7,045	3,284	1,323	2,962
Non-Western Countries									
Japan	(s)	2	(s)	1	(s)	1	1	(s)	221
Republic of Korea	0	0	1	0	0	0	(s)	1	(s)
Other Non-Western	156	163	84	294	84	148	469	792	291
Subtotal*	156	165	85	295	84	149	470	793	512
Total*	725	470	155	493	697	7,195	3,754	2,116	3,474

*Total may not equal sum of components due to independent rounding.
(s) = less than 500 barrels.

TOTAL U.S. EXPORTS OF JET FUEL AND KEROSENE*
(Thousand Barrels)

	1977	1978	1979	1980	1981	1982	1983	1984	1985
Western Countries									
Belgium & Luxembourg	(s)	0	0	0	0	0	0	0	0
Canada	3	11	2	1	6	42	228	1,871	2,822
France	(s)	0	0	0	(s)	0	(s)	0	(s)
Italy	0	0	0	0	0	245	(s)	(s)	(s)
Mexico	210	221	231	489	221	388	387	467	462
Netherlands	3	1	0	(s)	206	223	235	(s)	10
Netherlands Antilles	0	0	(s)	(s)	(s)	(s)	0	128	0
Puerto Rico	0	0	0	2	0	22	0	(s)	0
Spain	0	0	0	0	0	0	0	0	0
Virgin Islands	0	9	0	0	0	0	0	0	0
Other Western	3	5	7	2	18	406	307	878	1,016
Subtotal§	219	247	240	494	451	1,326	1,157	3,344	4,310
Non-Western Countries									
Japan	3	3	2	1	236	476	1	(s)	485
Republic of Korea	0	0	1	(s)	0	0	0	0	0
Other Non-Western	407	304	12	13	3	563	1,293	2	188
Subtotal§	410	307	15	14	239	1,039	1,294	2	673
Total§	629	554	255	508	690	2,365	2,451	3,346	4,982

*Includes naphtha jet, kerojet, and kerosene.
§Total may not equal sum of components due to independent rounding.
(s) = less than 500 barrels.

TOTAL U.S. EXPORTS OF DISTILLATE
(Thousand Barrels)

	1977	1978	1979	1980	1981	1982	1983	1984	1985
Western Countries									
Belgium & Luxembourg	0	0	0	0	90	99	72	(s)	0
Canada	10	67	69	7	9	6	1,403	5,531	2,994
France	0	0	0	(s)	1	1,485	770	1	317
Italy	(s)	0	0	(s)	(s)	588	538	(s)	360
Mexico	1	164	797	913	112	4,460	6	(s)	3
Netherlands	1	0	0	0	192	3,112	3,495	(s)	3,948
Netherlands Antilles	0	0	0	0	0	16	1,265	1,495	517
Puerto Rico	200	375	(s)	1	340	15	(s)	(s)	1
Spain	1	0	0	0	3	443	1,191	994	3,319
Virgin Islands	78	49	0	0	0	346	0	0	197
Other Western	8	12	6	271	357	7,346	5,566	4,484	6,293
Subtotal*	299	667	872	1,192	1,104	17,916	14,306	12,505	17,949
Non-Western Countries									
Japan	13	276	202	20	409	5,458	4,980	3,321	2,535
Republic of Korea	0	0	0	0	127	1,318	1,032	705	1,850
Other Non-Western	207	259	5	7	244	2,430	3,076	2,106	2,263
Subtotal*	220	535	207	27	780	9,206	9,088	6,132	6,648
Total*	519	1,202	1,079	1,220	1,885	27,124	23,396	18,637	24,597

*Total may not equal sum of components due to independent rounding.
(s) = less than 500 barrels.

TOTAL U.S. EXPORTS OF RESIDUAL FUEL, COKE, AND ASPHALT
(Thousand Barrels)

	1977	1978	1979	1980	1981	1982	1983	1984	1985
Western Countries									
Belgium & Luxembourg	5,185	5,023	6,628	6,850	4,015	5,998	7,735	7,464	9,334
Canada	6,763	8,430	8,310	6,510	7,159	7,797	7,396	8,560	7,058
France	1,381	1,877	3,020	1,784	3,967	4,698	5,600	5,304	2,195
Italy	2,209	2,401	3,676	3,349	6,549	8,113	10,111	12,624	9,055
Mexico	1,914	2,560	1,562	719	679	709	381	3,007	6,572
Netherlands	5,112	5,475	8,321	7,151	13,253	24,835	11,913	12,611	11,131
Netherlands Antilles	(s)	70	0	100	(s)	2,812	4,056	7,210	4,199
Puerto Rico	709	824	964	4,725	4,976	5,384	876	203	244
Spain	1,039	918	2,247	2,245	5,879	7,357	10,371	8,974	6,233
Virgin Islands	1	1	0	1,785	5,698	752	4,412	5,314	2,965
Other Western	5,513	6,282	7,002	8,487	12,395	23,504	16,024	17,825	19,660
Subtotal*	29,826	33,861	41,730	43,705	64,570	91,959	78,875	89,096	78,646
Non-Western Countries									
Japan	7,993	8,350	10,916	10,234	12,483	18,243	28,690	29,202	35,631
Republic of Korea	0	0	505	201	3,106	8,730	4,397	5,408	7,749
Other Non-Western	2,102	2,999	3,526	8,209	13,522	14,925	26,912	17,339	18,309
Subtotal*	10,095	11,349	14,947	18,644	29,111	41,757	59,999	51,549	61,689
Total*	39,921	45,210	56,677	62,349	93,681	133,716	138,874	140,645	140,335

*Total may not equal sum of components due to independent rounding.
(s) = less than 500 barrels.

TOTAL U.S. EXPORTS OF ALL OTHER PRODUCTS
(Thousand Barrels)

	1977	1978	1979	1980	1981	1982	1983	1984	1985
Western Countries									
Belgium & Luxembourg	698	602	405	343	205	230	262	122	186
Canada	2,748	2,115	1,912	2,294	8,742	10,048	10,189	8,222	5,759
France	1,726	1,393	1,787	2,090	1,371	2,493	1,912	1,330	1,591
Italy	1,569	1,199	1,805	1,781	1,528	2,694	2,272	1,679	1,628
Mexico	6,653	6,886	5,193	7,783	7,989	8,238	7,983	9,156	15,124
Netherlands	1,088	1,097	1,729	1,440	1,650	2,291	2,223	1,082	1,004
Netherlands Antilles	117	24	29	34	324	18	10	45	159
Puerto Rico	747	898	1,596	1,762	4,290	2,045	629	552	525
Spain	934	776	1,112	654	646	833	781	696	723
Virgin Islands	187	86	7	18	12	24	168	14	10
Other Western	7,034	6,958	6,974	5,321	4,221	6,142	7,099	5,410	6,118
Subtotal*	23,501	22,034	22,549	23,520	30,978	35,868	33,528	28,308	32,827
Non-Western Countries									
Japan	942	1,011	1,422	1,340	886	660	4,460	1,134	597
Republic of Korea	0	0	234	480	380	121	79	516	295
Other Non-Western	4,096	3,851	3,777	4,408	4,669	4,342	3,365	3,142	3,448
Subtotal*	5,098	4,862	5,433	6,228	5,926	5,123	7,904	4,792	4,340
Total*	28,539	26,896	27,983	29,749	36,904	40,809	41,432	33,100	37,167

*Total may not equal sum of components due to independent rounding.
(s) = less than 500 barrels.

FINISHED PRODUCT DEMAND BY REGION

UNITS: MB/CD

UNITED STATES

	GASO	JET/KERO	DIST	OTHER	RESID*	TOTAL
1977	7,177	1,214	3,352	3,135	2,929	17,807
1978	7,412	1,232	3,432	3,454	2,885	18,415
1979	7,034	1,265	3,311	4,076	2,826	18,513
1980	6,579	1,227	2,866	3,876	2,508	17,056
1981	6,588	1,134	2,829	3,420	2,088	16,058
1982	6,539	1,142	2,671	3,226	1,716	15,296
1983	6,622	1,173	2,690	3,259	1,487	15,231
1984	6,693	1,291	2,845	3,464	1,433	15,726
1985	6,831	1,333	2,868	3,432	1,262	15,726

* Residual products and crude oil used directly

OTHER WESTERN HEMISPHERE

	GASO	JET/KERO	DIST	OTHER	RESID*	TOTAL
1977	1,582	371	1,326	680	1,411	5,370
1978	1,658	403	1,379	726	1,493	5,659
1979	1,826	360	1,499	786	1,515	5,986
1980	1,816	420	1,597	1,129	1,654	6,614
1981	1,820	399	1,572	1,188	1,477	6,456
1982	1,865	352	1,530	1,138	1,492	6,378
1983	1,864	325	1,470	886	1,319	5,864

* Excludes refinery fuel

WESTERN EUROPE

	GASO	JET/KERO	DIST	OTHER	RESID*	TOTAL
1977	2,313	546	4,414	1,978	4,061	13,311
1978	2,404	604	4,749	1,945	3,826	13,527
1979	2,495	595	4,738	2,229	4,070	14,127
1980	2,469	554	4,343	1,929	3,726	13,021
1981	2,408	596	3,949	1,802	3,277	12,032
1982	2,474	500	3,934	1,573	3,320	11,802
1983	2,469	514	3,922	1,731	2,897	11,534

* Excludes refinery fuel

MIDDLE EAST

	GASO	JET/KERO	DIST	OTHER	RESID*	TOTAL
1977	207	211	367	101	513	1,401
1978	261	208	353	106	600	1,529
1979	250	210	385	161	662	1,668
1980	302	277	446	159	670	1,854
1981	315	245	521	199	704	1,984
1982	345	282	792	131	569	2,120
1983	326	278	762	172	715	2,253

* Excludes refinery fuel

FAR EAST AND OCEANIA

	GASO	JET/KERO	DIST	OTHER	RESID*	TOTAL
1977	1,093	893	1,540	1,455	3,017	7,999
1978	1,136	1,010	1,288	1,548	3,388	8,369
1979	1,223	1,038	1,859	1,660	3,353	9,133
1980	1,209	1,017	1,860	1,465	3,022	8,573
1981	1,220	1,027	1,916	1,631	2,771	8,565
1982	1,256	979	1,920	1,858	2,300	8,314
1983	1,304	967	1,920	1,476	2,544	8,211

* Excludes refinery fuel

AFRICA

	GASO	JET/KERO	DIST	OTHER	RESID*	TOTAL
1977	233	123	326	105	270	1,057
1978	275	155	378	111	321	1,240
1979	302	185	424	131	307	1,348
1980	317	182	412	141	344	1,396
1981	344	155	430	120	375	1,424
1982	374	181	471	146	407	1,580
1983	388	193	508	118	405	1,611

* Excludes refinery fuel

TOTAL NON-COMMUNIST WORLD

	GASO	JET/KERO	DIST	OTHER	RESID*	TOTAL
1977	12,644	3,358	11,299	7,454	12,201	46,956
1978	13,184	3,612	11,554	7,876	12,513	48,740
1979	13,169	3,652	12,215	9,007	12,732	50,775
1980	12,726	3,675	11,524	8,666	11,924	48,515
1981	12,695	3,556	11,218	8,358	10,693	46,520
1982	12,879	3,228	11,318	8,260	9,803	45,488
1983	12,999	3,243	11,273	7,890	9,300	44,705

* Excludes refinery fuel

CHANGE IN NON-COMMUNIST WORLD DEMAND

	GASO	JET/KERO	DIST	OTHER	RESID*	TOTAL
1979	13,169	3,652	12,215	9,007	12,732	50,775
1983	12,999	3,243	11,273	7,890	9,300	44,705
Change	(170)	(409)	(942)	(1,117)	(3,432)	(6,070)
% of TTL	2.8	6.7	15.5	18.4	56.5	100.0

APPENDIX H

An Analysis of Oxygenate Usage

FUTURE OF OXYGENATES

In March 1985, the Environmental Protection Agency (EPA) finalized lead phasedown regulations that restricted the lead in gasoline to 0.10 grams per leaded gallon (gplg) effective January 1, 1986. This has forced refiners to turn to alternatives in order to meet octane requirements in gasoline production. For example, at current U.S. refinery utilization rates, there is some flexibility in naphtha reformer severity to raise pool octane. Also, light straight-run and natural gasolines constitute a major remaining low-octane component in the U.S. gasoline pool that can be upgraded through additional isomerization capacity. Catalytic cracking and catalyst innovations, increased alkylation, hydrogenation of coker gasoline to provide additional reformer feed, and oxygenate blending are other alternatives.

Oxygenates can be very important to the small refiner lacking capital to invest in major process equipment. Oxygenates can also be important for a large refiner with an existing investment in a methanol or ethanol plant or a special incentive to produce methyl tertiary butyl ether (MTBE). In addition, a large refiner could turn to oxygenates to fill an octane requirement prior to new process equipment being constructed and coming on stream. Ethanol blending has been of great interest to many refiners due to the large tax subsidies it receives.

In many situations, oxygenates are the most economic alternative to lead, as evidenced by their rapid growth over the last five years. Many experts are forecasting continued fast growth over the next five years. However, current availability of oxygenates for gasoline blending in the United States is limited. Further growth in oxygenate blending will require substantial new construction. Whether the investment will be made depends upon many factors. For example, the demand for high-performance American cars will affect the size of the octane pool required in the future. The price of crude oil will determine whether oxygenates can be competitive with traditional hydrocarbons. Another major factor is whether the problems of blending certain oxygenates, in particular methanol, can be solved to the satisfaction of the marketplace.

The remainder of this appendix examines the background and issues surrounding the use of oxygenates as well as results of the National Petroleum Council's 1985 Survey of U.S. Petroleum Refineries, and results of the NPC's refinery modeling studies.

BACKGROUND

Concerns about air quality led the EPA to propose, in 1971, limiting the amount of lead used by refiners in gasoline blending. In 1973, under the Clean Air Act, the EPA was given authority to regulate the use of lead in gasoline. The Act initially called for a reduction to 0.5 gplg, on a pool average basis, by January 1, 1979. This was later changed, and in fact the lead phasedown schedule was modified several times prior to its current form. The most recent and restrictive

regulations were proposed in August 1984 and finalized in March 1985. They called for lead phasedown as follows: prior to July 1, 1985—1.1 gplg; effective July 1, 1985—0.5 gplg; effective January 1, 1986—0.10 gplg.

Lead restrictions were followed in 1977 with similar restrictions on MMT (methylcyclopentadienyl manganese tricarbonyl), a manganese compound. It became obvious to refiners during this period that organometallic compounds would continue to be severely restricted as octane enhancers, and attention turned to oxygenates as a means to supplement the conventional octane pool.

Initial interest focused on chemical by-products such as tertiary butyl alcohol (TBA), which had already been established as a suitable blending component, and certain ethers such as MTBE, which had also been previously studied. Investigation began into usage of ethanol and methanol as well as other potential oxygenates.

OXYGENATE USAGE RESTRICTIONS

The Clean Air Act states that no fuel or fuel additive may be introduced into commerce that is not "substantially similar" to any fuel or fuel additive used in the certification of any 1974 or later model year vehicle. In July 1981, the EPA defined "substantially similar" to include fuels blended with ethers or alcohols (except methanol) up to 2.0 wt.% oxygen. Methanol could be used as a de-icer up to 0.3 volume percent, or up to 2.75 volume percent if blended with a co-solvent such as butanol or higher molecular weight alcohol. Table H-1 shows "substantially similar" fuels.

TABLE H-1

"SUBSTANTIALLY SIMILAR" FUELS

Oxygenate	Maximum Volume %
Methanol	0.3
Ethanol	5.4
IPA	7.1
TBA	8.7
MTBE	11.0
50/50 Methanol/TBA	5.5

The Act also provides for the EPA to waive the prohibition on new fuels or fuel additives that are not "substantially similar" if it can determine that the fuel or fuel additive will not cause failure of any vehicle emission control system. The EPA has granted waivers as shown in Table H-2.

In order for a new fuel or fuel blend to be commercially successful, certain broad criteria must be met. Performance of the new fuel must be comparable to the traditional fuel, cost must be competitive, and the product must be readily available. The fact that there is significant and growing consumption of certain oxygenates suggests that these criteria are being met. MTBE, TBA, ethanol, and methanol in various blends are the primary oxygenates being used today. Following is a brief discussion of each.

MTBE

Methyl tertiary butyl ether is a high-octane gasoline blending component produced by the reaction of isobutylene and methanol. It is currently used in the United States and Europe. MTBE is the only oxygenate to be generally accepted by the industry for refinery blending and pipeline transportation. The blending characteristics of MTBE are very close to that of hydrocarbon components. It is essentially interchangeable with toluene and other aromatics.

The volatility blending properties of MTBE are similar to those of debutanized light straight-run gasoline. Gasolines containing MTBE have shown no phase separation problems as occur with alcohols. No unusual problems are encountered in normal handling, storage, or distribution of MTBE or of gasoline containing MTBE. In addition, gasolines containing MTBE have not exhibited any adverse effects on drivability, carburetor icing, vapor lock, fuel consumption, horsepower, or corrosion.

MTBE is not a readily available additive although limited merchant MTBE is available. Most of the production capacity is captive for individual oil company gasoline pools. Little or no MTBE is exported from Europe to the United States.

Total U.S. production capacity, including some still under construction, is about 33,000 barrels per calendar day (B/CD); however, about 3,000 B/CD has been shut down, leaving an estimated effective capacity of 30,000 B/CD. Isobutylene for MTBE manufacturing is obtained from the product streams of both fluid catalytic

TABLE H-2

FUEL WAIVERS GRANTED BY EPA

	Oxygenate	Maximum Volume %	Maximum Oxygen Wt. %
Gasohol	Ethanol	10.0	3.7
Arconol	TBA	16.0	3.5
Oxinol 30	30% Methanol 70% TBA	7.8 3.4	3.5
Oxinol 50	50% Methanol 50% TBA	4.7 4.7	3.5
Petrocoal*	80% Methanol 20% TBA Proprietary Rust Inhibitor	12.0 3.0	5.9
DuPont	Methanol Cosolvent (Ethanol, Propanols, GTBA and/or Butanols)	5.0 2.5	3.7

*The EPA moved to revoke this waiver.

cracking (FCC) and steam cracking. The volume that is available fluctuates and is limited. It is estimated that about one-third of the U.S. isobutylene is currently being used for MTBE production. Technology is available for MTBE production, using gas and gas liquids as raw materials. This process is, however, more expensive in terms of both operating costs and capital outlays.

Outside the United States, approximately 18,450 B/CD of MTBE capacity exists, all of which is in Europe. It has been estimated that sufficient isobutylene exists in Europe to produce between 14,000 and 18,000 B/CD of MTBE, which indicates very little unused European capacity.

MTBE has a blending octane value of about 109 octane number [(R+M)/2], compared with TBA at 98, ethanol at 114, and methanol at 116. Also, for comparison, typical high-octane reformate has a blending octane value of 94 to 96, and toluene has 106. While the blending octane value of MTBE is relatively high, the cost of MTBE on the open market is also relatively high. The cost per octane number gallon ranks MTBE similar to TBA, xylene, and toluene, on the upper end of the cost scale. The capital cost of MTBE production capacity is relatively high at $3,500 per daily production barrel. It can, however, be attractive for refiners with a special economic incentive such as low-cost methanol or an incentive to separate isobutylene from mixed butylenes.

TBA

Tertiary butyl alcohol is a coproduct from the manufacture of propylene oxide. It is the most common cosolvent for methanol and has been blended directly into gasoline in the United States since 1969, under the trade name of "Arconol." Arconol is composed of TBA, which is a four-carbon alcohol with properties similar to other alcohols, but is more compatible as a gasoline blending component than lower molecular weight alcohols. Although it has a Reid Vapor Pressure (RVP) of 6 to 8 pounds per square inch (psi), when blended in hydrocarbons it results in a somewhat higher RVP, thus resulting in the need to reduce the amount of butane blended. The drivability of gasoline blended with Arconol compares favorably to base gasoline except under certain conditions. Some tests have shown that with a cold engine during warm weather, engine performance is not as good as with base gasoline, although comparable to gasoline blended with ethanol.

The only U.S. plant to use peroxidation of propylene via isobutane to yield TBA is in Bayport, Texas, and it is estimated that maximum output is in the range of 20,000 to 25,000 B/CD. The only other source of TBA for fuel blending is in the Netherlands, where a 10,000 B/CD plant has been in operation since 1982 in conjunction with a propylene oxide operation. Arconol has a blending octane value of about 98 (R+M)/2. Its cost per octane number gallon is similar to MTBE, xylene, and toluene.

ETHANOL

The use of ethanol for blending into gasoline became significant in 1979 as a means to reduce dependence upon imported hydrocarbons. The economic incentive for its use was provided by the National Energy Act of 1978, which suspended the 4¢/gallon motor fuel excise tax for gasoline blended with agricultural based alcohol. This federal subsidy later increased to 5¢/gallon and then 6¢/gallon, which was supplemented by varying state subsidies. Lead phasedown was responsible for expanding interest in ethanol as a blending agent to increase octane.

Gasoline containing ethanol is typically a mixture of 90 volume percent unleaded regular gasoline and 10 volume percent denatured anhydrous ethyl alcohol, popularly known as "gasohol." It is sold as "regular" leaded gasoline, as "regular" unleaded gasoline, and as higher octane "premium" unleaded gasoline. While in recent years ethanol has been the most widely used oxygenate, there are a number of problems associated with it. Most of the problems are less severe than with methanol, which is a lighter alcohol compound but more severe than TBA, which is a heavier alcohol compound.

One problem is "drivability." The presence of oxygen in alcohol molecules causes a gasoline–alcohol blend to burn lean, which can result in engine misfire, hesitation, and stumble, especially in warm weather during warmup. The addition of alcohol to gasoline causes the vapor pressure of the gasoline–alcohol blend to be higher than the vapor pressure of the base gasoline. Therefore, the addition of alcohol to gasoline that has been correctly seasonalized will result in above specification vapor pressure and potential poor performance characteristics. Alcohol also acts as a solvent in a vehicle fuel system and tends to dislodge existing rust, potentially causing fuel filter plugging. Alcohols can soften elastomeric parts found throughout an automotive fuel system. Additionally, corrosion of magnesium, aluminum, copper, zinc, and brass has been shown to be accelerated by alcohol in the fuel. Perhaps the biggest problem is with storage and distribution of gasoline–alcohol blends due to the tendency toward phase separation when the blend comes into contact with free water. Alcohol is completely soluble in water and is drawn out of gasoline by contact with free water. To avoid phase separation, the storage system must be kept in essentially dry condition. Contact with water results in an alcohol-rich water bottom in storage tanks. This material not only causes a waste removal problem but can also cause an engine to stall if it enters a fuel line. Due to these storage and distribution problems, both ethanol and methanol are only infrequently blended at the refinery level. Most ethanol is blended at distribution terminals or bulk storage plants, to eliminate pipeline transportation of the gasoline blend. Ethanol contains only about 77 percent of the BTU (British thermal unit) content of gasoline and therefore results in lower mileage when used in gasoline. Tests have shown the mileage loss to be about 2.2 percent versus base gasoline. Due to the large incentive provided by the federal and state governments in the form of tax subsidies, the industry has managed for the most part to deal with these problems, and the use of ethanol–gasoline blends has grown.

Since their introduction in the marketplace, ethanol–gasoline blends have grown very rapidly. It is estimated that about 80 million gallons of ethanol were blended into fuel in the United States in 1981 and about 760 million gallons in 1985. Currently, total U.S. production capacity is about 750 million gallons per year. Brazil, the leading foreign supplier, can supplement domestic production.

Ethanol has a very high blending octane value of 114 (R+M)/2. However, the cost per gallon is also very high. It is doubtful that ethanol will ever be competitive with gasoline on a full-cost basis. Consequently, the future of ethanol as a blending component depends upon continued government subsidies. Currently, there is a 6¢ exemption from the 9¢/gallon federal motor fuel tax paid at the gasoline pump for each gallon of ethanol-blended fuel sold. Many states have enacted similar subsidies, ranging from 1¢ to 16¢/gallon. The average state subsidy is 3¢. The average combined subsidy is therefore 9¢/gallon of ethanol blended fuel, or 90¢/gallon of pure

ethanol. Without the subsidy, ethanol is the most expensive method to increase octane but with the subsidy, it is one of the cheapest. Because the subsidies are reducing state tax receipts, many states have phased out or reduced the allowed subsidy.

METHANOL

The use of methyl alcohol for gasoline blending is by far the most controversial of all the alcohols. For the most part, it is manufactured from natural gas but can also be made from renewable resources. Methanol has the potential to be a major substitute for hydrocarbons in the 21st century.

Federal regulations prohibit blending methanol alone into gasoline but permit it to be blended in conjunction with a butyl alcohol cosolvent. TBA is the most effective and economic cosolvent at this time. The problems associated with alcohol blends, discussed above with ethanol, also pertain to methanol. However, methanol is even more highly water extractable than ethanol and more highly corrosive. While corrosion is said to be controlled by proper additive usage, long-term results remain in question. As with ethanol, problems associated with storage and distribution have forced most methanol blending at the marketing distribution terminals and bulk plants rather than at refineries. In addition, methanol contains only about 49 percent of the BTU content of gasoline and a TBA cosolvent contains about 86 percent. In tests conducted by a major oil company, the loss in mileage varied by car up to about 5 percent.

Worldwide methanol manufacturing capacity is substantially in excess of current demand for conventional chemical markets. As a result of the overcapacity, methanol prices have been severely depressed, and there is strong incentive to blend it with motor gasolines. The worldwide surplus is expected to continue as natural gas producing countries such as Saudi Arabia, Indonesia, Canada, the U.S.S.R., Mexico, and others attempt to find markets for their natural gas reserves. Announced new plants, if completed, will increase already surplus methanol capacity about 50 percent worldwide by 1986. Production capacity in the United States is about 1.9 billion gallons annually. U.S. demand for methanol is only about 1.3 to 1.4 billion gallons. Both Canada and Mexico have spare production capacity, and traditional North American export markets in Europe and Japan will continue to be under pressure from Middle East and eastern European plants.

Methanol has the highest blending octane available in an oxygenate, at 116 (R+M)/2. It also has the lowest cost per gallon, making the cost per octane number gallon lower than any alternative with the exception of lead.

OXYGENATE GROWTH

Table H-3 presents the approximate growth in oxygenate consumption through hydrocarbon

TABLE H-3

OXYGENATE USE IN MOTOR FUEL
(Millions of Gallons per Year)

	1981	1982	1983	1984	1985 (Est.)
TBA	130	120	110	100	90
MTBE	35	50	80	100	115
Methanol*	17	35	121	145	183
Ethanol	85	235	430	567	760
Total	**267**	**440**	**741**	**912**	**1,148**

*Includes Petrocoal, Oxinol, and Deicer.

Source: Information Resources Incorporated.

fuel blends from 1981 through 1985. The total consumption has grown from about 270 million gallons in 1981 to 1,150 million gallons in 1985, an increase of about 325 percent. Ethanol has been the fastest growing of the oxygenates and accounts for 760 million gallons in 1985, or 66 percent of the total. Growth in usage since 1981 has been almost 800 percent. MTBE consumption has increased from 35 million gallons in 1981 to about 115 million gallons in 1985, or about 230 percent. Methanol consumption has increased from 17 million gallons in 1981 to about 183 million gallons in 1985, or about 976 percent. TBA has limited production capability, and consumption in motor fuel has declined over the last five years.

Experts predict that demand for fuel ethanol will double between 1985 and 1995. This will, of course, depend upon continued tax subsidy. Other oxygenates are also expected to continue their growth through 1995.

SURVEY RESULTS

The NPC's 1985 Survey of U.S. Petroleum Refineries included some data on oxygenate usage. In one section, refiners were asked to report actual oxygenates used in 1984 and projected usage in 1986 and 1988. In another section, refiners were asked to report on gasoline manufacturing capabilities for 1985 through 1988 while maximizing unleaded volumes, with lead content not to exceed 1.1 gplg in one case and 0.1 gplg in another. They also reported gasoline manufacturing capabilities under the same parameters, but excluding all oxygenate usage.

Table H-4 shows the survey response to actual oxygenates used by refiners in 1984 and their projected usage in 1986 and 1988. Refiners responding to this portion of the survey reported gasoline production in 1984 of about 6,310,000 B/CD, or about 97.8 percent of total U.S. gasoline production of 6,453,000 B/CD.

A total of 29 refiners reported using 25,847 B/CD of oxygenates in 1984. MTBE was the most widely used oxygenate, with 15 refiners reporting the use of 12,416 B/CD. TBA had the next highest volume usage, at 7,701 B/CD, with only three refiners reporting its use. TBA was followed by methanol at 3,031 B/CD and ethanol at 2,699 B/CD.

The survey shows a 118 percent projected increase in oxygenate usage from 1984 to 1986 at 25,847 B/CD and 56,499 B/CD, respectively. In 1988, refiners are projecting a 12 percent decrease in oxygenate usage from 1986, to 49,472 B/CD. The 30,602 B/CD increase from 1984 to 1986 is made up of an 11,232 B/CD increase in ethanol, a 10,076 B/CD increase in MTBE, and a 7,300 B/CD increase in TBA. Methanol increases slightly. The 1988 projection shows a 9,474 B/CD decline in TBA usage, with slight increases in the other three oxygenates.

Table H-5 presents a comparison of oxygenate usage for 1984 as reported in the NPC

TABLE H-4

1985 NPC SURVEY
OXYGENATE USAGE

	Actual 1984		Projected 1986		Projected 1988	
	B/CD	No. of Responses*	B/CD	No. of Responses*	B/CD	No. of Responses*
Ethanol	2,699	10	13,931	15	14,865	16
Methanol	3,031	4	5,025	10	5,053	11
TBA	7,701	3	15,001	4	5,587	4
MTBE	12,416	15	22,492	13	23,967	14
Total	**25,847**	**29**	**56,449**	**37**	**49,472**	**39**

*Number of refiners reporting feedstock requirement.

TABLE H-5

COMPARISON OF 1984 OXYGENATE USAGE (B/CD)

	Information Resources	NPC Survey*	Difference
Ethanol	37,000	2,699	34,301
Methanol	9,500	3,031	6,469
TBA	6,500	7,701	(1,201)
MTBE	6,500	12,416	(5,916)
Total	**59,500**	**25,847**	**33,653**

*For refiners reporting usage.

survey and as estimated by Information Resources, Inc. The NPC survey includes only those oxygenates blended at the refinery level, while the Information Resources data represent all U.S. consumption. As expected, total ethanol and methanol consumption is much higher as reported by Information Resources. Due to storage and transportation problems, as previously discussed, most ethanol and methanol is blended at the distribution terminal level rather than at refineries. Out of 37,000 B/CD ethanol consumption in 1984, only 2,699 B/CD was blended at the refinery level. Total methanol consumption was about 9,500 B/CD, with about 3,031 B/CD blended at refineries. TBA consumption was very close between the two sources. MTBE usage was reported at 12,416 B/CD by the survey but only 6,500 B/CD by Information Resources. Since MTBE is largely captive for individual company gasoline pools, it appears likely that the Information Resources estimate is understated.

Table H-6 summarizes oxygenate usage as projected by refiners while maximizing production of unleaded gasoline with leaded gasoline constrained at: a) 1.1 gplg and b) 0.1 gplg. Also under b), refiners projected their oxygenate requirements with unleaded gasoline at 87 octane and at 88 octane.

Moving from refiners' "expected" operations to a maximum unleaded production case shows a substantial increase in oxygenate usage. In 1986, refiners project using 56,449 B/CD of oxygenates, which assumes leaded regular at 0.21 gplg. Under a maximum unleaded production case and 0.1 gplg, refiners project using 68,001 B/CD, or about a 20 percent increase. In 1988, refiners project using 49,472 B/CD of oxygenates, versus 79,109 B/CD, assuming maximum unleaded production (with both cases at 0.1 gplg). Under the "expected" case and the maximum unleaded case, the largest volume oxygenate is MTBE, followed by ethanol. In the maximum unleaded case with 0.1 gplg, MTBE represents 53.5 percent of total oxygenates, ethanol 36.5 percent, TBA 6 percent, and methanol 4 percent. In the "expected" case, MTBE represents 48.5 percent, ethanol 30 percent, TBA 11.5 percent, and methanol 10 percent.

From Table H-6 it is also apparent that reducing lead content in regular leaded gasoline from 1.1 gplg to 0.1 gplg increases oxygenates required. Although 1985 usage does not change much, 1986 usage increases from 44,341 B/CD in the high lead case to 68,001 B/CD in the low lead case. In 1988, oxygenate usage in the low lead case increases 55 percent, from 50,957 B/CD to 79,109 B/CD.

Refiners also reported that increasing octane by 1.0 number in 1988 would trigger an increase in oxygenate usage from 79,000 B/CD to 99,000 B/CD. Virtually all of the increase is with ethanol and MTBE.

Table H-7 shows a breakdown of projected oxygenate volume by region and refinery type as projected under a maximum unleaded gasoline production case with lead constrained to 0.1 gplg. Table H-8 is a compilation of the number of refiners projecting the use of each oxygenate under the same case.

TABLE H-6

1985 NPC SURVEY
OXYGENATE USAGE — PROJECTION OF
MAXIMUM UNLEADED GASOLINE PRODUCTION
(B/CD)

	Oxygenate Usage at 1.1 gplg		
	1985	**1986**	**1988**
Ethanol	6,400	10,433	15,679
Methanol	1,920	3,912	4,573
TBA	5,760	5,869	5,880
MTBE	23,040	24,127	24,825
Total	**37,120**	**44,341**	**50,957**

	Oxygenate Usage at 0.1 gplg			
	1985	**1986**	**1988***	**1988†**
Ethanol	6,392	22,453	28,942	33,153
Methanol	1,918	1,924	3,216	2,960
TBA	5,753	4,491	4,502	4,736
MTBE	25,569	39,133	42,449	58,018
Total	**39,632**	**68,001**	**79,109**	**98,867**

*Current octane, i.e., 87 (R+M)/2.
†Increased octane, i.e., 88 (R+M)/2.

Several comments can be made about the survey data on a geographic basis. PADD II, Midwest, and PADD III, Gulf Coast, account for the majority of oxygenates used in all years surveyed. Projected growth from 1985 through 1988 is the highest in PADD II, which increases from 6,300 B/CD to 22,200 B/CD. PADD III also shows a rapid growth, from 18,700 B/CD in 1985 to 37,700 B/CD in 1988. PADD I, East Coast, shows 7,400 B/CD used in 1985, escalating to 10,000 B/CD in 1988. Little good data are available for PADD IV, Rocky Mountains, and PADD V, West Coast (see Table H-7).

The only significant oxygenate in PADD I, East Coast, is MTBE. Three of fifteen refiners projected its use in 1988. On a volume basis, MTBE makes up over 7,000 B/CD out of 10,600 B/CD total projected oxygenate usage in 1988. In PADD II, Midwest, ethanol is by far the most commonly used oxygenate, with 10 of 31 refiners projecting its use in 1988. Only 2 refiners project using MTBE. Although the report does not give a breakdown of oxygenate volume in PADD II, it is clear that the majority of the 22,200 B/CD of oxygenates projected in 1988 is ethanol. In PADD III, Gulf Coast, 18 of 47 refiners expect to be blending MTBE with gasoline in 1988, with 4 using ethanol. MTBE makes up about 32,000 B/CD out of a total of 37,700 B/CD of total oxygenates projected in 1988. In PADD IV, Rocky Mountains, only 1 refiner projected using oxygenates, which was ethanol. In PADD V, West Coast, 6 refiners expect to be using ethanol, while 2 project blending MTBE.

In another section of the NPC survey, refiners were asked to report the impact of eliminating all oxygenates on gasoline production assuming maximum unleaded production, 0.1 gplg effective January 1, 1986, and constant crude oil rates. They reported that disallowing oxygenates in

TABLE H-7

1985 NPC SURVEY
PROJECTED USAGE OF OXYGENATES BY PADD
MAXIMUM UNLEADED GASOLINE PRODUCTION, 0.1 gplg
(B/CD)

	1985	1986	1988
PADD I			
No Conversion	0	0	0
All Conversion	7,390	9,680	10,570
Subtotal	7,390	9,680	10,570
PADD II			
No Conversion	0	0	0
Gas Oil Conversion	*	3,340	5,010†
Deep Conversion	6,320	14,010	17,170
Subtotal	6,320	17,350	22,180
PADD III			
No Conversion	*	690	*
Gas Oil Conversion	5,160	5,390	6,290
Deep Conversion	13,530†	30,000	31,380
Subtotal	18,690	36,080	37,670
PADD IV			
All Refiners	*	*	*
PADD V			
No Conversion	*	*	*
Outside California	*	*	*
Inside California	*	*	4,240
L.A. Basin	*	*	4,260
Offshore	*	*	*
Subtotal	*	*	8,500
Unidentified	7,200	5,490	180
Total	**39,600**	**68,600**	**79,100**

*Represents unidentified data.
†Constructed from partial data, therefore a minimum number.

1986 could reduce gasoline production by up to 81,000 B/CD, or 1.26 percent of total gasoline. Without oxygenates, 1988 gasoline production could reportedly fall by almost 100,000 B/CD, or 1.55 percent.

The impact of reducing RVP on all gasolines to 1.0 psi less than current specifications was an additional area examined in the survey. This was examined under a maximum unleaded gasoline basis assuming 0.1 gplg. While this constraint caused a significant reduction in gasoline production capability, oxygenate consumption was not projected to vary significantly. Refiners reported that in 1986 gasoline production could fall by 233,000 B/CD under the constraint but only about 3,100 B/CD additional oxygenates would be utilized. In 1988, 218,000 B/CD of gasoline could be lost with about 1,700 B/CD additional oxygenates required.

TABLE H-8

1985 NPC SURVEY
NUMBER OF REFINERS USING OXYGENATES — 1988 PROJECTION
MAXIMUM UNLEADED GASOLINE PRODUCTION, 0.1 gplg

	Number of Refineries	Oxygenate Reported			
		EOH	MTBE	MOH	TBA
PADD I					
No Conversion	4	0	0	0	0
All Conversion	11	0	3	1	1
Subtotal	15	0	3	1	1
PADD II					
No Conversion	0	0	0	0	0
Gas Oil Conversion	9	4	0	0	0
Deep Conversion	22	6	2	0	0
Subtotal	31	10	2	0	0
PADD III					
No Conversion	3	1	1	1	0
Gas Oil Conversion	14	1	4	1	1
Deep Conversion	30	2	13	1	1
Subtotal	47	4	18	3	2
PADD IV					
All Refiners	13	1	0	0	0
PADD V					
No Conversion	5	2	0	0	0
Outside California	6	0	0	0	0
Inside California	13	2	0	0	0
L.A. Basin	9	2	0	0	0
Offshore	4	0	2	1	1
Subtotal	37	6	2	1	1
Total	**143**	**21**	**25**	**5**	**4**

MODEL RESULTS

Turner, Mason and Company developed a computer model to simulate the U.S. refining industry for the NPC. A number of cases were run to assist in answering questions regarding U.S. refining capability, including the use of oxygenates.

Model assumptions concerning oxygenates varied somewhat from survey data; however, none of the cases are on a completely identical basis. Table H-9 shows a comparison of applicable model and survey cases in terms of gasoline production and oxygenate usage. The 1988 high demand model case is most closely comparable to the 1988 refiner projected survey case. Total gasoline production is 132,000 B/CD higher under the survey case, with unleaded production 194,000 B/CD higher and unleaded premium production 85,000 B/CD lower. While gasoline production is higher under the survey case, oxygenate usage is 9,000 B/CD lower. Oxygenate usage is 58,000 B/CD under the model case and 49,000 B/CD under the survey case.

The 1988 maximum unleaded production survey case shows higher unleaded and unleaded premium production and lower leaded production than the 1988 refiner projected case. Corresponding to this is an increase in oxygenate usage from 49,000 B/CD to 79,000 B/CD. The 1988 optimum major products model case shows a 436,000 B/CD increase in gasoline production from the 1988 high demand model case (specific gasolines not identified) but no increase in oxygenate usage.

TABLE H-9

COMPARISON OF GASOLINE PRODUCTION AND OXYGENATE USAGE MODEL VS. SURVEY (MB/CD)

	Model		Survey	
	1988 High Demand	1988 Optimum Major Products	1988 Refiner Projected	1988 Maximum Unleaded
Leaded Gasoline	1,027	—	1,050	812
Unleaded Gasoline	4,020	—	4,214	4,334
Unleaded Premium	1,255	—	1,170	1,259
Total Gasoline	**6,302**	**6,738**	**6,434**	**6,432**
Oxygenates	58	58	49	79

Further comparing the 1988 optimum major products model case to the 1988 maximum unleaded survey case shows that PADD III, Gulf Coast, has the greatest usage of oxygenates in both cases. The survey case shows usage of 37,700 B/CD while the model case assumes 33,000 B/CD. The greatest discrepancy occurs in PADD II, Midwest, where the survey shows a projected usage of 22,200 B/CD, but the model assumption is only 10,000 B/CD. The model case also assumes lower usage of oxygenates in PADD I and PADD V.

Another area that was examined using the model is the sensitivity of refining results to changes in RVP and octane. Cases were run for 1988 to produce optimum major products assuming current RVP and also a 1.0 psi reduction in RVP. The impact of the reduction in RVP was to reduce gasoline production by 190,000 B/CD from a total of 6.7 million B/CD. The reduction in RVP did not trigger any incremental consumption of oxygenates. This conclusion was supported by the NPC survey. Refiners projected that a 1.0 psi reduction in RVP in 1988 would reduce production by 218,000 B/CD from a total of 6.1 million B/CD and would trigger only about 1,700 B/CD in incremental oxygenates.

Combining the reduction in RVP with a 1.0 (R+M)/2 increase in required octane, the model showed a 439,000 B/CD decrease in gasoline production. The increased octane also triggered a 74 percent increase in oxygenate consumption, from 58,000 B/CD to 101,000 B/CD. Two-thirds of the increased oxygenate consumption took place in only two categories, PADD II, deep conversion, and PADD III, deep conversion, which were the two primary users of oxygenates under the base case. It is interesting to note that while octane costs are relatively high for PADD III, deep conversion refineries at 97¢/octane number/barrel, they are relatively low for PADD II, deep conversion refineries at 62¢/octane number/barrel. PADD III, low conversion refiners have the highest octane cost at $1.10/octane number/barrel, but relatively no incremental oxygenates are consumed in the increased octane case. There seems to be little pattern between additional oxygenates required and octane cost, according to the model data.

APPENDIX I

Results of the Refinery Capability Modeling

ATTACHMENT A-1

PRIMARY ASSUMPTIONS

BASIS FOR 1984 CALIBRATION RUNS - NPC STUDY

- Allocate all refineries into 13 groups -- 9 LP Models and 4 Hand Models -- according to geographical areas and refinery complexities.
- Use DOE data as basis for material balances on refinery groups.
- Estimate blanked-out DOE data which could not be reported due to low cell counts.
- Use DOE foreign crude import destination data -- assign modeled crudes.
- Estimate domestic crudes based on production data and some gravity data.
- Allocate domestic crudes using old 1980 DOE allocations, 1984 NPC survey -- crude type breakdowns, crude source plus pipeline and waterborne shipping.
- Match allocated crude composite gravity against NPC survey and DOE PADD data and match NPC crude types.
- Refinery process unit capacities = average of 1/1/84 and 1/1/85 DOE PSA operable capacity data -- supplemented by O&GJ and NPC survey.
- Breakdown of motor gasoline, residual fuel, oxygenates, aromatics and H_2 feed based on NPC survey for 1984.
- Unfinished oils and petrochemicals breakdown based on TM&C sources.
- Use basic TM&C refinery LP models with minor adjustments based on NPC survey data.
- Use NPC survey data for finished product qualities, some process unit yields improvements, some intermediate stream qualities and unit severities and utilizations.
- Use average spot low cargo prices for 7/84-6/85 at refinery PADD locations for raw materials, products and utilities. Prices have minor impact on calibration runs.

TABLE A-2

1984 CALIBRATION CRITERIA

NPC STUDY

	Maximum Variance
• Match Material Balance from DOE	
Allow Residual Fuels, C4- and Gain to Vary	± 0.3% of Total Input
• Match Utilities from DOE	
Usage	± 3% of Target
Fuel Composition	± 4% of Total Fuel
• Match Major Product Primary Qualities(1)	
Mogas Octanes: (R+M)/2	+ 0.1
Mogas Lead, Gms./Gal.	- 0.1
Mogas RVP, psi	- 0.5
Distillate Fuels Sulfur, Wt.%	- 0.2(2)
• Match Unit Utilizations(1)	
Conversion Units by Type	± 8%
Composite of Conversion Units	± 5%
Catalytic Reformers	± 15%
• Match Unit Severities(1)	
Cat Cracking Conversion, %	± 5%
Reformate Octane, RONC	± 0.5
• Judgement Review of Shadow Values	
None Constraining Severely	± 20%

(1) From NPC survey data.
(2) Adjusted to zero on future runs by allowing high-sulfur diesel to by-pass distillate HDS unit.

TABLE A-3

1984 CALIBRATION RUN RESULTS

ACTUAL VARIANCES(1) COMPARED TO ACCEPTABLE VARIANCES

NPC STUDY

	Maximum Acceptable Variance	IC	IIDC	IILC	IIIDC	IIILC	IV	VCOC	VCC	VCLA
Material Balance, % Total Input										
Residual Fuels	± 0.3	0.05	-0.01	0.04	0.26	0.18	0.01	0.1	-0.1	0.05
Propane	± 0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Produced Fuels (FOE)	± 0.3	-0.08	0.03	-0.02	-0.11	-0.25	-0.27	-0.12	0.07	-0.03
Gain	± 0.2	-0.01	0.01	0.03	0.15	-0.16	0.0	0.01	0.0	0.08
Utilities Usage, % Target										
Total Fuels (FOE)	± 2%	-0.1	0.4	0.3	-0.9	0.1	-1.1	-0.3	-0.7	-0.9
Purchased Fuels (FOE)(2)	± 4%	0.9	0.0	0.6	0.4	3.6	2.6	1.5	-1.4	-0.5
Produced Fuels (FOE)(2)	± 4%	-1.0	0.4	-0.3	-1.3	-3.5	-3.7	-1.8	0.7	-0.4
Power (KWH)	± 3%	0.4	0.2	0.5	-2.5	-0.2	-1.4	-0.2	0.0	-1.0
Product Qualities										
Motor Gasolines										
Octane - R+M/2										
Grade	+0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pool	+0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Lead, Gms./Gal.										
Regular Leaded	-0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Premium Leaded	-0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RVP, psi										
Grade	-0.5	-0.46	-0.4	-0.1	0.0	0.0	0.0	0.0	0.0	0.0
Pool	-0.2	-0.14	-0.17	-0.04	0.0	0.0	0.0	0.0	0.0	0.0
Distillate Fuels, % S(3)	-0.2	-0.01	-0.17	-0.17	0.0	-0.15	0.0	0.0	-0.25	0.0
Capacity Utilization, %(4)										
Cat Cracking	± 8	1.8	4.9	2.5	-2.5	-6.7	4.9	7.7	-5.0	-0.5
Hydrocracking	± 8	2.2	7.3	*	8.3	*	*	*	4.0	0.4
Coking Combined	± 8	*	-1.1	-	7.1	-	*	*	-5.3	-5.2
Composite Conversion(5)	± 5	*	3.9	*	0.6	*	*	*	-1.8	-1.7
Cat Reforming Combined	± 15	-14.8	2.7	-5.4	-0.3	-1.3	-4.7	5.0	-6.2	3.4
Unit Severities										
Cat Cracking Conversion, %	± 5	3.2	-1.5	-4.3	0.0	1.3	-2.2	-1.9	3.1	-1.7
Reformate Octane, RONC	± 0.5	-0.1	0.1	0.2	-0.3	-0.3	0.1	0.0	0.0	-0.1

(1) LP run results minus target (from DOE or survey data).
(2) Variance expressed as % of total fuel.
(3) Forecast case runs changed to allow bypassing distillate HDS with high-sulfur distillate, hence forecast case runs variance from distillate fuels sulfur target is zero.
(4) Utilizations based on calendar day capacities and actual feed rates, ignoring severity effects.
(5) Utilizations for cat cracking, hydrocracking and coking combined on an actual feed basis, ignoring severity effects.
* Survey data excluded by NPC.

ATTACHMENT A-4

PRIMARY ASSUMPTIONS FOR INITIAL OVERALL 1988

HIGH AND LOW DEMAND BASE CASES

- Use NPC supply and demand forecast (N-S&D) with necessary modification.
- Use NPC survey 1988 gasoline grade distribution (% low lead regular, % unleaded premium and total pool octane are all higher than N-S&D).
- Assume product exports same as 1984. Assume extra N-S&D exports are all crude.
- Assume product imports in 1988 low case is 2.6 MMBPCD (2.0 in 1984 and 3.0 in 1990) -- interpolate composition.
- Assume initial crude imports in 1988 low case were 0.2 MMBPCD lower than 1984 (less U.K. and Saudi Arabia -- 60% sweet crude).
- Assume initial crude imports in 1988 high case increase of 1.7 MMBPCD over 1984 is primarily from Saudi Arabia (0.6), Nigeria (0.5) and secondarily from Algeria (0.2), Canada (0.1), Mexico (0.1), Indonesia (0.1), United Kingdom (0.1) and United Arab Emirates (0.1) -- 50% sweet.
- Shift N-S&D demands for LPG and petrochemical naphtha and gas oil to fit refinery LPG requirements.
- Distribute other raw materials and products in N-S&D based on 1984 data, NPC survey and our judgment.
- Oxygenate availability based on NPC survey. High case = minimum at planned level up to maximum shown as sensitivity. Low case = 1984 as minimum up to 80% of maximum shown as sensitivity.
- Use N-S&D forecast of domestic crude declines and increases.
- Refinery process unit capacities for high 1988 case based on DOE 1/1/85 operable capacity, less published permanent shutdowns, plus facilities under construction by 6/85, plus restarts, plus NPC incremental 1/1/84 capacity above DOE capacity, plus NPC 1/88 less 1/84 capacity above construction and restarts.
- Refinery process unit capacities for low 1988 case = high 1988 case capacities less capacity that is idle or has been temporarily shutdown for economic reasons, even if it has restarted -- including partial refinery shutdowns. (This eliminates all capacity shown to be marginal, based on published information, and increases utilizations. The NPC survey indicated no reduction in refining capacity from 1984 to 1988.)

ATTACHMENT A-5

ASSUMPTIONS AND METHODOLOGY

FOR INITIAL DETAIL ALLOCATIONS

1988 HIGH AND LOW DEMAND BASE CASES

- In estimating 1988 crude runs by models, refinery crude unit utilizations were raised proportionately to 1984 DOE data with minor adjustments.
- Calculated simple refinery yields assuming high oxygenate use (5% of mogas), no natural gasoline input, 98 RON reformate and unleaded regular gasoline production. Kept crude composition constant.
- Checked high 1988 case conversion refineries composite incremental product yield changes from incremental crude. Incremental yields are similar to crude distillate yields, which implies continued excess conversion capacity with NPC forecasts of net refinery demands.
- Checked high 1988 case products demand growth by PADDs and available transportation to compensate for refinery production increases not matching demands by PADDs. Only very minor changes from 1984 transportation rates are indicated in a transportation system with low utilization in 1984.
- Allocate domestic crudes for 1988 cases based on 1984 allocation and 1988 crude supply. Maintain low crude imports into PADDs IV and V and low domestic crude movements into PADD I.
- Allocate foreign crudes based on 1984 allocations plus estimated 1988 imported crude supply.
- Allocate product pool demands based on crude allocations; then adjust for conversion capability relative to 1984. Finally adjust gasoline to make total products equal total raw materials for each model.
- Allocate pool gasoline and residual fuel into grades based on ratio to 1984 and NPC survey for 1988.
- Allocate oxygenates based on survey data.
- Normalize allocated productions and inputs to match U.S. totals.

ATTACHMENT A-6

FLEXIBILITY FOR LP RUNS

1988 HIGH AND LOW DEMAND CASES

- Allow LP to change input rate of major imported crudes; to vary major domestic crude rates; and to vary Saudi crude rates and composition -- to meet demands and to utilize refinery processing flexibility based on historic prices (7/84-6/85).

- Adjusted Saudi Arabian crude prices in the 1988 high cases to spot market levels based on market prices of similar crudes for the period 7/84-6/85. The differentials between U.K. Brent and Saudi crudes were reduced by one-third for the 1988 low cases with their increased demand for residual fuels relative to gasoline.

- Allow LP to build increments of typical size additional process units, which increase pool octane, if required. New capacity costs are based on total operating costs (including capital charge) whereas costs are based on incremental operating costs for existing capacity.

- In LP forecast runs, limit crude unit utilization to 88% of stream day capacities (93% of CD capacities at 95% onstream factor). Limit downstream units utilizations to 85% of SD capacities (92% of CD capacities and 92% onstream factor).

- Allow LP to vary process unit utilizations below these upper limits. Allow LP to vary process unit severities.

- Allow LP oxygenate input rates flexibility between limits used in initial allocations.

- Allow LP runs to vary production rates of butanes and lighter products as well as marketable and catalytic coke. Limit butane purchases to 50 to 150% of base level.

- Meet total product demands by varying petrochemical naphtha and gas oil output to compensate for LP changes in light ends and coke production.

- Adjust product imports of LPG, gasoline and petrochemical naphtha and gas oil as required to meet total demands without large refinery changes in gasoline and petrochemical naphtha production.

- Produced refinery fuel rates can vary in LP runs, except for small amounts of residual fuel, distillate and marketable coke which are fixed at 1984 rates. Purchased utility (natural gas and power) rates can vary in LP runs.

TABLE A-7

CRUDE IMPORTS COMPARISON

1984 ACTUAL VS. 1988 FORECAST CASES - MODEL RESULTS

NPC STUDY - MBPCD

Country	1984 Actual	Final Increase(1) For 1988 Low Case	1988 Low Case	Final Increase(1) For 1988 High Case	1988 High Case
Abu Dhabi/UAE	69	-	69	100	169
Algeria	198	(158)	40	106	304
Canada	349	-	349	97	446
Indonesia	320	(119)	201	(6)	314
Mexico	627	-	627	100	727
Nigeria	209	(99)	110	42	251
Norway	104	(101)	3	-	104
Saudi Arabia					
Heavy	151	152	303	987	1,138
Light	82	404	486	326	408
Medium	62	(14)	48	50	112
United Kingdom	308	(227)	81	13	321
All Others	867	-	867	-	867
Total	3,346	(162)	3,184	1,815	5,161
% Sweet	47.3	N/A	27.7	8.4	33.6

(1) U.S. refineries can tolerate these changes to high-sulfur crudes. The NPC survey crude substitution results (on page 1-14) showed that reporting refineries with only 6.5 MMBPCD of crude capacity could substitute 0.8 MMBPCD of high sulfur-heavy crude for sweet crude.

TABLE A-8

ESTIMATED OXYGENATES USE AND CAPACITY

1984 AND 1988 CASES - MBPCD

NPC STUDY

	1984					1988						
	NPC Survey		Calibration Runs			NPC Survey			NPC Forecast			
	Refinery Input	Refinery Use(1)	Refinery Use	Estimated Total Use(2)	Estimated Total Capacity(2)	Refinery Input	Refinery Use(1)	Maximum Refinery Use(1)	Low Demand	High Demand	Estimated Total Use(2)	Estimated Total Capacity(2)
MTBE	12.4	16.3	12	21	32	24	38	61	24	36	61	70
Ethanol	2.7	2.7	2	34	40	15	15	33	7	15	60	70
Methanol	3.0	1.6	3	7	30	5	0	3	2	2	7	30
TBA	7.7	7.7	8	10	22	6	5	5	7	5	7	25
Total	25.8	28.3	25	72	124	50	58	102	40	58	135	195
% of Mogas Pool	0.41	0.45	0.39	1.08	1.85	0.77	0.91	1.68	0.74	0.93	1.99	2.87
% of Capacity Used	21	23	21	58	100	26	30	52	21	30	69	100

(1) Input corrected for MTBE production in refineries.
(2) From literature sources.

TABLE A-9

LIST OF 1988 SENSITIVITY RUNS

DEFINITION OF CASES

NPC STUDY

Based on 1988 High Demand Cases

1. Lower RVP
   - Decrease RVP of all gasoline grades by 1.0 psi.

2. Higher Octane
   - Raise octanes of unleaded gasoline grades by 1.0 (Research + Motor)/2.
   - Increase oxygenate usage from 58 to 102 MBPCD.

3. No Oxygenate Usage
   - Eliminate all oxygenates used in refineries.

4. Combined Lower RVP and Higher Octane (Cases 1 plus 2)
   - Increase oxygenate usage from 58 to 102 MBPCD.

5. Maximum Major Light Products With New Facilities
   - Allow LP to optimize the three major product pools -- gasolines, middle distillates and residual fuels -- based on market prices at constant total crude rates.
   - Hold product pool grade distributions constant for gasolines, middle distillates and residual fuels.
   - Reduce asphalt, lubes and petrochemical naphtha/gas oil to 1984 levels.
   - Optimize imported crude composition.
   - Optimize butane purchases and marketable coke.

7. Optimum Major Products Without New Facilities Case
   - Same as maximum major light products Case 5 except no new facilities and no increase in butane purchases allowed.

Based on 1988 Maximum Major Light Products WITH New Facilities Case (Case 5)

6. Higher Sulfur, Heavier Crudes
   - Substitute 10% of total crude - more Arab Heavy and less imported sweet crudes in conversion refineries only.
   - Shift imported and domestic crudes as required.

Based on 1988 Optimum Major Products WITHOUT New Facilities (Case 7)

8. Lower RVP(1)
   - Decrease RVP of all gasoline grades by 1.0 psi.
   - Route butane backed out of gasoline to fuel.
   - Allow reduction in premium unleaded by 25% if required (at an octane cost of 2.5¢/gallon) to avoid over-constrained solutions.

9. Combined Lower RVP and Higher Octane (Cases 2 plus 8)(1)
   - Same as lower RVP Case 8 plus:
   - Raise octanes of unleaded gasoline grades by 1.0 (Research + Motor)/2.
   - Increase oxygenate usage from 58 to 102 MBPCD.
   - Allow sales of low-octane LSR naphtha and natural gasoline to petrochemical feed if required (at an octane cost of 2.7 to 3.0¢/gallon) to avoid dumping or over-constrained solutions.

(1) Cases 8 and 9 are parallel to Cases 1 and 4. They bracket (show upper limit) of costs for changes in gasoline specifications. This approach avoided having only single low cost answers based on surplus conversion capacity in all refineries. Some refineries would be at upper cost limit and lose gasoline production when tightening specifications, as indicated in NPC survey results. Others would have surplus conversion capacity and be at lower cost limit.

TABLE A-10

FLEXIBILITY OF LP MODELS

FOR 1988 SENSITIVITY RUNS

NPC STUDY

Minimum Cost Gasoline Specification Sensitivity Cases: 1, 2, 3, 4

Allow:

- Addition of new process units which enhance octane.
- Changes in imported crude runs: Saudi and major sweet crudes (ANS on West Coast).
- Variations in butane and lighter product rates.
- Changes in catalytic coke and increases in marketable coke.
- No secondary effects included. No attempt to hold total U.S. output constant by compensating for changes in raw materials or products from the sensitivity run results of other models by adjusting Model III DC.
- Items included in definition (Table A-9).

Maximum Major Light Products WITH New Facilities Case: 5

Basis: Utilize all cat cracking capacity and almost all coking capacity. Reach economic maximum gasoline potential by allowing new process units which enhance octane.

Allow:

- All of above.
- Reduced residual fuel and Saudi heavy crude prices to July-October 1985 spot level to increase incentive for major light products.
- Increase purchased gas oil if necessary to fully utilize FCC capacity.
- Items included in definition (Table A-9).

High Sulfur, Heavy Crude Substitution Case: 6

Basis: Maximum major light products with new facilities case.

Allow:

- All of flexibility in maximum major light products with new facilities case.
- Shift in residual fuels grade mix to accommodate heavier crude.
- Items included in definition (Table A-9).

Optimum Major Products WITHOUT New Facilities Case: 7

Basis: Utilize all cat cracking capacity and almost all coking capacity. Limit gasoline by not allowing new facilities or increased butane purchases.

Allow:

- All of flexibility in maximum major light products cases except as noted above under basis.

Maximum Cost Gasoline Specification Sensitivity Cases: 8, 9

Basis: Optimum major products without new facilities case.

Allow:

- All of flexibility in optimum major products without new facilities case.
- Items included in definition (Table A-9).

TABLE A-11

PRICING BASIS

1988 MAXIMUM/OPTIMUM MAJOR PRODUCTS SENSITIVITY CASES

BASED ON 1984-85 SPOT CARGO - ADJUSTED

NPC STUDY

	PADD				
	I	II	III	IV	V
Major Products[1]					
Unleaded Reg. Gasoline, ¢/G	77.0	76.5	75.5	78.5	80.5
Distillate Fuel, ¢/G	75.5	73.5	72.5	75.5	74.0
Residual Fuel (Bunker), $/B[2]	22.50	21.50	21.50	18.50	21.50
Major Crudes[3], $/B					
Domestic					
West Texas Intermediate			28.50		
West Texas Sour			26.90		
Alaska North Slope	27.70		27.50		26.50
California Kern River			26.00		23.00
Foreign					
U.K. Brent	28.40		28.50		
Saudi Arabia Light[2]	27.40		27.50		
Saudi Arabia Heavy[2]	25.40		25.90		
Nigeria Medium	28.70		28.80		
Other					
MTBE, ¢/G	95.6	94.6	93.6	104.6	98.6
Iso-Butane, ¢/G	69.0	56.0	56.0	54.0	69.0
N. Butane, ¢/G	53.5	53.5	53.5	51.5	53.5
Propane, ¢/G	47.5	38.0	38.0	36.0	49.5
Process Gas, $/B - FOE	20.00	20.00	20.00	20.00	30.00
Coke, <3%S, $/ST	20.00	20.00	20.00	20.00	20.00

(1) Average 7/84-6/85 Platt's P/L cargo lows for clean products and waterborne cargo lows for bunker in PADD III. OPIS L.A. P/L lows for clean products in PADD V. All Platt's waterborne cargo lows in PADD I.
(2) Also partially based on July-October 1985 spot prices.
(3) Calculated average 7/84-6/85 delivered spot crude costs from Platt's. Some estimated.

TABLE A-12

SUMMARY OF SENSITIVITY RESULTS

NPC STUDY

	Model Results			
	Average Cost Between Cases		Gasoline Production Change, MBPCD	
	Minimum	Maximum	Minimum	Maximum
Motor Gasolines				
• Vapor Pressure Reduction - By 1.0 psi				
◦ Surplus Conversion Capability, Excess Butane Sales with New Octane Facilities: Table E-1	20¢/B/# RVP	-	(4)	-
◦ No Surplus Conversion Capacity, Excess Butane Burned, No New Facilities: Table E-8	-	42¢/B/# RVP	-	(190)(1)
• Unleaded Octane Increase - By 1.0 (R + M)/2 Octane				
◦ Surplus Conversion Capacity, with New Octane Facilities: Table E-2	38¢/B/O.N.	-	(8)	-
◦ Surplus Conversion Capacity, with New Octane Facilities, After RVP Reduction: Table E-4	41¢/B/O.N.	-	(8)	-
◦ No Surplus Conversion Capacity, No New Facilities, Distressed Lt Naphtha to Petrochemicals, Reduced Premium Unleaded, After RVP Reduction: Table E-9	-	81¢/B/O.N.	-	(249)(2)
• Elimination of Oxygenates				
◦ Surplus Conversion Capacity with New Octane Facilities: Table E-3	1.1¢/G Oxygenate(3)	-	(15)(4)	-
◦ No Surplus Conversion Capacity, No New Facilities: No Model Results	-	N/A	-	N/A
• Maximum Economic Gasoline Production at 13.18 MMBPCD Crude Run with No Surplus Conversion Capacity				
◦ With New Octane Facilities and Increased Net Butane Purchases to 540 MBPCD: Table E-5	-	N/A	-	777 (5)
◦ With No New Facilities and Net Butane Purchases Limited to 282 MBPCD (Base Rate): Table E-7	-	N/A	-	436 (6)
Crude Substitution - 10% Shift from Sweet to High Sulfur Heavy				
◦ No Surplus Conversion Capacity with New Octane Facilities: Table E-6	53¢/B Crude(7)	-	-	(103)(8)

(1) With butane rejected to fuel at 132 MBPCD,or 2.0% of motor gasoline.
(2) Unleaded premium decreased from 20 to 17% of pool. Includes 74 MBPCD of lt naphtha/natural gasoline rejection.
(3) Average value of oxygenates under cost based on a Gulf Coast MTBE price of 93.6¢/G, or 18.1¢/G above unleaded regular.
(4) Oxygenate decrease of 58 MBPCD.
(5) To 7,079 MBPCD total motor gasolines.
(6) To 6,738 MBPCD total motor gasolines.
(7) Heavy crude value under cost.
(8) Also includes a reduction in distillate fuels of 187 MBPCD and a residual fuels increase of 312 MBPCD, from a crude substitution of 1,226 MBPCD.

TABLE B-1

U.S. SUPPLY AND DEMAND

1984 ACTUAL - MBPCD(1)

NPC STUDY - DOE/PSA DATA

	Supply				Demand		
	Field Production	Imports	Inventory and Adjustments	Refinery Production	Refinery Input	Exports	Production
Crudes							
Domestic	8,879	-	-	-	8,698	181	-
Foreign	-	3,426	(16)	-	3,346	-	64
[Total Crudes]	[8,879]	[3,426]	[(16)]	[-]	[12,044]	[181]	[64]
Products - NGL/Unfinished							
Natural Gasoline	292	46	3	-	209	3	129
Ethane	505	67	4	20	2	5	589
Propane	527	67	(8)	281	4	30	833
Normal Butane	203	37	18	62	167	10	143
Iso-Butane	99	24	5	-	118	3	7
Unfinished	-	231	41	-	422	-	(150)
Mogas Components	-	83	(3)	-	115	-	(35)
Oxygenates and Other	45	-	-	-	45	-	-
[Total - NGL/Unf. Prod.]	[1,671]	[555]	[60]	[363]	[1,082]	[51]	[1,516]
Products - Finished							
Leaded Gasolines	-	135	6	2,570	-	6	2,705
Unleaded Gasolines	-	164	(60)	3,883	-	-	3,987
[Total Gasolines]	[-]	[299]	[(54)]	[6,453]	[-]	[6]	[6,692]
Aviation Gasolines	-	-	(1)	25	-	-	24
Naphtha Jet	-	14	(1)	213	-	3	223
Kero Jet/Kerosene	-	60	(19)	1,034	-	7	1,068
Distillate Fuels	1	272	(57)	2,680	-	51	2,845
Residual Fuels							
<0.3% Sulfur	-	272	-	73	-	-	345
0.3-1.0% Sulfur	-	132	(1)	273	-	-	404
>1.0% Sulfur	-	277	(11)	545	-	190	621
[Total Residual Fuels]	[-]	[681]	[(12)]	[891]	[-]	[190]	[1,370]
Petrochem Naphtha	-	33	-	117	-	6	144
Petrochem Gas Oil and C. Black	-	-	1	234	-	15	220
Special Naphtha/Misc.	2	65	(1)	112	-	3	175
Lube	-	13	(1)	159	-	15	156
Wax	-	1	-	15	-	1	15
Marketable Coke - FOE	-	-	1	260	-	193	68
Catalytic Coke - FOE	-	-	-	179	-	-	179
Asphalt/Road Oil	-	18	5	386	-	1	408
Process Gas - FOE	-	-	-	559	-	-	559
[Total - Finished Prods.]	[3]	[1,456]	[(139)]	[13,317]	[-]	[491]	[14,146]
Total Crude and Products	10,553	5,437	(95)	13,680	13,126	723	15,726
(Gain)/Loss	-	-	-	(554)	-	-	-

(1) Rates may be off from DOE/PSA data by 1 MBPCD due to DOE independent round-off and our forced fit with Table 1-2 and the other "B" tables.

TABLE B-2

REFINERY RAW MATERIALS INPUT RATES

ESTIMATED ACTUAL 1984 AVERAGE(1) - MBPCD

NPC STUDY

	IC	IS	IIDC	IILC	IIS	IIIDC	IIILC	IIIS	IV	VCOC	VCC	VS	U.S. Total	VCLA
Domestic Crudes	100	45	1,739	481	36	3,014	664	225	402	364	1,321	307	8,698	742
Foreign Crudes	878	83	368	126	11	1,146	456	31	34	57	152	4	3,346	99
	978	128	2,107	607	47	4,160	1,120	256	436	421	1,473	311	12,044	841
Natural Gasoline	-	1	45	8	1	95	34	12	5	-	6	2	209	6
Reformate - 95 RONC(2)	10	6	17	1	-	31	39	8	1	(7)	3	6	115	11
Naphtha	17	-	2	11	-	60	18	20	(2)	-	-	-	126	35
Vacuum Gas Oil	107	(3)	6	23	(8)	114	43	-	-	5	65	(25)	327	15
Vacuum Resid.	(4)	-	(2)	(11)	-	(30)	(9)	-	(5)	1	6	-	(54)	-
Normal Butane	2	-	49	13	-	57	19	-	9	7	9	2	167	4
Iso-Butane	3	-	34	11	-	53	8	-	2	2	5	-	118	4
MTBE	-	-	-	-	-	8	4	-	-	-	-	-	12	-
Ethanol	-	-	2	-	-	-	-	-	-	-	-	-	2	-
Methanol	1	-	-	-	-	2	-	-	-	-	-	-	3	-
TBA	3	-	-	-	-	5	-	-	-	-	-	-	8	-
Propane	-	-	3	-	-	3	-	-	-	-	-	-	6	-
Nat. Gas Fd. to H_2 - FOE	1	-	2	-	-	21	-	-	-	2	17	-	43	3
Total Input	1,118	132	2,265	663	40	4,579	1,276	296	446	431	1,584	296	13,126	919

(1) Uses DOE data for totals of raw material groups (Table B-1) and NPC survey plus other sources for breakdown into group components.
(2) Estimated representation for all net gasoline components.

TABLE B-3

REFINERY PRODUCT RATES DETAIL

ESTIMATED ACTUAL 1984 AVERAGE(1) - MBPCD

NPC STUDY

	IC	IS	IIDC	IILC	IIS	IIIDC	IIILC	IIIS	IV	VCOC	VCC	VS	U.S. Total	VCLA
Motor Gasolines														
Leaded Regular	168	16	570	150	2	829	250	41	127	94	251	23	2,521	147
Leaded Premium	-	-	1	-	-	-	1	-	7	4	33	3	49	22
Unleaded Regular	288	4	634	182	1	1,034	252	16	91	61	369	17	2,949	235
Unleaded Premium	111	-	106	39	-	416	83	3	8	28	137	3	934	75
Total	567	20	1,311	371	3	2,279	586	60	233	187	790	46	6,453	479
Aviation Gasolines	-	-	2	1	-	12	2	-	1	1	6	-	25	3
Naphtha Jet	17	5	15	4	13	47	15	34	15	-	37	11	213	21
Kero Jet/Kerosene	42	1	108	56	-	451	83	15	24	64	168	22	1,034	92
Distillate Fuels	251	30	531	113	9	957	232	56	118	83	232	68	2,680	136
Residual Fuels														
<0.3% Sulfur	20	1	1	2	1	17	4	7	3	4	6	7	73	4
0.3-0.7% Sulfur	23	-	-	2	2	8	3	-	-	23	25	9	95	5
0.7-1.0% Sulfur	41	11	7	5	1	49	10	23	2	-	3	26	178	-
1.0-2.0% Sulfur	6	-	22	13	-	24	19	1	3	49	109	28	274	65
>2.0% Sulfur	19	-	8	5	2	63	116	-	2	-	41	15	271	15
Total	109	12	38	27	6	161	152	31	10	76	184	85	891	89
Asphalt/Road Oil	42	43	61	54	5	35	41	21	24	1	17	42	386	3
Marketable Coke - FOE	13	-	55	-	-	99	-	-	2	9	81	1	260	56
Benzene	1	-	2	1	-	17	6	1	-	-	-	-	28	-
Toluene	5	-	9	-	-	29	5	-	-	-	-	-	48	-
Xylene	-	-	10	-	-	39	6	-	-	-	-	-	55	-
Spcl. Naph./Misc.	8	4	17	1	2	(1)	10	40	2	-	13	2	98	2
Lubes	8	12	21	4	1	60	20	21	1	-	9	2	159	2
Wax	-	2	1	1	-	3	1	4	1	-	2	-	15	-
Petrochem Gas Oil	-	-	-	-	-	117	68	1	-	-	-	8	194	-
Carbon Black Feed	-	-	-	4	-	21	13	-	-	-	2	-	40	6
Normal Butane	6	-	(4)	-	-	53	(4)	2	(2)	2	9	-	62	5
Propane	33	-	60	19	-	108	23	1	5	5	27	-	281	14
Process Gas/Ethane	52	1	91	20	-	225	44	10	15	15	101	5	579	62
Catalytic Coke - FOE	23	-	36	9	-	67	14	-	7	5	18	-	179	10
(Gain)/Loss	(59)	2	(99)	(22)	1	(200)	(41)	(1)	(10)	(17)	(112)	4	(554)	(61)
Total Products	1,118	132	2,265	663	40	4,579	1,276	296	446	431	1,584	296	13,126	919

(1) Uses DOE data for total of product groups (Table B-1) and NPC survey plus other sources for breakdown into group components.

TABLE B-4

REFINERY DOMESTIC CRUDE INPUT RATES DETAIL

ESTIMATED 1984 AVERAGE(1) - MBPCD

NPC STUDY

Location/Name	LP Code	Type	IC	IS	IIDC	IILC	IIS	IIIDC	IIILC	IIIS	IV	VCOC	VCC	VS	Total U.S.	VCLA
AL Heavy	ALH	MH	-	-	-	-	-	31	-	-	-	-	-	-	31	-
Light	ALL	S	-	-	10	-	-	-	-	13	-	-	-	-	23	-
AK Cook	AKC	S	-	-	-	-	-	-	-	-	-	19	13	14	46	6
North Slope	ANS	MH	75	-	54	8	26	279	18	-	-	305	646	120	1,531	316
AZ Sweet	AZS	S	-	-	-	-	-	1	-	-	-	-	-	-	1	-
AR Heavy	ARH	HH	-	-	-	-	-	-	41	10	-	-	-	-	51	-
CA Beta	CBT	HH	-	-	-	-	-	-	-	-	-	-	17	-	17	17
Elk Hills	CEH	S	-	-	40	-	-	44	-	-	-	-	22	44	150	1
Huntington Beach	CHB	HH	-	-	-	-	-	-	-	-	-	-	23	-	23	23
Hondo	CAH	HH	13	4	-	-	-	34	-	-	-	-	-	17	68	-
LA Basin Light	CLL	HH	-	-	-	-	-	-	-	-	-	-	3	32	35	3
San Ardo	CSA	HH	-	-	-	-	-	-	-	-	-	-	71	-	71	25
SJV Light	CJL	HH	-	-	-	-	-	-	-	-	-	-	46	53	99	40
SJV Kern River	CJH	HH	-	-	-	-	-	-	14	-	-	-	96	22	132	64
SJV Heavy	CVH	HH	-	-	-	-	-	47	27	-	-	-	228	-	302	91
Ventura	CCV	HH	-	-	-	-	-	-	13	-	-	40	-	-	53	-
Wilmington Heavy	CWH	HH	-	-	-	-	-	-	-	-	-	-	100	-	100	100
Wilmington Light	CWL	HH	-	-	-	-	-	-	-	-	-	-	56	-	56	56
CO Rangely	COR	S	-	-	10	-	-	-	-	-	69	-	-	-	79	-
FL Jay	FLJ	S	-	1	-	9	-	-	29	-	-	-	-	-	39	-
IL Sweet	ILS	S	-	-	39	-	-	-	-	-	-	-	-	-	39	-
Weeks	ILW	S	-	-	-	40	-	-	-	-	-	-	-	-	40	-
IN Sweet	IDS	S	-	-	15	-	-	-	-	-	-	-	-	-	15	-
KS Butler	KSB	S	-	-	-	30	-	-	-	-	-	-	-	-	30	-
Common	KSC	S	-	-	53	-	-	-	-	-	-	-	-	-	53	-
Light	KSL	S	-	-	124	-	-	-	-	-	-	-	-	-	124	-
KY Sweet	KYS	S	-	-	23	-	-	-	-	-	-	-	-	-	23	-
LA Condensate	LAC	S	-	-	-	-	-	67	-	33	-	-	-	-	100	-
Light Sweet	LLS	S	-	-	-	50	-	75	75	-	-	-	-	-	200	-
North Mix	LAM	S	-	-	-	-	-	49	-	30	-	-	-	-	79	-
Heavy Sweet	LAO	S	5	2	250	-	-	771	-	-	-	-	-	-	1,028	-
MI Sweet	MIS	S	-	7	30	20	10	-	-	-	-	-	-	-	67	-
MS Baxterville	MSB	HH	-	-	-	-	-	44	-	14	-	-	-	-	58	-
Light Hey	MSH	HL	-	-	-	-	-	22	-	-	-	-	-	-	22	-
Sweet	MSS	S	-	-	-	-	-	10	-	-	-	-	-	-	10	-
MT Sour	MTS	HH	-	-	10	-	-	-	-	-	10	-	-	-	20	-
Rebeki	MTR	S	-	-	31	-	-	-	-	-	30	-	-	-	61	-
NE Light Sour	NES	ML	-	-	18	-	-	-	-	-	-	-	-	-	18	-
NV Sweet	NVS	S	-	-	-	-	-	-	-	-	-	-	-	5	5	-
NM Intermediate	NMI	S	-	-	39	-	-	-	80	20	-	-	-	-	139	-
Sour	NMS	HL	-	-	-	-	-	78	-	-	-	-	-	-	78	-
NY Lube	NYL	S	-	2	-	-	-	-	-	-	-	-	-	-	2	-
ND Light Sour	NDS	S	-	-	89	37	-	-	-	-	18	-	-	-	144	-
OH/MO Light	OHL	S	-	7	36	-	-	-	-	-	-	-	-	-	43	-
OK Cement	OKM	S	-	-	170	7	-	40	-	-	-	-	-	-	217	-
Condensate	OKC	S	-	-	-	13	-	-	-	-	-	-	-	-	13	-
Garber	OKG	S	-	-	60	87	-	-	-	-	-	-	-	-	147	-
Velma	OKV	HH	-	-	11	72	-	-	-	-	-	-	-	-	83	-
PA Lube	PAL	S	-	12	-	-	-	-	-	-	-	-	-	-	12	-
SD Sweet	SDS	S	-	-	4	-	-	-	-	-	-	-	-	-	4	-
TX Condensate	TXC	S	-	-	-	-	-	-	20	20	-	-	-	-	40	-
East	TXE	S	-	-	100	-	-	98	-	-	-	-	-	-	198	-
Hawkins	TEH	HH	-	-	143	-	-	29	43	-	-	-	-	-	215	-
Gulf Refugio	TGR	S	7	-	-	-	-	498	163	20	-	-	-	-	688	-
West Intermed.	TWI	S	-	-	124	93	-	249	50	65	-	-	-	-	581	-
West Scurry	TWY	S	-	-	50	-	-	-	-	-	-	-	-	-	50	-
West Sour	TWS	HL	-	-	61	15	-	548	76	-	-	-	-	-	700	-
UT Altamont	UTA	S	-	-	-	-	-	-	-	-	30	-	-	-	30	-
Mix	UTM	S	-	-	-	-	-	-	15	-	50	-	-	-	65	-
WV Lube	WVL	S	-	10	-	-	-	-	-	-	-	-	-	-	10	-
WY Platte/Sour	WYP	HH	-	-	145	-	-	-	-	-	62	-	-	-	207	-
Sweet	WYS	S	-	-	-	-	-	-	-	-	133	-	-	-	133	-
Total			100	45	1,739	481	36	3,014	664	225	402	364	1,321	307	8,698	742
Subtotal By Type																
Sweet		S	12	41	1,297	386	10	1,902	432	201	330	19	35	63	4,728	7
Medium Sulfur Light		ML	-	-	18	-	-	-	-	-	-	-	-	-	18	-
Medium Sulfur Heavy		MH	75	-	54	8	26	310	18	-	-	305	646	120	1,562	316
High Sulfur Light		HL	-	-	61	15	-	648	76	-	-	-	-	-	800	-
High Sulfur Heavy		HH	13	4	309	72	-	154	138	24	72	40	640	124	1,590	419

(1) Uses DOE data for state production rates and NPC survey plus other sources for allocations to representative modeled crudes.

TABLE B-5

REFINERY FOREIGN CRUDE INPUT RATES DETAIL

ESTIMATED ACTUAL 1984 AVERAGE(1) - MBPCD

NPC STUDY

Country	Name	LP Code	Type	IC	IS	IIDC	IILC	IIS	IIIDC	IIILC	IIIS	IV	VCOC	VCC	VS	U.S. Total	VCLA
Abu Dhabi/Dubai/Oman/UAE		UAD	HL	5	-	5	-	-	12	47	-	-	-	-	-	69	-
Algeria	Condensate	AGC	S	13	-	3	20	-	53	19	-	-	-	1	-	109	-
	Saharan	AGH	S	55	-	3	2	-	23	4	-	-	-	2	-	89	2
Angola		ANG	S	55	2	-	-	-	18	12	-	-	-	-	-	87	-
Australia		AUS	S	4	-	-	-	-	2	2	-	-	4	13	1	26	12
Cameroon	Kole	CMK	S	22	-	-	2	-	14	6	-	-	-	-	-	44	-
Canada	Condensate	CNC	S	-	-	-	1	-	-	-	-	2	-	-	-	3	-
	Interprov.	CNI	ML	33	-	20	1	2	-	-	-	-	-	-	-	56	-
	Lloydmin.	CNL	HH	7	-	213	12	8	-	-	-	8	-	-	-	248	-
	Rangeland	CNR	ML	-	-	-	-	-	-	-	-	24	18	-	-	42	-
China	Daqing	CHD	S	4	9	-	-	-	3	-	-	-	-	-	-	16	-
Congo	Djeno	CGO	S	11	-	-	-	-	11	12	-	-	-	-	-	34	-
Ecuador	Oriente	ECO	MH	1	-	2	13	-	27	3	-	-	-	1	-	47	1
Egypt	Belayim	EGB	HH	6	-	-	-	-	-	-	-	-	-	-	-	6	-
Gabon	Gamba	GBG	S	7	-	-	-	-	11	1	-	-	-	-	-	19	-
	Lucina	GBL	S	5	-	-	-	-	4	-	-	-	-	-	-	9	-
	Mandji	GBM	HH	5	-	-	-	-	22	5	-	-	-	-	-	32	-
Guatemala		GUT	HH	-	-	-	-	-	3	-	-	-	-	-	-	3	-
India	Bombay	IDB	S	-	-	-	-	-	25	39	-	-	-	4	-	68	2
Indonesia	Attaka	INA	S	-	-	-	-	-	-	-	-	-	-	8	-	8	7
	Condensate	INC	S	-	-	-	-	-	1	-	4	-	9	18	1	33	11
	Heavy	INV	S	2	-	-	-	-	4	1	-	-	1	3	-	11	3
	Minas	INM	S	69	2	-	-	-	52	18	-	-	25	102	-	268	61
Iran	Heavy	IRH	HH	2	-	-	-	-	5	1	-	-	-	-	-	8	-
	Light	IRL	HL	-	-	4	-	-	-	-	-	-	-	-	-	4	-
Iraq	Kirkuk	IQK	HL	-	-	-	-	-	6	6	-	-	-	-	-	12	-
Ivory Coast		ICE	S	-	-	-	-	-	6	-	-	-	-	-	-	6	-
Kuwait		KUW	HH	6	-	2	1	-	17	-	-	-	-	-	-	26	-
Mexico	Blend	MXB	HH	2	-	10	8	-	4	53	-	-	-	-	-	77	-
	Isthmus	MXI	HL	3	-	12	16	-	76	37	-	-	-	-	-	144	-
	Maya	MXM	HH	75	26	45	42	-	137	81	-	-	-	-	-	406	-
Netherlands		NTH	S	-	-	3	-	-	-	-	-	-	-	-	-	3	-
Nigeria	Forcados	NGF	S	11	-	1	3	-	12	10	-	-	-	-	-	37	-
	Light	NGL	S	16	-	1	-	-	37	3	-	-	-	-	-	57	-
	Medium	NGM	S	46	-	2	-	-	53	14	-	-	-	-	-	115	-
Norway	Ekofisk	NWE	S	48	-	1	-	-	32	-	-	-	-	-	-	81	-
	Statfjord	NWS	S	20	-	-	-	-	3	-	-	-	-	-	-	23	-
Saudia Arabia	Heavy	SAH	HH	29	1	1	1	-	108	11	-	-	-	-	-	151	-
	Light	SAL	HL	44	2	6	-	-	25	5	-	-	-	-	-	82	-
	Medium	SAM	HH	1	-	-	-	-	22	39	-	-	-	-	-	62	-
Sharja		SHJ	S	2	-	6	-	-	7	-	-	-	-	-	-	15	-
Trinidad	Light	TDL	S	17	-	16	4	-	54	-	-	-	-	-	-	91	-
United Kingdom	Brent	UKB	S	187	-	11	-	-	71	22	-	-	-	-	-	291	-
	Light	UKL	S	3	-	-	-	-	1	4	-	-	-	-	-	8	-
	Sour	UKS	HL	3	-	-	-	-	6	-	-	-	-	-	-	9	-
Venezuela	Roscan	VZR	HH	-	41	-	-	-	-	-	-	-	-	-	2	43	-
	H. Bach. 14	VZH	HH	34	-	-	-	1	151	-	27	-	-	-	-	213	-
	Lagomedia	VZL	HH	3	-	1	-	-	5	-	-	-	-	-	-	9	-
	T.Juana Med.	VZT	HH	3	-	-	-	-	11	-	-	-	-	-	-	14	-
Zaire		ZAR	S	19	-	-	-	-	12	1	-	-	-	-	-	32	-
Total				878	83	368	126	11	1,146	456	31	34	57	152	4	3,346	99
Subtotal by Type																	
Sweet			S	616	13	47	32	-	509	168	4	2	39	151	2	1,583	98
Medium Sulfur Light			ML	33	-	20	1	2	-	-	-	24	18	-	-	98	-
Medium Sulfur Heavy			MH	1	-	2	13	-	27	3	-	-	-	1	-	47	1
High Sulfur Light			HL	55	2	27	16	-	125	95	-	-	-	-	-	320	-
High Sulfur Heavy			HH	173	68	272	64	9	485	190	27	8	-	-	2	1,298	-

(1) Uses DOE data for crude imports separated into crude categories according to refining group destinations. DOE data were further broken down by source countries and gravity/sulfur ranges. The NPC survey data and other sources were used to allocate these crude segregations into specific representative modeled crudes.

TABLE B-6

REFINERY PROCESS UNIT CAPACITIES

ESTIMATED 1984 AVERAGE(1)(2) - MBPSD

NPC STUDY

	IC	IS	IIDC	IILC	IIS	IIIDC	IIILC	IIIS	IV	VCOC	VCC	VS	U.S. Total	VCLA
Number of Refineries	11	13	24	12	8	33	14	24	21	6	18	30	214	10
Feed Rate														
Crude - Atmospheric	1,296.5	358.8	2,632.9	836.1	63.7	5,411.3	1,657.7	444.7	595.5	481.6	2,191.1	569.6	16,539.5	1,231.2
Crude - Vacuum	615.9	184.8	984.0	329.0	5.9	2,261.4	670.7	128.1	199.1	190.5	1,197.3	177.0	6,943.7	629.0
Catalytic Cracking	581.6	-	989.6	293.5	-	1,974.7	515.6	-	190.9	113.5	583.3	-	5,242.7	353.3
Hydrocracking	74.0	4.4	112.2	44.5	-	317.7	30.0	-	10.9	55.0	348.3	-	997.0	145.1
Coking - Delayed	35.3	-	274.4	-	-	532.0	-	-	17.3	51.5	328.3	-	1,238.8	276.8
Coking - Fluid	49.0	-	-	-	-	14.8	-	-	11.8	-	89.3	-	164.9	-
Combined	84.3	-	274.4	-	-	546.8	-	-	29.1	51.5	417.6	-	1,403.7	276.8
Combined Coke - FOE	31.5	-	71.7	-	-	177.2	-	-	10.4	12.7	95.0	-	398.5	69.4
Thermal Cracking	-	-	-	3.8	-	14.6	55.0	-	-	-	-	17.2	90.6	-
Visbreaking	13.0	-	6.7	-	-	47.5	22.5	2.0	-	-	45.8	6.4	143.9	33.8
Total	13.0	-	6.7	3.8	-	62.1	77.5	2.0	-	-	45.8	23.6	234.5	33.8
Solvent Deasphalting	16.0	6.4	41.6	-	-	136.0	33.2	7.1	17.7	7.4	50.0	-	315.4	-
Catalytic Reforming														
Low Pressure	118.8	-	358.9	135.4	-	837.3	176.3	0.6	40.6	31.8	203.0	3.0	1,905.7	74.0
High Pressure	237.0	30.0	295.2	111.8	2.0	480.6	160.0	46.2	75.6	76.5	299.6	42.6	1,857.1	212.7
Total	355.8	30.0	654.1	247.2	2.0	1,317.9	336.3	46.8	116.2	108.3	502.6	45.6	3,762.8	286.7
Hydrotreating														
Naphtha	406.9	29.3	710.5	208.5	1.3	1,218.3	372.9	53.1	143.0	90.0	470.5	38.3	3,742.6	255.5
Distillate	358.3	11.4	307.6	117.4	-	1,138.3	360.3	16.3	69.1	75.0	320.0	16.9	2,790.6	137.0
Heavy Gas Oil	117.0	30.0	197.8	100.7	-	432.7	131.0	27.6	18.5	-	378.0	27.4	1,460.7	127.0
Residuum	-	30.3	-	-	-	226.0	-	-	-	-	24.0	-	280.3	24.0
Product Rate														
Alkylation	68.0	-	181.3	66.1	-	368.8	76.5	-	30.9	29.1	103.2	-	923.9	63.0
Polymerization	12.0	-	14.4	5.0	-	28.8	8.2	-	11.5	1.1	5.6	0.1	86.7	2.4
Isomerization - C5/C6	25.0	-	32.0	8.3	-	68.7	-	1.0	-	-	-	-	135.0	-
Isomerization - C4	-	-	15.3	0.5	-	22.1	10.0	7.2	8.9	4.3	10.9	-	79.2	10.9
Hydrogen - MMCFPSD	96.0	5.0	145.5	28.5	-	803.5	70.5	8.8	23.0	85.6	934.5	5.5	2,206.4	437.0
Hydrogen, FOE - MBPSD	4.9	0.3	7.4	1.4	-	40.9	3.6	0.4	1.2	4.4	47.5	0.3	112.3	22.2
Asphalt	67.0	97.2	142.5	92.9	5.6	99.9	63.0	31.8	37.0	1.3	28.0	101.6	767.8	6.0
Lube	23.3	19.7	29.6	4.6	0.8	91.5	30.5	17.1	1.7	-	16.6	5.1	240.5	-
Aromatics	12.5	2.7	39.3	-	-	113.1	32.7	6.2	-	-	4.8	-	211.3	2.8
Hydrodealkylation	1.8	-	5.5	-	-	19.7	3.1	-	-	-	-	-	30.1	-

(1) Operable capacity average for 1/1/84 and 1/1/85.
(2) Based primarily on DOE data; supplemented with data from NPC survey, the Oil & Gas Journal and other sources.

TABLE B-7

CRUDE UNIT CAPACITIES AND UTILIZATIONS

ESTIMATED 1984 AVERAGES(1)

NPC STUDY

Model	Number of Refineries	Crude Capacity (MBPSD)	Crude Input (MBPCD)	Utilization(2) (%)
IC	11	1,296	978	79.4
IS	13	359	128	37.5
IIDC	24	2,633	2,107	84.2
IILC	12	836	607	76.4
IIS	8	64	47	77.3
IIIDC	33	5,411	4,160	80.9
IIILC	14	1,658	1,120	71.1
IIIS	24	445	256	60.6
IV	21	595	436	77.1
VCOC	6	482	421	91.9
VCC	18	2,191	1,473	70.8
VS	30	570	311	57.4
U.S. Total	214	16,540	12,044	76.6
VCLA	10	1,231	841	71.9
Subtotal by Type				
Simple	75	1,438	742	54.3
Conversion(3)	139	15,102	11,302	78.8

(1) Based primarily on DOE data (from Tables B-2 and B-6).
(2) Utilization of operable calendar day capacity assuming 95% stream factor.
(3) Includes five simple refineries in PADD IV with a capacity of 31 MBPSD.

TABLE B-8

REFINERY PROCESS UNIT UTILIZATIONS

1984 CALIBRATION CASE RESULTS - %(1)

NPC STUDY

	IC	IIDC	IILC	IIIDC	IIILC	IV	VCOC	VCC	Combined Simple(7)	U.S. Total	VCLA
Crude - Atmospheric	79.4	84.2	76.4	80.9	71.1	77.1	91.9	70.8	54.3	76.6	71.9
- Vacuum	71.5	90.5	67.4	75.0	65.0	83.5	106.7(4)	73.0	47	74.3	80.0
Catalytic Cracking(2)	86.8#	92.3*	86.7#	85.2#	76.7#	85.7	94.8*(4)	91.2#	-	N/A	95.4*(4)
Catalytic Cracking(3)	81.8	89.6	82.5	79.6	73.0	84.1	97.8(4)	91.0	-	83.1	93.7
Conversion, %	76.7	73.0	72.8	74.6	72.3	74.2	73.5	64.6	-	72.9	64.4
Hydrocracking	85.0	93.0*	84.8	92.6*	90.5	83.8*	92.5*	92.1*	92 *	91.4	97.4*(4)
Jet Yield, % of Maximum	87.9	0	100.0*	100.0*	100.0*	100.0*	86.3	40.3	N/A	65.5	66.3
Coking - Delayed(2)	91.5*	83.0	-	89.7#	-	49.2	91.9	95.4*(4)	-	N/A	88.6
- Delayed(3)	91.5	83.0	-	89.7	-	49.2	79.9	90.8	-	87.6	88.6
- Fluid	30.3	-	-	84.8#	-	0	-	61.8	-	50.1	-
- Combined(3)	55.9	83.0	-	89.6	-	29.2	79.9	84.6	-	83.2	88.6
Combined Coke	43.3	83.3	-	60.7	-	20.9	77.0	92.7	N/A(5)	70.5	87.7
Th. Crk./Vis. Brk.	92.0*	93.4*	0	15.8	28.0	-	-	94.0*	54	45.5	93.3*
Solvent Deasphalting	89.7*	44.6	-	16.8	91.7*	40.5	88.1*	0	54	34.0	-
Catalytic Reforming											
Low Pressure(2)	86.6*	81.4*	81.9*	77.5*	86.3*	56.2*	91.3*	92.5*	N/A	N/A	92.5*
RONC	99.5	96.6	95.7	97.1	98.7	94.3	96.7	96.8	N/A	N/A	94.3
High Pressure(2)	49.4	61.5	9.6	51.3	44.5	37.1	92.1*	56.7	N/A	N/A	80.2
RONC	98.0	93.6	90.0	93.8	94.7	87.1	99.5	99.4	N/A	N/A	99.6
Combined(3)	54.6	71.5	51.9	67.3	63.9	45.8	76.8*	64.0	N/A	N/A	69.7
Adjusted Combined(3)(6)	60.4	76.9	54.3	74.1	69.4	53.4	89.1	66.1	68	70.1	73.9
RONC	96.4	94.0	94.2	94.2	94.9	88.0	95.0	97.1	93	94.6	96.4
Hydrotreating											
Naphtha	39.6	56.3	57.9	62.3	54.0	36.2	68.4	33.6	61	53.1	62.7
Distillate	52.2	92.4*	59.7	53.2	62.6	58.9	46.5	71.1	54	60.9	49.5
Heavy Gas Oil	53.3	92.3*	88.1#	91.2#	86.0#	92.5*	-	92.7*	54	85.9	92.4*
Residuum	-	-	-	0	-	-	-	0	54	5.8	0
Alkylation	75.9	83.2	60.9	63.6	79.9	87.1	58.2	62.7	-	70.0	71.5
Polymerization	6.2	15.8	0	7.1	0	2.8	0	0	0	6.2	0
Isomerization - C5/C6	0.0*	85.6*	92.7*	62.7*	-	-	-	-	54	58.3	-
- C4	-	0	0	0	3.2	29.8	0	0	54	8.7	0
Hydrogen	73.2#	81.1#	82.0#	78.9#	80.3#	83.7#	80.0#	79.5#	80	79.2	81.8#
Asphalt	66.5	45.8	62.0	37.0	69.0	67.6	83.8	62.1	51	53.6	54.3
Lubes	37.3	77.1	94.4	71.3	71.3	64.5	-	58.9	92 *	71.9	N/A(5)
Aromatics	52.2	53.0	N/A(5)	81.7	56.5	-	-	0	12	67.4	0
Hydrodealkylation	0	0	-	49.3	93.3*	-	-	-	-	41.9	-

* Limited at maximum throughput in LP run. Some unit maximums set below real limits to balance utilizations of similar units and to calibrate.
\# Limited at minimum throughput in LP run.
- = No unit; 0 = Unit not operating; N/A = Not applicable or not available.
(1) Utilizations assume a 95% stream factor for crude units and a 92% stream factor for all other units.
(2) Utilization includes effects of non-unitary capacity factors for some feedstocks and severities.
(3) Alternate utilization is based on actual feed rates, ignoring severity effects. Comparable to survey.
(4) High utilizations (above 94.5%) indicated errors in reported capacity or abnormally low shutdown time.
(5) Reported production with no reported capacity.
(6) Combined actual feed plus naphtha bypassed in the model which we deemed fed to the reformers in the survey results.
(7) Estimated from survey and atmospheric crude unit utilizations.

TABLE B-9

REFINERY PROCESS UNIT UTILIZATIONS

1984 CALIBRATION CASE RESULTS - MBPCD

NPC STUDY

	IC	IIDC	IILC	IIIDC	IIILC	IV	VCOC	VCC	Combined Simple	U.S. Total	VCLA
Feed Rate											
Crude - Atmospheric	978	2,107	607	4,160	1,120	436	421	1,473	742	12,044	841
- Vacuum	418	846	211	1,611	414	158	193	830	221	4,902	478
Catalytic Cracking(1)	438	816	223	1,446	346	148	102	488	-	4,007	305
Conversion(2)	336	595	162	1,079	250	110	75	315	-	2,922	196
Hydrocracking	58	96	35	271	25	8	47	295	4	839	130
Jet Yield	27	0	18	143	13	4	21	61	N/A	287	44
Coking - Delayed(1)	30	210	-	439	-	8	38	274	-	999	226
- Fluid	14	-	-	12	-	0	-	51	-	77	-
- Combined(1)	44	210	-	451	-	8	38	325	-	1,076	226
Combined Coke - FOE	13	55	-	99	-	2	9	81	1	260	56
Th. Crk./Vis. Brk.	11	6	0	9	20	-	-	40	13	99	29
Solvent Deasphalting	13	17	-	21	28	7	6	0	7	99	-
Catalytic Reforming											
Adjusted Combined(1)(3)	198	463	123	898	215	57	89	306	78	2,427	195
Hydrotreating											
Naphtha	148	368	111	698	185	48	57	145	68	1,828	147
Distillate	172	261	64	558	208	37	32	209	22	1,563	62
Heavy Gas Oil	57	168	82	363	104	16	-	322	42	1,154	108
Residuum	-	-	-	0	-	-	-	0	15	15	0
Product Rate											
Alkylation	47	139	37	216	56	25	16	60	-	596	41
Polymerization	1	2	0	2	0	0	0	0	0	5	0
Isomerization - C5/C6	0	25	7	40	-	-	-	-	0	72	-
- C4	-	0	0	0	0	2	0	0	4	6	0
Hydrogen - FOE	3	6	1	30	3	1	3	35	1	83	17
Asphalt	41	60	53	34	40	23	1	16	111	379	3
Lubes	8	21	4	60	20	1	-	9	36	159	2
Aromatics	6	21	1	85	17	-	-	0	1	131	0
Hydrodealkylation	0	0	-	9	3	-	-	-	-	12	-

- = No unit; 0 = Unit not operating; N/A = Not applicable.
(1) Based on actual feed rate, ignoring severity effects.
(2) Fresh feed times percent conversion divided by 100.
(3) Combined actual feed plus naphtha bypassed in the model which we deemed fed to the reformers in survey results.

TABLE B-10

REFINERY INCREMENTAL OCTANE COSTS

1984 CALIBRATION CASE RESULTS

NPC STUDY

(Cents/Barrel/Octane Number)

Model	Incremental Octane Costs[1]
IC	26
IIDC	29
IILC	13
IIIDC	20
IIILC	20
IV	14
VCOC	17
VCC	16
U.S. Average[2]	21
VCLA	14

(1) Shadow values determined by models based on stock costs and variable operating costs.
(2) Weighted average of conversion refineries only.

TABLE B-11

PRICING BASIS

1984 CALIBRATION RUNS

1984-85 SPOT CARGO

NPC STUDY

	PADD I	PADD II	PADD III	PADD IV	PADD V
Major Products(1)					
Unleaded Reg. Gasoline, ¢/G	77.0	76.5	75.5	78.5	80.5
Distillate Fuel, ¢/G	75.5	73.5	72.5	75.5	74.0
Residual Fuel (Bunker) $/B	26.00	25.00	25.00	22.00	25.00
Major Crudes(2), $/B					
Domestic					
West Texas Intermediate			28.50		
West Texas Sour			26.90		
Alaska North Slope	27.70		27.50		26.50
California Kern River			26.00		23.00
Foreign					
U.K. Brent	28.40		28.50		
Saudi Arabia Light	29.10		29.20		
Saudi Arabia Heavy	27.90		28.00		
Nigeria Medium	28.70		28.80		
Other					
Process Gas, $/B - FOE	20.00	20.00	20.00	20.00	30.00

(1) Average 7/84-6/85 Platt's P/L cargo lows for clean products and waterborne cargo lows for bunker in PADD III. OPIS L.A. P/L lows for clean products in PADD V. All Platt's waterborne cargo lows in PADD I.
(2) Calculated average 7/84-6/85 delivered spot crude costs from Platt's. Some estimated.

TABLE B-12

REFINERY ENERGY CONSUMPTION RATES

ESTIMATED ACTUAL 1984 AVERAGE - MBPCD - FOE

NPC STUDY - DOE DATA(1)

	IC	IS	IIDC	IILC	IIS	IIIDC	IIILC	IIIS	IV	VCOC	VCC	VS	U.S. Total	VCLA
Produced(2)														
Crude	-	-	-	-	0.2	0.2	-	-	-	-	-	-	0.4	-
Distillate Fuels	1.6	0.3	0.1	0.1	0.1	0.1	0.1	-	-	-	0.9	0.4	3.7	0.9
Residual Fuels	10.8	2.2	9.0	10.4	0.1	3.6	3.3	0.1	2.7	3.9	3.9	1.4	51.4	-
Propane	0.4	0.5	3.3	0.1	0.1	1.0	1.7	0.1	0.7	0.5	5.3	0.1	13.8	3.1
Process Gas	44.0	5.0	90.4	22.8	0.1	189.8	40.0	4.4	16.6	15.4	91.7	5.0	525.2	54.2
Marketable Coke	3.5	-	-	-	-	-	-	-	-	-	1.8	-	5.3	-
Catalytic Coke	22.6	0.6	35.7	9.2	-	66.9	14.6	-	6.7	5.1	18.0	-	179.4	10.2
Total Produced	82.9	8.6	138.5	42.6	0.6	261.6	59.7	4.6	26.7	24.9	121.6	6.9	779.2	68.4
Purchased														
Natural Gas	8.8	2.9	20.3	8.5	0.7	129.3	30.7	4.1	6.1	3.6	30.3	3.4	248.7	12.4
Coal	-	1.5	0.7	-	-	1.2	-	-	-	-	-	-	3.4	-
Power	9.0	1.6	21.6	7.5	0.6	39.4	9.7	5.6	4.6	4.3	21.9	1.7	127.5	11.3
Steam	5.5	-	0.4	-	-	5.3	-	0.3	-	-	4.2	0.2	15.9	-
Total Purchased	23.3	6.0	43.0	16.0	1.3	175.2	40.4	10.0	10.7	7.9	56.4	5.3	395.5	23.7
Total Energy	106.2	14.6	181.5	58.6	1.9	436.8	100.1	14.6	37.4	32.8	178.0	12.2	1,174.7	92.1

(1) Converted to equivalent MBPCD-FOE.
(2) Refinery produced energy consumption rates are included in gross refinery product rates shown in Table B-3. This is consistent with DOE reporting in the PSA.

TABLE B-13

REFINERY PRODUCT RATES SUMMARY

1984 ACTUAL - MBPCD

NPC STUDY - DOE/PSA DATA

	PADD I	PADD II	PADD III	PADD IV	PADD V	U.S. Total
Motor Gasolines	587	1,685	2,925	233	1,023	6,453
Naphtha Jet	22	32	96	15	48	213
Kerosene Jet	35	140	474	23	248	920
Distillate Fuels	281	653	1,245	118	383	2,680
Residual Fuels	121	71	344	10	345	891
LPG(1)	34	(35)	63	(8)	18	72
Other(2)	83	335	631	55	265	1,369
Total(2)	1,163	2,881	5,778	446	2,330	12,598

(1) PADD III includes 18 MBPCD of ethane shown in process gas on Table B-3.
(2) Other and total refinery products rates are net from crude, including refinery gain.

TABLE B-14

NET SHIPMENT OF PRODUCTS TO OTHER PADDS

1984 ACTUAL - MBPCD

NPC STUDY - DOE/PSA DATA(1)

	PADD I	PADD II	PADD III	PADD IV	PADD V	U.S. Total
Motor Gasolines	(1,364)	(490)	1,913	1	(60)	0
Naphtha Jet	(10)	(2)	17	5	(10)	0
Kerosene Jet	(294)	(70)	390	(17)	(9)	0
Distillate Fuels	(546)	(184)	737	9	(16)	0
Residual Fuels	(27)	6	22	-	(1)	0
LPG	(87)	(86)	132	41	-	0
Other	(88)	(51)	135	7	(3)	0
Total	(2,416)	(877)	3,346	46	(99)	0

(1) Net shipments = Refinery product rates (Table B-13) plus product import rates (Table B-15) plus natural gas plant production (Table B-17) plus inventory reduction (not tabulated) minus product demands (Table 1-2) minus product export rates (Table B-16).

TABLE B-15

PRODUCT IMPORT RATES SUMMARY

1984 ACTUAL - MBPCD

NPC STUDY - DOE/PSA DATA

	PADD I	PADD II	PADD III	PADD IV	PADD V	U.S. Total
Motor Gasolines	254	4	18	2	21	299
Naphtha Jet	9	0	5	0	0	14
Kerosene Jet	40	0	0	0	8	48
Distillate Fuels	251	8	3	4	6	272
Residual Fuels	598	6	64	0	13	681
LPG	19	134	13	15	14	195
Other	174	25	251	4	48	502
Total	1,345	177	354	25	110	2,011

TABLE B-16

PRODUCT EXPORT RATES SUMMARY

1984 ACTUAL(1) - MBPCD

NPC STUDY - DOE/PSA DATA

	PADD I	PADD II	PADD III	PADD IV	PADD V	U.S. Total
Motor Gasolines	1	0	3	0	2	6
Naphtha Jet	0	1	2	0	0	3
Kerosene Jet	1	0	3	0	2	6
Distillate Fuels	3	0	17	0	31	51
Residual Fuels	3	0	81	0	106	190
LPG	1	15	26	0	6	48
Other	15	14	123	0	86	238
Total	24	30	255	0	233	542

(1) Rates in 1988 forecasts are the same as these 1984 rates.

TABLE B-17

NATURAL GAS PROCESSING PLANT PRODUCTION SUMMARY(1)

1984 ACTUAL - MBPCD

NPC STUDY - DOE/PSA DATA

	PADD I	PADD II	PADD III	PADD IV	PADD V	U.S. Total
LPG(2)	26	288	937	64	19	1,334
Other(3)	6	53	224	28	26	337
Total(4)	32	341	1,161	92	45	1,671

(1) Includes other hydrocarbon and alcohol production.
(2) Rates in MBPCD in 1988 forecasts are less as follows by PADDs: II = 5, III = 15, IV = 1; U.S. Total = 21.
(3) Rates in 1988 forecasts are the same as 1984 rates.
(4) Excludes finished products production in 1984 only of 3 MBPCD which occurred in PADD III.

TABLE C-1

U.S. SUPPLY AND DEMAND FORECAST

1988 LOW DEMAND CASE RESULTS - MBPCD

NPC STUDY

	Supply			Demand		
	Field Production	Imports	Refinery Production	Refinery Input	Exports	Demand Products
Crudes						
Domestic	8,260	-	-	8,017	243	-
Foreign	-	3,184	-	3,184	-	-
[Total Crudes]	[8,260]	[3,184]	[-]	[11,201]	[243]	[-]
Products - NGL/Unfin.						
Natural Gasoline	287	50	-	139	3	195
Ethane	497	17	16	-	5	525
Propane	519	6	253	5	30	743
Normal Butane	200	133	51	246	10	128
Iso-Butane	97	17	-	105	3	6
Unfinished	-	253	-	261	-	(8)
Mogas Components	-	91	-	91	-	-
Oxygenates and Other	50	-	-	50	-	-
[Total - NGL/Unf. Prd.]	[1,650]	[567]	[320]	[897]	[51]	[1,589]
Products - Finished						
Motor Gasolines	-	578	5,531	-	6	6,103
Aviation Gasolines	-	-	40	-	-	40
Naphtha Jet	-	35	214	-	3	246
Kero Jet/Kerosene	-	120	959	-	7	1,072
Distillate Fuels	-	372	2,543	-	51	2,864
Residual Fuels						
<0.3% Sulfur	-	208	51	-	-	259
0.3-1.0% Sulfur	-	142	209	-	-	351
>1.0% Sulfur	-	287	608	-	190	705
[Total Residual Fuels]	[-]	[637]	[868]	[-]	[190]	[1,315]
Petrochem Naphtha	-	138	166	-	6	298
P/Chem Gas Oil + C. Black	-	47	289	-	15	321
Special Naphtha/Misc.	-	71	138	-	3	206
Lube and Wax	-	15	181	-	16	180
Marketable Coke - FOE	-	-	202	-	193	9
Catalytic Coke - FOE	-	-	167	-	-	167
Asphalt/Road Oil	-	20	450	-	1	469
Process Gas - FOE	-	-	513	-	-	513
[Total Finished Prods.]	[-]	[2,033]	[12,261]	[-]	[491]	[13,803]
Total Crudes and Products	9,910	5,784	12,581	12,098	785	15,392
(Gain)/Loss	-	-	(483)	-	-	-

TABLE C-2

REFINERY RAW MATERIALS INPUT RATES DETAIL

FORECAST 1988 LOW DEMAND CASE RESULTS - MBPCD

NPC STUDY

	IC	IS	IIDC	IILC	IIS	IIIDC	IIILC	IIIS	IV	VCOC	VCC	VS	U.S. Total
Domestic Crudes	158	36	1,491	259	25	3,047	508	198	394	364	1,252	285	8,017
Foreign Crudes	793	66	581	240	8	743	491	27	31	59	141	4	3,184
Total Crudes	951	102	2,072	499	33	3,790	999	225	425	423	1,393	289	11,201
Natural Gasoline	-	-	32	6	-	71	25	-	1	-	4	-	139
Reformate - 95 RONC	8	-	14	1	-	26	32	8	1	(6)	3	4	91
Naphtha	9	-	1	6	-	36	10	11	(1)	(2)	-	-	70
Vacuum Gas Oil	69	(6)	4	15	(6)	75	31	-	-	3	42	(32)	195
Vacuum Resid.	(3)	-	(1)	(7)	-	(21)	(6)	-	(4)	1	4	-	(37)
Normal Butane	15	-	60	19	-	85	29	-	13	15	9	1	246
Iso-Butane	1	-	36	9	-	47	9	-	1	1	1	-	105
MTBE	3	1	2	-	-	9	4	3	-	-	-	2	24
Ethanol	-	-	2	2	-	1	-	-	-	1	1	-	7
Methanol	1	-	-	-	-	1	-	-	-	-	-	-	2
TBA	2	-	-	-	-	5	-	-	-	-	-	-	7
Propane	-	-	3	-	-	2	-	-	-	-	-	-	5
Nat. Gas Fd. to H_2 - FOE	1	-	2	-	-	21	-	-	-	2	17	-	43
Total Input	1,057	97	2,227	550	27	4,148	1,133	247	436	438	1,474	264	12,098

TABLE C-3

REFINERY PRODUCT RATES DETAIL

FORECAST 1988 LOW DEMAND CASE RESULTS - MBPCD

NPC STUDY

	IC	IS	IIDC	IILC	IIS	IIIDC	IIILC	IIIS	IV	VCOC	VCC	VS	U.S. Total
Motor Gasolines													
Low Lead Regular	69	-	205	41	-	306	73	-	64	34	109	-	901
Unleaded Regular	336	7	846	199	2	1,130	312	50	134	97	373	37	3,523
Unleaded Premium	119	-	158	38	-	447	86	-	14	47	198	-	1,107
Total	524	7	1,209	278	2	1,883	471	50	212	178	680	37	5,531
Aviation Gasolines	-	-	3	2	-	18	3	-	2	2	10	-	40
Naphtha Jet	20	5	17	4	9	44	16	30	15	11	34	9	214
Kero Jet/Kerosene	40	1	120	45	-	371	75	13	23	52	200	19	959
Distillate Fuels	248	23	520	93	6	901	228	50	107	92	210	65	2,543
Residual Fuels													
<0.3% Sulfur	14	-	1	1	1	11	3	6	2	3	4	5	51
0.3-0.7% Sulfur	24	-	-	3	1	20	1	-	2	13	8	6	78
0.7-1.0% Sulfur	29	5	5	8	1	28	13	18	4	-	1	19	131
1.0-2.0% Sulfur	9	-	27	4	-	74	15	1	4	68	136	21	359
>2.0% Sulfur	17	-	8	9	1	56	102	-	3	-	42	11	249
Total	93	5	41	25	4	189	134	25	15	84	191	62	868
Asphalt/Road Oil	55	36	81	60	3	42	50	20	32	1	21	49	450
Marketable Coke - FOE	12	-	54	-	-	63	-	-	2	6	65	-	202
Benzene	1	-	5	1	-	15	6	-	-	-	-	-	28
Toluene	6	-	8	-	-	29	5	-	-	-	-	-	48
Xylene	-	-	9	-	-	41	5	-	-	-	-	-	55
Spcl. Naph./Misc.	5	4	18	1	1	-	25	22	2	-	13	2	93
Petrochem Naphtha	17	3	18	10	-	-	12	-	4	6	6	4	80
Lubes	13	9	23	4	1	68	22	13	1	-	10	2	166
Wax	-	1	1	1	-	4	1	3	1	-	3	-	15
Petrochem Gas Oil	(31)	-	-	-	-	236	30	8	-	-	-	6	249
Carbon Black Feed	-	-	-	4	-	21	13	-	-	-	2	-	40
Normal Butane	5	-	(4)	-	-	45	(3)	1	(2)	2	7	-	51
Propane	33	-	65	18	-	77	21	-	7	4	28	-	253
Process Gas/Ethane	49	1	101	14	-	204	37	10	18	11	79	5	529
Catalytic Coke - FOE	24	-	36	7	-	48	13	-	7	5	27	-	167
(Gain)/Loss	(57)	2	(98)	(17)	1	(151)	(31)	2	(10)	(16)	(112)	4	(483)
Total Products	1,057	97	2,227	550	27	4,148	1,133	247	436	438	1,474	264	12,098

TABLE C-4

REFINERY DOMESTIC CRUDE INPUT RATES DETAIL

FORECAST 1988 LOW DEMAND CASE RESULTS - MBPCD

NPC STUDY

Location/Name	LP Code	Type	IC	IS	IIDC	IILC	IIS	IIIDC	IIILC	IIIS	IV	VCOC	VCC	VS	Total U.S.
AL Heavy	ALH	MH	-	-	-	-	-	28	-	-	-	-	-	-	28
Light	ALL	S	-	-	9	-	-	-	-	12	-	-	-	-	21
AK Cook	AKC	S	-	-	-	-	-	-	-	-	-	13	9	13	35
North Slope	ANS	MH	88	-	248	18	18	408	36	-	-	271	477	111	1,675
AZ Sweet	AZS	S	-	-	-	-	-	1	-	-	-	-	-	-	1
AR Heavy	ARH	HH	-	-	-	-	-	-	38	8	-	-	-	-	46
CA Beta	CBT	HH	-	-	-	-	-	-	-	-	-	-	18	-	18
Elk Hills	CEH	S	-	-	40	-	-	44	-	-	-	-	33	41	158
Huntington Beach	CHB	HH	-	-	-	-	-	-	-	-	-	-	24	-	24
Hondo	CAH	HH	13	4	-	-	-	39	-	-	-	-	-	15	71
LA Basin Light	CLL	HH	-	-	-	-	-	-	-	-	-	-	11	26	37
San Ardo	CSA	HH	-	-	-	-	-	-	-	-	-	-	75	-	75
SJV Light	CJL	HH	-	-	-	-	-	-	-	-	-	-	51	53	104
SJV Kern River	CJH	HH	-	-	-	-	-	-	-	-	-	14	104	21	139
SJV Heavy	CVH	HH	-	-	-	-	-	-	1	-	-	26	286	-	313
Ventura	CCV	HH	-	-	-	-	-	-	16	-	-	40	-	-	56
Wilmington Heavy	CWH	HH	-	-	-	-	-	-	-	-	-	-	105	-	105
Wilmington Light	CWL	HH	-	-	-	-	-	-	-	-	-	-	59	-	59
CO Rangely	COR	S	-	-	5	-	-	-	-	-	59	-	-	-	64
FL Jay	FLJ	S	-	1	-	7	-	-	25	-	-	-	-	-	33
IL Sweet	ILS	S	-	-	32	-	-	-	-	-	-	-	-	-	32
Weeks	ILW	S	-	-	-	33	-	-	-	-	-	-	-	-	33
IN Sweet	IDS	S	-	-	12	-	-	-	-	-	-	-	-	-	12
KS Butler	KSB	S	-	-	-	21	-	-	-	-	-	-	-	-	21
Common	KSC	S	-	-	36	-	-	-	-	-	-	-	-	-	36
Light	KSL	S	-	-	85	-	-	-	-	-	-	-	-	-	85
KY Sweet	KYS	S	-	-	16	-	-	-	-	-	-	-	-	-	16
LA Condensate	LAC	S	-	-	-	-	-	60	-	30	-	-	-	-	90
Light Sweet	LLS	S	45	-	-	-	-	68	67	-	-	-	-	-	180
North Mix	LAM	S	-	-	-	-	-	44	-	27	-	-	-	-	71
Heavy Sweet	LAO	S	5	1	225	-	-	694	-	-	-	-	-	-	925
MI Sweet	MIS	S	-	5	18	16	7	-	-	-	-	-	-	-	46
MS Baxterville	MSB	HH	-	-	-	-	-	39	-	13	-	-	-	-	52
Light Hey	MSH	HL	-	-	-	-	-	20	-	-	-	-	-	-	20
Sweet	MSS	S	-	-	-	-	-	9	-	-	-	-	-	-	9
MT Sour	MTS	HH	-	-	5	-	-	-	-	-	11	-	-	-	16
Rebeki	MTR	S	-	-	20	-	-	-	-	-	29	-	-	-	49
NE Light Sour	NES	ML	-	-	12	-	-	-	-	-	-	-	-	-	12
NV Sweet	NVS	S	-	-	-	-	-	-	-	-	-	-	-	5	5
NM Intermediate	NMI	S	-	-	32	-	-	-	75	18	-	-	-	-	125
Sour	NMS	HL	-	-	-	-	-	70	-	-	-	-	-	-	70
NY Lube	NYL	S	-	2	-	-	-	-	-	-	-	-	-	-	2
ND Light Sour	NDS	S	-	-	56	24	-	-	-	-	18	-	-	-	98
OH/MO Light	OHL	S	-	5	30	-	-	-	-	-	-	-	-	-	35
OK Cement	OKM	S	-	-	117	5	-	27	-	-	-	-	-	-	149
Condensate	OKC	S	-	-	-	9	-	-	-	-	-	-	-	-	9
Garber	OKG	S	-	-	41	60	-	-	-	-	-	-	-	-	101
Velma	OKV	HH	-	-	8	49	-	-	-	-	-	-	-	-	57
PA Lube	PAL	S	-	10	-	-	-	-	-	-	-	-	-	-	10
SD Sweet	SDS	S	-	-	3	-	-	-	-	-	-	-	-	-	3
TX Condensate	TXC	S	-	-	-	-	-	-	21	15	-	-	-	-	36
East	TXE	S	-	-	90	-	-	88	-	-	-	-	-	-	178
Hawkins	TEH	HH	-	-	88	-	-	66	39	-	-	-	-	-	193
Gulf Refugio	TGR	S	7	-	-	-	-	544	53	15	-	-	-	-	619
West Intermed.	TWI	S	-	-	96	3	-	307	57	60	-	-	-	-	523
West Scurry	TWY	S	-	-	45	-	-	-	-	-	-	-	-	-	45
West Sour	TWS	HL	-	-	56	14	-	491	68	-	-	-	-	-	629
UT Altamont	UTA	S	-	-	-	-	-	-	-	-	25	-	-	-	25
Mix	UTM	S	-	-	-	-	-	-	12	-	41	-	-	-	53
WV Lube	WVL	S	-	8	-	-	-	-	-	-	-	-	-	-	8
WY Platte/Sour	WYP	HH	-	-	63	-	-	-	-	-	106	-	-	-	169
Sweet	WYS	S	-	-	3	-	-	-	-	-	105	-	-	-	108
Total			158	36	1,491	259	25	3,047	508	198	394	364	1,252	285	8,017
Subtotal By Type															
Sweet		S	57	32	1,011	178	7	1,886	310	177	277	13	42	59	4,049
Medium Sulfur Light		ML	-	-	12	-	-	-	-	-	-	-	-	-	12
Medium Sulfur Heavy		MH	88	-	248	18	18	436	36	-	-	271	477	111	1,703
High Sulfur Light		HL	-	-	56	14	-	581	68	-	-	-	-	-	719
High Sulfur Heavy		HH	13	4	164	49	-	144	94	21	117	80	733	115	1,534

TABLE C-5

REFINERY FOREIGN CRUDE INPUT RATES DETAIL

FORECAST 1988 LOW DEMAND CASE RESULTS - MBPCD

NPC STUDY

Country	Name	LP Code	Type	IC	IS	IIDC	IILC	IIS	IIIDC	IIILC	IIIS	IV	VCOC	VCC	VS	U.S. Total
Abu Dhabi/Dubai/Oman/UAE		UAD	HL	5	-	5	-	-	12	47	-	-	-	-	-	69
Algeria	Condensate	AGC	S	-	-	-	-	-	-	-	-	-	-	1	-	1
	Saharan	AGH	S	34	3	-	-	-	-	-	-	-	-	2	-	39
Angola		ANG	S	74	1	-	-	-	-	12	-	-	-	-	-	87
Australia		AUS	S	4	-	-	-	-	2	2	-	-	4	13	1	26
Cameroon	Kole	CMK	S	38	-	-	-	-	-	6	-	-	-	-	-	44
Canada	Condensate	CNC	S	-	-	-	-	-	-	-	-	3	-	-	-	3
	Interprov.	CNI	ML	10	-	46	1	1	-	-	-	-	-	-	-	58
	Lloydmin.	CNL	HH	7	-	215	12	6	-	-	-	8	-	-	-	248
	Rangeland	CNR	ML	-	-	-	-	-	-	-	-	20	20	-		40
China	Daqing	CHD	S	4	9	-	-	-	3	-	-	-	-	-	-	16
Congo	Djeno	CGD	S	34	-	-	-	-	-	-	-	-	-	-	-	34
Ecuador	Oriente	ECO	MH	1	-	2	13	-	27	3	-	-	-	1	-	47
Egypt	Belayim	EGB	HH	6	-	-	-	-	-	-	-	-	-	-	-	6
Gabon	Gamba	GBG	S	18	-	-	-	-	-	1	-	-	-	-	-	19
	Lucina	GBL	S	5	-	-	-	-	4	-	-	-	-	-	-	9
	Mandji	GBM	HH	5	-	-	-	-	22	5	-	-	-	-	-	32
Guatemala		GUT	HH	-	-	-	-	-	3	-	-	-	-	-	-	3
India	Bombay	IDB	S	64	-	-	-	-	-	-	-	-	-	4	-	68
Indonesia	Attaka	INA	S	-	-	-	-	-	-	-	-	-	-	8	-	8
	Condensate	INC	S	-	-	-	-	-	-	-	3	-	9	18	1	31
	Heavy	INV	S	2	-	-	-	-	-	1	-	-	1	3	-	7
	Minas	INM	S	20	1	-	-	-	-	18	-	-	25	91	-	155
Iran	Heavy	IRH	HH	2	-	-	-	-	5	1	-	-	-	-	-	8
	Light	IRL	HL	-	-	4	-	-	-	-	-	-	-	-	-	4
Iraq	Kirkuk	IQK	HL	-	-	-	-	-	6	6	-	-	-	-	-	12
Ivory Coast		ICE	S	-	-	-	-	-	6	-	-	-	-	-	-	6
Kuwait		KUW	HH	6	-	2	1	-	17	-	-	-	-	-	-	26
Mexico	Blend	MXB	HH	2	-	10	8	-	4	53	-	-	-	-	-	77
	Isthmus	MXI	HL	3	-	24	10	-	70	37	-	-	-	-	-	144
	Maya	MXM	HH	75	18	100	35	-	97	81	-	-	-	-	-	406
Netherlands		NTH	S	3	-	-	-	-	-	-	-	-	-	-	-	3
Nigeria	Forcados	NGF	S	-	-	-	-	-	-	-	-	-	-	-	-	-
	Light	NGL	S	-	-	-	-	-	-	-	-	-	-	-	-	-
	Medium	NGM	S	76	-	-	-	-	-	34	-	-	-	-	-	110
Norway	Ekofisk	NWE	S	-	-	-	-	-	-	-	-	-	-	-	-	-
	Statfjord	NWS	S	-	-	-	-	-	3	-	-	-	-	-	-	3
Saudia Arabia	Heavy	SAH	HH	25	-	21	125	-	49	83	-	-	-	-	-	303
	Light	SAL	HL	100	2	83	31	-	195	75	-	-	-	-	-	486
	Medium	SAM	HH	1	-	22	-	-	-	25	-	-	-	-	-	48
Sharja		SHJ	S	8	-	-	-	-	7	-	-	-	-	-	-	15
Trinidad	Light	TDL	S	17	-	46	4	-	24	-	-	-	-	-	-	91
United Kingdom	Brent	UKB	S	70	5	-	-	-	-	-	-	-	-	-	-	75
	Light	UKL	S	-	-	-	-	-	-	-	-	-	-	-	-	-
	Sour	UKS	HL	3	-	-	-	-	3	-	-	-	-	-	-	6
Venezuela	Boscan	VZB	HH	-	27	-	-	-	14	-	-	-	-	-	2	43
	H. Bach. 14	VZH	HH	34	-	-	-	1	154	-	24	-	-	-	-	213
	Lagomedia	VZL	HH	3	-	1	-	-	5	-	-	-	-	-	-	9
	T.Juana Med.	VZT	HH	3	-	-	-	-	11	-	-	-	-	-	-	14
Zaire		ZAR	S	31	-	-	-	-	-	1	-	-	-	-	-	32
Total				793	66	581	240	8	743	491	27	31	59	141	4	3,184
Subtotal by Type																
Sweet			S	502	19	46	4	-	49	75	3	3	39	140	2	882
Medium Sulfur Light			ML	10	-	46	1	1	-	-	-	20	20	-	-	98
Medium Sulfur Heavy			MH	1	-	2	13	-	27	3	-	-	-	1	-	47
High Sulfur Light			HL	111	2	116	41	-	286	165	-	-	-	-	-	721
High Sulfur Heavy			HH	169	45	371	181	7	381	248	24	8	-	-	2	1,436

TABLE C-6

REFINERY PROCESS UNIT CAPACITIES

1988 LOW DEMAND CASE - MBPSD

NPC STUDY

	IC	IS	IIDC	IILC	IIS	IIIDC	IIILC	IIIS	IV	VCOC	VCC	VS	U.S. Total
Number of Refineries	10	9	23	8	5	28	12	17	18	6	16	25	177
Feed Rate													
Crude - Atmospheric	1,226.0	146.0	2,508.4	656.3	47.3	4,782.5	1,381.1	321.9	565.8	512.0	1,963.3	484.8	14,595.4
Crude - Vacuum	602.4	57.3	975.3	277.7	6.1	2,120.8	645.4	75.5	189.2	194.0	1,164.8	171.5	6,480.0
Catalytic Cracking	574.3	-	983.0	234.0	-	1,717.3	496.2	-	190.9	114.5	577.0	-	4,887.2
Hydrocracking	74.0	4.4	113.4	44.5	-	367.7	30.0	-	4.9	65.5	353.2	-	1,057.6
Coking - Delayed	35.0	-	281.4	-	-	489.6	-	-	8.5	59.0	325.5	-	1,199.0
Coking - Fluid	54.0	-	-	-	-	49.0	-	-	16.5	-	86.5	-	206.0
Combined	89.0	-	281.4	-	-	538.6	-	-	25.0	59.0	412.0	-	1,405.0
Combined Coke - FOE	33.5	-	78.0	-	-	170.1	-	-	10.1	14.9	92.2	-	398.8
Thermal Cracking	-	-	-	-	-	14.6	55.0	-	-	-	-	17.2	86.8
Visbreaking	13.0	-	6.6	-	-	36.0	22.5	-	-	-	45.8	5.0	128.9
Total	13.0	-	6.6	-	-	50.6	77.5	-	-	-	45.8	22.2	215.7
Solvent Deasphalting	16.0	7.0	36.4	-	-	123.2	28.2	7.1	17.7	7.4	50.0	-	293.0
Catalytic Reforming													
Low Pressure	118.8	-	339.3	133.5	-	764.4	187.5	-	39.5	31.8	204.0	6.0	1,824.8
High Pressure	232.1	11.7	277.8	60.5	3.0	436.5	142.8	45.0	71.8	78.0	289.9	36.1	1,685.2
Total	350.9	11.7	617.1	194.0	3.0	1,200.9	330.3	45.0	111.3	109.8	493.9	42.1	3,510.0
Hydrotreating													
Naphtha	403.8	14.5	705.9	160.5	1.3	1,169.1	342.4	53.1	157.8	91.5	463.0	38.4	3,601.3
Distillate	343.0	1.3	326.6	106.4	-	1,074.5	382.5	12.0	67.0	76.0	315.9	16.4	2,721.6
Heavy Gas Oil	117.0	-	230.5	100.7	-	453.3	138.0	27.6	18.5	-	444.6	25.0	1,555.2
Residuum	-	0.5	-	-	-	176.0	-	-	-	-	24.0	-	200.5
Product Rate													
Alkylation	70.3	-	189.2	54.7	-	359.7	76.3	-	31.7	29.1	102.7	-	913.7
Polymerization	15.0	-	16.1	2.5	-	25.2	7.4	-	11.7	1.1	5.6	0.1	84.7
Isomerization - C5/C6	25.0	1.1	85.7	14.9	-	106.4	31.0	2.0	3.9	-	16.7	2.7	289.4
Isomerization - C4	-	-	24.3	-	-	10.1	10.0	2.0	8.4	4.4	17.2	-	76.4
Hydrogen - MMCFPSD	96.0	5.0	159.0	-	-	838.0	71.0	8.8	19.0	107.8	923.0	-	2,227.6
Hydrogen, FOE - MBPSD	4.9	0.3	8.1	-	-	42.6	3.6	0.4	1.0	5.5	47.0	-	113.4
Asphalt	67.0	26.6	137.8	87.9	3.2	90.4	54.1	12.6	36.0	1.3	26.0	98.0	640.9
Lube	20.0	20.2	29.6	4.6	-	91.6	30.9	17.2	1.5	-	21.1	5.3	242.0
Aromatics	12.7	-	42.2	-	-	112.9	32.7	6.2	-	-	3.5	-	210.2
Hydrodealkylation	1.8	-	6.1	-	-	20.2	-	-	-	-	-	-	28.1

TABLE C-7

CRUDE UNIT CAPACITIES AND UTILIZATIONS

FORECAST 1988 LOW DEMAND CASE RESULTS

NPC STUDY

Model	Number of Refineries	Crude Capacity (MBPSD)	Crude Input (MBPCD)	Utilization[1] (%)
IC	10	1,226	951	81.7
IS	9	146	102	73.4
IIDC	23	2,508	2,072	87.0
IILC	8	656	499	80.1
IIS	5	47	33	73.9
IIIDC	28	4,783	3,790	83.4
IIILC	12	1,381	999	76.1
IIIS	17	322	225	73.6
IV	18	566	425	79.0
VCOC	6	512	423	87.0
VCC	16	1,963	1,393	74.7
VS	25	485	289	62.7
U.S. Total	177	14,595	11,201	80.8
Subtotal by Type				
Simple	56	1,000	649	64.9
Conversion[2]	121	13,595	10,552	81.7

(1) Utilization of operable calendar day capacity assuming 95% stream factor.
(2) Includes two simple refineries in PADD IV with a capacity of 18 MBPSD.

TABLE C-8

REFINERY PROCESS UNIT UTILIZATIONS

1988 LOW DEMAND CASE RESULTS - %(1)

NPC STUDY

	IC	IIDC	IILC	IIIDC	IIILC	IV	VCOC	VCC
Crude - Atmospheric	81.7	87.0	80.1	83.4	76.1	79.0	87.0	74.7
- Vacuum	73.4	92.7	78.2	73.1	64.6	92.3	106.1(4)	73.0
Catalytic Cracking(2)	84.8	92.3*	80.2	74.4	61.3	87.9	92.3*	88.6
Conversion, %	77.6	76.5	73.5	74.4	76.1	74.1	70.6	77.2
Hydrocracking	92.5*	92.6*	91.8*	92.7*	91.3*	91.8*	92.6*	92.6*
Jet Yield, % of Maximum	87.7	33.0	100.0*	100.0*	100.0*	100.0*	85.7	100.0*
Coking - Delayed(2)	36.9	79.5	-	62.6	-	92.1*	53.1	74.3
- Fluid	56.4	-	-	0	-	0	-	60.3
Coke	37.3	75.2	-	40.1	-	19.6	42.5	76.1
Th. Crk./Vis. Brk.	92.0*	90.9*	-	62.6	16.9	-	-	91.1*
Solvent Deasphalting	92.4*	92.7*	-	51.7	92.5*	72.7	92.5*	93.9*
Catalytic Reforming								
Low Pressure(2)	92.4	92.1*	74.4	92.4*	92.5*	92.6*	92.3*	92.1*
RONC	99.2	98.4	93.7	99.5	97.3	99.7	100.0	97.5
High Pressure(2)	43.6	75.6	0	62.5	18.7	38.6	92.8*	40.6
RONC	97.5	95.2	-	96.5	95.0	94.7	98.8	99.2
Combined(3)	54.5	80.0	55.5	77.7	61.5	54.5	77.3*	57.0
RONC	98.4	97.2	93.7	98.8	97.0	97.7	99.2	98.0
Hydrotreating								
Naphtha	38.6	58.8	55.8	64.1	50.1	38.0	59.3	29.7
Distillate	50.1	58.3	34.1	53.7	45.4	57.5	27.1	45.3
Heavy Gas Oil	47.4	87.9	88.1	92.0	85.1	92.0*	-	74.3
Residuum	-	-	-	92.3*	-	-	-	94.2*
Alkylation	82.6	92.3	72.8	66.5	89.9	87.3	82.5	93.1*
Polymerization	0	0	0	0	0	40.1	0	0
Isomerization - C5/C6	33.0*	77.6	62.2	92.4*	92.6*	92.3*	-	92.4*
- C4	-	0	-	0	92.6*	50.1	42.4	24.7
Hydrogen	82.1	80.2	-	81.4	79.7	86.1	81.8	81.4
Asphalt	87.6	62.3	71.7	48.1	96.4(4)	93.6	83.8	83.6
Lubes	70.7	84.5	94.5	80.7	77.4	73.0	-	51.5
Aromatics	59.9	56.6	N/A(5)	81.8	53.2	-	-	0
Hydrodealkylation	0	41.4	-	53.3	-	-	-	-

* Limited at maximum throughput in LP run.
- = No unit; 0 = Unit not operating;N/A = Not applicable.
(1) Utilizations assume a 95% stream factor for crude units and a 92% stream factor for all other units.
(2) Utilization includes effects of non-unitary capacity factors for some feedstocks and severities.
(3) Alternate utilization is based on actual feed rates, ignoring severity effects.
(4) High utilizations (above 95%) indicate errors in reported capacity (calibration) or minor process with little impact on results.
(5) Reported production with no reported capacity - same as calibration case.

TABLE C-10

NEW PROCESS UNITS CAPACITY REQUIRED

AND INCREMENTAL OCTANE COST RESULTS

FORECAST 1988 LOW DEMAND CASE

NPC STUDY

	IC	IIDC	IILC	IIIDC	IIILC	IV	VCOC	VCC	U.S. Total/ Average(1)
New Capacity - MBPSD									
Crude - Vacuum	-	-	-	-	-	-	7.6	-	7.6
Incremental Octane Costs(2) - ¢/B/O.N.									
Pool Average	27	24	15	33	29	25	27	17	27

(1) Total new capacity. Weighted average octane costs for conversion refineries only.
(2) Shadow values determined by models based on stock costs and variable operating costs.

TABLE C-11

PRICING BASIS

1988 LOW REFINERY SUPPLY CASE

BASED ON 1984-85 SPOT CARGO - ADJUSTED

NPC STUDY

	PADD				
	I	II	III	IV	V
Major Products[1]					
Unleaded Reg. Gasoline, ¢/G	77.0	76.5	75.5	78.5	80.5
Distillate Fuel, ¢/G	75.5	73.5	72.5	75.5	74.0
Residual Fuel (Bunker), $/B	26.00	25.00	25.00	22.00	25.00
Major Crudes[2], $/B					
Domestic					
West Texas Intermediate			28.50		
West Texas Sour			26.90		
Alaska North Slope	27.70		27.50		26.50
California Kern River			26.00		23.00
Foreign					
U.K. Brent	28.40		28.50		
Saudi Arabia Light[3]	27.75		27.85		
Saudi Arabia Heavy[3]	26.80		26.90		
Algeria Saharan	28.20		28.30		
Indonesia Minas	28.80		28.90		28.40
Nigeria Medium	28.70		28.80		
Other					
MTBE, ¢/G	95.6	94.6	93.6	104.6	98.6
Iso-Butane, ¢/G	69.0	56.0	56.0	54.0	69.0
N. Butane, ¢/G	53.5	53.5	53.5	51.5	53.5
Propane, ¢/G	47.5	38.0	38.0	36.0	49.5
Process Gas, $/B - FOE	20.00	20.00	20.00	20.00	30.00
Coke, <3%S, $/ST	20.00	20.00	20.00	20.00	20.00

(1) Average 7/84-6/85 Platt's P/L cargo lows for clean products and waterborne cargo lows for bunker in PADD III. OPIS L.A. P/L lows for clean products in PADD V. All Platt's waterborne cargo lows in PADD I.
(2) Calculated average 7/84-6/85 delivered spot crude costs from Platt's. Some estimated.
(3) Estimated based on WTS, Maya, high resid demands.

TABLE C-12

REFINERY ENERGY CONSUMPTION RATES

1988 LOW DEMAND CASE RESULTS - MBPCD - FOE

NPC STUDY

	IC	IS	IIDC	IILC	IIS	IIIDC	IIILC	IIIS	IV	VCOC	VCC	VS	U.S. Total
Produced(1)													
Distillate Fuels	1.5	0.2	-	-	0.2	-	-	-	-	-	0.9	0.4	3.2
Residual Fuels	9.8	1.8	8.7	3.4	0.1	2.5	2.9	0.1	2.3	3.9	4.3	1.2	41.0
Propane	0.5	0.4	5.3	0.3	0.1	1.7	2.5	0.1	0.9	0.9	7.8	0.1	20.6
Process Gas	40.9	4.0	99.6	14.1	0.1	175.3	33.5	3.7	18.1	11.6	69.9	4.5	475.3
Marketable Coke	3.2	-	-	-	-	-	-	-	-	-	1.6	-	4.8
Catalytic Coke	24.0	0.5	36.1	6.8	-	48.1	12.7	-	7.4	4.8	26.6	-	167.0
Total Produced	79.9	6.9	149.7	24.6	0.5	227.6	51.6	3.9	28.7	21.2	111.1	6.2	711.9
Purchased													
Natural Gas	11.8	3.5	13.7	18.4	0.5	135.0	32.6	3.4	6.0	8.1	36.5	3.0	272.5
Power	9.1	1.3	22.2	6.8	0.4	40.8	9.3	4.7	4.9	4.7	21.5	1.5	127.2
Steam	5.5	-	0.4	-	-	5.3	-	0.3	-	-	4.2	0.2	15.9
Total Purchased	26.4	4.8	36.3	25.2	0.9	181.1	41.9	8.4	10.9	12.8	62.2	4.7	415.6
Total Energy	106.3	11.7	186.0	49.8	1.4	408.7	93.5	12.3	39.6	34.0	173.3	10.9	1,127.5

(1) Refinery produced energy consumption rates are included in gross refinery product rates shown in Table C-3.

TABLE C-13

REFINERY PRODUCT RATES SUMMARY

FORECAST 1988 LOW DEMAND CASE RESULTS - MBPCD

NPC STUDY

	PADD I	PADD II	PADD III	PADD IV	PADD V	U.S. Total
Motor Gasolines	531	1,489	2,404	212	895	5,531
Naphtha Jet	25	30	90	15	54	214
Kerosene Jet	24	146	397	22	266	855
Distillate Fuels	271	619	1,179	107	367	2,543
Residual Fuels	98	70	348	15	337	868
LPG(1)	22	(48)	(15)	(9)	14	(36)
Other(2)	137	412	791	73	296	1,709
Total(2)	1,108	2,718	5,194	435	2,229	11,684

(1) PADD III includes 16 MBPD of ethane shown in process gas on Table C-3.
(2) Other and total refinery products rates are net from crude, including refinery gain.

TABLE C-14

NET SHIPMENT OF PRODUCTS TO OTHER PADDS

FORECAST 1988 LOW DEMAND CASE RESULTS(1) - MBPCD

NPC STUDY

	PADD I	PADD II	PADD III	PADD IV	PADD V	U.S. Total
Motor Gasolines	(1,065)	(413)	1,501	8	(31)	0
Naphtha Jet	12	2	(12)	9	(11)	0
Kerosene Jet	(265)	(22)	295	(4)	(4)	0
Distillate Fuels	(465)	(213)	686	3	(11)	0
Residual Fuels	(64)	(10)	68	4	2	0
LPG	(72)	(48)	111	32	(23)	0
Other	(138)	(209)	419	26	(98)	0
Total	(2,057)	(913)	3,068	78	(176)	0

(1) Net shipments = Refinery product rates (Table C-13) plus product import rates (Table C-15) plus natural gas plant production (Table B-17) minus product demands (Table 1-6) minus product export rates (Table B-16). Assumes 1988 low demand case rates are the same as 1984 actual rates for product exports (Table B-16) and natural gas plant production (Table B-17).

TABLE C-15

PRODUCT IMPORT RATES SUMMARY

1988 LOW DEMAND CASE RESULTS - MBPCD

NPC STUDY

	PADD I	PADD II	PADD III	PADD IV	PADD V	U.S. Total
Motor Gasolines	535	3	1	2	37	578
Naphtha Jet	28	7	0	0	0	35
Kerosene Jet	108	0	0	1	11	120
Distillate Fuels	339	8	13	4	8	372
Residual Fuels	549	5	69	0	14	637
LPG	27	122	11	6	7	173
Other	230	28	376	3	48	685
Total	1,816	173	470	16	125	2,600

TABLE D-1

U.S. SUPPLY AND DEMAND FORECAST

1988 HIGH DEMAND CASE RESULTS - MBPCD

NPC STUDY

	Supply			Demand		
	Field Production	Imports	Refinery Production	Refinery Input	Exports	Demand Products
Crudes						
Domestic	8,260	-	-	8,017	243	-
Foreign	-	5,161	-	5,161	-	-
[Total Crudes]	[8,260]	[5,161]	[-]	[13,178]	[243]	[-]
Products - NGL/Unfin.						
Natural Gasoline	287	46	-	125	3	205
Ethane	497	42	21	-	5	555
Propane	519	4	297	6	30	784
Normal Butane	200	117	73	246	10	134
Iso-Butane	97	22	-	109	3	7
Unfinished	-	232	-	289	-	(57)
Mogas Components	-	83	-	83	-	-
Oxygenates and Other	50	-	-	50	-	-
[Total - NGL/Unf. Prd.]	[1,650]	[546]	[391]	[908]	[51]	[1,628]
Products - Finished						
Motor Gasolines	-	209	6,302	-	6	6,505
Aviation Gasolines	-	-	50	-	-	50
Naphtha Jet	-	13	236	-	3	246
Kero Jet/Kerosene	-	45	1,184	-	7	1,222
Distillate Fuels	-	286	2,897	-	51	3,132
Residual Fuels						
<0.3% Sulfur	-	269	40	-	-	309
0.3-1.0% Sulfur	-	132	279	-	-	411
>1.0% Sulfur	-	279	741	-	190	830
[Total Residual Fuels]	[-]	[680]	[1,060]	[-]	[190]	[1,550]
Petrochem Naphtha	-	114	199	-	6	307
P/Chem Gas Oil + C. Black	-	-	374	-	15	359
Special Naphtha/Misc.	-	65	148	-	3	210
Lube and Wax	-	14	207	-	16	205
Marketable Coke - FOE	-	-	229	-	193	36
Catalytic Coke - FOE	-	-	191	-	-	191
Asphalt/Road Oil	-	18	533	-	1	550
Process Gas - FOE	-	-	615	-	-	615
[Total Finished Prods.]	[-]	[1,444]	[14,225]	[-]	[491]	[15,178]
Total Crudes and Products	9,910	7,151	14,616	14,086	785	16,806
(Gain)/Loss	-	-	(530)	-	-	-

TABLE D-2

REFINERY RAW MATERIALS INPUT RATES DETAIL

FORECAST 1988 HIGH DEMAND CASE RESULTS - MBPCD

NPC STUDY

	IC	IS	IIDC	IILC	IIS	IIIDC	IIILC	IIIS	IV	VCOC	VCC	VS	U.S. Total	VCLA
Domestic Crudes	100	38	1,345	288	36	3,008	488	236	398	366	1,344	370	8,017	754
Foreign Crudes	971	132	918	374	11	1,670	754	33	68	67	158	5	5,161	106
Total Crudes	1,071	170	2,263	662	47	4,678	1,242	269	466	433	1,502	375	13,178	860
Natural Gasoline	-	-	29	5	-	64	22	-	1	-	4	-	125	4
Reformate - 95 RONC	7	-	12	1	-	22	27	10	1	(5)	2	6	83	18
Naphtha	9	-	1	6	-	34	10	13	(1)	-	-	-	72	20
Vacuum Gas Oil	85	(10)	4	16	(8)	72	31	-	-	3	46	(42)	197	5
Vacuum Resid.	(3)	-	(1)	(8)	-	(23)	(7)	-	(4)	1	4	-	(41)	-
Normal Butane	15	-	62	21	-	85	21	-	14	15	11	2	246	9
Iso-Butane	2	-	36	7	-	57	5	-	1	-	1	-	109	2
MTBE	3	1	1	-	-	22	4	3	-	-	-	2	36	-
Ethanol	-	-	7	2	-	2	-	-	1	1	2	-	15	2
Methanol	1	-	-	-	-	-	1	-	-	-	-	-	2	-
TBA	2	-	-	-	-	3	-	-	-	-	-	-	5	-
Propane	-	-	3	-	-	3	-	-	-	-	-	-	6	-
Nat. Gas Fd. to H_2 - FOE	1	-	3	-	-	26	-	-	-	2	21	-	53	4
Total Input	1,193	161	2,420	712	39	5,045	1,356	295	479	450	1,593	343	14,086	924

TABLE D-3

REFINERY PRODUCT RATES DETAIL

FORECAST 1988 HIGH DEMAND CASE RESULTS - MBPCD

NPC STUDY

	IC	IS	IIDC	IILC	IIS	IIIDC	IIILC	IIIS	IV	VCOC	VCC	VS	U.S. Total	VCLA
Motor Gasolines														
Low Lead Regular	75	-	223	55	-	365	87	-	70	34	118	-	1,027	71
Unleaded Regular	367	12	915	262	3	1,331	372	61	148	97	402	50	4,020	245
Unleaded Premium	130	-	171	51	-	526	103	-	15	46	213	-	1,255	129
Total	672	12	1,309	368	3	2,222	562	61	233	177	733	50	6,302	445
Aviation Gasolines	-	-	4	2	-	24	4	-	2	2	12	-	50	6
Naphtha Jet	19	9	16	5	13	52	17	36	16	11	30	12	236	17
Kero Jet/Kerosene	46	1	133	53	-	495	106	15	27	58	225	25	1,184	108
Distillate Fuels	259	39	563	120	9	1,072	252	60	119	95	225	84	2,897	155
Residual Fuels														
<0.3% Sulfur	17	-	-	-	1	-	7	7	1	-	-	7	40	-
0.3-0.7% Sulfur	18	-	-	12	2	27	1	-	4	16	9	8	97	4
0.7-1.0% Sulfur	52	8	7	12	1	30	18	21	6	-	2	25	182	1
1.0-2.0% Sulfur	1	-	27	10	-	122	21	1	4	75	151	27	439	68
>2.0% Sulfur	20	-	10	-	2	85	123	-	3	-	45	14	302	21
Total	108	8	44	34	6	264	170	29	18	91	207	81	1,060	94
Asphalt/Road Oil	58	61	83	75	5	49	58	24	33	1	23	63	533	4
Marketable Coke - FOE	16	-	52	-	-	88	-	-	2	5	66	-	229	47
Benzene	1	-	6	1	-	25	6	-	-	-	-	-	39	-
Toluene	6	-	8	-	-	33	7	-	-	-	-	-	54	-
Xylene	-	-	9	-	-	40	6	-	-	-	-	-	55	-
Spcl. Naph./Misc.	5	4	18	1	1	-	25	27	2	-	13	2	98	2
Petrochem Naphtha	20	6	15	10	-	19	15	(1)	4	3	6	4	101	4
Lubes	17	15	23	5	1	75	26	15	1	-	11	3	192	3
Wax	-	2	1	1	-	3	1	4	1	-	2	-	15	-
Petrochem Gas Oil	-	-	20	-	-	256	40	10	-	-	-	8	334	-
Carbon Black Feed	-	-	-	4	-	21	13	-	-	-	2	-	40	6
Normal Butane	7	-	(5)	-	-	65	(5)	1	(2)	2	10	-	73	6
Propane	35	-	70	24	-	101	27	-	8	4	28	-	297	15
Process Gas/Ethane	57	1	110	21	-	262	49	12	19	12	87	6	636	58
Catalytic Coke - FOE	24	-	38	10	-	64	16	-	8	5	26	-	191	12
(Gain)/Loss	(57)	3	(97)	(22)	1	(185)	(39)	2	(12)	(16)	(113)	5	(530)	(58)
Total Products	1,193	161	2,420	712	39	5,045	1,356	295	479	450	1,593	343	14,086	924

TABLE D-4

REFINERY DOMESTIC CRUDE INPUT RATES DETAIL

FORECAST 1988 HIGH DEMAND CASE RESULTS - MBPCD

NPC STUDY

	Location/Name	LP Code	Type	IC	IS	IIDC	IILC	IIS	IIIDC	IIILC	IIIS	IV	VCOC	VCC	VS	Total U.S.	VCLA
AL	Heavy	ALH	MH	-	-	-	-	-	28	-	-	-	-	-	-	28	-
	Light	ALL	S	-	-	7	-	-	-	-	14	-	-	-	-	21	-
AK	Cook	AKC	S	-	-	-	-	-	-	-	-	-	9	9	17	35	4
	North Slope	ANS	MH	75	-	56	8	26	459	18	-	-	277	612	144	1,675	316
AZ	Sweet	AZS	S	-	-	-	-	-	1	-	-	-	-	-	-	1	-
AR	Heavy	ARH	HH	-	-	-	-	-	-	36	10	-	-	-	-	46	-
CA	Beta	CBT	HH	-	-	-	-	-	-	-	-	-	-	18	-	18	18
	Elk Hills	CEH	S	-	-	40	-	-	44	-	-	-	-	20	54	158	1
	Huntington Beach	CHB	HH	-	-	-	-	-	-	-	-	-	-	24	-	24	24
	Hondo	CAH	HH	13	4	-	-	-	34	-	-	-	-	-	20	71	-
	LA Basin Light	CLL	HH	-	-	-	-	-	-	-	-	-	-	3	34	37	3
	San Ardo	CSA	HH	-	-	-	-	-	-	-	-	-	-	75	-	75	26
	SJV Light	CJL	HH	-	-	-	-	-	-	-	-	-	-	35	69	104	31
	SJV Kern River	CJH	HH	-	-	-	-	-	-	-	-	-	14	98	27	139	72
	SJV Heavy	CVH	HH	-	-	-	-	-	-	1	-	-	26	286	-	313	95
	Ventura	CCV	HH	-	-	-	-	-	-	16	-	-	40	-	-	56	-
	Wilmington Heavy	CWH	HH	-	-	-	-	-	-	-	-	-	-	105	-	105	105
	Wilmington Light	CWL	HH	-	-	-	-	-	-	-	-	-	-	59	-	59	59
CO	Rangely	COR	S	-	-	5	-	-	-	-	-	59	-	-	-	64	-
FL	Jay	FLJ	S	-	1	-	7	-	-	25	-	-	-	-	-	33	-
IL	Sweet	ILS	S	-	-	32	-	-	-	-	-	-	-	-	-	32	-
	Weeks	ILW	S	-	-	-	33	-	-	-	-	-	-	-	-	33	-
IN	Sweet	IDS	S	-	-	12	-	-	-	-	-	-	-	-	-	12	-
KS	Butler	KSB	S	-	-	-	21	-	-	-	-	-	-	-	-	21	-
	Common	KSC	S	-	-	36	-	-	-	-	-	-	-	-	-	36	-
	Light	KSL	S	-	-	85	-	-	-	-	-	-	-	-	-	85	-
KY	Sweet	KYS	S	-	-	16	-	-	-	-	-	-	-	-	-	16	-
LA	Condensate	LAC	S	-	-	-	-	-	54	-	36	-	-	-	-	90	-
	Light Sweet	LLS	S	-	-	-	45	-	68	67	-	-	-	-	-	180	-
	North Mix	LAM	S	-	-	-	-	-	39	-	32	-	-	-	-	71	-
	Heavy Sweet	LAO	S	5	2	225	-	-	693	-	-	-	-	-	-	925	-
MI	Sweet	MIS	S	-	5	18	13	10	-	-	-	-	-	-	-	46	-
MS	Baxterville	MSB	HH	-	-	-	-	-	37	-	15	-	-	-	-	52	-
	Light Hey	MSH	HL	-	-	-	-	-	20	-	-	-	-	-	-	20	-
	Sweet	MSS	S	-	-	-	-	-	9	-	-	-	-	-	-	9	-
MT	Sour	MTS	HH	-	-	5	-	-	-	-	-	11	-	-	-	16	-
	Rebeki	MTR	S	-	-	24	-	-	-	-	-	25	-	-	-	49	-
NE	Light Sour	NES	ML	-	-	12	-	-	-	-	-	-	-	-	-	12	-
NV	Sweet	NVS	S	-	-	-	-	-	-	-	-	-	-	-	5	5	-
NM	Intermediate	NMI	S	-	-	32	-	-	-	72	21	-	-	-	-	125	-
	Sour	NMS	HL	-	-	-	-	-	70	-	-	-	-	-	-	70	-
NY	Lube	NYL	S	-	2	-	-	-	-	-	-	-	-	-	-	2	-
ND	Light Sour	NDS	S	-	-	56	24	-	-	-	-	18	-	-	-	98	-
OH/MO	Light	OHL	S	-	6	29	-	-	-	-	-	-	-	-	-	35	-
OK	Cement	OKM	S	-	-	117	5	-	27	-	-	-	-	-	-	149	-
	Condensate	OKC	S	-	-	-	9	-	-	-	-	-	-	-	-	9	-
	Garber	OKG	S	-	-	41	60	-	-	-	-	-	-	-	-	101	-
	Velma	OKV	HH	-	-	8	49	-	-	-	-	-	-	-	-	57	-
PA	Lube	PAL	S	-	10	-	-	-	-	-	-	-	-	-	-	10	-
SD	Sweet	SDS	S	-	-	3	-	-	-	-	-	-	-	-	-	3	-
TX	Condensate	TXC	S	-	-	-	-	-	-	18	18	-	-	-	-	36	-
	East	TXE	S	-	-	90	-	-	88	-	-	-	-	-	-	178	-
	Hawkins	TEH	HH	-	-	129	-	-	24	39	-	-	-	-	-	192	-
	Gulf Refugio	TGR	S	7	-	-	-	-	523	71	18	-	-	-	-	619	-
	West Intermed.	TWI	S	-	-	107	-	-	299	45	72	-	-	-	-	523	-
	West Scurry	TWY	S	-	-	45	-	-	-	-	-	-	-	-	-	45	-
	West Sour	TWS	HL	-	-	56	14	-	491	68	-	-	-	-	-	629	-
UT	Altamont	UTA	S	-	-	-	-	-	-	-	-	25	-	-	-	25	-
	Mix	UTM	S	-	-	-	-	-	-	12	-	41	-	-	-	53	-
WV	Lube	WVL	S	-	8	-	-	-	-	-	-	-	-	-	-	8	-
WY	Platte/Sour	WYP	HH	-	-	59	-	-	-	-	-	111	-	-	-	170	-
	Sweet	WYS	S	-	-	-	-	-	-	-	-	108	-	-	-	108	-
	Total			100	38	1,345	288	36	3,008	488	236	398	366	1,344	370	8,017	754
	Subtotal By Type																
	Sweet		S	12	34	1,020	217	10	1,845	310	211	276	9	29	76	4,049	5
	Medium Sulfur Light		ML	-	-	12	-	-	-	-	-	-	-	-	-	12	-
	Medium Sulfur Heavy		MH	75	-	56	8	26	487	18	-	-	277	612	144	1,703	316
	High Sulfur Light		HL	-	-	56	14	-	581	68	-	-	-	-	-	719	-
	High Sulfur Heavy		HH	13	4	201	49	-	95	92	25	122	80	703	150	1,534	433

TABLE D-5

REFINERY FOREIGN CRUDE INPUT RATES DETAIL

FORECAST 1988 HIGH DEMAND CASE RESULTS - MBPCD

NPC STUDY

Country	Name	LP Code	Type	IC	IS	IIDC	IILC	IIS	IIIDC	IIILC	IIIS	IV	VCOC	VCC	VS	U.S. Total	VCLA
Abu Dhabi/Dubai/Oman/UAE		UAD	HL	6	-	-	-	-	103	60	-	-	-	-	-	169	-
Algeria	Condensate	AGC	S	13	-	3	20	-	-	19	-	-	-	1	-	56	-
	Saharan	AGH	S	63	15	96	37	-	-	35	-	-	-	2	-	248	2
Angola		ANG	S	55	2	-	-	-	18	12	-	-	-	-	-	87	-
Australia		AUS	S	4	-	-	-	-	2	2	-	-	4	13	1	26	12
Cameroon	Kole	CMK	S	22	-	-	2	-	14	6	-	-	-	-	-	44	-
Canada	Condensate	CNC	S	-	-	-	1	-	-	-	-	3	-	-	-	4	-
	Interprov.	CNI	ML	37	-	39	1	2	-	-	-	-	-	-	-	79	-
	Lloydmin.	CNL	HH	8	-	235	19	8	-	-	-	9	-	-	-	279	-
	Rangeland	CNR	ML	-	-	-	-	-	-	-	-	56	28	-	-	84	-
China	Daqing	CHD	S	4	9	-	-	-	3	-	-	-	-	-	-	16	-
Congo	Djeno	CGD	S	11	-	-	-	-	11	12	-	-	-	-	-	34	-
Ecuador	Oriente	ECO	MH	1	-	2	13	-	27	3	-	-	-	1	-	47	1
Egypt	Belayim	EGB	HH	6	-	-	-	-	-	-	-	-	-	-	-	6	-
Gabon	Gamba	GBG	S	7	-	-	-	-	11	1	-	-	-	-	-	19	-
	Lucina	GBL	S	5	-	-	-	-	4	-	-	-	-	-	-	9	-
	Mandji	GBM	HH	5	-	-	-	-	22	5	-	-	-	-	-	32	-
Guatemala		GUT	HH	-	-	-	-	-	3	-	-	-	-	-	-	3	-
India	Bombay	IDB	S	-	-	-	-	-	25	39	-	-	-	4	-	68	2
Indonesia	Attaka	INA	S	-	-	-	-	-	-	-	-	-	-	9	-	9	7
	Condensate	INC	S	-	-	-	-	-	1	-	4	-	9	20	2	36	12
	Heavy	INV	S	2	-	-	-	-	7	1	-	-	1	3	-	14	3
	Minas	INM	S	78	3	-	-	-	-	44	-	-	25	105	-	255	67
Iran	Heavy	IRH	HH	2	-	-	-	-	5	1	-	-	-	-	-	8	-
	Light	IRL	HL	-	-	4	-	-	-	-	-	-	-	-	-	4	-
Iraq	Kirkuk	IQK	HL	-	-	-	-	-	6	6	-	-	-	-	-	12	-
Ivory Coast		ICE	S	-	-	-	-	-	6	-	-	-	-	-	-	6	-
Kuwait		KUW	HH	6	-	2	1	-	17	-	-	-	-	-	-	26	-
Mexico	Blend	MXB	HH	2	-	12	9	-	5	61	-	-	-	-	-	89	
	Isthmus	MXI	HL	3	-	15	18	-	88	43	-	-	-	-	-	167	-
	Maya	MXM	HH	85	35	50	46	-	165	90	-	-	-	-	-	471	-
Netherlands		NTH	S	-	-	3	-	-	-	-	-	-	-	-	-	3	-
Nigeria	Forcados	NGF	S	13	-	43	17	-	29	24	-	-	-	-	-	126	-
	Light	NGL	S	18	-	66	-	-	-	7	-	-	-	-	-	91	-
	Medium	NGM	S	2	-	32	-	-	-	-	-	-	-	-	-	34	-
Norway	Ekofisk	NWE	S	48	-	1	-	-	32	-	-	-	-	-	-	81	-
	Statfjord	NWS	S	20	-	-	-	-	3	-	-	-	-	-	-	23	-
Saudia Arabia	Heavy	SAH	HH	115	1	174	149	-	564	135	-	-	-	-	-	1,138	-
	Light	SAL	HL	29	3	43	37	-	235	61	-	-	-	-	-	408	-
	Medium	SAM	HH	1	-	32	-	-	31	48	-	-	-	-	-	112	-
Sharja		SHJ	S	2	-	6	-	-	7	-	-	-	-	-	-	15	-
Trinidad	Light	TDL	S	17	-	16	4	-	54	-	-	-	-	-	-	91	-
United Kingdom	Brent	UKB	S	213	9	43	-	-	-	33	-	-	-	-	-	298	-
	Light	UKL	S	5	-	-	-	-	1	5	-	-	-	-	-	11	-
	Sour	UKS	HL	4	-	-	-	-	8	-	-	-	-	-	-	12	-
Venezuela	Boscan	VZB	HH	-	41	-	-	-	-	-	-	-	-	-	2	43	-
	H. Bach. 14	VZH	HH	34	14	-	-	1	135	-	29	-	-	-	-	213	-
	Lagomedia	VZL	HH	3	-	1	-	-	5	-	-	-	-	-	-	9	-
	T.Juana Med.	VZT	HH	3	-	-	-	-	11	-	-	-	-	-	-	14	-
Zaire		ZAR	S	19	-	-	-	-	12	1	-	-	-	-	-	32	-
Total				971	132	918	374	11	1,670	754	33	68	67	158	5	5,161	106
Subtotal by Type																	
Sweet			S	621	38	309	81	-	240	241	4	3	39	157	3	1,736	105
Medium Sulfur Light			ML	37	-	39	1	2	-	-	-	56	28	-	-	163	-
Medium Sulfur Heavy			MH	1	-	2	13	-	27	3	-	-	-	1	-	47	1
High Sulfur Light			HL	42	3	62	55	-	440	170	-	-	-	-	-	772	-
High Sulfur Heavy			HH	270	91	506	224	9	963	340	29	9	-	-	2	2,443	-

TABLE D-6

REFINERY PROCESS UNIT CAPACITIES

1988 HIGH DEMAND CASE - MBPSD

NPC STUDY

	IC	IS	IIDC	IILC	IIS	IIIDC	IIILC	IIIS	IV	VCOC	VCC	VS	U.S. Total	VCLA
Number of Refineries	10	11	24	12	7	32	14	21	20	6	17	28	202	9
Feed Rate														
Crude - Atmospheric	1,296.0	371.0	2,623.4	826.8	65.8	5,487.5	1,633.9	374.8	590.6	512.0	2,152.8	583.2	16,517.8	1,209.4
Crude - Vacuum	602.4	180.3	985.3	327.7	8.6	2,287.8	673.9	107.5	199.2	194.0	1,187.8	171.5	6,926.0	620.0
Catalytic Cracking	574.3	-	998.5	286.0	-	1,951.8	521.8	-	190.9	114.5	577.0	-	5,214.8	352.0
Hydrocracking	74.0	4.4	113.4	44.5	-	367.7	30.0	-	10.9	65.5	353.2	-	1,063.6	138.7
Coking - Delayed	35.0	-	281.4	-	-	559.9	-	-	13.0	59.0	337.3	-	1,285.6	272.0
Coking - Fluid	54.0	-	-	-	-	49.0	-	-	16.5	-	86.5	-	206.0	-
Combined	89.0	-	281.4	-	-	608.9	-	-	29.5	59.0	423.8	-	1,491.6	272.0
Combined Coke - FOE	33.5	-	78.0	-	-	184.9	-	-	11.0	14.9	95.2	-	417.5	66.8
Thermal Cracking	-	-	-	1.5	-	14.6	55.0	-	-	-	-	17.2	88.3	-
Visbreaking	13.0	-	6.6	-	-	43.5	22.5	-	-	-	45.8	5.0	136.4	33.8
Total	13.0	-	6.6	1.5	-	58.1	77.5	-	-	-	45.8	22.2	224.7	33.8
Solvent Deasphalting	16.0	7.0	41.6	-	-	145.2	28.2	7.1	17.7	7.4	50.0	-	320.2	-
Catalytic Reforming														
Low Pressure	118.8	-	339.3	133.5	-	866.4	187.5	-	39.5	31.8	204.0	6.0	1,926.8	75.0
High Pressure	232.1	11.7	283.5	111.8	3.0	461.5	144.5	45.0	75.2	78.0	289.9	36.1	1,772.3	212.2
Total	350.9	11.7	622.8	245.3	3.0	1,327.9	332.0	45.0	114.7	109.8	493.9	42.1	3,699.1	287.2
Hydrotreating														
Naphtha	403.8	14.5	711.9	201.0	1.3	1,261.6	360.8	53.1	161.0	91.5	463.0	38.4	3,761.9	249.0
Distillate	343.0	1.3	326.6	117.4	-	1,142.0	382.5	12.0	67.0	76.0	315.9	16.4	2,800.1	134.5
Heavy Gas Oil	117.0	-	230.5	100.7	-	513.3	138.0	27.6	18.5	-	444.6	25.0	1,615.2	227.0 (1)
Residuum	-	0.5	-	-	-	176.0	-	-	-	-	24.0	-	200.5	- (1)
Product Rate														
Alkylation	70.3	-	192.5	64.3	-	403.4	76.6	-	31.7	29.1	102.7	-	970.6	63.5
Polymerization	15.0	-	16.1	5.0	-	27.2	8.0	-	11.7	1.1	5.6	0.1	89.8	2.4
Isomerization - C5/C6	25.0	1.1	85.7	15.4	-	111.1	31.0	2.0	3.9	-	16.7	2.7	294.6	-
Isomerization - C4	-	-	24.3	0.5	-	10.1	10.0	2.0	8.4	4.4	17.2	-	76.9	10.9
Hydrogen - MMCFPSD	96.0	5.0	159.0	-	-	858.0	71.0	8.8	27.0	107.8	923.0	-	2,255.6	433.0
Hydrogen, FOE - MBPSD	4.9	0.3	8.1	-	-	43.7	3.6	0.4	1.4	5.5	47.0	-	114.9	22.0
Asphalt	67.0	89.6	142.6	95.1	5.7	95.4	54.1	27.1	36.0	1.3	26.0	98.0	737.9	4.0
Lube	20.0	20.2	29.6	4.6	1.0	91.6	30.9	17.2	1.5	-	21.1	5.3	243.0	-
Aromatics	12.7	-	42.2	-	-	119.3	32.7	6.2	-	-	3.5	-	216.6	1.5
Hydrodealkylation	1.8	-	6.1	-	-	20.2	-	-	-	-	-	-	28.1	-

(1) Includes 24.0 MBPSD of residuum HDS in heavy gas oil service.

TABLE D-7

CRUDE UNIT CAPACITIES AND UTILIZATIONS

FORECAST 1988 HIGH DEMAND CASE RESULTS

NPC STUDY

Model	Number of Refineries	Crude Capacity (MBPSD)	Crude Input (MBPCD)	Utilization[1] (%)
IC	10	1,296	1,071	87.0
IS	11	371	170	48.2
IIDC	24	2,623	2,263	90.8
IILC	12	827	662	84.3
IIS	7	66	47	75.0
IIIDC	32	5,487	4,678	89.7
IIILC	14	1,634	1,242	80.0
IIIS	21	375	269	75.5
IV	20	591	466	83.0
VCOC	6	512	433	89.0
VCC	17	2,153	1,502	73.4
VS	28	583	375	67.7
U.S. Total	202	16,518	13,178	84.0
VCLA	9	1,209	860	74.9
Subtotal by Type				
Simple	67	1,395	861	65.0
Conversion[2]	135	15,123	12,317	85.7

(1) Utilization of operable calendar day capacity assuming 95% stream factor.
(2) Includes three simple refineries in PADD IV with a capacity of 19 MBPSD.

TABLE D-8

REFINERY PROCESS UNIT UTILIZATIONS

1988 HIGH DEMAND CASE RESULTS - %(1)

NPC STUDY

	IC	IIDC	IILC	IIIDC	IIILC	IV	VCOC	VCC	Combined Simple(7)	U.S. Total	VCLA
Crude - Atmospheric	87.0	90.8	84.3	89.7	80.0	83.0	89.0	73.4	65.0	84.0	74.9
- Vacuum	82.0	94.7(6)	83.7	86.9	76.2	94.7(6)	105.0(4)(6)	76.4	52	83.1(6)	83.7
Catalytic Cracking(2)	87.7	92.5*	87.7	81.6	72.8	90.3	92.3*	92.6*	-	N/A	92.3*
Catalytic Cracking(3)	82.9	88.5	84.8	75.9	68.2	87.1	95.5	88.8	-	81.1	88.6
Conversion, %	76.5	75.2	74.3	78.1	78.3	76.5	73.3	70.0*	-	75.9	70.0*
Hydrocracking	92.5*	91.0*	93.8*	92.7*	91.3*	91.7*	92.6*	92.6*	85	92.4	92.4*
Jet Yield, % of Max.	78.9	5.8	68.2	100.0*	100.0*	100.0*	100.0*	86.6	N/A	81.8	76.9
Coking - Delayed(2)	84.3	77.0	-	77.2	-	71.6	45.9	74.0	-	N/A	76.8
- Delayed(3)	84.3	77.0	-	77.2	-	71.6	45.9	74.0	-	75.0	76.8
- Fluid	56.4	-	-	0	-	0	-	59.8	-	39.9	-
- Combined(3)	67.4	77.0	-	71.0	-	31.6	45.9	71.1	-	70.2	76.8
Combined Coke	51.7	72.9	-	52.1	-	21.5	36.7	75.6	-	60.0	77.4
Th. Crk./Vis. Brk.	92.0*	90.9*	95.7*(4)	77.7	27.1	-	-	92.8*	65	63.4	92.3*
Solvent Deasphalting	92.4*	94.1*	-	93.4*	91.7*	72.8	92.5*	92.4*	75	91.2	-
Catalytic Reforming											
Low Pressure(2)	92.4*	92.4*(6)	92.8*	92.3*	92.5*	91.9*	92.3*	92.4*	N/A	N/A	92.3*
RONC	99.2	99.7	97.2	99.1	98.1	95.7	100.0	99.7	N/A	N/A	98.2
High Pressure(2)	67.9	92.0*	11.0	72.9	68.1	56.0	92.8*	59.2	N/A	N/A	86.2
RONC	98.2	94.2	90.0	95.7	96.4	93.4	99.3	99.4	N/A	N/A	99.7
Combined(3)	66.5	88.7	56.7	81.9	77.0	67.7	76.6*	64.5	75.4*	76.4(6)	72.2
RONC	98.7	97.4	96.5	98.2	97.6	94.6	99.6	99.6	98.0	98.0	99.2
Hydrotreating											
Naphtha	47.2	66.6	56.8	70.7	62.9	47.3	62.8	36.7	78	60.7	55.0
Distillate	52.5	68.2	48.9	68.8	51.8	53.5	29.6	58.1	65	60.9	92.4*
Heavy Gas Oil	47.4	92.8*	88.1	92.2*	92.6*	92.8*	-	80.9	47	84.2	92.4*(6)
Residuum	-	-	-	92.9*	-	-	-	92.4*	65	92.8	-
Alkylation	86.9	92.6*	71.2	71.3	92.4*(6)	92.6*	82.1	87.0*	-	81.0(6)	83.4
Polymerization	0	0	0	13.6	0	40.9	0	0	0	9.5	0
Isomerization - C5/C6	33.0*	87.1*	85.6*	92.4*	92.3*	92.4*(6)	92.4*(6)	92.4*	92.4*	85.5*(6)	-
- C4	-	0	104.3*(4)	0	92.8*	43.0	62.0	6.9	0	22.5	12.6
Hydrogen	82.1	80.5	-	79.6	80.3	77.6	81.8	81.4	80	80.6	81.4
Asphalt	92.5	61.7	82.3	53.6	112.5(4)	93.6	83.8	92.0	75	76.5	108.6(4)
Lubes	92.4	84.4	118.2(4)	89.0	91.5	72.5	-	56.7	85	85.9	N/A(5)
Aromatics	59.9	59.2	N/A(5)	89.3	63.2	-	-	0	0	73.8	0
Hydrodealkylation	0	94.1*	-	72.0	-	-	-	-	-	72.2	-

* Limited at maximum throughput in LP run.
- = No unit; 0 = Unit not operating; N/A = Not applicable or not available.
(1) Utilizations assume a 95% stream factor for crude units and a 92% stream factor for all other units.
(2) Utilization includes effects of non-unitary capacity factors for some feedstocks and severities.
(3) Alternate utilization is based on actual feed rates, ignoring severity effects.
(4) High utilizations (above 95%) indicate errors in reported capacity (calibration) or minor process with little impact on results.
(5) Reported production with no reported capacity - same as calibration case.
(6) Utilization based on base 1988 capacity (Table D-6) plus new capacity (Table D-10).
(7) Estimated from hand calculations and survey.

TABLE D-9

REFINERY PROCESS UNIT UTILIZATIONS

1988 HIGH DEMAND BASE CASE RESULTS - MBPCD

NPC STUDY

	IC	IIDC	IILC	IIIDC	IIILC	IV	VCOC	VCC	Combined Simple	U.S. Total	VCLA
Feed Rate											
Crude - Atmospheric	1,071	2,263	662	4,678	1,242	466	433	1,502	861	13,178	861
- Vacuum	469	906	261	1,889	488	180	207	862	231	5,493	493
Catalytic Cracking(1)	438	813	223	1,363	327	153	101	471	-	3,889	287
Conversion(2)	335	611	166	1,064	256	117	74	330	-	2,953	201
Hydrocracking	63	95	38	314	25	9	56	301	3	904	118
Jet Yield	26	3	14	165	13	5	29	135	N/A	390	47
Coking - Delayed(1)	27	199	-	398	-	9	25	230	-	888	192
- Fluid	28	-	-	0	-	0	-	48	-	76	-
- Combined(1)	55	199	-	398	-	9	25	278	-	964	192
Combined Coke - FOE	16	52	-	88	-	2	5	66	-	229	48
Th. Crk./Vis. Brk.	11	6	1	42	19	-	-	39	13	131	29
Solvent Deasphalting	14	36	-	125	24	12	6	43	10	270	-
Catalytic Reforming											
Combined(1)	215	514	128	1,001	235	71	77	293	70	2,604	191
Hydrotreating											
Naphtha	175	436	105	821	209	70	53	156	77	2,102	126
Distillate	166	205	53	723	182	33	21	169	18	1,570	114
Heavy Gas Oil	51	197	82	435	118	16	-	331	23	1,253	211
Residuum	-	-	-	150	-	-	-	20	0	170	-
Product Rate											
Alkylation	56	164	42	265	67	27	22	82	-	725	49
Polymerization	0	0	0	3	0	4	0	0	0	7	0
Isomerization - C5/C6	8	69	12	94	26	4	2	14	5	234	-
- C4	-	0	0	0	9	3	3	1	0	16	1
Hydrogen - FOE	4	6	-	32	3	1	4	35	1	86	16
Asphalt	57	81	72	47	56	31	1	22	152	519	4
Lubes	17	23	5	75	26	1	-	11	34	192	3
Aromatics	7	23	1	98	19	-	-	0	0	148	0
Hydrodealkylation	0	5	-	13	-	-	-	-	-	18	-

- = No unit; 0 = Unit not operating; N/A = Not applicable.
(1) Based on actual feed rate, ignoring severity effects.
(2) Fresh feed times percent conversion divided by 100.

TABLE D-10

NEW PROCESS UNITS CAPACITY REQUIRED

AND INCREMENTAL OCTANE COST RESULTS

FORECAST 1988 HIGH DEMAND CASE

NPC STUDY

	IC	IIDC	IILC	IIIDC	IIILC	IV	VCOC	VCC	U.S. Total/ Average(1)	VCLA
New Capacity - MBPSD(2)										
Crude - Vacuum	-	21.5	-	-	-	0.8	11.9	-	34.2	-
Catalytic Reforming	-	6.9	-	-	-	-	-	-	6.9	-
Alkylation	-	-	-	-	2.7	-	-	-	2.7	-
Isomerization - C5/C6	-	-	-	-	-	1.2	2.3	-	3.5	-
Hydrotreating - Heavy Gas Oil	-	-	-	-	-	-	-	-	-	21.2
Incremental Octane Costs(3) - ¢/B/O.N.										
Pool Average	32	33	21	28	40	30	32	19	29	19

(1) Total new capacity. Weighted average octane costs for conversion refineries only.
(2) LP includes capital charge for new capacity except crude-vacuum unit.
(3) Shadow values determined by models, based on stock costs and variable operating costs, plus capital charge and fixed operating costs for new capacity only.

TABLE D-11

PRICING BASIS

1988 HIGH REFINERY SUPPLY CASE

BASED ON 1984-85 SPOT CARGO - ADJUSTED

NPC STUDY

	PADD				
	I	II	III	IV	V
Major Products(1)					
Unleaded Reg. Gasoline, ¢/G	77.0	76.5	75.5	78.5	80.5
Distillate Fuel, ¢/G	75.5	73.5	72.5	75.5	74.0
Residual Fuel (Bunker), $/B	26.00	25.00	25.00	22.00	25.00
Major Crudes(2), $/B					
Domestic					
West Texas Intermediate			28.50		
West Texas Sour			26.90		
Alaska North Slope	27.70		27.50		26.50
California Kern River			26.00		23.00
Foreign					
U.K. Brent	28.40		28.50		
Saudi Arabia Light(3)	27.40		27.50		
Saudi Arabia Heavy(3)	26.00		26.10		
Nigeria Medium	28.70		28.80		
Other					
MTBE, ¢/G	95.6	94.6	93.6	104.6	98.6
Iso-Butane, ¢/G	69.0	56.0	56.0	54.0	69.0
N. Butane, ¢/G	53.5	53.5	53.5	51.5	53.5
Propane, ¢/G	47.5	38.0	38.0	36.0	49.5
Process Gas, $/B - FOE	20.00	20.00	20.00	20.00	30.00
Coke, <3%S, $/ST	20.00	20.00	20.00	20.00	20.00

(1) Average 7/84-6/85 Platt's P/L cargo lows for clean products and waterborne cargo lows for bunker in PADD III. OPIS L.A. P/L lows for clean products in PADD V. All Platt's waterborne cargo lows in PADD I.
(2) Calculated average 7/84-6/85 delivered spot crude costs from Platt's. Some estimated.
(3) Estimated based on WTS, Maya, high resid demands.

TABLE D-12

REFINERY ENERGY CONSUMPTION RATES

1988 HIGH DEMAND CASE RESULTS - MBPCD - FOE

	IC	IS	IIDC	IILC	IIS	IIIDC	IIILC	IIIS	IV	VCOC	VCC	VS	U.S. Total	VCLA
Produced(1)														
Distillate Fuels	1.5	0.4	-	-	0.3	-	-	-	-	-	0.9	0.5	3.6	0.9
Residual Fuels	9.8	2.9	9.1	10.6	0.1	2.9	3.4	0.1	2.6	3.9	4.6	1.7	51.7	-
Propane	0.5	0.7	5.5	0.4	0.1	1.9	2.9	0.1	1.0	0.9	8.3	0.1	22.4	2.8
Process Gas	48.9	6.6	108.7	21.6	0.1	226.8	45.1	4.6	19.5	11.9	78.0	6.0	577.8	49.9
Marketable Coke	3.2	-	-	-	-	-	-	-	-	-	1.7	-	4.9	-
Catalytic Coke	24.2	0.8	37.5	9.7	-	63.6	15.5	-	8.2	5.1	25.5	-	190.1	12.3
Total Produced	88.1	11.4	160.8	42.3	0.6	295.2	66.9	4.8	31.3	21.8	119.0	8.3	850.5	65.9
Purchased														
Natural Gas	14.8	5.8	16.5	13.4	0.7	144.5	35.0	4.3	6.5	7.6	36.3	4.1	289.5	16.2
Power	9.7	2.1	23.7	8.0	0.6	46.1	10.4	5.9	5.6	4.6	22.3	2.0	141.0	11.4
Steam	5.5	-	0.4	-	-	5.3	-	0.3	-	-	4.2	0.2	15.9	-
Total Purchased	30.0	7.9	40.6	21.4	1.3	195.9	45.4	10.5	12.1	12.2	62.8	6.3	446.4	27.6
Total Energy	118.1	19.3	201.4	63.7	1.9	491.1	112.3	15.3	43.4	34.0	181.8	14.6	1,296.9	93.5

(1) Refinery produced energy consumption rates are included in gross refinery product rates shown in Table D-3.

TABLE D-13

REFINERY PRODUCT RATES SUMMARY

FORECAST 1988 HIGH DEMAND CASE RESULTS - MBPCD

NPC STUDY

	PADD I	PADD II	PADD III	PADD IV	PADD V	U.S. Total
Motor Gasolines	584	1,680	2,845	233	960	6,302
Naphtha Jet	28	34	105	16	53	236
Kerosene Jet	29	163	542	26	302	1,062
Distillate Fuels	298	692	1,384	119	404	2,897
Residual Fuels	116	84	463	18	379	1,060
LPG(1)	25	(40)	39	(9)	15	30
Other(2)	215	477	1,033	75	321	2,121
Total(2)	1,295	3,090	6,411	478	2,434	13,708

(1) PADD III includes 21 MBPCD of ethane shown in process gas on Table D-3.
(2) Other and total refinery products rates are net from crude, including refinery gain.

TABLE D-14

NET SHIPMENT OF PRODUCTS TO OTHER PADDS

FORECAST 1988 HIGH DEMAND CASE RESULTS(1)

NPC STUDY - MBPCD

	PADD I	PADD II	PADD III	PADD IV	PADD V	U.S. Total
Motor Gasolines	(1,505)	(348)	1,882	16	(45)	0
Naphtha Jet	(4)	3	3	10	(12)	0
Kerosene Jet	(381)	(27)	418	(4)	(6)	0
Distillate Fuels	(608)	(222)	838	3	(11)	0
Residual Fuels	(140)	(12)	143	6	3	0
LPG	(73)	(56)	108	35	(14)	0
Other	(196)	(228)	518	18	(112)	0
Total	(2,907)	(890)	3,910	84	(197)	0

(1) Net shipments = Refinery product rates (Table D-13) plus product import rates (Table D-15) plus natural gas plant production (Table B-17) minus product demands (Table 1-3) minus product export rates (Table B-16). Assumes 1988 high demand case rates are the same as 1984 actual for product exports (Table B-16) and natural gas plant production (Table B-17).

TABLE D-15

PRODUCT IMPORT RATES SUMMARY

1988 HIGH DEMAND CASE RESULTS - MBPCD

NPC STUDY

	PADD I	PADD II	PADD III	PADD IV	PADD V	U.S. Total
Motor Gasoline	183	3	-	2	21	209
Naphtha Jet	9	4	0	0	0	13
Kerosene Jet	34	0	0	1	10	45
Distillate Fuels	253	8	13	4	8	286
Residual Fuels	592	5	69	0	14	680
LPG	27	122	11	9	16	185
Other	160	28	331	3	50	572
Total	1,258	170	424	19	119	1,990

TABLE E-1

1988 MINIMUM SENSITIVITY TO REDUCED GASOLINE VAPOR PRESSURE CASE(1)

INCREMENTAL RESULTS ABOVE 1988 HIGH DEMAND CASE

NPC STUDY

	IC	IIDC	IILC	IIIDC	IIILC	IV	VCOC	VCC	Combined Simple	U.S. Total	VCLA
Total Costs, MM$/Yr.(2)(3)	26.6	95.9	22.0	99.2	46.5	28.1	18.2	46.8	16.9	400.2	26.4
RVP Costs, ¢/B/# RVP(4)	13	20	16	12	23	33	28	17	37	17 (5)	16
Summer RVP Costs, ¢/B/# RVP(6)	13	32	16	12	25	37	35	17	37	20 (5)	18
Added New Capacity Required, MBPSD(2)											
Cat Reforming	-	34.1	-	-	-	-	3.5	-	-	37.6	-
Alkylation	-	-	-	-	1.8	0.7	-	-	-	2.5	-
Isomerization - C5/C6	0.2	-	-	-	-	0.9	-	-	-	1.1	-
Hydrotreating - Distillate	-	-	-	-	-	-	-	-	-	-	0.8
- Heavy Gas Oil	-	-	-	-	-	-	-	-	-	-	2.4
Material Balance Changes, MBPCD(2)											
Raw Materials											
Sweet Crudes	0.1	-	-	-	-	11.1	-	-	-	11.2	-
High Sulfur Light Crudes	2.3	12.5	-	13.6	25.6	-	-	-	-	54.0	-
High Sulfur Heavy Crudes	9.1	13.9	-	(4.2)	(11.9)	(5.8)	4.2	11.8	-	17.1	2.0
Total Crudes	11.5	26.4	-	9.4	13.7	5.3	4.2	11.8	-	82.3	2.0
Normal Butane	(8.4)	-	(2.8)	-	(11.3)	(4.7)	(2.4)	(7.5)	-	(37.1)(7)	-
Iso-Butane	-	(20.7)	4.7	-	0.3	-	-	-	-	(15.7)(7)	-
Oxygenates	-	-	-	-	-	-	-	-	(0.1)	(0.1)	-
Total Raw Materials	3.1	5.7	1.9	9.4	2.7	0.6	1.8	4.3	(0.1)	29.4	2.0
Products											
Motor Gasolines	-	-	-	-	-	-	-	-	(4.1)	(4.1)	-
Marketable Coke - FOE	0.8	1.5	-	0.1	-	-	0.8	0.5	-	3.7	0.1
Petrochem Naphtha	-	-	-	-	-	-	-	-	1.4	1.4	-
Propane	0.1	1.4	-	0.8	0.7	0.2	0.3	0.5	-	4.0	-
Process Gas - FOE	1.9	4.2	0.1	2.4	2.2	0.5	0.8	2.1	1.8(8)	16.0	0.5
Catalytic Coke - FOE	0.3	0.5	-	0.6	0.4	-	-	-	-	1.8	-
Loss/(Gain)	-	(1.9)	1.8	5.5	(0.6)	(0.1)	(0.1)	1.2	0.8(8)	6.6	1.4
Total Products	3.1	5.7	1.9	9.4	2.7	0.6	1.8	4.3	(0.1)	29.4	2.0
Process Units - Added Utilization, %(2)											
Cat Cracking(9)	1.1	- *	-	0.5	1.2	1.9*	- *	- *	-	N/A	- *
Coking(9)	3.5	2.2	-	0.1	-	-	7.1	0.6	-	N/A	0.2
Cat Reforming(9)	3.1	5.1*	0.4	1.2	4.9	4.7	3.0*	3.0	- *	N/A	2.1
Alkylation	5.8*	- *	10.1	7.9	2.2*	1.9*	3.9	5.0*	-	5.5	9.0*
Isomerization - C5/C6	0.7*	- *	- *	- *	- *	21.1*	- *	- *	- *	0.7*	-
- C4	-	86.5	- *	-	- *	1.0	16.7	20.3	-	32.5	43.5

(1) Based on a 1.0 psi reduction in RVP on an annual basis.
(2) Above 1988 High Demand Case.
(3) Based on stock costs and variable operating costs; plus capital charge and fixed costs for added capacity.
(4) Based on total costs above 1988 high demand case divided by motor gasoline rate.
(5) Average.
(6) Based on a summer only (four months) RVP reduction, the capital charge for these new facilities required for reduced RVP would triple.
(7) Net change in C4 purchases equals 0.9% of motor gasoline.
(8) Based on 2.6 MBPCD of butane routed to fuel.
(9) Utilization increase includes effects of non-unitary capacity factors for some feedstocks and severities.
* At limiting capacity utilization.
N/A Not available.

TABLE E-1A

1988 MINIMUM SENSITIVITY TO REDUCED GASOLINE VAPOR PRESSURE CASE(1)

MATERIAL BALANCE AND MAJOR PROCESS UNIT RESULTS(2)

NPC STUDY

Material Balance(3) - MBPCD	IC	IIDC	IILC	IIIDC	IIILC	IV	VCOC	VCC	Combined Simple	U.S. Total	VCLA
Raw Materials											
Sweet Crudes	633	1,329	298	2,085	551	290	48	186	376	5,796	110
High Sulfur Light Crudes	81	182	70	1,034	264	56	28	-	5	1,720	-
High Sulfur Heavy Crudes	368	779	294	1,568	441	125	361	1,328	480	5,744	752
Total Crudes	1,082	2,290	662	4,687	1,256	471	437	1,514	861	13,260	862
Normal Butane	7	62	18	85	10	9	13	4	2	210	9
Iso-Butane	2	15	12	57	5	1	-	1	-	93	2
Vacuum Gas Oil	85	4	16	72	31	-	3	46	(60)	197	5
Oxygenates	6	8	2	27	5	1	1	2	6	58	2
Other	14	47	4	126	52	(3)	(2)	31	29	298	46
Total Raw Materials	1,196	2,426	714	5,054	1,359	479	452	1,598	838	14,116	926
Products											
Motor Gasolines	572	1,309	368	2,222	562	233	177	733	122	6,298	445
Kero Jet/Distillate Fuels	305	696	173	1,567	358	146	153	450	233	4,081	263
Residual Fuels	108	44	34	264	170	18	91	207	124	1,060	94
Asphalt/Road Oil	58	83	75	49	58	33	1	23	153	533	4
Marketable Coke - FOE	17	53	-	88	-	2	6	67	-	233	47
Petrochem Naphtha	20	15	10	19	15	4	3	6	10	102	4
Lubes	17	23	5	75	26	1	-	11	34	192	3
Petrochem Gas Oil	-	20	-	256	40	-	-	-	18	334	-
Propane	35	71	24	102	28	8	4	29	-	301	15
Process Gas - FOE	59	114	21	264	52	19	13	89	21	652	59
Catalytic Coke - FOE	24	39	10	65	16	8	5	26	-	193	12
Other	38	57	14	263	74	19	15	69	111	660	37
Loss/(Gain)	(57)	(98)	(20)	(180)	(40)	(12)	(16)	(112)	12	(523)	(57)
Total Products	1,196	2,426	714	5,054	1,359	479	452	1,598	838	14,116	926
Major Process Units											
Utilization - MBPCD											
Cat Cracking(4)	443	820	223	1,367	333	157	100	471	-	3,914	287
Coking - Feed(4)	58	205	-	399	-	9	26	279	-	976	193
- Coke, FOE	17	53	-	88	-	2	6	67	-	233	47
Cat Reforming(4)	219	542	129	1,013	243	76	80	303	70	2,675	195
Alkylation	60	164	49	295	68	28	23	87	-	774	55
Isomerization - C5/C6	8	69	12	95	26	5	2	14	5	236	-
- C4	-	19	1	0	9	3	3	4	0	39	6
Severity											
Cat Cracking, Conv. %	76.5	74.8	74.3	78.3	78.4	76.0	73.4	70.0	-	75.9(5)	70.0
Cat Reforming, RONC	99.2	97.2	96.6	98.2	98.0	94.6	99.6	99.8	98.0	98.1(5)	99.1

(1) Based on 1.0 psi reduction in RVP on an annual basis.
(2) For reduced vapor pressure case.
(3) Individual entries may be off by 1 MBPCD due to round-off.
(4) Utilization is based on actual feed rates, ignoring severity effects.
(5) Weighted average.

TABLE E-2

1988 MINIMUM SENSITIVITY TO INCREASED GASOLINE OCTANES CASE(1)

INCREMENTAL RESULTS ABOVE 1988 HIGH DEMAND CASE

NPC STUDY

	IC	IIDC	IILC	IIIDC	IIILC	IV	VCOC	VCC	Combined Simple	U.S. Total
Total Costs, MM$/Yr.(2)(3)	80.1	151.4	36.4	260.2	79.1	19.3	25.0	68.3	19.1	738.9
Octane Costs, ¢/B/O.N.(4)(5)	44	38	27	38	46	32	48	31	43	38 (6)
Added New Capacity Required, MBPSD(2)										
Cat Reforming	-	45.8	-	6.9	-	-	6.3	-	-	59.0
Alkylation	-	-	-	-	9.7	0.2	-	-	-	9.9
Isomerization - C5/C6	14.2	-	-	53.2	5.3	0.3	4.3	18.6	-	95.9
Material Balance Changes, MBPD(2)										
Raw Materials										
Sweet Crudes	-	-	-	-	11.1	3.6	-	-	-	14.7
High Sulfur Light Crudes	-	1.3	(0.8)	8.2	(24.8)	-	-	-	-	(16.1)
High Sulfur Heavy Crudes	-	5.2	(3.2)	(2.5)	9.5	(1.9)	3.6	8.7	-	19.4
Total Crudes	-	6.5	(4.0)	5.7	(4.2)	1.7	3.6	8.7	-	18.0
Normal Butane	-	-	0.5	-	3.9	(0.9)	-	-	-	3.5
Iso-Butane	-	(8.6)	1.6	-	6.0	-	-	-	-	(1.0)
Oxygenates	5.0	13.0	4.0	16.0	2.0	0.7	1.0	2.0	(0.4)	43.3
Total Raw Materials	5.0	10.9	2.1	21.7	7.7	1.5	4.6	10.7	(0.4)	63.8
Products										
Motor Gasolines	-	-	-	-	-	-	-	-	(7.6)	(7.6)
Marketable Coke - FOE	-	0.4	-	0.1	-	(0.1)	1.3	0.4	-	2.1
Petrochem Naphtha	-	-	-	-	-	-	-	-	6.5	6.5
Propane	0.2	2.0	-	3.5	0.8	0.2	0.8	0.7	-	8.2
Process Gas - FOE	3.4	7.7	1.2	14.2	3.7	1.2	2.1	7.1	0.5 (7)	41.1
Catalytic Coke - FOE	(0.1)	0.4	(0.1)	0.3	0.1	-	1.0	0.3	-	1.9
Loss/(Gain)	1.5	0.4	1.0	3.6	3.1	0.2	(0.6)	2.2	0.2 (7)	11.6
Total Products	5.0	10.9	2.1	21.7	7.7	1.5	4.6	10.7	(0.4)	63.8
Process Units - Added Utilization, %(2)										
Cat Cracking(8)	(1.7)	- *	(1.0)	0.1	(0.6)	0.8*	- *	- *	-	N/A
Coking(8)	-	0.5	-	-	-	(1.5)	10.7	0.5	-	N/A
Cat Reforming(8)	10.0	6.8*	4.6	7.4*	10.5	8.7	5.3*	9.2	- *	N/A
Alkylation	1.5	- *	3.1	2.4	11.8*	0.6*	6.9	1.9	-	2.7
Isomerization - C5/C6	61.7*	- *	- *	44.3*	15.7*	7.2*	187.0*	54.5*	- *	27.3*
- C4	-	25.7	- *	-	- *	(1.3)	19.7	5.2	-	9.9

(1) Based on a 1.0 increase in (Research + Motor)/2 octane on unleaded gasolines.
(2) Above 1988 High Demand Case.
(3) Based on stock costs and variable operating costs, plus capital charge and fixed costs for added capacity.
(4) Based on total costs above 1988 high demand case, divided by unleaded motor gasoline rate.
(5) Based on oxygenates octane cost of 40¢/B/O.N.
(6) Average.
(7) Based on 0.7 MBPCD of butane routed to fuel.
(8) Utilization increase includes effects of non-unitary capacity factors for some feedstocks and severities.
* At limiting capacity utilization.
N/A Not applicable or not available.

TABLE E-2A

1988 MINIMUM SENSITIVITY TO INCREASED GASOLINE OCTANES CASE(1)

MATERIAL BALANCE AND MAJOR PROCESS UNIT RESULTS(2)

NPC STUDY

Material Balance(3) - MBPCD	IC	IIDC	IILC	IIIDC	IIILC	IV	VCOC	VCC	Combined Simple	U.S. Total
Raw Materials										
Sweet Crudes	633	1,329	298	2,085	562	283	48	186	376	5,800
High Sulfur Light Crudes	79	170	69	1,030	213	56	28	-	5	1,650
High Sulfur Heavy Crudes	359	770	291	1,569	463	129	361	1,324	480	5,746
Total Crudes	1,071	2,269	658	4,684	1,238	468	437	1,510	861	13,196
Normal Butane	15	62	22	85	25	13	15	11	2	250
Iso-Butane	2	27	9	57	11	1	-	1	-	108
Vacuum Gas Oil	85	4	16	72	31	-	3	46	(60)	197
Oxygenates	10	21	6	43	7	2	2	4	6	101
Other	14	47	4	126	52	(3)	(2)	31	29	298
Total Raw Materials	1,197	2,430	715	5,067	1,364	481	455	1,603	838	14,150
Products										
Motor Gasolines	572	1,309	368	2,222	562	233	177	733	118	6,294
Kero Jet/Distillate Fuels	305	696	173	1,567	358	146	153	450	233	4,081
Residual Fuels	108	44	34	264	170	18	91	207	124	1,060
Asphalt/Road Oil	58	83	75	49	58	33	1	23	153	533
Marketable Coke - FOE	16	52	-	88	-	2	6	66	-	230
Petrochem Naphtha	20	15	10	19	15	4	3	6	16	108
Lubes	17	23	5	75	26	1	-	11	34	192
Petrochem Gas Oil	-	20	-	256	40	-	-	-	18	334
Propane	35	72	24	105	28	8	5	29	-	306
Process Gas - FOE	60	118	22	276	53	21	14	94	20	678
Catalytic Coke - FOE	24	38	11	64	16	8	6	26	-	193
Other	38	57	14	263	74	19	15	69	111	660
Loss/(Gain)	(56)	(97)	(21)	(181)	(36)	(12)	(16)	(111)	11	(519)
Total Products	1,197	2,430	715	5,067	1,364	481	455	1,603	838	14,150
Major Process Units										
Utilization - MBPCD										
Cat Cracking(4)	429	793	222	1,361	325	154	95	470	-	3,849
Coking - Feed(4)	55	201	-	399	-	8	27	279	-	969
- Coke, FOE	16	52	-	88	-	2	6	66	-	230
Cat Reforming(4)	232	528	137	1,034	250	78	83	321	70	2,733
Alkylation	57	163	44	274	76	27	24	84	-	749
Isomerization - C5/C6	20	68	12	139	31	5	6	23	5	309
- C4	-	6	1	0	8	3	3	2	0	23
Severity										
Cat Cracking, Conv. %	77.0	77.0	74.0	78.5	78.3	76.4	76.2	70.0	-	76.5(5)
Cat Reforming, RONC	99.6	98.8	96.8	99.4	98.8	95.8	99.6	100.0	98.0	99.1(5)

(1) Based on a 1.0 increase in (Research + Motor)/2 octane on unleaded gasoline.
(2) For increased octanes case.
(3) Individual entries may be off by 1 MBPCD due to round-off.
(4) Utilization is based on actual feed rates, ignoring severity effects.
(5) Weighted average.

TABLE E-3

1988 MINIMUM SENSITIVITY TO ELIMINATION OF OXYGENATES CASE(1)

INCREMENTAL RESULTS ABOVE 1988 HIGH DEMAND CASE

NPC STUDY

	IC	IIDC	IILC	IIIDC	IIILC	IV	VCOC	VCC	Combined Simple	U.S. Total
Total Costs, MM$/Yr.(2)(3)	(2.3)	4.6	(4.1)	(9.3)	2.3	0.4	3.0	(5.0)	0.7	(9.7)
Oxygenate's Values Over Costs, ¢/G(4)	(2.5)	3.8	(13.5)	(2.3)	3.0	1.8	19.5	(16.3)	0.7	(1.1)(5)
Added New Capacity Required, MBPSD(2)										
Cat Reforming	-	21.6	-	-	-	-	3.0	-	-	24.6
Alkylation	-	-	-	-	0.9	0.3	-	-	-	1.2
Isomerization - C5/C6	0.2	-	-	-	-	0.2	-	-	-	0.4
Material Balance Changes, MBPD(2)										
Raw Materials										
Sweet Crudes	-	-	-	-	-	2.9	-	-	-	2.9
High Sulfur Light Crudes	1.9	2.2	-	62.5	14.8	-	-	-	-	81.4
High Sulfur Heavy Crudes	7.4	8.7	-	(19.8)	(6.9)	(1.5)	1.9	3.1	-	(7.1)
Total Crudes	9.3	10.9	-	42.7	7.9	1.4	1.9	3.1	-	77.2
Normal Butane	-	-	1.7	-	(0.1)	0.2	-	-	-	1.8
Iso-Butane	-	0.8	1.2	-	-	-	-	-	-	2.0
Oxygenates	(6.0)	(8.0)	(2.0)	(27.0)	(5.0)	(1.3)	(1.0)	(2.0)	(6.1)	(58.4)
Total Raw Materials	3.3	3.7	0.9	15.7	2.8	0.3	0.9	1.1	(6.1)	22.6
Products										
Motor Gasolines	-	-	-	-	-	-	-	-	(14.9)	(14.9)
Marketable Coke - FOE	0.7	0.8	-	0.5	-	-	0.4	0.1	-	2.5
Petrochem Naphtha	-	-	-	-	-	-	-	-	7.6	7.6
Propane	0.8	0.7	0.1	3.6	0.6	0.1	0.1	0.2	-	6.2
Process Gas - FOE	2.1	2.7	0.3	10.9	2.2	0.3	0.5	0.8	0.8 (6)	20.6
Catalytic Coke - FOE	0.3	0.2	-	1.7	0.2	-	-	-	-	2.4
Loss/(Gain)	(0.6)	(0.7)	0.5	(1.0)	(0.2)	(0.1)	(0.1)	-	0.4 (6)	(1.8)
Total Products	3.3	3.7	0.9	15.7	2.8	0.3	0.9	1.1	(6.1)	22.6
Process Units - Added Utilization, %(2)										
Cat Cracking(7)	1.3	- *	-	2.1	0.6	0.8	- *	- *	-	N/A
Coking(7)	2.9	1.1	-	0.4	-	-	3.2	0.2	-	N/A
Cat Reforming(7)	3.3	3.2*	1.0	4.4	4.6	2.3	2.5*	1.0	- *	N/A
Alkylation	2.0	- *	2.7	2.8	1.1*	1.0*	0.4	(0.2)	-	1.6
Isomerization - C5/C6	0.7*	- *	- *	- *	- *	5.6*	- *	- *	- *	0.4*
- C4	-	-	- *	-	- *	0.8	(0.3)	(1.7)	-	-

(1) Based on elimination of all oxygenates.
(2) Above 1988 High Demand Case.
(3) Based on stock costs and variable operating costs, plus capital charge and fixed costs for added capacity.
(4) Based on total costs above 1988 high demand case, divided by oxygenate rate in 1988 high demand case. Oxygenate's cost in Gulf Coast are as follows (in ¢/G): MTBE - 93.6; ethanol - 90.5; methanol - 70.8; TBA - 76.4.
(5) Average.
(6) Based on 1.2 MBPCD of butane routed to produced fuel.
(7) Utilization increase includes effects of non-unitary capacity factors for some feedstocks and severities.
* At limiting capacity utilization.
N/A Not available.

TABLE E-3A

1988 MINIMUM SENSITIVITY TO ELIMINATION OF OXYGENATES CASE(1)

MATERIAL BALANCE AND MAJOR PROCESS UNIT RESULTS(2)

NPC STUDY

Material Balance(3) - MBPCD	IC	IIDC	IILC	IIIDC	IIILC	IV	VCOC	VCC	Combined Simple	U.S. Total
Raw Materials										
Sweet Crudes	633	1,329	298	2,085	551	282	48	186	376	5,788
High Sulfur Light Crudes	81	171	70	1,083	253	56	28	-	5	1,747
High Sulfur Heavy Crudes	366	774	294	1,553	446	129	359	1,319	480	5,720
Total Crudes	1,080	2,274	662	4,721	1,250	467	435	1,505	861	13,255
Normal Butane	15	62	22	85	21	14	15	11	2	247
Iso-Butane	2	37	8	57	5	1	-	1	-	111
Vacuum Gas Oil	85	4	16	72	31	-	3	46	(60)	197
Oxygenates	-	-	-	-	-	-	-	-	-	0
Other	14	47	4	126	52	(3)	(2)	31	29	298
Total Raw Materials	1,196	2,424	712	5,061	1,359	479	451	1,594	832	14,108
Products										
Motor Gasolines	572	1,309	368	2,222	562	233	177	733	111	6,287
Kero Jet/Distillate Fuels	305	696	173	1,567	358	146	153	450	233	4,081
Residual Fuels	108	44	34	264	170	18	91	207	124	1,060
Asphalt/Road Oil	58	83	75	49	58	33	1	23	153	533
Marketable Coke - FOE	17	53	-	89	-	2	5	66	-	232
Petrochem Naphtha	20	15	10	19	15	4	3	6	17	109
Lubes	17	23	5	75	26	1	-	11	34	192
Petrochem Gas Oil	-	20	-	256	40	-	-	-	18	334
Propane	36	71	24	104	28	8	4	28	-	303
Process Gas - FOE	59	113	21	273	51	19	13	88	20	657
Catalytic Coke - FOE	24	38	10	66	16	8	5	26	-	193
Other	38	57	14	263	74	19	15	69	111	660
Loss/(Gain)	(58)	(98)	(22)	(186)	(39)	(12)	(16)	(113)	11	(533)
Total Products	1,196	2,424	712	5,061	1,359	479	451	1,594	832	14,108
Major Process Units										
Utilization - MBPCD										
Cat Cracking(4)	445	816	223	1,393	331	155	101	471	-	3,935
Coking - Feed(4)	58	202	-	400	-	9	25	278	-	972
- Coke, FOE	17	53	-	89	-	2	5	66	-	232
Cat Reforming(4)	218	527	130	1,013	240	74	80	296	70	2,648
Alkylation	58	164	44	275	67	27	22	82	-	739
Isomerization - C5/C6	8	69	12	94	26	5	2	14	5	235
- C4	-	0	1	0	9	3	2	1	0	16
Severity										
Cat Cracking, Conv. %	76.4	75.0	74.3	78.1	78.3	76.2	73.4	70.0	-	75.9(5)
Cat Reforming, RONC	99.5	97.5	96.6	99.1	98.3	94.6	99.5	99.8	98.0	98.5(5)

(1) Based elimination of all oxygenates.
(2) For no oxygenates case.
(3) Individual entries may be off by 1 MBPCD due to round-off.
(4) Utilization is based on actual feed rates, ignoring severity effect.
(5) Weighted average.

TABLE E-4

1988 MINIMUM SENSITIVITY TO REDUCED GASOLINE VAPOR PRESSURE COMBINED WITH INCREASED GASOLINE OCTANES CASE(1)

INCREMENTAL RESULTS ABOVE 1988 HIGH DEMAND CASE

NPC STUDY

	IC	IIDC	IILC	IIIDC	IIILC	IV	VCOC	VCC	Combined Simple	U.S. Total
Total Costs, MM$/Yr.(2)(3)	111.2	257.2	58.4	383.5	132.3	49.0	44.3	123.3	36.2	1,195.4
RVP Costs, ¢/B/# RVP(4)	13	20	16	12	23	33	28	17	37	17 (6)
Octane Costs, ¢/B/O.N.(4)(5)	46	40	27	42	50	35	50	29	45	41 (6)
Added New Capacity Required, MBPSD(2)										
Cat Reforming	-	67.9	-	31.4	11.5	-	10.0	-	-	120.8
Alkylation	-	-	-	-	9.9	0.4	-	-	-	10.3
Isomerization - C5/C6	14.2	-	-	52.6	5.2	1.3	4.9(7)	10.3	-	88.5
Material Balance Changes, MBPCD(2)										
Raw Materials										
Sweet Crudes	-	-	-	-	25.6	16.0	-	-	-	41.6
High Sulfur Light Crudes	1.6	6.4	-	22.3	(25.3)	-	-	-	-	5.0
High Sulfur Heavy Crudes	6.5	20.4	-	(7.0)	7.2	(8.3)	7.6	19.1	-	45.5
Total Crudes	8.1	26.8	-	15.3	7.5	7.7	7.6	19.1	-	92.1
Normal Butane	(4.5)	-	(4.4)	-	(6.9)	(5.7)	(2.3)	-	-	(23.8)
Iso-Butane	-	(20.7)	4.3	-	6.0	-	-	-	-	(10.4)
Oxygenates	5.0	13.0	4.0	16.0	2.0	0.7	1.0	2.0	(0.5)	43.2
Total Raw Materials	8.6	19.1	3.9	31.3	8.6	2.7	6.3	21.1	(0.5)	101.1
Products										
Motor Gasolines	-	-	-	-	-	-	-	-	(11.7)	(11.7)
Marketable Coke - FOE	0.6	1.8	-	0.2	-	-	2.1	0.9	-	5.6
Petrochem Naphtha	-	-	-	-	-	-	-	-	7.9	7.9
Propane	(0.6)	3.4	0.3	3.9	0.9	0.5	1.1	8.0	-	17.5
Process Gas - FOE	5.3	11.1	1.8	16.8	4.6	2.1	2.8	8.7	2.2 (8)	55.4
Catalytic Coke - FOE	(0.3)	0.8	-	0.6	(0.3)	-	1.0	0.3	-	2.1
Loss/(Gain)	3.6	2.0	1.8	9.8	3.4	0.1	(0.7)	3.2	1.1 (8)	24.3
Total Products	8.6	19.1	3.9	31.3	8.6	2.7	6.3	21.1	(0.5)	101.1
Process Units - Added Utilization, %(2)										
Cat Cracking(9)	(5.3)	- *	-	(0.1)	0.3	1.2	- *	- *	-	N/A
Coking(9)	2.4	2.5	-	0.1	-	-	19.2	1.0	-	N/A
Cat Reforming(9)	14.8	10.1*	6.0	9.1*	13.9*	13.9	8.4*	12.3	- *	N/A
Alkylation	5.8*	- *	9.8	9.4	12.1*	1.2*	11.1*	5.0*	-	7.7
Isomerization - C5/C6	61.7*	- *	- *	43.8*	15.6*	30.6*	189.9*	56.8*	- *	27.7*
- C4	-	85.5	- *	14.0	- *	(2.3)	38.0*	26.3	-	36.7

(1) Based on a 1.0 psi reduction in RVP on an annual basis combined with a 1.0 (R+M)/2 octane increase on unleaded grades.
(2) Above 1988 High Demand Case.
(3) Based on stock costs and variable operating costs, plus capital charge and fixed costs for added capacity.
(4) Total and unit costs for reduced vapor pressure were taken from Table E-1; then total costs for increased octanes were calculated based on the difference between total costs for reduced RVP and total costs for combined reduced RVP and increased octanes. These calculated total costs for increased octanes were then divided by unleaded gasoline rate to get unit octane costs.
(5) Based on oxygenates octane cost of 40¢/B/O.N.
(6) Average.
(7) Includes 0.4 MBPSD of C_4 isomerization.
(8) Based on 3.3 MBPCD of butane routed to produced fuel.
(9) Utilization increase includes effects of non-unitary capacity factors for some feedstocks and severities.
* At limiting capacity utilization.
N/A Not available.

TABLE E-4A

1988 MINIMUM SENSITIVITY TO REDUCED GASOLINE VAPOR PRESSURE

COMBINED WITH INCREASED GASOLINE OCTANE CASE(1)

MATERIAL BALANCE AND MAJOR PROCESS UNIT RESULTS(2)

NPC STUDY

Material Balance(3) - MBPCD	IC	IIDC	IILC	IIIDC	IIILC	IV	VCOC	VCC	Combined Simple	U.S. Total
Raw Materials										
Sweet Crudes	633	1,329	298	2,085	577	295	48	186	376	5,827
High Sulfur Light Crudes	81	175	70	1,043	213	56	28	-	5	1,671
High Sulfur Heavy Crudes	365	785	294	1,565	460	123	365	1,335	480	5,772
Total Crudes	1,079	2,289	662	4,693	1,250	474	441	1,521	861	13,270
Normal Butane	11	62	17	85	14	8	12	11	2	222
Iso-Butane	2	15	11	58	11	1	-	1	-	99
Vacuum Gas Oil	85	4	16	72	31	-	3	46	(60)	197
Oxygenates	11	21	6	42	7	2	2	4	6	101
Other	14	47	4	126	52	(3)	(2)	31	29	298
Total Raw Materials	1,202	2,438	716	5,076	1,365	482	456	1,614	838	14,187
Products										
Motor Gasolines	572	1,308	368	2,222	562	233	177	733	116	6,291
Kero Jet/Distillate Fuels	305	696	173	1,567	358	146	153	450	233	4,081
Residual Fuels	108	44	34	264	170	18	91	207	124	1,060
Asphalt/Road Oil	58	83	75	49	58	33	1	23	153	533
Marketable Coke - FOE	17	54	-	88	-	2	7	67	-	235
Petrochem Naphtha	20	15	10	19	15	4	3	6	16	108
Lubes	17	23	5	75	26	1	-	11	34	192
Petrochem Gas Oil	-	20	-	256	40	-	-	-	18	334
Propane	34	73	24	106	28	9	5	36	-	315
Process Gas - FOE	62	121	23	278	54	21	15	96	21	691
Catalytic Coke - FOE	24	39	10	64	16	8	6	26	-	193
Other	38	57	14	263	74	19	15	69	111	660
Gain/(Loss)	(53)	(95)	(20)	(175)	(36)	(12)	(17)	(110)	12	(506)
Total Products	1,202	2,438	716	5,076	1,365	482	456	1,614	838	14,187
Major Process Units										
Utilization - MBPCD										
Cat Cracking(4)	410	793	223	1,354	329	156	95	470	-	3,830
Coking - Feed(4)	57	206	-	398	-	9	30	281	-	981
- Coke, FOE	17	54	-	88	-	2	7	67	-	235
Cat Reforming(4)	244	548	140	1,053	261	82	86	332	70	2,816
Alkylation	60	166	49	301	76	27	25	90	-	794
Isomerization - C5/C6	20	69	12	139	31	5	6	23	5	310
- C4	-	19	1	1	9	3	4	5	0	42
Severity										
Cat Cracking, Conv. %	78.1	77.2	74.3	78.6	78.2	76.4	76.1	70.0	-	76.8(5)
Cat Reforming, RONC	99.7	98.8	96.9	99.4	98.9	96.3	99.6	100.0	98.0	99.1(5)

(1) Based on a 1.0 psi reduction in RVP on an annual basis combined with a 1.0 (Research + Motor)/2 octane increase on unleaded grades.
(2) For reduced vapor pressure combined with increased octanes case.
(3) Individual entries may be off by 1 MBPCD due to round-off.
(4) Utilization based on actual feed rates, ignoring severity effects.
(5) Weighted average.

TABLE E-5

1988 SENSITIVITY TO MAXIMUM MAJOR LIGHT PRODUCTS WITH NEW FACILITIES CASE(1)

INCREMENTAL RESULTS ABOVE 1988 HIGH DEMAND CASE

NPC STUDY

	IC	IIDC	IILC	IIIDC	IIILC	IV	VCOC	VCC	Combined Simple	U.S. Total
Added Capacity Required, MBPSD(2)										
Cat Reforming	-	(6.9)(3)	-	9.6	19.7	-	12.1	-	-	34.5
Alkylation	-	-	-	51.6	23.7	2.2	-	16.4	-	93.9
Isomerization - C5/C6	8.3	-	-	-	18.8	1.3	0.8	-	-	29.2
Material Balance Changes, MBPCD(2)										
Raw Materials										
Sweet Crudes	144	(59)	97	100	334	-	-	-	-	616
High Sulfur Light Crudes	(29)	12	34	324	(87)	-	-	-	-	254
High Sulfur Heavy Crudes	(115)	47	(131)	(424)	(247)	-	-	-	-	(870)
Total Crudes	-	-	-	-	-	-	-	-	-	-
Normal Butane	5	37	11	115	19	4	2	30	-	223
Iso-Butane	(2)	(19)	5	44	10	(2)	-	(1)	-	35
Vacuum Gas Oil	36	-	-	-	7	-	-	-	-	43
Total Raw Materials	39	18	16	159	36	2	2	29	-	301
Products										
Motor Gasolines	67	7	58	408	141	23	17	56	-	777
Kero Jet/Distillate Fuels	48	58	3	88	16	(6)	(5)	33	-	235
Residual Fuels	(44)	(4)	(16)	(211)	(96)	(10)	(14)	(78)	-	(473)
Asphalt	(16)	(22)	(21)	(14)	(17)	(9)	-	(6)	-	(105)
Marketable Coke - FOE	6	13	-	30	-	5	5	20	-	79
Petrochem Naphtha	(17)	(16)	(10)	(20)	(30)	(4)	(3)	(6)	-	(106)
Lubes/Wax	(9)	(2)	(1)	(15)	(6)	-	-	(2)	-	(35)
Petrochem Gas Oil	-	(20)	-	(139)	28	-	-	-	-	(131)
Propane	3	2	-	8	-	1	1	6	-	21
Process Gas - FOE	7	4	3	27	4	3	3	12	-	63
Catalytic Coke - FOE	2	2	-	13	(1)	1	-	(1)	-	16
Loss/(Gain)	(8)	(4)	-	(16)	(3)	(2)	(2)	(5)	-	(40)
Total Products	39	18	16	159	36	2	2	29	-	301
Process Units - Added Utilization, %(2)										
Cat Cracking(4)	4.6*	- *	4.9*	10.7*	19.7*	1.9*	- *	- *	-	N/A*
Coking(4)	25.4*	15.6*	-	20.2	-	60.8*	46.7*	21.3*	-	N/A
Cat Reforming(4)	11.3	(1.0)*	16.4	7.5*	16.0*	15.3	10.2*	4.1	- *	N/A
Alkylation	5.8	- *	13.6	32.8*	28.0*	6.4*	9.1	19.9*	-	21.4
Isomerization - C5/C6	30.5*	- *	- *	- *	56.0*	30.1*	29.8*	- *	- *	9.1*
- C4	-	92.0*	- *	92.0*	- *	26.7	31.4*	85.5*	-	67.8
Octane Costs, ¢/B/O.N.(5)	45	32	29	37	44	29	37	29	45 (6)	36 (6)(7)
RVP Costs, ¢/B/# RVP (5)	14 (6)	16 (6)	25	25	26	29	29	28	37 (6)	23 (6)(7)

(1) Based on market prices and unlimited demand. Assume fixed grade ratios and fixed total crude rate. Allow LP runs to add "octane-enhancing units" capacity, if economic based on variable and fixed operating costs plus capital charge.
(2) Above 1988 high demand case.
(3) Smaller increase than required for 1988 high demand case.
(4) Utilization increase includes effects of non-unitary capacity factors for some feedstocks and severities.
(5) Incremental or shadow value costs determined by models.
(6) Estimated.
(7) Average.
* At limiting capacity utilization.
N/A Not available.

TABLE E-5A

1988 SENSITIVITY TO MAXIMUM MAJOR LIGHT PRODUCTS

WITH NEW OCTANE-ENHANCING FACILITIES CASE(1)

MATERIAL BALANCE RESULTS(2) - MBPCD

NPC STUDY

	IC	IIDC	IILC	IIIDC	IIILC	IV	VCOC	VCC	Combined Simple	U.S. Total
Raw Materials										
Sweet Crudes	777	1,270	395	2,185	885	279	48	186	376	6,401
High Sulfur Light Crudes	50	181	104	1,345	151	56	28	-	5	1,920
High Sulfur Heavy Crudes	244	812	163	1,148	206	131	357	1,316	480	4,857
Total Crudes	1,071	2,263	662	4,678	1,242	466	433	1,502	861	13,178
Normal Butane	20	99	32	200	40	18	17	41	2	469
Iso-Butane	-	17	12	101	15	(1)	-	-	-	144
Vacuum Gas Oil	121	4	16	72	38	-	3	46	(60)	240
Oxygenates	6	8	2	27	5	1	1	2	6	58
Other	14	47	4	126	52	(3)	(2)	31	29	298
Total Raw Materials	1,232	2,438	728	5,204	1,392	481	452	1,622	838	14,387
Products										
Motor Gasolines	639	1,316	426	2,630	703	256	194	789	126	7,079
Kero Jet/Distillate Fuels	353	754	176	1,655	374	140	148	483	233	4,316
Residual Fuels	64	40	18	53	74	8	77	129	124	587
Asphalt/Road Oil	42	61	54	35	41	24	1	17	153	428
Marketable Coke - FOE	22	65	-	118	-	7	10	86	-	308
Petrochem Naphtha	3	(1)	-	(1)	(15)	-	-	-	9	-5
Lubes	8	21	4	60	20	1	-	9	34	157
Petrochem Gas Oil	-	-	-	117	68	-	-	-	18	203
Propane	38	72	24	109	27	9	5	34	-	318
Process Gas - FOE	64	114	24	289	53	22	15	99	19	699
Catalytic Coke - FOE	26	40	10	77	15	9	5	25	-	207
Other	38	57	14	263	74	19	15	69	111	660
Loss/(Gain)	(65)	(101)	(22)	(201)	(42)	(14)	(18)	(118)	11	(570)
Total Products	1,232	2,438	728	5,204	1,392	481	452	1,622	838	14,387

(1) Based on market prices and unlimited demand. Assume fixed grade ratios on fixed total crude rate. Allow LP runs to add "octane-enhancing units" capacity if economic based on variable and fixed operating costs plus capital charge.

(2) For maximum major light products with new facilities case. Individual entries may be off by 1 MBPCD due to round-off.

TABLE E-6

1988 SENSITIVITY TO 10% HEAVY CRUDE SUBSTITUTION CASE[1]

INCREMENTAL RESULTS ABOVE 1988 MAXIMUM MAJOR LIGHT PRODUCTS WITH NEW FACILITIES CASE

NPC STUDY

	IC	IIDC	IILC	IIIDC	IIILC	IV	VCOC	VCC	Combined Simple	U.S. Total
Total Costs, MM$/Yr.[2][3]	29.7	75.0	19.3	73.5	(5.8)	38.0	14.2	(6.9)	-	237.0
Heavy Crude Value Under Cost,$/B[4]	0.76	0.91	0.80	0.43	(0.13)	2.23	0.90	(0.13)	-	0.53[5]
Added Capacity Required, MBPSD[2][6]										
Cat Reforming	-	-	-	(9.6)	(9.9)	-	(7.3)	-	-	(26.8)
Alkylation	-	-	-	11.2	(1.1)	(0.5)	-	(1.3)	-	8.3
Isomerization - C5/C6	2.2	-	-	-	3.1	0.3	(0.6)	-	-	5.0
Material Balance Changes, MBPCD[2]										
Raw Materials										
Sweet Crudes	(106.3)	(226.3)	(66.1)	(467.8)	(124.1)	(46.7)	(43.3)	(144.9)	-	(1,225.5)
High Sulfur Heavy Crudes	107.1	226.3	66.2	467.8	124.2	46.7	43.3	144.9	-	1,226.5
Total Crudes	0.8	-	0.1	-	0.1	-	-	-	-	1.0
Normal Butane	(1.7)	(5.4)	(1.6)	(7.7)	(3.1)	(0.7)	(0.8)	0.9	-	(20.1)
Iso-Butane	-	0.1	0.6	4.3	-	-	-	-	-	5.0
Total Raw Materials	(0.9)	(5.3)	(0.9)	(3.4)	(3.0)	(0.7)	(0.8)	0.9	-	(14.1)
Products										
Motor Gasolines	(8.8)	(8.4)	(9.8)	(16.0)	(19.6)	(17.9)	(9.8)	(12.7)	-	(103.0)
Kero Jet/Distillate Fuels	(28.4)	(55.9)	(13.2)	(114.5)	(26.7)	4.0	(4.6)	(23.3)	-	(262.6)
Residual Fuels	34.1	49.4	21.3	103.4	41.0	15.0	14.9	32.4	-	311.5
Marketable Coke - FOE	-	2.1	-	8.8	-	(0.4)	(0.1)	-	-	10.4
Propane	0.8	2.3	0.4	5.2	0.6	(0.5)	(0.3)	1.0	-	9.5
Process Gas - FOE	0.4	2.6	(0.4)	7.6	0.0	(1.3)	(1.0)	0.3	-	8.2
Catalytic Coke - FOE	-	1.6	0.7	6.5	0.2	0.0	0.1	2.7	-	11.8
Loss/(Gain)	1.0	1.0	0.1	(4.4)	1.5	0.4	0.0	0.5	-	0.1
Total Products	(0.9)	(5.3)	(0.9)	(3.4)	(3.0)	(0.7)	(0.8)	0.9	-	(14.1)
Process Units - Added Utilization, %[2]										
Cat Cracking[7]	(0.5)	- *	- *	- *	(1.2)	(1.4)	- *	- *	-	N/A
Coking[7]	- *	- *	-	1.4*	-	- *	- *	- *	-	N/A*
Cat Reforming[7]	(1.4)	- *	(4.1)	(0.7)*	(2.6)*	(12.2)	(6.5)*	(1.2)	- *	N/A
Alkylation	-	- *	1.8	2.5*	(1.0)*	(1.5)*	(0.4)	(1.0)*	-	0.9
Isomerization - C5/C6	12.1*	- *	- *	- *	5.7*	5.1*	(21.0)*	- *	- *	1.7*
- C4	-	- *	- *	- *	-	6.4	(3.5)	- *	-	1.4

(1) Based on substituting 10% of total crude run, replacing sweet crude with high sulfur heavy crude. Based on market prices and unlimited demand. Fixed grade ratios except residual fuels. Fixed total crude rate.
(2) Above 1988 maximum major light products with new facilities case.
(3) Based on stock costs and variable operating costs, plus capital charge and fixed costs for added capacity.
(4) Based on total costs above 1988 maximum major light products case, divided by heavy crude substitution rate.
(5) Average.
(6) Smaller increase than required for 1986 maximum major light products case with new facilities is indicated by negative added capacity.
(7) Utilization increase includes effects of non-unitary capacity factors for some feedstocks and severities.
* At limiting capacity utilization.
N/A Not available.

TABLE E-6A

1988 SENSITIVITY TO 10% HEAVY CRUDE SUBSTITUTION CASE(1)

BASED ON MAXIMUM MAJOR LIGHT PRODUCTS WITH NEW FACILITIES

MATERIAL BALANCE RESULTS(2) - MBPCD

NPC STUDY

	IC	IIDC	IILC	IIIDC	IIILC	IV	VCOC	VCC	Combined Simple	U.S. Total
Raw Materials										
Sweet Crudes	671	1,044	329	1,717	761	232	5	41	376	5,176
High Sulfur Light Crudes	50	181	104	1,345	151	56	28	-	5	1,920
High Sulfur Heavy Crudes	351	1,038	229	1,616	330	178	400	1,461	480	6,083
Total Crudes	1,072	2,263	662	4,678	1,242	466	433	1,502	861	13,179
Normal Butane	18	94	30	193	37	17	16	42	2	449
Iso-Butane	-	17	13	105	15	(1)	-	-	-	149
Vacuum Gas Oil	121	4	16	72	38	-	3	46	(60)	240
Oxygenates	6	8	2	27	5	1	1	2	6	58
Other	14	47	4	126	52	(3)	(2)	31	29	298
Total Raw Materials	1,231	2,433	727	5,201	1,389	480	451	1,623	838	14,373
Products										
Motor Gasolines	630	1,308	416	2,614	684	238	184	776	126	6,976
Kero Jet/Distillate Fuels	325	698	163	1,540	347	144	143	460	233	4,053
Residual Fuels	98	89	39	156	116	23	92	161	124	899
Asphalt/Road Oil	42	61	54	35	41	24	1	17	153	428
Marketable Coke - FOE	22	67	-	127	-	7	10	86	-	318
Petrochem Naphtha	3	(1)	-	(1)	(15)	-	-	-	9	(5)
Lubes	8	21	4	60	20	1	-	9	34	157
Petrochem Gas Oil	-	-	-	117	68	-	-	-	18	203
Propane	39	74	24	115	27	9	5	35	-	328
Process Gas - FOE	64	117	24	297	53	20	14	99	19	707
Catalytic Coke - FOE	26	42	11	83	15	9	5	28	-	219
Other	38	57	14	263	74	19	15	69	111	660
Loss/(Gain)	(64)	(100)	(22)	(205)	(41)	(14)	(18)	(117)	11	(570)
Total Products	1,231	2,433	727	5,201	1,389	480	451	1,623	838	14,373

(1) Based on substituting 10% of total crude run, replacing sweet crude with high sulfur heavy crude. Based on market prices and unlimited demand. Fixed grade ratios except residual fuels. Fixed total crude rate.

(2) For case with heavy crude substitution, maximum light product with new facilities. Individual entries may be off by 1 MBPCD due to round-off.

TABLE E-7

1988 SENSITIVITY TO OPTIMUM MAJOR PRODUCTS WITHOUT NEW FACILITIES CASE[1]

INCREMENTAL RESULTS ABOVE 1988 HIGH DEMAND CASE

NPC STUDY

Material Balance Changes, MBPCD[2]	IC	IIDC	IILC	IIIDC	IIILC	IV	VCOC	VCC	Combined Simple	U.S. Total	VCLA
Raw Materials											
Sweet Crudes	155	(59)	103	200	200	-	-	-	-	599	2
High Sulfur Light Crudes	(22)	12	29	244	(61)	-	-	-	-	202	-
High Sulfur Heavy Crudes	(133)	47	(132)	(444)	(139)	-	-	-	-	(801)	(2)
Total Crudes	-	-	-	-	-	-	-	-	-	-	-
Normal Butane	-	-	-	-	-	-	-	-	-	-	-
Iso-Butane	(2)	(8)	-	-	(3)	-	-	(1)	-	(14)	(1)
Vacuum Gas Oil	36	-	-	-	109	-	-	-	-	145	-
Total Raw Materials	34	(8)	-	-	106	-	-	(1)	-	131	(1)
Products											
Motor Gasolines	57	(8)	33	218	86	18	-	32	-	436	(5)
Kero Jet/Distillate Fuels	64	52	15	151	67	(3)	22	33	-	401	28
Residual Fuels	(57)	(4)	(17)	(220)	(27)	(10)	(28)	(79)	-	(442)	(25)
Asphalt	(16)	(22)	(21)	(14)	(17)	(9)	-	(6)	-	(105)	(1)
Marketable Coke - FOE	5	13	-	30	-	5	5	20	-	78	6
Petrochem Naphtha	(17)	(16)	(10)	(20)	(30)	(4)	(3)	(6)	-	(106)	(4)
Lubes/Wax	(9)	(2)	(1)	(15)	(6)	-	-	(2)	-	(35)	(1)
Petrochem Gas Oil	-	(20)	-	(139)	28	-	-	-	-	(131)	-
Propane	3	1	-	8	3	1	1	4	-	21	1
Process Gas - FOE	8	5	3	27	8	3	4	13	-	71	3
Catalytic Coke - FOE	2	2	(1)	11	4	1	1	(1)	-	19	-
Loss/(Gain)	(6)	(9)	(1)	(37)	(10)	(2)	(2)	(9)	-	(76)	(3)
Total Products	34	(8)	-	-	106	-	-	(1)	-	131	(1)
Process Units - Added Utilization, %[2]											
Cat Cracking[6]	4.6*	- *	4.9*	10.7*	19.7*	1.9*	- *	- *	-	N/A*	- *
Coking[6]	21.6	15.6*	-	19.7	-	60.8*	46.7*	21.3*	-	N/A	15.7*
Cat Reforming[6]	16.1*	- *	9.5	6.9*	10.7*	14.0	- *	5.5	- *	N/A	(1.6)
Alkylation	4.4	- *	-	6.0	- *	- *	7.2	3.0	-	3.5	0.5
Isomerization - C5/C6	- *	- *	- *	- *	- *	- *	- *	- *	- *	- *	-
- C4	-	(29.3)	(92.4)	-	(38.2)	(6.7)	23.0	3.7	-	5.7	15.4
Octane Costs, ¢/B/O.N.[3]	62	30	25	40	96	28	91	26	96 (5)	45 (4)(5)	23
RVP Costs, ¢/B/# RVP[3]	11 (5)	13 (5)	14	12	30	24	21 (5)	15	37 (5)	15 (4)(5)	15

(1) Based on market prices and unlimited demand. Assume fixed grade ratios, fixed total crude rate units and no new facilities.
(2) Above 1988 high demand case.
(3) Incremental or shadow value costs determined by models.
(4) Average.
(5) Estimated.
(6) Utiization increase includes effects of non-unitary factors for some feedstocks and severities.
* At limiting capacity utilization.

TABLE E-7A

1988 SENSITIVITY TO OPTIMUM MAJOR PRODUCTS WITHOUT NEW FACILITIES CASE(1)

MATERIAL BALANCE AND MAJOR PROCESS UNIT RESULTS(2)

NPC STUDY

Material Balance(3) - MBPCD	IC	IIDC	IILC	IIIDC	IIILC	IC	VCOC	VCC	Combined Simple	U.S. Total	VCLA
Raw Materials											
Sweet Crudes	788	1,270	401	2,285	751	279	48	186	376	6,384	112
High Sulfur Light Crudes	57	181	99	1,265	177	56	28	-	5	1,868	-
High Sulfur Heavy Crudes	226	812	162	1,128	314	131	357	1,316	480	4,926	748
Total Crudes	1,071	2,263	662	4,678	1,242	466	433	1,502	861	13,178	860
Normal Butane	15	62	21	85	21	14	15	11	2	246	9
Iso-Butane	-	28	7	57	2	1	-	-	-	95	1
Vacuum Gas Oil	121	4	16	72	140	-	3	46	(60)	342	5
Oxygenates	6	8	2	27	5	1	1	2	6	58	2
Other	14	47	4	126	52	(3)	(2)	31	29	298	46
Total Raw Materials	1,227	2,412	712	5,045	1,462	479	450	1,592	838	14,217	923
Products											
Motor Gasolines	629	1,301	401	2,440	648	251	177	765	126	6,738	440
Kero Jet/Distillate Fuels	369	748	188	1,718	425	143	175	483	233	4,482	291
Residual Fuels	51	40	17	44	143	8	63	128	124	618	69
Asphalt/Road Oil	42	61	54	35	41	24	1	17	153	428	3
Marketable Coke - FOE	21	65	-	118	-	7	10	86	-	307	53
Petrochem Naphtha	3	(1)	-	(1)	(15)	-	-	-	9	(5)	-
Lubes	8	21	4	60	20	1	-	9	34	157	2
Petrochem Gas Oil	-	-	-	117	68	-	-	-	18	203	-
Propane	38	71	24	109	30	9	5	32	-	318	16
Process Gas - FOE	65	115	24	289	57	22	16	100	19	707	61
Catalytic Coke - FOE	26	40	9	75	20	9	6	25	-	210	12
Other	38	57	14	263	74	19	15	69	111	660	37
(Gain)/Loss	(63)	(106)	(23)	(222)	(49)	(14)	(18)	(122)	11	(506)	(61)
Total Products	1,227	2,412	712	5,045	1,462	479	450	1,592	838	14,217	923
Major Process Units											
Utilization - MBPCD											
Cat Cracking(4)	460	827	232	1,535	406	156	97	472	-	4,185	286
Coking - Feed(4)	73	240	-	508	-	25	50	360	-	1,256	231
- Coke, FOE	21	65	-	118	-	7	10	86	-	307	53
Cat Reforming(4)	247	501	148	1,052	251	84	77	311	70	2,741	187
Alkylation	59	163	42	287	69	27	24	85	-	756	49
Isomerization - C5/C6	8	69	12	94	26	4	2	14	5	234	-
- C4	-	7	0	0	5	3	3	2	0	20	3
Severity											
Cat Cracking, Conv. %	78.1	74.9	75.1	78.6	79.6	75.8	75.0	70.0	-	76.6(5)	70.0
Cat Reforming, RONC	99.7	97.7	97.0	98.6	98.9	94.7	99.6	99.8	98.0	98.5(5)	99.3

(1) Based on market prices and unlimited demand. Assume fixed grade ratios, fixed total crude rate and no new facilities.
(2) For optimum major products without new facilities case.
(3) Individual entries may be off by 1 MBPCD due to round-off.
(4) Utilization based on actual feed rates, ignoring severity effects.
(5) Weighted average.

TABLE E-8

1988 MAXIMUM SENSITIVITY TO REDUCED GASOLINE VAPOR PRESSURE CASE[1][2]

INCREMENTAL RESULTS ABOVE 1988 OPTIMUM MAJOR PRODUCTS WITHOUT NEW FACILITIES CASE[2]

NPC STUDY

	IC	IIDC	IILC	IIIDC	IIILC	IV	VCOC	VCC	Combined Simple	U.S. Total	VCLA
Total Costs, MM$/Yr.[3]	96.6	174.9	59.9	388.5	116.6	39.0	25.0	83.0	23.8	1,007.3	46.7
RVP Costs, ¢/B/# RVP	43	37	42	44	50	43	39	30	52	42 [4]	29
Material Balance Changes, MBPCD[3]											
Raw Materials											
Sweet Crudes	(46)	131	5	(51)	-	-	-	-	-	39	-
High Sulfur Light Crudes	9	(26)	(4)	(134)	31	-	-	-	-	(124)	-
High Sulfur Heavy Crudes	37	(105)	(1)	185	(31)	-	-	-	-	85	-
Total Crudes	-	-	-	-	-	-	-	-	-	-	-
Normal Butane	-	-	-	-	-	-	-	-	-	-	-
Iso-Butane	-	5	-	-	-	-	-	-	-	5	-
Total Raw Materials	-	5	-	-	-	-	-	-	-	5	-
Products											
Low Lead Regular Gasolines	(3)	(5)	(3)	(12)	(2)	(2)	(1)	(2)	-	(30)	(1)
Unleaded Regular Gasolines	(12)	(21)	(14)	(43)	6	(5)	(3)	(9)	(4)	(105)	(5)
Unleaded Premium Gasolines	(5)	(4)	(3)	(17)	(19) [5]	(1)	(1)	(5)	-	(55) [5]	(3)
Total Motor Gasolines	(20)	(30)	(20)	(72)	(15)	(8)	(5)	(16)	(4)	(190)	(9)
Kero Jet/Distillate Fuels	(2)	25	13	(19)	2	3	-	-	-	22	-
Residual Fuels	9	(1)	(1)	25	-	-	-	-	-	32	-
Marketable Coke - FOE	1	(8)	-	4	-	-	-	-	-	(3)	-
Petrochem Naphtha	-	-	-	-	-	-	-	-	1	1	-
Butane to Fuel[6]	12	23	8	49	13	5	4	15	3	132	9
Propane	-	(2)	-	3	-	-	-	-	-	1	-
Process Gas - FOE	-	(5)	-	6	-	-	1	1	-	3	-
Catalytic Coke - FOE	-	(2)	-	1	-	-	-	-	-	(1)	-
Loss/(Gain)	-	5	-	3	-	-	-	-	-	8	-
Total Products	-	5	-	-	-	-	-	-	-	5	-
Process Units - Added Utilization, %[3]											
Cat Cracking[7]	- *	- *	- *	- *	- *	- *	- *	- *	-	N/A*	- *
Coking[7]	3.8*	(9.5)	-	1.8*	-	- *	- *	- *	-	N/A	- *
Cat Reforming[7]	- *	- *	(2.4)	- *	- *	0.3	- *	1.6	- *	N/A	0.4
Alkylation	1.4*	(0.9)	0.5	1.9	- *	- *	(0.1)	0.9	-	1.1	0.7
Isomerization - C5/C6	- *	- *	- *	- *	- *	- *	- *	- *	- *	- *	-
- C4	-	(16.0)	-	-	(0.8)	2.8	(0.4)	3.0	-	(5.6)	2.2

(1) Based on 1.0 psi reduction in RVP on an annual basis with the butane which is removed from gasoline routed to refinery fuel.
(2) Based on market prices and unlimited demand. Assume fixed grade ratios, fixed total crude rate units and no new facilities.
(3) Above 1988 optimum major products without new facilities case (Tables E-7 and E-7A).
(4) Average.
(5) Reduced premium unleaded grade disproportionately (at $1.00/B/O.N.) to avoid over-constrained solution.
(6) Butane removed from gasolines, which is 2.0% of gasoline volume, is routed to fuel.
(7) Utilization increase includes effects of non-unitary capacity factors for some feedstocks and severities.
* At limiting capacity utilization.
N/A Not available.

TABLE E-8A

1988 MAXIMUM SENSITIVITY TO REDUCED GASOLINE VAPOR PRESSURE CASE(1)
WITH OPTIMUM MAJOR PRODUCTS WITHOUT NEW FACILITIES(2)
MATERIAL BALANCE AND MAJOR PROCESS UNIT RESULTS(3)
NPC STUDY

Material Balance(4) - MBPCD	IC	IIDC	IILC	IIIDC	IIILC	IV	VCOC	VCC	Combined Simple	U.S. Total	VCLA
Raw Materials											
Sweet Crudes	742	1,401	406	2,234	751	279	48	186	376	6,423	110
High Sulfur Light Crudes	66	155	95	1,131	208	56	28	-	5	1,744	-
High Sulfur Heavy Crudes	263	707	161	1,313	283	131	357	1,316	480	5,011	750
Total Crudes	1,071	2,263	662	4,678	1,242	466	433	1,502	861	13,178	860
Normal Butane	15	62	21	85	21	14	15	11	2	246	9
Iso-Butane	-	33	7	57	2	1	-	-	-	100	1
Vacuum Gas Oil	121	4	16	72	140	-	3	46	(60)	342	5
Oxygenates	6	8	2	27	5	1	1	2	6	58	2
Other	14	47	4	126	52	(3)	(2)	31	29	298	46
Total Raw Materials	1,227	2,417	712	5,045	1,462	479	450	1,592	838	14,222	923
Products											
Low Lead Regular Gasolines	79	217	57	389	98	73	33	121	-	1,067	69
Unleaded Regular Gasolines	392	888	271	1,418	435	155	94	411	122	4,186	237
Unleaded Premium Gasolines	138	166	53	561	100	15	45	217	-	1,295	125
Total Motor Gasolines	609	1,271	381	2,368	633	243	172	749	122	6,548	431
Kero Jet/Distillate Fuels	367	773	201	1,699	427	146	175	483	233	4,504	291
Residual Fuels	60	39	16	69	143	8	63	128	124	650	69
Asphalt/Road Oil	42	61	54	35	41	24	1	17	153	428	3
Marketable Coke - FOE	22	57	-	122	-	7	10	86	-	304	53
Petrochem Naphtha	3	(1)	-	(1)	(15)	-	-	-	10	(4)	-
Lubes	8	21	4	60	20	1	-	9	34	157	2
Petrochem Gas Oil	-	-	-	117	68	-	-	-	18	203	-
Butane to Fuel	12	23	8	49	13	5	4	15	3	132	9
Propane	38	69	24	112	30	9	5	32	-	319	16
Process Gas - FOE	65	110	24	295	57	22	17	101	19	710	61
Catalytic Coke - FOE	26	38	9	76	20	9	6	25	-	209	12
Other	38	57	14	263	74	19	15	69	111	660	37
Loss/(Gain)	(63)	(101)	(23)	(219)	(49)	(14)	(18)	(122)	11	(598)	(61)
Total Products	1,227	2,417	712	5,045	1,462	479	450	1,592	838	14,222	923
Major Process Units											
Utilization - MBPCD											
Cat Cracking(5)	460	831	232	1,513	404	156	97	472	-	4,165	286
Coking - Feed(5)	76	216	-	519	-	25	50	360	-	1,246	231
- Coke, FOE	22	57	-	122	-	7	10	86	-	304	53
Cat Reforming(5)	247	492	142	1,029	251	84	77	315	70	2,707	188
Alkylation	60	164	42	294	69	27	24	86	-	766	49
Isomerization - C5/C6	8	69	12	94	26	4	2	14	5	234	-
- C4	-	3	0	0	5	3	3	2	0	16	3
Severity											
Cat Cracking, Conv. %	78.1	74.5	75.0	79.7	79.9	75.8	75.0	70.0	-	76.9(6)	70.0
Cat Reforming, RONC	99.7	98.1	97.2	99.4	98.9	94.7	99.6	99.9	98.0	98.9(6)	99.8

(1) Based on a 1.0 psi reduction in gasoline RVP on an annual basis with the butane which is removed from gasolines routed to refinery fuel.
(2) Based on market prices and unlimited demand. Assume fixed grade ratios, fixed total crude rate and no new facilities.
(3) For case with reduced vapor pressure, optimum major products without new facilities.
(4) Individual entries may be off by 1 MBPCD due to round-off.
(5) Utilization is based on actual feed rates, ignoring severity effects.
(6) Weighted average.

TABLE E-9

1988 MAXIMUM SENSITIVITY TO REDUCED GASOLINE VAPOR PRESSURE COMBINED WITH INCREASED GASOLINE OCTANES CASE(1)(2)

INCREMENTAL RESULTS ABOVE 1988 OPTIMUM MAJOR PRODUCTS WITHOUT NEW FACILITIES CASE(2)

NPC STUDY

	IC	IIDC	IILC	IIIDC	IIILC	IV	VCOC	VCC	Combined Simple	U.S. Total
Total Costs, MM$/Yr.(3)	262.9	403.9	111.2	1,079.2	320.8	59.8	77.3	208.0	73.6	2,596.7
RVP Costs, ¢/B/# RVP(4)	43	37	42	44	50	43	39	30	52	42 (6)
Octane Costs, ¢/B/O.N.(4)(5)	89	62	44	97	110	34	104	55	116	81 (6)
Material Balance Changes, MBPCD(3)										
Raw Materials										
Sweet Crudes	(55)	157	10	(53)	-	-	-	-	-	59
High Sulfur Light Crudes	2	(31)	(8)	(350)	9	-	-	-	-	(378)
High Sulfur Heavy Crudes	53	(126)	(2)	403	(9)	-	-	-	-	571
Total Crudes	-	-	-	-	-	-	-	-	-	-
Natural Gasoline	-	-	-	-	(22)	-	-	-	-	(22)
Normal Butane	-	-	-	-	-	-	-	-	-	-
Iso-Butane	1	8	-	-	(2)	(1)	-	-	-	6
Vacuum Gas Oil	-	-	-	-	(21)	-	-	-	-	(21)
Oxygenates	5	13	4	16	2	1	1	2	(1)	43
Total Raw Materials	6	21	4	16	(43)	-	1	2	(1)	6
Products										
Low Lead Regular Gasolines	(7)	(17)	(3)	(22)	(11)	(4)	(2)	(5)	-	(71)
Unleaded Regular Gasolines	(2)	(71)	(11)	57	(21)	(8)	6	(17)	(12)	(79)
Unleaded Premium Gasolines	(45) (7)	(13)	(2)	(167) (7)	(39) (7)	(1)	(13) (7)	(9)	-	(289) (7)
Total Motor Gasolines	(54)	(101)	(16)	(132)	(71)	(13)	(9)	(31)	(12)	(439)
Kero Jet/Distillate Fuels	11	107	11	(27)	5	6	-	4	-	117
Residual Fuels	35	(5)	(1)	69	4	-	3	-	-	105
Marketable Coke - FOE	(2)	(10)	-	3	-	-	-	-	-	(9)
Petrochem Naphtha	-	-	-	38	7	-	-	-	8	53
Butane to Fuel(8)	12	23	8	49	13	5	4	15	3	132
Propane	(2)	(4)	-	3	(1)	-	-	2	-	(2)
Process Gas - FOE	1	(4)	1	6	(2)	1	2	8	-	13
Catalytic Coke - FOE	(1)	(6)	-	1	(2)	-	-	-	-	(8)
Loss/(Gain)	6	21	1	6	4	1	1	4	-	44
Total Products	6	21	4	16	(43)	-	1	2	(1)	6
Process Units - Added Utilization, %(3)										
Cat Cracking(9)	(4.4)	(7.5)	- *	(0.5)	(7.3)	(1.5)	- *	- *	-	N/A
Coking(9)	(6.6)	(11.5)	-	1.8*	-	- *	(0.5)	- *	-	N/A
Cat Reforming(9)	- *	- *	3.7	- *	- *	4.9	- *	11.9	- *	N/A
Alkylation	1.4*	- *	2.5	1.5	- *	- *	0.6	1.9*	-	1.2
Isomerization - C5/C6	- *	-	- *	- *	- *	- *	- *	- *	- *	- *
- C4	-	(8.3)	92.4*	-	34.1	10.8	1.9	4.6	-	5.7

(1) Based on 1.0 psi reduction in gasoline RVP on an annual basis (with the butane, which is removed from gasoline, routed to refinery fuel), combined with a 1.0 (R + M)/2 octane increase on unleaded gasoline grades.
(2) Based on market prices and unlimited demand. Assume fixed grade ratios, fixed total crude rate and no new facilities.
(3) Above 1988 optimum major products without new facilities case (Tables E-7 and E-7A).
(4) Total and unit costs for reduced RVP were taken from Table E-8; then total costs for increased octanes were calculated based on the difference between total cost for reduced RVP and total costs for combined reduced RVP and increased octanes. These calculated total costs for increased octanes were then divided by average unleaded gasoline rate to get unit octane costs.
(5) Based on oxygenates octane costs of 80¢/B/O.N.
(6) Average.
(7) Reduced premium unleaded grade disproportionately (at about $1.00/B/O.N.) to avoid over-constrained solution.
(8) Butane removed from gasolines, which is 2.0% of gasoline volume, is routed to fuel.
(9) Utilization increase includes effects of non-unitary capacity factors for some feedstocks and severities.
* At limiting capacity utilization; N/A = Not available.

TABLE E-9A

1988 MAXIMUM SENSITIVITY TO REDUCED GASOLINE VAPOR PRESSURE COMBINED WITH INCREASED GASOLINE OCTANES CASE(1)
WITH OPTIMUM MAJOR PRODUCTS WITHOUT NEW FACILITIES(2)
MATERIAL BALANCE AND MAJOR PROCESS UNIT RESULTS(3)
NPC STUDY

Material Balance(4) - MBPCD	IC	IIDC	IILC	IIIDC	IIILC	IV	VCOC	VCC	Combined Simple	U.S. Total
Raw Materials										
Sweet Crudes	733	1,427	411	2,232	751	279	48	186	376	6,443
High Sulfur Light Crudes	59	150	91	915	186	56	28	-	5	1,490
High Sulfur Heavy Crudes	279	686	160	1,531	305	131	357	1,316	480	5,245
Total Crudes	1,071	2,263	662	4,678	1,242	466	433	1,502	861	13,178
Natural Gasoline	-	29	5	64	-	1	-	4	-	103
Normal Butane	15	62	21	85	21	14	15	11	2	246
Iso-Butane	1	36	7	57	-	-	-	-	-	101
Vacuum Gas Oil	121	4	16	72	119	-	3	46	(60)	321
Oxygenates	11	21	6	43	7	2	2	4	5	101
Other	14	18	(1)	62	30	(4)	(2)	27	29	173
Total Raw Materials	1,233	2,433	716	5,061	1,419	479	451	1,594	837	14,223
Products										
Low Lead Regular Gasolines	75	205	57	379	89	71	32	118	-	1,026
Unleaded Regular Gasolines	402	838	274	1,518	408	152	103	403	114	4,212
Unleaded Premium Gasolines	98	157	54	411	80	15	33	213	-	1,061
Total Motor Gasolines	575	1,200	385	2,308	577	238	168	734	114	6,299
Kero Jet/Distillate Fuels	380	855	199	1,691	430	149	175	487	233	4,599
Residual Fuels	86	35	16	113	147	8	66	128	124	723
Asphalt/Road Oil	42	61	54	35	41	24	1	17	153	428
Marketable Coke - FOE	19	55	-	121	-	7	10	86	-	298
Petrochem Naphtha	3	(1)	-	37	(8)	-	-	-	17	48
Lubes	8	21	4	60	20	1	-	9	34	157
Petrochem Gas Oil	-	-	-	117	68	-	-	-	18	203
Butane to Fuel	12	23	8	49	13	5	4	15	3	132
Propane	36	67	24	112	29	9	5	34	-	316
Process Gas - FOE	66	111	25	295	55	23	18	108	19	720
Catalytic Coke - FOE	25	34	9	76	18	9	6	25	-	202
Other	38	57	14	263	74	19	15	69	111	660
Loss/(Gain)	(57)	(85)	(22)	(216)	(45)	(13)	(17)	(118)	11	(562)
Total Products	1,233	2,433	716	5,061	1,419	479	451	1,594	837	14,223
Major Process Units Utilization - MBPCD										
Cat Cracking(5)	439	738	233	1,500	373	154	94	471	-	4,002
Coking - Feed(5)	68	210	-	519	-	25	50	360	-	1,232
- Coke, FOE	19	55	-	121	-	7	10	86	-	298
Cat Reforming(5)	247	477	150	1,028	251	85	77	349	70	2,734
Alkylation	60	165	44	292	67	28	24	87	-	767
Isomerization - C5/C6	8	69	12	94	26	4	2	14	5	234
- C4	-	5	1	0	8	4	4	2	0	24
Severity										
Cat Cracking, Conv. %	78.0	77.3	74.9	79.9	79.8	76.2	76.9	70.0	-	77.5(6)
Cat Reforming, RONC	99.7	99.5	98.5	99.4	98.9	96.7	99.6	99.9	98.0	99.3(6)

(1) Based on a 1.0 psi reduction in gasoline RVP on an annual basis (with the butane, which is removed from gasolines, routed to refinery fuel), combined with a 1.0 (R + M)/2 octane increase on unleaded gasoline grades.
(2) Based on market prices and unlimited demand. Assume fixed grade ratios, fixed total crude rate and no new facilities.
(3) For case with reduced vapor pressure combined with increased octanes, optimum major products without new facilities.
(4) Individual entries may be off by 1 MBPCD due to round-off.
(5) Utilization based on actual feed rates, ignoring severity effects.
(6) Weighted average.

TABLE E-10

1988 SENSITIVITY CASE RESULTS FOR LOS ANGELES REFINING MODEL[1]

WITH OPTIMUM PRODUCTS WITHOUT NEW FACILITIES

NPC STUDY

	Optimum Base[2]	With Maximum COCS Crude[3]	Delta Maximum COCS Crude Less Base	With Optimum COCS Crude[3]	Delta Optimum COCS Crude Less Base	Delta Maximum COCS Crude Less Optimum COCS Crude	With 1984 HGO HDS Capacity[4]	Delta 1984 HGO HDS Capacity Less Base
Refining Margin, MM $/Yr.	1,248.7	1,208.1	(40.6)	1,286.9	38.2	(78.8)	1,110.2	(138.5)[5]
Offshore Crude Value, $/B	24.84[6]	21.16[6]	22.58[7]	22.96[6]	24.42[7]	21.87[7]	-	-
Gasoline Cost Increase, ¢/Gal.	-	-	-	-	-	-	-	2.1
Added Capacity Required, MBPSD								
Hydrotreating								
Heavy Gas Oil	-	9.6	9.6	-	-	9.6	(116.5)	(116.5)
Material Balance, MBPCD								
Raw Materials								
Alaska North Slope Crude	314.3	51.3	(263.0)	242.7	(71.6)	(191.4)	124.0	(190.3)
San Joaquin Valley Heavy Crudes	167.0	232.0	65.0	167.0	-	65.0	167.0	-
California Offshore Crudes	-	200.0	200.0	73.6	73.6	126.4	-	-
Indonesia Minas Crude	69.0	67.0	(2.0)	67.0	(2.0)	-	259.3	190.3
Other Crudes	310.0	310.0	-	310.0	-	-	310.0	-
Total Crudes	860.3	860.3	-	860.3	-	-	860.3	-
Other	63.0	63.0	-	63.0	-	-	63.0	-
Total Raw Materials	923.3	923.3	-	923.3	-	-	923.3	-
Products								
Motor Gasolines[8]	439.7	458.0	18.3	438.7	(1.0)	19.3	433.8	(5.9)
Kero Jet/Distillate Fuels[8]	213.8	109.9	(103.9)	208.0	(5.8)	(98.1)	212.5	(1.3)
Diesel - 0.05% Sulfur	77.0	77.0	-	77.0	-	-	77.0	-
Residual Fuels								
<0.3% Sulfur	-	-	-	-	-	-	-	-
0.3-0.7% Sulfur	2.9	4.0	1.1	4.0	1.1	-	3.3	0.4
0.7-1.0% Sulfur	0.7	-	(0.7)	-	(0.7)	-	0.8	0.1
1.0-2.0% Sulfur	50.1	42.5	(7.6)	42.4	(7.7)	0.1	56.1	6.0
>2.0% Sulfur	15.5	105.3	89.8	26.1	10.6	79.2	17.3	1.8
Total Residual Fuels	69.2[8]	151.8[9]	82.6	72.5[9]	3.3	79.3	77.5[8]	8.3
Marketable Coke	54.0	57.3	3.3	57.3	3.3	-	52.0	(2.0)
Propane	15.6	17.1	1.5	16.1	0.5	1.0	14.8	(0.8)
Process Gas - FOE	60.7	60.0	(0.7)	61.0	0.3	(1.0)	60.7	-
Catalytic Coke	12.5	11.9	(0.6)	12.4	(0.1)	(0.5)	12.2	(0.3)
Other Products	42.0	42.0	-	42.0	-	-	42.0	-
Loss/(Gain)	(61.2)	(61.7)	(0.5)	(61.7)	(0.5)	-	(59.2)	2.0
Total Products	923.3	923.3	-	923.3	-	-	923.3	-

TABLE E-10

(Page 2)

1988 SENSITIVITY CASE RESULTS FOR LOS ANGELES REFINING MODEL(1)

WITH OPTIMUM PRODUCTS WITHOUT NEW FACILITIES

NPC STUDY

	Optimum Base(2)	With Maximum COCS Crude(3)	Delta Maximum COCS Crude Less Base	With Optimum COCS Crude(3)	Delta Optimum COCS Crude Less Base	Delta Maximum COCS Crude Less Optimum COCS Crude	With 1984 HGO HDS Capacity(4)	Delta 1984 HGO HDS Capacity Less Base
Process Units								
Utilization, MBPCD								
Cat Cracking(10)	286.4*	288.0*	1.6	287.4*	1.0	0.6	286.2*	(0.2)
Coking - Feed(10)	231.3*	231.3*	-	231.3*	-	-	231.3*	-
- Coke - FOE	54.0	57.3	3.3	57.3	3.3	-	52.0	(2.0)
Cat Reforming(10)	187.5	198.7*	11.2	186.9	(0.6)	11.8	185.0	(2.5)
Alkylation	49.0	50.5	1.5	49.4	0.4	1.1	48.1	(0.9)
Isomerization - C5/C6	-	-	-	-	-	-	-	-
- C4	2.8	3.1	0.3	3.3	0.5	(0.2)	2.5	(0.3)
Hydrotreating								
Distillate	114.3*	99.9	(14.4)	114.3*	-	(14.4)	114.3*	-
Heavy Gas Oil	211.2*	219.3*	8.2	211.2*	-	8.2	112.2*	(99.0)
Severity								
Cat Cracking, Conv. %	70.0*	70.0*	-	69.3	(0.7)	0.7	70.0*	-
Cat Reforming, RONC	99.3	99.7	0.4	99.5	0.2	0.2	99.6	0.3

(1) Special sensitivity results from runs on Los Angeles model only.
(2) 1988 optimum products without new facilities case (Tables E-7 and E-7A) serves as the base case for these sensitivity cases.
(3) Processing additional crude supply from new South Coast Pipeline, including California offshore (COCS) and incremental San Joaquin Valley Heavy (SJVH) crudes.
(4) With heavy gas oil (HGO) hydrotreating (HDS) capacity reduced to 1984 level (before imposition of future cat cracking SOX emission rule). Planned compliance has almost doubled HGO hydrotreating capacity for 1988. This case uses an alternate means of low sulfur crude substitution to comply with 1988 SOX limit rule.
(5) This reduction in earnings is sufficient to payout the $168 million HGO hydrotreating investment to get from 1984 to 1988 capacity in 2.2 years after taxes.
(6) Shadow values of last barrel of COCS crude based on product prices and variable operating costs.
(7) Average value of COCS and SJVH crudes increment based on refinery margin change between cases.
(8) Fixed grade ratio at 1988 high demand case level. Distillate varies at combined distillate plus 0.05% sulfur diesel production ratio.
(9) Highest sulfur residual fuel allowed to optimize independently. Lower sulfur (<2%) residual fuels allowed to optimize up to maximum of 1988 high demand case rate.
(10) Utilization is based on actual feed rates, ignoring severity effects.
* Limited at maximum throughput rate or severity in LP run. Limiting rates include effects of non-unitary capacity factors for some feedstocks and severities.

TABLE F-1

U.S. SUPPLY AND DEMAND FORECAST

1990 LOW DEMAND CASE ESTIMATE - MBPCD

NPC STUDY

	Supply			Demand		
	Field Production	Imports	Refinery Production	Refinery Input	Exports	Demand Products
Crudes						
Domestic	7,830(1)	-	-	7,587	243	-
Foreign	-	3,229	-	3,229	-	-
[Total Crudes]	[7,830]	[3,229]	[-]	[10,816]	[243]	[-]
Products - NGL/Unfin.						
Natural Gasoline	280	52	-	136	3	193
Ethane	484	27	16	-	5	522
Propane	506	37	231	5	30	739
Normal Butane	195	108	47	231	10	109
Iso-Butane	95	-	-	68	3	24
Unfinished	-	264	-	264	-	-
Mogas Components	-	95	-	95	-	-
Oxygenates and Other	60	-	-	60	-	-
[Total - NGL/Unf. Prd.]	[1,620]	[583]	[294]	[859]	[51]	[1,587]
Products - Finished						
Motor Gasolines	-	869	5,005	-	6	5,868
Aviation Gasolines	-	-	40	-	-	40
Naphtha Jet	-	49	213	-	3	259
Kero Jet/Kerosene	-	163	916	-	7	1,072
Distillate Fuels	-	418	2,553	-	51	2,920
Residual Fuels						
<0.3% Sulfur	-	173	92	-	-	265
0.3-1.0% Sulfur	-	148	211	-	-	359
>1.0% Sulfur	-	289	621	-	190	720
[Total Residual Fuels]	[-]	[610]	[924]	[-]	[190]	[1,344]
Petrochem Naphtha	-	142	187	-	21	308
P/Chem Gas Oil + C. Black	-	-	351	-	15	336
Special Naphtha/Misc.	-	74	154	-	3	225
Lube and Wax	-	16	188	-	16	188
Marketable Coke - FOE	-	-	178	-	178	-
Catalytic Coke - FOE	-	-	150	-	-	150
Asphalt/Road Oil	-	21	486	-	1	506
Process Gas - FOE	-	-	475	-	-	475
[Total Finished Prods.]	[-]	[2,362]	[11,820]	[-]	[491]	[13,691]
Total Crudes and Products	9,450	6,174	12,114	11,675	785	15,278
(Gain)/Loss	-	-	(439)	-	-	-

(1) Includes 30 MBPCD of syncrude.

TABLE F-2

REFINERY RAW MATERIALS INPUT RATES DETAIL

FORECAST 1990 LOW DEMAND CASE RESULTS - MBPCD

NPC STUDY

	IC	IS	IIDC	IILC	IIS	IIIDC	IIILC	IIIS	IV	VCOC	VCC	VS	U.S. Total
Domestic Crudes	148	35	1,451	213	24	2,780	516	190	382	352	1,225	271	7,587
Foreign Crudes	766	63	540	277	8	879	449	26	31	58	128	4	3,229
Total Crudes	914	98	1,991	490	32	3,659	965	216	413	410	1,353	275	10,816
Natural Gasoline	-	-	31	6	-	69	25	-	1	-	4	-	136
Reformate - 95 RONC	8	-	15	1	-	27	34	8	1	(6)	3	4	95
Naphtha	9	-	1	6	-	37	11	10	(1)	(2)	-	-	71
Vacuum Gas Oil	69	(6)	4	15	(6)	76	31	-	-	3	42	(31)	197
Vacuum Resid.	(3)	-	(1)	(7)	-	(21)	(6)	-	(4)	1	4	-	(37)
Normal Butane	14	-	58	13	-	89	27	-	12	14	3	1	231
Iso-Butane	-	-	36	6	-	18	7	-	1	-	-	-	68
MTBE	3	1	2	-	-	16	4	3	-	-	-	2	31
Ethanol	-	-	4	2	-	2	-	-	-	1	2	-	11
Methanol	1	-	-	-	-	1	-	-	-	-	-	-	2
TBA	2	-	-	-	-	4	-	-	-	-	-	-	6
Propane	-	-	3	-	-	2	-	-	-	-	-	-	5
Nat. Gas Fd. to H_2 - FOE	1	-	2	-	-	21	-	-	-	2	17	-	43
Total Input	1,018	93	2,146	532	26	4,000	1,098	237	423	423	1,428	251	11,675

TABLE F-3

REFINERY PRODUCT RATES DETAIL

FORECAST 1990 LOW DEMAND CASE RESULTS - MBPCD

NPC STUDY

	IC	IS	IIDC	IILC	IIS	IIIDC	IIILC	IIIS	IV	VCOC	VCC	VS	U.S. Total
Motor Gasolines													
Low Lead Regular	37	-	112	23	-	170	40	-	40	19	60	-	501
Unleaded Regular	313	7	816	188	2	1,068	296	48	136	94	350	35	3,353
Unleaded Premium	124	-	165	40	-	464	90	-	15	48	205	-	1,151
Total	474	7	1,093	251	2	1,702	426	48	191	161	615	35	5,005
Aviation Gasolines	-	-	3	2	-	18	3	-	2	2	10	-	40
Naphtha Jet	20	5	17	4	8	45	16	29	15	11	35	8	213
Kero Jet/Kerosene	38	1	115	43	-	354	72	12	22	50	191	18	916
Distillate Fuels	250	22	523	94	6	907	229	48	108	93	211	62	2,553
Residual Fuels													
<0.3% Sulfur	29	-	2	2	1	23	6	6	4	6	8	5	92
0.3-0.7% Sulfur	25	-	-	3	1	20	1	-	2	13	8	6	79
0.7-1.0% Sulfur	22	5	6	9	1	31	19	17	3	-	1	18	132
1.0-2.0% Sulfur	7	-	28	4	-	72	13	1	4	72	146	20	367
>2.0% Sulfur	17	-	8	9	1	58	105	-	3	-	43	10	254
Total	100	5	44	27	4	204	144	24	16	91	206	59	924
Asphalt/Road Oil	62	34	91	67	3	47	56	19	36	1	24	46	486
Marketable Coke - FOE	8	-	44	-	-	58	-	-	2	5	61	-	178
Benzene	1	-	5	1	-	15	6	-	-	-	-	-	28
Toluene	6	-	8	-	-	29	5	-	-	-	-	-	48
Xylene	-	-	9	-	-	41	5	-	-	-	-	-	55
Spcl. Naph./Misc.	6	4	21	1	1	-	30	21	2	-	15	2	103
Petrochem Naphtha	23	3	25	14	-	-	16	-	6	8	8	4	107
Lubes	14	8	25	4	1	72	23	12	1	-	11	2	173
Wax	-	1	1	1	-	4	1	3	1	-	3	-	15
Petrochem Gas Oil	(32)	-	33	(2)	-	273	20	8	2	(5)	8	6	311
Carbon Black Feed	-	-	-	4	-	21	13	-	-	-	2	-	40
Normal Butane	5	-	(4)	-	-	41	(3)	1	(2)	2	7	-	47
Propane	29	-	59	17	-	70	19	-	7	4	26	-	231
Process Gas/Ethane	44	1	86	14	-	193	35	10	17	11	75	5	491
Catalytic Coke - FOE	22	-	31	7	-	41	11	-	7	6	25	-	150
(Gain)/Loss	(52)	2	(83)	(17)	1	(135)	(29)	2	(10)	(17)	(105)	4	(439)
Total Products	1,018	93	2,146	532	26	4,000	1,098	237	423	423	1,428	251	11,675

TABLE F-4

REFINERY DOMESTIC CRUDE INPUT RATES DETAIL

FORECAST 1990 LOW DEMAND CASE RESULTS - MBPCD

NPC STUDY

Location/Name	LP Code	Type	IC	IS	IIDC	IILC	IIS	IIIDC	IIILC	IIIS	IV	VCOC	VCC	VS	U.S. Total
AL Heavy	ALH	MH	-	-	-	-	-	24	-	-	-	-	-	-	24
Light	ALL	S	-	-	6	-	-	-	-	12	-	-	-	-	18
AK Cook	AKC	S	-	-	-	-	-	-	-	-	-	12	6	12	30
North Slope	ANS	MH	83	-	248	18	17	470	152	-	-	262	438	106	1,794
AZ Sweet	AZS	S	-	-	-	-	-	1	-	-	-	-	-	-	1
AR Heavy	ARH	HH	-	-	-	-	-	-	32	8	-	-	-	-	40
CA Beta	CBT	HH	-	-	-	-	-	-	-	-	-	-	18	-	18
Elk Hills	CEH	S	-	-	43	-	-	44	-	-	-	-	34	39	160
Huntington Beach	CHB	HH	-	-	-	-	-	-	-	-	-	-	24	-	24
Hondo	CAH	HH	13	4	-	-	-	41	-	-	-	-	-	14	72
LA Basin Light	CLL	HH	-	-	-	-	-	-	-	-	-	-	12	25	37
San Ardo	CSA	HH	-	-	-	-	-	-	-	-	-	-	76	-	76
SJV Light	CJL	HH	-	-	-	-	-	-	-	-	-	-	56	50	106
SJV Kern River	CJH	HH	-	-	-	-	-	-	-	-	-	14	106	20	140
SJV Heavy	CVH	HH	-	-	-	-	-	-	-	-	-	25	288	-	313
Ventura	CCV	HH	-	-	-	-	-	-	18	-	-	39	-	-	57
Wilmington Heavy	CWH	HH	-	-	-	-	-	-	-	-	-	-	107	-	107
Wilmington Light	CWL	HH	-	-	-	-	-	-	-	-	-	-	60	-	60
CO Rangely	COR	S	-	-	4	-	-	-	-	-	53	-	-	-	57
Shale Oil Syncr.	SHO	S	-	-	-	-	-	-	-	-	30	-	-	-	30
FL Jay	FLJ	S	-	1	-	7	-	-	25	-	-	-	-	-	33
IL Sweet	ILS	S	-	-	35	-	-	-	-	-	-	-	-	-	35
Weeks	ILW	S	-	-	-	36	-	-	-	-	-	-	-	-	36
IN Sweet	IDS	S	-	-	13	-	-	-	-	-	-	-	-	-	13
KS Butler	KSB	S	-	-	-	17	-	-	-	-	-	-	-	-	17
Common	KSC	S	-	-	30	-	-	-	-	-	-	-	-	-	30
Light	KSL	S	-	-	70	-	-	-	-	-	-	-	-	-	70
KY Sweet	KYS	S	-	-	13	-	-	-	-	-	-	-	-	-	13
LA Condensate	LAC	S	-	-	-	-	-	50	-	29	-	-	-	-	79
Light Sweet	LLS	S	42	-	3	-	-	39	39	-	-	-	-	-	123
North Mix	LAM	S	-	-	-	-	-	36	-	26	-	-	-	-	62
Heavy Sweet	LAO	S	4	1	126	-	-	681	-	-	-	-	-	-	812
MI Sweet	MIS	S	-	3	25	18	7	-	-	-	-	-	-	-	53
MS Baxterville	MSB	HH	-	-	-	-	-	34	-	12	-	-	-	-	46
Light Hey	MSH	HL	-	-	-	-	-	17	-	-	-	-	-	-	17
Sweet	MSS	S	-	-	-	-	-	8	-	-	-	-	-	-	8
MT Sour	MTS	HH	-	-	6	-	-	-	-	-	12	-	-	-	18
Rebeki	MTR	S	-	-	27	-	-	-	-	-	27	-	-	-	54
NE Light Sour	NES	ML	-	-	10	-	-	-	-	-	-	-	-	-	10
NV Sweet	NVS	S	-	-	-	-	-	-	-	-	-	-	-	5	5
NM Intermediate	NMI	S	-	-	32	-	-	-	37	17	-	-	-	-	86
Sour	NMS	HL	-	-	-	-	-	62	-	-	-	-	-	-	62
NY Lube	NYL	S	-	2	-	-	-	-	-	-	-	-	-	-	2
ND Light Sour	NDS	S	-	-	46	20	-	-	-	-	15	-	-	-	81
OH/MO Light	OHL	S	-	5	34	-	-	-	-	-	-	-	-	-	39
OK Cement	OKM	S	-	-	117	5	-	1	-	-	-	-	-	-	123
Condensate	OKC	S	-	-	-	7	-	-	-	-	-	-	-	-	7
Garber	OKG	S	-	-	54	30	-	-	-	-	-	-	-	-	84
Velma	OKV	HH	-	-	6	41	-	-	-	-	-	-	-	-	47
PA Lube	PAL	S	-	11	-	-	-	-	-	-	-	-	-	-	11
SD Sweet	SDS	S	-	-	2	-	-	-	-	-	-	-	-	-	2
TX Condensate	TXC	S	-	-	-	-	-	-	18	14	-	-	-	-	32
East	TXE	S	-	-	90	-	-	67	-	-	-	-	-	-	157
Hawkins	TEH	HH	-	-	90	-	-	50	30	-	-	-	-	-	170
Gulf Refugio	TGR	S	6	-	-	-	-	477	46	14	-	-	-	-	543
West Intermed.	TWI	S	-	-	99	-	-	255	47	58	-	-	-	-	459
West Scurry	TWY	S	-	-	40	-	-	-	-	-	-	-	-	-	40
West Sour	TWS	HL	-	-	56	14	-	423	59	-	-	-	-	-	552
UT Altamont	UTA	S	-	-	-	-	-	-	-	-	26	-	-	-	26
Mix	UTM	S	-	-	-	-	-	-	13	-	44	-	-	-	57
WV Lube	WVL	S	-	8	-	-	-	-	-	-	-	-	-	-	8
WY Platte/Sour	WYP	HH	-	-	57	-	-	-	-	-	126	-	-	-	183
Sweet	WYS	S	-	-	69	-	-	-	-	-	49	-	-	-	118
Total			148	35	1,451	213	24	2,780	516	190	382	352	1,225	271	7,587
Subtotal By Type															
Sweet		S	52	31	978	140	7	1,659	225	170	244	12	40	56	3,614
Medium Sulfur Light		ML	-	-	10	-	-	-	-	-	-	-	-	-	10
Medium Sulfur Heavy		MH	83	-	248	18	17	494	152	-	-	262	438	106	1,818
High Sulfur Light		HL	-	-	56	14	-	502	59	-	-	-	-	-	631
High Sulfur Heavy		HH	13	4	159	41	-	125	80	20	138	78	747	109	1,514

TABLE F-5

REFINERY FOREIGN CRUDE INPUT RATES DETAIL

FORECAST 1990 LOW DEMAND CASE RESULTS - MBPCD

NPC STUDY

Country	Name	LP Code	Type	IC	IS	IIDC	IILC	IIS	IIIDC	IIILC	IIIS	IV	VCOC	VCC	VS	U.S. Total
Abu Dhabi/Dubai/Oman/UAE		UAD	HL	5	-	5	-	-	12	47	-	-	-	-	-	69
Algeria	Condensate	AGC	S	-	-	-	-	-	34	-	-	-	-	1	-	35
	Saharan	AGH	S	-	3	-	-	-	-	-	-	-	-	2	-	5
Angola		ANG	S	74	1	-	-	-	-	12	-	-	-	-	-	87
Australia		AUS	S	4	-	-	-	-	2	2	-	-	4	13	1	26
Cameroon	Kole	CMK	S	38	-	-	-	-	-	6	-	-	-	-	-	44
Canada	Condensate	CNC	S	-	-	-	-	-	-	-	-	3	-	-	-	3
	Interprov.	CNI	ML	10	-	46	1	1	-	-	-	-	-	-	-	58
	Lloydmin.	CNL	HH	7	-	215	12	6	-	-	-	8	-	-	-	248
	Rangeland	CNR	ML	-	-	-	-	-	-	-	-	20	20	-	-	40
China	Daqing	CHD	S	4	8	-	-	-	4	-	-	-	-	-	-	16
Congo	Djeno	CGD	S	34	-	-	-	-	-	-	-	-	-	-	-	34
Ecuador	Oriente	ECO	MH	1	-	2	13	-	27	3	-	-	-	1	-	47
Egypt	Belayim	EGB	HH	6	-	-	-	-	-	-	-	-	-	-	-	6
Gabon	Gamba	GBG	S	18	-	-	-	-	-	1	-	-	-	-	-	19
	Lucina	GBL	S	5	-	-	-	-	4	-	-	-	-	-	-	9
	Mandji	GBM	HH	5	-	-	-	-	22	5	-	-	-	-	-	32
Guatemala		GUT	HH	-	-	-	-	-	3	-	-	-	-	-	-	3
India	Bombay	IDB	S	64	-	-	-	-	-	-	-	-	-	4	-	68
Indonesia	Attaka	INA	S	-	-	-	-	-	-	-	-	-	-	-	-	-
	Condensate	INC	S	-	-	-	-	-	-	-	3	-	9	18	1	31
	Heavy	INV	S	2	-	-	-	-	-	1	-	-	1	3	-	7
	Minas	INM	S	23	1	-	-	-	65	21	-	-	24	86	-	220
Iran	Heavy	IRH	HH	2	-	-	-	-	5	1	-	-	-	-	-	8
	Light	IRL	HL	-	-	4	-	-	-	-	-	-	-	-	-	4
Iraq	Kirkuk	IQK	HL	-	-	-	-	-	6	6	-	-	-	-	-	12
Ivory Coast		ICE	S	-	-	-	-	-	6	-	-	-	-	-	-	6
Kuwait		KUW	HH	6	-	2	1	-	17	-	-	-	-	-	-	26
Mexico	Blend	MXB	HH	2	-	10	8	-	4	53	-	-	-	-	-	77
	Isthmus	MXI	HL	3	-	24	10	-	70	37	-	-	-	-	-	144
	Maya	MXM	HH	75	17	101	35	-	97	81	-	-	-	-	-	406
Netherlands		NTH	S	3	-	-	-	-	-	-	-	-	-	-	-	3
Nigeria	Forcados	NGF	S	-	-	-	-	-	-	-	-	-	-	-	-	-
	Light	NGL	S	-	-	-	-	-	-	-	-	-	-	-	-	-
	Medium	NGM	S	139	-	62	-	-	-	8	-	-	-	-	-	209
Norway	Ekofisk	NWE	S	-	-	-	-	-	-	-	-	-	-	-	-	-
	Statfjord	NWS	S	-	-	-	-	-	3	-	-	-	-	-	-	3
Saudia Arabia	Heavy	SAH	HH	66	-	-	154	-	52	111	-	-	-	-	-	383
	Light	SAL	HL	17	2	-	39	-	209	28	-	-	-	-	-	295
	Medium	SAM	HH	1	-	22	-	-	-	25	-	-	-	-	-	48
Sharja		SHJ	S	8	-	-	-	-	7	-	-	-	-	-	-	15
Trinidad	Light	TDL	S	17	-	46	4	-	24	-	-	-	-	-	-	91
United Kingdom	Brent	UKB	S	53	5	-	-	-	17	-	-	-	-	-	-	75
	Light	UKL	S	-	-	-	-	-	-	-	-	-	-	-	-	-
	Sour	UKS	HL	3	-	-	-	-	3	-	-	-	-	-	-	6
Venezuela	Boscan	VZB	HH	-	26	-	-	-	15	-	-	-	-	-	2	43
	H. Bach. 14	VZH	HH	34	-	-	-	1	155	-	23	-	-	-	-	213
	Lagomedia	VZL	HH	3	-	1	-	-	5	-	-	-	-	-	-	9
	T.Juana Med.	VZT	HH	3	-	-	-	-	11	-	-	-	-	-	-	14
Zaire		ZAR	S	31	-	-	-	-	-	1	-	-	-	-	-	32
Total				766	63	540	277	8	879	449	26	31	58	128	4	3,229
Subtotal by Type																
Sweet			S	517	18	108	4	-	166	52	3	3	38	127	2	1,038
Medium Sulfur Light			ML	10	-	46	1	1	-	-	-	20	20	-	-	98
Medium Sulfur Heavy			MH	1	-	2	13	-	27	3	-	-	-	1	-	47
High Sulfur Light			HL	28	2	33	49	-	300	118	-	-	-	-	-	530
High Sulfur Heavy			HH	210	43	351	210	7	386	276	23	8	-	-	2	1,516

TABLE F-7

CRUDE UNIT CAPACITIES AND UTILIZATIONS

FORECAST 1990 LOW DEMAND CASE RESULTS

NPC STUDY

Model	Number of Refineries	Crude Capacity (MBPSD)	Crude Input (MBPCD)	Utilization[1] (%)
IC	10	1,226	914	78.5
IS	9	146	98	70.6
IIDC	23	2,508	1,991	83.6
IILC	8	656	490	78.6
IIS	5	47	32	71.7
IIIDC	28	4,783	3,659	80.5
IIILC	12	1,381	965	73.6
IIIS	17	322	216	70.6
IV	18	566	413	76.8
VCOC	6	512	410	84.3
VCC	16	1,963	1,353	72.5
VS	25	485	275	59.7
U.S. Total	177	14,595	10,816	78.0
Subtotal by Type				
Simple	56	1,000	621	62.1
Conversion[2]	121	13,595	10,195	78.9

(1) Utilization of operable calendar day capacity assuming 95% stream factor.
(2) Includes two simple refineries in PADD IV with a capacity of 18 MBPSD.

TABLE F-8

REFINERY PROCESS UNIT UTILIZATIONS

1990 LOW DEMAND CASE RESULTS - %(1)

NPC STUDY

	IC	IIDC	IILC	IIIDC	IIILC	IV	VCOC	VCC
Crude - Atmospheric	78.5	83.6	78.6	80.5	73.6	76.8	84.3	72.5
- Vacuum	71.7	87.4	79.9	71.9	65.7	94.7	102.8(4)	71.6
Catalytic Cracking(2)	76.4	84.3	75.6	60.0	55.0	80.2	92.3*	87.1
Catalytic Cracking(3)	72.3	79.0	74.3	59.1	54.1	77.2	89.7	83.3
Conversion, %	77.9	75.6	74.7	75.8	75.9	76.3	75.8	70.0
Hydrocracking	92.5*	92.6*	91.8*	92.7*	91.3*	91.8*	92.6*	86.8
Jet Yield, % of Maximum	79.8	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Coking - Delayed(2)	0	64.4	-	58.0	-	92.1*	43.6	68.9
- Delayed(3)	0	64.4	-	58.0	-	92.1	43.6	68.9
- Fluid	56.4	-	-	0	-	0	-	60.3
- Combined(3)	34.5	64.4	-	52.8	-	31.3	43.6	67.1
Combined Coke	26.2	60.9	-	37.2	-	19.8	34.9	71.6
Th. Crk./Vis. Brk.	92.0*	90.9*	-	92.6*	44.1	-	-	91.1*
Solvent Deasphalting	92.4*	92.7*	-	54.8	80.9	57.7	92.5*	93.9*
Catalytic Reforming								
Low Pressure(2)	92.4*	92.1*	70.1	92.4*	92.5*	92.6*	92.3*	92.1*
RONC	98.7	98.6	93.4	99.5	97.2	99.0	98.2	100.0*
High Pressure(2)	35.8	49.3	0	29.9	0.9	26.0	76.4	27.8
RONC	97.7	94.2	-	96.2	95.0	91.4	99.4	100.0*
Combined(3)	50.3	70.7	52.4	74.8	53.6	49.5	68.3	50.1
RONC	98.3	97.4	93.4	98.8	97.2	96.5	98.9	100.0*
Hydrotreating								
Naphtha	34.6	55.0	52.2	61.1	44.7	34.1	52.8	26.6
Distillate	46.2	47.1	32.5	54.9	47.7	57.3	13.0	43.5
Heavy Gas Oil	47.4	87.9	89.0	92.0	85.1	92.0*	-	74.3
Residuum	-	-	-	92.3*	-	-	-	94.2*
Alkylation	73.7	86.2	60.0	53.5	80.4	79.1	84.7	79.1
Polymerization	0	0	0	0	0	40.1	0	0
Isomerization - C5/C6	0	45.4	33.6	92.4*	92.6*	42.9	-	92.4*
- C4	-	0	-	0	92.6*	48.0	64.0	12.7
Hydrogen	82.1	80.2	-	81.4	79.7	86.1	81.8	81.4
Asphalt	99.0(4)	70.2	80.4	54.1	108.5(4)	105.7(4)	83.8	96.2
Lubes	76.1	91.8	94.5	85.4	80.9	73.0	-	56.7
Aromatics	59.9	56.6	N/A (5)	81.8	53.2	-	-	0
Hydrodealkylation	0	41.4	-	53.3	-	-	-	-

* Limited at maximum throughput in LP run.
- = No unit; 0 = Unit not operating; N/A = Not applicable.
(1) Utilizations assume a 95% stream factor for crude units and a 92% stream factor for all other units.
(2) Utilization includes effects of non-unitary capacity factors for some feedstocks and severities.
(3) Alternate utilization is based on actual feed rates, ignoring severity effects.
(4) High utilizations (above 94.5%) indicate errors in reported capacity (calibration) or minor process capacity with little impact on results.
(5) Reported production with no reported capacity - same as calibration case.
(6) Utilization based on base 1988 capacity (Table C-6) plus new capacity (Table F-10).

TABLE F-10

NEW PROCESS UNITS CAPACITY REQUIRED

AND INCREMENTAL OCTANE COST RESULTS

FORECAST 1990 LOW DEMAND CASE

NPC STUDY

	IC	IIDC	IILC	IIIDC	IIILC	IV	VCOC	VCC	U.S. Total/ Average(1)
New Capacity - MBPSD	-	-	-	-	-	-	-	-	-
Incremental Octane Costs(2) - ¢/B/O.N.									
Pool Average	25	22	13	34	28	24	17	19	26

(1) Total new capacity. Weighted average octane costs for conversion refineries only.
(2) Shadow values determined by models based on stock costs and variable operating costs.

TABLE G-1

U.S. SUPPLY AND DEMAND FORECAST

1990 HIGH DEMAND CASE ESTIMATE - MBPCD

NPC STUDY

	Supply			Demand		
	Field Production	Imports	Refinery Production	Refinery Input	Exports	Demand Products
Crudes						
Domestic	7,830(1)	-	-	7,587	243	-
Foreign	-	6,485	-	6,485	-	-
[Total Crudes]	[7,830]	[6,485]	[-]	[14,072]	[243]	[-]
Products - NGL/Unfin.						
Natural Gasoline	280	46	-	120	3	203
Ethane	484	67	21	-	5	567
Propane	506	25	305	6	30	800
Normal Butane	195	129	73	250	10	137
Iso-Butane	95	22	-	107	3	7
Unfinished	-	232	-	248	-	(16)
Mogas Components	-	83	-	83	-	-
Oxygenates and Other	60	-	-	60	-	-
[Total - NGL/Unf. Prd.]	[1,620]	[604]	[399]	[874]	[51]	[1,698]
Products - Finished						
Motor Gasolines	-	198	6,352	-	6	6,544
Aviation Gasolines	-	-	56	-	-	56
Naphtha Jet	-	14	248	-	3	259
Kero Jet/Kerosene	-	45	1,283	-	7	1,321
Distillate Fuels	-	286	3,163	-	51	3,398
Residual Fuels						
<0.3% Sulfur	-	266	81	-	-	347
0.3-1.0% Sulfur	-	135	332	-	-	467
>1.0% Sulfur	-	281	845	-	190	936
[Total Residual Fuels]	[-]	[682]	[1,258]	[-]	[190]	[1,750]
Petrochem Naphtha	-	64	283	-	6	341
P/Chem Gas Oil + C. Black	-	-	435	-	15	420
Special Naphtha/Misc.	-	65	163	-	3	225
Lube and Wax	-	14	212	-	16	210
Marketable Coke - FOE	-	-	226	-	193	33
Catalytic Coke - FOE	-	-	198	-	-	198
Asphalt/Road Oil	-	18	563	-	1	580
Process Gas - FOE	-	-	638	-	-	638
[Total Finished Prods.]	[-]	[1,386]	[15,078]	[-]	[491]	[15,973]
Total Crudes and Products	9,450	8,475	15,477	14,946	785	17,671
(Gain)/Loss	-	-	(531)	-	-	-

(1) Includes 30 MBPCD of syncrude.

TABLE G-2

REFINERY RAW MATERIALS INPUT RATES DETAIL

FORECAST 1990 HIGH DEMAND CASE RESULTS - MBPCD

NPC STUDY

	IC	IS	IIDC	IILC	IIS	IIIDC	IIILC	IIIS	IV	VCOC	VCC	VS	U.S. Total
Domestic Crudes	95	51	1,327	220	38	2,538	365	252	462	382	1,459	398	7,587
Foreign Crudes	1,053	178	994	509	12	2,282	1,088	35	70	70	189	5	6,485
Total Crudes	1,148	229	2,321	729	50	4,820	1,453	287	532	452	1,648	403	14,072
Natural Gasoline	-	-	27	5	-	60	23	-	1	-	4	-	120
Reformate - 95 RONC	7	-	11	1	-	20	28	11	1	(5)	2	7	83
Naphtha	7	-	1	5	-	24	8	14	(1)	-	-	-	58
Vacuum Gas Oil	75	(16)	3	15	(9)	62	30	-	-	3	42	(45)	160
Vacuum Resid.	(2)	-	(1)	(7)	-	(18)	(6)	-	(3)	1	3	-	(33)
Normal Butane	16	-	62	22	-	89	20	-	15	15	9	2	250
Iso-Butane	1	-	35	11	-	56	3	-	1	-	-	-	107
MTBE	4	1	1	-	-	26	5	3	-	-	-	2	42
Ethanol	-	-	9	3	-	2	-	-	2	2	3	-	21
Methanol	1	-	-	-	-	-	1	-	-	-	-	-	2
TBA	2	-	-	-	-	3	-	-	-	-	-	-	5
Propane	-	-	3	-	-	3	-	-	-	-	-	-	6
Nat. Gas Fd. to H_2 - FOE	1	-	3	-	-	26	-	-	-	2	21	-	53
Total Input	1,260	214	2,475	784	41	5,173	1,565	315	548	470	1,732	369	14,946

TABLE G-3

REFINERY PRODUCT RATE DETAIL

FORECAST 1990 HIGH DEMAND CASE RESULTS - MBPCD

NPC STUDY

	IC	IS	IIDC	IILC	IIS	IIIDC	IIILC	IIIS	IV	VCOC	VCC	VS	U.S. Total
Motor Gasolines													
Low Lead Regular	46	-	133	35	-	218	56	-	52	21	74	-	635
Unleaded Regular	383	12	964	289	3	1,371	416	61	177	102	429	50	4,257
Unleaded Premium	152	-	197	62	-	597	126	-	19	53	254	-	1,460
Total	581	12	1,294	386	3	2,186	598	61	248	176	757	50	6,352
Aviation Gasolines	-	-	5	2	-	26	5	-	2	2	14	-	56
Naphtha Jet	18	16	15	5	14	49	18	41	16	10	29	17	248
Kero Jet/Kerosene	50	1	138	60	-	506	125	16	31	79	250	27	1,283
Distillate Fuels	284	53	603	144	10	1,123	301	64	153	86	252	90	3,163
Residual Fuels													
<0.3% Sulfur	43	-	-	-	1	-	19	7	3	-	-	8	81
0.3%-0.7% Sulfur	20	-	-	15	2	31	1	-	8	18	11	9	115
0.7-1.0% Sulfur	37	11	9	15	1	67	24	23	-	-	3	27	217
1.0-2.0% Sulfur	1	-	30	12	-	125	27	1	9	80	187	29	501
>2.0% Sulfur	22	-	11	-	2	91	148	-	4	-	51	15	344
Total	123	11	50	42	6	314	219	31	24	98	252	88	1,258
Asphalt/Road Oil	58	82	79	77	5	47	63	26	34	1	23	68	563
Marketable Coke - FOE	17	-	57	-	-	78	-	-	4	5	65	-	226
Benzene	1	-	6	1	-	25	6	-	-	-	-	-	39
Toluene	6	-	8	-	-	33	7	-	-	-	-	-	54
Xylene	-	-	9	-	-	40	6	-	-	-	-	-	55
Spcl. Naphtha/Misc.	5	6	19	1	1	-	29	29	2	-	15	2	109
Petrochem Naphtha	41	8	25	21	-	29	34	-	8	6	12	5	189
Lubes	17	17	23	5	1	75	29	15	1	-	11	3	197
Wax	-	3	1	1	-	2	1	4	1	-	2	-	15
Petrochem Gas Oil	(7)	-	27	-	-	297	58	12	-	-	-	8	395
Carbon Black Feed	-	-	-	4	-	20	14	-	-	-	2	-	40
Normal Butane	7	-	(5)	-	-	65	(5)	1	(2)	2	10	-	73
Propane	36	-	71	26	-	100	31	-	8	4	29	-	305
Process Gas/Ethane	58	1	111	22	-	266	54	13	22	12	94	6	659
Catalytic Coke - FOE	25	-	40	11	-	67	17	-	8	5	25	-	198
(Gain)/Loss	(60)	4	(101)	(24)	1	(175)	(45)	2	(12)	(16)	(110)	5	(531)
Total Products	1,260	214	2,475	784	41	5,173	1,565	315	548	470	1,732	369	14,946

TABLE G-4

REFINERY DOMESTIC CRUDE INPUT RATES DETAIL

FORECAST 1990 HIGH DEMAND CASE RESULTS - MBPCD

NPC STUDY

Location/Name	LP Code	Type	IC	IS	IIDC	IILC	IIS	IIIDC	IIILC	IIIS	IV	VCOC	VCC	VS	U.S. Total
AL Heavy	ALH	MH	-	-	-	-	-	24	-	-	-	-	-	-	24
Light	ALL	S	-	-	3	-	-	-	-	15	-	-	-	-	18
AK Cook	AKC	S	-	-	-	-	-	-	-	-	-	9	3	18	30
North Slope	ANS	MH	72	-	56	8	27	431	17	-	-	289	739	155	1,794
AZ Sweet	AZS	S	-	-	-	-	-	1	-	-	-	-	-	-	1
AR Heavy	ARH	HH	-	-	-	-	-	-	29	11	-	-	-	-	40
CA Beta	CBT	HH	-	-	-	-	-	-	-	-	-	-	18	-	18
Elk Hills	CEH	S	-	-	40	-	-	44	-	-	-	-	18	58	160
Huntington Beach	CHB	HH	-	-	-	-	-	-	-	-	-	-	24	-	24
Hondo	CAH	HH	13	5	-	-	-	32	-	-	-	-	-	22	72
LA Basin Light	CLL	HH	-	-	-	-	-	-	-	-	-	-	-	37	37
San Ardo	CSA	HH	-	-	-	-	-	-	-	-	-	-	76	-	76
SJV Light	CJL	HH	-	-	-	-	-	-	-	-	-	-	32	74	106
SJV Kern River	CJH	HH	-	-	-	-	-	-	-	-	-	15	96	29	140
SJV Heavy	CVH	HH	-	-	-	-	-	-	-	-	-	27	286	-	313
Ventura	CCV	HH	-	-	-	-	-	-	15	-	-	42	-	-	57
Wilmington Heavy	CWH	HH	-	-	-	-	-	-	-	-	-	-	107	-	107
Wilmington Light	CWL	HH	-	-	-	-	-	-	-	-	-	-	60	-	60
CO Rangely	COR	S	-	-	4	-	-	-	-	-	53	-	-	-	57
Shale Oil Syncr.	SHO	S	-	-	-	-	-	-	-	-	30	-	-	-	30
FL Jay	FLJ	S	-	1	-	7	-	-	25	-	-	-	-	-	33
IL Sweet	ILS	S	-	-	35	-	-	-	-	-	-	-	-	-	35
Weeks	ILW	S	-	-	-	36	-	-	-	-	-	-	-	-	36
IN Sweet	IDS	S	-	-	13	-	-	-	-	-	-	-	-	-	13
KS Butler	KSB	S	-	-	-	17	-	-	-	-	-	-	-	-	17
Common	KSC	S	-	-	30	-	-	-	-	-	-	-	-	-	30
Light	KSL	S	-	-	70	-	-	-	-	-	-	-	-	-	70
KY Sweet	KYS	S	-	-	13	-	-	-	-	-	-	-	-	-	13
LA Condensate	LAC	S	-	-	-	-	-	40	-	39	-	-	-	-	79
Light Sweet	LLS	S	-	-	45	-	-	39	39	-	-	-	-	-	123
North Mix	LAM	S	-	-	-	-	-	28	-	34	-	-	-	-	62
Heavy Sweet	LAO	S	4	3	225	-	-	580	-	-	-	-	-	-	812
MI Sweet	MIS	S	-	7	20	15	11	-	-	-	-	-	-	-	53
MS Baxterville	MSB	HH	-	-	-	-	-	30	-	16	-	-	-	-	46
Light Hey	MSH	HL	-	-	-	-	-	17	-	-	-	-	-	-	17
Sweet	MSS	S	-	-	-	-	-	8	-	-	-	-	-	-	8
MT Sour	MTS	HH	-	-	6	-	-	-	-	-	12	-	-	-	18
Rebeki	MTR	S	-	-	26	-	-	-	-	-	28	-	-	-	54
NE Light Sour	NES	ML	-	-	10	-	-	-	-	-	-	-	-	-	10
NV Sweet	NVS	S	-	-	-	-	-	-	-	-	-	-	-	5	5
NM Intermediate	NMI	S	-	-	32	-	-	-	32	22	-	-	-	-	86
Sour	NMS	HL	-	-	-	-	-	62	-	-	-	-	-	-	62
NY Lube	NYL	S	-	2	-	-	-	-	-	-	-	-	-	-	2
ND Light Sour	NDS	S	-	-	46	20	-	-	-	-	15	-	-	-	81
OH/MO Light	OHL	S	-	14	25	-	-	-	-	-	-	-	-	-	39
OK Cement	OKM	S	-	-	117	5	-	1	-	-	-	-	-	-	123
Condensate	OKC	S	-	-	-	7	-	-	-	-	-	-	-	-	7
Garber	OKG	S	-	-	34	50	-	-	-	-	-	-	-	-	84
Velma	OKV	HH	-	-	6	41	-	-	-	-	-	-	-	-	47
PA Lube	PAL	S	-	11	-	-	-	-	-	-	-	-	-	-	11
SD Sweet	SDS	S	-	-	2	-	-	-	-	-	-	-	-	-	2
TX Condensate	TXC	S	-	-	-	-	-	-	13	19	-	-	-	-	32
East	TXE	S	-	-	90	-	-	67	-	-	-	-	-	-	157
Hawkins	TEH	HH	-	-	129	-	-	16	25	-	-	-	-	-	170
Gulf Refugio	TGR	S	6	-	-	-	-	456	62	19	-	-	-	-	543
West Intermed.	TWI	S	-	-	107	-	-	239	36	77	-	-	-	-	459
West Scurry	TWY	S	-	-	40	-	-	-	-	-	-	-	-	-	40
West Sour	TWS	HL	-	-	56	14	-	423	59	-	-	-	-	-	552
UT Altamont	UTA	S	-	-	-	-	-	-	-	-	26	-	-	-	26
Mix	UTM	S	-	-	-	-	-	-	13	-	44	-	-	-	57
WV Lube	WVL	S	-	8	-	-	-	-	-	-	-	-	-	-	8
WY Platte/Sour	WYP	HH	-	-	47	-	-	-	-	-	136	-	-	-	183
Sweet	WYS	S	-	-	-	-	-	-	-	-	118	-	-	-	118
Total			95	51	1,327	220	38	2,538	365	252	462	382	1,459	398	7,587
Subtotal By Type															
Sweet		S	10	46	1,017	157	11	1,503	220	225	314	9	21	81	3,614
Medium Sulfur Light		ML	-	-	10	-	-	-	-	-	-	-	-	-	10
Medium Sulfur Heavy		MH	72	-	56	8	27	455	17	-	-	289	739	155	1,818
High Sulfur Light		HL	-	-	56	14	-	502	59	-	-	-	-	-	631
High Sulfur Heavy		HH	13	5	188	41	-	78	69	27	148	84	699	162	1,514

TABLE G-5

REFINERY FOREIGN CRUDE INPUT RATES DETAIL

FORECAST 1990 HIGH DEMAND CASE RESULTS - MBPCD

NPC STUDY

Country	Name	LP Code	Type	IC	IS	IIDC	IILC	IIS	IIIDC	IIILC	IIIS	IV	VCOC	VCC	VS	U.S. Total
Abu Dhabi/Dubai/Oman/UAE		UAD	HL	6	-	-	-	-	103	60	-	-	-	-	-	169
Algeria	Condensate	AGC	S	13	-	3	20	-	3	19	-	-	-	1	-	59
	Saharan	AGH	S	63	20	25	37	-	7	35	-	-	-	2	-	189
Angola		ANG	S	54	3	-	-	-	18	12	-	-	-	-	-	87
Australia		AUS	S	4	-	-	-	-	2	2	-	-	4	13	1	26
Cameroon	Kole	CMK	S	22	-	-	2	-	14	6	-	-	-	-	-	44
Canada	Condensate	CNC	S	-	-	-	1	-	-	-	-	3	-	-	-	4
	Interprov.	CNI	ML	37	-	39	1	2	-	-	-	-	-	-	-	79
	Lloydmin.	CNL	HH	8	-	234	19	9	-	-	-	9	-	-	-	279
	Rangeland	CNR	ML	-	-	-	-	-	-	-	-	58	29	-	-	87
China	Daqing	CHD	S	2	12	-	-	-	2	-	-	-	-	-	-	16
Congo	Djeno	CGD	S	11	-	-	-	-	11	12	-	-	-	-	-	34
Ecuador	Oriente	ECO	MH	1	-	2	13	-	27	3	-	-	-	1	-	47
Egypt	Belayim	EGB	HH	6	-	-	-	-	-	-	-	-	-	-	-	6
Gabon	Gamba	GBG	S	7	-	-	-	-	11	1	-	-	-	-	-	19
	Lucina	GBL	S	5	-	-	-	-	4	-	-	-	-	-	-	9
	Mandji	GBM	HH	5	-	-	-	-	22	5	-	-	-	-	-	32
Guatemala		GUT	HH	-	-	-	-	-	3	-	-	-	-	-	-	3
India	Bombay	IDB	S	-	-	-	-	-	25	39	-	-	-	4	-	68
Indonesia	Attaka	INA	S	-	-	-	-	-	-	-	-	-	-	9	-	9
	Condensate	INC	S	-	-	-	-	-	1	-	4	-	9	20	2	36
	Heavy	INV	S	2	-	-	-	-	7	1	-	-	1	3	-	14
	Minas	INM	S	121	4	-	-	-	19	54	-	-	27	136	-	361
Iran	Heavy	IRH	HH	2	-	-	-	-	5	1	-	-	-	-	-	8
	Light	IRL	HL	-	-	4	-	-	-	-	-	-	-	-	-	4
Iraq	Kirkuk	IQK	HL	-	-	-	-	-	6	6	-	-	-	-	-	12
Ivory Coast		ICE	S	-	-	-	-	-	6	-	-	-	-	-	-	6
Kuwait		KUW	HH	6	-	2	1	-	17	-	-	-	-	-	-	26
Mexico	Blend	MXB	HH	2	-	12	9	-	5	61	-	-	-	-	-	89
	Isthmus	MXI	HL	3	-	15	18	-	88	43	-	-	-	-	-	167
	Maya	MXM	HH	83	47	49	45	-	160	87	-	-	-	-	-	471
Netherlands		NTH	S	-	-	3	-	-	-	-	-	-	-	-	-	3
Nigeria	Forcados	NGF	S	13	-	43	28	-	9	24	-	-	-	-	-	117
	Light	NGL	S	18	-	66	-	-	12	36	-	-	-	-	-	132
	Medium	NGM	S	52	-	-	85	-	-	135	-	-	-	-	-	272
Norway	Ekofisk	NWE	S	48	-	1	-	-	32	-	-	-	-	-	-	81
	Statfjord	NWS	S	20	-	-	-	-	3	-	-	-	-	-	-	23
Saudia Arabia	Heavy	SAH	HH	153	2	170	162	-	276	287	-	-	-	-	-	1,050
	Light	SAL	HL	38	4	228	64	-	1,104	72	-	-	-	-	-	1,510
	Medium	SAM	HH	1	-	32	-	-	31	48	-	-	-	-	-	112
Sharja		SHJ	S	2	-	6	-	-	7	-	-	-	-	-	-	15
Trinidad	Light	TDL	S	17	-	16	4	-	54	-	-	-	-	-	-	91
United Kingdom	Brent	UKB	S	164	12	43	-	-	33	33	-	-	-	-	-	285
	Light	UKL	S	5	-	-	-	-	1	5	-	-	-	-	-	11
	Sour	UKS	HL	4	-	-	-	-	8	-	-	-	-	-	-	12
Venezuela	Boscan	VZB	HH	-	41	-	-	-	-	-	-	-	-	-	2	43
	H. Bach. 14	VZH	HH	30	33	-	-	1	118	-	31	-	-	-	-	213
	Lagomedia	VZL	HH	3	-	1	-	-	5	-	-	-	-	-	-	9
	T.Juana Med.	VZT	HH	3	-	-	-	-	11	-	-	-	-	-	-	14
Zaire		ZAR	S	19	-	-	-	-	12	1	-	-	-	-	-	32
Total				1,053	178	994	509	12	2,282	1,088	35	70	70	189	5	6,485
Subtotal by Type																
Sweet			S	662	51	206	177	-	293	415	4	3	41	188	3	2,043
Medium Sulfur Light			ML	37	-	39	1	2	-	-	-	58	29	-	-	166
Medium Sulfur Heavy			MH	1	-	2	13	-	27	3	-	-	-	1	-	47
High Sulfur Light			HL	51	4	247	82	-	1,309	181	-	-	-	-	-	1,874
High Sulfur Heavy			HH	302	123	500	236	10	653	489	31	9	-	-	2	2,355

TABLE G-7

CRUDE UNIT CAPACITIES AND UTILIZATIONS

FORECAST 1990 HIGH DEMAND CASE RESULTS

NPC STUDY

Model	Number of Refineries	Crude Capacity (MBPSD)	Crude Input (MBPCD)	Utilization[1] (%)
IC	10	1,296	1,148	93.2
IS	11	371	229	65.0
IIDC	24	2,623	2,321	93.1
IILC	12	827	729	92.8
IIS	7	66	50	80.0
IIIDC	32	5,487	4,820	92.5
IIILC	14	1,634	1,453	93.6
IIIS	21	375	287	80.5
IV	20	591	532	94.8
VCOC	6	512	452	92.9
VCC	17	2,153	1,648	80.6
VS	28	583	403	72.7
U.S. Total	202	16,518	14,072	89.7
Subtotal by Type				
Simple	67	1,395	969	73.1
Conversion[2]	135	15,123	13,103	91.2

(1) Utilization of operable calendar day capacity assuming 95% stream factor.
(2) Includes three simple refineries in PADD IV with a capacity of 19 MBPSD.

TABLE G-8

REFINERY PROCESS UNIT UTILIZATIONS

1990 HIGH DEMAND CASE RESULTS - %[1]

NPC STUDY

	IC	IIDC	IILC	IIIDC	IIILC	IV	VCOC	VCC
Crude - Atmospheric	93.2	93.1	92.8	92.5	93.6	94.8*	92.9	80.6
- Vacuum	88.4	94.7	91.3	89.2	90.8	94.7	105.3[4]	83.0
Catalytic Cracking[2]	92.0	92.5*	92.6*	77.6	78.5	92.3*	92.3*	92.6*
Catalytic Cracking[3]	87.0	89.9	90.8	75.4	76.4	93.4	99.7	88.8
Conversion, %	76.7	74.7	74.2	76.0	76.3	74.0	69.8	70.0*
Hydrocracking	92.5*	92.0*	93.8*	92.7*	91.3*	91.8*	92.6*	92.6*
Jet Yield, % of Maximum	87.7	28.7	80.7	100.0	100.0	100.0	100.0	62.1
Coking - Delayed[2]	93.2*	83.0	-	66.0	-	92.0*	47.0	72.5
- Delayed[3]	93.2	83.0	-	66.0	-	92.0	47.0	72.5
- Fluid	56.4	-	-	0	-	21.7	-	59.8
- Combined[3]	70.8	83.0	-	60.7	-	52.7	47.0	69.9
Combined Coke	54.3	78.5	-	45.8	-	36.2	37.6	74.3
Th. Crk./Vis. Brk.	92.0*	90.9*	95.7*[4]	82.9	37.3	-	-	92.8*
Solvent Deasphalting	92.4*	94.1*	-	93.4*	91.7*	78.4	92.5*	92.4*
Catalytic Reforming								
Low Pressure[2]	92.4*	92.4*[6]	92.8*	92.3*	92.5*	91.9*	92.4*[6]	92.4*
RONC	98.6	99.7	96.4	92.5	98.2	95.6	100.0*	100.0*
High Pressure[2]	65.3	92.0*	11.7	44.1	82.6	70.6	92.8*	73.8
RONC	97.7	92.9	90.0	97.9	95.9	93.5	99.3	99.5
Combined[3]	65.9	89.3*	57.7	83.2	82.8	76.4	76.7*	70.8
RONC	98.1	96.8	95.8	98.7	97.4	94.4	99.6	99.8
Hydrotreating								
Naphtha	48.7	66.8	59.3	71.6	68.2	51.7	62.9	36.9
Distillate	58.4	73.4	58.0	75.1	60.4	85.1	68.0	79.3
Heavy Gas Oil	51.6	92.8*	92.0*	92.2*	92.6*	92.9*	-	74.4
Residuum	-	-	-	92.9*	-	-	-	89.2
Alkylation	88.1	92.3*	78.7	71.4	92.4*[6]	92.4*[6]	79.9	85.6
Polymerization	0	0	0	5.4	8.9	40.9	0	0
Isomerization - C5/C6	23.3	87.1*	85.5*	92.4*	92.3*	92.4*[6]	92.4*[6]	92.4*
- C4	-	4.4	0	0	92.8*	48.7	82.6	0
Hydrogen	82.1	80.5	-	79.6	80.3	77.7	81.8	81.4
Asphalt	92.5	58.7	84.6	51.3	122.6[4]	96.6[4]	83.8	92.0
Lubes	92.4	84.4	118.2[4]	89.0	102.0[4]	72.5	-	56.7
Aromatics	59.9	59.2	N/A [5]	89.3	63.2	-	-	0
Hydrodealkylation	0	94.1*	-	72.0	-	-	-	-

* Limited at maximum throughput in LP run.
- = No unit; 0 = Unit not operating; N/A - Not applicable.
(1) Utilizations assume a 95% stream factor for crude units and a 92% stream factor for all other units.
(2) Utilization includes effects of non-unitary capacity factors for some feedstocks and severities.
(3) Alternate utilization is based on actual feed rates, ignoring severity effects.
(4) High utilizations (above 95%) indicate errors in reported capacity (calibration) or minor process with little impact on overall results.
(5) Reported production with no reported capacity - same as calibration case.
(6) Utilization based on base 1988 capacity (Table D-6) plus new capacity (Table G-10).

TABLE G-10

NEW PROCESS UNITS CAPACITY REQUIRED

AND INCREMENTAL OCTANE COST RESULTS

FORECAST 1990 HIGH DEMAND CASE

NPC STUDY

	IC	IIDC	IILC	IIIDC	IIILC	IV	VCOC	VCC	U.S. Total/ Average(1)
New Capacity - MBPSD(2)									
Crude - Vacuum	-	67.2	-	-	-	29.4	22.5	-	119.1
Catalytic Reforming	-	1.9	-	-	-	-	0.1	-	2.0
Alkylation	-	-	-	-	4.2	0.4	-	-	4.6
Isomerization - C5/C6	-	-	-	-	-	0.5	1.7	-	2.2
Incremental Octane Costs(3) - ¢/B/O.N.									
Pool Average	26	34	24	32	38	26	33	26	31

(1) Total new capacity above definite 1988 capacities shown in Table D-8. Weighted average octane costs for conversion refineries only.
(2) LP includes capital charge for new capacity except crude-vacuum unit.
(3) Shadow values determined by models based on stock costs and variable operating costs, plus capital charge and fixed operating costs for new capacity only.

TABLE H-1

U.S. SUPPLY AND DEMAND FORECAST

1995 LOW DEMAND CASE - MBPCD

NPC STUDY

	Supply			Demand		
	Field Production	Imports	Refinery Production	Refinery Input	Exports	Demand Products
Crudes						
Domestic	5,650(1)	-	-	5,407	243	-
Foreign	-	5,292	-	5,292	-	-
[Total Crudes]	[5,650]	[5,292]	[-]	[10,699]	[243]	[-]
Products - NGL/Unfin.						
Natural Gasoline	260	52	-	122	3	187
Ethane	451	27	16	-	5	489
Propane	470	37	221	5	30	693
Normal Butane	181	108	45	226	10	98
Iso-Butane	88	-	-	76	3	9
Unfinished	-	264	-	264	-	-
Mogas Components	-	95	-	95	-	-
Oxygenates and Other	80	-	-	80	-	-
[Total - NGL/Unf. Prd.]	[1,530]	[583]	[282]	[868]	[51]	[1,476]
Products - Finished						
Motor Gasolines	-	869	4,613	-	6	5,476
Aviation Gasolines	-	-	40	-	-	40
Naphtha Jet	-	49	245	-	3	291
Kero Jet/Kerosene	-	163	832	-	7	988
Distillate Fuels	-	418	2,640	-	51	3,007
Residual Fuels						
<0.3% Sulfur	-	173	128	-	-	301
0.3-1.0% Sulfur	-	148	252	-	-	400
>1.0% Sulfur	-	289	700	-	190	799
[Total Residual Fuels]	[-]	[610]	[1,080]	[-]	[190]	[1,500]
Petrochem Naphtha	-	142	217	-	6	353
P/Chem Gas Oil + C. Black	-	-	385	-	15	370
Special Naphtha/Misc.	-	74	169	-	3	240
Lube and Wax	-	16	195	-	16	195
Marketable Coke - FOE	-	-	193	-	193	0
Catalytic Coke - FOE	-	-	147	-	-	147
Asphalt/Road Oil	-	21	497	-	1	517
Process Gas - FOE	-	-	441	-	-	441
[Total Finished Prods.]	[-]	[2,362]	[11,694]	[-]	[491]	[13,565]
Total Crudes and Products	7,180	8,237	11,976	11,567	785	15,041
(Gain)/Loss	-	-	(409)	-	-	-

(1) Includes 280 MBPCD of syncrude.

TABLE H-2

U.S. REFINERY RAW MATERIALS INPUT RATES

FORECAST 1995 LOW DEMAND ESTIMATE - MBPCD

NPC STUDY

	U.S. Total
Domestic Crudes	5,407
Foreign Crudes	5,292
Total Crudes	10,699
Natural Gasoline	122
Reformate - 95 RONC	95
Naphtha	71
Vacuum Gas Oil	197
Vacuum Resid.	(37)
Normal Butane	226
Iso-Butane	76
MTBE	42
Ethanol	21
Methanol	2
TBA	5
Propane	5
Natural Gas Feed to H_2 - FOE	43
Total Input	11,567

TABLE H-3

U.S. REFINERY PRODUCT RATES

FORECAST 1990 LOW DEMAND ESTIMATE - MBPCD

NPC STUDY

	U.S. Total
Motor Gasolines	
Low Lead Regular	-
Unleaded Regular	3,322
Unleaded Premium	1,291
Total	4,613
Aviation Gasolines	40
Naphtha Jet	245
Kero Jet/Kerosene	832
Distillate Fuels	2,640
Residual Fuels	
<0.3% Sulfur	128
0.3-0.7% Sulfur	94
0.7-1.0% Sulfur	158
1.0-2.0% Sulfur	413
>2.0% Sulfur	287
Total	1,080
Asphalt/Road Oil	497
Marketable Coke - FOE	193
Benzene	39
Toluene	54
Xylene	55
Special Naphtha/Miscellaneous	113
Petrochem Naphtha	125
Lubes	180
Wax	15
Petrochem Gas Oil	345
Carbon Black Feed	40
Normal Butane	45
Propane	221
Process Gas/Ethane - FOE	457
Catalytic Coke - FOE	147
(Gain)/Loss	(409)
Total Products	11,567

TABLE I-1

U.S. SUPPLY AND DEMAND FORECAST

1995 HIGH DEMAND CASE - MBPCD

NPC STUDY

	Supply			Demand		
	Field Production	Imports	Refinery Production	Refinery Input	Exports	Demand Products
Crudes						
Domestic	5,650(1)	-	-	5,407	243	-
Foreign	-	10,593	-	10,593	-	-
[Total Crudes]	[5,650]	[10,593]	[-]	[16,000]	[243]	[-]
Products - NGL/Unfin.						
Natural Gasoline	260	46	-	107	3	196
Ethane	451	67	20	-	5	533
Propane	470	27	291	6	30	752
Normal Butane	181	127	73	242	10	129
Iso-Butane	88	22	-	101	3	6
Unfinished	-	232	-	232	-	-
Mogas Components	-	83	-	83	-	-
Oxygenates and Other	80	-	-	80	-	-
[Total - NGL/Unf. Prd.]	[1,530]	[604]	[384]	[851]	[51]	[1,616]
Products - Finished						
Motor Gasolines	-	198	6,356	-	6	6,548
Aviation Gasolines	-	-	60	-	-	60
Naphtha Jet	-	14	280	-	3	291
Kero Jet/Kerosene	-	45	1,330	-	7	1,368
Distillate Fuels	-	286	3,672	-	51	3,907
Residual Fuels						
<0.3% Sulfur	-	266	308	-	-	574
0.3-1.0% Sulfur	-	135	598	-	-	733
>1.0% Sulfur	-	281	1,361	-	190	1,452
[Total Residual Fuels]	[-]	[682]	[2,267]	[-]	[190]	[2,759]
Petrochem Naphtha	-	64	402	-	6	460
P/Chem Gas Oil + C. Black	-	-	525	-	15	510
Special Naphtha/Misc.	-	65	203	-	3	265
Lube and Wax	-	14	227	-	16	225
Marketable Coke - FOE	-	-	205	-	193	12
Catalytic Coke - FOE	-	-	172	-	-	172
Asphalt/Road Oil	-	18	683	-	1	700
Process Gas - FOE	-	-	602	-	-	602
[Total Finished Prods.]	[-]	[1,386]	[16,984]	[-]	[491]	[17,879]
Total Crudes and Products	7,180	12,583	17,368	16,851	785	19,495
(Gain)/Loss	-	-	(517)	-	-	-

(1) Includes 280 MBPCD of syncrude.

TABLE I-2

U.S. REFINERY RAW MATERIALS INPUT RATES

FORECAST 1995 HIGH DEMAND ESTIMATE - MBPCD

NPC STUDY

	U.S. Total
Domestic Crudes	5,407
Foreign Crudes	10,593
Total Crudes	16,000
Natural Gasoline	107
Reformate - 95 RONC	83
Naphtha	50
Vacuum Gas Oil	137
Vacuum Resid.	(28)
Normal Butane	242
Iso-Butane	101
MTBE	60
Ethanol	32
Methanol	3
TBA	5
Propane	6
Natural Gas Feed to H_2 - FOE	53
Total Input	16,851

TABLE I-3

U.S. REFINERY PRODUCT RATES

FORECAST 1995 HIGH DEMAND ESTIMATE - MBPCD

NPC STUDY

	U.S. Total
Gasolines	
Low Lead Regular	-
Unleaded Regular	4,577
Unleaded Premium	1,779
Total	6,356
Aviation Gasolines	60
Naphtha Jet	280
Kero Jet/Kerosene	1,330
Distillate Fuels	3,672
Residual Fuels	
<0.3% Sulfur	308
0.3-0.7% Sulfur	208
0.7-1.0% Sulfur	390
1.0-2.0% Sulfur	806
>2.0% Sulfur	555
Total	2,267
Asphalt/Road Oil	683
Marketable Coke - FOE	205
Benzene	39
Toluene	54
Xylene	55
Special Naphtha/Miscellaneous	135
Petrochem Naphtha	322
Lubes	207
Wax	20
Petrochem Gas Oil	485
Carbon Black Feed	40
Normal Butane	73
Propane	291
Process Gas/Ethane - FOE	622
Catalytic Coke - FOE	172
(Gain)/Loss	(517)
Total Products	16,851

TABLE I-4

U.S. REFINERY DOMESTIC CRUDE INPUT RATES

FORECAST 1995 HIGH DEMAND ESTIMATE - MBPCD

NPC STUDY

Location/Name	LP Code	Type	Total
AL Heavy	ALH	MH	16
Light	ALL	S	12
AK Cook	AKC	S	24
North Slope	ANS	MH	850
AZ Sweet	AZS	S	1
AR Heavy	ARH	HH	26
CA Beta	CBT	HH	15
Elk Hills	CEH	S	130
Huntington Beach	CHB	HH	20
Hondo	CAH	HH	59
LA Basin Light	CLL	HH	30
San Ardo	CSA	HH	62
SJV Light	CJL	HH	86
SJV Kern River	CJH	HH	114
SJV Heavy	CVH	HH	214
Ventura	CCV	HH	46
Wilmington Heavy	CWH	HH	67
Wilmington Light	CWL	HH	45
CO Rangely	COR	S	84
Shale Syn Crude	SHO	S	280
FL Jay	FLJ	S	31
IL Sweet	ILS	S	41
Weeks	ILW	S	42
IN Sweet	IDS	S	16
KS Butler	KSB	S	10
Common	KSC	S	18
Light	KSL	S	42
KY Sweet	KYS	S	8
LA Condensate	LAC	S	51
Light Sweet	LLS	S	102
North Mix	LAM	S	40
Heavy Sweet	LAO	S	525

Location/Name	Code	Type	U.S. Total
MI Sweet	MIS	S	46
MS Baxterville	MSB	HH	30
Light Hey	MSH	HL	11
Sweet	MSS	S	5
MT Sour	MTS	HH	22
Rebeki	MTR	S	65
NE Light Sour	NES	ML	6
NV Sweet	NVS	S	4
NM Intermediate	NMI	S	71
Sour	NMS	HL	40
NY Lube	NYL	S	2
ND Light Sour	NDS	S	49
OH Light	OHL	S	45
OK Cement	OKM	S	74
Condensate	OKC	S	5
Garber	OKG	S	50
Velma	OKV	HH	28
PA Lube	PAL	S	12
SD Sweet	SDS	S	1
TX Condensate	TXC	S	21
East	TXE	S	101
Hawkins	TEH	HH	110
Gulf Refugio	TGR	S	352
West Intermed.	TWI	S	296
West Scurry	TWY	S	25
West Sour	TWS	HL	358
UT Altamont	UTA	S	32
Mix	UTM	S	69
WV Lube	WVL	S	8
WY Platte/Sour	WYP	HH	220
Sweet	WYS	S	142
Total			5,407

Subtotal By Type

Sweet	S	2,932
Medium Sulfur Light	ML	6
Medium Sulfur Heavy	MH	866
High Sulfur Light	HL	409
High Sulfur Heavy	HH	1,194

TABLE J-1

COMPARISON OF TOTAL U.S. REFINERY PROCESS UNIT UTILIZATIONS

NPC SURVEY VS. MODEL RESULTS

NPC STUDY

	1984		1988		
				Models	
	Survey	Models Calibration	Survey	High Demand	Optimum Products
Number of Refineries	179	214	173	202	202
Feed Rate					
Crude - Atmospheric, MBPCD	11,643	12,044	12,420	13,178	13,178
Catalytic Cracking, MBPCD	4,104	4,007	4,359	3,889	4,185*
Conversion, %	72.6	72.9	73.5	75.9	76.6
Conversion, MBPCD(1)	2,979	2,921	3,204	2,952	3,206
Hydrocracking, MBPCD	723	835	930	904*	904*
Jet and Heavier Yield, %	28.1	34.2	31.9	43.1	42.7
Coking, MBPCD	1,102	1,074	1,216	964	1,256
Coke, MBPCD FOE	276	260	298	229	307
Catalytic Reforming, MBPCD	2,445	2,427	2,776	2,604	2,741
RONC	94.8	94.6	97.1	98.0	98.9
Product Rate					
Alkylation, MBPCD	630	595	751	725	756
Isomerization - C5/C6, MBPCD	58	72	228	234*	234*

* Limiting rate.
(1) Feed rate times % conversion divided by 100.

TABLE J-2

COMPARISON OF CATALYTIC REFORMER UTILIZATIONS AND SEVERITIES

NPC SURVEY VS. MODEL RESULTS

NPC STUDY

	1984				1988					
	Feed - MBPCD		Severity-RONC		Feed - MBPCD			Severity - RONC		
		Model		Model		Model			Model	
Model	Survey	Calibration	Survey	Calibration	Survey	High Demand	Optimum Products	Survey	High Demand	Optimum Products
IC	231	198	96.5	96.4	235	215	247*	98.2	98.7	99.7
IIDC	463	463	93.9	94.0	506	514*	501*	96.2	97.4	97.7
IILC	124	123	94.0	94.2	129	128	148	95.9	96.5	97.0
IIIDC	898	898	94.5	94.2	1,070	1,001	1,052*	96.4	98.2	99.6
IIILC	220	215	95.2	94.9	248	235	251*	97.7	97.6	98.9
IV	57#	57	87.9#	88.0	N/A	71	84	96.2	94.6	94.7
VCOC	89#	89	95.0#	95.0	N/A	77*	77*	N/A	99.6	99.6
VCC	306	306	97.1	97.1	368	293	311	99.5	99.6	99.8
Simples	57#	78	N/A	93.0	N/A	70*	70*	N/A	98.0	98.0
U.S. Total	2,445	2,427	94.8	94.6	2,776	2,604	2,741	97.1	98.0	98.9

N/A = Not available.
* = Limiting rate.
\# = Estimated.

TABLE J-3

RECONCILIATION OF 1984 CATALYTIC REFORMER CAPACITIES

NPC SURVEY VS. MODELS - AT NPC SURVEY SEVERITIES

NPC STUDY

	Survey				Model				Difference
		Capacity - MBPCD			Reported (1)		Equivalent (2)		Model Less Revised Survey
	Octane Basis RONC (3)	Reported	No Survey Response	Revised	Octane Basis RONC (4)	Capacity MBPSD	NPC Octane Basis RONC	Capacity MBPCD	Capacity MBPCD
IC									
Cyclic	98.9	113.6	-	113.6	-	-	98.9	113.6	-
Semi-Regen.	94.8	193.3	-	193.3	-	-	94.8	189.8	-
Low Pressure	-	-	-	-	100	118.8	-	-	-
High Pressure	-	-	-	-	90	237.0	-	-	-
Total	-	306.9	-	306.9	-	355.8	-	303.4	(3.4)
IIDC									
Cyclic	94.9	273.4	-	273.4	-	-	94.9	273.4	-
Semi-Regen.	93.1	350.3	16.3	366.6	-	-	93.1	339.4	-
Low Pressure	-	-	-	-	100	358.9	-	-	-
High Pressure	-	-	-	-	90	295.2	-	-	-
Total	-	623.7	16.3	640.0	-	654.1	-	612.8	(27.2)
IILC									
Cyclic	94.2	97.1	0.9	98.0	-	-	94.2	98.0	-
Semi-Regen.	93.8	109.8	29.9	139.7	-	-	93.8	131.9	-
Low Pressure	-	-	-	-	100	135.4	-	-	-
High Pressure	-	-	-	-	90	111.8	-	-	-
Total	-	206.9	30.8	237.7	-	247.2	-	229.9	(7.8)
IIIDC									
Cyclic	97.0	636.5	2.3	638.8	-	-	97.0	638.8	-
Semi-Regen.	91.4	571.4	5.5	576.9	-	-	91.4	607.9	-
Low Pressure	-	-	-	-	100	837.3	-	-	-
High Pressure	-	-	-	-	90	480.6	-	-	-
Total	-	1,207.9	7.8	1,215.7	-	1,317.9	-	1,246.7	31.0
IIILC									
Cyclic	97.6	163.2	-	163.2	-	-	97.6	163.2	-
Semi-Regen.	91.8	148.0	1.6	149.6	-	-	91.8	146.7	-
Low Pressure	-	-	-	-	100	176.3	-	-	-
High Pressure	-	-	-	-	90	160.0	-	-	-
Total	-	311.2	1.6	312.8	-	336.3	-	309.9	(2.9)
IV									
Cyclic	N/A	N/A	5.1	N/A	-	-	N/A	N/A	-
Semi-Regen.	N/A	N/A	11.1	N/A	-	-	N/A	N/A	-
Low Pressure	-	-	-	-	100	40.6	-	-	-
High Pressure	-	-	-	-	90	75.6	-	-	-
Total	-	N/A	16.2	N/A	-	116.2	-	N/A	N/A
VCOC									
Cyclic	N/A	N/A	-	N/A	-	-	N/A	N/A	-
Semi-Regen.	N/A	N/A	-	N/A	-	-	N/A	N/A	-
Low Pressure	-	-	-	-	100	31.8	-	-	-
High Pressure	-	-	-	-	90	76.5	-	-	-
Total	-	N/A	-	N/A	-	108.3	-	N/A	N/A
VCC									
Cyclic	100.6	79.0	-	79.0	-	-	100.6	79.0	-
Semi-Regen.	96.1	343.7	21.3	365.0	-	-	96.1	347.3	-
Low Pressure	-	-	-	-	100	203.0	-	-	-
High Pressure	-	-	-	-	90	299.6	-	-	-
Total	-	422.7	21.3	444.0	-	502.6	-	426.3	(17.7)
Simples									
Cyclic	N/A	N/A	-	N/A	-	-	N/A	N/A	-
Semi-Regen.	N/A	N/A	21.6	N/A	-	-	N/A	N/A	-
Low Pressure	-	-	-	-	100	3.6	-	-	-
High Pressure	-	-	-	-	90	120.8	-	-	-
Total	-	N/A	21.6	N/A	-	124.4	-	N/A	N/A
U.S. Total									
Cyclic	97.0	1,392.2	8.3	1,400.5	-	-	97.0	1,400.5	-
Semi-Regen.	93.1	1,969.7	107.3	2,077.0	-	-	93.1	2,001.1	-
Low Pressure	-	-	-	-	100	1,905.7	-	-	-
High Pressure	-	-	-	-	90	1,857.1	-	-	-
Total	-	3,361.9	115.6	3,477.5	-	3,762.8	-	3,401.6	(75.9)

(1) From 1983 and 1984 DOE PSA (Table B-6).
(2) Equivalent reformer capacity based on NPC severities and type of unit using capacity vs. severity (octane) factors based on limited heat input which agreed with NPC survey data. Converted from MBPSD to MBPCD, based on a 92% on-stream factor.
(3) RONC = Research Octane Number Clear, of C5+ reformate.
(4) Assumed from literature sources.

TABLE J-4

RECONCILIATION OF 1988 NPC SURVEY WITH 1988 OPTIMUM PRODUCTS CASE MODEL RESULTS[1]

U.S. TOTAL MATERIAL BALANCE - MBPCD

NPC STUDY

	Survey								Model	Difference
	Survey Results[2]	Units and Format Adjustments[3]	Shifts to Match Other 1988 Optimum Inputs	Shifts to Match 1988 Optimum Crudes[4]	Shifts to Match 1988 Optimum Minor Products	Process Shifts for Maximum Gasoline[5]	Feed Composition Changes for Maximum Middle Distillates[6]	Revised Survey Results	1988 Optimum Products Results	Model Less Survey[7]
Raw Materials Input										
Sweet Crudes	5,741	42	-	601	-	-	-	6,384	6,384	-
M. Sulfur Light Crudes	251	-	-	(76)	-	-	-	175	175	-
M. Sulfur Heavy Crudes	1,753	-	-	(3)	-	-	-	1,750	1,750	-
H. Sulfur Light Crudes	1,209	-	-	484	-	-	-	1,693	1,693	-
H. Sulfur Heavy Crudes	3,466	-	-	(290)	-	-	-	3,176	3,176	-
Total Crudes	12,420	42	-	716	-	-	-	13,178	13,178	-
Natural Gasoline	93	-	32	-	-	-	-	125	125	-
Gasoline Components	87	-	(4)	-	-	-	-	83	83	-
Naphtha	169	(97)	-	-	-	-	-	72	72	-
Vacuum Gas Oil	466	-	(124)	-	-	-	-	342	342	-
Vacuum Residuum	130	-	(171)	-	-	-	-	(41)	(41)	-
Butanes and Propane	356	-	1	(10)	-	-	-	347	347	-
Oxygenates	49	-	9	-	-	-	-	58	58	-
Natural Gas - FOE	271	(204)	(14)	-	-	-	-	53	53	-
Other/Distillates	165	(42)	(123)	-	-	-	-	-	-	-
Residual Fuels	22	-	(22)	-	-	-	-	-	-	-
Total Input	14,228	(204)	(513)	706	-	-	-	14,217	14,217	-
Products Output										
Motor Gasolines	6,435	-	-	-	6	221	-	6,662	6,738	76
Naphtha Jet	211	-	-	-	25	-	-	236	236	-
Kero Jet/Kerosene	1,211	-	-	123	-	-	(33)	1,301	1,301	-
Distillate Fuels	2,657	-	-	142	(18)/55	4/22	319	3,181	3,181	-
Residual Fuels	875	-	(22)	-	(221)	(4)/8	-	636	618	(18)
Asphalt/ Vac. Resid.	432	-	(171)	1	166	-	-	428	428	-
Marketable Coke - FOE	61	(33)/284	-	-	-	-	-	312	307	(5)
Aromatics/Avgas	180	-	9	-	9	-	-	198	198	-
Naphtha-Spcl./PC/Misc.	362	-	32/(97)	189	(25)	(219)	-	242	93	(149)
Lube/Wax	184	26	-	-	(38)	-	-	172	172	-
PC Gas Oil/C. Black Fd.	485	-	(124)	250	38	(120)	(286)	243	243	-
Other/Distillates	105	-	(123)	-	18	-	-	-	-	-
Gasoline Components	19		(4)	-	(15)	-	-	-	-	-
Propane and Butanes	376	-	1	1	-	53	-	431	391	(40)
Natural Gas/Coal - FOE	211	(211)	-	-	-	-	-	-	-	-
Process Gas - FOE	536	-	(14)	-	-	40	-	562	707	145
Catalytic Coke - FOE	159	33	-	-	-	8	-	200	210	10
(Gain)/Loss	(271)	(303)	-	-	-	(13)	-	(587)	(606)	(19)
Total Products	14,228	204	(513)	706	-	-	-	14,217	14,217	-

(1) Hand calculated adjustments to 1988 survey results to closely match model results for 1988 Optimum Major Products Without New Facilities Case.

(2) Includes estimates of missing data from totals. Other specialty assumed to be gas oil and miscellaneous assumed to be naphtha. Lube intermediates included in gas oil and resid fuel blendstocks included in resid fuels. Marketable coke estimated from total refinery fuel. Atmospheric resid assumed to be 70% vacuum gas oil and 30% vacuum resid.

(3) Delete natural gas to fuel (204 MBPCD), coal to fuel (7 MTPCD). Convert from tons to BFOE for marketable coke (284 MBPCD - FOE) and wax (26 MBPCD). [Wax was not included in survey products total.] Shift marketable coke in fuel to catalytic coke (33 MBPCD - FOE) and condensate to crude (42 MBPCD).

(4) Based on crude unit yields for primary swing crudes: Nigerian medium, Arab light and Arab heavy.

(5) Based on survey maximum gasoline delta of 221 MBPCD over base survey level. Assumes reformer severity increase from 97.1 to 98.9 RONC to match 1988 optimum products results which permits upgrading of LSR (219 MBPCD) to gasoline. Rest of increased gasoline based on increased FCC feed (120 MBPCD) and alkylation (13 MBPCD).

(6) Assumes ability to remove 286 MBPCD of distillates from hydrocracker and FCC feed to optimize distillates production.

(7) Final reconciliation shows that our model downgrades more propane, butane and light gasoline to produced fuel (145 MBPCD) and upgrades 76 MBPCD more naphtha to gasoline.

APPENDIX J

World Refining and Transportation Model Assumptions

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION MODEL ASSUMPTIONS

Table of Contents

Attachment	Title	Page
1	Model Design	J-1
2	Basic Assumptions	J-3
3	World Model Regions/Refineries	J-8
4	World (ex. U.S.) Refinery Unit Capacity Assumptions	J-11
5	Expected Changes in World (ex. U.S.) Refining Capacity -- January 1, 1986 to January 1, 1988	J-39
6	U.S. Refinery Process Unit Capacity Assumptions -- 1986	J-40
7	U.S. Refinery Process Unit Capacity Assumptions -- 1988	J-41
8	World (non-U.S.) Hydrocracker Feed	J-42
9	U.S. Crude Oil Type	J-45
10	U.S. Crude Oil Slate	J-46
11	World (non-U.S.) Crude Oil Type	J-47
12	World (non-U.S.) Crude Oil Slate	J-48
13	World (non-U.S.) Regions with Significant NGL Production Available as Refinery Feedstock	J-49
14	Petroleum Products	J-50
15	World Aromatics Demand	J-51
16	World (non-OECD) LPG Demand	J-52
17	World (non-U.S.) Gasoline Octane Demand	J-53
18	World (non-U.S.) Resid Demand	J-55
19	World (non-U.S.) Distillate Demand	J-56
20	U.S. Petroleum Product Regional Demand	J-57
21	Centrally Planned Economies Petroleum Exports	J-58

Table of Contents (Continued)

Attachment	Title	Page
22	Trade Measures Affecting Oil Products.....	J-59
23	Region/Port Assignments in the Petroleum Allocation (PAL) Model.....	J-64
24	World (non-U.S.) Pipelines.....	J-65
25	U.S. Clean Product Pipelines.....	J-66
26	U.S. LPG/NGL Pipelines.....	J-67
27	U.S. Crude Oil Pipelines.....	J-68
28	Vessel and Pipeline Operating Characteristics.....	J-69
29	World (non-U.S.) Marine Capacity.....	J-70
30	U.S. Marine Capacity.....	J-71
31	Incremental Marine Capacity.....	J-72
32	Intra-U.S. Voyages.....	J-73
33	World (non-U.S.) Marine Cost.....	J-74
34	U.S. Marine Cost.....	J-75
35	Port/Operating Restrictions.....	J-76
36	U.S. Region Map.....	J-77
37	Inter-PADD Crude Transportation Map.....	J-78
38	Inter-PADD Clean Product System Map.....	J-79
39	Inter-PADD LPG/NGL Transportation System Map.....	J-80
40	Reference Cases and Scenarios Studied to Analyze the Domestic Refining Industry.....	J-81

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION MODEL ASSUMPTIONS

MODEL DESIGN

- Linear Programming Model of the world's refineries, petroleum transportation system, crude oil supply, and petroleum product demand
- L.P. Model calculates least cost combination of refinery and transportation activities that exactly satisfies world petroleum product demand
- L.P. Model Inputs:
  - Refining Assumptions
  - Transportation Assumptions
  - Trade Assumptions
  - Petroleum Product Demand
  - Base Crude Oil and NGL Supply
  - Marginal Crude Oil Supply
  - Marginal Crude Oil Cost
  - Natural Gas (Refinery Fuel) Cost
- L.P. Model Output:
  - Refinery Utilization
  - Transportation Utilization
  - Petroleum Product Flows
  - Crude Oil Flows
  - Petroleum Product Marginal Costs
  - Crude Oil Marginal Costs
- World (non-U.S.) divided into thirty-one regions (Attachment 3) (including 3 Centrally Planned Economies net export regions)
- U.S. Region Map (Attachment 36)
- U.S. Crude Oil Transportation System Map (Attachment 37)
- U.S. Clean Petroleum Product Transportation System Map (Attachment 38)
- U.S. LPG/NGL Transportation System Map (Attachment 39)

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY ASSUMPTIONS

BASIC ASSUMPTIONS

REFINING ASSUMPTIONS

- Free World (non-U.S.) represented by twenty-eight regional refinery models (Attachment 3)
- Centrally Planned Economies (CPE) refineries represented by fixed petroleum product slate exported to free world (Attachment 21)
- U.S. refineries represented by seven regional refinery models (Attachment 3)
- Refinery capacities (Attachment 4)
- World (non-U.S.) hydrocracker capacities (Attachment 8)
- World (non-U.S.) regions catalytic reformer capacities not specified as either low or high pressure units are assumed to be 50% low and 50% high pressure units
- Refinery model process unit characteristics and variable operating costs reflect industry norms
- Refinery model maximum utilization:
  - World (non-U.S.): 90% of calendar day capacity
  - United States : 92% of calendar day capacity
- U.S. refinery models purchase power, steam, and natural gas per NPC Refinery Survey Task Group
- OECD region refinery models (non-U.S.) purchase natural gas at OECD reported volumes
- Non-OECD region refinery models (except Asian regions) purchase locally available natural gas at average OECD volumes
- U.S. crude oil types (Attachment 9)

- U.S. crude oil slate (Attachment 10)
- U.S. refinery model feedstock includes natural butane, isobutane, and natural gasoline per NPC Refinery Survey Task Group
- World (non-U.S.) crude oil types (Attachment 11)
- World (non-U.S.) crude oil slate (Attachment 12)
- World (non-U.S.) refinery model feedstock includes local NGL-derived normal butane, isobutane, and natural gasoline (Attachment 13)
- Crude oil and NGL supply forecast per DOE
- Petroleum products (Attachment 14)
- Petroleum product qualities per NPC Refinery Survey Task Group

PIPELINE TRANSPORTATION ASSUMPTIONS

- World (non-U.S.) pipeline capacities and costs (Attachment 24)
- U.S. clean product pipeline capacities and costs (Attachment 25)
- U.S. LPG/NGL pipeline capacities and costs (Attachment 26)
- U.S. crude oil pipeline capacities and costs (Attachment 27)

MARINE TRANSPORTATION ASSUMPTIONS

- Marine capacity:
  - World (non-U.S.) (Attachment 29)
  - United States (Attachment 30)
  - Incremental supply (Attachment 31)
- Intra-U.S. voyages (Attachment 32)

- Marine Costs:
  - World (non-U.S.) (Attachment 33)
  - United States (Attachment 34)
- Port/operating restrictions (Attachment 35)

PETROLEUM PRODUCT DEMAND ASSUMPTIONS

- Demand scenarios defined by NPC Oil Supply/Demand Task Group
- U.S. petroleum product regional demand (Attachment 20)
- World aromatics demand (Attachment 15)
- World (non-U.S.) resid demand (Attachment 18)
- U.S. premium gasoline demand equals 18% of total U.S. gasoline demand
- World (non-U.S.) gasoline octane demand (Attachment 17)
- World (non-U.S.) distillate demand (No. 2 & No. 4) (Attachment 19)
- World (non-OECD) LPG demand as percentage of total demand (Attachment 16)
- U.S. NGL supply not input as refinery feedstock satisfies LPG demand directly
- World (non-U.S.) NGL supply not input as refinery feedstock satisfies LPG demand directly
- 14 MB/D New Zealand gasoline demand satisfied by synthetic gasoline production

TRADE ASSUMPTIONS

- No U.S. crude oil exports
- No U.S. aromatics imports or exports
- No Japanese exports except "other" and aromatics

- Japanese gasoline, distillate, and jet imports limited to 7% of demand
- Region X (other Asia) minimum refinery throughput volume equals 80% of product demand
- Region Y (other exporters) minimum refinery throughput volume equals:
  - 725 MB/D 1986
  - 625 MB/D 1988
  - 625 MB/D 1990
- No other minimum refinery throughput requirements
- No South African petroleum product exports
- Canadian crude oil imports limited to 585 MB/D

OPERATING ASSUMPTIONS

- No U.S. crude oil exports
- No U.S. aromatics imports or exports
- No Soviet or Libyan crude oil exports to the United States
- PADD V imports 150 MB/D Indonesian crude oil
- Maximum U.S. PADD V refinery throughput equals 2.5 MMB/D
- Maximum U.S. imports of Mexican crude oil equal 750 MB/D for 1986 and 1,000 MB/D for 1990
- Region U (Puerto Rico, Virgin Islands) minimum refinery throughput equals 100 MB/D ANS and total local product demand
- No Soviet or Libyan crude oil exports to Region U (Puerto Rico, Virgin Islands)
- Maximum Japan refinery throughput equals 3.6 MMB/D (does not apply to 1990 high demand case)
- Japan imports 180 MB/D Mexican crude oil

- Japan allowed to export any product

- Maximum Japan product imports (does not apply to 1990 high demand case):

Product	Volumes
Gasoline	6% Gasoline Demand
Jet/Kero	11% Jet/Kero Demand
No. 2 Distillate	1% No. 2 Demand
No. 4 Distillate	10% No. 4 Demand
Resid	20% Resid Demand

- Region A (Australia, New Zealand) minimum product imports equal 10% of each product's demand

- Region I (Indonesia) maximum refinery throughput equals 80% of calendar day capacity

- Region X (Asia) minimum refinery throughput equals 80% of total product demand

- No South African petroleum product exports

SOCIOECONOMIC ASSUMPTIONS

- Minimum refinery throughput:

Region	% Calendar Day Capacity
L (Algeria, Libya)	50
F (Other Africa)	65
O (Angola, Congo, Zaire)	65
N (Gabon, Nigeria)	65
Q (Bahrain, Eqypt, Syria)	65
R (Iran)	65
P (Arab Gulf)	75
K (Caribbean)	20
S (Other Americas)	45

Region	% Calendar Day Capacity
M (Mexico)	60
V (Ecuador, Venezuela)	45
B (Bolivia, Brazil, Colombia, Peru)	45

- Region Y (Asian Exporters) minimum refinery throughput equals 725 MB/D
- Region 1 (Finland, Iceland, Norway, Sweden) minimum refinery throughput equals 95% of total product demand
- Minimum sum of European refinery throughput equals 65% of total European calenday day capacity

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

WORLD MODEL REGIONS/REFINERIES

Region	Description
A	Australia, New Zealand
B	Bolivia, Brazil, Colombia, Peru
C	Canada (including St. Pierre and Miguelon)
F	Other Africa (including Benin, Botswana, Burkina, Burundi, Cameroon, Cape Verde, Central African Republic, Chad, Comoros, Dahomey, Djibouti, Equatorial Guinea, Ethiopia, Gambia, Gibraltar, Ghana, Guinea, Guinea-Bissau, Ivory Coast, Kenya, Lesotho, Liberia, Madagascar, Malawi, Mali, Malta, Mauritania, Mauritius, Morocco, Mozambique, Namibia, Niger, Reunion, Rwanda, Saotome and Principe, Senegal, Seychelles, Sierra Leone, Somalia, South Africa, Sudan, Swaziland, Tanzania, Togo, Tunisia, Uganda, Upper Volta, Western Sahara, Zambia, Zimbabwe)
I	Indonesia
J	Japan (including Okinawa)
K	Non-U.S. Caribbean (including Bahama Islands, Barbados, Dominican Republic, Jamaica, Martinique, Netherlands Antilles, Trinidad and Tobago)
L	Algeria, Libya
M	Mexico
N	Gabon, Nigeria
O	Angola, Congo, Zaire
P	Arab Gulf (including Iraq, Kuwait, Neutral Zone, North Yemen, Oman, Qatar, Saudia Arabia, South Yemen, United Arab Emirates)

WORLD MODEL REGIONS/REFINERIES (Continued)

Region	Description
Q	Bahrain, Eqypt, Syria
R	Iran
S	Other Central and South America (including Antigua, Argentina, Barbuda, Belize, Bermuda, British Virgin Islands, Cayman Islands, Chile, Costa Rica, Dominica, El Salvador, Falkland Islands, French Guiana, Grenada, Guadaloupe, Guatemala, Guyana, Haiti, Honduras, Montserrat, Nicaragua, Panama Republic, Paraguay, St. Kitts-Nevis, St. Lucia, St. Vincent and the Grenadines, Surinam, Uruguay)
U	United States Territories (including Guam, Hawaiian Free Trade Zone, Puerto Rico, Virgin Islands)
V	Ecuador, Venezuela
X	Other Middle East, Far East, and Oceania (including Afghanistan, American Samoa, Bangladesh, Bhutan, Burma, Cook Island, Cyprus, Fiji, French Polynesia, Hong Kong, India, Israel, Jordan, Kiribatia, Lebanon, Macau, Nauru, Nepal, New Caledonia, Pacific Islands, Pakistan, Papua New Guinea, Philippines, Samoa, Solomon Islands, South Korea, Sri Lanka, Thailand, Tonga, Tuvalu, Vanuatu, Wake Island)
Y	Non-OPEC Asian Exporters of Petroleum (including Brunei, Malaysia, Singapore, Taiwan)
1	Finland, Iceland, Norway, Sweden
2	Ireland, United Kingdom
3	Belgium, Denmark, Luxembourg, Netherlands
4	West Germany
5	France
6	Austria, Switzerland

WORLD MODEL REGIONS/REFINERIES (Continued)

Region	Description
7	Portugal, Spain
8	Italy
9	Greece, Turkey
CPE1	Soviet Union
CPE2	East Bloc (Non-Soviet)
CPE3	Asian Centrally Planned Economies
	United States
US1	PADD I North Atlantic
US2	PADD I Mid-Atlantic
US3	PADD I South Atlantic
US4	PADD II
US5	PADD III
US6	PADD IV
US7	PADD V

NOTE: All world regions except CPEs represented by unique refinery models. All U.S. PADDs except PADD II and PADD III represented by unique refinery models; PADD II and PADD III regions represented by 2 refinery models per region.

Region A

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

REFINERY UNIT CAPACITY ASSUMPTIONS
(MB/CD)

Region: A - Australia, New Zealand

	Operable Capacity	
Process Unit	1/1/86	1/1/88
Crude Distillation	774.3	804.7
Vacuum Distillation	250.8	288.8
Coker - Delayed	00.0	00.0
Coker - Fluid	00.0	00.0
Visbreaker	00.0	00.0
Naphtha Hydrotreater	183.6	190.8
Distillate HDS	112.5	134.1
FCC Feed Hydrofiner	17.1	17.1
Resid Desulfurizer	00.0	00.0
Cat Reformer 450 psi	180.9	188.1
Cat Reformer 200 psi		
Fluid Cat Cracker	170.1	170.1
FCC Gasoline Splitter	00.0	00.0
Hydrocracker-2 Stage	00.0	19.8
Alkylation Plant	19.8	19.8
Cat Polymerization	06.3	06.3
Hydro. Plant (MB/D, FOE)	00.0	02.8
Sulfur Plant (MST/D)	04.1	04.6
Aromatics Recovery Plant	00.9	00.9
Pen/Hex Isomerization	07.2	07.2
Butane Isomerization	13.5	13.5
Lube & Wax Plants	12.6	12.6
Solvent Deasphalting	33.3	47.7
Lube Hydrotreater	19.8	19.8
Vacuum Gas Oil/Heavy Gas Oil Desulfurization	00.0	09.0

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

REFINERY UNIT CAPACITY ASSUMPTIONS
(MB/CD)

Region: B - Bolivia, Brazil, Colombia, Peru

Process Unit	Operable Capacity 1/1/86	Operable Capacity 1/1/88
Crude Distillation	1,824.3	1,824.3
Vacuum Distillation	159.4	159.4
Coker - Delayed	23.9	23.9
Coker - Fluid	00.0	00.0
Visbreaker	65.5	65.5
Naphtha Hydrotreater	57.4	57.4
Distillate HDS	96.0	96.0
FCC Feed Hydrofiner	36.1	36.1
Resid Desulfurizer	00.0	00.0
Cat Reformer 450 psi	44.9	44.9
Cat Reformer 200 psi	00.0	00.0
Fluid Cat Cracker	376.5	376.5
FCC Gasoline Splitter	00.0	00.0
Hydrocracker-2 Stage	00.0	00.0
Alkylation Plant	11.5	11.5
Cat Polymerization	00.0	00.0
Hydro. Plant (MB/D, FOE)	08.1	08.1
Sulfur Plant (MST/D)	00.0	00.0
Aromatics Recovery Plant	00.0	00.0
Pen/Hex Isomerization	00.0	00.0
Butane Isomerization	00.0	00.0
Lube & Wax Plants	20.6	20.6

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

REFINERY UNIT CAPACITY ASSUMPTIONS
(MB/CD)

Region: C - Canada

Process Unit	Operable Capacity 1/1/86	1/1/88
Crude Distillation	1,795.0	1,795.0
Vacuum Distillation	627.0	627.0
Coker - Delayed	13.5	13.5
Coker - Fluid	12.6	12.6
Visbreaker	53.1	53.1
Naphtha Hydrotreater	398.0	398.0
Distillate HDS	350.1	350.1
FCC Feed Hydrofiner	03.6	03.6
Resid Desulfurizer	03.6	03.6
Cat Reformer 450 psi	00.0	00.0
Cat Reformer 200 psi	340.0	340.0
Fluid Cat Cracker	384.0	384.0
FCC Gasoline Splitter	287.0	287.0
Hydrocracker-2 Stage	96.0	96.0
Alkylation Plant	53.1	54.0
Cat Polymerization	18.0	18.0
Hydro. Plant (MB/D, FOE)	118.5	118.5
Sulfur Plant (MST/D)	1,020.0	1,020.0
Aromatics Recovery Plant	19.0	19.0
Pen/Hex Isomerization	05.4	05.4
Butane Isomerization	09.0	09.0
Lube & Wax Plants	17.1	17.1

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

REFINERY UNIT CAPACITY ASSUMPTIONS
(MB/CD)

Region: F - Other Africa
Includes: Cameroon, Ethiopia, Ghana, Ivory Coast, Kenya, Liberia, Madagascar, Morocco, Mozambique, Senegal, Somalia, South Africa, Sudan, Tanzania, Tunisia, Zambia

	Operable Capacity	
Process Unit	1/1/86	1/1/88
Crude Distillation	792.0	792.0
Vacuum Distillation	170.0	184.0
Coker - Delayed	00.0	00.0
Coker - Fluid	00.0	00.0
Visbreaker	43.0	49.0
Naphtha Hydrotreater	83.0	94.0
Distillate HDS	110.0	119.0
FCC Feed Hydrofiner	03.0	03.0
Resid Desulfurizer	00.0	00.0
Cat Reformer 450 psi	00.0	00.0
Cat Reformer 200 psi	121.0	128.0
Fluid Cat Cracker	55.0	55.0
FCC Gasoline Splitter	00.0	00.0
Hydrocracker-2 Stage	20.0	21.0
Alkylation Plant	03.0	04.0
Cat Polymerization	00.0	00.0
Hydro. Plant (MB/D, FOE)	15.0	15.0
Sulfur Plant (MST/D)	00.0	00.0
Aromatics Recovery Plant	02.0	02.0
Pen/Hex Isomerization	00.0	00.0
Butane Isomerization	03.0	03.0
Lube & Wax Plants	08.0	08.0

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

REFINERY UNIT CAPACITY ASSUMPTIONS
(MB/CD)

Region: I - Indonesia

Note: Crude oil distillation capacity is "effective" rather than "installed."

Process Unit	Operable Capacity 1/1/86	Operable Capacity 1/1/88
Crude Distillation	761.9	811.3
Vacuum Distillation	245.1	245.1
Coker - Delayed	31.5	31.5
Coker - Fluid	00.0	00.0
Visbreaker	71.1	91.8
Naphtha Hydrotreater	65.7	65.7
Distillate HDS	72.0	72.0
FCC Feed Hydrofiner	00.0	00.0
Resid Desulfurizer	00.0	00.0
Cat Reformer 450 psi	67.5	92.7
Cat Reformer 200 psi		
Fluid Cat Cracker	10.8	19.8
FCC Gasoline Splitter	00.0	00.0
Hydrocracker-2 Stage	99.9	99.9
Alkylation Plant	00.9	00.9
Cat Polymerization	00.9	00.9
Hydro. Plant (MB/D, FOE)	67.1	67.1
Sulfur Plant (MST/D)	00.0	00.0
Aromatics Recovery Plant	00.0	00.0
Pen/Hex Isomerization	00.0	00.0
Butane Isomerization	00.0	00.0
Lube & Wax Plants	05.4	05.4
Solvent Deasphalting	08.1	08.1
Vacuum Gas Oil/Heavy Gas Oil Desulfurization	09.0	09.0

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

REFINERY UNIT CAPACITY ASSUMPTIONS
(MB/CD)

Region: J - Japan
Includes: Okinawa

Process Unit	Operable Capacity 1/1/86	Operable Capacity 1/1/88
Crude Distillation	4,670.2	4,670.2*
Vacuum Distillation	1,739.5	1,773.7
Coker - Delayed	36.0	36.0
Coker - Fluid	18.9	18.9
Visbreaker	32.4	32.4
Naphtha Hydrotreater	814.5	814.5
Distillate HDS	1,227.6	1,227.6
FCC Feed Hydrofiner	62.1	62.1
Resid Desulf. (Vacuum Resid)	22.5	22.5
Cat Reformer 450 psi Cat Reformer 200 psi	527.4	531.9
Fluid Cat Cracker	451.8	479.7
FCC Gasoline Splitter	00.0	00.0
Hydrocracker-2 Stage	13.5	13.5
Alkylation Plant	00.9	00.9
Cat Polymerization	00.9	00.9
Hydro. Plant (MB/D, FOE)	442.0	442.0
Sulfur Plant (MST/D)	81.9	81.9
Aromatics Recovery Plant	44.1	44.1
Pen/Hex Isomerization	00.0	00.0
Butane Isomerization	00.0	00.0
Lube & Wax Plants	46.8	46.8
Solvent Deasphalting	44.1	44.1
Lube Hydrotreater	36.0	36.0
Atmospheric Resid Desulf.	390.6	390.6
Vacuum Gas Oil Desulfurization	786.6	786.6
Mild Hydro/Vacuum Gas Oil	35.1	35.1
Naphtha Hydrocracker	02.7	02.7

*Japan has announced a shutdown of 700-1,000 MB/D during the 1986-1988 period. For modeling purposes, an operating capacity of 4.0 MMB/D for 1988 was assumed. It was not reflected here since the units to be shut down were not known.

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

REFINERY UNIT CAPACITY ASSUMPTIONS
(MB/CD)

Region: K - Caribbean
Includes: Bahamas, Barbados, Dominican Republic, Jamaica, Netherlands Antilles, Trinidad

Process Unit	Operable Capacity 1/1/86	1/1/88
Crude Distillation	691.0	691.0
Vacuum Distillation	330.0	330.0
Coker - Delayed	00.0	00.0
Coker - Fluid	00.0	00.0
Visbreaker	85.0	85.0
Naphtha Hydrotreater	90.0	90.0
Distillate HDS	117.0	117.0
FCC Feed Hydrofiner	100.0	100.0
Resid Desulfurizer	00.0	00.0
Cat Reformer 450 psi	00.0	00.0
Cat Reformer 200 psi	59.0	59.0
Fluid Cat Cracker	67.0	67.0
FCC Gasoline Splitter	00.0	00.0
Hydrocracker-2 Stage	00.0	00.0
Alkylation Plant	06.0	06.0
Cat Polymerization	00.0	00.0
Hydro. Plant (MB/D, FOE)	00.0	00.0
Sulfur Plant (MST/D)	00.0	00.0
Aromatics Recovery Plant	00.0	00.0
Pen/Hex Isomerization	00.0	00.0
Butane Isomerization	00.0	00.0
Lube & Wax Plants	12.0	12.0

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

REFINERY UNIT CAPACITY ASSUMPTIONS
(MB/CD)

Region: L - Algeria, Libya

Process Unit	Operable Capacity 1/1/86	1/1/88
Crude Distillation	831.0	834.0
Vacuum Distillation	45.0	45.0
Coker - Delayed	00.0	00.0
Coker - Fluid	00.0	00.0
Visbreaker	00.0	00.0
Naphtha Hydrotreater	23.0	23.0
Distillate HDS	19.0	19.0
FCC Feed Hydrofiner	02.0	02.0
Resid Desulfurizer	00.0	00.0
Cat Reformer 450 psi	00.0	00.0
Cat Reformer 200 psi	71.0	72.0
Fluid Cat Cracker	00.0	00.0
FCC Gasoline Splitter	00.0	00.0
Hydrocracker-2 Stage	00.0	00.0
Alkylation Plant	00.0	00.0
Cat Polymerization	00.0	00.0
Hydro. Plant (MB/D, FOE)	00.0	00.0
Sulfur Plant (MST/D)	00.0	00.0
Aromatics Recovery Plant	05.0	05.0
Pen/Hex Isomerization	00.0	00.0
Butane Isomerization	00.0	00.0
Lube & Wax Plants	02.0	02.0
Fuel Mixing (MB/D, FOE)	00.0	00.0

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

REFINERY UNIT CAPACITY ASSUMPTIONS
(MB/CD)

Region: M - Mexico

	Operable Capacity	
Process Unit	1/1/86	1/1/88
Crude Distillation	1,269.0	1,269.0
Vacuum Distillation	593.0	593.0
Coker - Delayed	00.0	00.0
Coker - Fluid	09.0	09.0
Visbreaker	73.0	73.0
Naphtha Hydrotreater	226.0	226.0
Distillate HDS	276.0	276.0
FCC Feed Hydrofiner	00.0	00.0
Resid Desulfurizer	05.0	05.0
Cat Reformer 450 psi	00.0	00.0
Cat Reformer 200 psi	164.0	164.0
Fluid Cat Cracker	297.0	297.0
FCC Gasoline Splitter	204.9	204.9
Hydrocracker-2 Stage	18.0	18.0
Alkylation Plant	07.0	07.0
Cat Polymerization	00.6	00.6
Hydro. Plant (MB/D, FOE)	11.9	11.9
Sulfur Plant (MST/D)	1,128.1	1,128.1
Aromatics Recovery Plant	01.1	01.1
Pen/Hex Isomerization	02.1	02.1
Butane Isomerization	00.0	00.0
Lube & Wax Plants	09.0	09.0

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

REFINERY UNIT CAPACITY ASSUMPTIONS
(MB/CD)

Region: N - Gabon, Nigeria

	Operable Capacity	
Process Unit	1/1/86	1/1/88
Crude Distillation	298.0	448.0
Vacuum Distillation	66.0	66.0
Coker - Delayed	00.0	00.0
Coker - Fluid	00.0	00.0
Visbreaker	10.0	10.0
Naphtha Hydrotreater	38.0	38.0
Distillate HDS	27.0	27.0
FCC Feed Hydrofiner	00.0	00.0
Resid Desulfurizer	00.0	00.0
Cat Reformer 450 psi	00.0	00.0
Cat Reformer 200 psi	43.0	43.0
Fluid Cat Cracker	46.0	46.0
FCC Gasoline Splitter	00.0	00.0
Hydrocracker-2 Stage	00.0	00.0
Alkylation Plant	00.0	00.0
Cat Polymerizati on	00.0	00.0
Hydro. Plant (MB/D, FOE)	00.0	00.0
Sulfur Plant (MST/D)	00.0	00.0
Aromatics Recovery Plant	00.0	00.0
Pen/Hex Isomerization	00.0	00.0
Butane Isomerization	00.0	00.0
Lube & Wax Plants	06.0	06.0

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

REFINERY UNIT CAPACITY ASSUMPTIONS
(MB/CD)

Region: O - Angola, Congo, Zaire

	Operable Capacity	
Process Unit	1/1/86	1/1/88
Crude Distillation	52.0	52.0
Vacuum Distillation	04.0	04.0
Coker - Delayed	00.0	00.0
Coker - Fluid	00.0	00.0
Visbreaker	00.0	00.0
Naphtha Hydrotreater	04.0	04.0
Distillate HDS	03.0	03.0
FCC Feed Hydrofiner	00.0	00.0
Resid Desulfurizer	00.0	00.0
Cat Reformer 450 psi	00.0	00.0
Cat Reformer 200 psi	02.0	02.0
Fluid Cat Cracker	00.0	00.0
FCC Gasoline Splitter	00.0	00.0
Hydrocracker-2 Stage	00.0	00.0
Alkylation Plant	00.0	00.0
Cat Polymerization	00.0	00.0
Hydro. Plant (MB/D, FOE)	00.0	00.0
Sulfur Plant (MST/D)	00.0	00.0
Aromatics Recovery Plant	00.0	00.0
Pen/Hex Isomerization	00.0	00.0
Butane Isomerization	00.0	00.0
Lube & Wax Plants	00.0	00.0

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

REFINERY UNIT CAPACITY ASSUMPTIONS
(MB/CD)

Region: P - Arab Gulf
Includes: Iraq, Kuwait, Neutral Zone, Oman, Qatar, Saudi Arabia, South Yemen, U.A.E.

Process Unit	Operable Capacity 1/1/86	1/1/88
Crude Distillation	2,883.0	3,352.0
Vacuum Distillation	522.0	522.0
Coker - Delayed	00.0	79.0
Coker - Fluid	00.0	00.0
Visbreaker	57.0	57.0
Naphtha Hydrotreater	310.0	310.0
Distillate HDS	542.0	659.0
FCC Feed Hydrofiner	254.0	254.0
Resid Desulfurizer	00.0	66.0
Cat Reformer 450 psi	00.0	00.0
Cat Reformer 200 psi	330.0	330.0
Fluid Cat Cracker	70.0	98.0
FCC Gasoline Splitter	00.0	00.0
Hydrocracker-2 Stage	258.0	330.0
Alkylation Plant	12.0	12.0
Cat Polymerization	00.0	00.0
Hydro. Plant (MB/D, FOE)	379.0	379.0
Sulfur Plant (MST/D)	00.0	00.0
Aromatics Recovery Plant	06.0	06.0
Pen/Hex Isomerization	00.0	00.0
Butane Isomerization	00.0	00.0
Lube & Wax Plants	06.0	06.0

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

REFINERY UNIT CAPACITY ASSUMPTIONS
(MB/CD)

Region: Q - Bahrain, Egypt, Syria

	Operable Capacity	
Process Unit	1/1/86	1/1/88
Crude Distillation	861.0	909.0
Vacuum Distillation	247.0	247.0
Coker - Delayed	17.0	17.0
Coker - Fluid	10.0	10.0
Visbreaker	44.0	44.0
Naphtha Hydrotreater	48.0	48.0
Distillate HDS	104.0	104.0
FCC Feed Hydrofiner	52.0	52.0
Resid Desulfurizer	52.0	52.0
Cat Reformer 450 psi	00.0	00.0
Cat Reformer 200 psi	66.0	66.0
Fluid Cat Cracker	34.0	34.0
FCC Gasoline Splitter	00.0	00.0
Hydrocracker-2 Stage	05.0	05.0
Alkylation Plant	00.0	00.0
Cat Polymerization	01.0	01.0
Hydro. Plant (MB/D, FOE)	16.0	16.0
Sulfur Plant (MST/D)	00.0	00.0
Aromatics Recovery Plant	00.0	00.0
Pen/Hex Isomerization	00.0	00.0
Butane Isomerization	00.0	00.0
Lube & Wax Plants	03.0	03.0

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

REFINERY UNIT CAPACITY ASSUMPTIONS
(MB/CD)

Region: R - Iran

Process Unit	Operable Capacity 1/1/86	1/1/88
Crude Distillation	613.0	613.0
Vacuum Distillation	215.0	215.0
Coker - Delayed	00.0	00.0
Coker - Fluid	00.0	00.0
Visbreaker	98.0	98.0
Naphtha Hydrotreater	34.0	34.0
Distillate HDS	65.0	65.0
FCC Feed Hydrofiner	00.0	00.0
0Resid Desulfurizer	00.0	00.0
Cat Reformer 450 psi	00.0	00.0
Cat Reformer 200 psi	78.0	78.0
Fluid Cat Cracker	00.0	00.0
FCC Gasoline Splitter	00.0	00.0
Hydrocracker-2 Stage	111.0	111.0
Alkylation Plant	00.0	00.0
Cat Polymerization	00.0	00.0
Hydro. Plant (MB/D, FOE)	36.0	36.0
Sulfur Plant (MST/D)	00.0	00.0
Aromatics Recovery Plant	00.0	00.0
Pen/Hex Isomerization	00.0	00.0
Butane Isomerization	00.0	00.0
Lube & Wax Plants	05.0	05.0

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

REFINERY UNIT CAPACITY ASSUMPTIONS
(MB/CD)

Region: S - Other Americas

	Operable Capacity	
Process Unit	1/1/86	1/1/88
Crude Distillation	1,092.8	1,092.8
Vacuum Distillation	295.1	295.1
Coker - Delayed	68.0	68.0
Coker - Fluid	00.0	00.0
Visbreaker	62.0	62.0
Naphtha Hydrotreater	77.9	77.9
Distillate HDS	73.4	73.4
FCC Feed Hydrofiner	00.0	00.0
Resid Desulfurizer	00.0	00.0
Cat Reformer 450 psi	00.0	00.0
Cat Reformer 200 psi	77.9	77.9
Fluid Cat Cracker	141.5	141.5
FCC Gasoline Splitter	106.2	106.2
Hydrocracker-2 Stage	20.7	20.7
Alkylation Plant	03.0	03.0
Cat Polymerization	02.7	02.7
Hydro. Plant (MB/D, FOE)	03.0	03.0
Sulfur Plant (MST/D)	1,149.6	1,149.6
Aromatics Recovery Plant	00.0	00.0
Pen/Hex Isomerization	00.0	00.0
Butane Isomerization	00.0	00.0
Lube & Wax Plants	31.0	31.0

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

REFINERY UNIT CAPACITY ASSUMPTIONS
(MB/CD)

Region: U - Puerto Rico, Virgin Islands

	Operable Capacity	
Process Unit	1/1/86	1/1/88
Crude Distillation	721.0	721.0
Vacuum Distillation	249.0	249.0
Coker - Delayed	00.0	00.0
Coker - Fluid	00.0	00.0
Visbreaker	40.0	40.0
Naphtha Hydrotreater	139.0	139.0
Distillate HDS	178.0	178.0
FCC Feed Hydrofiner	00.0	00.0
Resid Desulfurizer	130.0	130.0
Cat Reformer 450 psi	00.0	00.0
Cat Reformer 200 psi	138.0	138.0
Fluid Cat Cracker	12.0	12.0
FCC Gasoline Splitter	00.0	00.0
Hydrocracker-2 Stage	00.0	00.0
Alkylation Plant	00.0	00.0
Cat Polymerization	00.0	00.0
Hydro. Plant (MB/D, FOE)	00.0	00.0
Sulfur Plant (MST/D)	00.0	00.0
Aromatics Recovery Plant	30.0	30.0
Pen/Hex Isomerization	15.0	15.0
Butane Isomerization	00.0	00.0
Lube & Wax Plants	00.0	00.0

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

REFINERY UNIT CAPACITY ASSUMPTIONS
(MB/CD)

Region: V - Ecuador, Venezuela

Process Unit	Operable Capacity 1/1/86	1/1/88
Crude Distillation	1,503.4	1,503.4
Vacuum Distillation	543.2	543.2
Coker - Delayed	00.0	00.0
Coker - Fluid	46.8	46.8
Visbreaker	100.5	100.5
Naphtha Hydrotreater	24.0	24.0
Distillate HDS	93.6	93.6
FCC Feed Hydrofiner	189.2	189.2
Resid Desulfurizer	200.4	200.4
Cat Reformer 450 psi	21.6	21.6
Cat Reformer 200 psi	00.0	00.0
Fluid Cat Cracker	192.0	192.0
FCC Gasoline Splitter	00.0	00.0
Hydrocracker-2 Stage	00.0	00.0
Alkylation Plant	59.6	59.6
Cat Polymerization	00.0	00.0
Hydro. Plant (MB/D, FOE)	00.0	00.0
Sulfur Plant (MST/D)	00.0	00.0
Aromatics Recovery Plant	00.0	00.0
Pen/Hex Isomerization	00.0	00.0
Butane Isomerization	19.0	19.0
Lube & Wax Plants	06.4	06.4

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

REFINERY UNIT CAPACITY ASSUMPTIONS
(MB/CD)

Region: X - Other Asia
Includes: Guam and HIRI

Process Unit	Operable Capacity 1/1/86	Operable Capacity 1/1/88
Crude Distillation	3,241.6	3,226.4
Vacuum Distillation	616.9	619.8
Coker - Delayed	44.1	67.5
Coker - Fluid	00.0	00.0
Visbreaker	165.6	165.6
Naphtha Hydrotreater	275.4	284.4
Distillate HDS	343.8	352.8
FCC Feed Hydrofiner	22.5	22.5
Resid Desulfurizer	00.0	00.0
Cat Reformer 450 psi	244.8	252.9
Cat Reformer 200 psi		
Fluid Cat Cracker	184.5	184.5
FCC Gasoline Splitter	00.0	00.0
Hydrocracker-2 Stage	36.0	36.0
Alkylation Plant	03.6	03.6
Cat Polymerization	01.8	01.8
Hydro. Plant (MB/D, FOE)	45.8	45.8
Sulfur Plant (MST/D)	07.0	10.8
Aromatics Recovery Plant	38.7	40.5
Pen/Hex Isomerization	00.0	00.0
Butane Isomerization	00.9	00.9
Lube & Wax Plants	33.3	33.3
Solvent Deasphalting	23.4	23.4
Lube Hydrotreater	13.5	13.5
Atmospheric Resid Desulf.	00.0	47.7
Vacuum Gas Oil/Heavy Gas Oil Desulfurization	51.3	51.3

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

REFINERY UNIT CAPACITY ASSUMPTIONS
(MB/CD)

Region: Y - Other Exporters of Petroleum
Includes: Brunei, Malaysia, Singapore

	Operable Capacity	
Process Unit	1/1/86	1/1/88
Crude Distillation	1,088.7	1,088.7
Vacuum Distillation	239.4	261.3
Coker - Delayed	00.0	00.0
Coker - Fluid	00.0	00.0
Visbreaker	131.4	131.4
Naphtha Hydrotreater	89.1	89.1
Distillate HDS	316.8	316.8
FCC Feed Hydrofiner	00.0	00.0
Resid Desulfurizer	00.0	00.0
Cat Reformer 450 psi Cat Reformer 200 psi	70.2	70.2
Fluid Cat Cracker	00.0	00.0
FCC Gasoline Splitter	00.0	00.0
Hydrocracker-2 Stage	35.1	44.1
Alkylation Plant	00.0	00.0
Cat Polymerization	00.0	00.0
Hydro. Plant (MB/D, FOE)	12.0	15.1
Sulfur Plant (MST/D)	07.3	07.3
Aromatics Recovery Plant	00.0	00.0
Pen/Hex Isomerization	00.0	00.0
Butane Isomerization	00.0	00.0
Lube & Wax Plants	11.7	11.7
Vacuum Gas Oil/Heavy Gas Oil Desulfurization	39.6	39.6

Region 1

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

REFINERY UNIT CAPACITY ASSUMPTIONS
(MB/CD)

Region: 1 - Finland, Iceland, Norway, Sweden

Process Unit	Operable Capacity 1/1/86	1/1/88
Crude Distillation	910.0	910.0
Vacuum Distillation	191.0	191.0
Coker - Delayed	27.0	27.0
Coker - Fluid		
Visbreaker	209.0	209.0
Naphtha Hydrotreater	182.0	182.0
Distillate HDS	248.0	248.0
FCC Feed Hydrofiner	166.0	166.0
Resid Desulfurizer	50.0	50.0
Cat Reformer 450 psi	158.9	158.9
Cat Reformer 200 psi		
Fluid Cat Cracker	68.5	68.5
FCC Gasoline Splitter	28.1	28.1
Hydrocracker-2 Stage	14.0	14.0
Alkylation Plant	00.0	00.0
Cat Polymerization	08.0	08.0
Hydro. Plant (MB/D, FOE)	03.7	03.7
Sulfur Plant (MST/D)	1,046.2	1,046.2
Aromatics Recovery Plant	03.0	03.0
Pen/Hex Isomerization		
Butane Isomerization	00.0	00.0
Lube & Wax Plants	02.6	02.6

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

REFINERY UNIT CAPACITY ASSUMPTIONS
(MB/CD)

Region: 2 - Ireland, United Kingdom

	Operable Capacity	
Process Unit	1/1/86	1/1/88
Crude Distillation	1,848.0	1,848.0
Vacuum Distillation	620.0	802.6
Coker - Delayed	60.0	60.0
Coker - Fluid		
Visbreaker	166.0	166.0
Naphtha Hydrotreater	778.0	778.0
Distillate HDS	137.0	137.0
FCC Feed Hydrofiner	132.1	132.1
Resid Desulfurizer	25.0	25.0
Cat Reformer 450 psi	380.0	380.0
Cat Reformer 200 psi		
Fluid Cat Cracker	364.0	364.0
FCC Gasoline Splitter	235.3	235.3
Hydrocracker-2 Stage	29.0	29.0
Alkylation Plant	32.0	32.0
Cat Polymerization	16.0	16.0
Hydro. Plant (MB/D, FOE)	13.6	13.6
Sulfur Plant (MST/D)	1,909.1	1909.1
Aromatics Recovery Plant	35.0	35.0
Pen/Hex Isomerization		
Butane Isomerization	12.6	12.6
Lube & Wax Plants	17.0	17.0

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

REFINERY UNIT CAPACITY ASSUMPTIONS
(MB/CD)

Region: 3 - Belgium, Denmark, Luxembourg, Netherlands

	Operable Capacity	
Process Unit	1/1/86	1/1/88
Crude Distillation	2,286.0	2,286.0
Vacuum Distillation	449.0	449.0
Coker - Delayed	00.0	00.0
Coker - Fluid	00.0	27.8
Visbreaker	258.0	258.0
Naphtha Hydrotreater	900.0	480.0
Distillate HDS	348.0	328.0
FCC Feed Hydrofiner	294.8	294.8
Resid Desulfurizer	112.0	112.0
Cat Reformer 450 psi	227.0	00.0
Cat Reformer 200 psi		312.0
Fluid Cat Cracker	252.0	252.0
FCC Gasoline Splitter	160.8	160.8
Hydrocracker-2 Stage	00.0	57.0
Alkylation Plant	10.0	10.0
Cat Polymerization	03.0	03.0
Hydro. Plant (MB/D, FOE)	07.7	07.7
Sulfur Plant (MST/D)	1,367.1	1,367.1
Aromatics Recovery Plant	00.0	00.0
Pen/Hex Isomerization	03.3	03.3
Butane Isomerization	00.0	00.0
Lube & Wax Plants	04.0	04.0

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

REFINERY UNIT CAPACITY ASSUMPTIONS
(MB/CD)

Region: 4 - West Germany

Process Unit	Operable Capacity 1/1/86	Operable Capacity 1/1/88
Crude Distillation	1,933.0	1,797.0
Vacuum Distillation	537.0	537.0
Coker - Delayed Coker - Fluid	} 96.0	} 96.0
Visbreaker	186.0	186.0
Naphtha Hydrotreater	797.0	799.0
Distillate HDS	323.0	323.0
FCC Feed Hydrofiner	323.2	323.2
Resid Desulfurizer	87.0	87.0
Cat Reformer 450 psi Cat Reformer 200 psi	} 356.0	} 343.0
Fluid Cat Cracker	183.0	167.0
FCC Gasoline Splitter	131.7	131.7
Hydrocracker-2 Stage	106.0	106.0
Alkylation Plant	08.5	08.5
Cat Polymerization	02.5	02.5
Hydro. Plant (MB/D, FOE)	23.8	23.8
Sulfur Plant (MST/D)	622.8	622.8
Aromatics Recovery Plant Pen/Hex Isomerization	} 35.0	} 35.0
Butane Isomerization	00.0	00.0
Lube & Wax Plants	07.9	07.9

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

REFINERY UNIT CAPACITY ASSUMPTIONS
(MB/CD)

Region: 5 - France

Process Unit	Operable Capacity 1/1/86	1/1/88
Crude Distillation	1,947.0	1,865.0
Vacuum Distillation	463.0	463.0
Coker - Delayed	00.0	00.0
Coker - Fluid	00.0	00.0
Visbreaker	145.0	145.0
Naphtha Hydrotreater	517.0	484.0
Distillate HDS	368.6	368.6
FCC Feed Hydrofiner	92.7	92.7
Resid Desulfurizer	234.2	234.2
Cat Reformer 450 psi Cat Reformer 200 psi	271.0	251.0
Fluid Cat Cracker	258.0	241.0
FCC Gasoline Splitter	172.7	172.7
Hydrocracker-2 Stage	13.5	13.5
Alkylation Plant	11.0	11.0
Cat Polymerization	01.0	01.0
Hydro. Plant (MB/D, FOE)	04.8	04.8
Sulfur Plant (MST/D)	2,374.0	2,374.0
Aromatics Recovery Plant Pen/Hex Isomerization	15.0	15.0
Butane Isomerization	00.0	00.0
Lube & Wax Plants	24.7	24.7

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

REFINERY UNIT CAPACITY ASSUMPTIONS
(MB/CD)

Region: 6 - Austria, Switzerland

Process Unit	Operable Capacity 1/1/86	Operable Capacity 1/1/88
Crude Distillation	341.0	341.0
Vacuum Distillation	68.0	68.0
Coker - Delayed	00.0	00.0
Coker - Fluid	00.0	00.0
Visbreaker	41.0	41.0
Naphtha Hydrotreater	93.0	93.0
Distillate HDS	76.0	76.0
FCC Feed Hydrofiner	33.0	33.0
Resid Desulfurizer	42.0	42.0
Cat Reformer 450 psi Cat Reformer 200 psi	56.0	56.0
Fluid Cat Cracker	24.0	24.0
FCC Gasoline Splitter	17.3	17.3
Hydrocracker-2 Stage	00.0	00.0
Alkylation Plant	00.0	00.0
Cat Polymerization	00.0	00.0
Hydro. Plant (MB/D, FOE)	00.0	00.0
Sulfur Plant (MST/D)	426.1	426.1
Aromatics Recovery Plant Pen/Hex Isomerization	09.5	09.5
Butane Isomerization	00.0	00.0
Lube & Wax Plants	02.3	02.3

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

REFINERY UNIT CAPACITY ASSUMPTIONS
(MB/CD)

Region: 7 - Portugal, Spain

Process Unit	Operable Capacity 1/1/86	1/1/88
Crude Distillation	1,663.0	1,402.0
Vacuum Distillation	339.0	339.0
Coker - Delayed Coker - Fluid	} 13.0	} 13.0
Visbreaker	111.0	111.0
Naphtha Hydrotreater	331.0	242.0
Distillate HDS	202.0	202.0
FCC Feed Hydrofiner	103.0	103.0
Resid Desulfurizer	63.5	63.5
Cat Reformer 450 psi Cat Reformer 200 psi	} 229.0	} 196.0
Fluid Cat Cracker	98.0	98.0
FCC Gasoline Splitter	43.8	43.8
Hydrocracker-2 Stage	20.0	20.0
Alkylation Plant	24.0	24.0
Cat Polymerization	00.0	00.0
Hydro. Plant (MB/D, FOE)	08.0	08.0
Sulfur Plant (MST/D)	1,577.9	1,577.9
Aromatics Recovery Plant Pen/Hex Isomerization	} 31.0	} 46.0
Butane Isomerization	00.0	00.0
Lube & Wax Plants	12.0	12.0

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

REFINERY UNIT CAPACITY ASSUMPTIONS
(MB/CD)

Region: 8 - Italy

Process Unit	Operable Capacity 1/1/86	Operable Capacity 1/1/88
Crude Distillation	2,738.0	2,402.0
Vacuum Distillation	700.0	581.0
Coker - Delayed	00.0	00.0
Coker - Fluid	20.0	20.0
Visbreaker	307.0	278.0
Naphtha Hydrotreater	525.0	443.0
Distillate HDS	415.0	296.0
FCC Feed Hydrofiner	250.0	250.0
Resid Desulfurizer	136.0	95.9
Cat Reformer 450 psi Cat Reformer 200 psi	} 312.0	} 262.0
Fluid Cat Cracker	274.0	273.0
FCC Gasoline Splitter	187.1	187.1
Hydrocracker-2 Stage	00.0	00.0
Alkylation Plant	32.0	32.0
Cat Polymerization	02.0	02.0
Hydro. Plant (MB/D, FOE)	06.6	06.6
Sulfur Plant (MST/D)	2,711.5	2,711.5
Aromatics Recovery Plant Pen/Hex Isomerization	} 57.0	} 77.0
Butane Isomerization	10.5	10.5
Lube & Wax Plants	28.3	28.3

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

REFINERY UNIT CAPACITY ASSUMPTIONS
(MB/CD)

Region: 9 - Greece, Turkey

Process Unit	Operable Capacity 1/1/86	Operable Capacity 1/1/88
Crude Distillation	851.0	851.0
Vacuum Distillation	187.0	233.1
Coker - Delayed	00.0	00.0
Coker - Fluid	00.0	00.0
Visbreaker	20.0	39.5
Naphtha Hydrotreater	233.0	233.0
Distillate HDS	20.0	20.0
FCC Feed Hydrofiner	00.0	00.0
Resid Desulfurizer	26.8	26.8
Cat Reformer 450 psi Cat Reformer 200 psi	} 76.0	} 76.0
Fluid Cat Cracker	62.0	62.0
FCC Gasoline Splitter	45.9	45.9
Hydrocracker-2 Stage	00.0	00.0
Alkylation Plant	00.2	00.2
Cat Polymerization	00.2	00.2
Hydro. Plant (MB/D, FOE)	00.0	00.0
Sulfur Plant (MST/D)	219.6	219.6
Aromatics Recovery Plant	00.0	00.0
Pen/Hex Isomerization	00.0	00.0
Butane Isomerization	00.0	00.0
Lube & Wax Plants	06.8	06.8

EXPECTED CHANGES IN REFINING CAPACITY -- JANUARY 1, 1986 TO JANUARY 1, 1988
(MB/CD)

Process Unit	Region A	F	I	J	L	N	P	Q	X	Y	2	3	4	5	7	8	9	Total
Crude Distillation	30.4	-	49.4	-	3.0	150.0	469.0	38.0	(15.2)	-	-	-	(136.0)	(82.0)	(261.0)	(336.0)	-	(90.4)
Vacuum Distillation	38.0	14.0	-	-	-	-	-	-	2.9	21.9	182.6	-	-	-	-	(119.0)	46.1	186.5
Coker - Delayed	-	-	-	-	-	-	79.0	-	23.0	-	-	-	-	-	-	-	-	102.0
Coker - Fluid	-	-	-	-	-	-	-	-	-	-	-	27.8	-	-	-	-	-	27.8
Visbreaker	-	6.0	20.7	-	-	-	-	-	-	-	-	-	-	-	-	(29.0)	19.5	17.2
Naphtha Hydrotreater	7.2	11.0	-	-	-	-	-	-	9.0	-	-	(420.0)	-	33.0	(89.0)	(82.0)	-	(596.8)
Distillate HDS	21.6	9.0	-	-	-	-	117.0	-	-	-	-	(20.0)	-	-	-	(119.0)	-	8.6
FCC Feed Hydrofiner	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Resid Desulfurizer	-	-	-	-	-	-	66.0	-	-	-	-	-	-	-	-	(40.0)	-	26.0
Cat Reformer 450 psi Cat Reformer 200 psi	7.2	7.0	25.2	4.5	1.0	-	-	-	8.1	-	-	85.0	(13.0)	(20.0)	(33.0)	(50.0)	-	22.0
Fluid Cat Cracker	-	-	9.0	27.9	-	-	28.0	-	-	-	-	-	(16.0)	(17.0)	-	(1.0)	-	30.9
FCC Gasoline Splitter	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hydrocracker-2 Stage	-	-	-	-	-	-	72.0	-	-	9.0	-	57.0	-	-	-	-	-	138.0
Alkylation Plant	-	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.0
Cat Polymerization	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hydro. Plant (MB/D, FOE)	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	3.1
Sulfur Plant (MST/D)	-	-	-	-	-	-	-	-	3.8	-	-	-	-	-	-	-	-	3.8
Aromatics Recovery Plant Pen/Hex Isomerization	-	-	-	-	-	-	-	-	18.0	-	-	-	-	15.0	20.0	-	-	53.0

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

REFINERY PROCESS UNIT CAPACITY ASSUMPTIONS -- 1986
(MB/SD)

	PADD I	PADD II		PADD III		PADD IV	PADD V	U.S.
	All	D*	S&L**	D*	S&L**	All	All	Total
Number of Refineries	21	24	19	32	35	20	51	202
Feed Rate								
Crude - Atmospheric	1,667.0	2,548.4	892.6	5,487.5	2,008.7	590.6	3,248.0	16,442.8
Crude - Vacuum	782.7	954.0	336.3	2,287.8	781.4	199.2	1,533.3	6,894.7
Catalytic Cracking	574.3	998.5	286.0	1,951.8	521.8	190.9	691.5	5,214.8
Hydrocracking	78.4	113.4	44.5	367.7	30.0	10.9	418.7	1,063.6
Coking - Delayed	35.0	271.4	-	532.0	-	13.0	396.3	1,247.7
Coking - Fluid	54.0	-	-	49.0	-	16.5	86.5	206.0
Coke Make	33.5	75.2	-	180.0	-	11.0	110.1	409.8
Thermal Cracking	-	-	1.5	14.6	55.0	-	17.2	88.3
Visbreaking	13.0	6.6	-	43.5	22.5	-	50.8	136.4
Total	13.0	6.6	1.5	58.1	77.5	-	68.0	224.7
Catalytic Reforming								
Low Pressure	118.8	339.3	133.5	837.3	187.5	39.5	241.8	1,897.7
High Pressure	243.8	283.5	114.8	461.5	189.5	75.2	404.0	1,772.3
Total	362.6	622.8	248.3	1,298.8	377.0	114.7	645.8	3,670.0
Solvent Deasphalting	23.0	41.6	-	145.2	35.3	17.7	57.4	320.2
Hydrotreating								
Naphtha	418.3	711.9	202.3	1,261.6	413.9	161.0	592.9	3,761.9
Distillate	344.3	326.6	117.4	1,142.0	394.5	67.0	408.3	2,799.5
Heavy Gas Oil	117.0	220.5	100.7	501.8	165.6	18.5	469.6	1,593.7
Residuum	0.5	-	-	176.0	-	-	24.0	200.5
Product Rate								
Alkylation	70.3	192.5	64.3	371.3	76.6	31.7	131.8	970.6
Polymerization	15.0	16.1	5.0	27.2	8.0	11.7	6.8	89.8
Isomerization - C5/C6	25.0	73.5	9.5	104.6	23.8	-	-	236.4
Isomerization - C4	-	24.3	0.5	10.1	12.0	8.4	21.6	76.9
Hydrogen - MMCFD	101.0	159.0	-	858.0	79.8	27.0	1,030.8	2,255.6
Hydrogen, FOE - MB/D	5.2	8.1	-	43.7	4.0	1.4	52.5	114.9
Asphalt	156.6	142.6	100.8	95.4	81.2	36.0	125.3	737.9
Lube	40.2	29.6	5.6	91.6	48.1	1.5	26.4	243.0
Aromatics	12.7	42.2	-	113.1	38.9	-	3.5	210.4
Hydrodealkylation	1.8	5.5	-	20.2	-	-	-	27.5

*Deep conversion refiners.
**Simple and low conversion refiners.

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

REFINERY PROCESS UNIT CAPACITY ASSUMPTIONS -- 1988
(MB/SD)

	PADD I	PADD II		PADD III		PADD IV	PADD V	U.S.
	All	D*	S&L**	D*	S&L**	All	All	Total
Number of Refineries	21	24	19	32	35	20	51	202
Feed Rate								
Crude - Atmospheric	1,667.0	2,623.4	892.6	5,487.5	2,008.7	590.6	3,248.0	16,517.8
Crude - Vacuum	782.7	985.3	336.3	2,287.8	781.4	199.2	1,533.3	6,926.0
Catalytic Cracking	574.3	998.5	286.0	1,951.8	521.8	190.9	691.5	5,214.8
Hydrocracking	78.4	113.4	44.5	367.7	30.0	10.9	418.7	1,063.6
Coking - Delayed	35.0	281.4	-	559.9	-	13.0	396.3	1,285.6
Coking - Fluid	54.0	-	-	49.0	-	16.5	86.5	206.0
Coke Make	33.5	78.0	-	184.9	-	11.0	110.1	417.5
Thermal Cracking	-	-	1.5	14.6	55.0	-	17.2	88.3
Visbreaking	13.0	6.6	-	43.5	22.5	-	50.8	136.4
Total	13.0	6.6	1.5	58.1	77.5	-	68.0	224.7
Catalytic Reforming								
Low Pressure	118.8	339.3	133.5	866.4	187.5	39.5	241.8	1,926.8
High Pressure	243.8	283.5	114.8	461.5	189.5	75.2	404.0	1,772.3
Total	362.6	622.8	248.3	1,327.9	377.0	114.7	645.8	3,699.1
Solvent Deasphalting	23.0	41.6	-	145.2	35.3	17.7	57.4	320.2
Hydrotreating								
Naphtha	418.3	711.9	202.3	1,261.6	413.9	161.0	592.9	3,761.9
Distillate	344.3	326.6	117.4	1,142.0	394.5	67.0	408.3	2,800.1
Heavy Gas Oil	117.0	230.5	100.7	513.3	165.6	18.5	469.6	1,615.2
Residuum	0.5	-	-	176.0	-	-	24.0	200.5
Product Rate								
Alkylation	70.3	192.5	64.3	403.4	76.6	31.7	131.8	970.6
Polymerization	15.0	16.1	5.0	27.2	8.0	11.7	6.8	89.8
Isomerization - C5/C6	26.1	85.7	15.4	111.1	33.0	3.9	19.4	294.6
Isomerization - C4	-	24.3	0.5	10.1	12.0	8.4	21.6	76.9
Hydrogen - MMCFD	101.0	159.0	-	858.0	79.8	27.0	1,030.0	2,255.6
Hydrogen, FOE - MB/D	5.2	8.1	-	43.7	4.0	1.4	52.5	114.9
Asphalt	156.6	142.6	100.8	95.4	81.2	36.0	125.3	737.9
Lube	40.2	29.6	5.6	91.6	48.1	1.5	26.4	243.0
Aromatics	12.7	42.2	-	119.3	38.9	-	3.5	216.6
Hydrodealkylation	1.8	6.1	-	20.2	-	-	-	28.1

*Deep conversion refiners.
**Simple and low conversion refiners.

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

WORLD (NON-U.S.) HYDROCRACKER FEED -- 1986
(MB/CD)

Region	Description	Dist. Feed	VGO Feed	Resid Feed	Total
A	Australia, New Zealand				0.0
C	Canada	25.0	71.0		96.0
F	Other Africa		10.7	9.3	20.0
I	Indonesia		99.9		99.9
J	Japan		13.5		13.5
M	Mexico			18.0	18.0
P	Arab Gulf		204.0	54.0	258.0
Q	Bahrain, Eqypt, Syria		5.0		5.0
R	Iran		111.0		111.0
S	Other Americas		20.7		20.7
X	Other Asia		36.0		36.0
Y	Brunei, Malaysia, Singapore		35.1		35.1
1	Finland, Iceland, Norway, Sweden		14.0		14.0
2	United Kingdom, Ireland	14.0	15.0		29.0
3	Benelux				0.0
4	West Germany	53.0	53.0		106.0
5	France		13.5		13.5
7	Spain, Portugal		20.0		20.0

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

WORLD (NON-U.S.) HYDROCRACKER FEED -- 1988
(MB/CD)

Region	Description	Dist. Feed	VGO Feed	Resid Feed	Total
A	Australia, New Zealand		19.8		19.8
C	Canada	25.0	71.0		96.0
F	Other Africa		11.7	9.3	21.0
I	Indonesia		99.9		99.9
J	Japan		13.5		13.5
M	Mexico			18.0	18.0
P	Arab Gulf		276.0	54.0	330.0
Q	Bahrain, Eqypt, Syria		5.0		5.0
R	Iran		111.0		111.0
S	Other Americas		20.7		20.7
X	Other Asia		36.2		36.2
Y	Brunei, Malaysia, Singapore		44.1		44.1
1	Finland, Iceland, Norway, Sweden		14.0		14.0
2	United Kingdom, Ireland	14.0	15.0		29.0
3	Benelux		30.0		30.0
4	West Germany	53.0	53.0		106.0
5	France		13.5		13.5
7	Spain, Portugal		37.2		37.2

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

MAJOR PRODUCT YIELD PER BARREL OF HYDROCRACKER FEEDSTOCK

	Distillate Feed		VGO Feed		Resid
	Gas Mode	Jet Mode	Jet Mode	Dist. Mode	Feed
Gasoline	103	45	14	14	13
Jet/Kero	0	64	49	0	20
Distillate	0	0	48	97	11
VGO	0	0	0	0	45
Resid	0	0	0	0	16

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

U.S. CRUDE OIL TYPE

Indigenous PADD I North Atlantic and indigenous PADD I Mid-Atlantic

Indigenous PADD II

Indigenous PADD III (except WTI, WTS, LLS) and indigenous PADD I South Atlantic

Indigenous PADD IV

Indigenous PADD V (except ANS, Offshore Calif.)

WTI

WTS

LLS

ANS

Offshore California

Canadian Light

Canadian Heavy

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

U.S. CRUDE OIL SLATE

Region	Base	Increment*
PADD I	1984 Slate	PADD III Indigenous WTI, WTS, LLS, ANS, Offshore California, Canadian Light, Canadian Heavy, World Trade Crudes
PADD II (2 Refineries)	1984 Slate	PADD III Indigenous PADD IV Indigenous, WTI, WTS, LLS, ANS, Canadian Light, Canadian Heavy, World Trade Crudes
PADD III (2 Refineries)	1984 Slate	PADD IV Indigenous PADD V Indigenous WTI, WTS, LLS, ANS, Canadian Light, Canadian Heavy, Offshore California, World Trade Crudes
PADD IV	1984 Slate	Canadian Light, Canadian Heavy
PADD V	1984 Slate	ANS, Offshore California, Canadian Light, Canadian Heavy, World Trade Crudes

*Also indigenous crude oil supply.

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

WORLD (NON-U.S.) CRUDE OIL TYPE

Algeria
Saudi Arabian Heavy
Saudi Arabian Light
Angola, Congo, Zaire
Bolivia, Peru
China
Ecuador
Egypt, Syria, Bahrain
Iranian Heavy
Iranian Light
Indonesia
Iraq
Kuwait
Libya
Qatar, United Arab Emirates
Mexico
Nigeria
Norway
Russia
South Asia Mix
Trinidad
United Kingdom
Venezuela

Marginal crude oil supply*

* Composite barrel of unused OPEC production.

NOTE: Each crude oil is available in all regions; indigenous crude oil also available in all regions for internal consumption.

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

WORLD (NON-U.S.) CRUDE OIL SLATE

Region	Base	Increment
Angola/Congo/Zaire	1983 Slate	Indigenous
Egypt/Syria/Bahrain	1983 Slate	Indigenous
Indonesia	1983 Slate	Indigenous
Iran	1983 Slate	Indigenous
Libya/Algeria	1983 Slate	Indigenous
Mexico	1983 Slate	Indigenous
Nigeria/Gabon	1983 Slate	Indigenous
Arab Gulf	1983 Slate	Indigenous
Venezuela/Ecuador	1983 Slate	Indigenous
All Other Regions*	1983 Slate	World Trade Crudes

* Puerto Rico/Virgin Islands slate includes 100 MB/D ANS.

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

WORLD (NON-U.S.) REGIONS WITH SIGNIFICANT NGL PRODUCTION* AVAILABLE AS REFINERY FEEDSTOCK

Algeria, Libya

Australia, New Zealand

Canada

Ecuador, Venezuela

Finland, Iceland, Norway, Sweden

Indonesia

Ireland, United Kingdom

Iran

Mexico

Arab Gulf

- Butanes and natural gasoline yield from NGL per U.S. average; butanes and natural gasoline, not input as refinery feedstock, and remaining NGLs satisfy LPG demand directly

*Greater than 10 MB/D.

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

PETROLEUM PRODUCTS

Product	Comment
LPG	World
Gasoline*	
Unleaded Regular (87 R+M/2)	U.S.
Unleaded Premium (92 R+M/2)	U.S.
80 R+M/2 clear	Non-U.S.
90 R+M/2 clear	Non-U.S.
Distillate	
No. 2	World
No. 4	Non-U.S.
Jet Fuel/Kero	World
Residual Fuel	World
Aromatics	World
Other	Lubes, Chemical Feedstocks (Naphtha)

*Non-U.S. gasolines blended to satisfy local clear octane requirement (Attachment 29).

Gasoline exported to U.S. is blended by manufacturer to 87 R+M/2 clear octane.

Any region that requires gasoline with octane below 80 R+M/2 clear produces that gasoline for internal consumption and produces an 87 R+M/2 clear gasoline for internal consumption or export.

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

WORLD AROMATICS DEMAND
(MB/D)

Region	Description	1986	1988	1990
1	Finland, Iceland, Norway, Sweden	1.95	1.95	1.95
2	Ireland, United Kingdom	28.65	29.17	29.67
3	Benelux	34.95	35.41	35.86
4	West Germany	53.14	53.06	52.98
5	France	19.33	19.32	19.31
6	Austria, Switzerland	1.10	1.11	1.12
7	Portugal, Spain	11.59	12.09	12.57
8	Italy	27.11	28.11	29.10
9	Greece, Turkey	0	0	0
A	Australia, New Zealand			
I	Indonesia			
X	Other Asia	38.00	45.00	53.00
Y	Other Exporters of Petroleum			
C	Canada			
M	Mexico	48.00	50.00	53.00
B	Bolivia, Brazil, Colombia, Peru			
K	Caribbean			
S	Other Americas	50.00	51.00	53.00
U	Puerto Rico, Virgin Islands			
V	Venezuela, Ecuador			
J	Japan	40.00	40.00	40.00
F	Other Africa			
L	Algeria, Libya			
N	Gabon, Nigeria	16.00	17.00	19.00
O	Angola, Congo, Zaire			
P	Arab Gulf			
Q	Eqypt, Bahrain, Syria	11.00	15.00	19.00
R	Iran			
	United States	142.00	165.00	167.00

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

WORLD (NON-OECD) LPG DEMAND

Region	LPG Demand* (Percent)
Bolivia, Brazil, Colombia, Peru	5
Other Africa (Includes: Cameroon, Ethiopia, Ghana, Ivory Coast, Kenya, Liberia, Madagascar, Morocco, Mozambique, Senegal, Somalia, South Africa, Sudan, Tanzania, Tunisia, Zambia)	2
Indonesia	1
Caribbean (Includes: Bahamas, Barbados, Dominican Republic, Jamaica, Netherlands Antilles, Trinidad)	4
Algeria, Libya	8
Mexico	13
Gabon, Nigeria	1
Angola, Congo, Zaire	2
Arab Gulf (Includes: Iraq, Kuwait, Neutral Zone, Oman, Qatar, Saudia Arabia, South Yemen, U.A.E.)	1
Bahrain, Eqypt, Syria	3
Iran	2
Other Americas	5
Ecuador, Venezuela	7
Other Asia (Includes: Guam and HIRI)	5

*LPG as a percent of each region's total product demand.

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

WORLD (NON-U.S.) GASOLINE OCTANE DEMAND

Clear Pool Octane (R+M/2)	Region
84	Australia, New Zealand
68	Bolivia, Brazil, Colombia, Peru
85	Canada
80	Other Africa (Includes: Cameroon, Ethiopia, Ghana, Ivory Coast, Kenya, Liberia, Madagascar, Morocco, Mozambique, Senegal, Somalia, South Africa, Sudan, Tanzania, Tunisia, Zambia
70	Indonesia
87	Japan (Includes: Okinawa)
84	Caribbean (Includes: Bahamas, Barbados, Dominican Republic, Jamaica, Netherlands Antilles, Trinidad)
79	Algeria, Libya
73	Mexico
79	Gabon, Nigeria
77	Angola, Congo, Zaire
79	Arab Gulf (Includes: Iraq, Kuwait, Neutral Zone, Oman, Qatar, Saudia Arabia, South Yemen, U.A.E.)
72	Bahrain, Eqypt, Syria
79	Iran
75	Other Americas
87	Puerto Rico, Virgin Islands
73	Ecuador, Venezuela

WORLD (NON-U.S.) GASOLINE OCTANE DEMAND (Continued)

Clear Pool Octane (R+M/2)	Region
77	Other Asia (Includes: Guam and HIRI)
82	Other Exporters of Petroleum (Includes: Brunei, Malaysia, Singapore)
87	Finland, Iceland, Norway, Sweden
86	Ireland, United Kingdom
88	Belgium, Denmark, Luxembourg, Netherlands
89	West Germany
88	France
90	Austria, Switzerland
83	Portugal, Spain
88	Italy
77	Greece, Turkey

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

WORLD (NON-U.S.) RESID DEMAND

1. 250 MB/D of Japan resid demand satisfied directly by sweet crude oil (less than 0.5% sulfur).

2. 50% of remaining Japan resid demand must be satisfied by sweet resid (less than 1% sulfur).

3. 30% of Europe resid demand must be satisfied by sweet resid (less than 1% sulfur).

4. 20% of Region X, Asia, resid demand must be satisfied by sweet resid (less than 1% sulfur)

5. All other regions resid demand can be satisfied by either sweet or sour resid.

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

WORLD (NON-U.S.) DISTILLATE DEMAND

Region	Percentage Shares	
	No.2 Fuel Oil*	No.4 Fuel Oil**
Canada	56.8	43.2
Japan	57.0	43.0
Australia, New Zealand	65.4	34.6
Finland, Iceland, Norway, Sweden	58.1	41.9
Ireland, United Kingdom	63.3	36.7
Benelux, Denmark	64.7	35.3
West Germany	57.4	42.6
France	60.5	39.5
Austria, Switzerland	54.6	45.4
Spain, Portugal	79.0	21.0
Italy	68.1	31.9
Greece, Turkey	78.3	21.7
OECD Total (Assumed for all other regions)	64.9	35.1

*No.2 Fuel Oil demand equals OECD transport sector distillate and 50% OECD commercial sector distillate.

**No.4 Fuel Oil demand equals OECD industrial sector distillate and 50% OECD commercial sector distillate.

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

U.S. PETROLEUM PRODUCT REGIONAL DEMAND

Model Region	Product Demand
PADD I North Atlantic	NPC Supply/Demand Region 1
PADD I Mid-Atlantic	NPC Supply/Demand Region 2
PADD I South Atlantic	NPC Supply/Demand Region 3
	54% of clean product demand can be served only by pipeline
	26% (9% after 1988) of clean product demand can be served only by marine*
	20% (37% after 1988) of clean product demand can be served by pipeline or marine*
PADD II	NPC Supply/Demand Regions 4 and 5
PADD III	NPC Supply/Demand Region 6
PADD IV	NPC Supply/Demand Region 7
PADD V	NPC Supply/Demand Regions 8 and 9

*Transgulf Pipeline beginning 1988.

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

CENTRALLY PLANNED ECONOMIES PETROLEUM EXPORTS*
(MB/D)

	1986			1988			1990		
	East Bloc (Non-Soviet)	Soviet Union	P.R.C.	East Bloc (Non-Soviet)	Soviet Union	P.R.C.	East Bloc (Non-Soviet)	Soviet Union	P.R.C.
Gasoline	46	24	37	46	17	40	41	13	63
Gas Oil	126	403	13	128	287	14	117	220	23
Resid	105	171	5	97	111	5	82	77	8
Other	43	143	70	41	99	67	37	74	96
Total Product	320	741	125	312	514	126	277	384	190
Crude Oil	(379)	572	301	(398)	444	302	(424)	275	298
TOTAL EXPORTS	(59)	1,313	426	(86)	958	428	(147)	659	488

NOTE: Gas Oil assumed to be 30% No. 2 oil and 70% No. 4 oil.
Resid assumed to be 20% < 1% sulfur and 80% > 1% sulfur.

*SOURCE: C.I.A., Office of Geographical Intelligence.

NATIONAL PETROLEUM COUNCIL
U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

TRADE MEASURES AFFECTING OIL PRODUCTS

The following is a preliminary overview of trade measures in a number of OECD Member countries affecting oil products, as prepared in co-operation with the OECD Trade Directorate. The information, compiled at the request of the SOM, comes from a variety of sources, including publications by the Customs Co-operation Council, the GATT inventory, and OECD trade files currently available. As trade regulations change often, and as they are sometimes difficult to identify or to interpret, Delegations are invited to verify this overview and inform the Secretariat of any changes they deem necessary.

European Community

The Community applies no quantitative restrictions (quota) to product imports. Feedstocks for refining or petro-chemical processing are exempt from tariffs. Duties (3.5 percent for gas oil and heavy fuel oils, 6 percent for lighter products) have to be paid only for products from industrialized countries and CPEs destined for consumption in the EC. Products from the Soviet Union and the United States fall into this category.

Under the General System of Preferences, products from a number of countries (including Saudi Arabia, Kuwait, Libya) can be imported free of duty. There is a volume ceiling, however, which is fixed annually for each of the three main product categories and is applied to each exporting country individually. When the ceiling is reached or exceeded, the Commission can reimpose the duty, either on its own initiative or at the request of an EC Member State. Although the ceilings have often been exceeded in recent years, this facility has not been used.

In addition, France maintained, through December 6, 1985, restrictions (import licenses) that limit the access of non-EC products to 20 percent of total French product imports. In Greece the state has a monopoly on product imports. These imports are subject to a licensing scheme executed by the Ministry of Trade. In Ireland, oil companies are obliged to purchase 35 percent of their product throughput from the domestic refinery.

Finland

Only gasolines are subject to a duty of 0.11 Finnish marks per litre ($2.50/bbl) and are not eligible for preferential treatment (GSP). For most products quota are applied as well as discretionary licensing.

Portugal

Tariffs are:

Light oil	7-35%	of import value
Medium oil	5-6%	of " "
Kerosene	25%	of " "
Heavy oil	5-6%	of " "

A license is required for all product imports. Only the oil companies with a license to operate in the domestic market can import products, but under a general quota law and only if state-owned refineries cannot supply them with sufficient products.

Spain

Imports of oil products are subject to state trading. These products are to be imported in accordance with the contract signed between the state and the concessionary company (no customs duties). Only domestic refiners have the right to import products.

Switzerland

Importers of oil products have to pay the same amounts as those charged to domestic refiners when they deliver products to the domestic market. Products are not eligible for preferential tariff treatment.

Turkey

All imports of oil products are government-controlled and are part of an annual programme.

United States

The main oil products do not fall under the U.S. preferential system from which most OPEC countries are in any case excluded. Tariffs are:

1.	Naphtha	10.5 cts/bbl	(0.25 cts/gallon)
2.	Gasoline	52.5 cts/bbl	(1.25 cts/gallon)
3.	Diesel oils	10.5 cts/bbl	(0.25 cts/gallon)
4.	Heavy fuel oil	10.5 cts/bbl	(0.25 cts/gallon)
5.	Lubricants	84.0 cts/bbl	(0.25 cts/gallon)

In addition, customs classifies leaded gasoline blending material as a chemical mixture, with an ad valorem tariff of 98 percent of about $200/bbl.

Japan

Gasoline imports are now allowed, but are subject to limits. For other products the tariffs, which are progressive to fuel oil, are as follows:

1. Fuel Oil[1)]
   - Type A: 955 yen/kl for the first two million m^3 imported into Japan (not by individual company but for the country as a whole). For imports over two million m^3 the tariff is 2,280 yen/kl
   - Type B: 730 yen/kl for the first 5.5 million m^3
   - Type C: 660 yen/kl for first 5.5 million m^3
2. Jet Fuel: 3,033 yen/kl
3. Naphtha (for burning): 125 yen/kl
4. Kerosene: 1,010 yen/kl
5. Gas Oil: 1,890 yen/kl
6. LPG: 550 yen/kl

1)Type A is for boilers, small and mid-size diesel engines. Type B is for big diesel engines. Type C is for power generation.

Most oil products are eligible for varying forms of preferential treatment when imported from any developing country.

Austria

Tariffs are:

Gasolines	31.50	schillings/100 kg
Kerosenes	14	" "
Gas Oils	18	" "
Fuel Oils	5	" "

Oil products are eligible for preferential tariff treatment (GSP) when imported from any developing country.

There are no quantitative restrictions on imports.

Australia

Importers of oil products have to pay the same amounts as those charged to domestic refiners when they deliver products to the domestic market.

There are no quantitative restrictions on imports.

Canada

Imports of oil products are duty-free except for lubricating oil, some categories of which are subject to rates up to 20 percent (general tariff). Oil products are eligible for preferential treatment. Libya and Saudi Arabia are not GSP beneficiaries.

KNOWN CUSTOMS DUTIES

Region	Country	Monetary and Volume Units	Crude Oil	Motor Gasoline	Jet	Kero-sene	Diesel	Distillate Fuel Oil	Residual Fuel Oil	LPG
A	Australia	Aust.¢/Gal.	None	36.5	29.2	7.6	36.5	7.6	7.6	-
I	Indonesia (1)	%	None	5	5	5	5	5	-	-
J	Japan	Yen/KL	640	2,150	-	1,010	1,890	1,890	0-3,390	0-200/ton
X	Hong Kong (2)	US$/Gal.	None	1.07	10.7	10.7	0.53	-	-	-
	India (3)	%	10	16	None	-	16	None	-	-
	Pakistan (4)	US$/Gal.	None	0.21	-	None	0.06	0.01	-	-
	Philippines (5)	%	10-20	20	30	30	20	20	-	20
	South Korea (6)	US$/bbl	0.50	0.50	0.50	0.50	0.50	0.50	0.30	$215/ton
	Sri Lanka	US$/Gal.	-	-	-	0.04	0.07	-	-	-
	Taiwan (7)	%	2.5	20	20	20	20	5	-	7.5
	Thailand (8)	US$/Gal.	None	0.41	-	0.08	0.08	Nil	-	Nil
Y	Malaysia (9)	US¢/Gal.	None	58.5	-	2.3	1.1	-	-	1.8-12.3
	Singapore (10)	US$/Gal.	None	1.03-1.07	0.18	0.02	0.10	-	-	-

Primary Source: Caltex Petroleum Corporation.

Notes:

(1) Indonesian product imports are subject to 10% Value Added Tax. Import surcharges are levied on some goods (50-400%); 100% is the most common rate, with luxury items and goods competitive with domestic products subject to the highest rates.
(2) Converted at 1 $ US = 7.80 $ Hong Kong.
(3) Lubes 40%.
(4) Pakistan crude oil imports are subject to 10% CIF surcharge. Product imports are exempted from the 10% surcharge. Development surcharge in $ US/gal.: Gasoline 0.45, Kerosene 0.02, Diesel 0.05, and Fuel Oil 0.02. Fuel oil is converted from metric tons at 6.66 barrels per metric ton. Bulk lubes no duty, cans 10%.
(5) Philippines crude oil duty is 10% if used for electric power generation, and 20% for other uses, based on 100% fob. In addition to customs duty based on 110% fob, a 5% surcharge and a 10% advance sales tax are levied on petroleum product imports. Lubes duty 20%.
(6) South Korean imports are subject to a 5% CIF surcharge. A 1% CIF surcharge is currently applied to crude oil imports.
(7) Taiwan's product imports are also subject to 4% harbor tax and a 5% uplift tax, which will be abolished 1/1/86. Lubes duty 15%.
(8) Thailand's duties converted at 1 $ US = 26.65 Baht. Product imports also subject to business tax as follows: mogas and kerosene 7%, diesel 6%, lubes 5%, and fuel oil and LPG none. Lubes customs duty 0.09 $ US/gal.
(9) Malaysian LPG import duties in US¢/gal. are 12.3 for auto LPG and 1.8 for bottle LPG. A sales tax of 10% is levied on all imported goods. Almost all imports are subject to a 5% surtax based on their CIF value.
(10) Singapore's duties converted at 1 $ US = 2.26 $ Singapore.

Region/Port Assignments in the Petroleum Allocation (PAL) Model

Region Name	Crude Oil Port(s)	Product Port(s)
East Coast, United States	New York	Boston New York Port Everglades
Gulf Coast, United States	Houston St. James LOOP	Houston
West Coast, United States	Los Angeles Valdez (for ANS only)	Los Angeles
Puerto Rico/ Virgin Islands	Hovic, Virgin Islands	Hovic, Virgin Islands
Canada	Montreal	Montreal
Japan	Yokohama	Yokohama
Australia/ New Zealand	Sydney, Australia	Sydney, Australia
Scandinavia	Gothenborg, Sweden	Gothenborg, Sweden
United Kingdom/Ireland	Milford Haven, U.K.	Milford Haven, U.K.
Benelux/Denmark	Rotterdam, Netherlands	Rotterdam, Netherlands
West Germany	Hamburg	Hamburg
France	Lavera	Lavera
Austria/Switzerland	Trieste, Italy	Trieste, Italy
Spain/Portugal	Algeciras, Spain	Algeciras, Spain
Italy	Genoa	Genoa
Greece/Turkey	Athens, Greece	Athens, Greece
Venezuela/Ecuador	Amuay Bay, Venezuela Esmeraldas, Ecuador	Amuay Bay, Venezuela
Libya/Algeria	Arzew, Algeria Marsa el Brega, Libya	Arzew, Algeria
Nigeria/Gabon	Port Harcourt, Nigeria	Port Harcourt, Nigeria
Indonesia	Balikpapan	Balikpapan
Iran	Kharg Island	Kharg Island
Arab Gulf (Arab OPEC)	Ras Tanura, Saudi Arabia Shuaiba, Kuwait Umm Said, Qatar Basrah, Iraq	Ras Tanura, Saudi Arabia
Non-U.S. Caribbean	Port of Spain, Trinidad	Port of Spain, Trinidad
Mexico	Coatzacoalcos, Mexico	Coatzacoalcos, Mexico
Bolivia/Brazil/ Colombia/Peru	Talara, Peru	Rio de Janeiro, Brazil
Egypt/Syria/Bahrain	Port Said, Egypt	Port Said, Egypt
Angola/Congo/Zaire	Pointe Noire, Congo	Pointe Noire, Congo
Other Exporters of Petroleum	Pulo Bukom, Singapore	Pulo Bukom, Singapore
Other Americas	Buenos Aires, Argentina	Buenos Aires, Argentina
Other Africa	Durban, South Africa	Durban, South Africa
Other Asia	Bombay, India	Bombay, India
Centrally Planned Economies	Tuapse, U.S.S.R. Shanghai, China Burghaz, Bulgaria	Tuapse, U.S.S.R. Shanghai, China Burghaz, Bulgaria

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WORLD REFINING AND TRANSPORTATION CAPABILITY

WORLD (NON-U.S.) PIPELINES

Model Region		Volume (MB/D)			
Source	Destination	1986	1988	1990	Cost
		Crude Oil			
Iraq	Turkey	985	1,500	1,500	*
Red Sea	Mediterranean	1,600	1,600	1,600	*
P.G.	Yanbu (effective)	1,100	2,200	2,200	*
Iraq	Yanbu	0	1,600	1,600	*
Benelux	W. Germany	470	470	470	*
France	W. Germany	400	400	400	*
France	Switzerland	50	50	50	*
Italy	W. Germany	1,060	1,060	1,060	*
Italy	Austria	175	175	175	*
		Product			
Benelux	W. Germany	350	350	350	*
France	Switzerland	20	20	20	*
Italy	France	50	50	50	*

*Equivalent to least cost marine alternative plus holding and losses.

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WORLD REFINING AND TRANSPORTATION CAPABILITY

U.S. CLEAN PRODUCT PIPELINES

Model Region		Volume	Full Cost	Variable Cost
Source	Destination	(MB/D)	(¢/bbl)	(¢/bbl)
PADD I Mid-Atlantic	PADD II	42	61	11
PADD II	PADD I Mid-Atlantic	112	71	06
PADD II	PADD III	60	59	04
PADD II	PADD IV	40	63.5	14
PADD III	PADD I Mid-Atlantic	800*	99.2	57
PADD III	PADD I South Atlantic	2,250*	90	41
PADD III	PADD I South Atlantic	260**	85	37
PADD III	PADD II	290	65	38
PADD III	PADD II	300***	65	38
PADD III	PADD II	380****	65	38
PADD III	PADD IV	42	93	15
PADD III	PADD V	57	79.5	14
PADD IV	PADD II	60	126.2	05
PADD IV	PADD V	67	93.5	12

*Total pipeline movements from PADD III to PADD I South Atlantic are less than or equal to 2,250 MB/D; Total pipeline movements from PADD III to PADD I Mid-Atlantic are lesser of 800 MB/D or 2,250 minus total pipeline volume to PADD I South Atlantic.

**Transgulf Pipeline available 1988.

***Clean products or LPG.

****Clean products or crude oil.

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WORLD REFINING AND TRANSPORTATION CAPABILITY

U.S. LPG/NGL PIPELINES

Model Region		Volume	Full Cost	Variable Cost
Source	Destination	(MB/D)	(¢/bbl)	(¢/bbl)
PADD II	PADD I Mid-Atlantic	44	123.2	10
PADD II	PADD III	100	94	11
PADD III	PADD I Mid-Atlantic	146	123	20
PADD III	PADD II	160	134.3	33
PADD III	PADD II	300*	134.3	33
PADD IV	PADD II	26	185.3	06
PADD IV	PADD III	29	58	07
Canada	PADD I Mid-Atlantic	**	50	
Canada	PADD II	**	50	
Canada	PADD IV	**	50	
Canada	PADD V	**	50	

*LPG or clean products.
**No capacity limit.

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U.S. CRUDE OIL PIPELINES

Model Region		Volume		Cost		Variable Cost
Source	Destination	(MB/D)	Crude Type	(¢/bbl)	Comment	(¢/bbl)
PADD III	PADD II	1,062	WTI	61		40
			WTS	61		40
PADD III	PADD II	1,478	LLS	30 + 48 = 78	30¢ LLS to	49
			ANS	48	St. James	29
			World Trade Crudes	48		29
PADD III	PADD II	380*	LLS	30 + 48 = 78	30¢ LLS to	49
			ANS	48	St. James	29
			World Trade Crudes	48		29
PADD IV	PADD II	355	Indigenous PADD IV	94		35
PADD IV	PADD III	70**	Indigenous PADD IV	89.5		05
PADD V	PADD III	50	Indigenous PADD V	223		19
PADD V	PADD III	300	Offshore California	345	Beginning 1988	68
Canada	PADD I	60	Canadian Light	84		
			Canadian Heavy	84		
Canada	PADD II	550***	Canadian Light	72		
			Canadian Heavy	72		
Canada	PADD IV	100	Canadian Light	121		
			Canadian Heavy	121		
Canada	PADD V	60	Canadian Light	81		
			Canadian Heavy	81		

*Crude oil or light products.
**70 MB/D less indigenous PADD V to PADD III.
***550 MB/D less volume to PADD I; 705 MB/D less volume to PADD I beginning 1988.

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WORLD REFINING AND TRANSPORTATION CAPABILITY

VESSEL OPERATING CHARACTERISTICS

	United States		World (Non-U.S.)	
	Speed (Knots)	Consumption (Bbl/Day)	Speed (Knots)	Consumption (Bbl/Day)
Medium Crude	16.1	553	12.5	258
Large Crude	16.2	780	11.7	365
VLCC	15.7	1,092	10.5	347
Small Product	14.3	286	14.5	151
Medium Product	16.0	455	15.4	225
Large Product	15.9	351	15.8	328
Very Large Product	15.4	657	15.8	322
Barges	7		-	

Port Days : 3.5 per round voyage
Weather Delay Days : 2 per round voyage
Dry Dock/Repair Days: 25 per year
Cargo Capacity : 97%
Losses : 0.3% (plus 0.15% if lightering)

PIPELINE OPERATING CHARACTERISTICS

Speed : 4 mph
Losses: 0.1%

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WORLD REFINING AND TRANSPORTATION CAPABILITY

WORLD (NON-U.S) MARINE CAPACITY

Product Carriers (MMDWT)

	1986	1988	1990
Small Product Carriers (10-19.9 MDWT)	1.8	1.6	1.6
Medium Product Carriers (20-39.9 MDWT)	13.6	13.2	13.1
Large Product Carriers (40-59.9 MDWT)	4.4	4.7	4.7
Very Large Product Carriers (60+ MDWT)	6.7	7.6	7.7
TOTAL	26.5	27.1	27.1

Crude Carriers (MMDWT)

	1986	1988	1990
Medium Crude Carriers (Less than 60 MDWT)	29.0	26.6	31.6
Large Crude Carriers (60-175 MDWT)	88.6	85.9	88.4
Very Large Crude Carriers (Greater than 175 MDWT)	133.5	118.9	102.7
TOTAL	251.1	231.4	222.7

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U.S MARINE CAPACITY

Product Carriers (MDWT)

	1986	1988	1990
Small Product Carriers (10-19.9 MDWT)	55	50	47
Medium Product Carriers (20-39.9 MDWT)	2,309	2,102	1,962
Large Product Carriers (40-59.9 MDWT)	538	490	458
Very Large Product Carriers (60+ MDWT)	62	57	53
TOTAL	2,964	2,699	2,520

Crude Carriers (MDWT)

	1986	1988	1990
Medium Crude Carriers (Less than 60 MDWT)	905	855	755
Large Crude Carriers (60-175 MDWT)	4,464	4,344	4,224
Very Large Crude Carriers (Greater than 175 MDWT)	1,715	2,133	2,133
TOTAL	7,084	7,332	7,112

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WORLD REFINING AND TRANSPORTATION CAPABILITY

INCREMENTAL MARINE CAPACITY*

VLCC Product Conversion

Conversion Cost	:	$5.0 MM
Cost Recapture	:	1 Year
Voyages Allowed	:	Far East & Northwest Europe
Spot Charter Cost	:	VLCC crude plus 5 WS points plus $0.43/bbl cost recapture
Capacity	:	5 MMDWT; Tonnage required to transport incremental Mideast light products (650 MB/D)

New Builds

Vessel Size	:	45 MDWT
Construction Cost	:	$18.7 MM
Rate of Return	:	12%
Cost Recapture	:	15 years
Spot Charter Cost	:	WS 167 Short Voyage (0-2,800 Nautical Miles)
	:	WS 161 Medium Voyage (2,801-6,100 Nautical Miles)
	:	WS 155 Long Voyage (6,101+ Nautical Miles)
Capacity	:	Unlimited

* Incremental supply only available if 100% utilization of existing product carriers.

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WORLD REFINING AND TRANSPORTATION CAPABILITY

INTRA-U.S. VOYAGES

Model Region		Vessel Class	
Source	Destination	Type	Ports/Voyage
		Crude Oil	
PADD III	PADD I Mid-Atlantic	Tanker	Houston to New York
PADD III	PADD II	Inland Barge	St. James to Chicago
PADD V	PADD I Mid-Atlantic	Tanker	Los Angeles to New York
PADD V	PADD III	Tanker	Los Angeles to Houston (Los Angeles to St. James if crude destined for PADD II; origin of ANS is Valdez)
		Products and LPG/NGL	
PADD I Mid-Atlantic	PADD I North Atlantic	Tanker	New York to Boston
	PADD I South Atlantic	Tanker	New York to Port Everglades
	PADD II	Inland Barge	Pittsburgh to Cincinnati
PADD II	PADD I Mid-Atlantic	Inland Barge	Cincinnati to Pittsburgh
	PADD III	Inland Barge	Chicago to St. James
PADD III	PADD I North Atlantic	Tanker	Houston To Boston
	PADD I Mid-Atlantic	Tanker	Houston to New York
	PADD I South Atlantic	Tanker	Houston to Port Everglades
PADD V	PADD I North Atlantic	Tanker	Los Angeles to Boston
	PADD I Mid-Atlantic	Tanker	Los Angeles to New York
	PADD I South Atlantic	Tanker	Los Angeles to Port Everglades
	PADD III		Los Angeles to Houston

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WORLD REFINING AND TRANSPORTATION CAPABILITY

WORLD (NON-U.S.) MARINE COST

1985 Worldscale Multiplier
(Percentage of WS 100 Flat Rate)

	Length of Voyage (Nautical Miles)		
	0-2,800	2,801-6,000	6,000+
Medium Crude Carrier (45 MDWT)	80	77	74
Large Crude Carrier (120 MDWT)	41	37	34
VLCC (250 MDWT)	30	28	25
Small Product Carrier (15 MDWT)	160	155	150
Medium Product Carrier (32 MDWT)	120	115	110
Large Product Carrier (50 MDWT)	100	96	92
Very Large Product Carrier (80 MDWT)	70	66	63
VLCC Product (250 MDWT)*	35	33	30

*Plus $0.43/bbl

Real Rate Increase
(Annual % Change)

	1986	1987	1988	1989	1990
45 MDWT Crude	4.0	5.0	5.0	6.0	7.0
120 MDWT Crude	4.0	5.0	5.0	6.0	7.0
250 MDWT Crude	4.0	5.0	5.0	6.0	7.0
15 MDWT Product	5.0	6.0	7.0	7.0	8.0
32 MDWT Product	6.0	7.0	8.0	9.0	9.0
50 MDWT Product	5.0	5.0	6.0	7.0	7.0
80 MDWT Product	5.0	5.0	5.0	6.0	7.0
25 MDWT Product	5.0	5.0	5.0	6.0	7.0

Holding Cost	:	8% per year
Insurance	:	$0.02/bbl
Part Cargo Lightering	:	$0.40/bbl plus 1½ days @ WS demurrage
LOOP	:	$0.40/bbl

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WORLD REFINING AND TRANSPORTATION CAPABILITY

U.S. MARINE COST

American Rate Multiplier
(% of AR 100 Flat Rate)

Tankers	From	To	AR Multiplier <60 MDWT	AR Multiplier 60-175 MDWT	AR Multiplier >175 MDWT
Crude Oil	Los Angeles*	Houston	180	118	95
	Los Angeles	New York	180	118	95
	Houston	New York	160	105	84

			AR Multiplier <20 MDWT	AR Multiplier 20-40 MDWT	AR Multiplier 40-60 MDWT	AR Multiplier >60 MDWT
Product	Los Angeles	Houston	180	180	162	162
		Port Everglades	180	180	162	162
		New York	180	180	162	162
		Boston	180	180	162	162
	Houston	Los Angeles	180	180	162	162
		Port Everglades	170	170	154	154
		New York	160	160	144	144
		Boston	160	160	144	144
	New York	Boston	160	160	144	144

Inland Barges	From	To	$/bbl
Crude Oil	St. James	Chicago	1.86
Product	St. James	Chicago	2.50
	Cincinnati	Pittsburgh	0.80
	Sarnia	Chicago	2.25
	Sarnia	Albany	5.50

Holding Cost : 8% per year
Losses : 0.3%
Insurance : $0.2/bbl
Part Cargo Lightering: $0.40/bbl plus 1½ day @ AR demurrage
LOOP : $0.40/bbl
Terminal Cost : $0.15/bbl

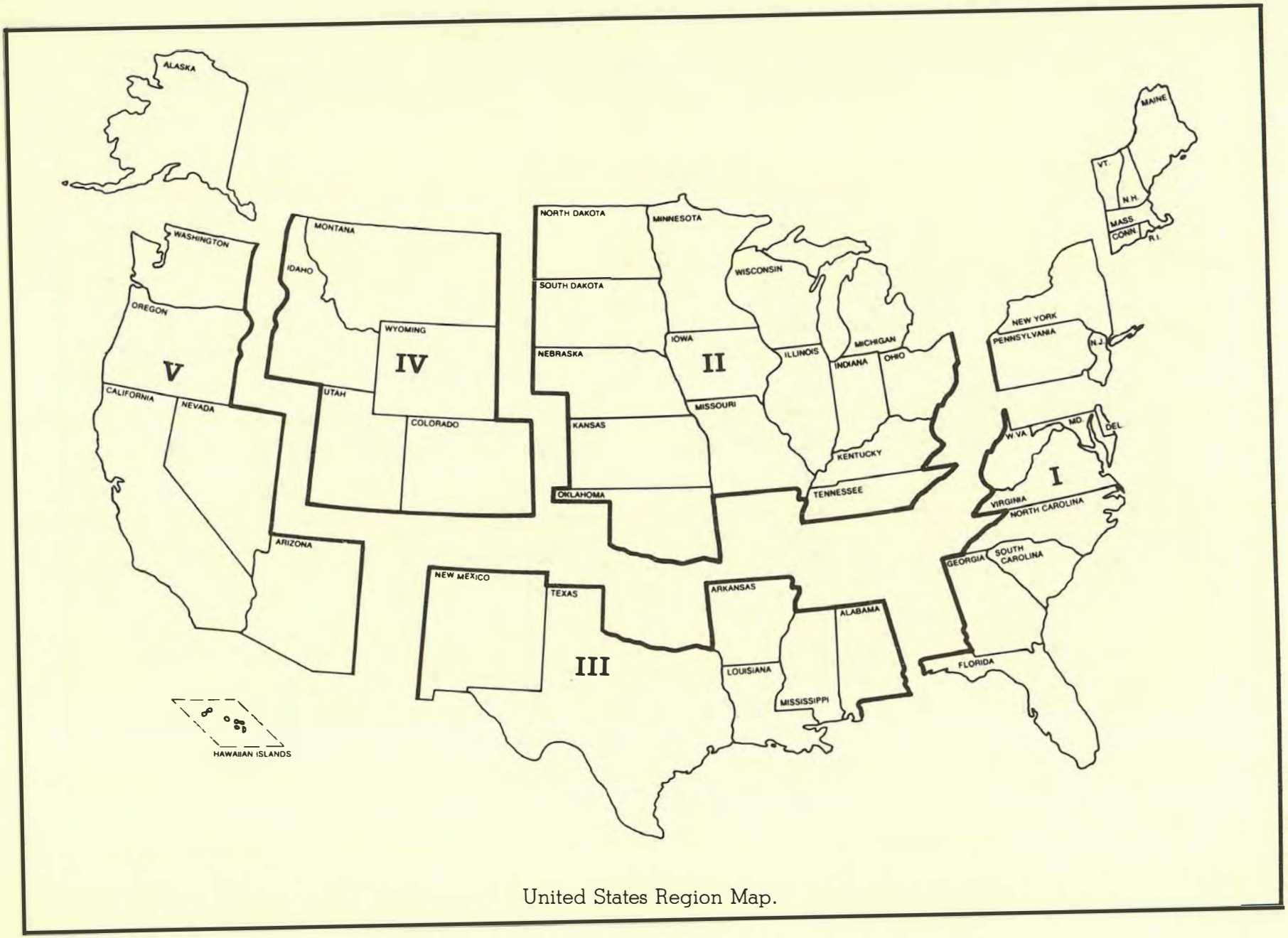
*Valdez to Houston for ANS.

NOTE: If no marine link available, resid or aromatics move from a region to an adjacent region by rail car for $6.30/bbl cost.

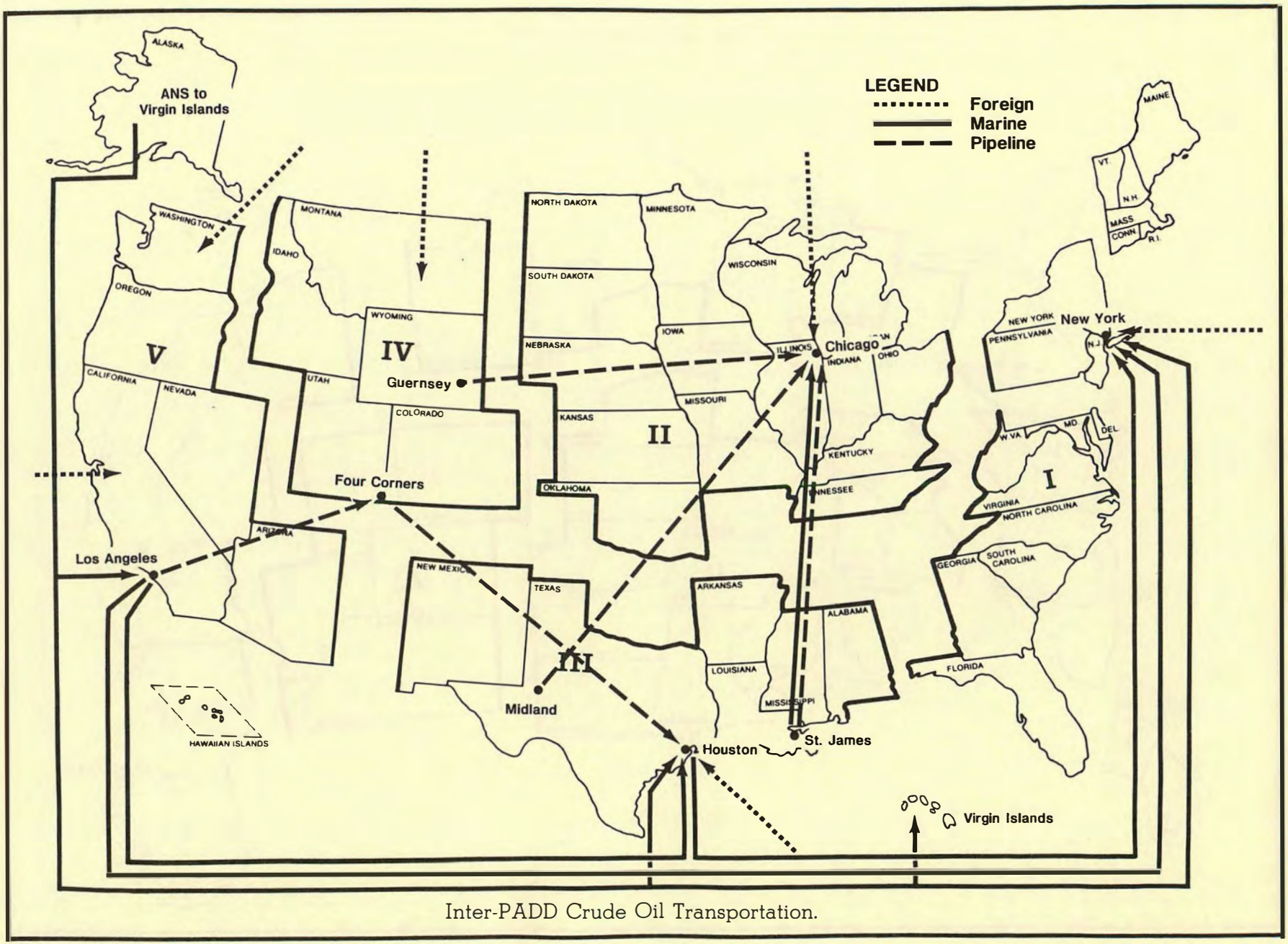
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WORLD REFINING AND TRANSPORTATION CAPABILITY

PORT/OPERATING RESTRICTIONS

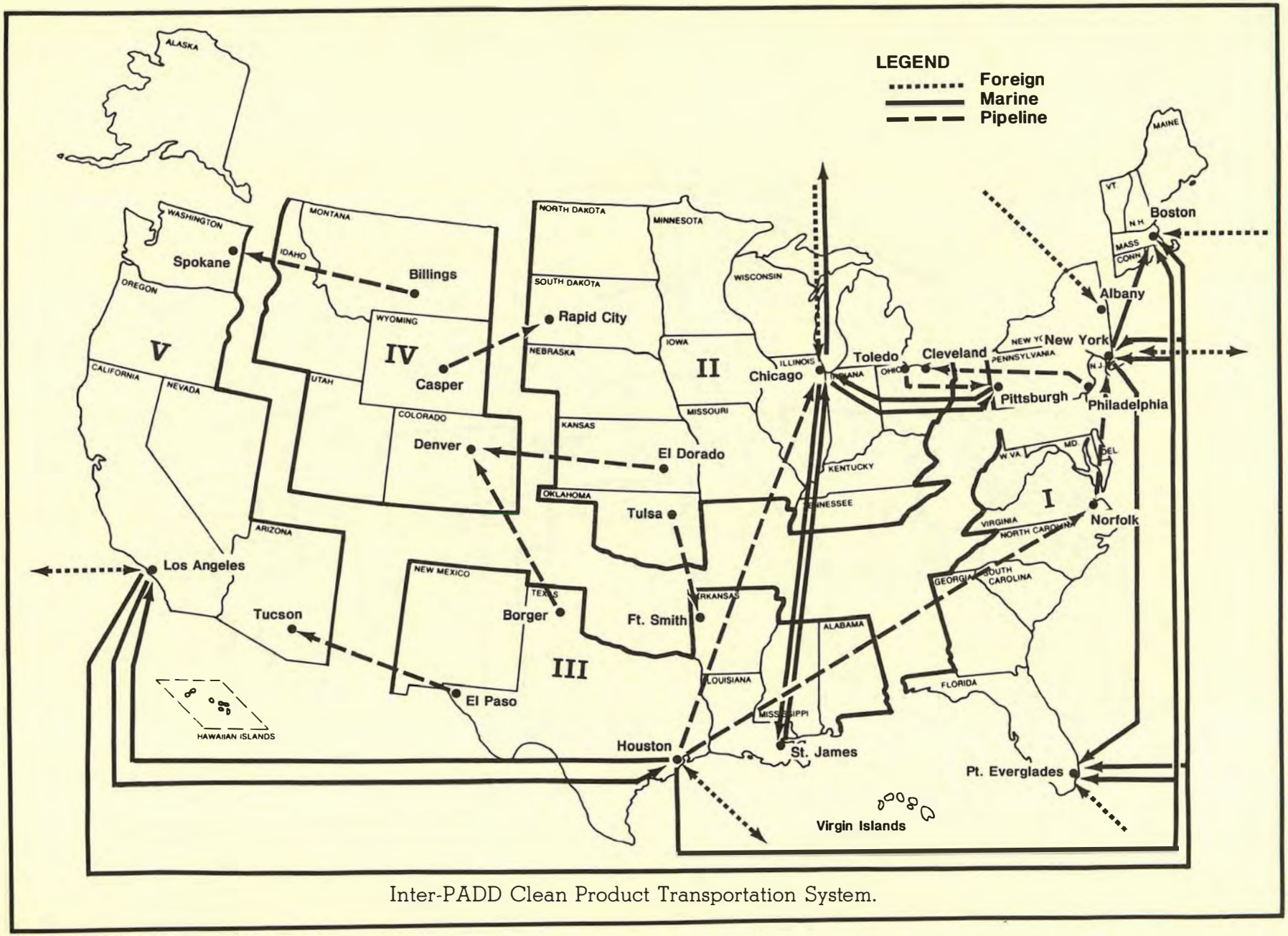
- VLCCs excluded from:
  - U.S. and Canadian East Coast
  - Nigeria/Gabon
  - Indonesia
- Large Crude Carriers must lighter part cargo for U.S. and Canadian East Coast
- VLCCs discharge at LOOP for U.S. Gulf Coast
- Large Crude Carriers discharge at LOOP for U.S Gulf Coast
- Large Product Carriers excluded from U.S. East Coast
- Very Large Product Carriers excluded from U.S. East Coast
- Voyages from U.S. port to U.S. port must use U.S. tankers
- Voyages to and from Region U, Puerto Rico/Virgin Islands use foreign tankers
- Canadian crude oil imports limited to 585 MB/D
- No back hauls.



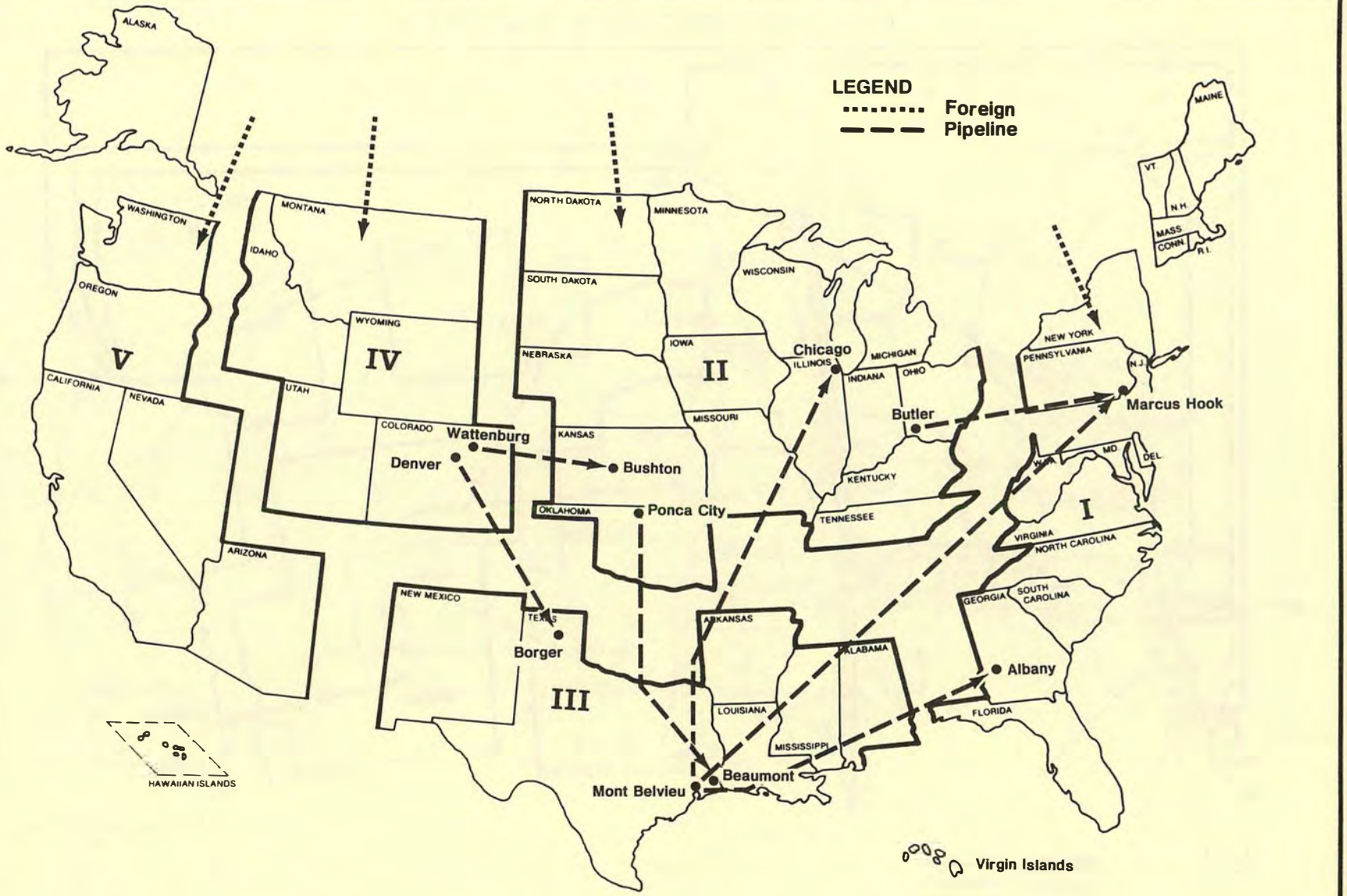
United States Region Map.



Inter-PADD Crude Oil Transportation.



Inter-PADD Clean Product Transportation System.



Inter-PADD LPG/NGL Transportation System.

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U.S. PETROLEUM REFINING STUDY
WORLD REFINING AND TRANSPORTATION CAPABILITY

REFERENCE CASES AND SCENARIOS STUDIED
TO ANALYZE THE DOMESTIC REFINING INDUSTRY

Case No.	Case Description	World Demand (MMB/CD) Total Products	Residual Fuel Oil	% Residual Fuel Oil	Refinery Utilization (%) U.S.	Non-U.S.	World
	REFERENCE CASES						
1	1986 - Simulates 1986 projected actual	43.7	8.0	18	80	69	72
2	1990 - Lower demand--no change in product mix	42.4	7.7	18	75	68	70
3	1990 - Increasing world demand and high residual fuel ratio	50.8	10.5	21	86	85	86
	DEMAND SCENARIOS WITH CHANGING PRODUCT MIX						
4	1990 - Low demand with a high ratio of residual fuel	42.7	10.1	24	74	69	71
5	1990 - Low demand with a low ratio of residual fuel	42.4	6.8	16	77	68	70
6.1-6.5	1990 - Increasing light oil demand in U.S. with world residual fuel held constant	42.9-45.4	7.8	18-17	77-86	69-72	71-76
7.1-7.5	1990 - Increasing light oil demand outside the U.S. with residual fuel held constant	42.9-45.4	7.8	18-17	75-80	69-74	71-76

Attachment 40

Case No.	Case Description	World Demand (MMB/CD) Total Products	Residual Fuel Oil	% Residual Fuel Oil	Refinery Utilization (%) U.S.	Non-U.S.	World
	SOCIAL, ECONOMIC, AND POLITICAL SCENARIOS						
8	1986 - Minimum refinery throughputs imposed on most non-U.S. refineries with low world demand and low residual fuel demand	43.7	8.0	18	80	69	72
9	1990 - Minimum refinery throughputs imposed on most non-U.S. refineries with low world demand and high residual fuel demand	42.7	10.1	24	73	70	71
10	1990 - Maximum refinery throughput imposed on Middle East refineries with low world demand and high residual fuel ratio	42.7	10.1	24	71	70	71
11.1-11.6	1990 - Tariff imposed by U.S. on product imports	42.7	10.1	24	76-84	69-66	71
12.1-12.6	1990 - Tariff imposed by U.S. and European countries on product imports	42.7	10.1	24	76-80	69-67	71
13	1990 - Tariff imposed by U.S. and European countries on product imports	42.7	10.1	24	69	71	71

Case No.	Case Description	World Demand (MMB/CD) Total Products	Residual Fuel Oil	% Residual Fuel Oil	Refinery Utilization (%) U.S.	Non-U.S.	World
	SOCIAL, ECONOMIC, AND POLITICAL SCENARIOS (cont.)						
14.1-14.5	1990 - Minimum refinery throughputs imposed on most non-U.S. refineries with low world demand and tariff imposed on U.S. product imports	42.7	10.1	24	73-77	70-69	71
15.1-15.6	1990 - Increasing U.S. product import tariffs with no minimum refinery throughputs	42.7	10.1	24	76-89	69-67	71
16	1990 - Tariff imposed by U.S. on crude oil and product imports	42.7	10.1	24	72	70	71
17.1	Marine rates held constant from 1986 to 1990	42.4	7.8	18	74	69	70
17.2	1990 - Availability of world clean product tankers increased	42.4	7.8	18	76	68	70
18	1990 - Very low priced natural gas used as refinery fuel in Middle East refineries with low world demand	42.4	7.8	18	75	68	70

THE REFERENCE CASES

Case 1: 1986 Reference Case

	Demand			Refinery Utilization
	Total Products	Residual Fuel		
	MMB/CD	MMB/CD	% of Total	%
World	43.7	8.0	18	72
United States	15.2	1.3	9	80

The 1986 reference case is based upon 1980-1983 EIA world demand trends (which were the latest data available at the time the model was developed), industry developed data, and the judgement of the study participants.

In this scenario, world petroleum demand has declined about 7 million barrels per calendar day (MMB/CD) from 1979 actual with residual fuel demand representing about 6 MMB/CD of that drop. Residual fuel demand represents about 18 percent of the total product barrel.

U.S. refineries are operating at about 12 MMB/CD (of 15.25 MMB/CD capacity) throughput, which is about an 80 percent utilization rate of operable calendar-day capacity, while the rest of the free world is operating at about 72 percent of capacity. PADDs I and V operate at the highest rate, which is 92 percent in the model, PADD II is close to capacity at 90 percent, while PADD III has the majority of spare distillation capacity.

In this scenario, U.S. net imports are about 1.5 MMB/CD, including 1.2 MMB/CD of light products and 0.3 MMB/CD of residual fuel. This level of imports exceeded 1985 actual of 1.1 MMB/CD by about 0.4 MMB/CD, with the difference all in light products. It was felt that this variance was acceptably close for the 1986 reference case, but that analyses of the 1990 cases should be reported as differences from the 1986 reference case, rather than absolute volumes. Residual fuel imports of 0.3 MMB/CD in the reference case are net after exporting 0.2 MMB/CD from the West Coast.

Case 2: 1990 Reference Case -- A Low Demand - Low Residual Fuel Scenario

	Demand			Refinery Utilization
	Total Products	Residual Fuel		
	MMB/CD	MMB/CD	% of Total	%
World	42.4	7.7	18	70
United States	14.6	1.3	9	75

This 1990 reference case provides a low demand scenario with world demand down about 1.3 MMB/CD, or 3 percent, from the 1986 reference case, but residual fuel demand is held at about 18 percent of the product barrel.

In this scenario, the slackening demand is absorbed nearly proportionately around the world by reduced refinery throughputs. U.S. refinery throughputs decrease more than in the rest of the world, but this is primarily because U.S. demand is down proportionally more than that of the rest of the world (the United States is down 0.6 MMB/CD and the rest of the world is down 0.7 MMB/CD). In addition, all of the U.S. decline is in light products, while lower residual fuel demands make up more than half of the decline in the rest of the world. U.S. net imports decline 0.2 MMB/CD from the 1986 reference case, with West Coast residual fuel exports increasing about 0.2 MMB/CD.

Most of the decline in U.S. refinery throughputs takes place in PADD III with lower complexity refineries in PADD II absorbing the balance.

The conclusion from analysis of this case is that U.S. refineries approximately maintain their share of market supply in a falling demand scenario, despite changes in refinery hardware expected through 1988 both inside and outside the United States.

Case 3: 1990 Reference Case -- A High Demand - High Residual Fuel Scenario

	Demand			Refinery Utilization
	Total Products	Residual Fuel		
	MMB/CD	MMB/CD	% of Total	%
World	50.8	10.5	21	86
United States	17.1	1.8	11	86

This 1990 reference case provides a high demand scenario with a high level of residual fuel demand. World demand increases 7.1 MMB/CD, or 16 percent, from the 1986 reference case with a residual fuel demand increase of 2.5 MMB/CD, making up more than a third of the total increase in demand. In this scenario, the world product barrel is heavier, with residual fuel making up 21 percent of the product barrel and reversing the downward trend in residual fuel demand experienced over the past six years.

U.S. demand increases about 1.7 MMB/CD, or 11 percent, less than the increase for the rest of the world. U.S. residual fuel demand increases about 40 percent, while the world increases about 30 percent.

Refiners around the world share the increase in demand, with worldwide utilization increasing to 86 percent. Refiners outside the United States increase throughputs more than the United States, as their growth in demand is greater than in the United States and residual fuel demand growth is less than in the United States. U.S. imports increase about 0.5 MMB/CD, with gasoline and distillate imports up about 0.1 MMB/CD; LPG, petrochemical feedstocks, and other streams up about 0.2 MMB/CD; and residual fuel imports up 0.2 MMB/CD in PADD I.

The analysis indicates that U.S. refineries can approximately maintain their present share of gasoline/distillate demand in a growth demand scenario as long as the product mix stays relatively constant.

1990 DEMAND SCENARIOS WITH CHANGING PRODUCT MIX

Case 4: 1990 -- A Low Demand - High Residual Fuel Scenario

	Demand			Refinery Utilization
	Total Products	Residual Fuel		
	MMB/CD	MMB/CD	% of Total	%
World	42.7	10.1	24	71
United States	14.7	1.7	12	74

This 1990 case provides a low demand - high residual fuel scenario, with world demand up 0.3 MMB/CD from Reference Case 2, but with the percentage of residual fuel in the product barrel increasing a third from about 18 percent to 24 percent in the world and from about 9 percent to nearly 12 percent in the United States.

In this case, U.S. refinery throughputs decline slightly while they increase in the rest of the world about the same amount. U.S. light product imports increase by 0.4 MMB/CD, and the United States becomes a net exporter of residual fuel with PADD I imports up slightly but PADD V exports up 0.3 MMB/CD.

The analysis indicates that increasing the percentage of residual fuel in the product barrel lowers U.S. refinery utilization and increases U.S. light product imports. The case simulates the experience of the 1983-1984 U.K. coal strike when residual fuel demand in the U.K. rose 0.3-0.5 MMB/CD to fuel power plants and, in supplying this residual fuel, the world refining system responded by running more crude oil. This, in turn, generated more coproduct light oils, which entered world markets and reduced the economic incentive to run conversion capacity. Since the United States has the largest conversion capacity as well as the highest ratio of light products to total demand in the world, U.S. refineries reduced their runs and light product imports increased.

Case 5: 1990 -- A Low Demand - Low Residual Fuel Scenario

	Demand			Refinery Utilization
	Total Products	Residual Fuel		
	MMB/CD	MMB/CD	% of Total	%
World	42.4	6.8	16	70
United States	14.6	0.9	6	77

This 1990 case is a low demand scenario of 42.4 MMB/CD like 1990 Reference Case 2, but with the percentage of residual fuel dropping from 18 percent to 16 percent worldwide, and from about 9 percent to about 6 percent in the United States.

In this scenario, U.S. refinery throughputs increase from the reference case and the rest of the world declines. Net U.S. imports decline by 0.3 MMB/CD with light product imports down 0.2 MMB/CD and residual fuel imports down 0.1 MMB/CD.

The conclusion from analysis of this case is that U.S. refineries operate at higher rates and increase their market share when the world product barrel gets lighter.

Cases 6.1 to 6.5: 1990 -- U.S. Light Product Demand Increasing - Residual Fuel Constant Scenario

	Demand			Refinery Utilization
	Total Products	Residual Fuel		
	MMB/CD	MMB/CD	% of Total	%
World	42.9-45.4	7.8	18-17	71-76
United States	15.1-17.6	1.3	9-7	77-86

These 1990 cases provide a series of successive scenarios where U.S. light oil demands are increased by 0.5 MMB/CD increments up to a 2.0 MMB/CD increase and then to a 3.0 MMB/CD increase, while the volume of the world residual fuel demand is held constant.

In the first scenario, a departure from the 1990 low demand reference case (Reference Case 2), total demand is up by 0.5 MMB/CD of increased light product in the United States. U.S. refinery utilization increases by 2 percent in this scenario, with refineries in the rest of the world up only slightly. U.S. imports increase by 0.3 MMB/CD including 0.2 MMB/CD in light products.

In three successive scenarios, with U.S. light product demand increasing 0.5 MMB/CD in each scenario, U.S. refinery utilization increases more than in the rest of the world and U.S. product imports increase by about half of the increase in U.S. demand.

In the final scenario, where U.S. light product demand is 3.0 MMB/CD over Reference Case 2, U.S. refinery utilization has increased 11 percent, while in the rest of the world refinery utilization increased 3 percent. U.S. imports increase by 1.3 MMB/CD versus the demand increase of 3.0 MMB/CD over Reference Case 2.

This group of cases indicates that a growth in U.S. demand is shared by the United States and the rest of the world, with the United States taking 57 percent of the increase.

Cases 7.1 to 7.5: 1990 -- Light Product Demand Increasing Outside the United States - Residual Fuel Constant

	Demand			Refinery Utilization
	Total Products	Residual Fuel		
	MMB/CD	MMB/CD	% of Total	%
World	42.9-45.4	7.8	18-17	71-76
United States	14.6	1.3	9	75-80

This group of five cases parallels Cases 6.1 to 6.5, except the increase in light oils is in foreign demand rather than in U.S. demand.

In comparing the first of these scenarios with Reference Case 2, U.S. refinery utilization increases slightly and U.S.

imports drop 0.1 MMB/CD. In each succeeding scenario, as foreign light product demands grow, U.S. refinery utilization increases and U.S. imports continue to decline.

In the last case, where foreign light oil demand has increased by 3.0 MMB/CD, U.S. refinery utilization has increased by 5 percentage points where refineries in the rest of the world increased their utilization by 6 percent. U.S. net imports have declined by 0.8 MMB/CD from Reference Case 2, including a drop in U.S. gasoline and distillate imports of 0.9 MMB/CD.

Again, a growth in demand is shared by the United States and the rest of the world. This group of cases indicates that U.S. refineries utilize their conversion capacity to share in foreign demand growth in light oils by reducing U.S. imports of light oils. Further, in comparing the two sets of cases where light product demand increases, U.S. refinery utilization is more sensitive to increases in light product demand in the United States than in foreign areas.

SOCIAL, ECONOMIC, AND POLITICAL SCENARIOS

Cases 8: 1986 Reference Case with Minimum Refinery Throughputs*

	Demand			Refinery Utilization
	Total Products	Residual Fuel		
	MMB/CD	MMB/CD	% of Total	%
World	43.7	8.0	18	72
United States	15.2	1.3	9	80

Case 8 is similar to Case 1, except that local, political, and social constraints, as listed in Appendix J, were imposed on refinery operations outside the United States. The case is a low residual fuel scenario.

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*See Appendix J, Attachment 2, Trade, Operating and Socioeconomic Assumptions, for minimum refinery throughputs.

Imposing these constraints exerted no measurable change to U.S. refinery utilization rates nor to U.S. imports or exports. It was concluded that these various local, political, and social constraints would not alter any of the other conclusions of the study about the United States, except those concerning the effectiveness of U.S. product import tariffs, as discussed later.

Case 9: 1990 -- A Low Demand - High Residual Fuel Scenario with Minimum Refinery Throughputs

	Demand			Refinery Utilization
	Total Products	Residual Fuel		
	MMB/CD	MMB/CD	% of Total	%
World	42.7	10.1	24	71
United States	14.7	1.7	12	73

Case 9 is similar to Case 4, except that local, political, and social constraints, as listed in Appendix J, were imposed on refinery operations outside the United States. The case is a high residual fuel scenario.

Imposing these constraints exerted no measurable change to U.S. refinery utilization rates nor to U.S. imports or exports. It was concluded that these various local, political, and social constraints would not alter any of the other conclusions of the study about the United States, except those concerning the effectiveness of U.S. product import tariffs, as discussed later.

Case 10: 1990 -- A Low Demand - High Residual Fuel Scenario with Middle East/North Africa Refineries Forced to Run at Maximum Throughput

	Demand			Refinery Utilization
	Total Products	Residual Fuel		
	MMB/CD	MMB/CD	% of Total	%
World	42.7	10.1	24	71
United States	14.7	1.7	12	71

This 1990 case is similar to Case 4, a low demand - high residual fuel scenario, except that refinery throughputs in the Middle East/North Africa refineries were increased to the maximum.

The result was an increase in Middle East/North Africa exports of 0.9 MMB/CD with about half of this going to Europe and 0.3 MMB/CD going to the Far East. About 0.3 MMB/CD moved to the United States as a part of a rebalancing of world supply, about 0.2 MMB/CD of which came from Middle East/North Africa.

It should be noted that this case was run utilizing all announced Middle East/North Africa refinery capacity expansions/additions. As of this writing, construction of one of these announced Middle East refineries, with a capacity of 0.4 MMB/CD, has been delayed.

Cases 11.1 to 11.6: 1990 -- A Low Demand - High Residual Fuel Scenario with Increasing U.S. Tariffs and Minimum Refinery Throughputs

	Demand			Refinery Utilization
	Total Products	Residual Fuel		
	MMB/CD	MMB/CD	% of Total	%
World	42.7	10.1	24	71
United States	14.7	1.7	12	76 - 86

These 1990 cases are similar to Case 9, a low demand - high residual fuel scenario with all local, political, and social constraints imposed on refineries outside the United States as

listed in Appendix J, except tariffs ranging from $.50 to $5 per barrel were imposed by the United States on product imports.

Imports into the United States decrease from 1,240 MB/CD in the case where a $0.50/barrel tariff is imposed to 470 MB/CD at a $2/barrel tariff and are eliminated at a $4/barrel tariff. U.S. refinery utilization increases by 9 percent as tariffs increase from $.50 to $5 per barrel.

Case 12.1 - 12.6: 1990 -- A Low Demand - High Residual Fuel Scenario with Increasing U.S. and European Tariffs with Minimum Refinery Throughputs

	Demand			Refinery Utilization
	Total Products	Residual Fuel		
	MMB/CD	MMB/CD	% of Total	%
World	42.7	10.1	24	71
United States	14.7	1.7	12	76-80

These 1990 cases are similar to Cases 11.1 to 11.6 except the same tariffs are imposed in Europe as well as by the United States.

As a result, imports into the United States decreased from 1,240 MB/CD in the case where a $0.50/barrel tarrif is imposed, to 620 MB/CD at a $2/barrel tariff, and are 490 MB/CD at the $4/barrel tariff level.

The conclusion drawn from these cases is that the imposition of a tariff by other consuming nations counteracts the effectiveness of the U.S. tariff in reducing product imports.

Case 13: 1990 -- A Low Demand - High Residual Fuel Scenario with a High European Tariff with Minimum Refinery Throughputs

	Demand			Refinery Utilization
	Total Products	Residual Fuel		
	MMB/CD	MMB/CD	% of Total	%
World	42.7	10.1	24	71
United States	14.7	1.7	12	69

This 1990 case is similar to Case 9, a low demand - high residual fuel scenario with minimum refinery throughputs, except that a $5/barrel European tariff is imposed on product imports.

As a result, U.S. product imports increase 0.4 MMB/CD and U.S. refinery utilization drops 4 percent.

The conclusion drawn from this case as well from Cases 11.1 to 11.6 and 12.1 to 12.6 is that should nations outside the United States impose product tariffs, the United States would see an increase in U.S. imports; and that this increase could be met by parallel U.S. tariffs. If the United States should initially impose product tariffs, the reverse could happen.

Cases 14.1 to 14.5: 1990 -- A Low Demand - High Residual Fuel Scenario with Increasing U.S. Tariffs and Middle East/North Africa Refineries Forced to Run at Maximum Throughput

	Demand			Refinery Utilization
	Total Products	Residual Fuel		
	MMB/CD	MMB/CD	% of Total	%
World	42.7	10.1	24	71
United States	14.7	1.7	12	73-77

These 1990 cases are similar to Case 9, a low demand - high residual fuel scenario with minimum refinery throughputs, except that U.S. tariffs ranging from $.50 to $4 per barrel are imposed

on product imports and further, the Middle East/North Africa refineries are run at maximum throughput. They are also similar to the other U.S. tariff cases, Cases 11.1 to 11.6, except for the maximum refinery throughput imposed on the Middle East/North Africa refineries in the above cases.

This results in imports into the United States decreasing from 1,660 MB/CD at the $0.50/barrel tariff level to 1,210 MB/CD at a $2/barrel tariff and 1,050 MB/CD at a tariff of $4/barrel.

In these cases, the effectiveness of the U.S. tariff is less than in Cases 11.1 to 11.6, and tariffs beyond $3/barrel become ineffective in further reducing imports.

Cases 15.1 to 15.6: 1990 -- A Low Demand - High Residual Fuel Scenario with Increasing U.S. Tariffs and with No Minimum Refinery Throughputs

	Demand			Refinery Utilization
	Total Products	Residual Fuel		
	MMB/CD	MMB/CD	% of Total	%
World	42.7	10.1	24	71
United States	14.7	1.7	12	76-89

These 1990 cases are similar to U.S. tariff Cases 11.1 to 11.6 except that all minimum refinery throughput listed in Appendix J are removed.

In these cases, a U.S. tariff of $2/barrel reduced net imports to zero.

Case 16: 1990 -- A Low Demand - High Residual Fuel Scenario with a U.S. Crude Oil and Product Tariff

	Demand			Refinery Utilization
	Total Products	Residual Fuel		
	MMB/CD	MMB/CD	% of Total	%
World	42.7	10.1	24	71
United States	14.7	1.7	12	72

This 1990 case is similar to Case 9, a low demand - high residual fuel scenario with minimum refinery throughputs, except that a $5/barrel U.S. tariff was imposed on both crude oil and product imports.

The results of this case are that U.S. net product imports increase 0.2 MMB/CD, with residual fuel imports increasing 0.3 MMB/CD and light products dropping 0.1 MMB/CD. U.S. exports become more expensive than in the rest of the world, so U.S. exports stop, resulting in net imports increasing. U.S. crude oil imports decline with the increase in product imports and U.S. refinery utilization decreased 1 percent.

Neither this case nor the study attempted to measure the impact on other U.S. industries.

Cases 17.1 to 17.2: 1990 -- A Low Demand - Low Residual Fuel Scenario with 1986 Marine Rate and Clean Tonnage Availability*

	Demand			Refinery Utilization
	Total Products	Residual Fuel		
	MMB/CD	MMB/CD	% of Total	%
World	42.4	7.8	18	70
United States	14.6	1.3	9	74-76

These two 1990 cases are low demand - low residual fuel scenarios that are similar to Case 2, the 1990 Reference Case,

*See Appendix J, Attachments 28 to 35, for Marine Assumptions.

except that marine rates and clean tanker availability were varied. The objective was to measure the effect of changing marine rates and product tanker availability.

In one case, marine rates in 1990 were kept equal to the 1986 level and in the other case they were allowed to escalate at 4-7 percent per year for crude oil and 5-9 percent for products varying with tanker size. (The rate escalation reflected continuing scrappage of older obsolete product tankers and reflected marine rates for new product tankers that approach full capital recovery.)

The largest variation in product imports between all three cases is less than 0.3 MMB/CD. In Case 17.1 marine rates were held to the 1986 level. In this case versus Reference Case 2, product imports increased only 1.0 MMB/CD and U.S. refinery utilization rates did not change. In Case 17.2 versus Reference Case 2, the product tanker rates were allowed to escalate faster than crude oil tanker rates; imports decreased only 0.1 MMB/CD and U.S. refinery utilization rates increased 1 percent.

The conclusion drawn was that the differential between crude oil and product tanker rates and that tanker availability, under the rate and availability assumptions used in these three cases, had minimum impact on U.S. imports.

Case 18: 1990 -- A Low Demand - Low Residual Fuel Scenario with Low Cost Refinery Fuel - Middle East and North Africa

	Demand			Refinery Utilization
	Total Products	Residual Fuel		
	MMB/CD	MMB/CD	% of Total	%
World	42.4	7.8	18	70
United States	14.6	1.3	9	75

This 1990 low demand - low residual fuel scenario is similar to Case 2, the 1990 reference case, except that Middle East/North Africa refineries were run on low cost refinery fuel, i.e. about 15 percent of the reference case fuel cost.

There was no impact on U.S. imports or refinery operations because the Middle East/North Africa refineries make a substantial portion of their own fuel from the refining process.

APPENDIX K

Regional Refiners

TABLE K-1

REGIONAL REFINERIES

Company	City	State	Total Capacity (MB/CD)
	PADD I		
American Refining Group	Indianola	PA	0.2*
Ashland	Freedom	PA	6.8
Pennzoil	Rouseville	PA	15.7
Quaker State	Bradford	PA	6.7
Witco	Bradford	PA	6.8
Quaker State Oil	Newell	WV	12.2
Quaker State Oil	St. Mary's	WV	4.5
	PADD II		
B-T Energy Corporation	Louisville	KY	3.0
Kentucky Oil & Refining	Betsy Lane	KY	0.6*
Somerset Refining	Somerset	KY	5.5
Crystal Refining Company	Carson City	MI	3.0
Lakeside Refining Company	Kalamazoo	MI	5.0
Total Petroleum Company	Alma	MI	40.0
Derby Refining Company	Wichita	KS	28.8
Farmland Industries	Coffeyville	KS	56.5
Farmland Industries	Phillipsburg	KS	26.4
National Cooperative	McPherson	KS	70.0
Pester Refining Company	El Dorado	KS	33.3
Texaco Refining & Marketing	El Dorado	KS	80.0
Total Petroleum	Arkansas City	KS	42.5
Amoco Oil Company	Mandan	ND	58.0
Flying J Petroleum	Williston	ND	5.0*
Allied Materials Corporation	Stroud	OK	7.6*
Conoco, Inc.	Ponca City	OK	134.0
Kerr-McGee Refining	Wynnewood	OK	43.0
Sinclair Oil Corporation	Tulsa	OK	50.0
Sun Company, Inc.	Tulsa	OK	85.0
Total Petroleum	Ardmore	OK	62.0

*Idle

TABLE K-1 (Continued)

Company	City	State	Total Capacity (MB/CD)
	PADD III		
Hunt Oil Company	Tuscaloosa	AL	33.5
Vulcan Oil Company	Cordova	AL	9.5*
Cross Oil & Refining Company	Smackover	AR	9.4
Crystal Oil Company	Stevens	AR	3.2
Macmillan Petroleum Company	Norphlet	AR	5.9
Tosco Corporation	El Dorado	AR	47.0
Calumet Refining Company	Princeton	LA	4.4
Claiborne Gasoline Company	Lisbon	LA	7.5
Kerr-McGee Refining Corporation	Cotton Valley	LA	7.8
Kerr-McGee Refining Corporation	Dubach	LA	10.0
Pennzoil Company, Inc.	Shreveport	LA	46.2
Amerada Hess Corporation	Purvis	MS	30.0
Ergon, Inc.	Vicksburg	MS	20.6
Southland Oil Company	Lumberton	MS	5.8
Southland Oil Company	Sandersville	MS	11.0
Vicksburg Refining, Inc.	Vicksburg	MS	6.0
Bloomfield Refining Company	Bloomfield	NM	13.7
Giant Refining Company	Gallup	NM	18.0
Navajo Refining Company	Artesia	NM	30.4
Thriftway Company	Farmington	NM	6.1
Amber Refining, Inc.	Fort Worth	TX	19.7
American Petrofina of Texas	Big Spring	TX	60.0
Chevron U.S.A., Inc.	El Paso	TX	76.0
Damson Gas Processing Corporation	White Deer	TX	0.0
Diamond Shamrock Refining & Mktg.	Sunray	TX	79.0
Diamond Shamrock Refining & Mktg.	Three Rivers	TX	47.0
Flint Chemical Company	San Antonio	TX	1.5
Howell Hydrocarbons Corporation	San Antonio	TX	9.9
La Gloria Oil & Gas Company	Tyler	TX	46.0
Liquid Energy Corporation	Bridgeport	TX	10.0
Petrolite Corporation	Kilgore	TX	1.0
Phillips Petroleum Company	Borger	TX	100.0
Pride Refining Company	Abilene	TX	42.8
Shell Oil Company	Odessa	TX	30.6
Texaco Refining & Marketing	Amarillo	TX	20.0
Texaco Refining & Marketing	El Paso	TX	17.0
Tropicana Energy Company	Fort Worth	TX	4.7*

*Idle

TABLE K-1 (Continued)

Company	City	State	Total Capacity (MB/CD)
	PADD IV		
Asamera Oil, Inc.	Denver	CO	26.0
Conoco, Inc.	Commerce City	CO	41.5
Gary Refining Corporation	Fruita	CO	15.2
Cenex	Laurel	MT	41.4
Conoco, Inc.	Billings	MT	48.5
Exxon	Billings	MT	42.0
Flying J Petroleum	Cutbank	MT	5.6*
Kenco Refining, Inc.	Wolf Point	MT	4.7
Montana Refining Company	Great Falls	MT	6.3
Amoco Oil Company	Salt Lake City	UT	40.0
Chevron, U.S.A., Inc.	Salt Lake City	UT	45.0
Crysen Corporation	Woods Cross	UT	12.5
Morrison Petroleum Company	Woods Cross	UT	6.0*
Phillips Petroleum Company	Woods Cross	UT	25.0
RMT Properties, Inc.	Salt Lake City	UT	25.0
Seagull Refining Company	Roosevelt	UT	8.0
Amoco Oil Company	Casper	WY	48.0
Little America Refining Company	Evansville	WY	24.5
Mountaineer Refining Company	La Barge	WY	0.4
RMT Properties, Inc.	Cheyenne	WY	33.6
Sinclair Oil Corporation	Sinclair	WY	53.0
Wyoming Refining Company	Newcastle	WY	12.6
	PADD V		
Atlantic Richfield Company	Prudhoe Bay	AK	22.0
Chevron U.S.A., Inc.	Kenai	AK	22.0
Mapco	North Pole	AK	46.5
Tesoro	Kenai	AK	48.5
Beacon Oil Company	Hanford	CA	17.3
Chevron U.S.A., Inc.	Bakersfield	CA	26.0
Coastal Petroleum Refining	Bakersfield	CA	10.0
Conoco	Santa Maria	CA	9.5
Gibson Oil & Refining	Bakersfield	CA	9.5
Kern Oil & Refining	Bakersfield	CA	21.4
Paramount Petroleum Corporation	Bakersfield	CA	21.5*
San Joaquin	Bakersfield	CA	24.3
Sunland Refining Corporation	Bakersfield	CA	12.0
Texaco Refining & Marketing	Bakersfield	CA	38.0
West Coast Oil	Oildale	CA	19.0
Witco Chemical Corporation	Bakersfield	CA	0.0
Nevada Refining Company	Tonopah	NV	4.5

*Idle

TABLE K-2

REFINING CENTERS

Company	City	State	Total Capacity (MB/CD)
	PADD I		
Texaco Refining & Marketing	Delaware City	DE	140.0
Chevron U.S.A., Inc.	Baltimore	MD	14.0*
Amerada Hess Corporation	Port Reading	NJ	68.0*
Chevron U.S.A., Inc.	Perth Amboy	NJ	168.0
Exxon Company U.S.A.	Linden	NJ	100.0
Mobil Oil Corporation	Paulsboro	NJ	100.0
Seaview Petroleum	Paulsboro	NJ	44.4
Texaco Refining & Marketing	Westville	NJ	90.0
Atlantic Richfield Company	Philadelphia	PA	125.0
BP Oil Corporation	Marcus Hook	PA	168.0
Gulf Refining & Marketing	Philadelphia	PA	174.0
Sun Company, Inc.	Marcus Hook	PA	155.0
	PADD II		
Clark Oil & Refining Corporation	Blue Island	IL	57.0
Clark Oil & Refining Corporation	Hartford	IL	48.0
Marathon Petroleum Company	Robinson	IL	195.0
Mobil Oil Corporation	Joliet	IL	180.0
Shell Oil Company	Wood River	IL	250.0
Texaco Refining & Marketing	Lawrenceville	IL	79.0
Unocal Corporation	Lemont	IL	151.0
Amoco Oil Company	Whiting	IN	350.0
Ashland Oil, Inc.	Cattlettsburg	KY	213.0
Ashland Oil, Inc.	Canton	OH	66.0
Gulf Refining & Marketing	Cincinnati	OH	44.0
Standard Oil	Lima	OH	168.0
Standard Oil	Toledo	OH	120.0
Sun Company, Inc.	Toledo	OH	118.0

*Idle

TABLE K-2 (Continued)

Company	City	State	Total Capacity (MB/CD)
	PADD III		
Louisiana Land & Exploration	Mobile	AL	80.0
Mobile Bay Refining Company	Chickasaw	AL	27.0*
Calcasieu Refining Company	Lake Charles	LA	14.0
Canal Refining Company	Church Point	LA	8.0
Citgo Petroleum Corporation	Lake Charles	LA	320.0
Clark Oil & Refining Company	Mount Airy	LA	0.0*
Conoco, Inc.	Acadia	LA	7.0
Conoco, Inc.	Lake Charles	LA	157.0
Exxon Company U.S.A.	Baton Rouge	LA	455.0
Gulf Refining & Marketing Company	Alliance	LA	199.0
International Processors	St. Rose	LA	28.0*
Marathon Petroleum Company	Garyville	LA	255.0
Murphy Oil U.S.A., Inc.	Meraux	LA	90.0
Placid Refining Company	Port Allen	LA	45.0
Shell Oil Company	Norco	LA	218.0
Tenneco Oil Company	Chalmette	LA	133.0
Texaco Refining & Marketing	Convent	LA	225.0
Texas NAPCO, Inc.	St. James	LA	20.0*
Chevron U.S.A., Inc.	Pascagoula	MS	295.0
American Petrofina Company of Texas	Port Arthur	TX	90.0
Amoco Oil Company	Texas City	TX	415.0
Atlantic Richfield Company	Houston	TX	260.0
Champlin Petroleum Company	Corpus Christi	TX	157.0
Charter International	Houston	TX	65.0*
Coastal States Petroleum Company	Corpus Christi	TX	88.0
Conoco, Inc.	Alvin	TX	33.0
Crown Central Petroleum Corporation	Pasadena	TX	100.0
Exxon Company U.S.A.	Baytown	TX	494.0
Gulf Refining & Marketing	Port Arthur	TX	407.0
Koch Refining Company	Corpus Christi	TX	125.0
Marathon Petroleum Company	Texas City	TX	70.0
Mobil Oil Corporation	Beaumont	TX	275.0
Petromax Refining Company, Inc.	Houston	TX	2.0*
Phillips Petroleum Company	Sweeny	TX	175.0
Saber Refining Company	Corpus Christi	TX	0.0
Shell Oil Company	Deer Park	TX	250.0
Southwestern Refining Company	Corpus Christi	TX	104.0
Texaco Refining & Marketing	Port Arthur	TX	326.0
Texaco Refining & Marketing	Port Neches	TX	31.0*
Texas City Refining, Inc.	Texas City	TX	120.0
Unocal Refining & Marketing	Beaumont	TX	120.0

*Idle

TABLE K-2 (Continued)

Company	City	State	Total Capacity (MB/CD)
	PADD V		
Atlantic Richfield Company	Carson	CA	215.0
Champlin Petroleum	Wilmington	CA	60.0
Chevron U.S.A., Inc.	El Segundo	CA	405.0
Edington Oil Company, Inc.	Long Beach	CA	42.0
Fletcher Oil & Refining	Carson	CA	30.0
Golden Eagle Refining Company	Carson	CA	16.0*
Golden West Refining Company	Santa Fe Springs	CA	41.0
Huntway Refining Company	Wilmington	CA	5.5
Lundy Thagard Oil Company	South Gate	CA	8.1
MacMillan Petroleum Company	Signal Hill	CA	11.0
Mobil Oil Corporation	Torrance	CA	124.0
Newhall Refining Company	Newhall	CA	21.0
Oxnard Refinery	Oxnard	CA	4.0
Paramount Petroleum	Paramount	CA	47.0
Shell Oil Company	Wilmington	CA	93.0
Texaco Refining & Marketing	Wilmington	CA	75.0*
Unocal Corporation	Wilmington	CA	108.0
Chevron U.S.A., Inc.	Richmond	CA	365.0
Exxon Company U.S.A.	Benicia	CA	109.0
Huntway Refining Company	Benicia	CA	7.0
Shell Oil Company	Martinez	CA	91.0
Tosco Corporation	Martinez	CA	126.0
Unocal Corporation	Rodeo	CA	70.0

*Idle

TABLE K-3

OTHER REFINERIES

Company	City	State	Total Capacity (MB/CD)
	PADD I		
Amoco Oil Company	Savannah	GA	24.0
Young Refining Corporation	Savannah	GA	4.5
Cibro Petroleum Products	Albany	NY	41.9*
GNC Energy Corporation	Greensboro	NC	3.0*
United Refining Company	Warren	PA	60.0
Amoco Oil Company	Yorktown	VA	51.0
Virginia Oil & Refining	Jonesville	VA	1.0
	PADD II		
Motors Oil Refining Company	McCook	IL	1.0
Gladieux Refinery, Inc.	Fort Wayne	IN	19.0
Indiana Farm Bureau Coop	Mt. Vernon	IN	21.2
Kentucky Oil & Refining	Troy	IN	1.0
Laketon Refining Corporation	Laketon	IN	7.9
Rock Island Refining	Indianapolis	IN	43.2
Marathon Petroleum	Detroit	MI	68.5
Mapco Petroleum, Inc.	Memphis	TN	60.0
Murphy Oil U.S.A.	Superior	WI	39.0
Ashland Oil, Inc.	St. Paul	MN	67.1
Koch Refining Company	St. Paul	MN	137.0
	PADD V		
Pacific Refining	Hercules	CA	55.0
Unocal Corporation	Arroyo Grande	CA	41.0
Chevron U.S.A., Inc.	Honolulu	HI	48.0
Chevron U.S.A., Inc.	Willbridge	OR	15.0*
Atlantic Richfield Company	Ferndale	WA	146.0
Chevron U.S.A., Inc.	Richmond Beach	WA	5.5
Crysen Corporation	Tacoma	WA	11.9
Mobil Oil Corporation	Ferndale	WA	71.5
Shell Oil Company	Anacortes	WA	72.0
Texaco Refining & Marketing	Anacortes	WA	78.0
U.S. Oil & Refining Company	Tacoma	WA	28.4

*Idle

APPENDIX L

Acronyms and Abbreviations

ANS—Alaskan North Slope

ASTM—American Society for Testing and Materials

BACT—Best Available Control Technology

bbl—barrel

BTU—British thermal unit

BTX—benzene, toluene, and xylene

CERCLA—Comprehensive Environmental Response, Compensation, and Liability Act of 1980

CO—carbon monoxide

CO_2—carbon dioxide

CPE—Centrally Planned Economies

DOE—Department of Energy

EEC—European Economic Community

EIA—Energy Information Administration

EPA—Environmental Protection Agency

FCC—fluid catalytic cracking

FCCU—fluid catalytic cracking unit

GDP—gross domestic product

GNP—gross national product

gplg—grams per leaded gallon

H_2S—hydrogen sulfide

LPG—liquified petroleum gas

MB/D—thousand barrels per day

MB/CD—thousand barrels per calendar day

MMB/D—million barrels per day

MMB/CD—million barrels per calendar day

MMB/SD—million barrels per stream day

MMBTUs—million British thermal units

MMDWT—million deadweight tons

MMT—methylcyclopentadienyl manganese tricarbonyl

MTBE—methyl tertiary butyl ether

NGL—natural gas liquids

NH_3—ammonia

NO_x—nitrogen oxides

NPC—National Petroleum Council

OCS—Outer Continental Shelf

OECD—Organization for Economic Cooperation and Development

OPEC—Organization of Petroleum Exporting Countries

PADD—Petroleum Administration for Defense District

ppm—parts per million

psi—pounds per square inch

(R+M)/2—an octane index described by the arithmetic average of the research and motor methods for determining octane

RONC—research octane number clear

RVP—Reid Vapor Pressure

SCAQMD—South Coast Air Quality Management District

SJVH—San Joaquin Valley heavy

SO_2—sulfur dioxide

SO_x—sulfur oxides

TBA—tertiary butyl alcohol

VLCC—very large crude carrier

WR&T Model—World Refining and Transportation Model

INDEX

Acid gas treating units, C-29
Alkylation, 16, 68, 75, 79, 87, C-19, C-22
Antiknock compound costs, 53
Aromatics demand, 117, 131
Asset values, 53
Atmospheric distillation units, 16, 25, C-15, C-17
Auxiliary operating facilities, C-15, C-27, C-29–C-30
Aviation fuel characteristics, C-37

Benzene, 10, 47–48, 69, 99–101, 135
Blending, C-15, C-26
Blendstock, 32, 131
Bromine number specification, 135, 137
Butane, 46–47, 69, 87, 91

C_5/C_6 isomerization, 16, 26, 71, 75, 79, 80
Catalyst and chemical costs, 53
Catalytic cracking, 25–26, 70, 75, 110, 135–38, 141, C-19
Catalytic reforming, 12, 75, 110, C-22–C-23
Chemical treating, C-23, C-26
Clean Air Act, 95, 96
Clear pool octane, 79, 118
Coke yields, 32, 36
Coking, C-18–C-19
Combining processes, C-19
Comparative U.S. position
  competitiveness, 119–21
  light oil demands and, 126–27
  marine transportation, and, 127–28
  Middle East/North Africa natural gas and, 126
  Middle East refining and, 124–26
  overview, 119
  reference cases, 120–21
  residual fuel demand and, 6, 121–22
  sociopolitical constraints, 8–9, 122–23
  U.S. tariffs and, 8–9, 123–24
Competitiveness
  Los Angeles Basin refineries, 130
  regional refineries, 146–48
  tax and subsidy factors, 133–34
  U.S. refineries, 6–9, 119–21
  world market, 113–17
Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (CERCLA), 132
Contract maintenance costs, 53
Conversion processes, C-13, C-17–C-19, C-22–C-23
Conversion refineries. *See* Gas oil conversion refineries and Deep conversion refineries
Conversion units, 6, 9, 68, 87, 104
Cooling water systems, C-34
Cost minimization, 113–14
Costs
  benzene removal, 100–101
  gasoline production, 82, 87, 90–91, 93, 95, 100–101
  hydrotreating, 137
  octane, 104
  refinery operations, 49, 53
  sulfur removal, 101
  vapor pressure reduction, 138
Cracking processes, C-17–C-19, C-22
Crude oil
  characteristics, C-34–C-35
  charge, 6, 12, 15–16
  distillation, 6, 9, 107, 110
  slates, 12, 26, 29, 104

substitutability, 37, 41
unit capability and utilization, 70, 73

Debottlenecking, 6, 87
Deep conversion refineries, 13, 25, 26, 29, 36, 37, 99
Delayed cokers, 25
Demand. *See* Supply and demand analysis
Department of Energy (DOE), 104, 109
Depreciation, 53
Desalters, C-15
Diesel fuel, 13, 48–49, 131, 135, C-37
Distillates
characteristics, C-37
demand, 3, 60
exports, 4, 56
high demand case, 73, 75
sulfur content, 10, 13, 48–49, 69, 101
Distillation capacity, 6, 9, 104, 107, 110
Downstream conversion units, 6, 9, 68

Emission control, 10, 37, 41, 135–37
Environmental Protection Agency (EPA), 42, 78, 95–96
Environmental regulations
emissions, 10, 37, 41, 135–37
impact of, 10, 137–38, 141, 145
lead content in gasoline, 42, 68, 78
Los Angeles Basin refineries, 10, 129–30, 135–38
oxygenate use, 95–96, H-1–H-2
sulfur content of distillates, 10, 48–49, 69, 101
sulfur content of gasoline, 135
Ethanol, 132, H-4–H-5
European Economic Community (EEC), 8, 9, 123, 130, 131, 134
Export, 4, 8, 9, 56, 124, 131

FCC naphtha, 26
Feedstock inputs, 12, 29, 32. *See also* Oxygenate use
Finished blendstocks, 32
Fire control systems, C-34
Flare systems, C-33–C-34
Fluid catalytic cracking (FCC) units, 25–26, 110, 135–38, 142
Fuel and utility costs, 49, 53
Fuel consumption, 37

Gas oil conversion refineries, 13, 25, 26, 29, 37, 49, 53, 70, 73
Gasoline
benzene content, 10, 47–48, 69, 99–101, 135
bromine number, 135
characteristics, C-35
cracked, 12, 26
demand, 3, 56, 60
imports, 4, 5, 56, 60, 75
lead content, 42, 68, 78
octane levels, 44–45, 68, 78–80, 91, 98–100, 104, 118
sulfur content, 135
vapor pressure, 5–6, 10, 12–13, 46–47, 69, 87, 90–91, 135, 137, 138, 141
yields, 12, 32
Gasoline production capability
benzene reduction factors, 10, 69, 99–101
environmental regulation and, 10
lead phasedown and, 41–45, 68, 78–79, 82, 100
measurement problems, 9
model results, 5–6, 68–69, 75, 82–83, 87
octane increase and, 91, 93, 95
oxygenate use and, 45–46, 91, 95–99
product specifications and, 5–6, 10
survey results, 5–6, 12–13, 41–47, 85, 87
vapor pressure reduction and, 5–6, 10, 46–47, 69, 87, 90–91
Gross fixed assets, 53

Heavy gas oil hydrotreating, 25
High demand case
assumptions, 60–62
gasoline production capability, 75, 82, 83, 87
Los Angeles Basin refineries, 138, 141
octane increase, 93
oxygenate use, 98–99
process unit capacity, 102, 104
refinery capability, 71, 73, 75
sensitivity, 104, 106
U.S. balances, 68, F-7–F-19
U.S. comparative position, 120–21
world refining capability, 107, F-35–F-49
See also Supply and demand analysis
Hydrocracking, 25, 26, 70, 75, C-19
Hydrodesulfurization, C-23
Hydrogen production units, C-27, C-29
Hydrotreating, 10, 49, 101, 137, 141

Idle capacity, 15–16, 68
Imports
  crude oil slates and, 26, 29
  feedstocks, 29
  gasoline, 4, 5, 56, 60, 75
  light products, 4, 127
  marine transportation and, 127–28
  product pattern, 4, 56, 60, 62
  sociopolitical constraints and, 123
  tariffs and, 8, 123–24
  taxes and subsidies and, 133–34
  U.S. refining and, 119–122. *See also* Appendix G
Industrial and heating fuel characteristics, C-37
Inputs, 12, 26, 29, 32
Isomerization, 4, 16, 26, 68, 71, 75, 79, 80, 82, C-23

Japanese petroleum tax, 131

Lead phasedown, 41–45, 68, 78–80, 82, 100
Least cost solution, 114
Light ends recovery units, C-29
Light products, 4, 75, 83, 87, 93, 121–22, 126–27, 134
Light-to-heavy products ratio, 6, 7, 62, 122
Los Angeles Basin refineries, 13, 48, 49
  capabilities models, 137–38, 141, 145
  environmental restrictions, 10, 129–30, 135–38
  production, 135
Low demand case
  assumptions, 60–61
  gasoline production capability, 82–83
  process unit capacity, 102, 104
  refinery capability, 68, 70–71
  sensitivity, 104, 106
  sociopolitical constraints, 122
  U.S. balance, 61–62, F-21–F-34
  U.S. comparative position, 120
  world balances, F-51–F-65
  See also Supply and demand analysis

Maintenance material costs, 53
Marine transportation, 111–12, 127–28
Market interactions, 112–17
Maximum cases
  light products, 75, 87
  throughput, 8, 122–23
  unleaded production survey, 99
Methanol, H-5
Methyl tertiary butyl (MTBE), H-2–H-3
Middle East/North Africa natural gas, 126
Middle East refining, 4, 124–26, 129
Motor fuel characteristics, C-35, C-37

Naphtha, 26, 36–37, 79, 80
Net back contracts, 7, 133
No refinery throughput minimums case, 8
Nonconversion refineries, 13, 25, 26, 29, 37, 49, 70, 73

Octane-enhancement units, 6, 9, 68, 75, 79, 104
Octane levels, 44–45, 68, 78–80, 91, 93, 98–100, 104, 118
Operable capacity, 16
Operating rate, 6–7
Operational expenses, 49, 53, D-50
Optimum cases
  light products, 75, 83, 87, 93
  Los Angeles refineries, 138, 142
  major products, 99
Oxygenate use
  ethanol, 132, H-4–H-5
  future of, H-1
  gasoline production capability and, 45–46, 91, 95–99
  growth, 95, H-5–H-6
  lead phasedown and, 42–45, 79, 82
  methanol, H-5
  Methyl tertiary butyl (MTBE), H-2–H-3
  model results, 98–99, H-10–H-11
  restrictions, 95–96, H-1–H-2
  role of, 95
  survey results, 45–46, 96–98, H-6–H-9
  tertiary butyl alcohol (TBA), H-3–H-4
  vapor pressure reduction and, 91

Payroll and payroll-related costs, 53
Percentage of residual fuel in the demand, 70, 121–22, 124–27
Petroleum coke, 4, 56
Pipeline capacities, 112
Polymerization, C-22
Process capacity and utilization, 11–12, 16, 25–26
Process units
  capacity, 102, 104
  requirements, 82, 87

Product mix, 5, 6, 121–22. *See also* Light products; Residual fuels
Product specifications
benzene, 10, 69, 99–101, 135
bromine number, 135, 138
lead, 41–45, 69, 78–79, 100
oxygenates, 45–46, 95–96, H-1–H-2
sulfur, 10, 48–49, 69, 101, 135
vapor pressure, 5–6, 10, 12–13, 46–47, 69, 87, 90–91, 135, 137, 138, 141
Product yields, 12, 32, 36, 37, 41

Receiving and distribution systems, C-34
Reference cases, 8, 119–21, 123, 126
Refinery models, 116–17
Refinery offsite facilities, C-15, C-31, C-33–C-34
Refinery shutdowns, 145, 148
Refining capabilities. *See* U.S. refining capabilities; World refining capabilities
Reformer capacity, 6, 16, 68, 79, 82
Reformer severity, 16, 26, 79, 98
Regional refineries, 9–10, 130, 145, 147–48
Reid Vapor Pressure (RVP). *See* Vapor pressure
Replacement costs, 53
Residual conversion units, 70, 75
Residual fuels
characteristics, C-37
demand, 3, 118
exports, 4
imports, 56, 60
percentage of demand, 70, 121–22, 124–27
Resource Conservation and Recovery Act of 1984 (RCRA), 132

Sensitivity cases, 104, 106
Separation of crude oil, C-13, C-17
Sociopolitical constraints, 5, 7–9, 122–23. *See also* Tariffs; Taxes
Sour water stripping units, C-30
South Coast Air Quality Management District (SCAQMD), 135–36
Steam generating systems, C-31
Storage tanks, C-31
Stream-day capacities, 102, 104
Substitutability of crude oil, 37, 41
Sulfur
diesel fuel content, 135
distillate content, 10, 13, 48–49, 69, 101
gasoline content, 135
recovery, 25, 36, C-30
yields, 32, 36
Superfund, 132
Supply and demand analysis
alternate cases, 62
assumptions, 60–61, F-1–F-2, F-73–F-75
caveats, F-2
historical trends, 55, 60
initial case balances, 61–62
methodology, 55
product import cases, F-67–F-72
results, F-2–F-3
U.S. high demand case, F-7–F-19
U.S. low demand case, F-21–F-34
world balances, 107, 117–18
world high demand case, F-35–F-49
world low demand case, F-51–F-65
Survey of U.S. Petroleum Refineries
benzene in gasoline, 47–48, 99
crude oil substitutability, 37, 41
distillate sulfur content, 48–49
findings, 11–13
gasoline production capabilities, 41–47
inputs, 26, 29, 32
methodology, 11, 13, 15
operational expenses, 49, 53
oxygenate use, 96–99, H-6–H-9
process capacity and utilization, 11–12, 16, 25–26
product yields, 32, 36, 37, 41
questionnaire, 11
response characterization, 15–16

Tail gas treating units, C-30
Tariffs, 7–8, 118, 123–124, 129–131
Taxes, 129, 130, 132–34
Tertiary butyl alcohol (TBA), H-3–H-4
Thermal cracking, C-18–C-19
Trade regulations, 118. *See also* Tariffs
Transportation, 111–12, 127–28, 148
Treatment processes, C-15, C-23, C-26

Unfinished feedstocks, 29
Unfinished oils, 36
U.S. refining capability
conclusions, 67–69
demand and, 3–4
environment regulation effects, 10, 137–38
high demand case, 69, 71, 73, 75
historical, 70
international constraints, 7–8

lead phasedown and, 78–80, 82
Los Angeles Basin refineries, 137–38, 141, 145
low demand case, 69–71
model development, 69, 101–02, 104, 106
optimum/maximum light products cases, 75
product mix and, 7–8
regional refinery role, 9–10
See also Comparative U.S. position
Utilization. *See* Process capability and utilization

Vacuum distillation units, C-17
Vacuum residuum, 13, 25
Vapor pressure, 5–6, 10, 12–13, 46–47, 69, 87, 90–91, 135, 137, 138, 141
Viscosity breaking, C-19

Wastewater treatment units, C-30
World Refining and Transportation (WR&T) Model, 109, 115–17
World refining capability
model development, 107, 109
product import modeling, 112–17
refining capacity overview, 107
regional trends, 109–11
supply and demand and, 3, 107, 117–18
tariffs and, 118
taxes and subsidies and, 129, 133–34
transportation capacity and, 112–12

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II–S	PADD II no conversion
II–LC	PADD II gas oil conversion
II–DC	PADD II deep conversion
III–S	PADD III no conversion
III–LC	PADD III gas oil conversion
III–DC	PADD III deep conversion
IV	PADD IV all refineries
V–S	PADD V no conversion
V–COC	PADD V conversion outside California
V–CC	PADD V conversion in California
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