U.S. Petroleum Refining

Meeting Requirements for Cleaner Fuels and Refineries

Volume I—Analyses and Results

National Petroleum Council
August 1993

Cover Photograph: Pascagoula Refinery, Chevron U.S.A. Inc.

NATIONAL PETROLEUM COUNCIL
1625 K Street, N.W., Washington, D.C. 20006 (202) 393-6100

August 30, 1993

The Honorable
Hazel R. O'Leary
Secretary of Energy
Washington, D.C. 20585

Dear Madam Secretary:

On behalf of the members of the National Petroleum Council, I am pleased to transmit herewith the Council's report entitled *U.S. Petroleum Refining*. This report was prepared in response to a request from the Secretary of Energy and presents a stark yet comprehensive portrayal of the U.S. petroleum refining industry over the next twenty years.

The U.S. refining industry is a vital link in the nation's industrial and economic health. During the 1980s, even though the industry earned a modest profit of about 2.5 cents per gallon and realized an average return on investment of 8.8 percent, 120 refineries shut down. Profits in 1991 and 1992 have been much lower and refineries have continued to shut down. To comply with environmental requirements, the total cost of supplying light products to consumers is projected to increase by 6 and 10 cents per gallon by 1995 and 2000, respectively. These cost increases far exceed the past profitability of the industry and will have to be reflected in the marketplace.

Investments in the 1990s to meet environmental requirements on refineries and products are projected to be 37 billion dollars. This is greater than the current 31 billion dollar book value of the refineries themselves. Even if profits return to the level of the 1980s, cash flow for the industry as a whole would be negative by about 30 billion dollars from 1991 through 1995 and remain negative through the year 2000. If profits improve significantly so as to recover the cost of capital on the new environmental investment, then cash flow would improve, although it would still be far short of covering cumulative cash flow requirements in the 1991-2000 period.

Many refiners expect refineries will be under-utilized in the 1990s. They are seriously concerned that margins in a very competitive market will be inadequate to recover large environmental investments and other regulatory costs and that refinery shutdowns will continue. Since this study considered average costs for all refineries in a refining region, no conclusions can be drawn relative to the financial health of individual refineries. Rationalization implies that poorer financial performers fail. However, the financial and legal barriers to shutting down facilities are large. Hence, continued overcapacity is possible.

Light product demand is a key determinant of the industry's health. In the optimistic, growing demand scenario, after the U.S. industry is fully utilized, the study projects that foreign product would be imported rather than new U.S. refining capacity being built. In the pessimistic, declining demand scenario, the U.S. industry backs out imports but suffers declining utilization. There is significant concern that various governmental policies will reduce demand while, at the same time, other policies require major new environmental investments. The industry also faces foreign competition and other major uncertainties; for example, the requirements for reformulated gasoline are not known, enforcement regulations could disrupt today's product distribution system, and large future environmental expenses are anticipated.

The U.S. industry is competing in a global marketplace. Foreign refined products presently have lower embedded environmental costs than U.S. products. This study projects that, over time, foreign refiners will have total cost increases, including those for capacity additions, similar to those in the United States. This projection is uncertain; if only the United States pursues an aggressive environmental agenda, it would not be valid. The ability of the U.S. industry to recover its large environmental investments and expenses would be severely hampered if foreign product cost increases were smaller or later than projected in this study. Imports of light products would increase, U.S. refinery utilization would decrease, and more refinery shutdowns could occur. Also, foreign refineries are not subject to the level of civil law suits, punitive damage awards, and joint and several liability exposures experienced by refiners in the United States.

To minimize costs to the consumer and help maintain the health of the industry, the National Petroleum Council recommends that you take the lead in implementing the following:

- Cost-effective reformulated gasoline regulations that are fully compatible with the existing distribution system.
- A constructive partnership process involving interested stakeholders to create cost-effective solutions to societal concerns related to the industry.
- Recognition by policy makers that the costs of regulation will ultimately be reflected in the marketplace and will affect rationalization, competitiveness, and the long-term financial health of the industry.

This report provides extensive data and analyses that underscore our concerns. We sincerely hope that it will be of value to you, to the Administration, and to Congress in agreeing on the appropriate actions to serve the interests of consumers and the nation.

Respectfully submitted,

Ray L. Hunt
Chairman

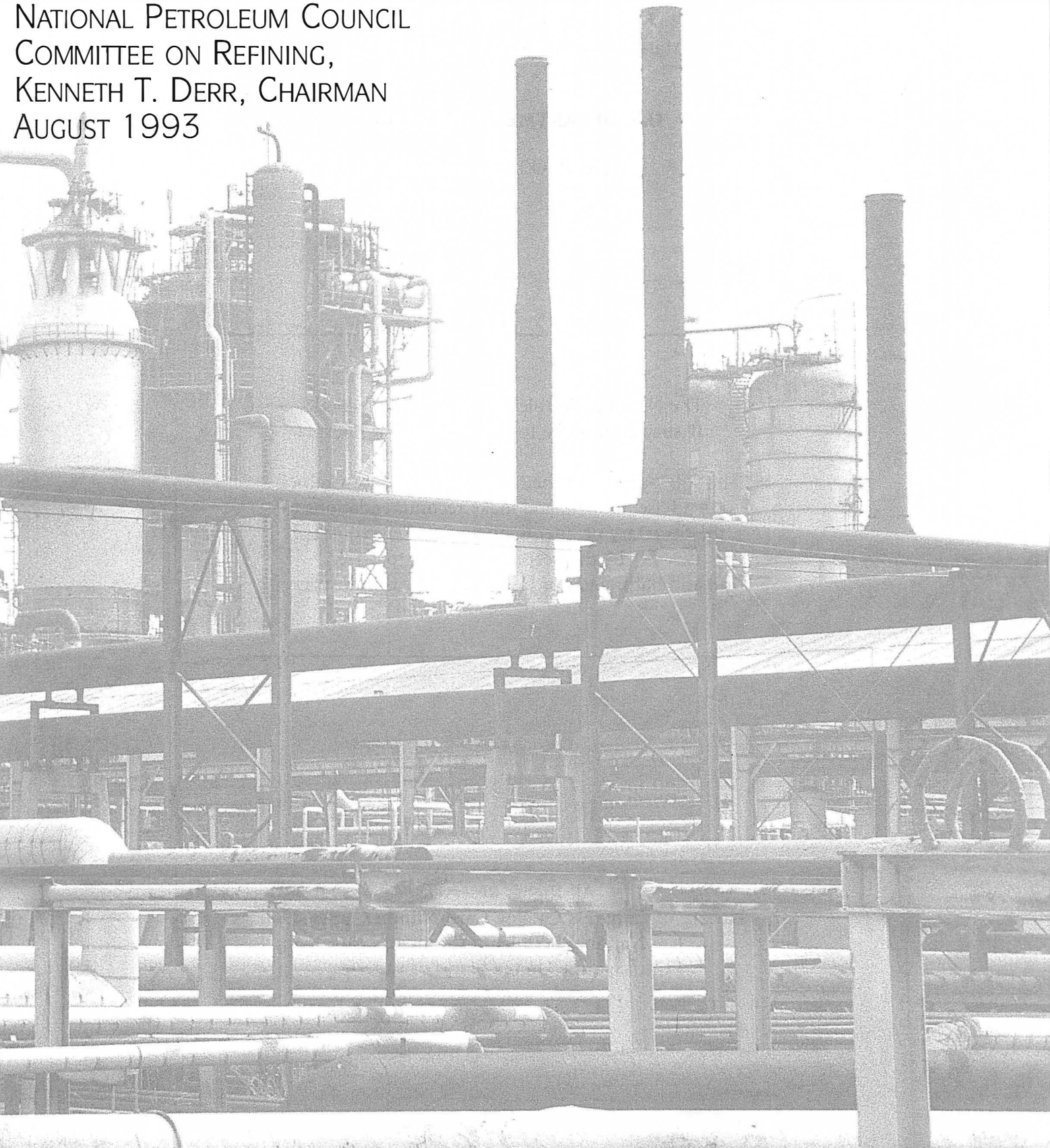
Enclosure

U.S. Petroleum Refining

Meeting Requirements for Cleaner Fuels and Refineries

Volume I–Analyses and Results

National Petroleum Council
Committee on Refining,
Kenneth T. Derr, Chairman
August 1993



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

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

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TABLE OF CONTENTS

Contents of Volumes II–VI ..... *i*

Executive Summary
Preface 1
Overview 4
Findings 8

Chapter One: Financial Analysis
Introduction and Summary 31
Costs of Regulation 34
Industry Financial Background 39
Projected Investment and Cash Flows 49
Implications for Consumers 56
Implications for the Refining Industry 58

Chapter Two: U.S. Refining Stationary Source Facilities
Summary 61
Study Design and Concepts 68
Historical Costs (1986–1990) 71
Current Costs (1991–1995) 79
Future Costs (1996–2010) 82
Uncertainties and Sensitivities 96
Study Support 98

Chapter Three: Supply, Demand, and Logistics
Objectives and Observations of the Supply, Demand, and Logistics Effort 101
General Approach 105
Demand Development 111
The NPC Logistics Model 124
Oxygenates 140
Logistics 156
Refining Industry Modeling 174
Cost of U.S. and Foreign Produced Products 191
Foundation Case Findings 198

Chapter Four: U.S. Refining Capability and Costs

Summary of Major Conclusions 215
Motor Fuel Quality Changes for the CAAA 222
Overview of Methodology 228
Gasoline 231
Distillate 292
Production Capability and Flexibility 305
Other Considerations 318
Methodology 326

Chapter Five: NPC Survey

Survey Development 333
Survey Results by Section 335

Appendices

Appendix A: Secretary of Energy's Request Letter and Description of the National Petroleum Council A-1
Appendix B: Rosters of Study Groups B-1
Appendix C: Discussion of Winter 1992-93 Oxygenate Supply Situation C-1
Appendix D: Review of Findings from 1986 NPC Refining Report D-1

Acronyms and Abbreviations AC-1
Glossary GL-1
Index IN-1

Order Form

CONTENTS OF VOLUMES II–VI

Volume II: General Information Appendices

APPENDIX E: Alternative Transportation Fuels
- Summary
- Methanol
- Ethanol
- Compressed Natural Gas
- Liquefied Natural Gas
- Liquefied Petroleum Gas
- Battery-Powered Electric Vehicles
- Hybrid Electric Vehicles

APPENDIX F: Summary of Environmental Legislation
- Air
- Water
- Waste
- Other Laws

APPENDIX G: History Primer: U.S. Petroleum Supply, Demand, and Logistics, 1970-1992
- Introduction
- The Changing U.S. Petroleum Industry
- Events Influencing the U.S. Petroleum Industry
- Supplemental Data and List of Sources

APPENDIX H: History and Fundamentals of Refining Operations
- History
- Growth and Changes in Refinery Configuration
- Refinery Operating Units
- Crude Oil Characteristics
- Product Characteristics

APPENDIX I: Environmental Operations Primer
- Air Pollution Controls
- Water Pollution Controls
- Solid Waste Pollution Controls

Volume III: Financial and Facilities Appendices

APPENDIX J: Appendix to Chapter One — Financial Analysis
- Section II: Costs of Regulation
- Section III: Industry Financial Background
- Section IV: Projected Cash Flows
- Section V: Implications for Consumers

APPENDIX K: Appendix to Chapter Two — U.S. Refining Stationary Source Facilities
- Section I: Study Support Attachments
- Section II: Bechtel Report: Impacts of Environmental Regulations on U.S. Petroleum Refineries, 1991-2010
- Section III: Executive Summary of Amoco/U.S. EPA Pollution Prevention Project

Volume IV: Supply, Demand, and Logistics Appendix
Part 1

APPENDIX L: Appendix to Chapter Three — Supply, Demand, and Logistics
- Section I: Objectives and Observations of the Supply, Demand, and Logistics Effort
- Section III: Demand Development
  - III-1: Foundation Case Regional & State Demands
  - III-2: Mid-Grade Projection Basis
  - III-3: Foundation Case – U.S. Demands
  - III-4: State Maps Showing CO and Ozone Nonattainment Areas
  - III-5: Computer Listings – County Attainment and Nonattainment
  - III-6: JP-4 to Kerojet Basis
  - III-7: World Oil Demand – Product Regional Details
- Section IV: The NPC Logistics Model
  - IV-1: Bonner and Moore Report on the NPC Logistics Model
  - IV-2: Production Price Basis Tables (1987/89)
  - IV-3: Reference Point Costs
  - IV-4: GDP Deflator
  - IV-5: Return on Capital
- Section V: Oxygenates
  - V-1: Oxygenate Properties
  - V-2: EIA MTBE Capacity Survey
  - V-3: EIA Fuel Ethanol Capacity Survey
  - V-4: U.S. Oxygenate Capacity by Supply Region
  - V-5: Foreign Oxygenates Supply/Demand Balances
  - V-6: MTBE Facility Capital Investment Costs
  - V-7: Ethanol Cost Assumptions
  - V-8: Ethanol State Subsidies
  - V-9: MTBE Facility Production Costs
  - V-10: Ethanol Incentives
  - V-11: Oxygenate Issues — Data Revisions, Changes, and Updates
- Section VI: Logistics
  - VI-1: Logistics Centroids for U.S. & Foreign Regions
  - VI-2: Logistics Transportation Cost Matrix
  - VI-3: U.S. Flag (Jones Act) Tankers Operating in Clean Product Services
  - VI-4: Tanker Markets, Worldscale and ATRS
- Section VII: Refining Industry Modeling
  - VII-1: Supplemental Notes on Chapter 3.VII Methodology
  - VII-2: Pace Report on U.S. PADD and Foreign Regional Models
  - VII-3: Expert Panel Notes
  - VII-4: Product Quality Specifications (Foreign)

Part 2

APPENDIX L: Appendix to Chapter Three — Supply, Demand, and Logistics (Continued)
- Section VII: Refining Industry Modeling (Continued)
  - VII-5: Summary Tables – Unit Capacity Information
  - VII-6: Regional Investments — 1995 Model Year
  - VII-7: Table – Bunker Fuel Outlook
  - VII-8: Summary Tables – LP Case Comparisons (Foreign)
  - VII-9: Pace Report on Foreign Refining Policy
  - VII-10: (Foreign) Refinery Stationary Emission, Health and Safety (EHS)
  - VII-11: EIA Integrated Petroleum Supply Reporting System
- Section VIII: Cost of U.S. and Foreign Produced Products
  - VIII-1: Layer Cost Calculations
  - VIII-2: Layered Cost Buildup (ABC) Tables
  - VIII-3: Cost-Volume Relationships and Supplemental Material
- Section IX: Foundation Case Findings
  - IX-1: Summary Regional/PADD Model Output Tables
  - IX-2: Rationale for Small Changes in Variables

Volume V: Refining Capability Appendix

APPENDIX M: Appendix to Chapter Four — U.S. Refining Capability and Costs

Section I: Cost Effectiveness Tables

Section II: Turner Mason Tables

Volume VI: Survey Appendix

APPENDIX N: Appendix to Chapter Five — NPC Survey

Section I: Survey Results – U.S. Totals

Section II: Survey Questionnaire – Blank Survey Forms

Working Papers

As input to the NPC refining study, a number of analyses were conducted on various topics. Copies of the following documents are being reproduced as NPC working papers in the public interest, and may be obtained from the National Petroleum Council. These documents were utilized by the NPC study participants in the course of the NPC study. The NPC **does not** necessarily endorse all of the specific information in these documents. These working papers **do not** constitute the advice and recommendation of the National Petroleum Council.

Financial Analysis

Floppy Disk of Appendix J

U.S. Refining Stationary Source Facilities

Simplified Profile of the U.S. Petroleum Refinery Industry (Bechtel Refinery Flow Charts)

Supply, Demand, and Logistics

Section VI – Logistics

Transportation Cost Data

Section VII – Refining Industry Capability Modeling

Cost-Volume Relationships (Detailed Pace Output)

Foreign Expert Panel Transcript

Section IX – Foundation Case Findings (Detailed Bonner & Moore Output)

Calibration Case - 1989

Validation Case - 1987

Foundation Case I - 1995

Foundation Case I - 2000

Foundation Case I - 2010

Foundation Case II - 2010

Foundation Case III - 1995

Foundation Case III - 2000

Foundation Case III - 2010

Foundation Case I (Environmental Sensitivity)- 1995

Foundation Case 1 (A) - 2000

Foundation Case 1 (B) - 2000

Foundation Case 1 (C) - 2000

Foundation Case 1 (D) - 2000

Alternative A, B, C's

U.S. Refinery Capability and Costs

Floppy Disk of Turner Mason Tables in Appendix M

NPC Survey

Detailed Survey Aggregations

PREFACE

STUDY REQUEST

The National Petroleum Council (NPC), an advisory committee to the Secretary of Energy, has completed a two-and-a-half-year comprehensive study on the future of U.S. petroleum refining. In requesting the study, the Secretary asked that it focus on how environmental regulations impact refineries and petroleum products:

> I request that the NPC assess the effects of these changing conditions on the U.S. refining industry, the ability of that industry to respond to these changes in a timely manner, regulatory and other factors that impede the construction of new capacity, and the potential economic impacts of this response on American consumers.

The complete text of the Secretary's request letter and a description of the National Petroleum Council can be found in Appendix A.

STUDY ORGANIZATION

To assist in its response to this request, the NPC established a Committee on Refining chaired by Kenneth T. Derr, Chairman of the Board and Chief Executive Officer, Chevron Corporation. The Honorable William H. White served as Government Cochairman.[1] To provide study coordination and technical analyses, the Committee established a Coordinating Subcommittee, a Financial Analysis Subgroup, and four Task Groups: Refinery Facilities; Supply, Demand, and Logistics; Product Quality; and Survey. Rosters of the study groups are presented in Appendix B.

STUDY APPROACH

The NPC Committee on Refining decided on a two-phase study approach to respond to the Secretary's request. The first phase was to focus on the impact of Title II of the Clean Air Act Amendments (1990). The second phase was to be a broader and more detailed examination of the capabilities of the refining industry and the potential impact of the broad range of environmental initiatives and other issues facing refiners.

Phase I

Phase I of the study was conducted in a six-month time frame. The Phase I report, entitled *Petroleum Refining in the 1990s—Meeting the Challenges of the Clean Air Act*, was issued by the NPC in June 1991. In the report, the NPC presented advice on efficient and effective ways to implement the motor gasoline and diesel fuel requirements of Title II of the Clean Air Act Amendments (1990). The basis of the report was a series of interviews conducted for the NPC by McKinsey & Company, Inc. Twenty leading refining companies, and five major engineering and construction firms, were interviewed. To protect the confidentiality of the individual interviews, only aggregated results were provided to the study participants. The NPC analysis of the interview results led to conclusions and recommendations on several key Environmental Protection Agency regulatory actions necessary to enhance the chances for successful compliance with the Clean Air Act. These conclusions and recommendations are related to the 1992 program for oxygenated fuels in carbon monoxide nonattainment areas, to the 1995 program for reformulated gasoline

[1] The Honorable Linda G. Stuntz cochaired the Committee until January 1993.

in ozone nonattainment areas, to the 1993 program requiring ultra-low sulfur on-highway diesel fuel, to timely permits for required modifications or new construction, and to post-1995 concerns. See Appendix C for a discussion of the winter 1992-93 oxygenate supply situation. The complete report is available from the NPC.

Phase II

This report presents the findings and conclusions of Phase II of the study, as well as the supporting analyses and documentation. It assesses the ability of the U.S. oil industry, both physically and economically, to manufacture and supply the quantity and quality of products required in the 1990s and beyond. The competitiveness of domestic versus foreign supplies is analyzed. The investment requirements and other costs associated with meeting the new environmental legislation and regulations on both refinery products and the refineries themselves are addressed. In particular, the requirements and consequences of the 1990 Clean Air Act Amendments and other environmental, health, and safety initiatives, both current and prospective, are evaluated.

To support the analysis of the U.S. refining industry, the NPC conducted an extensive survey of all U.S. refineries, including refineries located in U.S. territories in the Caribbean, pipeline operators, terminal operators, motor gasoline blenders, and companies with U.S. offices doing business in foreign countries. The aggregated survey results were provided to the study groups for use in the industry modeling and analysis, particularly for the 1991-1995 time frame. The NPC retained SRI International to conduct the survey and protect the confidentiality of the survey data by collecting and tabulating the survey data and providing only aggregated data to the NPC study participants. All survey data were destroyed upon completion of the study.

The report includes analyses and costs from the refinery inlet to the marketing facility inlet. In general, state and local regulations are not addressed. However, certain California regulatory costs are included in some analyses. All costs in this report are presented in constant 1990 dollars except where otherwise specifically stated.

Detailed regulations on refineries as stationary sources and on reformulated gasoline are not final. The approach used in addressing regulatory uncertainty was:

- To premise regulations and resulting hardware requirements for the refineries based on available technology and equipment.
- To assume cost-effective product regulations for federal Phase II reformulated gasoline for the year 2000. This results in a much less severe reformulation than, for example, California Air Resources Board Phase 2 gasoline.

U.S. product demand uncertainty was covered by considering three scenarios representing growth (Foundation Case I), no growth (Foundation Case II), and decline (Foundation Case III). These scenarios are expected to encompass the range of the U.S. demand through 2010.

Phase II analyses were conducted by the National Petroleum Council study groups, supported by a number of contractors and outside experts, as shown in Figure 1.

The principal results of Phase II are highlighted in this Executive Summary. Chapters One through Five in Volume I of this report provide discussion of the study analyses. Further levels of detail are available in the report's Appendices Volumes and Working Papers, which can be obtained by contacting the NPC offices or by using the order form in the back of this report.

A brief review of the October 1986 NPC report, *U.S. Petroleum Refining,* is provided in Appendix D. General information concerning the U.S. refining industry can be found in Volume II of this report, covering Alternative Transportation Fuels, Summary of Environmental Legislation, History, Refining Operations, and Environmental Operations.

The appendices to the report chapters are available in Volumes III-VI.

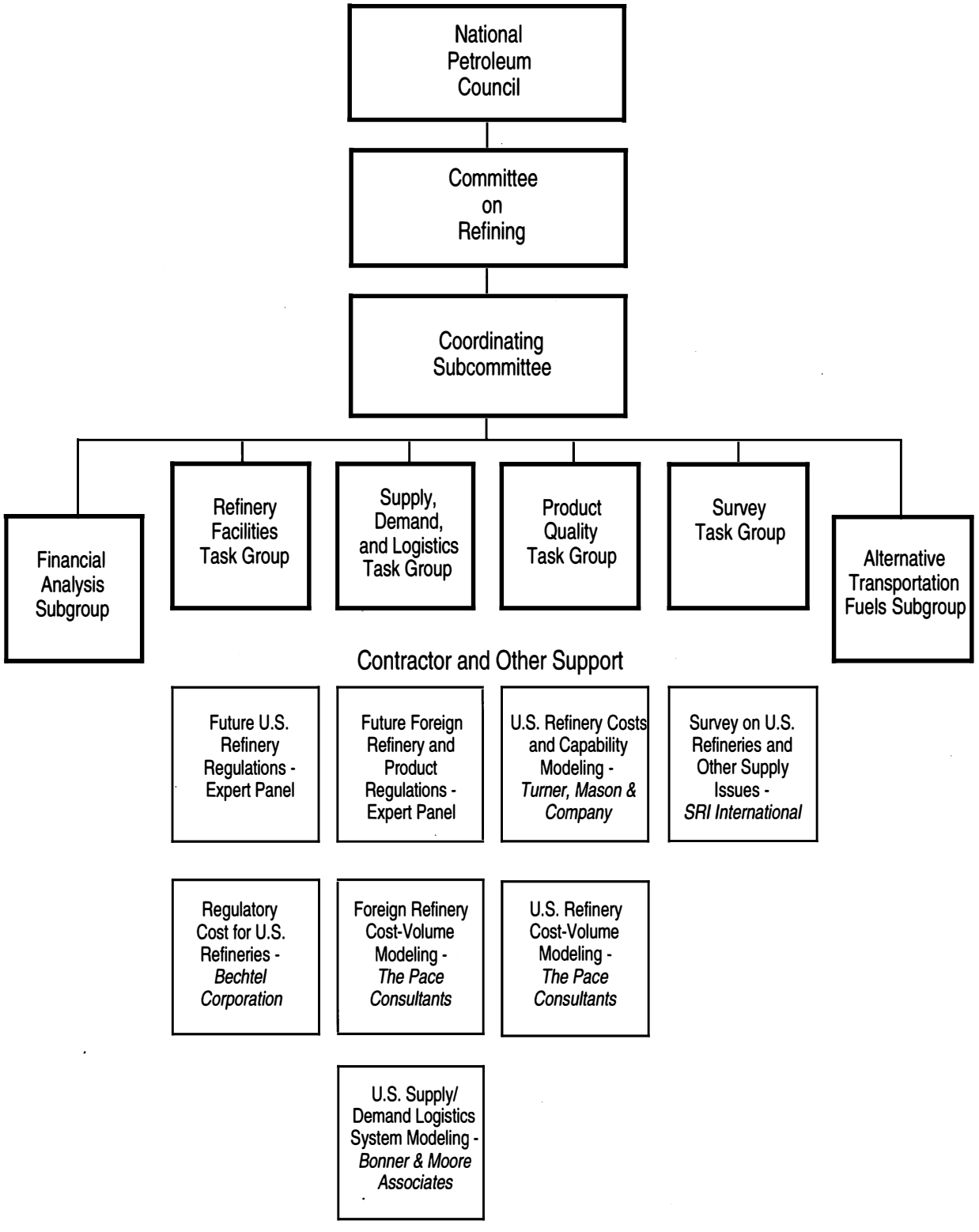


Figure 1. Study Organization.

OVERVIEW

The National Petroleum Council concludes that the U.S. refining industry can, with investment, meet foreseen consumer demand and environmental, health, and safety regulatory requirements. However, given the industry's recent low profitability and the uncertainties surrounding future regulations and product demands, it is by no means certain that companies will be willing and able to make the necessary expenditures for all facilities.

In the 1991-2000 decade, the U.S. refining industry will need to make capital expenditures of about $37 billion (1990 dollars) to meet refinery regulatory requirements and to manufacture reformulated gasoline and ultra-low sulfur diesel fuel. The additional cost of supplying gasoline, jet fuel, home heating oils, and diesel fuels to the American consumer to comply with these regulations will reach $18 billion per year by 2000, which is an increase of 10 cents per gallon of these products. Ultimately, the cost of meeting regulatory requirements will be reflected in the marketplace.

The first half of the 1990s poses financial difficulty for the U.S. refining industry because of the large projected capital expenditures for regulatory compliance coupled with declines in refinery utilization. Some shutdown of capacity, including entire refineries, has occurred and is likely to continue.

In studying the impact of health, safety, and environmental regulations on the U.S. refining industry, there are many uncertainties that could alter the conclusions. For example, detailed 1990 Clean Air Act Amendment regulations on refineries as stationary sources and on reformulated gasoline have yet to be promulgated. Another uncertainty is the future demand for petroleum products. The level of product demand affects U.S. refinery utilization, which directly impacts the ability to finance refinery modifications, the ability to recover costs, and the future structure of the refining industry. Demand is influenced by factors such as taxation, state of the economy, automobile efficiency, population growth, use of alternative fuels, and prices.

Based on this study, the National Petroleum Council suggests that the Department of Energy and other government policymakers and regulators carefully consider the following eight key conclusions and three general recommendations.

CONCLUSIONS

U.S. Refinery Stationary Source Regulatory Cost

Expenditures (capital, one-time expenses, and operating and maintenance expenses) of $106 billion (1990 dollars) are projected over the 20-year period 1991-2010 for new facilities and programs necessary for compliance with existing and anticipated stationary source regulations related to air, water, and waste and to safety and health requirements within U.S. refineries. In addition, $46 billion will be spent to operate and maintain similar facilities and programs now in place, for total stationary facilities environmental, health, and safety expenditures of $152 billion. As a comparison, the $152 billion represents average annual expenditures over twice that incurred in the last half of the 1980s. These stationary facilities' costs are in addition to costs for manufacturing reformulated gasoline and ultra-low sulfur diesel fuel.

Refining and Logistics Costs

Refining and logistics costs in the United States are projected to increase substantially. For example, relative to 1989 conventional

gasoline, reformulated gasoline is projected to cost about 8, 12, and 14 cents (1990 dollars) per gallon more in 1995, 2000, and 2010, respectively. These include costs to the refineries for stationary emissions control improvements and additional health and safety regulations, costs due to more intensive processing and oxygenate addition to produce fuels, and costs of changes in the product logistics system to meet future regulations. Similarly, in 1995, 2000, and 2010, the cost to supply on-highway diesel fuel will be 7, 9, and 11 cents per gallon more than the cost to supply conventional diesel fuel in 1989.

The consumer using reformulated or oxygenated gasoline can expect to see an additional effective increase in cost of 2 to 3 cents per gallon because these gasolines have a lower energy content and hence give poorer mileage. The ultimate impact on the consumer would also include other factors, such as changes in raw material cost, taxes, marketing costs, as well as marketplace competition.

More stringent, costlier reformulations of gasoline might be required. For example, the refining cost to make California Air Resources Board Phase 2 quality gasoline for the entire United States would be 9 cents per gallon more than the study's estimated cost of making federal Phase II reformulated gasoline.

Financial

Projected U.S. refining capital expenditures of $37 billion (1990 dollars) in the 1991-2000 period for product quality (cleaner transportation fuels) and stationary source regulatory compliance exceed the total net fixed asset base of U.S. refineries of $31 billion at the start of this period. About two-thirds of the capital expenditures are projected to be made in the 1991-1995 period. Assuming all operating expenses (including depreciation) are recovered, cash flow generated during the 1991-1995 period is still on the order of $25 billion less than the required capital expenditures.

Product revenue increases will be necessary to recover operating expenses and to provide competitive returns on the capital employed. The projected cost increase in 2000 for regulatory compliance is more than twice the U.S. refining, marketing, and transportation industry's historical average net income in the 1980s. Given the projection of declining refinery utilization through 1995, recovery of these costs will be difficult until capacity and demand are rebalanced by further capacity shutdowns and/or increased product demand.

Product Compatibility

The logistics system will remain effective only if regulated product specification and enforcement procedures, including testing tolerances, allow product compatibility throughout. Product compatibility means being able to mix separate batches of a specific product as necessary for effective operation of the logistics system. If absolute batch segregation were required, the logistics system as it exists today would be inoperable.

Current product specifications and enforcement procedures allow effective use of the logistics system because commingling of similar products does not result in off-specification products at the final point of sale. Regulations such as those proposed by the Environmental Protection Agency on February 26, 1993 for reformulated gasoline could preclude any mixing of batch shipments of gasolines of the same grade in any degree, no matter how incidental. This would require isolating each batch from other batches of reformulated gasoline and therefore require many more segregations. If the number of segregations exceeds what can be practicably accommodated, the expected consequences would range from increased manufacturing and distribution costs and sporadic runouts to complete failure of some systems.

Refining Capability

With appropriate capital expenditures, sufficient volumes of on-highway diesel fuel and reformulated gasoline meeting requirements of the 1990 Clean Air Act Amendments can be manufactured in existing and anticipated process facilities using current technology and available engineering and construction resources. This assumes regulations,

including enforcement and compliance provisions, for federal Phase II reformulated gasoline are set to provide cost-effective volatile organic compound reduction in ozone nonattainment areas.

Oxygenates

Assessment of worldwide existing capacity and announced expansion plans for producing oxygenates indicates adequate supply in 1995 for at least the legislated minimum requirements. By 2000, the potential supply is expected to cover essentially any situation permitted by the 1990 Clean Air Act Amendments. Needs in 2000 were estimated on the basis of all ozone nonattainment area opt-in to the federal reformulated motor gasoline program, the Northeast Ozone Transport Corridor using federal reformulated motor gasoline, and California using California Air Resources Board Phase 2 gasoline. Assuming all announced projects are built, the calculated supply for 2000 is close to the estimated requirements.

Foreign Product Supply Cost

Today, most foreign areas lag the United States in health, safety, and environmental regulations and, consequently, have lower embedded environmental costs than the United States. Over time, the total cost of foreign supply delivered to the United States is projected to increase as result of product quality changes outside the United States; foreign capacity additions needed to meet local demand growth; and foreign environmental, health, and safety regulations for stationary facilities. The study's projected foreign total cost increase is approximately the same as the corresponding U.S. cost increase. However, there is significant uncertainty in these cost increase estimates.

If future foreign environmental regulations are less severe than expected, or are not enforced, then the cost of foreign light product would be lower. Unlike the United States, where stationary facilities' environmental cost increases are the major factor, more of the foreign cost increases result from product quality and capacity addition factors. The financial ability of foreign refineries to meet these projected higher regulatory costs was not studied but could result in a situation similar to that projected for U.S. refineries.

Product Supply and U.S. Refinery Utilization

Evaluation of future oil product demand scenarios using expected foreign and U.S. product cost increases suggests that, if the required investments are made, the U.S. refinery complex will continue to supply most of the future U.S. light product demand. However, because of relatively flat U.S. demand through 1995 under all scenarios studied and increasing supply from oxygenate blending into gasoline, U.S. capacity utilization is lower in 1995 than in 1989, assuming no capacity shutdown. For later study years, capacity utilization changes consistent with projected demand conditions. Absent rationalization, the U.S. demand for light products is likely the most significant determinant of U.S. refinery capacity utilization.

However, the pace of foreign cost increases relative to those in the United States is important. Imports of light products would increase and U.S. refinery utilization would decrease if foreign refinery cost increases were smaller or later than premised. A sensitivity case with a foreign cost increase about two-thirds of the corresponding U.S. cost increase was evaluated. This cost differential was based on no increase in foreign stationary source environmental costs between 1989 and 2000 with corresponding U.S. costs only for those requirements supported by existing legislation. In this case, projected 2000, U.S. refinery output shifts from 94 percent of U.S. light product supply to 89 percent. The result is a light product import level of 1.24 million barrels per day, compared with 0.57 million barrels per day in the base case and a reduction in U.S. refining capacity utilization from 88 to 83 percent.

RECOMMENDATIONS

The National Petroleum Council requests that the Secretary of Energy take the lead in implementing the following recommendations.

Cost-Effective Regulations on Reformulated Gasoline

Reformulated gasoline certification and enforcement provisions should reflect the practical necessity to use the existing distribution system. Reformulated gasoline regulations that address product compatibility, fungibility, test tolerances, and enforcement should be developed on a cost-effective basis. The National Petroleum Council is especially concerned that the program for enforcement downstream of the refinery might remove much of the flexibility anticipated by refiners and raise the overall costs of the reformulated gasoline program beyond levels projected in this study.

Regulatory Resolution

U.S. refiners should be included in a constructive process with government and other interested stakeholders to plan strategies and develop cost-effective solutions to societal concerns related to the industry.

A more constructive process that involves all interested stakeholders—industry, government, and other affected parties—working in partnership could lead to more efficient cost-effective regulations and enforcement procedures for meeting a given environmental goal. Better overall solutions to problems such as meeting the federal air quality standards can be developed in a cooperative, multimedia approach rather than regulating individual pollutants from various sources. The recommended partnership should allow broader consideration of environmental goals and possible solutions, while sharing the burden of responsibility for cost-effective regulations and enforcement procedures and committing to proactive betterment of quality of life (i.e., reasonable reduction of health, safety, and environmental exposures).

The Environmental Protection Agency (EPA) ultra-low sulfur diesel fuel regulation is a good example of efforts that have been made to achieve negotiated, cost-effective solutions. Government, the oil industry, diesel engine manufacturers, and consumers were involved at an early stage. Since adequate time to comply was provided, the interactive process led to a level of diesel fuel desulfurization and engine modification that appears to be cost-effective and beneficial for the industries, the consumer, and the public. However, the process was not entirely satisfactory because ultra-low sulfur diesel fuel production had to begin before enforcement standards were final.

Other promising efforts to improve regulatory resolution are the Amoco-EPA Yorktown study of stationary source pollution prevention discussed in the full report, and the ongoing EPA industrial cluster concept.

Environmental Cost Recovery in the Competitive Marketplace

Government policymakers should recognize that in the competitive marketplace, product cost increases and some rationalization of the refining industry are probable outcomes of environmental and other regulation of refineries and petroleum products. Policies that reduce petroleum products demand also result in rationalization of the refining industry, with an attendant loss of jobs. Over the long term, refining expenditures will be reflected in the marketplace. In effect, the consumer pays an indirect tax for the mandated environmental improvements and, as with direct taxes, the public ought to receive commensurate benefits. Impacts of policy should be carefully and realistically evaluated prior to legislation or regulation.

Government policymakers should also recognize that the U.S. refining industry is competing in a global industry. If U.S. costs are significantly higher than those of foreign refineries, then U.S. source product is not as competitive, either for supplying U.S. customers or for export. The result could be a greater dependence on foreign source product and lower utilization of existing U.S. refining capacity.

FINDINGS

PROLOGUE

The U.S. refining industry enjoyed robust product demand growth in the post-World War II era into the early 1970s. Any excess capacity resulting from new plants or unit expansion was soon filled by demand growth. With the price shocks and periods of crude oil shortages in the 1970s, product demand growth slowed and in some periods declined. The refining industry changed in the 1970s from a growth industry to a mature industry. With the decline in U.S. crude oil production, imports of crude oil and other refinery feedstocks increased to meet refinery raw material requirements. However, light product (gasoline, jet fuel, and distillate) imports remained a small proportion of U.S. product supply. Figures 2 and 3 display the product demand as well as crude oil and product import levels from 1970 to 1992.

The number of refineries and distillation capacity grew steadily from 1970 through 1981. In 1979, crude oil runs started to decline, reflecting reduced product demand. With oil price decontrol in 1981, the total number of individual operating refineries dropped from a high of 315 in 1981 to 192 in 1986 as "crude oil entitlement" and other refineries became uneconomic, and shut down. Thereafter, slowly increasing light product demand resulted in increased downstream processing and conversion unit capacity and utilization, while rationalization of crude oil distillation capacity continued. Figure 4 shows the number of refineries, distillation capacity, and total crude oil runs from 1970 through 1992.

The U.S. refining industry is an important component of the U.S. economy and is especially vital to the transportation sector. The industry supplies 97 percent of the energy for the travel and freight needs of the nation. Fuel demands for more than 190 million automobiles, trucks, and buses as well as all aircraft are met by petroleum-based fuels.

U.S. refinery products have evolved over the last three decades and are not the same products bought by consumers in the 1960s. Although Los Angeles inaugurated gasoline regulation in 1959 in the form of a bromine number limitation (olefins content), federal regulation of gasoline quality began in the 1970s after the Clean Air Act of 1967. Significant use of oxygenates in gasoline for octane, volume, or emissions reduction began in the 1980s. The 1990 Clean Air Act Amendments mandated oxygenated gasoline in late 1992 and require reformulated gasolines (Phase I) in 1995. Oxygenates are expected to comprise 4 to 7 volume percent of U.S. gasoline in the year 2000 depending on the level of opt-in. Phase II reformulated gasoline performance standards require further emissions reduction in 2000. Lead will be completely eliminated by 1996, although very little lead is used even now. Gasoline quality has been further improved with enhanced additive packages that yield cleaner engines, improved efficiency, and lower emissions. In addition, ultra-low sulfur diesel fuel (0.05 weight percent sulfur) is required by the 1990 Clean Air Act Amendments for on-highway use beginning in October 1993.

The U.S. logistics system provides efficient distribution of light petroleum products to every part of the country. Terminals have been constructed at refineries, ports, and locations central to markets. Seventy-two thousand miles of major product pipelines cross the country connecting refineries and terminals. When economic, companies have joined together in pipeline and terminal ownership to seek efficiencies and economies of scale. Fleets of ships, barges, and rail tankcars serve the terminals. Trucks deliver products from terminals to retail outlets and wholesale customers.

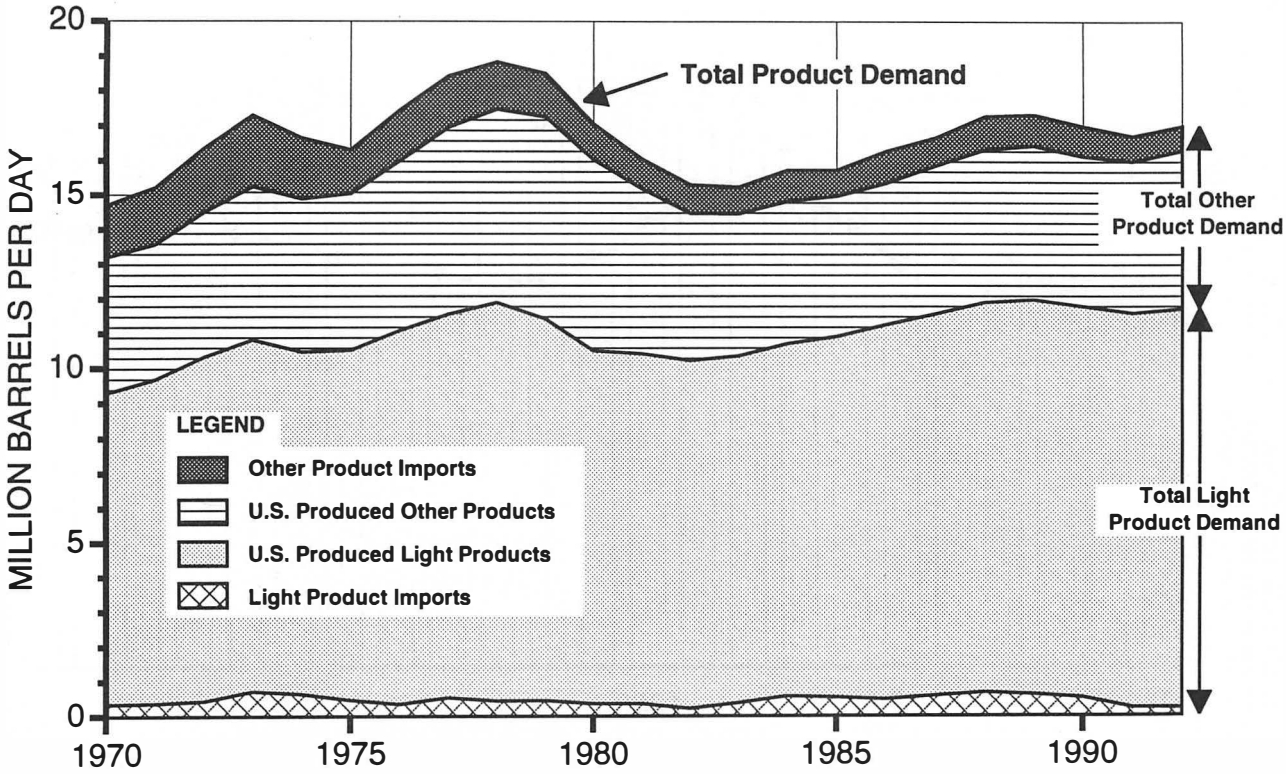


Figure 2. U.S. Petroleum Product Demand
Imports and Domestic Supply.

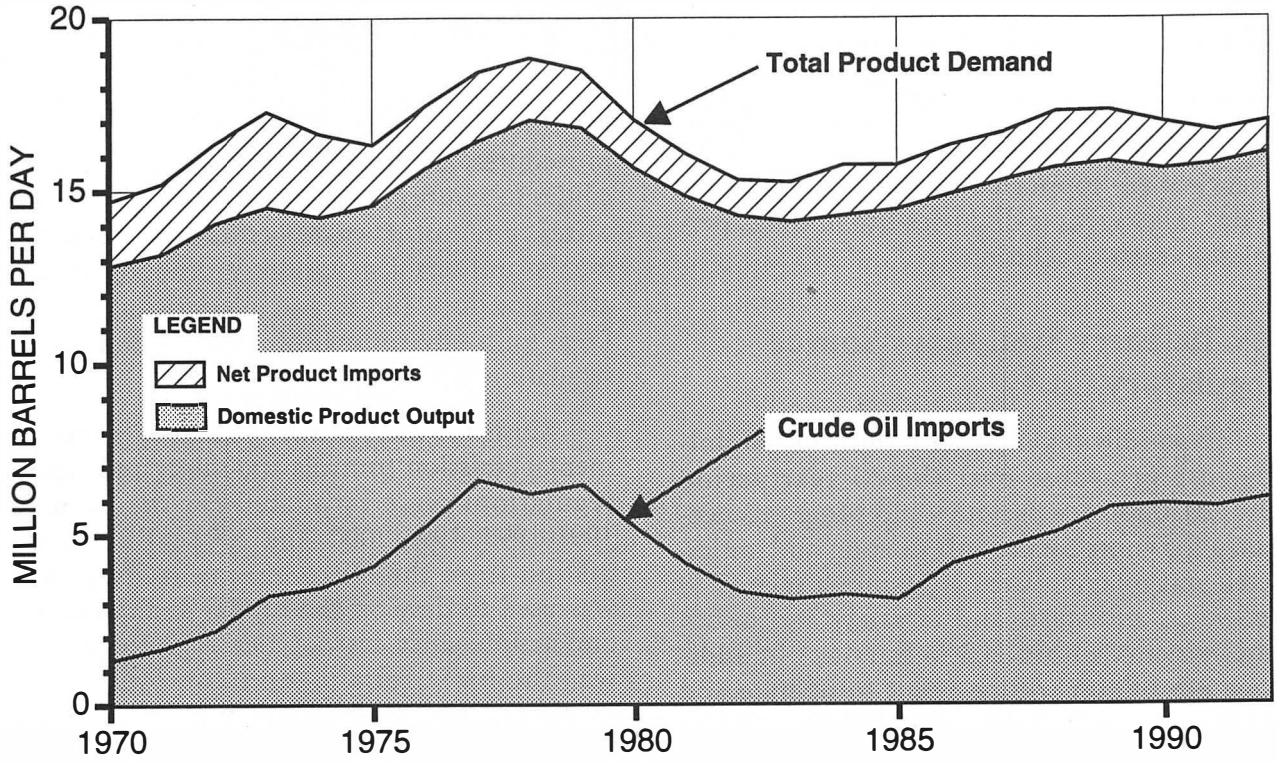
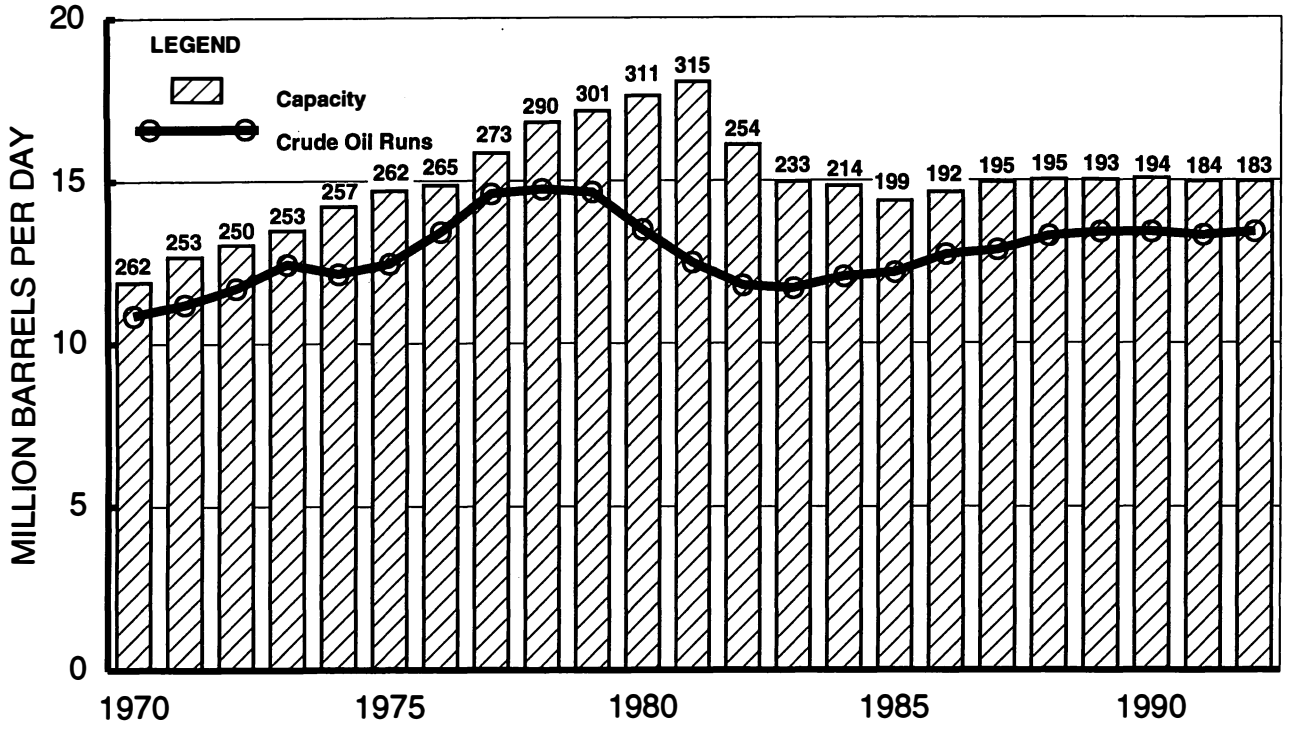


Figure 3. U.S. Product Demand
Relative to Refinery Input Source.



Source: U.S. Bureau of Mines (1970-1975), Energy Information Administration (1976-1992).

Figure 4. U.S. Operating Refining Capacity (With Number of Refineries and Crude Oil Runs).

Environmental regulations have affected the logistics system as well as the refineries.

DISCUSSION OF FINDINGS

The key conclusions presented in the Overview are supported by the findings of the study. This section discusses the findings pertinent to each conclusion.

U.S. Refinery Stationary Source Regulatory Cost

Expenditures of $106 billion (1990 dollars) are projected over the 20-year period 1991-2010 for new facilities and programs necessary for compliance with existing and anticipated stationary source regulations related to air, water, and waste and to safety and health requirements within U.S. refineries. In addition, $46 billion will be spent to operate and maintain similar facilities and programs now in place, for total stationary facilities environmental, health, and safety expenditures of $152 billion. As a comparison, the $152 billion represents average annual expenditures over twice that required in the last half of the 1980s.

Environmental regulations will impact the U.S. refining industry by requiring significant modifications and additions to facilities and procedures. Refiners must provide control facilities to assure compliance with all media (air, water, and solid waste) emissions requirements, and establish various procedures (operating practices, audits, and inspections) to conform with environmental, health, and safety regulations.

Costs for these refinery facilities' environmental emission controls and safety and health regulations were estimated for the periods 1991-1995, 1996-2000, and 2001-2010. Information from the NPC refining study survey was used to develop the capital and operating and maintenance cost for 1991-1995 because it was the most reliable and comprehensive source available. The following describes the approach for later periods:

- A panel of industry experts developed detailed premises defining current and an-

ticipated air, water, waste, safety, and health regulations.

- The premises were used to define the hardware needed for specific emission sources and programs to meet procedural requirements. For this effort, compliance with specific regulations was the overriding criterion without consideration of cost-effectiveness.
- Use of best, maximum, or reasonable available control technology as applicable was assumed. Needs were not set by site-specific evaluation of risks and cost-effectiveness.
- Capital, one-time, and operating and maintenance costs required for implementation were separately estimated.

Table 1 summarizes the results, which show a 20-year cash requirement (capital expenditures, one-time expenses, and operating and maintenance expenses) of $152 billion for compliance with existing and anticipated regulations relative to air, water, waste, safety, and health within the refinery fence lines. These stationary facilities costs are in addition to the costs associated with manufacturing reformulated and oxygenated gasolines and ultra-low sulfur diesel fuels.

These regulatory capital expenditures, one-time expenses, and operating and maintenance expenses require an average annual cash outlay before tax of over $6 billion per year in the early period, increasing to over $8 billion per year. During the 1980s, similar expenditures were about $3.5 billion per year.

The premises considered only those regulatory items believed to have significant individual financial impact. As the costs of numerous small items were not quantified, the overall study cost estimates tend to be conservatively low. Further, the forecasted decline in capital expenditures toward the end of the study period is typical of any long-range evaluation. Undefined expenditures for site closures including cleanup, possible increased soil incineration, and further, less cost-effective regulations are not included in this analysis. The ability to project the pace and severity of future regulations diminishes the farther one looks into the future.

Figure 5 indicates that, on average, the 24 refineries with 100 to 150 thousand barrels per day of capacity (which is near U.S. average-size conversion refinery) will be required to expend $1.2 billion each between 1991 and 2010. Generally, refineries face costs proportionate to their size.

TABLE 1

STATIONARY SOURCE ENVIRONMENTAL FACILITIES AND PROGRAM COST (Billions of 1990 Dollars)

	1991-1995	1996-2000	2001-2005	2006-2010	Total
Capital Expenditures	12.6	10.2	6.8	6.7	36.3
One-Time Expenses	4.5	1.3	0.6	0.6	7.0
Operating and Maintenance Expenses (New)	4.1	14.2	20.7	23.6	62.6
Subtotal	**21.2**	**25.7**	**28.1**	**30.9**	**105.9**
Operating and Maintenance Expenses (Base)	11.5	11.5	11.5	11.5	46.0
TOTAL	**32.7**	**37.2**	**39.6**	**42.4**	**151.9**
Annual Average	6.5	7.4	7.9	8.5	

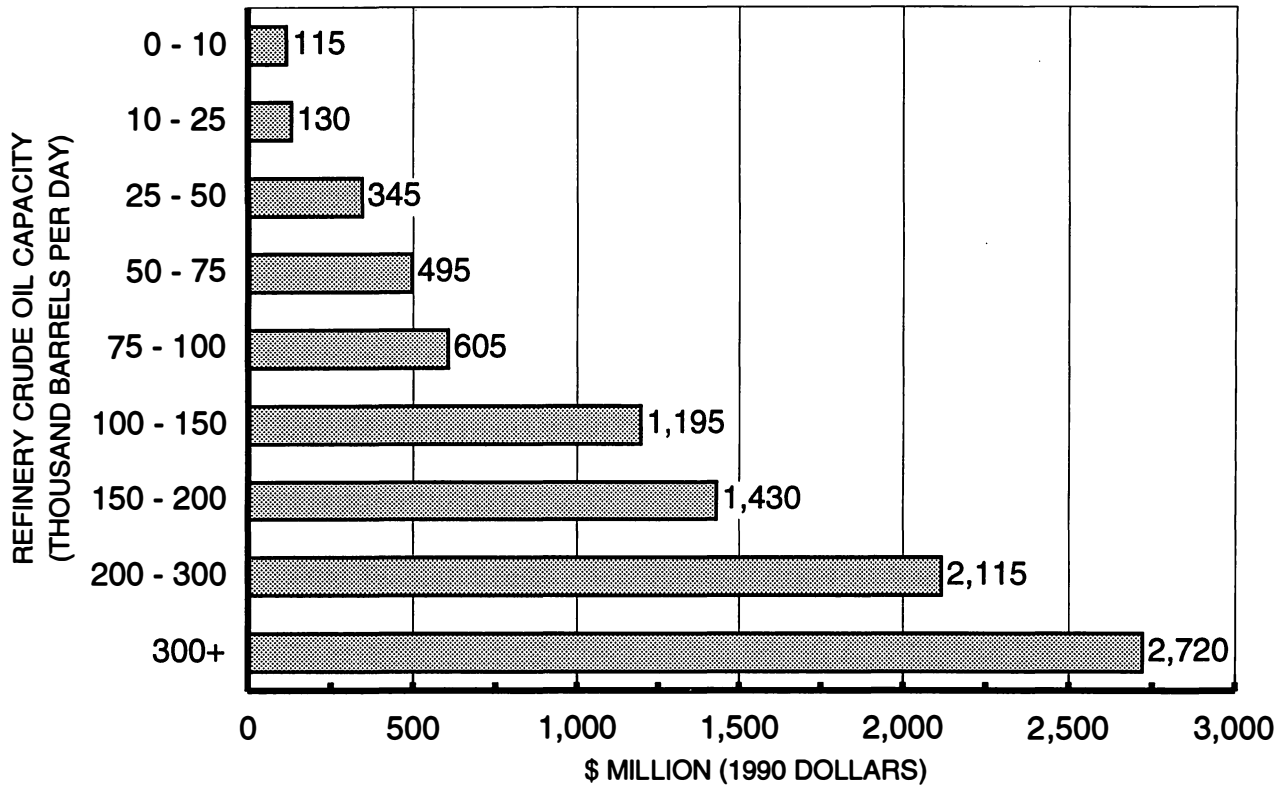


**Figure 5. Environmental Facilities and Programs—
Average Total 1991-2010 Cost for Each Operating Refinery.**

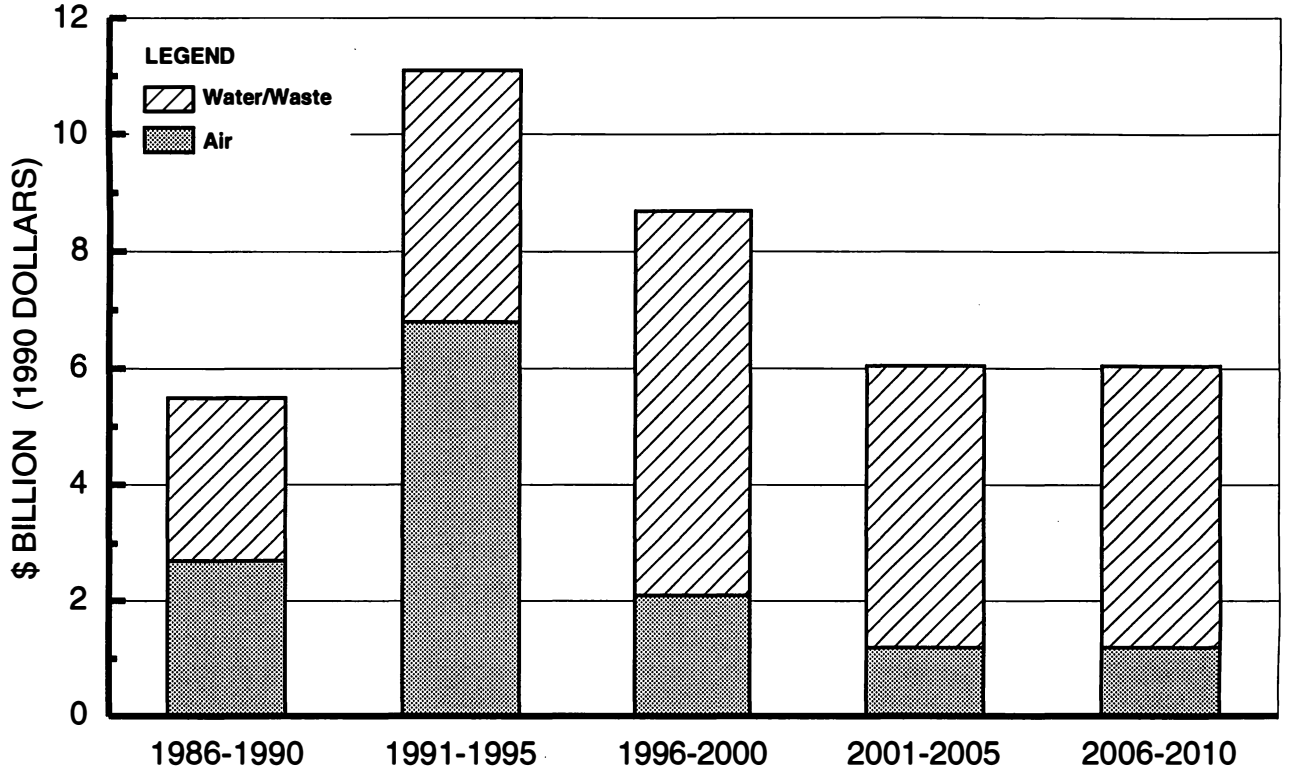


**Figure 6. Regulatory Environmental, Safety, and Health Capital Expenditure
Requirements for Stationary Facilities.**

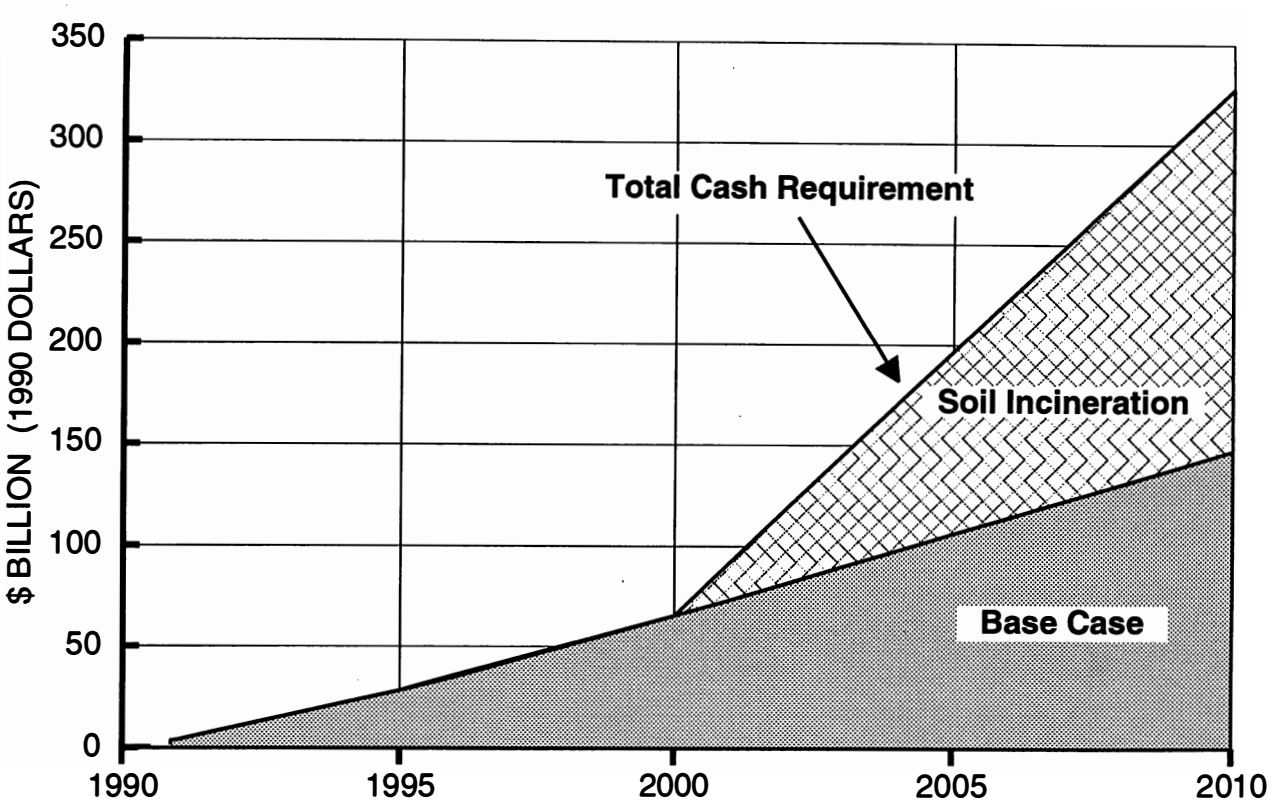


Figure 7. Cost Sensitivity for Soil Remediation. Incineration vs. Closure In-Place (Base)—Cumulative Cash Requirement.

Another perspective (Figure 6) shows the shift of capital spending from air-related issues to a future dominated by water and solid waste. Figure 7 shows the cost sensitivity for potential regulation regarding remediation of contaminated soil. For example, incineration of removed soil could be required for remediation rather than the assumed in-place closure of contaminated sites. If so, the total cash requirements for refineries operating January 1, 1991 would increase from $152 billion to $330 billion. This $180 billion cost increase, if expended over ten years, would equate to 10 cents per gallon of light product and could cause a significant loss of U.S. refining competitiveness.

While no quantitative downside sensitivities are presented, such possibilities as lower expenditures due to technological advances, extensions of deadlines, or significant changes in political direction were considered but not quantified.

This report's refinery stationary source cost estimates do not include environmentally related expenditures that are not directly attributable to operating refineries such as costs for: remediation of closed refinery sites, remediation at crude oil and product terminal sites, litigation costs, and punitive damage settlements of civil suits arising from environmental issues. These required expenditures, which will be borne by industry, could be substantial.

Refining and Logistics Costs

Refining and logistics costs in the United States are projected to increase substantially. For example, relative to 1989 conventional gasoline, reformulated gasoline is projected to cost about 8, 12, and 14 cents per gallon (1990 dollars) more in 1995, 2000, and 2010, respectively. These include costs to the refineries for stationary emissions control improvements and additional health and safety regulations, costs due to more intensive processing and oxygenate addition to produce fuels, and costs of changes in the product logistics system to meet future regulations. The ultimate impact on the consumer would include other factors, such as changes in raw material cost, taxes, marketing costs, and fuel energy content, as well as marketplace competition.

Stationary Source Emissions Control Costs

New stationary source emissions controls and additional health and safety regulations, if their costs are evenly applied to light products, will add 2.6 cents per gallon in 1995, 4.5 cents per gallon in 2000, and 6.5 cents per gallon in 2010 to the 1989 cost (1990 dollars). It is assumed that light products will solely bear the cost increase because heavy products compete with close substitute fuels such as natural gas.

Reformulated Product Processing Costs

In addition, because of the processing and oxygenate needs, the U.S. annual average cost to produce federal Phase I reformulated gasoline in 1995 will add another 4.8 cents per gallon to 1989 conventional gasoline. The cost to produce the year 2000 Phase II reformulated gasoline premised by the NPC will add 6.4 cents per gallon to 1989 conventional gasoline. Because volatile organic compound (VOC) reduction is required in the summer high-ozone period, the cost of reformulating gasoline is about 1 cent per gallon higher in the summer than the annual average cost. A preliminary version (4/92) of the "complex model" was used to calculate vehicle emissions from gasoline properties.

Refining costs developed in this study for reformulated gasoline were determined using industry regional aggregate models, one for each Petroleum Administration for Defense

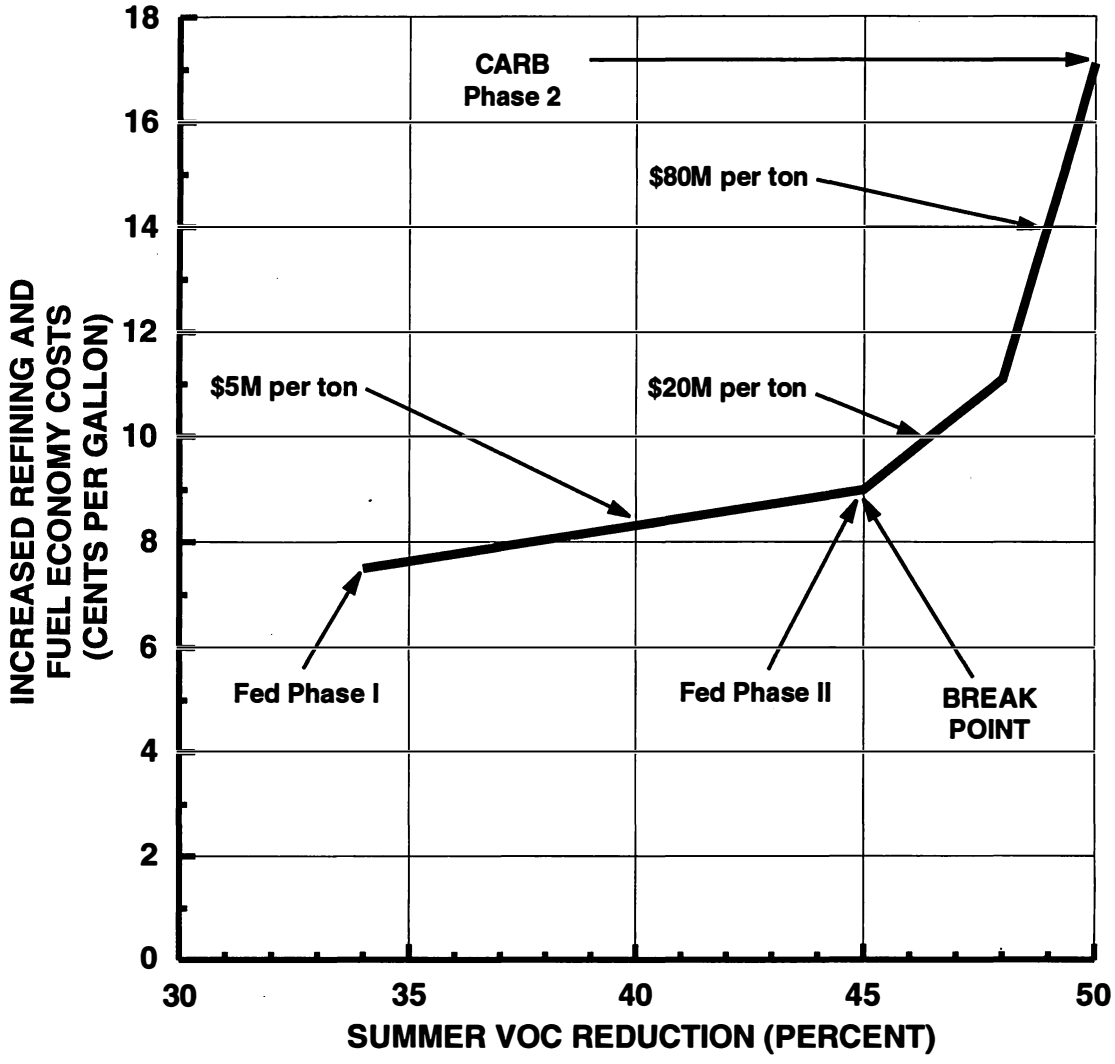


Figure 8. Incremental Cost-Effective Break Point Illustration for Reformulated Gasoline, PADD III, 4/92 Complex Model.

District (PADD). U.S. totals are volume averaged PADD results.

The reported cost corresponds to the cost curve break point (Figure 8), beyond which incremental refining and fuel economy costs for further reformulation severity are higher than the $10,000 per "6-months summer ton" assumed to be the upper limit of acceptable cost-effectiveness for VOC reduction. Refining cost and cost-effectiveness of reformulated gasoline vary from PADD to PADD. PADD III, the U.S. Gulf Coast, is shown as an example. This study's $10,000 per 6-months summer ton is equivalent to the EPA estimated upper limit for cost-effective VOC reductions of $5000 per annual ton (corresponds to the EPA definition of control decision benchmark).

Not including stationary source costs increases, refining cost for ultra-low sulfur diesel fuel starting in 1993 will average 3.8 cents per gallon in the United States (excluding California) above the 1989 cost of conventional product.

Logistics and Other Costs

Changes required to the logistics system are expected to add less than 1 cent per gallon to the cost of light products. Product quality enforcement is expected to add to the cost but was not estimated by this study.

The resulting increase in distribution cost from refinery to marketing location will vary by delivery location and source of product. For example, the cost increase to a New York service station from the U.S. Gulf Coast by pipeline or from Northwest Europe by tanker is about 3/4 cent per gallon for the 1989-1995 period.

Cost Summation

Product cost increases above 1989 levels along with retail marketing costs and lower fuel economy effects are shown in Table 2.

TABLE 2

FEDERAL EPA REFORMULATED PRODUCTS ANNUAL AVERAGE COST INCREASE ABOVE 1989 (Cents per Gallon—1990 Dollars)

	Reformulated Gasoline			Ultra-Low Sulfur Diesel Fuel		
Costs Increases in Study	**1995**	**2000**	**2010**	**1995**	**2000**	**2010**
Stationary Source Controls	2.6	4.5	6.5	2.6	4.5	6.5
Refining Costs (and Oxygenate for Reformulated Gasoline)	4.8	6.4	6.4	3.8	3.8	3.8
Logistics and Other	1.0	1.0	1.0	1.0	1.0	1.0
Subtotal	**8.4**	**11.9**	**13.9**	**7.4**	**9.3**	**11.3**
Retail Marketing Regulations*	1.5	1.5	1.5	1.0	1.0	1.0
Total Increase	**9.9**	**13.4**	**15.4**	**8.4**	**10.3**	**12.3**
Lower Fuel Economy† (Indirect Increase)	2.5	2.5	2.5	–	–	–
Total Effective Consumer Increase	**12.4**	**15.9**	**17.9**	**8.4**	**10.3**	**12.3**

* No detailed NPC study; estimated from EPA and American Petroleum Institute data.

† Gasolines with oxygenate have less energy content per gallon; therefore, the consumer requires more gallons to travel the same distance.

Regulatory Uncertainty Cost Sensitivities

To keep the processing cost per ton of VOC removed within EPA suggested target levels with implementation of reformulated gasoline, emission performance standards should be set lower than the incremental cost-effectiveness break point previously mentioned so that any required allowances for blending, testing, and enforcement will not cause reformulated gasoline VOC reductions to become more costly than available alternative, non-fuel strategies for VOC reductions. To do otherwise could result in processing costs for reformulated gasoline much higher than reported here.

The cost of reformulating gasoline to meet the standards of the year 2000 was calculated based on a complex emissions model available in April 1992. With this model, the required VOC reduction was met primarily by reducing the Reid Vapor Pressure below that of 1995 Phase I reformulated gasoline.

Other complex model proposals have since been made public. Emissions calculations were made with three of these proposed complex models for comparison. For the cost-effective reformulated gasoline determined by the 4/92 model, all three of the other models give a lower calculated VOC reduction. The incremental VOC reduction and, therefore, the cost-effectiveness, calculated for the next VOC reduction step also depends on the complex model used. Hence, the complex model has to be established before a cost-effective performance standard for Phase II reformulated gasoline can be determined.

Aside from the effect of model choice, more costly gasoline reformulations than reported herein may be required of refineries to:

- Produce RFG that would provide reduced oxides of nitrogen (NOx) emissions
- Allow for enforcement standards and testing tolerances
- Be within specified limits and ranges permitted for fuel properties
- Provide for compatibility in the logistics system
- Allow for the increased VOC emissions from blending high-ozone period reformulated gasoline with ethanol.

In some cases, these requirements would not result in an emissions reduction, and in other cases the emissions reduction is not cost effective.

Additional VOC reduction for reformulated gasoline using methyl tertiary butyl ether (MTBE) has been proposed to accommodate the use of ethanol during the summer, high-ozone period in up to 30 percent of the total reformulated gasoline sold in an area. If this additional VOC reduction were required, the added cost would be about 1.4 cents per gallon.

More stringent EPA requirements for diesel fuel after 1993 and for reformulated gasoline after 2000 are possible. As an example of more stringent requirements, if California-specification low aromatics diesel fuel were made on a U.S. basis, it would cost 10 cents per gallon more than ultra-low sulfur diesel fuel. If California Air Resources Board Phase 2 reformulated gasoline were made on a U.S. basis, it would cost 9 cents per gallon more than the federal Phase II reformulated gasoline of this study.

Financial

Projected U.S. refining capital expenditures of $37 billion (1990 dollars) in the 1991-2000 period for product quality (cleaner transportation fuels) and stationary source regulatory compliance exceed the total net fixed asset base ($31 billion) of U.S. refineries at the start of this period. About two-thirds of the capital expenditures are projected to be made in the 1991-1995 period. Assuming all operating expenses (including depreciation) are recovered, cash flow generated during the 1991-1995 period is still on the order of $25 billion less than the required capital expenditures.

Product revenue increases will be necessary to recover operating expenses and to provide competitive returns on the capital employed. The projected cost increase in 2000 for regulatory compliance is more than twice the U.S. refining, marketing, and transportation

industry's historical average net income in the 1980s. Given the projection of declining refinery utilization through 1995, recovery of these costs will be difficult until capacity and demand are rebalanced by further capacity shutdowns and/or increased product demand.

Historical and estimated future capital expenditures are shown in Table 3. Capital expenditures for environmental, health, and safety related to stationary source facilities were $10 billion in the 1980s. Capital expenditures for this category are estimated to be $23 billion for the 1990s and $14 billion for the period of 2001 to 2010. The projected stationary source expenditures for the 1990s are about 42 percent of the total capital expenditures expected to be made by the refining industry in 1991-2000, which is almost twice what it was in the 1980s. Refinery process facilities to manufacture products required by the 1990 Clean Air Act Amendments will cost another $14 billion.

The capital spending driven by environmental regulation will increase the amount of capital required by the industry per unit of product delivered with little change in capacity.

To assess the refining industry's ability to recover increased operating expenses and to fund this level of future capital expenditures, the NPC projected the industry's cash flow in then current dollars. The financial performance of the refining industry over the decade of the 1980s was, on average, below that of all U.S. industry, as represented by the Standard and Poor's 400 industrial firms (excluding energy firms). During the 1981-1990 period, U.S. petroleum refining, marketing, and transport operations realized an average return on investment (net income before interest, divided by net assets) of 8.8 percent, although

TABLE 3

U.S. REFINING CAPITAL EXPENDITURES
(Billions of 1990 Dollars)

	1981-1990	1991-2000	2001-2010
Environmental, Health, and Safety Stationary Source Facilities			
Pollution Abatement – Reported*	6.1	—	—
Stationary Facilities – NPC Estimates	3.9	22.8	13.5
Subtotal Stationary Source Facilities	**10.0**	**22.8**	**13.5**
Refinery Process Facilities			
Product Quality (Cleaner Fuels)	†	13.7	NS
Process Additions and Replacement	37.5	18.3	15.0
Total Capital Expenditures	**47.5**	**54.8**	**28.5**
Memo:			
Total Regulatory Compliance Expenditure	N/A	36.5	13.5
% Stationary Source Facilities	21%	42%	47%
Avg. Refining Capacity, Million B/SD	16.7	16.5	16.5
Capital Expenditures, $ per Daily Barrel of Capacity	$2,840	$3,320	$1,730

* From U.S. Department of Commerce, MA-200.

† 1981-1990 product quality facilities included in process additions and replacement.

Note: NS = Not Studied. N/A = Not Available.

cumulative net cash flow after capital expenditures was negative. In 1991 and 1992, profitability was lower than in the 1980s and cash flow continued to be lower than spending requirements.

Three cases were analyzed with alternative assumptions of net income to determine the impact on cumulative net cash flow and product costs (see Table 4). In the first case (A), net income in the 1993-2000 projection period was held equal to that of the historical levels of the 1980s; the resulting cumulative cash flow to 2000 is well short of requirements. If net income increases to recover the cost of capital on new environmental investment, as premised in the study (Case B), then the cash flow improves, although not sufficient to cover requirements in the 1991-2000 period. Only in the last case (C), where return on investment was held equal to that of the 1980s and net income is increased further, was cash flow sufficient to cover requirements.

The first half of the 1990s is a financially difficult period for the U.S. refining industry. Financial performance in the 1990s has been disappointing to date and shutdowns of refineries are on the increase. Even under the U.S. demand growth scenario, refinery utilization decreases in 1995 relative to 1990. If more refineries do not shut down, then an extended period of reduced profits can be expected.

If refiners perceive lower demand beyond 1995, then some may not be willing or able to make the required capital expenditures, and some refining capacity will be shut down. On the other hand, if refiners perceive demand growth after 1995, more may make these investments with the expectation of future recovery of the added costs of environmental and other regulations in the marketplace.

Product Compatibility

The logistics system will remain effective only if regulated product specification and enforcement procedures, including testing tolerances, allow product compatibility throughout. Product compatibility means being able to mix separate batches of a specific product as necessary for effective operation of the logistics system. If absolute batch segregation were required, the logistics system as it exists today would be inoperable.

Current product specifications and enforcement procedures allow effective use of the logistics system because commingling of similar products does not result in off-specification products at the final point of sale.

TABLE 4

SUMMARY OF CASES OF ALTERNATIVE NET INCOMES

	1981-1990	1991-2000		
		Case A	Case B	Case C
Return on Investment, %	8.8	5.7	7.1	8.8
Cumulative Net Cash Flow, billions then current dollars	(5)			
1991-1995		(31)	(28)	(22)
1991-2000		(37)	(19)	2
Net Income, cpg, all products,				
then current dollars	2.3	2.5	3.1	3.8
1990 dollars	2.7	2.0	2.4	3.0
Cost Increase in 2000 for Refinery Regulatory Compliance, cpg, all products, 1990 dollars		5.0	5.7	6.6

Commingling of new batches with some amount of the previous batch is inherent in the entire logistics system. Tanks are almost never empty because: (1) floating roof tanks fail to prevent evaporative emissions if allowed to become near empty; (2) reserve levels are needed to prevent product runout; and (3) batch sizes of shipments must meet individual system capabilities. The problem of mixing received product with the previous batch is not limited to tanks at terminals. Batches are loaded on top of small quantities of leftover product in barges and ocean-going tankers, in tank trucks, and in railcars. Blending with the previous batch occurs with every delivery to a retail service station where tanks are almost never empty. Finally, gasolines from multiple sources are blended in vehicle fuel tanks as consumers fill up at different service stations.

Regulations such as proposed by the Environmental Protection Agency on February 26, 1993 for reformulated gasoline could preclude any mixing of batch shipments of gasolines of the same grade in any degree, no matter how incidental. This would require isolating each batch from other batches of reformulated gasoline and require more segregations. The possible number of product segregations is limited by the physical characteristics of the logistics system. If the required number exceeds what can be practicably accommodated, the expected consequences would range from increased manufacturing and distribution costs and sporadic runouts, to complete failure of some systems. Regulations that effectively mandate complete segregation of individual batches would render the existing logistics system inoperable.

Environmental legislation and regulations require supply of more primary types of products. Several geographic and oxygenate-type variations of reformulated gasoline have been proposed. The additional product segregations will utilize more logistic system capacity relative to today's situation. The NPC refining study survey indicated that the industry is preparing to add a limited increased number of segregations. To satisfy regulatory requirements some refineries may find it preferable to produce a more costly common product (capable of meeting the most restrictive specification of two or more locations) instead of different products for each location.

Enforcement procedures should establish standards that include an adequate allowance for normal variation in testing — that is, to allow for testing tolerances. Otherwise, refineries and pipelines will target more stringent specifications to minimize the chance that complying products will be found to be out of compliance due to test result variations.

Refining Capability

With appropriate capital expenditures, sufficient volumes of on-highway diesel fuel and reformulated gasoline meeting requirements of the 1990 Clean Air Act Amendments can be manufactured in existing and anticipated process facilities using current technology and available engineering and construction resources.

Three significant areas relate to this finding and are discussed below.

Achievement of Reformulated Gasoline Emissions Reduction Performance

In 1995, under the simple emissions model proposed by the EPA, required reduction of emissions with reformulated gasoline will be produced with a lower Reid Vapor Pressure, a mandated oxygen content, and reduced benzene and aromatic content.

With Phase II reformulated gasoline in 2000, the level of emissions reduction calculated for a given processing cost is very dependent on the complex emissions model and the mobile source emissions inventory model used. The complex model is yet to be promulgated. However, calculations with various complex models indicate the 1990 Clean Air Act Amendments requirement of at least 20 percent volatile organic compounds reduction from the statutory baseline can be met. The processing costs for reformulation reported here reflect the use of an available model based on information published in the *Federal Register* in June and July 1991 and April 1992.

Availability of Resources

Refinery processes and stationary source emissions control requirements estimated in this study utilize current technology. No new technology is necessary to meet the future requirements studied.

A sampling of U.S. engineering and construction companies indicated ample availability of their resources as well as construction material and catalysts that may be required in the future for process facilities and stationary source emissions control equipment.

Oxygenates, as discussed in the Oxygenates Finding that follows, are expected to be available in quantities sufficient for the opt-in levels assumed for reformulated gasoline.

Availability of financial resources will depend on expectations for recovery of higher costs. Financial aspects are discussed in the Financial Finding, presented earlier in this Findings section.

Regulatory Concerns

The final complex emissions model performance standards and program enforcement regulations for reformulated gasoline were not known during this study. The study used an available complex emissions model. Cost-effective regulations and gasoline products compatibility were assumed. This resulted in relatively low-cost reformulations. More recent complex model proposals would require more costly gasoline reformulations. Use of some complex models in combination with proposed compliance enforcement would require all blends of gasoline to be segregated, which could severely limit refinery and distribution system flexibility, possibly causing occasional product runouts. Under conditions where options are limited, additional costs to supply reformulated gasoline could be substantial.

Refineries choosing to make reformulated products will need to maintain more segregations of products than in the past. This may require more tanks to retain operating flexibility, and tie up tanks with components and products for longer periods of time, adding to inventory costs.

The cost and strategy for reprocessing off-test reformulated gasoline to produce compliant or other gasoline will be highly dependent upon individual circumstances. All reprocessing strategies will incur increased costs compared to handling off-test gasoline currently and could result in the use of enough product tankage to restrict refinery output.

Oxygenates

Assessment of worldwide existing capacity and announced expansion plans for producing oxygenates indicates adequate supply in 1995 for at least the legislated minimum requirements. By 2000, the potential supply is expected to cover essentially any situation permitted by the 1990 Clean Air Act Amendments.

An analysis was made of the potential to produce oxygenates (methyl tertiary butyl ether [MTBE], tertiary amyl methyl ether [TAME], and ethanol) for blending into U.S. reformulated and oxygenated motor gasoline. The October 1992 survey of oxygenate producing capacity conducted by the U.S. Department of Energy's Energy Information Administration (EIA) was the primary source of information. Other surveys were used to supplement the EIA data, particularly beyond 1995. The capacity information was converted to potential supply assuming sufficient feedstock availability, and is shown in Table 5 as equivalent MTBE.

The demand assessment involved making assumptions concerning the number of nonattainment areas that would choose the reformulated gasoline program as a means of addressing the local ozone situation. The NPC refining study is based on the assumption that only the nine worst ozone nonattainment regions would use reformulated gasoline in 1995. It was assumed that all of the areas that could choose to use reformulated gasoline under the 1990 Clean Air Act Amendments would do so by 2000. In addition, it was assumed the entire Northeast Ozone Transport Corridor would choose to use reformulated motor gasoline by 2000. California is assumed to use California Air Resources Board Phase 2 reformulated gasoline beginning in 1996. These assump-

TABLE 5

U.S. OXYGENATE SUPPLY AND DEMAND
(Thousand Barrels per Day – MTBE Equivalent)

	1995			2000			2010		
	FC-I	FC-II	FC-III	FC-I	FC-II	FC-III	FC-I	FC-II	FC-III
U.S. Production*	442	442	442	566	566	566	566	566	566
Imports	81	90	90	21	71	79	0	57	80
Potential Supply	**523**	**532**	**532**	**587**	**637**	**645**	**566**	**623**	**646**
CAAA Demand	276	276	276	571	550	529	615	550	485
Gasohol Demand	69	69	69	43	43	41	47	43	37
Potential Demand	**345**	**345**	**345**	**614**	**593**	**570**	**662**	**593**	**522**
Potential Surplus	**178**	**187**	**187**	**(27)**	**44**	**75**	**(96)**	**30**	**124**

* January 1, 1993 production capability = 285 thousand barrels per day—MTBE equivalent.

Note: FC-I = Foundation Case I – Growth in U.S. demand.
FC-II = Foundation Case II –No growth in U.S. demand.
FC-III = Foundation Case III – Decline in U.S. demand.
CAAA = 1990 Clean Air Act Amendments.

tions add significantly to the demand assessments for the year 2000. The demand estimates are shown in Table 5.

One of the issues surrounding the use of oxygenates is geographic spillover. Geographic spillover of nonattainment area quality products into attainment areas is expected to be less than one percent. Higher costs for nonattainment area quality products provide a significant economic incentive to minimize the distribution of these products to areas where they are not required. Terminal and tankage capability near nonattainment-attainment areas interface locations appears sufficient to allow appropriate product segregations, through product exchanges between potential suppliers. In some situations, individual suppliers may find it economic to distribute oxygenated products to areas where they are not required.

As indicated on the last line of Table 5, the potential supply from already announced facilities is close to the estimated requirement for 2000-2010. There is ample time to build new capacity. Consequently, it does not appear likely that there would be a U.S. oxygenate supply shortfall under any of the situations evaluated.

Foreign Product Supply Cost

Today, most foreign areas lag the United States in health, safety, and environmental regulations and, consequently, have lower embedded environmental costs than the United States. Over time, the total cost of foreign supply delivered to the United States is projected to increase as result of product quality changes outside the United States; foreign capacity additions needed to meet local demand growth; and foreign environmental, health, and safety regulations for stationary facilities. The study's projected foreign total cost increase is approximately the same as the corresponding U.S. cost increase. However, there is significant uncertainty in these cost increase estimates.

Foreign product demands are expected to increase and demands for more environmentally acceptable products are also increasing. Input from experts on various foreign areas, review of foreign regulations, and the

NPC refining study survey indicates that there will be a significant effort in foreign refining centers to modify facilities from a health, safety, and environmental perspective. Waterborne transportation is also expected to bear increased costs as the result of health, safety, and environmental regulation. Extensive process facility additions are already underway or planned that will help meet foreign demand growth, which in many areas is outpacing growth in the United States.

Estimated existing and projected levels of health, safety, and environmental regulation of stationary facilities in foreign refining regions are shown in Table 6. The level is expressed as a percentage of the U.S. regulations in place as of 1990. The more industrialized areas such as Northwest Europe are shown on the table in 1990 as 75 percent of the U.S. regulation in the same year. Less industrialized areas such as the Middle East are assumed to have limited regulation in 1990. Local pressures are expected to result in all areas catching up to U.S. 1990 levels sometime in the next 20 years. There are diverse levels of regulations in each country in each area.

Foreign refineries are also expected to be required to adopt some of the future U.S. health, safety, and environmental standards over the next 20 years. Table 6 shows the percent adoption of premised future regulations by study year assumed for each foreign refining area. To illustrate, Latin America is expected to adopt the U.S. 1990 standards plus 75-100 percent of the future U.S. standards by the year 2010.

There is greater uncertainty surrounding the foreign health, safety, and environmental regulations and costs for stationary facilities than in the United States. Lacking detailed forecasts of anticipated foreign environmental regulations, the costs used for meeting the regulations in the foreign areas were derived from historical and projected U.S. costs. Foreign costs were discounted by 10 to 30 percent to reflect: (1) fewer environmentally sensitive processes; (2) greater cost sharing by foreign governments; (3) more "grandfathering;" and (4) in some lesser developed areas, lower levels of enforcement. There was no analysis of the financial ability of foreign refineries to meet regulatory costs. In some cases, the situation could be similar to that projected for U.S. refineries.

Oil product demand in some foreign regions is expected to grow. As a result, some new facilities will be required to meet increasing demand, which will result in higher cost for products that are exported to the United States. Table 7 shows the demands for the various for-

TABLE 6

HEALTH, SAFETY, AND ENVIRONMENTAL STANDARD COMPARISON (Percent of U.S. Regulation)

	Canada	Northwest Europe	Mediterranean	Pacific Rim	Middle East	Latin America
			1990 Regulation			
1990	75	75	50	0	0	0
1995	100	100	75	35	35	35
2000	100	100	100	70	70	70
2010	100	100	100	100	100	100
			Future Regulation			
1995	75-100	75-85	65-85	35-60	25-50	25-50
2000	100	100	85-100	60-80	50-75	50-75
2010	100	100	100	85-100	75-100	75-100

TABLE 7

WORLD OIL DEMAND* – BY REGION
(Million Barrels per Day)

	1989	1995			2000			2010		
		FC-I	FC-II	FC-III	FC-I	FC-II	FC-III	FC-I	FC-II	FC-III
Canada	1.7	1.8	1.8	1.8	1.9	1.8	1.7	1.9	1.8	1.6
NW Europe	8.9	9.4	8.9	8.9	9.5	9.0	8.8	9.6	9.1	8.8
Mediterranean/ North Africa	5.2	5.7	5.4	5.4	5.9	5.5	5.4	6.3	5.7	5.5
Middle East	3.1	3.7	3.5	3.5	4.2	3.7	3.6	5.1	4.0	3.7
Latin America	5.2	6.5	6.0	6.0	7.3	6.3	6.2	8.9	6.9	6.4
Pacific Rim	10.7	12.6	11.6	11.6	13.8	12.0	11.7	15.4	12.9	12.0
Total Modeled Regions	**34.9**	**39.6**	**37.2**	**37.2**	**42.6**	**38.3**	**37.4**	**47.2**	**40.4**	**38.1**
Africa (excluding North Africa)	1.0	1.2	1.2	1.2	1.4	1.2	1.2	1.7	1.3	1.2
USSR (Former)/ East Europe/ Other	10.2	8.2	8.2	8.2	9.5	9.5	9.5	11.6	11.6	11.6
China	2.3	2.7	2.7	2.7	3.1	3.1	3.1	3.7	3.7	3.7
United States	17.3	17.3	17.1	17.0	18.5	17.1	16.1	20.2	17.1	14.7
Total World Demand	**65.7**	**69.1**	**66.3**	**66.2**	**75.1**	**69.2**	**67.3**	**84.4**	**74.1**	**69.3**

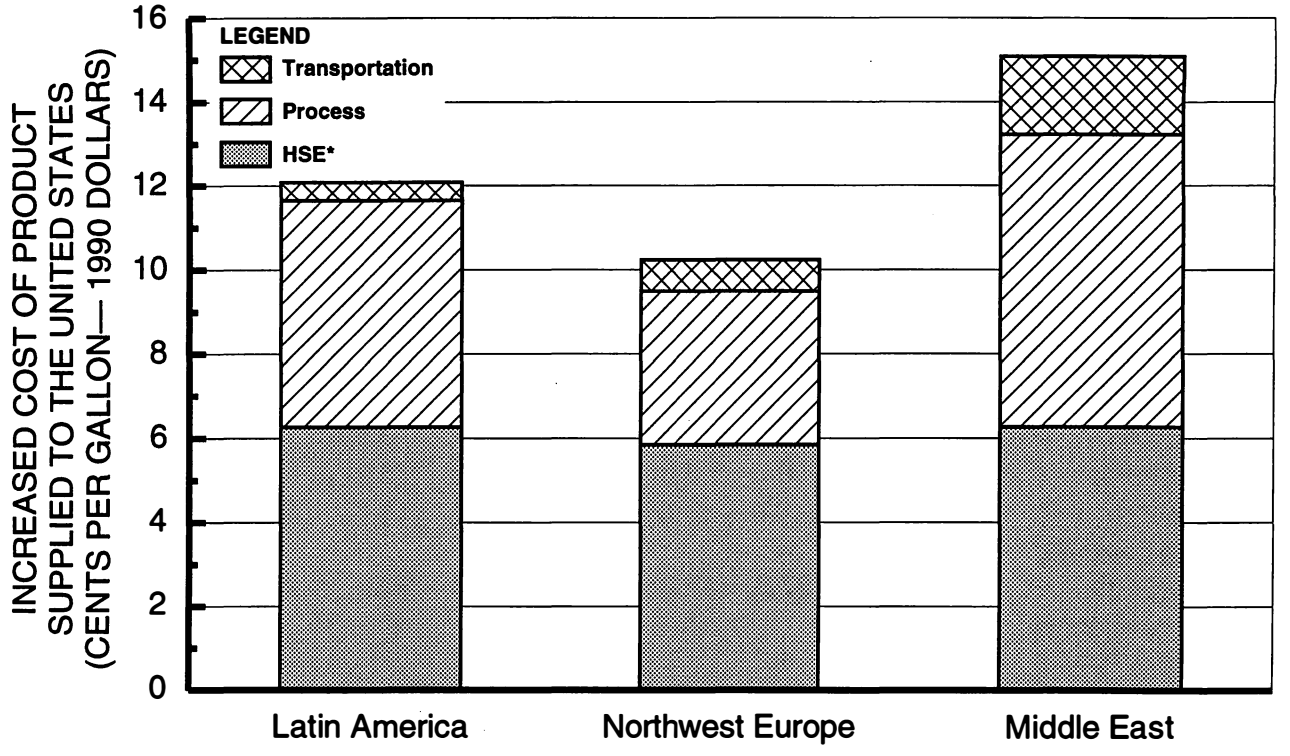
* Data may not add to totals due to independent rounding.

Note: FC-I = Foundation Case I – Growth in U.S. demand.
FC-II = Foundation Case II – No growth in U.S. demand.
FC-III = Foundation Case III – Decline in U.S. demand.

eign regions and the United States. Each foreign region is assumed to invest to maintain exports to the United States at 1989 levels. Thus, imports at historical levels reflect average cost increases rather than the higher cost increases associated with new capacity.

The total cost increase resulting from health, safety, and environmental regulation changes, process changes for capacity and product quality, and transportation impact each region differently. This analysis is based on both known laws and regulations and on projected environmental and product quality requirements. The EPA on-highway diesel fuel example shown in Figure 9 is indicative of the buildup of cost for every product in each foreign refining center for 2010. As can be seen in Figure 10, based on study assumptions, the sum of the foreign cost increases, excluding transportation costs, is similar to those expected in the United States. The U.S. cost increases are largely attributable to environmental requirements while foreign increases include a more significant capacity expansion component. The cost differences between the foreign regions and the U.S. regions vary in earlier study years, but the relationships are directionally the same.

The costs associated with unique California product qualities were not specifically analyzed on the assumption that the incremental costs of these products over EPA quality products would, on average, be the same



* HSE is health, safety, and environmental cost increase for fixed facilities.

Figure 9. Foreign Region Total Delivered Increase Cost EPA On-Highway Diesel Fuel—1989 to 2010.

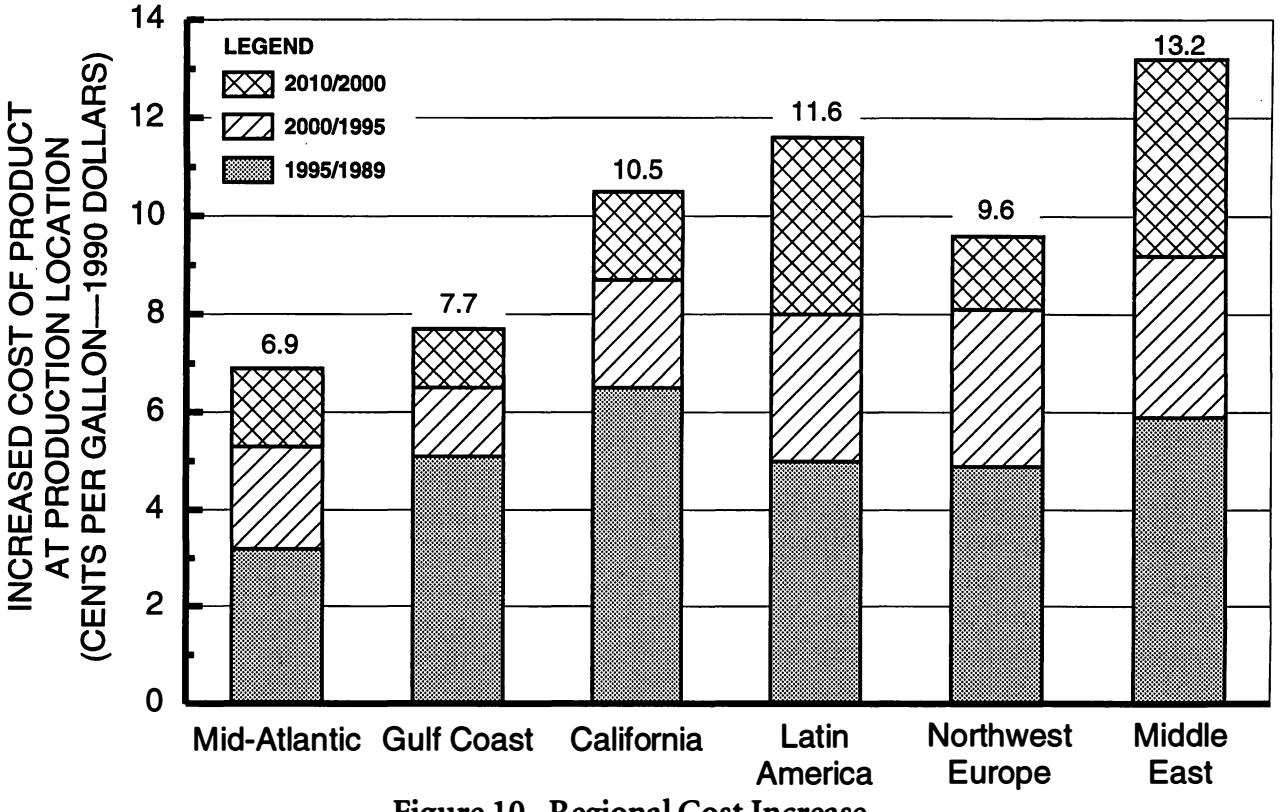


Figure 10. Regional Cost Increase EPA On-Highway Diesel—1989 to 2010.

in all production locations. This means that some volume of California product could be produced at some locations at lower cost.

The costs shown are regional averages. As with all average analyses, some individuals in the average will have lower costs. Consequently, some individual light product producers might have cost advantages at a given time.

In addition, this analysis is based on full recovery of fixed operating costs and a capital charge on new capital expenditures. The study does not address incremental cost analysis frequently used for day-to-day operating decisions.

Product Supply and U.S. Refinery Utilization

Evaluation of future oil product demand scenarios using expected foreign and U.S. product cost increases suggests that, if the required investments are made, the U.S. refinery complex will continue to supply most of the future U.S. light product demand. However, because of relatively flat U.S. demand through 1995 under all scenarios studied and increasing supply from oxygenate blending into gasoline, U.S. capacity utilization is lower in 1995 than in 1989, assuming no capacity shutdown. For later study years, capacity utilization changes consistent with projected demand conditions. Absent rationalization, the U.S. demand for light products is likely the most significant determinant of U.S. refinery capacity utilization.

Future supply patterns were evaluated for the United States in the context of three future demand scenarios. The purpose of this effort was to assess the possibility that U.S. light product market supply would move toward imports and away from output from U.S. refineries relative to the situation in 1989.

The demand scenarios were called Foundation Case I (growth in U.S. demand), Foundation Case II (no growth in U.S. demand), and Foundation Case III (decline in U.S. demand). Three Foundation Cases were used because NPC refining study participants realized that evaluation of a single demand projection would not effectively deal with the uncertainty that surrounds the future. Therefore, none of the Foundation Cases represent a consensus view of future U.S. product demand. The three projections are thought to represent a reasonable range of possible futures. These U.S. projections are summarized in Table 8. Since the inception of the study effort, additional projections for 1995 U.S. product demand have been made public. These projections, if used, would increase the 1995 light product demand range by several hundred thousand barrels per day. For example, the Foundation Case I projection is from the 1991 EIA Annual Energy Outlook. The 1993 Annual Energy Outlook projection is 500 thousand barrels per day higher, which represents a 3 percent higher refinery utilization rate. The directional results of the U.S. supply/demand analysis would not be affected by an increase of this magnitude.

The U.S. light product supply sources for the various Foundation Cases were evaluated by utilizing a mathematical representation of the U.S. light product logistics system. This necessarily required the assessment of anticipated changes in the cost of supplying both U.S. produced and foreign produced light products to U.S. demand centers. The assessment included cost changes for transportation and refinery products.

Transportation cost changes, including tariffs, were estimated by evaluating NPC refining study survey results and U.S. regulations concerning ocean transport of product imports as well as assessing existing and expected free trade arrangements with North American countries. The transportation cost increase in both waterborne and overland North American imports is associated with the application of more restrictive environmental regulations (double hulls for tankers and increased pipeline product segregations to handle more environmental grades of product are examples) relative to 1989. The impact of the free trade philosophy is to lower North American import costs by removing tariffs. The total transportation cost change is expected to be relatively small (less than 1 cent per gallon).

While transportation cost increases are expected to be small, cost increases for light

TABLE 8

UNITED STATES OIL DEMAND
(Million Barrels per Day)

	FC-I	FC-II	FC-III
1989			
Light Products *	12.0	12.0	12.0
Other Products	5.3	5.3	5.3
Total Products	**17.3**	**17.3**	**17.3**
1995			
Light Products *	12.1	11.9	11.8
Other Products	5.2	5.2	5.2
Total Products	**17.3**	**17.1**	**17.0**
2000			
Light Products *	12.8	11.9	11.4
Other Products	5.7	5.2	4.7
Total Products	**18.5**	**17.1**	**16.1**
2010			
Light Products *	14.2	11.9	10.4
Other Products	6.0	5.2	4.3
Total Products	**20.2**	**17.1**	**14.7**

* Light products equal the sum of motor gasoline, jet fuel, and distillate.

Note: FC-I = Foundation Case I – Growth in U.S. demand.
FC-II = Foundation Case II – No growth in U.S. demand.
FC-III = Foundation Case III – Decline in U.S. demand.

product from both U.S. and foreign refineries are expected to be substantial. Generally, this study projects that the total product cost increases for foreign refineries are of similar magnitude as those for U.S. refineries. This is true even though the health, safety, and environmental cost increases for refinery facilities are generally less than in the United States. Figure 11 indicates the magnitude of these effects for EPA on-highway diesel fuel (other products demonstrate similar cost impacts) for refineries in selected locations for 2000.

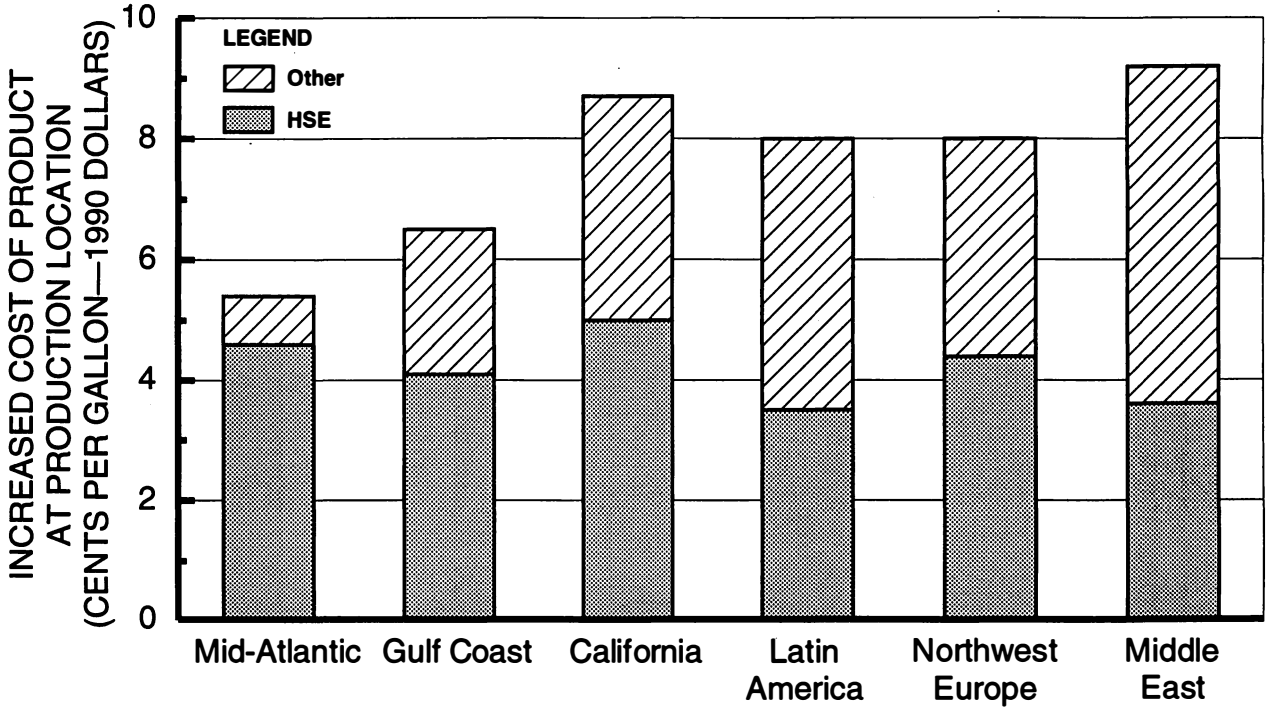
This study's assessment that the relevant calculated refinery cost increase by location coupled with the expectation that import transportation costs will be higher, leads to the realization that imports may be expected to play a decreasing role in U.S. light product supply. This is true assuming no significant change in the forces (other than future cost) that resulted in the balance in 1989 U.S. supply between imports and U.S. refinery output. The mathematical representation of the U.S. light product logistics system was used to verify this observation. The output from this effort is summarized in Figures 12 and 13. Exports were assumed to remain constant at 1989 levels. The depiction of imports shown in the figures should be viewed as a net import trend.

Figure 12 indicates that under Foundation Case I conditions, imports decline into the first decade of the next century as U.S. refinery output increases. After 2000, however,

U.S. refinery capability reaches effective capacity in locations where imports compete directly with U.S. produced products. At this juncture, imports begin to increase to meet the increase in demand. The availability of products from foreign refineries under these conditions results from changing refinery operations. No new refining capacity is built in the United States. New capacity is built in foreign areas to accommodate demand growth in those areas and maintain the historical level of exports to the United States. Economics do not support construction of new refining capacity in foreign areas specifically to supply just the United States.

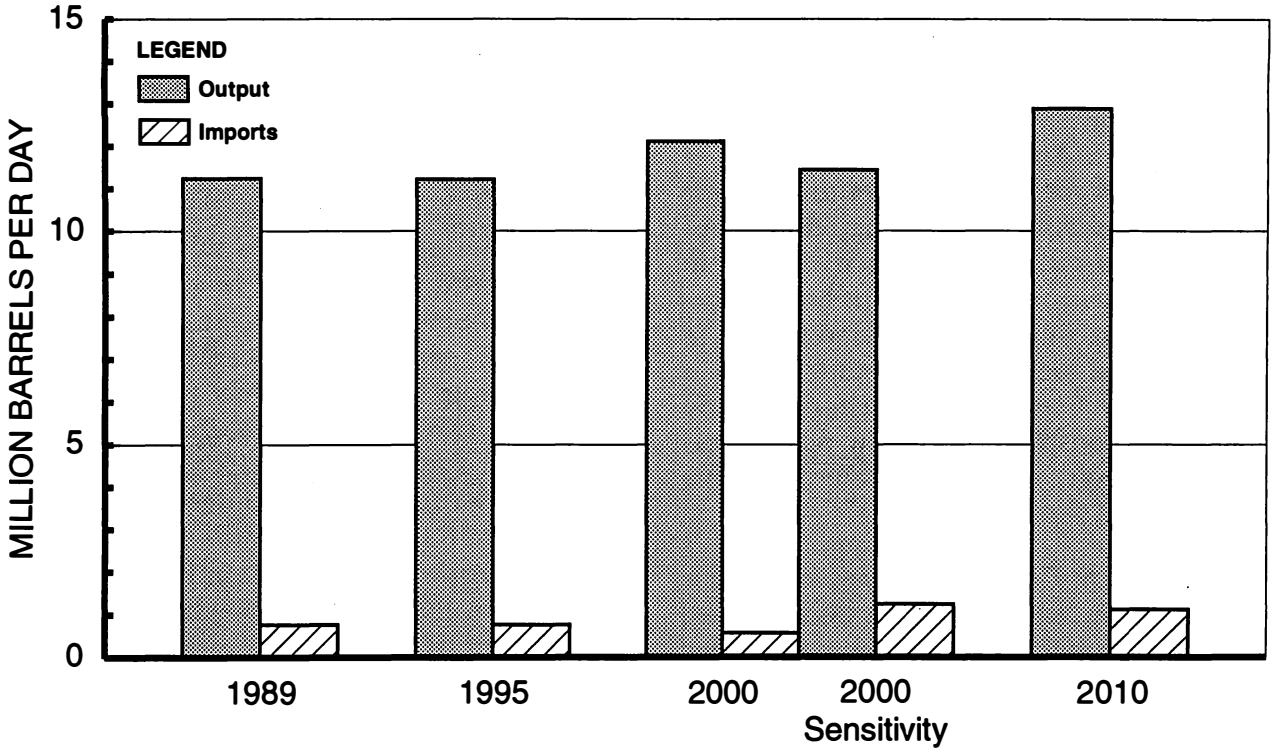
Foundation Case III was used to produce the results depicted in Figure 13. As indicated, imports decline to a minimum level after 2000. Ultimately there are insufficient product imports to be displaced as U.S. product demand declines and hence, U.S. refining output absorbs the decline with associated utilization reduction. There is no reason to believe that imports will cease altogether; rather it is expected that a minimum level will be reached. In this scenario, reduced light product utilization could lead to more than 2 million barrels per day of spare light product capability. The analysis was not structured to evaluate the opportunity for additional U.S. product exports.

The results were tested by evaluating a 2000 scenario that resulted in a substantially smaller cost increase for foreign product relative to U.S. product (-2.8 cents per gallon). The resulting foreign product cost increases are about two-thirds of those in the United States. In this situation, U.S. light product refinery output in 2000 under Foundation Case I conditions is 11.4 million barrels per day (89 percent of U.S. supply), which is down from the 12.1 million barrels per day (94 percent of U.S. supply) estimated under unadjusted Foundation Case I cost conditions. Similarly, U.S. refinery utilization drops from 88 percent to about 83 percent in 2000. These 2000 light-product output estimates compare with 1989 at 11.2 million barrels per day (94 percent of U.S. supply). This sensitivity case resulted in an indicated



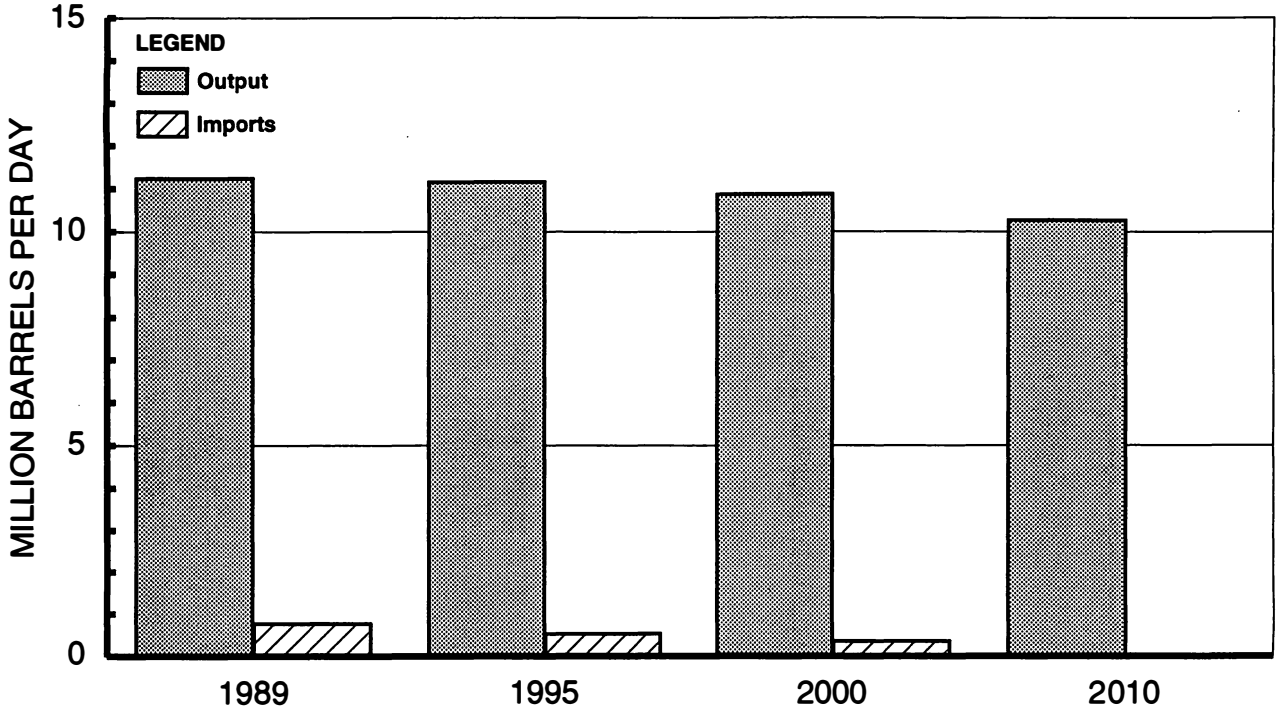
HSE is health, safety, and environmental cost change for fixed facilities.

Figure 11. Regional HSE and Other Cost Increases EPA On-Highway Diesel Fuel—1989 to 2000.



Light product is motor gasoline, jet fuel, and distillate.

Figure 12. U.S. Light Product Supply—Foundation Case I (Growth in Demand).



Light product is motor gasoline, jet fuel, and distillate.

Figure 13. U.S. Light Product Supply—Foundation Case III (Decline in Demand).

import increase of 700 thousand barrels per day. The results can be seen on Figure 12. The effects would have been similar under the other demand scenarios.

There is concern for the economic health of the U.S. refinery complex in that spare capability often leads to rationalization. No specific analysis of rationalization was undertaken. However, evaluating capability utilization can suggest the situations under which rationalization might occur.

The results of the analysis for the various Foundation Cases are shown in Table 9. Without rationalization, U.S. refinery utilization is expected to decline from 86 percent in 1989 to about 83 percent in 1995. In later years, 2000 and 2010, U.S. refinery utilization is strongly affected by U.S. light product demand.

In scenarios where U.S. refinery output decreases because demand declines (Foundation Case III) or where lower cost of foreign product increases imports, pressure will increase to rationalize refining capacity. If there is no growth in U.S. demand (Foundation Case II), the use of oxygenates to produce reformulated and oxygenated gasolines also reduces U.S. refinery utilization and increases the pressure for rationalization. In contrast, growth in U.S. demand (Foundation Case I) increases refinery utilization and reduces the pressure for rationalization.

TABLE 9

U.S. LIGHT PRODUCTS *
REFINERY OUTPUT — REFINERY CAPABILITY
(Million Barrels per Day)

	1989	1995			2000				2010		
		FC-I	FC-II	FC-III	FC-I	FC-IES	FC-II	FC-III	FC-1	FC-II	FC-III
Output	11.2	11.2	N/A	11.2	12.1	11.4	N/A	10.9	12.9	11.6	10.3
Capability†	13.1	13.5	13.5	13.5	13.8	13.8	13.8	13.8	13.8	13.8	13.7
Utilization	86%†	83%	N/A	82%	88%	83%	N/A	79%	93%	84%	75%

* Light Products = motor gasoline, jet fuel, and distillate.

† Operable capacity is derived from 1989 U.S. refinery operable crude oil capacity and crude oil input as reported by the Energy Information Administration equaling a utilization rate of 85.6 percent, which is rounded to 86 percent in the table. It is assumed that 1989 light product operable capability is directly related to this utilization and is calculated at 13.1 million barrels per day. Capability is increased in 1995 by 0.1 million barrels per day of announced U.S. refinery additions plus 0.3 million barrels per day of oxygenate blended in refineries. After 1995, capability changes reflect changes in refinery blending of oxygenate.

N/A = Not analyzed.

FC-IES = Environmental Sensitivity Case. Also represents other cost sensitivities.

CHAPTER ONE

FINANCIAL ANALYSIS

INTRODUCTION AND SUMMARY

Purpose and Conclusion

The purpose of this chapter is to summarize the financial implications of the regulatory mandates on the U.S. refining industry. It puts the size of the required capital expenditures into perspective—they are large in both absolute size and relative to the industry as it started the decade of the 1990s. The analysis estimates how the capital might be supplied for these requirements. The approach uses financial data gathered by the U.S. government to provide a historical basis for comparison.

From the findings and analysis presented in this chapter, the following conclusion was reached:

> Projected U.S. refining capital expenditures of $37 billion (1990 dollars) in the 1991-2000 period for product quality and stationary source regulatory compliance exceed the total net fixed asset base ($31 billion) of U.S. refineries at the start of this period. About two-thirds of the capital expenditures are projected to be made in the 1991-1995 period. Assuming all operating expenses (including depreciation) are recovered, cash flow generated during the 1991-1995 period is still on the order of $25 billion less than the required capital expenditures.
>
> Product revenue increases will be necessary to recover operating expenses and to provide competitive returns on the capital employed. The projected cost increase in 2000 for regulatory compliance is more than twice the U.S. refining, marketing, and transportation industry's historical average net income in the 1980s. Given the projection of declining refinery utilization through 1995, recovery of these costs will be difficult until capacity and demand are rebalanced by further capacity shutdowns and/or increased product demand.

Findings

Refining Capital Expenditures

The U.S. refining industry will make very large capital expenditures to meet government regulations through 2010. Refineries are expected to invest $37 billion (1990 dollars) over the period of 1991-2000 and $14 billion more in 2001-2010, assuming no rationalization of capacity (see Table 1-1). The impact of these investments will be to increase the amount of capital employed to deliver a gallon of product. The cumulative capital expenditures will be greater than the industry's total 1990 accounting category of net property, plant, and equipment (after depreciation), $31 billion (then current dollars).

TABLE 1-1

U.S. REFINING CAPITAL EXPENDITURES
(Billions of 1990 Dollars)

	1981-1990	1991-2000	2001-2010
Environmental, Health, and Safety Stationary Source Facilities			
Pollution Abatement – Reported*	6.1	—	—
Stationary Facilities – NPC Estimates	3.9	22.8	13.5
Subtotal Stationary Source Facilities	**10.0**	**22.8**	**13.5**
Refinery Process Facilities			
Product Quality	†	13.7	NS
Process Additions & Replacement	37.5	18.3	15.0
Total Capital Expenditures	**47.5**	**54.8**	**28.5**
Memo:			
Total Regulatory Compliance Expenditure	N/A	36.5	13.5
% Stationary Source Facilities	21%	42%	47%
Average Refining Capacity, Million Barrels per Stream Day	16.7	16.5	16.5
Capital Expenditures, $/Daily Barrel of Capacity	2,840	3,320	1,730

* From U.S. Department of Commerce, MA-200.

† 1981-1990 product quality facilities included in process additions and replacement.

Note: NS = Not Studied. N/A = Not Available.

The capital expenditures for environmental facilities for refinery stationary sources will increase as a share of total expenditures. During the 1980s, according to the Department of Commerce data and study estimates, refineries spent $10 billion (1990 dollars) on pollution abatement equipment, or 21 percent of their total capital expenditures. In contrast, the study projection for the 1990s is $23 billion or 42 percent of expected total refinery capital expenditures in 1991-2000 and $14 billion or 47 percent in 2001-2010. These mandated expenditures do not increase the economic efficiency of the refinery (i.e., they are not justified by increasing the value of product, lowering costs of operation, or increasing volume of output); rather, they add another layer of cost to products offered in competitive markets. All other things being equal, they reduce the demand for products.

In addition to the fixed facilities requirements, this study has projected that about $14 billion (1990 dollars) will be spent during 1991-2000 for refinery processing facilities to produce the new reformulated products specified by the 1990 Clean Air Act Amendments and other regulations. Capital expenditures for other refinery process additions and for the ongoing replacement of existing equipment are projected to total some $18 billion in 1991-2000.

The current five-year period (1991-1995) has the largest portion of the environmental capital expenditures, almost $24 billion. This, coupled with the industry's 1991-1992 financial performance, the lowest returns in over a decade, may result in the closing or downsizing of refineries that would otherwise be economic in the longer run.

Financial Performance

The objective of this section was to develop a reasonable cash flow projection and appraise what the financial position of the refining industry would be assuming the regulatory related capital expenditures are made. The Energy Information Administration's Financial Reporting System (FRS) for large energy companies provides the most extensive financial information with sector breakdowns. This study uses historical data gathered by the EIA on large energy companies as representative of industry performance. These firms operate 69 percent of the U.S. refining capacity in facilities of varying size and transport nearly 75 percent of petroleum pipeline throughput. Although the FRS data start in 1974, 1981 was selected for the start of the comparison period since it commenced after the end of petroleum price controls.

The FRS has extensive data on the downstream petroleum operations (refining, marketing, transportation). Earnings of the refining sector, alone, are not available. The EIA has recognized the inherent difficulties in separating refining and marketing performance because of inconsistent pricing of product transferred between the two. Petroleum pipelines present a similar problem. For these reasons, the EIA's information on the combined refining, marketing, and petroleum transportation (RMT) activities was used in projecting financial performance. The RMT sector performance was used in calculation of cash flow by incorporating historical capital expenditures for the marketing and transportation sectors, plus the refining capital expenditures developed by this study.[1]

The FRS companies' RMT business segment (proxy for the refining industry) average net income before interest was equal to about 2.3 cents per gallon (cpg) (then current dollars) of all products (about 3 cpg of light products) refined from 1981 through 1990. The return on investment [ROI – defined as net (after tax) income before interest divided by net investment in place][1] during this time period was 8.8 percent and net cash flow[1] was a negative $3.7 billion. Over the decade of the 1980s, net income was below average from 1981 to 1984, but above average in 1988 and 1989. Capital expenditures were high in 1981 and 1982 because of processing additions started in the late 1970s. There was a sharp decline in refinery capacity because of the shutdown of many uneconomic facilities. The negative cash flows of 1981 to 1984 were largely offset by 1985 to 1989 performance, but 1990 and 1991 turned sharply negative. The study's estimates of 1992 performance are lower than the results of 1991.

If the FRS companies have the same annual RMT net income for the 1993-2000 forecast period as they had in the 1980s, their cumulative net cash flow for the ten years (1991-2000) would be a negative $25 billion and their average ROI would be 5.7 percent. Because of the concentration of capital expenditures in the 1991-1995 period, cumulative net cash flow for the five years would be a negative $22 billion and the average ROI would be 5.3 percent. Extending this analysis of FRS companies to the entire U.S. industry, cumulative net cash flow for the 1991-2000 period would be a negative $37 billion. The bulk of this amount, $31 billion, would come in the 1991-1995 timeframe. The return on investment in each period would be the same as discussed above. (See text box "Total Industry Cash Flow," later in the chapter.)

If the industry earns the historical (base) net income level plus the return on new capital expenditures premised in the following chapters of this report, then net income would increase to the equivalent of 3.1 cpg on all products. The average ROI for 1991-2000 would be 7.1 percent and net cash flow would be a negative $13 billion. Average net income would need to increase to 3.8 cpg on all products to balance cash flow for the decade and earn the 8.8 percent average ROI of the 1980s.

Consumer Costs

The increased costs to the consumer result from four categories of expenditures necessary

[1] Cash flow projections and return on investment presented here are in then current dollars consistent with report data for FRS companies' refining, marketing, and transportation business segments.

to meet regulations—specific products (e.g., reformulated gasoline), logistics operations, marketing operations, and stationary refinery emission controls (e.g., air emissions, waste water, etc.). This study assumes that most of the cost recovery will be from light products (gasoline, jet fuel, and distillate) because there are limited or no short-term substitutes for these products. Figure 1-1 illustrates how costs to the consumer are allocated in this study. The total consumer costs for light products (including fuel economy effects) are projected to increase by an average of 6 cpg (1990 dollars) in 1995, 11 cpg in 2000, and 13 cpg in 2010 (Table 1-2).

No explicit estimate has been made of the impact of the increase in consumer cost on demand. Rather, as detailed in Chapter Three, two demand cases were assumed to provide an adequate envelope of demand (with an additional, intermediate case). The impact of added cost can be expected to reduce demand below where it would be otherwise.

Implications

The need for environmental capital expenditures is greatest in the 1991-1995 period. Announced additions to refineries, displacement of refinery stocks with mandated oxygenated blendstocks, and weak demand will decrease the utilization of refineries relative to the 1989 situation. With added expenses, the implication is clear—facilities with higher than average costs and/or higher than average environmental expenditures in this period will be among the first candidates for reducing or ceasing operations. Industry's utilization will increase if such plants exit from service. With increased utilization, the prospects for recovering environmental expenditures in the marketplace should improve.

COSTS OF REGULATION

The primary focus of this study is on capital expenditures which are long-term commitments. This section summarizes the projections developed in the later chapters for capital expenditures over the study period, 1991 to 2010. In addition, the section provides estimates of the annual costs which are on the same basis as the historical data collected by the Department of Commerce on pollution abatement.

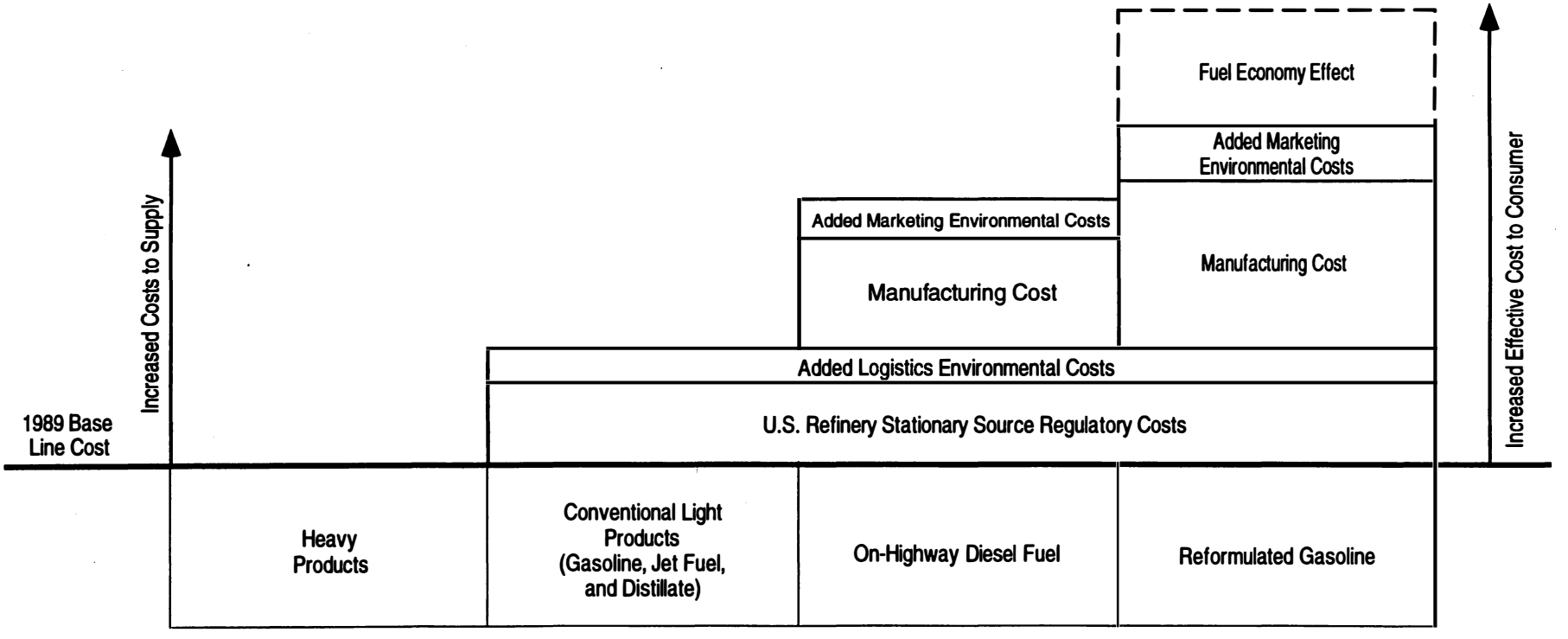
Projected Capital Expenditures

The study forecast of refinery capital expenditures for environmental and other regulations are divided into two basic categories, stationary source emissions control facilities and processing additions for product quality changes for the new reformulated fuels. These expenditures are summarized in Table 1-3 and Figure 1-2, and are detailed on a yearly basis in Appendix J, Table APP.J.II-1 (also, Figure APP.J.II-1).

TABLE 1-2

ESTIMATED INCREASED ANNUAL COSTS TO CONSUMERS (Billions of 1990 Dollars)

	1995	2000	2010
Stationary Source Facility Costs	4.7	8.2	11.8
Product Quality Manufacturing Costs	2.9	6.8	6.8
Logistics and Marketing	2.6	3.1	3.1
Total Direct Costs	**10.2**	**18.1**	**21.7**
Fuel Economy Effect (indirect)	0.8	1.8	1.8
Total Costs to Consumer	**11.0**	**19.9**	**23.5**
Average Cost Increase of Light Products, cents per gallon	6	11	13



California low aromatics diesel fuel and Phase 2 reformulated gasoline are significantly more costly.

Figure 1-1. Total Regulatory Costs to Consumers.

TABLE 1-3

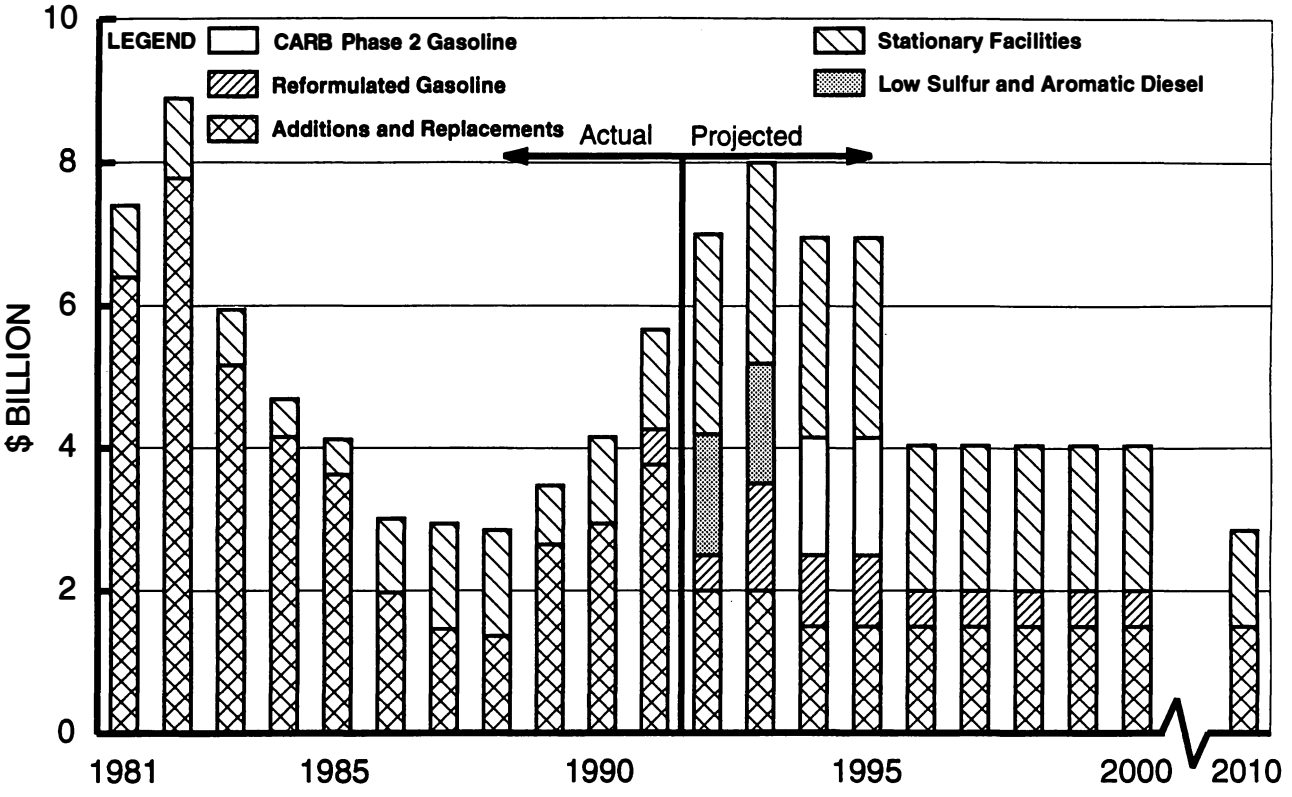
U.S. REFINING CAPITAL EXPENDITURES
(Billions of 1990 Dollars)

	1981-1985	1986-1990	80s Total	1991-1995	1996-2000	90s Total	2001-2010
Environmental, Health, & Safety							
Stationary Source Facilities							
Pollution Abatement – Reported*	3.2	2.9	6.1	—	—	—	—
Stationary Facilities – NPC Estimates	0.8	3.1	3.9	12.6	10.2	22.8	13.5
Subtotal Stationary Source Facilities	**4.0**	**6.0**	**10.0**	**12.6**	**10.2**	**22.8**	**13.5**
Refinery Process Facilities							
Product Quality	†	†	†	11.2	2.5	13.7	N/S
Process Additions & Replacement	27.1	10.4	37.5	10.8	7.5	18.3	15.0
Total Capital Expenditures	**31.1**	**16.4**	**47.5**	**34.6**	**20.2**	**54.8**	**28.5**
Memo:							
Total Regulatory Compliance Expenditure	N/A	N/A	N/A	23.8	12.7	36.5	13.5
% Stationary Source Facilities	13%	37%	21%	36%	51%	42%	47%
Average Refining Capacity, Million Barrels per Stream Day	17.1	16.3	16.7	16.5	16.5	16.5	16.5
Capital Expenditures, $/Daily Barrel of Capacity	1,870	960	2,840	2,100	1,220	3,320	1,730

* From U.S. Department of Commerce, MA-200.

† 1981-1990 product quality facilities included in process additions and replacement.

Note: NS = Not Studied. N/A = Not Available.



Historical Values taken from Department of Commerce report MA—200. No survey taken in 1987.
Value shown is 1986 and 1988 average.
CARB = California Air Resources Board.

Figure 1-2. U.S. Refining Industry Capital Expenditures (1990 Dollars).

Capital expenditures for stationary source facilities are forecast to total $22.8 billion (1990 dollars) in 1991-2000 and $13.5 billion in 2001-2010. This compares with the $10.0 billion identified by the Department of Commerce report and the study estimates for 1981-1990.

Capital expenditures for product quality total $11.2 billion in 1991-1995 and $2.5 billion in 1996-2000. This does not include about $10 billion of MTBE (methyl tertiary butyl ether) or other oxygenate manufacturing capacity that is projected to be built outside of refineries. The cost of oxygenate used in the calculation of product costs for reformulated gasoline (RFG) includes the recovery of capital.

Product quality capital expenditures are those premised by the study to enable the U.S. refining industry to produce the amounts of reformulated products as specified in the 1990 Clean Air Act Amendments. Products include oxygenated gasoline for carbon monoxide nonattainment areas starting in November 1992, ultra-low sulfur diesel fuel for all on-highway use by October 1993, California low aromatics diesel fuel by 1993, Phase I reformulated gasoline in nine ozone nonattainment areas by 1995, California Air Resources Board (CARB) Phase 2 gasoline in California by 1996, and federal Phase II RFG for all of ozone nonattainment and opt-in areas by the year 2000. Details of each of these programs are described in Chapter Four and its appendices.

Annual Costs

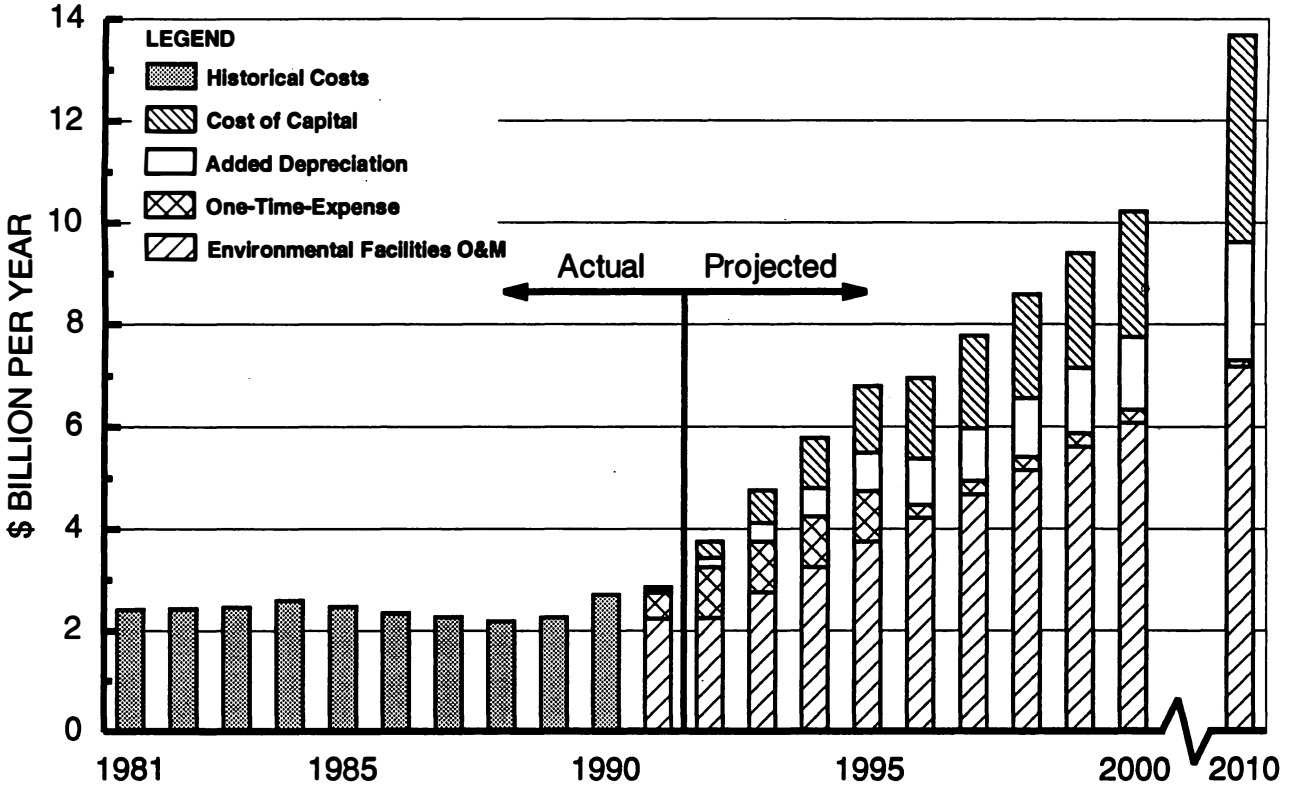
Besides the capital expenditures projected for stationary facilities, the study has identified increases in operating and maintenance (O&M) expenses, emissions reductions program costs, and one-time expenditures (OTE) that are projected to be required for regulatory compliance. Details are provided in Chapter Two, U.S. Refining Stationary Source Facilities. The study projects that by 1995, $3.7 billion per year of O&M expenses with about $1 billion per year in OTE will be required. By the

year 2000, the forecast O&M expenses total $6.1 billion per year, with OTE at about $0.3 billion per year (Figure 1-3 and Table APP.J.II-2).

The Department of Commerce report MA-200[2] measures Gross Annual Costs for pollution abatement using a definition similar to the above (see Appendix J.II-1 for discussion). One known difference is that depreciation on environmental equipment is included in the Department of Commerce survey, but was not in the study estimates. The MA-200 survey has measured an increase in Gross Annual Costs from $2.4 billion per year (1990 dollars) in 1981 to $2.8 billion in 1991. The study's forecast expenses, with depreciation added for consistency with the historical results, would result in Gross Annual Costs of $5.5 billion per year in 1995 and $7.8 billion by the year 2000 (see Figure 1-3). For this study these costs, along with the cost of capital for the capital expenditures, are allocated to all light products. On that basis, the added costs above a 1989 base would be 2.6 cpg in 1995 and 4.5 cpg in the year 2000 (Figure 1-4).

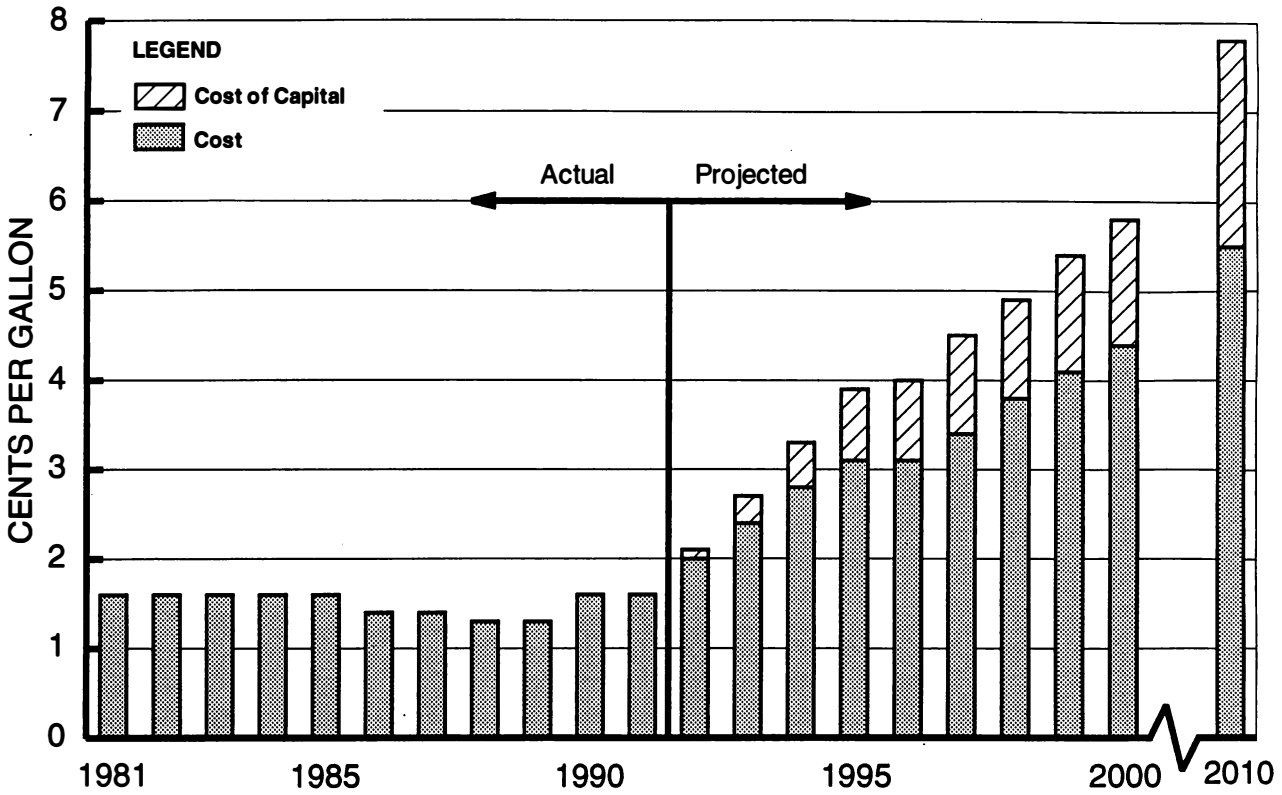
Added product quality costs for RFG and ultra-low sulfur diesel fuel can similarly be expressed as gross annual amounts. Beginning in October 1993, ultra-low sulfur diesel fuel is required for all on-highway use nationwide, and California additionally requires low aromatics diesel fuel. Including the capital charge, these products would cost $1.3 billion per year more than conventional diesel fuel. By 1995, Phase I RFG will be required in the worst nine ozone nonattainment areas, with costs of $1.6 billion per year more than conventional gasoline. In California, CARB Phase 2 gasoline will cost an additional $2 billion per year beginning in 1996. By the year 2000, the added cost of Phase II reformulated gasoline and the premised use of RFG in all ozone nonattainment areas outside of California is $3.5 billion

[2] See Appendix J for discussion of historical expenditures as reported by the Department of Commerce and other sources.



Historical costs for 1981-1991 taken from Department of Commerce report MA—200 do not include cost of capital. No survey was taken in 1987—value shown is 1986 and 1987 average. Cost of capital equivalent to 10 percent discounted cash flow rate of return after 1991 is shown for the projected new environmental capital expenditures.

Figure 1-3. Stationary Source Costs for U.S. Refinery Facilities (1990 Dollars).



Historical costs for 1981-1991 taken from Department of Commerce report MA—200 do not include cost of capital. Forecast costs include cost of capital sufficient for a 10 percent discounted cash flow rate of return.

Figure 1-4. U.S. Refinery Facilities Stationary Source Costs Cents per Gallon, Gasoline, Jet Fuel, and Distillate (1990 Dollars).

per year. As shown in Figure 1-5, the total of these product quality cost increases reaches $6.8 billion per year by 2000. (Details in Appendix J, Table APP.J.II-3.)

The capital expenditures described here are the starting point for analysis of the financial impact of regulations on the U.S. refining industry. With a measure of historical performance, the study projects the financial situation of the industry under alternative assumptions. The next section provides the historical financial data that were used in the analysis.

INDUSTRY FINANCIAL BACKGROUND

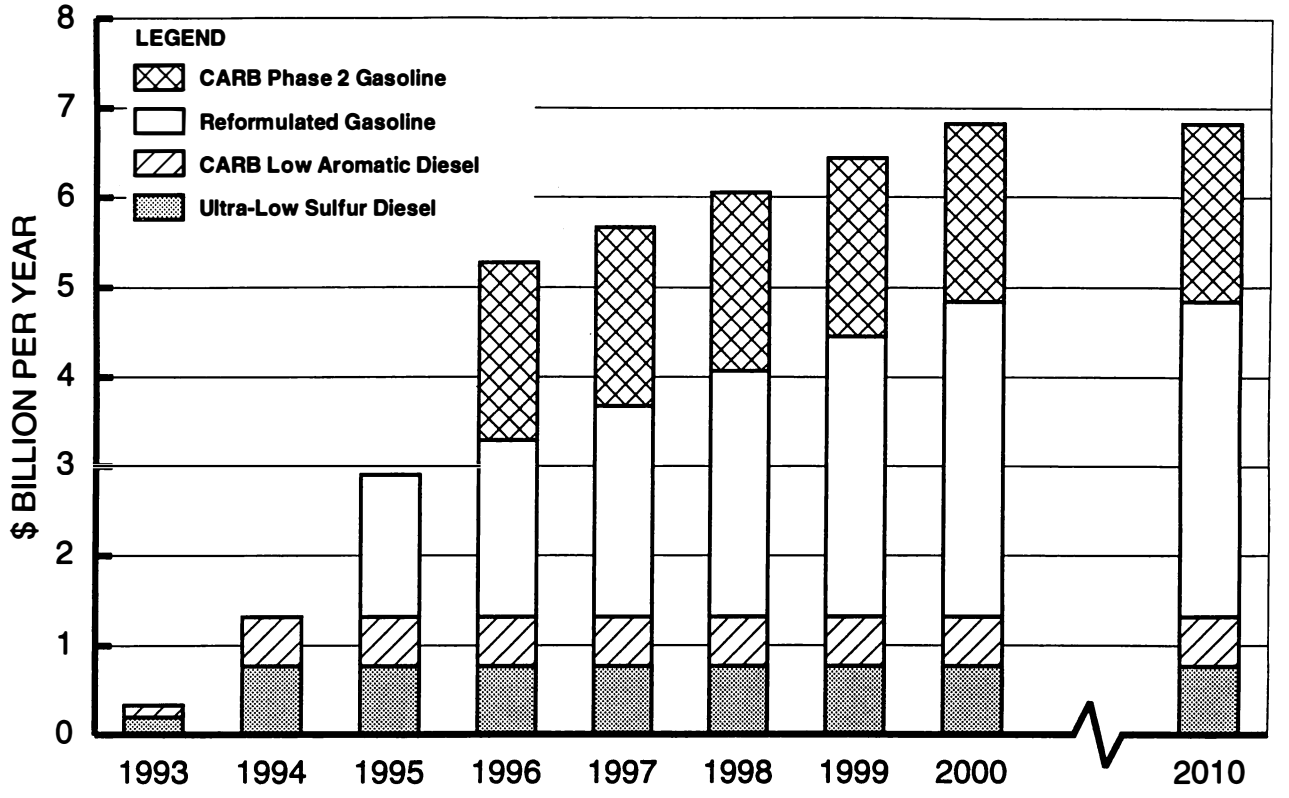
Introduction

A primary issue for the viability of the U.S. refining industry concerns the standing of the industry in the capital markets. That is, will the industry's prospective profitability and cash flow from operations be sufficient to finance the capital expenditures attending increased environmental requirements? To assess the refining industry's ability to finance future capital expenditures, this section reviews the past performance of the industry. The performance of the industry, as presented in comparative analysis below, has generally been below that registered by broader aggregates of activity such as the other operations of major petroleum companies or the Standard and Poor's 400 industrial companies (excluding energy concerns). In the next section, cash flow and profitability are projected for the remainder of the decade in light of recent trends in financial performance. The following section develops the historical basis of performance.

Historical Performance Data Sources[3]

Accurate historical financial data of refinery activities on which to base analysis are

[3] This section, dealing with financial performance, uses then current (as opposed to constant 1990) dollars.



Includes cost of capital on new capital expenditures at 10 percent discounted cash flow rate of return.
CARB = California Air Resources Board.
1993, 1994 oxygenated gasoline costs not developed.

Figure 1-5. U.S. Refinery Product Quality Cost Increases (1990 Dollars).

available from 1974 with the development of the Energy Information Administration's Financial Reporting System. An overview of the FRS is presented in the text box ("Application of the Financial Reporting System Data") and Appendix J.III-1 provides a detailed description of the FRS reporting structure. The FRS covered 69 percent of the industry's capacity in 1992. Key points concerning the FRS data used in this chapter include:

- Collection of financial data on a uniform, segmental basis is unique to the FRS and allows accurate comparisons of financial results across energy lines of business and over time.
- The FRS covers the 1974-1991 period. In 1991, 19 of the 23 FRS respondents had U.S. refining operations, accounting for 69 percent of U.S. refining capacity (Table 1-4).
- The FRS provides an income statement for the U.S. refining/marketing business segment and regulated pipelines, which are combined in order to minimize any problems of data interpretation arising from transfer pricing and to make the presentation closer to the segmental reporting practices found in companies' annual reports to shareholders.
- FRS reporting requires that segmental net income be net of taxes but not include an allocation of interest expense. Here for the purposes of cash flow analysis, interest expense was allocated to the U.S. RMT segment on the basis of fixed assets, and dividends were allocated on the basis of contribution to overall cash flow (see text box "Estimating Historical Sector Cash Flow").
- The FRS provides segmental values for fixed assets and capital expenditures. Profitability is measured by return on investment, which is defined as the ratio of segmental net income to segmental net

investment in place (depreciated property, plant, and equipment, plus investments and advances to unconsolidated subsidiaries).

Unlike the rest of this report, the analysis in this section uses current dollar values rather than inflation-adjusted (real) values. No reasonable method for converting the overall asset values of the FRS companies into 1990 dollars was available. Consequently, ROI, a key indicator of financial performance, can be measured only on a then current dollar basis. Appendix J, Table APP.J.III-1 also reports segmental net income in 1990 dollars.

The list of FRS companies is a matter of public record, as are the financial results from these publicly owned firms. On the basis of quarterly press releases of 1992 earnings, this study estimated a contribution to net income from the RMT business segment of $1.5 billion, or 0.9 cpg of refinery output. This estimated performance in 1992 was not used in the projections of earnings for the future but did affect the projected financial condition of

Application of the Financial Reporting System Data for Analysis of the U.S. Refining Industry

Pursuant to Section 205(h) of the Department of Energy Organization Act, which established the Energy Information Administration's Financial Reporting System (FRS), the Energy Information Administration, through its Form EIA-28, collects financial information and other measures of energy-related business efforts and results for U.S.-based major energy companies. Since the FRS data are collected on a uniform, segmented basis, the comparability of information across energy lines of business is unique to this reporting system. For example, petroleum activities can be compared to activities in other energy lines of business or nonenergy areas, and domestic activities can be compared to foreign activities. Annually, the report *Performance Profiles of Major Energy Producers* presents data collected on Form EIA-28 and analyses of financial performance based on these data. The FRS data are for the period 1974 through 1991.

In 1991, 23 major energy companies filed Form EIA-28. Nineteen of the companies had U.S. refining operations and, in 1992, accounted for 69 percent of U.S. refinery output. Appendix J, Section III, provides a list of FRS companies and a detailed description of the FRS structure.

Of particular usefulness for the purposes of this report is the FRS U.S. refining/marketing segment. For this line of activity, the FRS provides an income statement, a detailed presentation of refined product revenues and sales volumes by product categories, a disaggregation of operating expenses, the value of fixed assets, capital expenditures, and associated refining and marketing statistics. The FRS format also contains a business segment for regulated pipelines. Financial data for pipelines (excluding natural gas transmission) are combined with the U.S. refining/marketing segment in order to make the presentation closer to the segmental reporting practices found in companies' annual reports.

The analysis in this chapter makes substantial use of the FRS segmental net income measure. Segmental net income is similar to overall corporate net income except that certain corporate-level items are not allocated to the business segments. The largest unallocated item is interest expense. That is, segmental net income excludes interest expense but is net of income tax expense. Profitability is measured by return on investment, which is defined as the ratio of segmental net income to book value of net property, plant, and equipment, plus investments and advances. Capital expenditures are measured by additions to property, plant, and equipment.

TABLE 1-4

OPERATING CRUDE OIL DISTILLATION CAPACITY OF FINANCIAL REPORTING SYSTEM REFINERS — JANUARY 1, 1993 (Thousands of Barrels per Day)

Chevron	1,281	Amerada Hess†	400
Exxon	1,177	Ashland Oil	347
Amoco	979	Texaco	330
Shell Oil	973	Phillips Petroleum	305
Mobil	903	Coastal	218
BP America	747	Unocal	234
USX (Marathon)	620	Fina	199
Sun*	600	Total Petroleum	198
Atlantic Richfield	448	Kerr-McGee	155
Du Pont (Conoco)	422	**Total FRS**	**10,535**

Unconsolidated 50-50 Joint Ventures:‡	
Star Enterprise (Texaco/Aramco)	615
Uno-Ven (Unocal/Petroleos de Venezuela)	147
Pacific Refining (Coastal/Sinochem)	55
Total Joint Ventures	**817**

* Includes Puerto Rico.

† Includes U.S. Virgin Islands. The NPC study did not develop costs for the refineries in Puerto Rico or the Virgin Islands.

‡ Unconsolidated joint ventures are not included in Financial Reporting System (FRS) statistics.

Source: Energy Information Administration, *Petroleum Supply Annual 1992*, Volume 1.

the FRS companies' balance sheets at the outset of the forecast period.

Comparative Profitability

The capital markets consist of many corporations and would-be borrowers, and even within an integrated petroleum company, refining activities must compete with other business segments for financing. How did the RMT segment fare in relation to other competitors in the capital markets? Within the context of the FRS companies' many diversified business activities, the RMT segment was clearly a lesser performer in the first half of the 1980s (Figure 1-6). This was a period of large reductions of refinery crude oil distillation capacity (see Figure 1-7) with higher capital expenditures (see Figure 1-8) for upgrading directed to retained facilities. The RMT segment's ROI was below that of the combined total of the rest of the FRS companies' businesses in nearly every year over the 1981-1985 span.

Subsequently, the profitability of the FRS companies' upstream business (exploration, development, and production) was severely impacted by the oil price collapse in 1986 and its aftermath. However, sharply lower oil prices led to lower refinery input costs, which translated into lower petroleum product prices and increased demand. In this period, the light

to heavy crude oil price differential widened, and increased light product demand improved the return on investments for refinery upgrading. Cheaper, lower quality crude oils were increasingly being processed into lighter, higher value products. The RMT segment's ROI improved and generally exceeded the overall profitability of the other FRS business segments until 1990. Weakness in the U.S. economy followed by recession and flat economic growth reduced the demand for petroleum products, resulting in narrowing the spread between refined product prices and crude oil input costs. At the same time, RMT operating expenses were rising, due in part to increased environmental standards. The results were a sharp falloff in RMT profitability, beginning in 1990 and continuing through 1992, and a widening gap in comparison with the overall performance of the FRS companies' other lines of business.

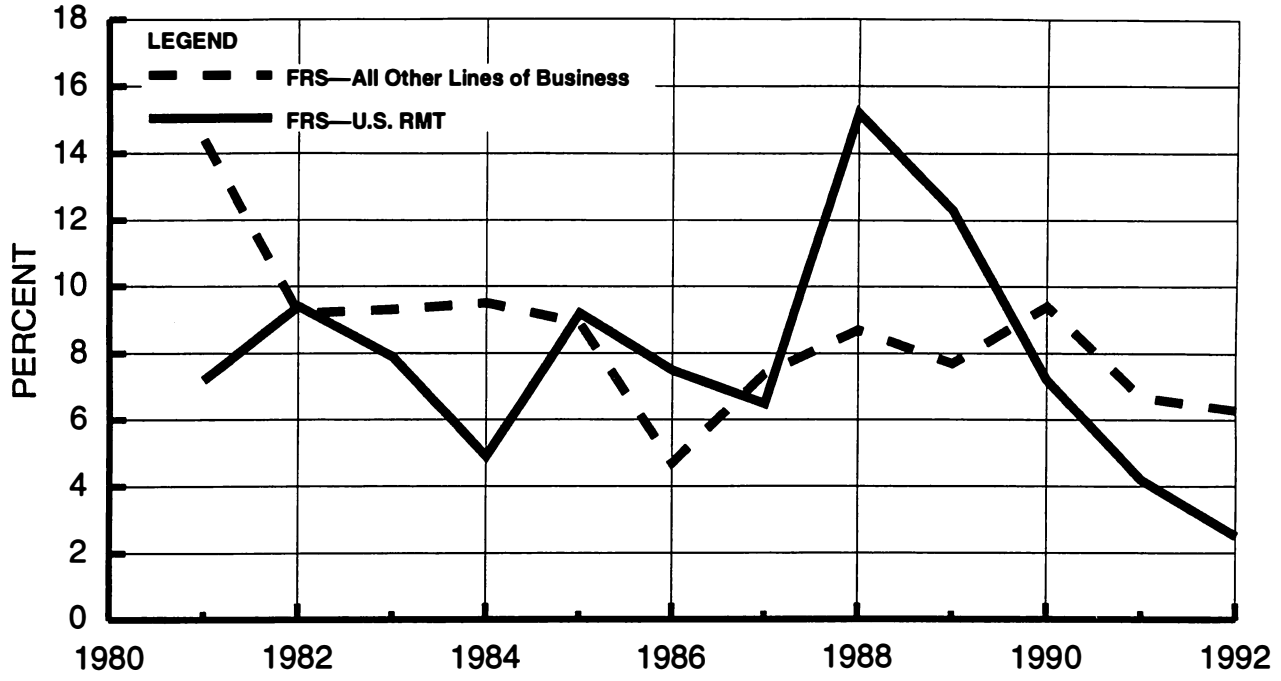
During most of the 1980s, the FRS companies' corporate profitability, as measured by return on equity (consolidated net income as a percent of stockholders' equity), was below that of other large industrial companies, as represented by the Standard and Poor's 400 excluding energy companies (see Figure 1-9). The comparison of performance of firms in

Estimating Historical Sector Cash Flow: Allocation of Interest and Dividends

In order to assess the adequacy of cash flow generated from U.S. refining, marketing, and petroleum transportation (hereafter, RMT) relative to capital expenditure requirements, a number of estimates are needed. First, cash flow from a business segment can be measured as the sum of net income, charges against income for depreciation, depletion, and amortization, and deferred taxes. The Financial Reporting System (FRS) collected deferred taxes by segment only for the years 1977-1980. To estimate deferred taxes for the RMT segment, a computational algorithm based on FRS capital expenditures, average depreciable asset lives for financial reporting and tax purposes, and federal corporate income tax rates was developed (see text box at the end of this section for description).

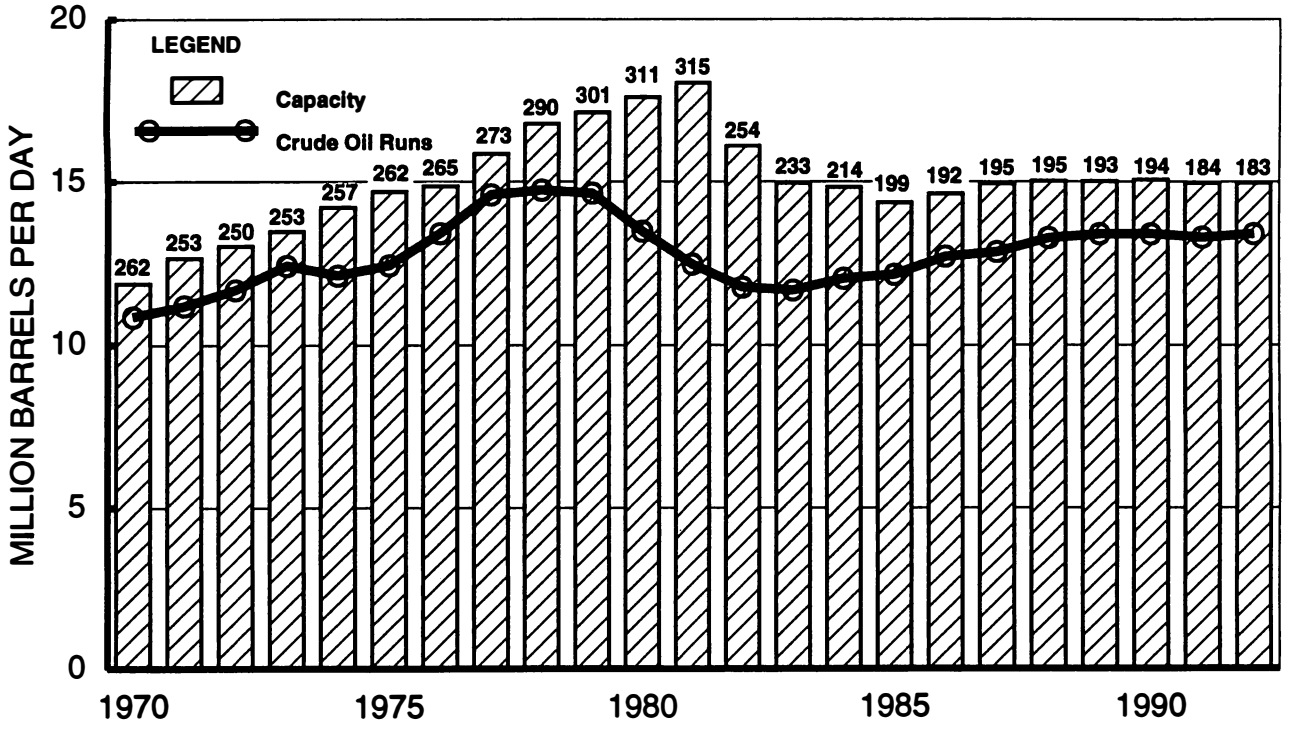
The algorithm produced results very close to those actually reported by the FRS companies for the 1977-1980 period: the estimated and actual deferred taxes for the RMT segment differed by only 1 percent. Second, although interest expense and dividends to shareholders are considered corporate-level outlays, the funds for interest and dividends are in fact derived from the cash flows generated by a corporation's business segments. A number of procedures were utilized to reasonably estimate the RMT segment's interest and dividend obligations. Historically, there is a strong relationship between the FRS companies' interest expense and their gross (i.e., undepreciated) value of property, plant, and equipment (PP&E). This relationship is not unexpected since most long-term borrowing is undertaken to expand productive capacity. Over the 1974-1991 period, the simple correlation coefficient between interest expense and gross PP&E was 0.96 (the maximum possible value is 1.0). Consequently, allocating a proportionate share of annual interest expense to the RMT segment based on the segment's share of gross PP&E appears reasonable.

Dividends also appear to be allocable on a reasonable basis. The ratio of the FRS companies' dividends to their overall cash flow varied little over the 1981-1988 period, ranging from 19 percent to 22 percent. In recent years, the FRS companies' dividend payout increased, averaging 26 percent in the 1989-1991 period. Over the entire 1974-1991 period of FRS data, the simple correlation between dividends and overall cash flow was 0.89. Since cash flow reflects a company's ability to pay dividends to its shareholders, a strong relationship between the two series is expected. A reasonable method for estimating the RMT segment's dividend obligation for past years is to allocate a proportionate share of annual dividends based on the RMT segment's share of cash flow generated from operations.



1992 results are based on 1992 fourth quarter reports.
FRS = Financial Reporting System.
RMT = Refining, Marketing, and Transportation.

Figure 1-6. Return on Investment for FRS Companies' RMT Segment and All Other Lines of Business.



Source: U.S. Bureau of Mines (1970-1975), Energy Information Administration (1976-1992).

Figure 1-7. U.S. Operating Refining Capacity (With Number of Refineries and Crude Oil Runs).

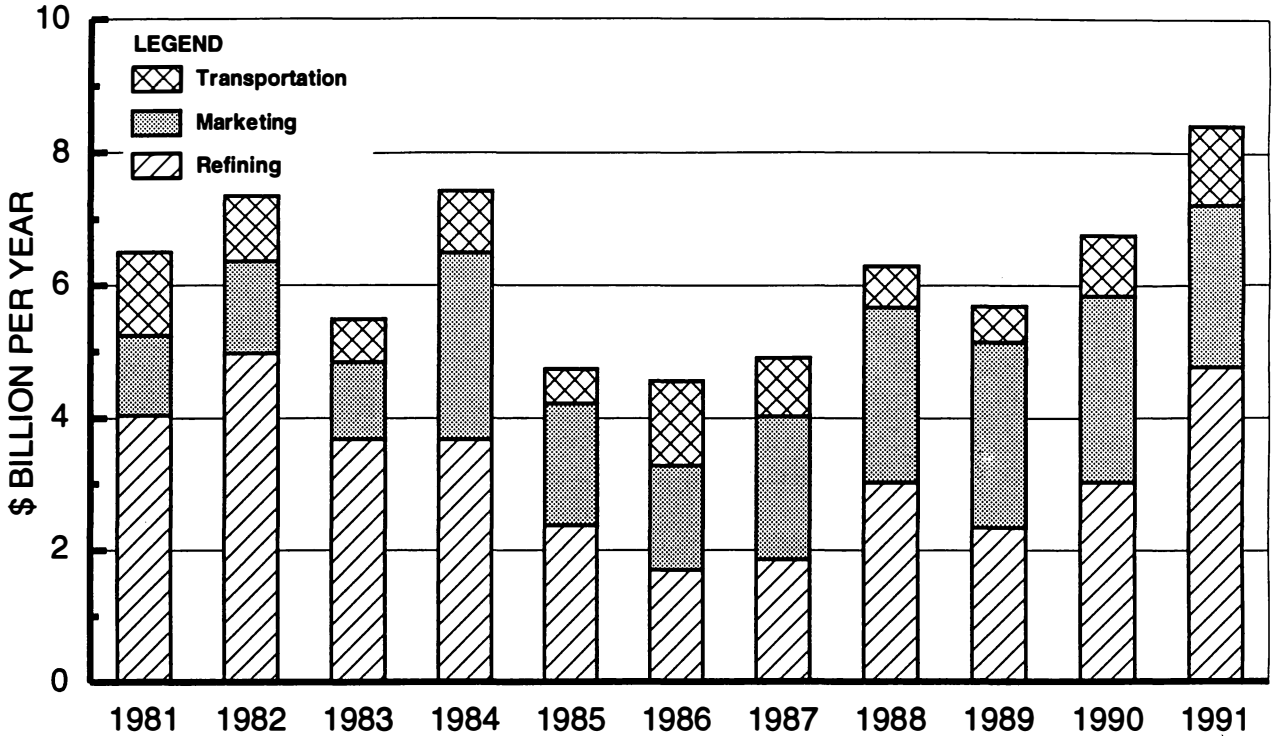
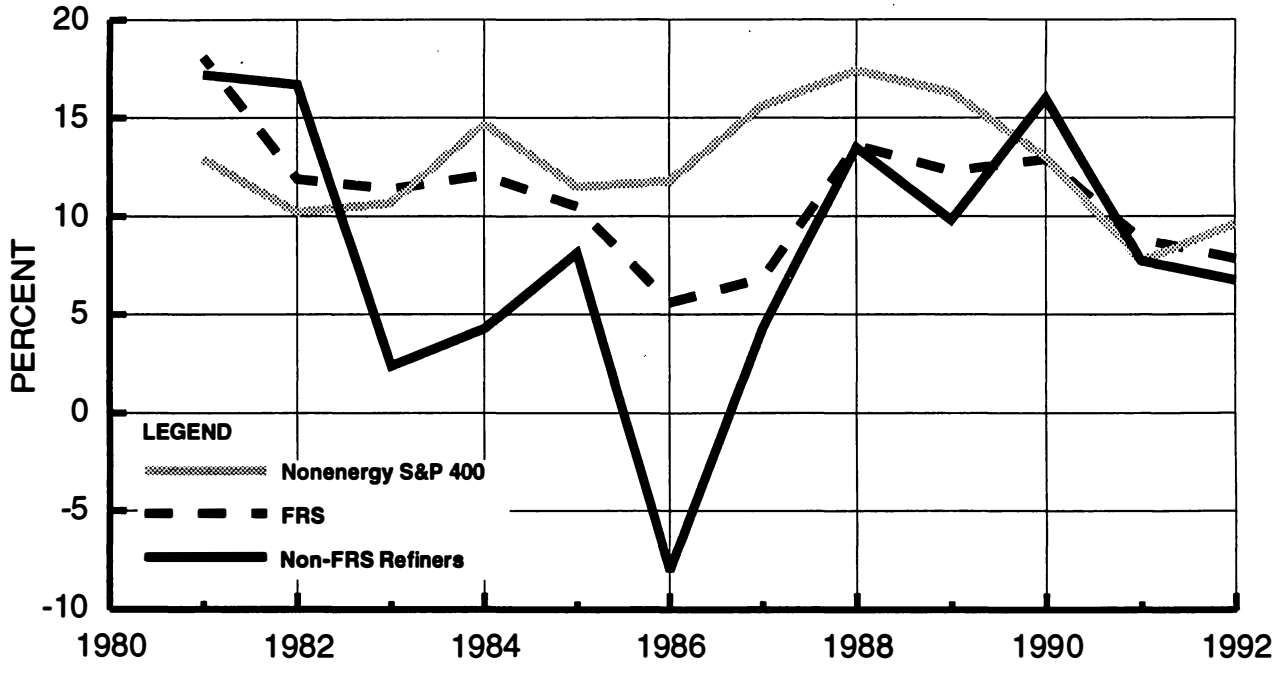


Figure 1-8. Capital Expenditures (Then Current Dollars) U.S. Refining, Marketing, and Transportation for Financial Reporting System Companies.



1992 results are based on 1992 fourth quarter results.
FRS = Financial Reporting System.
S&P = Standard and Poor's.

Figure 1-9. Return on Equity for FRS Companies, Other Refiners, and the S&P 400 Excluding Energy Companies.

different industries is made by use of return on equity rather than return on investment because the former compensates better for the variation in capital structures and risk across industries. The difference in profitability was greatest in the context of the 1986 oil price collapse and its aftermath. The gap was largely eliminated by 1990. On the one hand, the FRS companies restructured their operations, eliminating unprofitable enterprises and reducing operating costs. On the other hand, much of U.S. industry was adversely affected by high debt loads and intensified global economic pressures. Since 1990, the profitability of the FRS companies and other industrial companies, as well as smaller non-FRS refiners (11 companies drawn from the financial data base of Compustat), has fallen.

Historical Investment and Cash Flow

The EIA's Financial Reporting System companies' history of capital expenditures and net cash flows indicates an industry with strong competition and often low return on investment. In the period from 1981, the year of discontinuance of price controls, to 1985, the FRS companies made capital expenditures of $31.5 billion (then current dollars) in their domestic RMT business segments (Table 1-5). With the end of petroleum price controls, the FRS companies completed previously initiated expansions and aggressively invested in projects economically justified by reductions in raw material costs or operating expense. Over the first half of the 1980s, the contribution to net income from these businesses was $16.1 billion, equivalent to about 1.9 cpg of refinery output. This was enough to earn an average 7.7 percent rate of return on net investment in place. If corporate interest expense were allocated to the RMT business segment according to the proportion of assets (gross property, plant, and equipment) employed, RMT interest expense would total $3.6 billion after tax. Depreciation, depletion, and amortization (DD&A) allowances accounted for $13.7 billion of cash flow, and deferred taxes another $7.8 billion. See the text box "Deferred Taxes" for a description of deferred tax computations. The RMT segment's share of corporate dividends, based on its share of overall cash flow, would amount to $7.1 billion. Taken altogether, the combined RMT business experienced a negative net cash flow of $4.7 billion over the 1981-1985 period (Table 1-5 and Figure 1-10).

Over the following five years (1986-1990), the financial performance of the refining business improved. Net income before interest expenses for these five years rose to $23.0 billion for the FRS companies, or about 2.6 cpg of refinery output (Table 1-5). Capital expendi-

Deferred Taxes

Deferred taxes are calculated as tax depreciation less book depreciation and amortization times the estimated effective combined state and federal tax rate. Reported book depreciation and amortization was used for the historical period. Book depreciation for the forecast period was estimated by assuming a 16-year straight line method.

Tax depreciation had to be estimated for all years since it was not reported separately in the Financial Reporting System data. Tax depreciation was calculated using the predominant tax rates of each period. Assets placed in service prior to 1977 were assumed to have a net depreciable basis of $10 billion (versus an original cost of $36.4 billion) and was amortized on the sum of the years digits method using an 11-year life. Assets placed in service from 1977 to 1980 were amortized on 13-year Accelerated Depreciation Recovery mid-year convention. Assets placed in service from 1981 to 1986 were amortized on 5-year Accelerated Cost Recovery System with appropriate basis reduction for Investment Tax Credit. From 1987 forward, all asset additions were amortized on 10-year Modified Accelerated Cost Recovery System mid-year convention. Combined federal and state income tax rates were assumed to increase from 38.5 to 40.5 percent beginning in 1994.

TABLE 1-5

FINANCIAL INFORMATION FOR THE FINANCIAL REPORTING SYSTEM COMPANIES REFINING, MARKETING, AND TRANSPORTATION SEGMENT IN 1981-1992 (Billions of Then Current Dollars)

	1981-1985	1986-1990	1981-1990	1991-1992
Net Income Before Interest	**16.1**	**23.0**	**39.0**	**3.8**
less Estimated Interest Expense	3.6	5.2	8.9	2.1
plus Depreciation, Depletion, and Amortization	13.7	16.6	30.2	7.8
plus Estimated Deferred Taxes	7.8	5.2	12.9	0.8
equals **Estimated Gross Cash Flow**	**33.9**	**39.5**	**73.3**	**10.2**
less Estimated Dividends	7.1	10.2	17.3	3.9
less Capital Expenditures	31.5	28.2	59.7	17.5
equals **Estimated Net Cash Flow**	**(4.7)**	**1.0**	**(3.7)**	**(11.1)**
Period Averages				
Net Property, Plant, and Equipment	40.5	45.3	42.9	55.2
plus Investments and Advances	1.1	1.8	1.4	2.2
equals **Net Investment in Place**	**41.6**	**47.1**	**44.3**	**57.3**
Ratios				
Return on Investment, percent	7.7	9.7	8.8	3.4
Net Income/Total Refinery Output, cents per gallon	1.9	2.6	2.3	1.2
Memo—(1990 dollars)				
Average Annual Net Income before Interest	4.2	5.0	4.6	1.8
Net Income/Total Refinery Output, cents per gallon	2.5	2.8	2.7	1.1

Note: Components may not sum to totals due to independent rounding. 1992 net income is based on 1992 fourth quarter reports.

tures moderated to $28.2 billion, raising the overall investment in RMT to $4,514 of property, plant, and equipment per daily barrel of refining capacity. The allocated portion of corporate interest expense was an estimated $5.2 billion for the period. DD&A and deferred taxes were $16.6 billion and $5.2 billion, respectively. After an allocation of corporate dividend payments of $10.2 billion, the RMT business segment had a positive net cash flow of $1.0 billion for the five-year period.

Over the 1981-1990 period, the FRS group earned an average of 2.3 cpg of net income on total refinery output and estimated net cash flow was a negative $3.7 billion. RMT net investments that were $2,646 per barrel in 1981 grew to $4,514 per daily barrel of refining capacity in 1990 (see Figure 1-11).

In 1991 (and estimated for 1992) the profitability of the RMT segment fell to historic lows. The ROI for this segment was 4.2 percent in 1991, far below the ROI of 8.8 percent for the

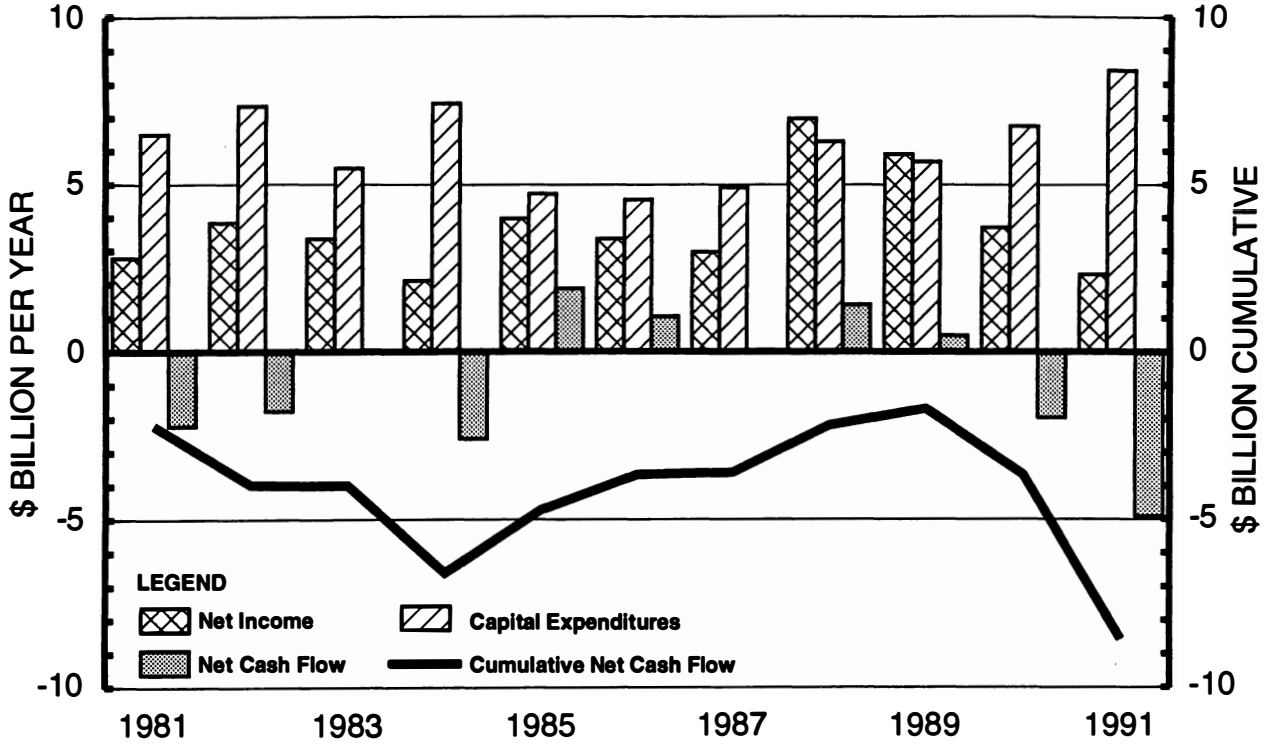


Figure 1-10. Historical Financial Performance (Then Current Dollars) U.S. Refining, Marketing, and Transportation for Financial Reporting System Companies.

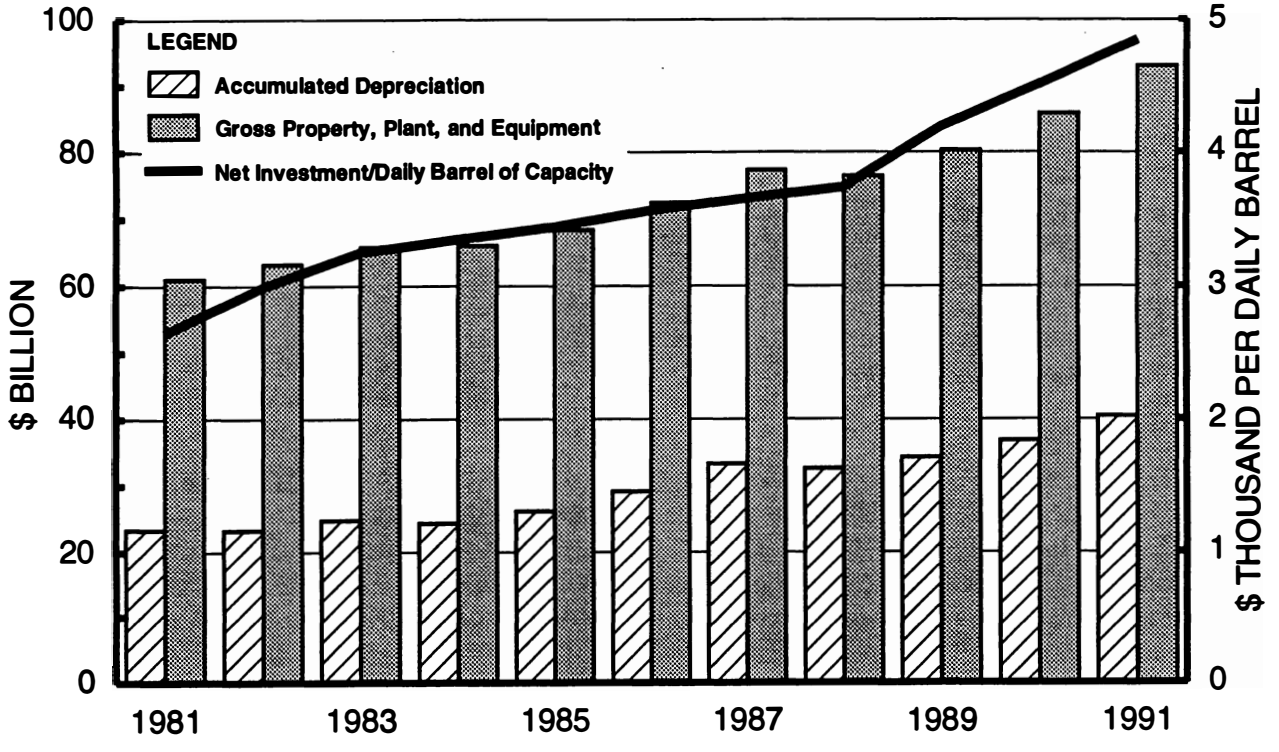


Figure 1-11. Net Property, Plant, and Equipment (Then Current Dollars) U.S. Refining, Marketing, and Transportation for Financial Reporting System Companies.

preceding 10 years (Table 1-5). Reduced demand for petroleum products and increased operating costs, due in part to heightened environmental requirements, eroded bottom-line financial results. However, capital expenditures increased, resulting in a negative cash flow for 1991 of $5 billion. Based on recent earnings announcements, net income in 1992 was 35 percent below 1991 and capital expenditures remained high. Net cash flow has been estimated at a negative $6 billion in 1992 and the return on investment 2.5 percent.

PROJECTED INVESTMENT AND CASH FLOWS[4]

Introduction

Cash flow analysis was used to evaluate the industry's ability to support capital expenditures under the economic scenarios and at constant light product demand. The results of the analysis indicate that historical earnings in themselves will not be sufficient to support the required capital expenditures. A more favorable outcome would be to attain an increase in revenue that results in a 10 percent rate of return for regulatory capital expenditures. This still leaves a negative cash flow over the decade (1991-2000) of $6 billion (then current dollars) and results in average profitability that is lower than the average of the 1980s.

Methodology

The study forecast of future capital expenditures for the U.S. refining industry has been adapted for use in analyzing the effect on FRS companies' performance and financial strength. Since FRS companies own and operate 69 percent of the total U.S. refining capacity, it is assumed that they will incur that portion of total environmental expenditures and costs. The financial performance of the companies is impossible to predict accurately, but cases were developed to test the impact of future cost recovery and net income scenarios on the FRS companies. This analysis views cumulative cash flow through 2000 as one indicator of viability.

As opposed to the criteria used in Chapters Two, Three, and Four, the analysis of cash flow here is in a "then current" (also called "nominal," "current" or "dollars of the day") dollar basis. This is necessary—and desirable—for several reasons. First, cash flow includes funds arising from the tax treatment of depreciation expense. All historical asset depreciation is based on then current dollar basis, with no way to effectively convert the account to a constant dollar basis. Second, capital expenditures made over a period of future years will have different cash flow effects than constant dollar analyses because of the impact of inflation. Inflation was assumed at 4 percent per year for 1992 and beyond.

The projection of net cash flow requirements for this analysis starts with the assumption of a level of FRS company net income for the refining, marketing and transportation sectors and capital expenditures for the marketing and transportation sectors. Using the most recent performance would be misleading, since profitability for 1991 and 1992 was at historic lows for the FRS companies. Rather, historical averages, calculated on a constant 1990 dollar basis, have been used for projections. These projections are then inflated to then current dollars. FRS company net income for the combined refining and marketing sectors is averaged over the decade since deregulation (1981). The forecast of capital expenditures for retail, marketing, and transportation (mainly crude oil and petroleum product pipelines) sectors was the average of the last five years (1987-1991) of actual expenditures in 1990 dollars. These expenditures were inflated by 4 percent per year beyond 1990.

The forecast of transportation sector net income was different, recognizing the significant role that rate regulated pipelines play in this sector. The sector's net income is much more stable than refining and marketing's, and the return on investment ranged from 16 to 24 percent. The forecast for 1993-2000 assumed that the transportation sector would maintain a return on investment equal to the average of the last five years (1987-1991), or 17.6 percent.

[4] The reader is reminded that all values in the cash flow projection are then current dollars for FRS companies refining, marketing, and transportation business segments.

Additional interest charges and dividend payouts are incurred during the projection period whenever cash flow, after dividends, falls short of capital expenditures (see text box "Projected Interest and Dividends").

This analysis assumes that the refining capacity of the FRS companies remains constant, so that future expenses and capital expenditure requirements can be estimated. Changes in capacity will undoubtedly occur, but that is not assumed in the base case. It is premised that refining companies will make the necessary capital expenditures. FRS companies are premised to make their pro-rata share of refinery process additions and replacement expenditures. The financial impact on the industry is assumed to be essentially the same as on the FRS companies.

Given these premises, FRS companies are forecast to invest some $91 billion (then current dollars) in their RMT business segment from 1991 through the year 2000 (see Figure 1-12 and Table APP.J.IV-1). This will raise the net investment in place for the FRS companies from $4,850 per barrel of capacity in 1991 to an estimated $7,820 per barrel by the year 2000 (see Figure 1-13 and Table APP.J.IV-1). It should be noted that this study did not include new environmental capital expenditures for pipelines, terminals, and marketing facilities that are part of the RMT business segment.

The actions of the refining industry are the sum of decisions made by individual firms, which all have their own specific circumstances. Factors that are likely to influence the decision to continue to invest include:

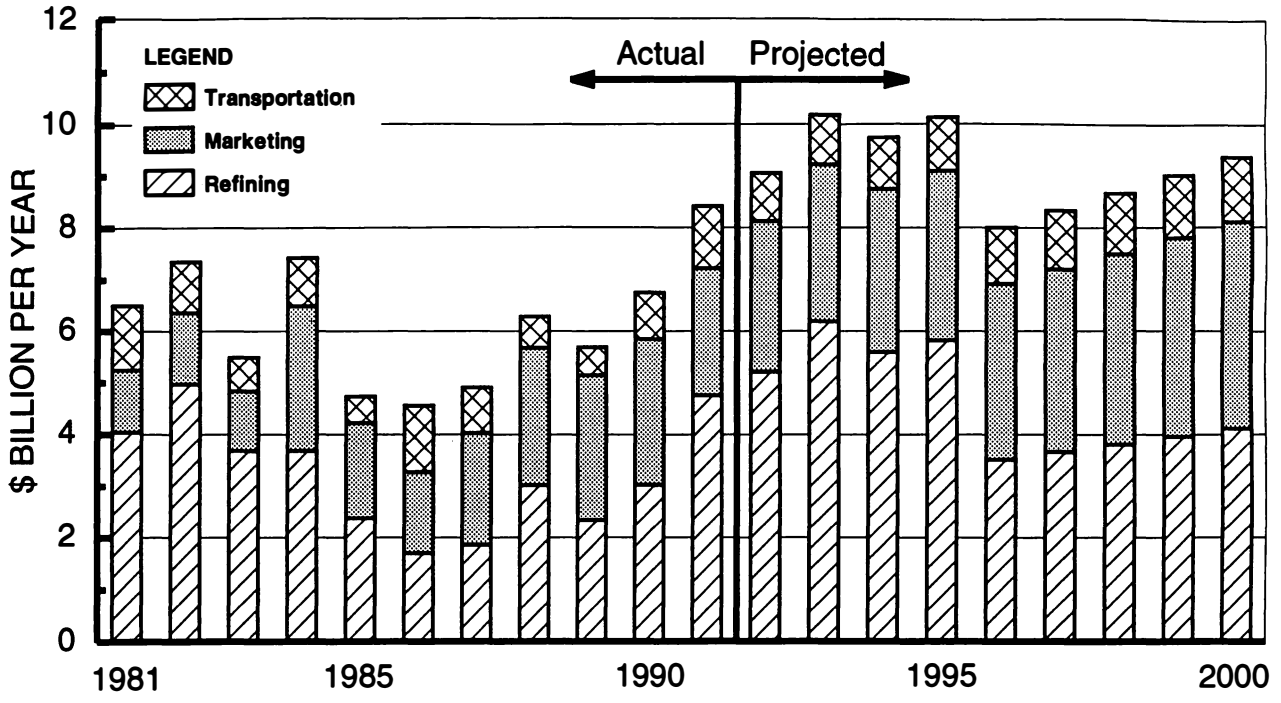
- The company's outlook on future demand
- The firm's financial strength
- Competitive position within the industry, including costs of raw materials, manufacturing, and distribution
- The level of environmental capital expenditures and associated operating expenses needed at the facilities owned and operated
- The costs of abandonment (i.e., cleanup costs, site remediation).

Projected Interest and Dividends

The analysis begins by financing the 1991 shortfall in cash flow through 40 percent long-term debt and 60 percent equity. In fact, all shortfalls in cash flow are assumed to be externally financed in these proportions in order to maintain the Financial Reporting System (FRS) group's debt-equity ratio at its 1991 value. Added debt incurs an after-tax interest charge of 6.1 percent (the overall FRS ratio of after-tax interest to long-term debt in 1991) and new equity requires a dividend yield to stockholders of 5.0 percent (the overall FRS ratio of dividends per share to the market price of their common stock in 1991). The added interest and dividends from the financing of 1991's cash flow shortfall became added obligations in 1992. This same calculation is repeated for all years in which cash flow from operations does not cover (after-tax) interest expense, dividend payout, and capital expenditures.

Cash Flow Criterion and Market Outlook

This analysis looks at cumulative cash flow to 2000 as one criterion for viability. In fact, with a 10 percent rate of return, 15 year project life and other premises of project work in this study, an individual project would have positive cash flow after year six. While companies and even industries may have longer periods of negative cash flow (but profitable operations), they do so normally only with strong growth outlooks. None of the demand scenarios adopted in Chapter Three have growth to 1995; after that the growth demand case has about 0.5 percent per year growth to 2010, and the decreasing demand case has about a 0.5 percent per year decline to 2010.



Forecast expenditures are inflated 4 percent per annum beyond 1990.

Figure 1-12. Capital Expenditures (Then Current Dollars) U.S. Refining, Marketing, and Transportation for Financial Reporting System Companies.

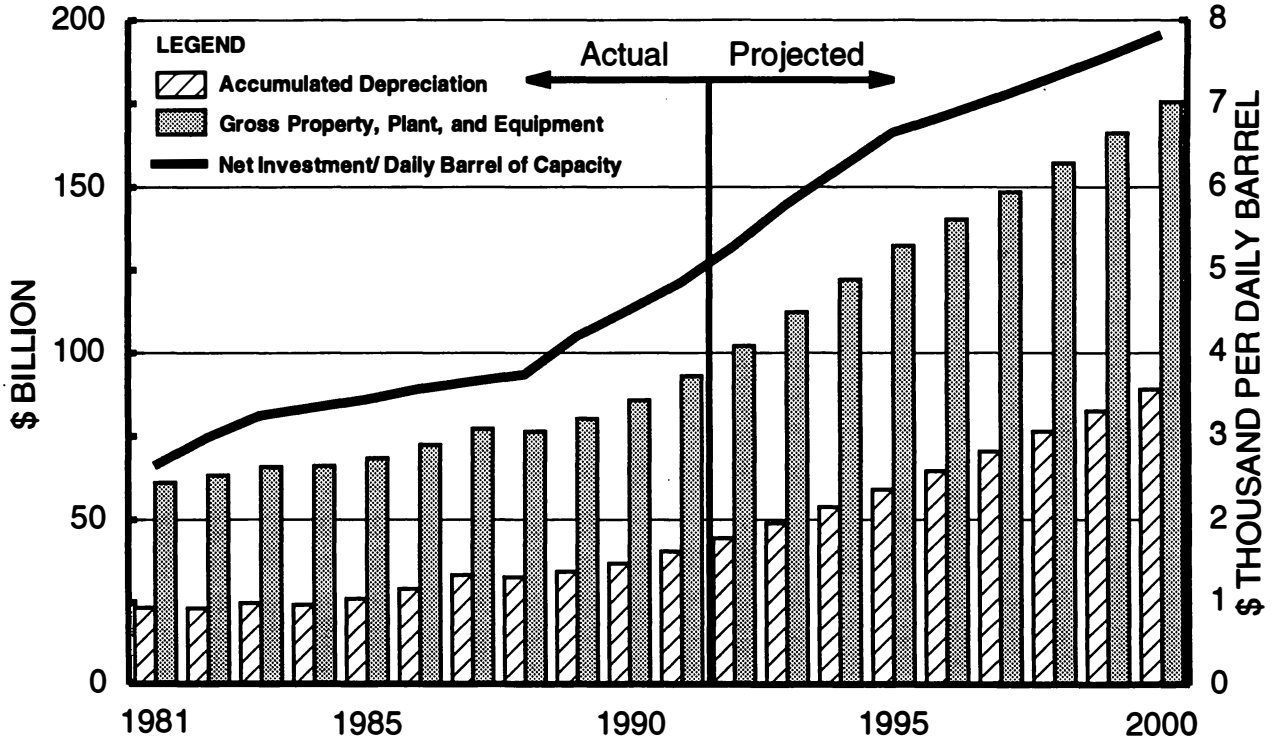


Figure 1-13. Net Property, Plant, and Equipment (Then Current Dollars) U.S. Refining, Marketing, and Transportation for Financial Reporting System Companies.

The following analysis, using FRS historical data, can only approximate the industry conditions and does not include representations of individual company circumstances such as outlined above.

Results of Analysis

The cases are described in the following subsections and the financial results are summarized in Table 1-6. All cases assume that revenues rise to match operating expenses and

TABLE 1-6

SUMMARY RESULTS — 1991-2000
FINANCIAL REPORTING SYSTEM COMPANIES
REFINING, MARKETING AND TRANSPORTATION SEGMENT
(Billions of Then Current Dollars)

	Case A	Case B	Case C
Net income Before Interest	42.5	52.8	65.0
Interest Allocated	14.2	13.5	12.3
Net Income After Interest	**28.3**	**39.4**	**52.6**
Depreciation, Depletion, and Amortization	52.5	52.5	52.5
Deferred Taxes	8.4	8.4	8.4
Gross Cash FLow	**89.2**	**100.3**	**113.5**
Capital Expenditures	90.9	90.9	90.9
Dividends	23.5	22.6	21.3
Net Cash Flow	**(25.2)**	**(13.2)**	**1.3**
Average Net Investment in Place	74.0	74.0	74.0
Return on Investment	5.7%	7.1%	8.8%
Net Income, cpg, of All Products	2.5	3.1	3.8

Totals for 10 year period. See Appendix J, Tables APP.J.IV-1 to -3 and Figures APP.J.IV-1 to -6 for annual details.

Total Industry Cash Flow

Although the Financial Reporting System (FRS) data provide the basis for analyzing past financial performance and projections of future cash flow, it is useful to extrapolate results for the FRS companies to the entire U.S. refining industry. Reasonable estimates for the U.S. industry can be obtained by dividing FRS values by 0.689 since the FRS companies accounted for 68.9 percent of U.S. crude oil distillation capacity in 1992. Based on this method, projected overall industry net cash flows for 1991-2000 in Cases A, B, and C (Table 1-6) are negative $36.7 billion, negative $19.2 billion, and positive $1.9 billion, respectively. Using the same method, overall industry refining net PP&E (property, plant, and equipment) in 1990 is an estimated $31.4 billion. All industry totals have been extrapolated by this method.

to provide the same level of net income of the 1980s as a minimum.

The significant descriptions for the cases analyzed are:

- Case A – 1980s net income; no return on new environmental capital expenditures
- Case B – 1980s net income plus this study's premised return on new environmental capital expenditures
- Case C – 1980s average return on net investment in place.

Case A: 1980s Net Income, No Return on Environmental Capital Expenditures

In Case A, FRS companies are assumed to be successful in passing through only the increased out-of-pocket expenses and depreciation but earn no return on new environmental expenditures. If they maintain a net income level in 1990 dollars over the 1993-2000 period equal to the average of the 1981-1990 period, then they would fall $25 billion (then current dollars) short of the cash flow needed to cover the total investment requirements projected (on a total industry basis this equates to a negative $37 billion). The historical average net income before interest allocation is not sufficient to fund the high levels of capital expenditures required. The average return on net investment for the 1990s would drop to 5.7 percent, considerably less than the average for the 1980s.

Net cash flow is most negative in the early years of the forecast period due to the heavy load of capital expenditures. In fact, the 1991-1995 period shows a total cash shortfall of $21.7 billion for the FRS companies' RMT operations. The last five years of the forecast, 1996-2000, add another $3.6 billion to the cash shortfall.

In a situation with product demand static or declining, without the prospect of higher future earnings and cash generation, not all refiners will be willing to invest or be able to attract sufficient capital. Full details of the model results and graphical exhibits are presented in Table 1-6 and Figures 1-14 and 1-15.

Case B: Full Cost Recovery Plus Cost of Capital

In Case B, the industry is assumed to be successful in passing along 100 percent of the increased expenses (like Case A). In addition, it is assumed that capital cost recovery is sufficient to earn a 10 percent discounted cash flow rate of return on the dollars invested for new regulatory compliance capital expenditures. (This return is the same as specified in the premises of other chapters of this study.)

Cumulative net cash flow after capital expenditures for the 1991-2000 period will still be negative, but with a positive $6.0 billion from 1996-2000. Net income before interest equal to the 1981-1990 average plus full recovery of the cost of capital would equate to a net income of 3.1 cpg of total refinery output. The average ROI would be 7.1 percent, higher toward the end of the period than during the first five years when capital expenditures are especially heavy. (See Figure 1-16. Full details are shown in Appendix J, Table APP.J.IV-2.)

Case C: Earn Historical Return on Investment

In Case C, revenues, income, and cash flows were calculated which generated an average ROI for the 1990s equal to that of the 1980s. With an 8.8 percent ROI, the resulting net cash flow is positive for 1991-2000. Cash flow is still a negative $14.9 billion in 1991-1995. Net income of 3.8 cpg of total refinery output is 23 percent greater than Case B. (See Figure 1-17. Detailed results are shown in Appendix J, Section IV, Table APP.J.IV-3).

Observations on Cases

In this section, the study has projected three cases with differences in net income (Cases A, B, and C). Using the 1981-1990 results as a benchmark, the observations are:

- Case A, with the same net income as the 1980s, would not generate enough cash,

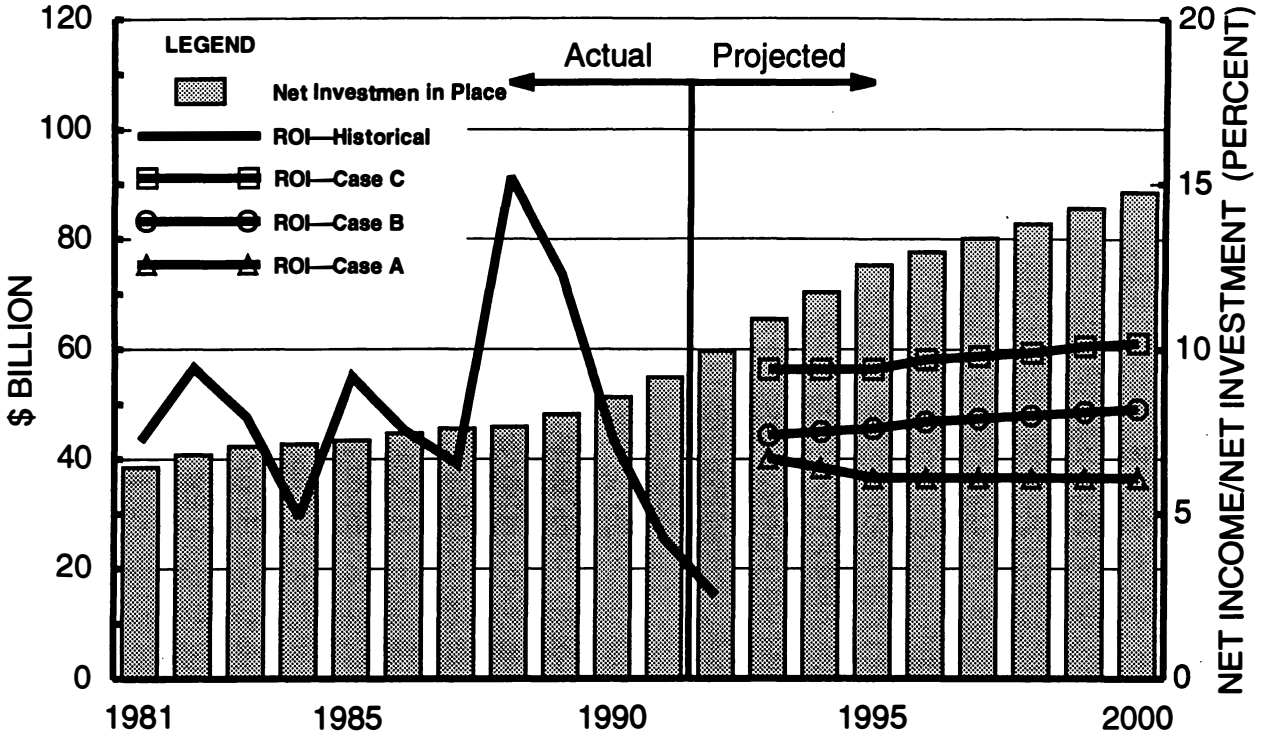
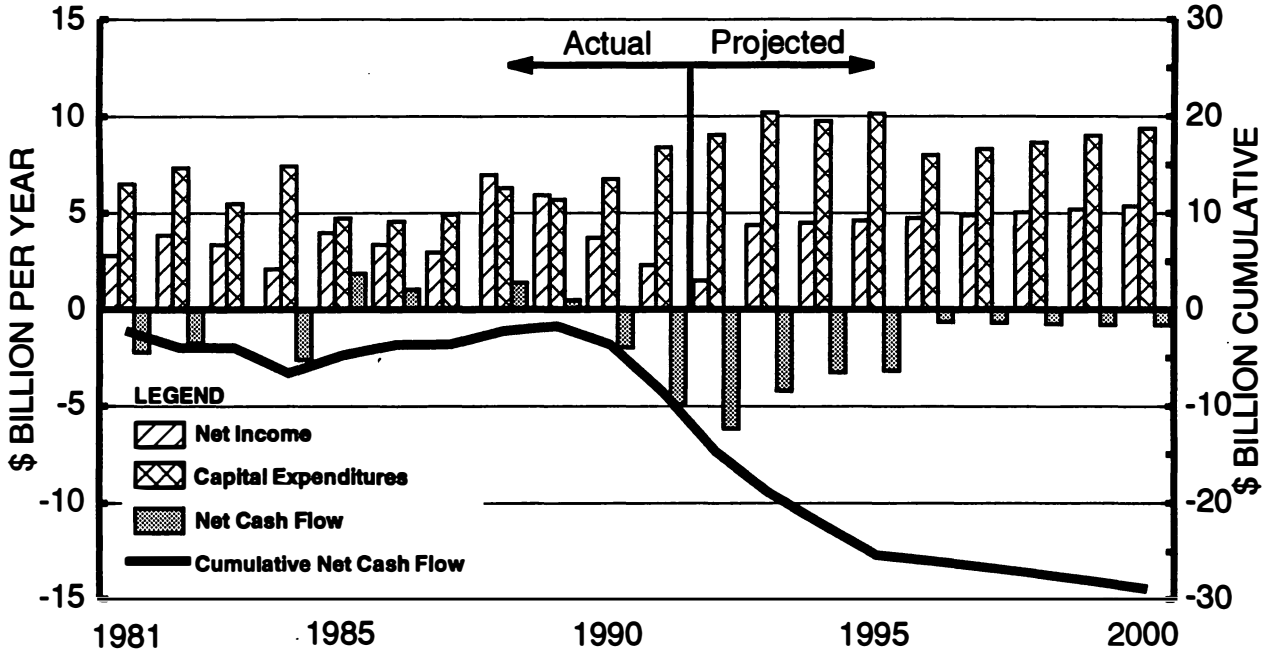
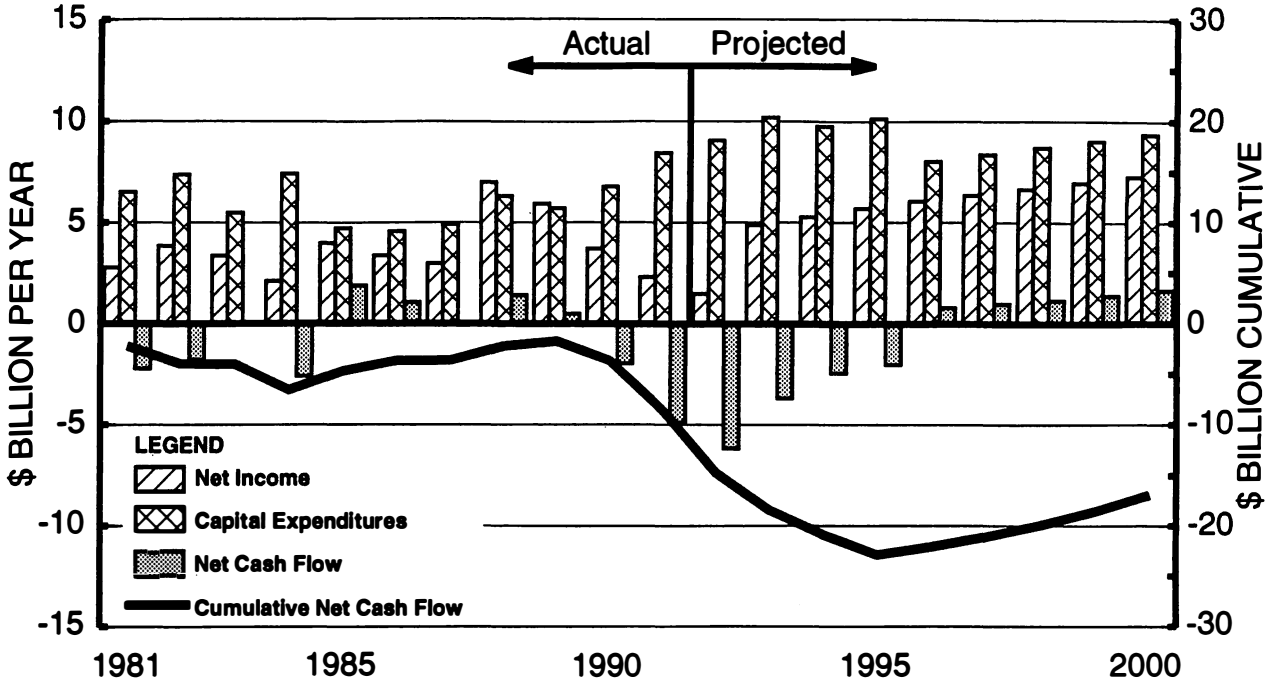


Figure 1-14. Return on Net Investment (Then Current Dollars)
U.S. Refining, Marketing, and Transportation for
Financial Reporting System Companies.



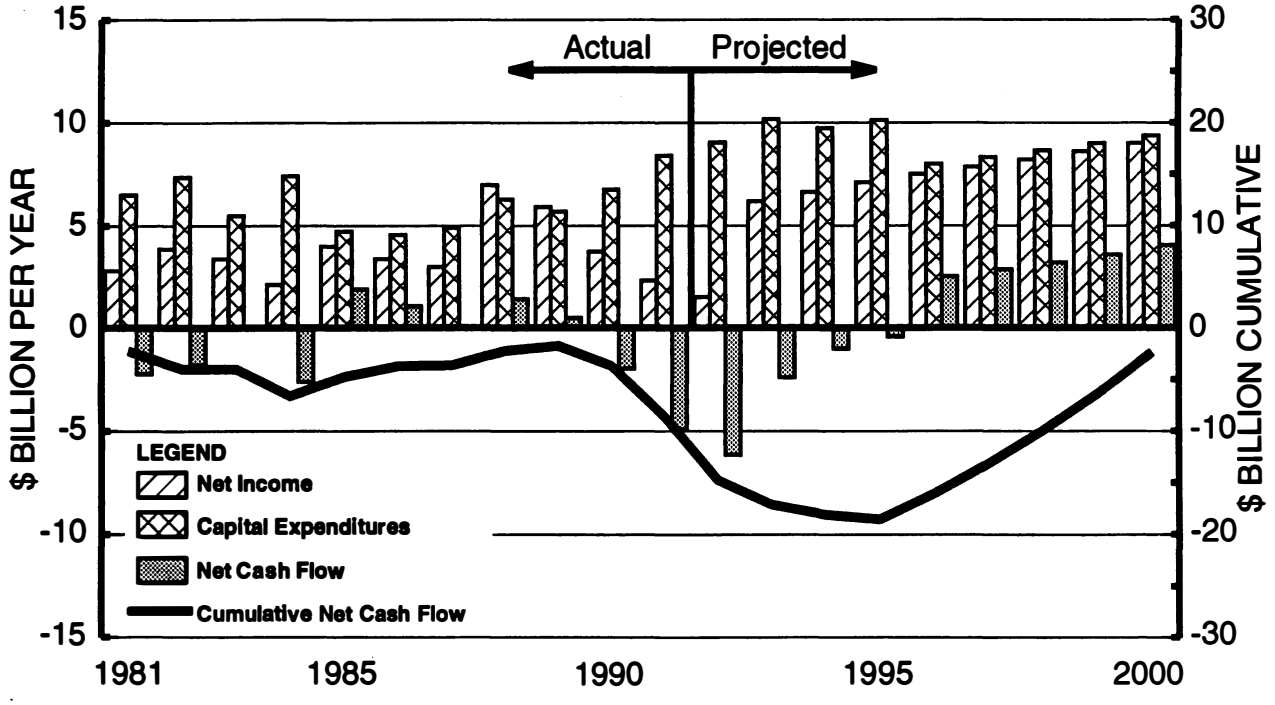
Net income for 1993-2000 equals the 1981-1990 average in real terms.
Full passthrough of increased refining expenses but no cost of capital recovery.

Figure 1-15. Cumulative Net Cash Flow—Case A (Then Current Dollars)
U.S. Refining, Marketing, and Transportation for
Financial Reporting System Companies.



Net income equal to Case A plus cost of capital on new environmental expenditures.

Figure 1-16. Cumulative Net Cash Flow—Case B (Then Current Dollars) U.S. Refining, Marketing, and Transportation for Financial Reporting System Companies.



Net income sufficient to provide average ROI for 1991-2000 equals average ROI for 1981-1990.

Figure 1-17. Cumulative Net Cash Flow—Case C (Then Current Dollars) U.S. Refining, Marketing, and Transportation for Financial Reporting System Companies.

after dividends, to cover capital expenditures for 1991 through 2000.

- Case B, which assumes additional income equal to the capital charge on the new environmental capital expenditures, still does not cover overall capital requirements.
- Case C, which assumes that the average ROI of the 1990s matches that of the 1980s, generates sufficient cash flow to cover capital requirements.

In all economic scenarios evaluated, the industry experiences negative cash flow in the early 1990s. The actual course of the industry in the decade between 1990 and 2000 will be significantly influenced by demand, rationalization, and light product realizations. Rationalization would help alleviate the cash flow problem, but not so much from capital expenditures savings as from increased net income. (See Appendix J.IV-1 for a general discussion of the relation between rationalization [or utilization] and income.) Capital expenditures do *not* decrease proportionately with capacity shutdowns. For example, the demand for reformulated gasoline and low sulfur diesel fuel will not decrease sufficiently due to rationalization. Instead, the former production from shutdown refineries must be made up by the remaining producers. Thus, capital expenditures for reformulated products would not be expected to decline appreciably from the figures presented in this report. Capital expenditures for stationary facilities should decline as capacity in place declines. However, this would be offset to an unknown extent by shutdown and site cleanup remediation costs. Thus, a 10 percent rationalization, for example, would see less than a 10 percent decline in the industry's capital expenditure requirements. The real effect would be seen in a probable increase in net income due to the removal of excess product supply from the marketplace, allowing the remaining producers to recover their total costs.

IMPLICATIONS FOR CONSUMERS

Increased light product costs result from four categories of expenditures necessary to meet regulations—those for specific products (e.g., reformulated gasoline), those for regula-

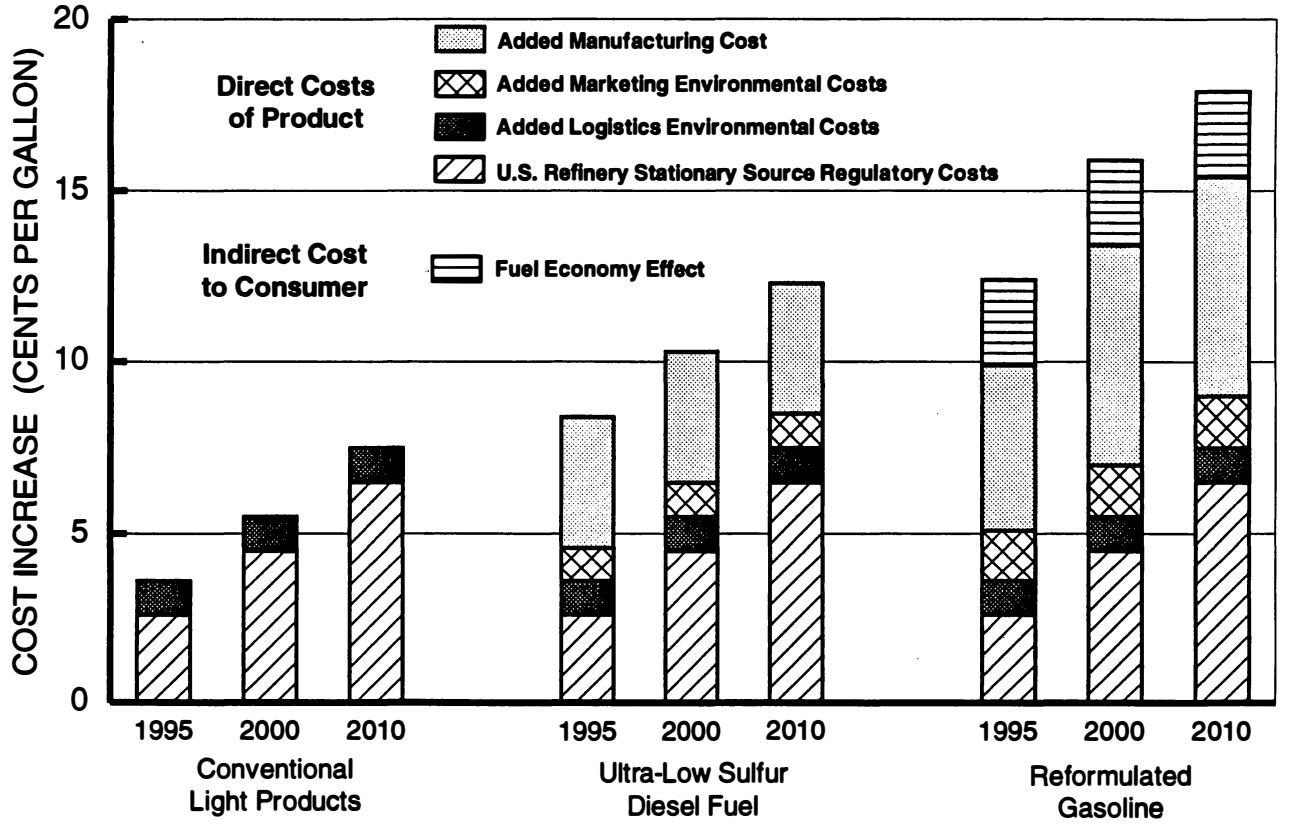


Figure 1-18. Consumer Cost Increases for Selected Products (1990 Dollars).

tions dealing primarily with stationary refinery emission controls (e.g., air emissions, waste water, etc.), and those for logistics and marketing.

Estimates of the total consumer cost increase, by product group, have been developed from the work of the subsequent chapters. In contrast to some costs derived in Chapter Four for reformulated products, costs presented in this chapter are annual averages and do not reflect seasonal variations. Costs for California fuels are also included. Figure 1-18 depicts consumer cost increases of selected products.

This study assumes that the regulatory expenditures for stationary facilities developed in Chapter Two will be recovered from light products because heavy products have close substitutes. A common cost per gallon was applied to all light products.

Added logistics costs developed in Chapter Three to handle distribution of fuels are applied to light product volumes. These costs arise primarily from the added segregation required for the new products in nonattainment areas. Reformulated gasoline costs include an additional 4 cpg to cover an estimated 1.5 cpg of increased marketing costs and 2.5 cpg as an indirect effect of the lower energy content of oxygenated fuels (Table 1-7).

No explicit estimate has been made of the impact of the increase in consumer cost on demand. Rather, as detailed in Chapter Three, two demand cases were assumed to provide an adequate envelope of demand (with an additional, intermediate case). However, the general effect of an added cost of production is well known (see Appendix J.V-1, Figures APP.J.V-1 to 3): it reduces the quantity of product demanded and the unit earnings of the facilities left in operation.

The extent to which the increased costs are passed through to consumers depends upon light product demand growth, the elasticity of

TABLE 1-7

FEDERAL EPA REFORMULATED PRODUCTS ANNUAL AVERAGE COST INCREASE ABOVE 1989 (Cents per Gallon—1990 Dollars)

	Reformulated Gasoline			Ultra-Low Sulfur Diesel Fuel		
	1995	2000	2010	1995	2000	2010
Stationary Source Controls	2.6	4.5	6.5	2.6	4.5	6.5
Refining Costs (and Oxygenate for Reformulated Gasoline)	4.8	6.4	6.4	3.8	3.8	3.8
Logistics and Other	1.0	1.0	1.0	1.0	1.0	1.0
Subtotal	**8.4**	**11.9**	**13.9**	**7.4**	**9.3**	**11.3**
Retail Marketing Regulations*	1.5	1.5	1.5	1.0	1.0	1.0
Total Increase	**9.9**	**13.4**	**15.4**	**8.4**	**10.3**	**12.3**
Lower Fuel Economy† (Indirect Increase)	2.5	2.5	2.5	–	–	–
Total Effective Consumer Cost Increase	**12.4**	**15.9**	**17.9**	**8.4**	**10.3**	**12.3**

* No detailed NPC study; estimated from EPA and API data.

† Gasolines with oxygenate have less energy content per gallon, therefore the consumer requires more gallons to travel the same distance.

TABLE 1-8

ESTIMATED INCREASED CONSUMER COST
FOUNDATION CASE II — CONSTANT U.S. DEMAND
(1990 Dollars)

	Million Barrels per Day	Cents per Gallon	$ Billion per Year
1995			
Reformulated Gasoline – Phase I	2.15	12.4	4.1
Low Sulfur Diesel Fuel	1.32	8.4	1.7
California Low Aromatics Diesel	0.25	19.1	0.7
Conventional Light Products	8.18	3.6	4.5
Total Light Products	**11.90**	**6.0**	**11.0**
2000			
Reformulated Gasoline – Phase II	3.59	15.9	8.8
California CARB Phase 2 Gasoline	0.91	23.7	3.3
Low Sulfur Diesel Fuel	1.32	10.3	2.1
California Low Aromatics Diesel	0.25	21.0	0.8
Conventional Light Products	5.82	5.5	4.9
Total Light Products	**11.89**	**10.9**	**19.9**
2010			
Reformulated Gasoline – Phase II	3.59	17.9	9.9
California CARB Phase 2 Gasoline	0.91	25.7	3.6
Low Sulfur Diesel Fuel	1.32	12.3	2.5
California Low Aromatics Diesel	0.25	23.0	0.9
Conventional Light Products	5.80	7.5	6.6
Total Light Products	**11.87**	**12.9**	**23.5**

demand (e.g., the availability and price of substitute products), and the potential for supplying the U.S. market through refined product imports. With limited or no short-term substitutes and flat demand, overall light product costs are likely to increase by about 11 cpg in 2000, adding about $20 billion per year to U.S. consumers' energy bills (Table 1-8).

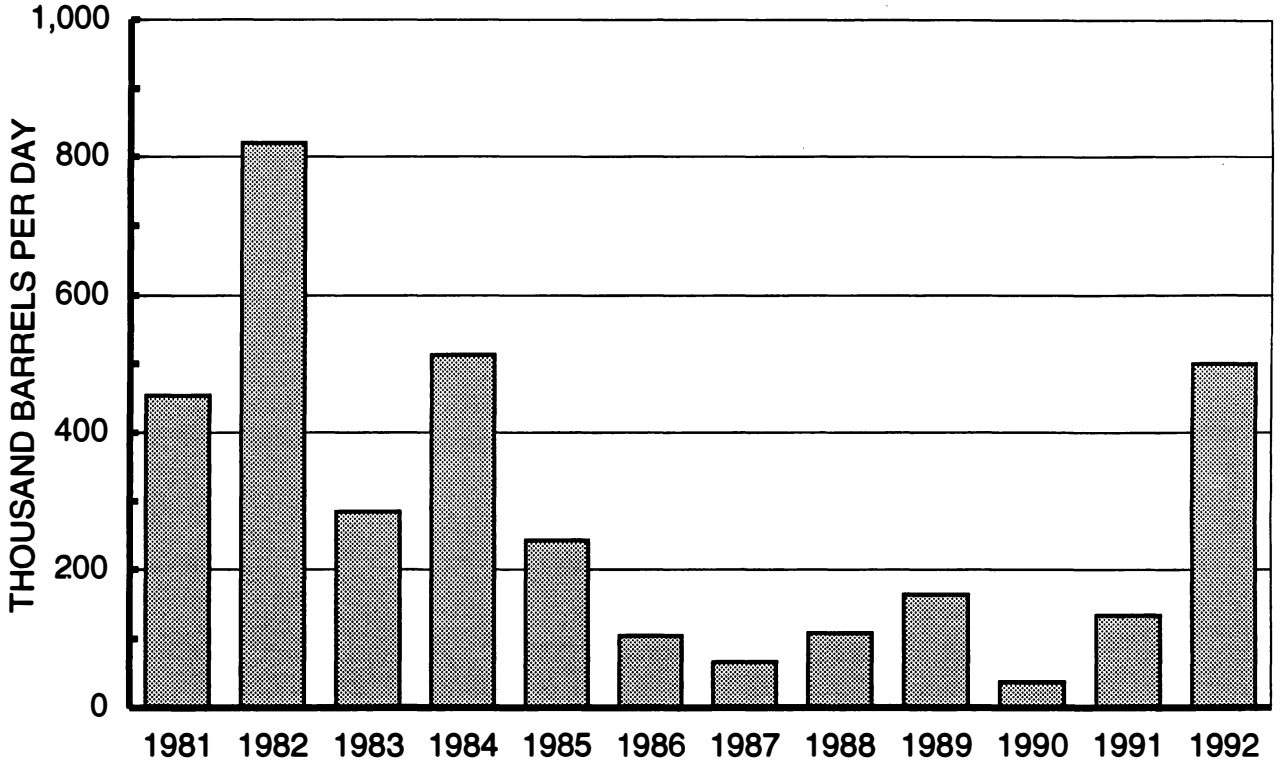
IMPLICATIONS FOR THE REFINING INDUSTRY

The financial analysis presented in this chapter clearly indicates that the historical net income of the refining industry will not generate sufficient internal cash flow to finance the capital expenditures for increased environmental requirements and product quality changes. If the trend of past refining industry net income were to continue, the attractiveness of petroleum refining as an investment will decrease. Full cost recovery, including the cost of capital, should, in the longer term, provide adequate cash flow and return on investment for the refining industry comparable to or greater than those realized on average during the 1981-1990 period. However, to fully recover the added costs of increased environ-

mental requirements and product quality changes, net income per gallon must increase substantially from the levels of 1991 and 1992. The question is, will petroleum product supply decrease or demand increase enough to raise overall net income and, if not, what adjustments in the current structure of the refining industry are likely, both in the near term (to 1996) and beyond?

The demand scenarios defined in Chapter Three all project decreasing utilization of refineries with essentially no growth in overall petroleum product demand through 1995. During the same period and into 1996, the greatest capital investments are projected for stationary requirements (Chapter Two) and for product reformulation (Chapter Four).

This chapter's financial analysis together with the demand projections and schedule of required regulatory investments imply that the refining industry is likely to undergo a substantial restructuring in the coming years. This restructuring would be characterized by shutdowns of refining capacity. The process appears to have begun already. Shutdowns accelerated in 1992 to the third highest level since 1981 (see Figure 1-19). If such a downsizing of the industry continues, surviving refineries will operate at higher levels of utilization, which should increase their income and cash flow.



Source: EIA Petroleum Supply Annuals—excludes non-operated capacity.

Figure 1-19. U.S. Refinery Shutdowns in Distillation Capacity.

CHAPTER TWO

U.S. REFINING STATIONARY SOURCE FACILITIES

SUMMARY

This section of Chapter Two describes the purpose and methodology of the Refining Facilities portion of the study and presents a summary of the primary findings.

Purpose and Methodology

The Refinery Facilities Task Group was charged with the responsibility of describing and quantifying the cost impact on the U.S. refining industry of current and future air, water, solid waste, and safety and health environmental controls and regulations relative to stationary emission sources from refinery production facilities during the 1991-2010 period. Costs associated with product quality (reformulated gasolines, oxygenates, low sulfur diesel fuel) were not included here but are discussed in Chapter Four.

This information was developed to determine whether regulatory costs will have a significant impact on the ability of the U.S. refining industry to remain economically viable and to compete in the worldwide market. The study utilized the following resources:

- A Task Group, composed of industry experts in the environmental and engineering fields, to conduct and/or oversee all aspects of the study effort
- A larger panel of industry environmental experts to formulate guidance for describing current and possible future air, water, solid waste, and health and safety regulations that were to be evaluated
- A comprehensive survey of the refining industry to establish historical and near-term cost, plans, and perceptions
- An engineering/construction contractor to develop detail costs for future requirements defined by premises developed by the Task Group and the expert panel.

Capital, one-time expenses (OTE), and operating and maintenance (O&M) expenses required for implementation of the defined environmental premises (see the Future Costs section of this chapter) were determined for nine basic refinery size/complexity configurations (see the Study Design and Concepts section of this chapter) for the time periods 1991-1995, 1996-2000, and 2001-2010. Survey results were used to establish historical numbers for the 1986-1990 time period and in developing 1991-1995 requirements. All of these costs were adjusted for geographic location factors and allocated to the thirteen specified NPC supply regions (Figure 2-10) according to the refinery size population in each region.

Other basic guidelines were:

- Existing regulations as well as regulations likely to become requirements in the future were used to guide premise development. Future requirements represent a

realistic scenario based on current regulatory trends.

- Current technologies were utilized to the fullest extent, but new or undeveloped technologies were not assumed to come into existence.
- Only costs within the refinery fence line were considered. Specifically, remediation of idle and/or abandoned sites were not evaluated and pipelines, terminals, etc., were not considered.

Additionally, because solid waste remediation was believed to be very significant, a sensitivity was developed to investigate the impact of more severe regulations in that area.

Findings

The cost shown below in Table 2-1 are the quantitative results of this study for *each separate time period.* Capital and OTE are for the total period. O&M costs for 2000 and 2010 are those associated with investments or programs implemented during the period, while cost for 1995 includes $2.3 billion per year from prior period regulations to thus allow development of a total environmental cash requirement.

These results were utilized by the other study groups, the *Product Quality Task Group* and the *Supply, Demand, and Logistics Task Group*, for use in determining product cost for the periods of interest (see Tables 2-7, 2-8, and 2-9).

TABLE 2-1

ENVIRONMENTAL FACILITIES AND PROGRAM COST
($ Billion – 1990 Dollars)

	1991–1995	1995	1996–2000	2000	2001–2010	2010
Capital	12.6		10.2		13.5	
One-Time Expenses	4.5		1.3		1.2	
O&M Expenses, $/Year		3.7*		2.3†		1.1‡

* Total 1995 operating & maintenance (O&M) expenses.
† Additional in 2000.
‡ Additional in 2010.

TABLE 2-2

ENVIRONMENTAL FACILITIES AND PROGRAM COST
($ Billion – 1990 Dollars)

	1991–1995	1996–2000	2001–2005	2006–2010	Total
Capital	12.6	10.2	6.8	6.7	36.3
One-Time Expenses	4.5	1.3	0.6	0.6	7.0
O&M (New)	4.1	14.2	20.7	23.6	62.6
Subtotal	21.2	25.7	28.1	30.9	105.9
O&M (Base)	11.5	11.5	11.5	11.5	46.0
Total	**32.7**	**37.2**	**39.6**	**42.4**	**151.9**
Annual Average	6.5	7.4	7.9	8.5	

Table 2-2 shows the cash requirements for each period and the total. Figure 2-1 displays an assumed annual O&M expenditure pattern including the prior period base.

Figures 2-2 and 2-3 illustrate the cash requirements that result from the O&M expenditures previously shown coupled with capital and OTE. Inspection of Figure 2-2 shows that this spending scenario will require $6 billion per year in the 1991-1995 period comprised of approximately one-half capital and OTE and one-half O&M. Then, even with capital and OTE projected to decline, the growth in O&M will result in over $8 billion per year estimated cost for 2006-2010, with this being 80 percent O&M. Figure 2-3 is the cumulative presentation of these numbers, showing a 20 year $152 billion requirement of $43 billion capital and OTE and $109 billion O&M.

To further expand on these potential cash needs, Figure 2-4 shows the total requirement for *each refinery* in the nine size ranges. As an example, *each* of the 24 refineries with a crude oil processing capacity of 100 to 150 thousand barrels per day (MB/D) is projected to expend $1.2 billion over the 20 years, which will be an average annual cost of $60 million.

Figure 2-5 is another view. It shows capital and OTE requirements per barrel of crude oil capacity for the size groups. This indicates that, except for the very small refineries (for which the numbers may be affected by low survey response), the environmental facilities costs are in a range of $2,000 to $3,000 per barrel of daily crude oil processing capacity with a trend toward somewhat lower costs at larger refineries.

Figures 2-6 and 2-7 give a historical perspective by combining survey information from 1985-1995 with study results for 1996-2010.

It should be noted that the premised regulations considered only items believed to have significant financial impact and, thus, by omitting numerous small items, these findings tend toward conservative or low cost results. Further, the decline in cost increases and particularly capital investments toward the end of the study period is typical of long range evaluations. History shows that our

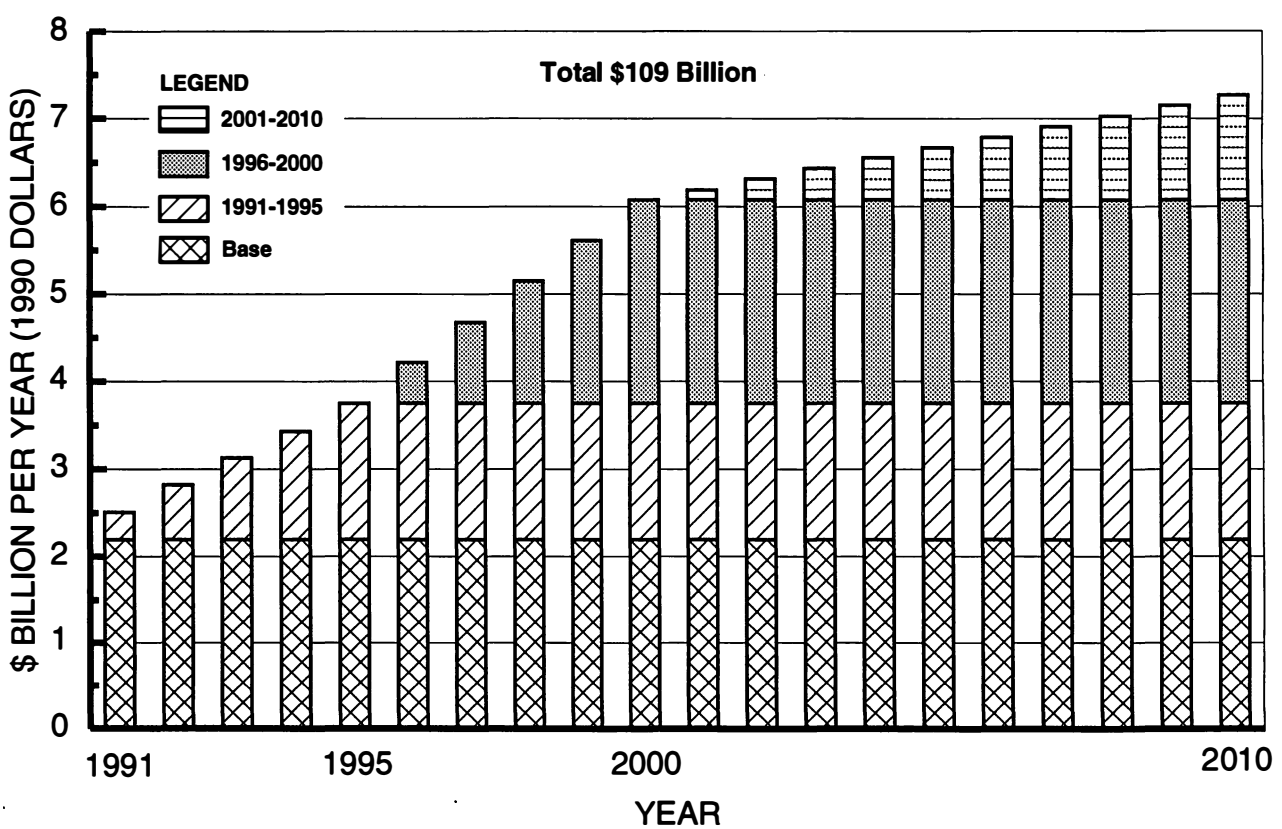


Figure 2-1. Operating and Maintenance Cost—Expenditure Pattern.

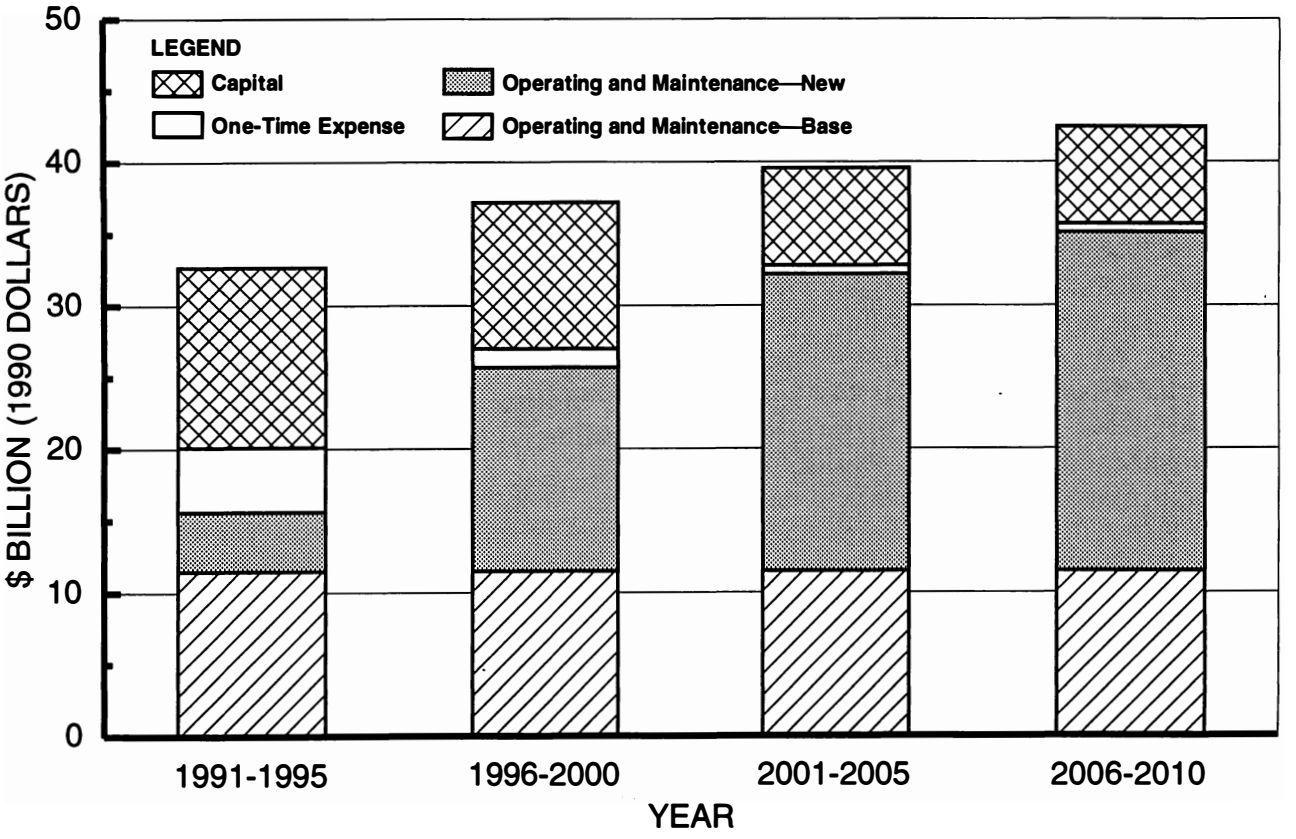


Figure 2-2. Environmental Facilities and Programs—Cash Requirements.

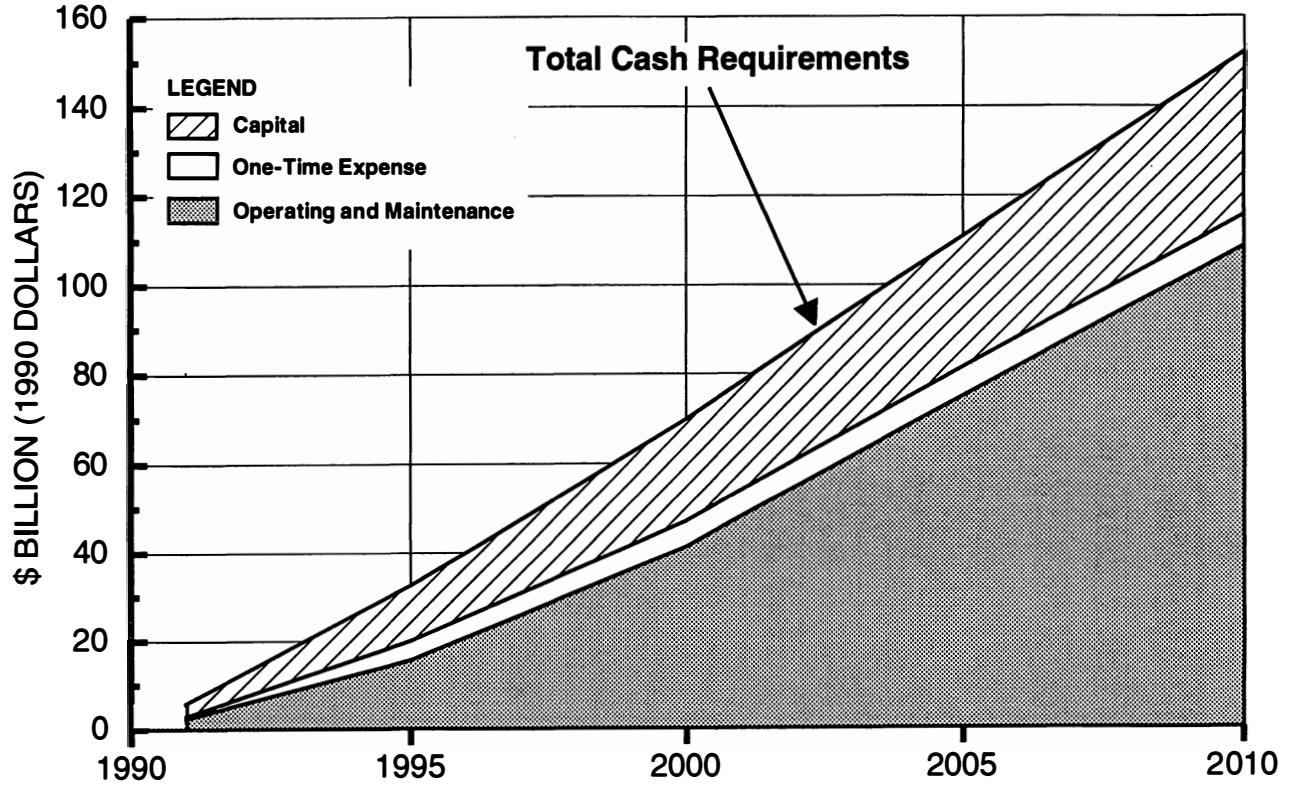


Figure 2-3. Environmental Facilities and Programs—Cumulative Cash Requirements.

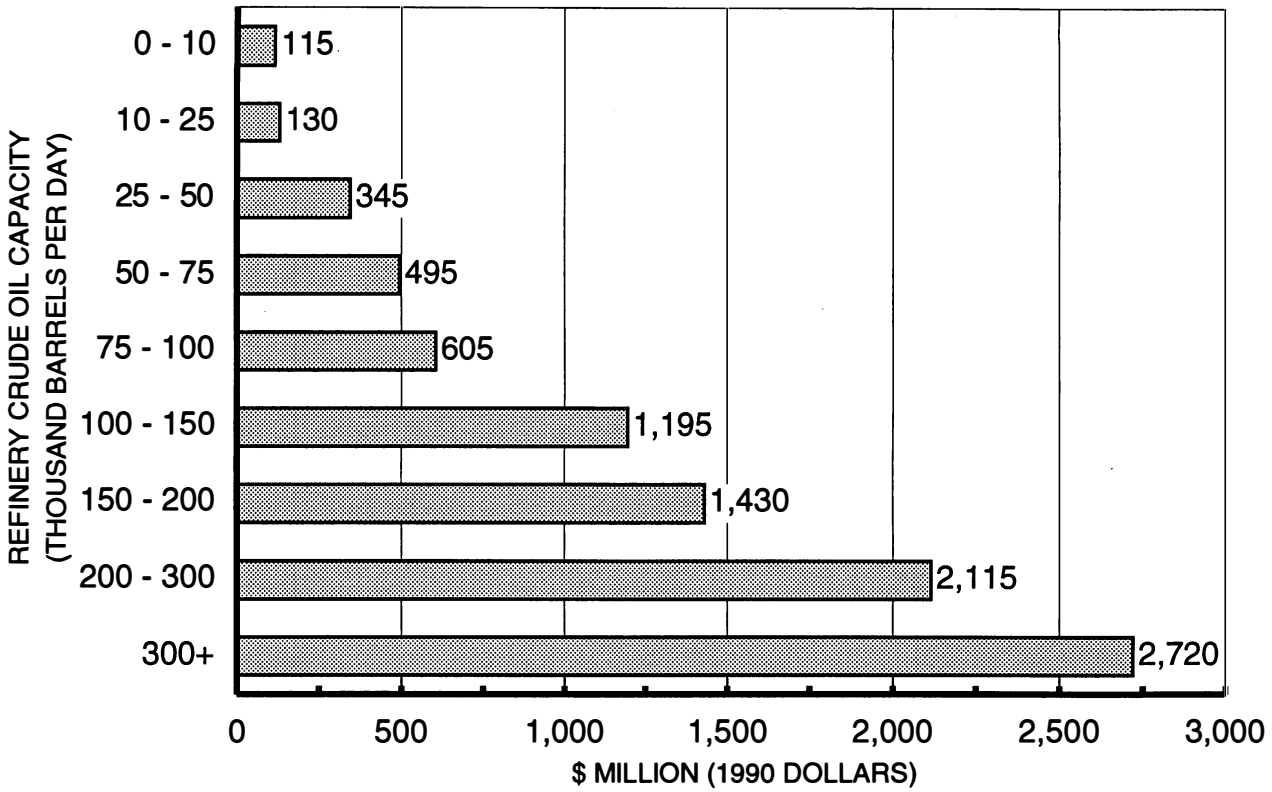


Figure 2-4. Environmental Facilities and Programs—Average Total 1991-2010 Cost for Each Operating Refinery.

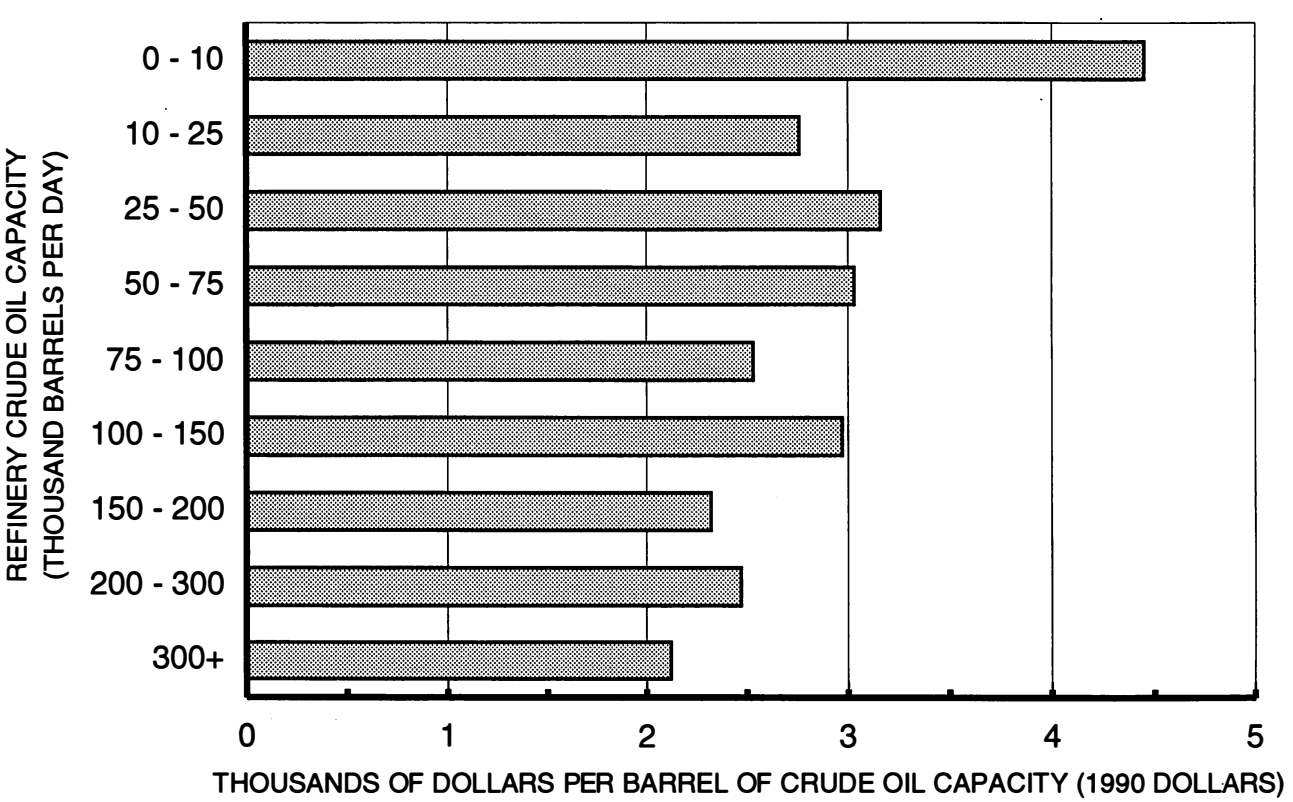


Figure 2-5. Refinery Size Group Environmental Cost—Capital and One-Time Expenses for 1991 through 2010.

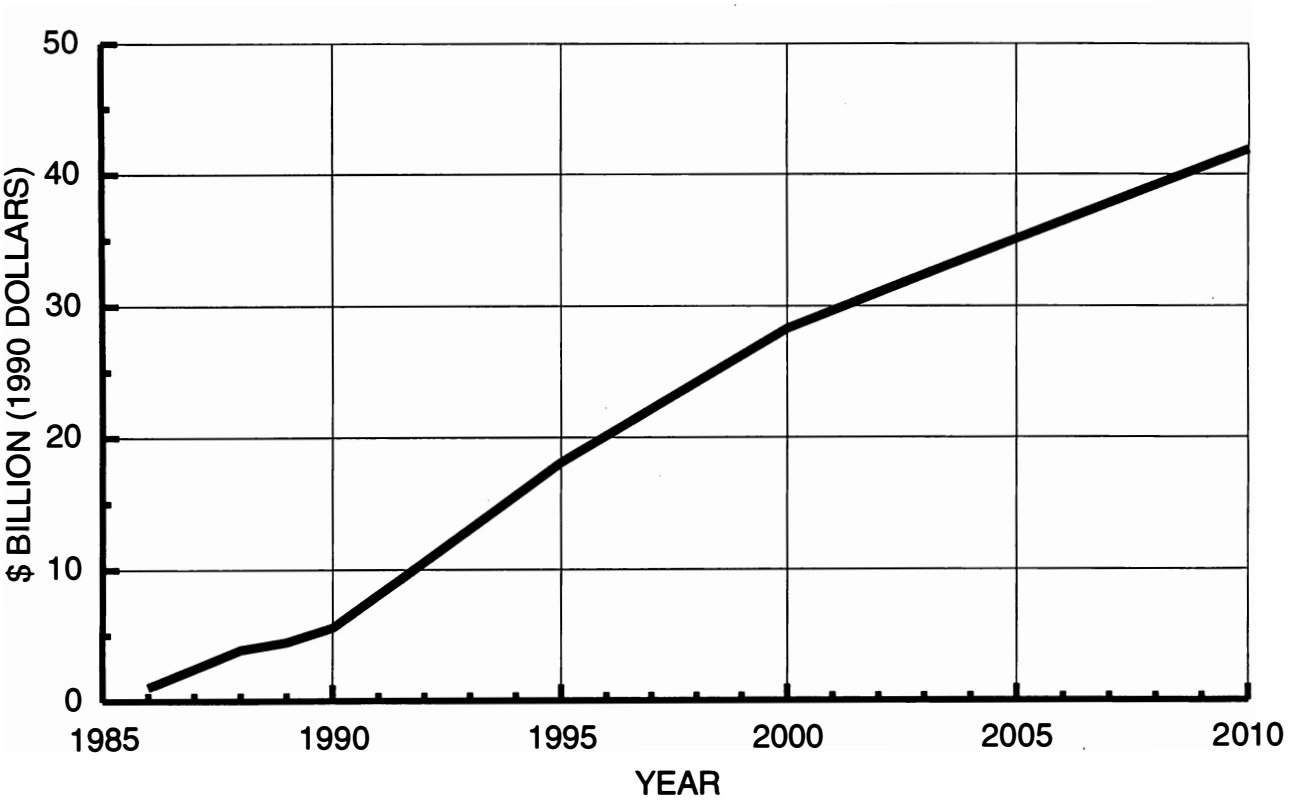


Figure 2-6. Environmental Capital Spending—Cumulative for 1986 through 2010.

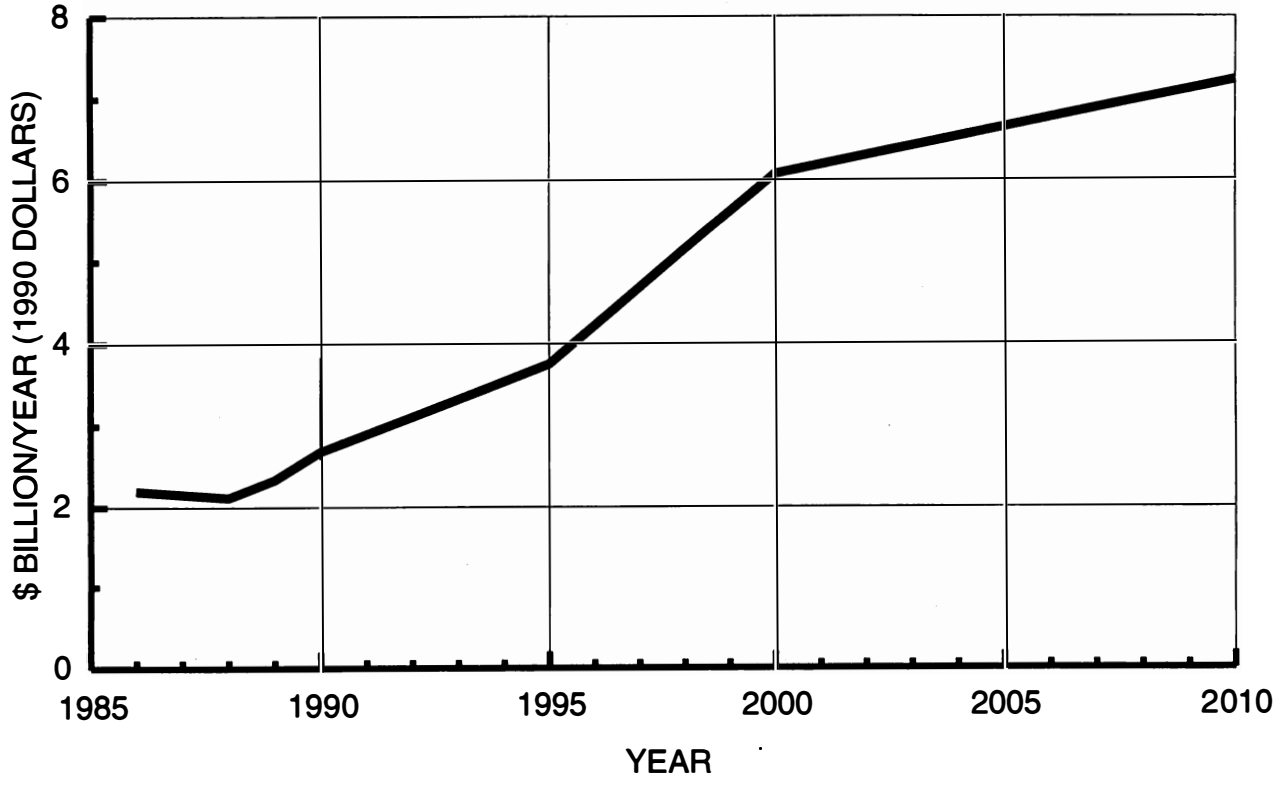


Figure 2-7. Environmental Operating & Maintenance Spending—Annual for 1986 through 2010.

ability to project the pace and severity of future regulations diminishes the further we look into the future.

A Sensitivity

To emphasize the potential effect of alternative rules interpretation, a cost sensitivity was developed (utilizing Section 5 of the Bechtel Report, which is in Appendix K, Section II). The base case, as shown in Figure 2-3, assumed contaminated soils could be handled through closure-in-place, but Figure 2-8 shows the added cost of over $180 billion for remediation of this same soil if incineration is required beginning in 1996. As can be seen, this "sensitivity" is larger than the *total* base case.

An Alternative — Amoco Yorktown

This chapter presents a comprehensive analysis of the overall effect of the environmental, health, and safety regulations (excluding reformulated fuels) on the U.S. refining industry. The study indicates that approximately $150 billion in capital and ongoing expenses are expected to be required to meet current and anticipated environmental regulations during the 1991-2010 period. While determining the costs of regulations, the NPC did not evaluate the current regulatory system nor rank the importance of various environmental programs and regulations.

Environmental protection and a healthy economy are two of America's most important goals. U.S. industries recognize that these two goals need not be mutually exclusive. However, if the United States is to remain competitive in a global marketplace, it must make the most effective use of its resources in achieving its environmental protection goals. Alternative approaches to the way environmental resources are currently protected must be considered.

A recent joint industry/EPA pollution prevention study at Amoco's Yorktown, Virginia refinery demonstrated that greater environmental benefits could be achieved at lower cost than the current command-and-control system

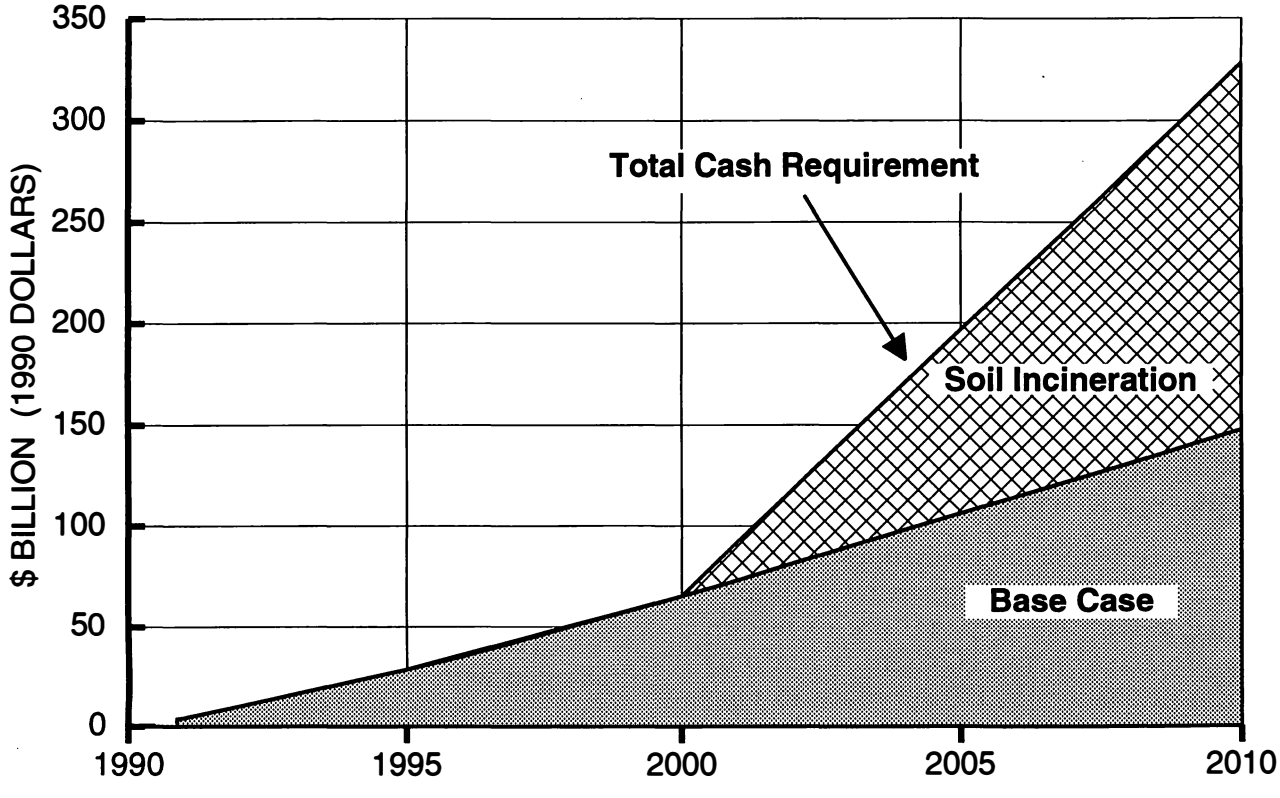


Figure 2-8. Cost Sensitivity for Soil Remediation. Incineration vs. Closure In-Place (Base)—Cumulative Cash Requirement.

allows. The findings of that study yielded these recommendations:

- Government and industry should establish partnerships to solve environmental problems, rather than operate as adversaries.
- Environmental protection objectives should incorporate risk assessment and relative risk reduction to establish long-term environmental protection priorities and achieve maximum benefits from finite resources.
- Legislation and regulations should direct environmental improvement by setting environmental protection standards rather than prescribing technologies. Allowing industries and facilities flexibility to achieve environmental performance goals will make the best use of resources, encourage innovation, and foster technology development.
- Government and industry should direct additional resources to quantifying emissions from facilities. Better emission inventories will yield improved legislation/regulations and help focus emission reduction strategies.

The Amoco/EPA project was not associated with the NPC study in any way, nor did it employ the same information gathering and cost estimating methodologies as the NPC study. Therefore, neither the premises of the two studies nor the cost estimates of the technologies applied can be directly compared. In fact, the Yorktown pollution prevention project indicated that facility emissions, and therefore associated emission reduction strategies, are site-specific and that the "one-size-fits-all" approach is unlikely to provide the most effective regulatory or technology solutions.

The Amoco/EPA study does suggest that current and future environmental goals may be attainable with less expenditure of resources than projected in the NPC study but only if significant changes in the approach to regulation and enforcement are effected.

The Executive Summary of the Amoco/EPA study is in Appendix K, Section III.

Observations

The following are based on analysis of quantitative study results and on qualitative observations.

- The cost for future environmental facilities and programs will be very large. This is graphically illustrated in Figure 2-9, which shows 12 regulatory requirements each of which will cost over a billion dollars.
- Directing limited resources (dollars and people) to environmental projects rather than to income producing or cost reduction projects has a detrimental effect on competitive posture.
- Environmental issues could be better handled as combined blocks (air, water, solid waste, etc.) rather than as individual items. The current fragmented approach tends to cause a dilution of effort, which is very cost-ineffective.
- Considering the long U.S. history of regulation by command and control through technology, perhaps more reasonable and economically sound controls could be achieved through objective risk assessment, multi-media controls, and market-based incentives.
- Even though responses to the qualitative sections of the survey indicated some perception that future construction permitting would be a problem, analysis of proposed project scheduling indicated that such would not be the case.
- It is projected that there are ample engineering, construction, and contractor resources available for the work required.

STUDY DESIGN AND CONCEPTS

Purpose

The Refinery Facilities Task Group was charged with the responsibility of describing and quantifying the cost impact of current and future environmental controls on U.S. refinery *stationary emission sources* during the 1991-2010 period. This information was developed to determine whether environmental costs will

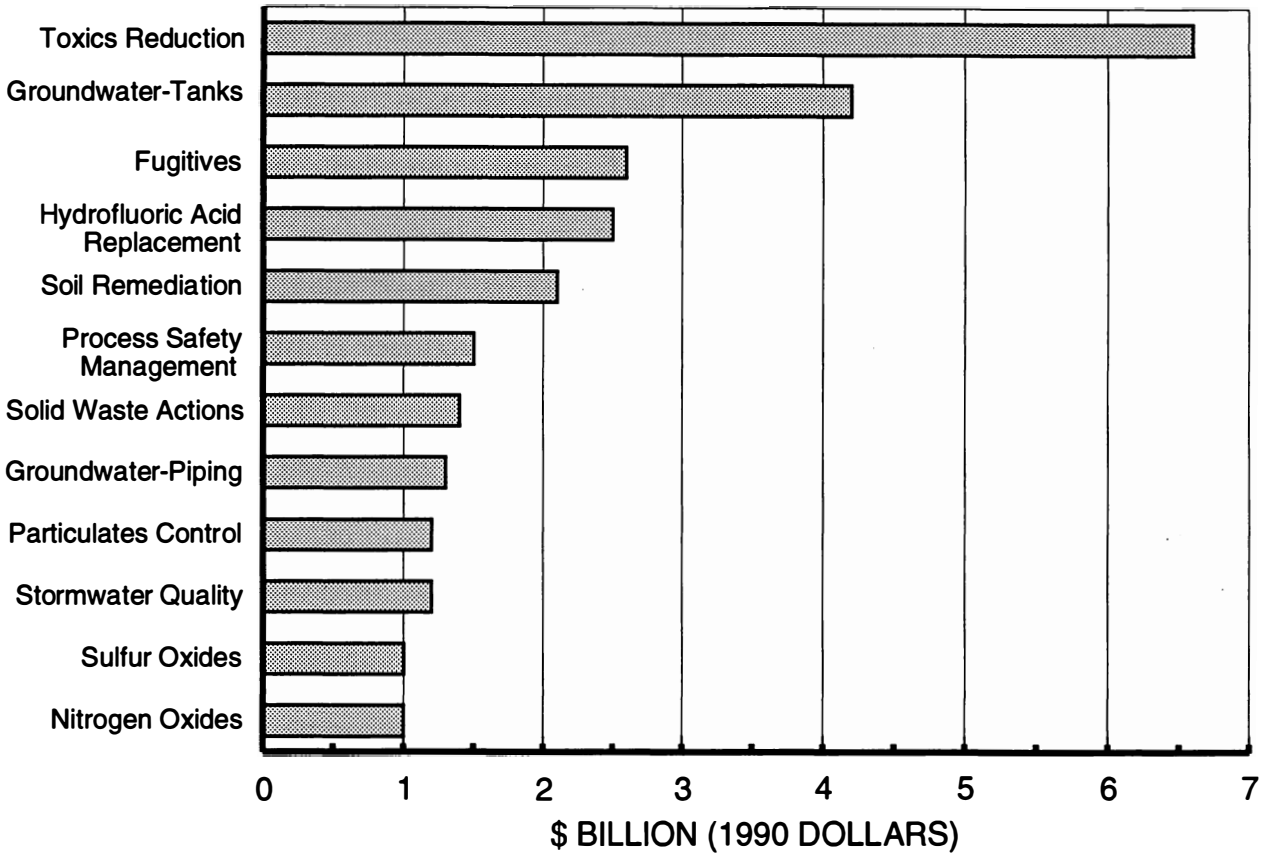


Figure 2-9. "Big" Environmental Items—Capital and One-Time Cost.

have a significant impact on the ability of the U.S. refining industry to compete. Costs associated with product quality (reformulated gasolines, oxygenates, low sulfur diesel fuel) were evaluated by the Product Quality Task Group.

Scope

Capital expenditures for new facilities, ongoing operating and maintenance costs for capital facilities and non-capital programs, and one-time expenses within the refinery fence line were to be developed for all U.S. refineries in the 1991-2010 period. Costs were determined for existing and anticipated regulations related to air, water, waste, and health and safety. Health and safety costs were included because existing and future regulations were expected to have a significant impact on refinery costs.

Methodology of Cost Estimation

The Task Group developed methodology to estimate the cost impacts for three periods: a historical period (1986 to 1990) and two covering the requested period (1991 to 2010). The historical period was added for reference and continuity. The other two periods were defined as the current period (1991 to 1995) and the future (1996 to 2010).

The methodology for preparation of estimates for each period is described below in detail. The cost estimates for the historical period (1986 to 1990) relied on data that refineries had previously submitted to the U.S. Department of Commerce. The estimates for the current period (1991 to 1995) were based on an NPC survey of U.S. refineries, soliciting their expenditures and plans, 1991 to 1995. Due to the uncertainty of future environmental regulation, the Task Group felt that refineries' estimates for expenditures beyond the year 1995 would be highly variable. As a result, the future period (1996 to 2010) required a different methodology.

In general, the current and future period results were based on a detailed "bottom-up" approach for estimating control technologies as opposed to extrapolation of historical data. Thus each significant element of environmental

regulation was identified and appraised, and suitable control responses estimated. In contrast, a "top-down" or aggregated approach would extrapolate the historical cost of the industry and adjust the extrapolation to account for anticipated step changes. The Task Group believed that the lack of precedents for new requirements would make historical projections unreliable and therefore chose the detailed "bottom-up" or "engineering" approach to measure the impact of the current and anticipated regulations.

Historical Period (1986–1990)

The determination of historical environmental cost information relied heavily on the NPC refining study survey because the best sources of accurate historical environmental information are the facilities that made the expenditures. The survey asked refineries to report O&M and capital costs already being submitted to the U.S. Department of Commerce on form MA-200 (see the Historical Costs section of this chapter). It was believed this approach would enhance the level of response and ensure a degree of consistency. The Task Group considered the alternative of preparing its own survey guidelines for historical data. It concluded that any improvement in data quality would be more than offset by reduced response relative to utilization of the MA-200. Refineries were requested to adjust MA-200 responses, removing depreciation from O&M, and to add refinery remediation costs. Capital expenditures were broken down into air-related, water-related, and hazardous and nonhazardous solid waste costs in current dollars.

Current Period (1991–1995)

To obtain information on projected expenditures over the short term for compliance with current and future environmental regulations, the Task Group sought to utilize data already available in the refining industry. The best source of expense and capital costs is again the facilities that face these costs. All companies have records of their actual environmental costs for the early years of this period and most companies have developed plans for expected capital expenditures during the later years of this period. Cost breakdowns were requested in the refinery survey for air, water, solid waste handling, as well as reformulated fuels and health and safety in 1991 constant dollars. Alternative approaches considered included having the Refinery Facilities Task Group or third party contractor estimate or extrapolate the costs for this time period, but it was determined that these options would not provide the same accuracy as data from those facilities affected by these regulations.

Future Period (1996–2010)

The methodology for calculating future costs relied on the premises of an expert panel (Table 2-3) and data characterizing refinery facilities from the NPC survey. The expert panel's premises on future environmental regulations (provided to the EPA for review) afforded the most complete and practical judgment of future regulations projected by individuals with extensive background in envi-

TABLE 2-3

FUTURE ENVIRONMENTAL REGULATIONS EXPERT PANEL

Air
Charlie Aarni – Chevron (Los Angeles)
Kent Rogers – Shell (Houston)
Karen Kennedy – Conoco (Houston)
Tom Richart – Chevron (Los Angeles)
John Gray – Ashland (Ashland)
Howard Klee – Amoco (Chicago)

Waste and Water
Harold Elkin – Sun Co. (Philadelphia)
Robert Nolan – Exxon (Houston)
Thomas Zale – Sun Co. (Philadelphia)
Ron Schmitt – Amoco (Chicago)
Julie Murphy – Amoco (Chicago)
Susan Sonnenberg – Mobil (Fairfax)

Safety
John Nabor – Sun Co. (Philadelphia)
Hal Day – Chevron (Los Angeles)

ronmental and safety regulations and refining knowledge. Again, the best source of information that describes the characteristics of refineries is the affected facilities questioned in the NPC refining study survey.

The estimating of future costs was done by Bechtel Corporation utilizing the expert panel's premises and data from the NPC survey. Bechtel reviewed all regulatory and technology assumptions before developing a cost estimating spread sheet model. The result of Bechtel's effort was capital expenditures, operating and maintenance expenses, and one-time expenses for future required environmental control systems (in constant 1990 dollars).

Because of a degree of uncertainty of future regulations, sensitivity cases were developed (see the Sensitivities section of this chapter). Downside sensitivities were not quantified but considered minimal; upside sensitivity could, though, be significant.

Total Industry Cost for Current and Future Periods

All current and future refinery environmental facilities costs were developed utilizing the nine size groupings shown in Table 2-4. The methodology using these groups takes advantage of certain technology size breaks and provides a strong analytical advantage. For the current period, survey responses were grouped by the nine sizes and average values determined. These were then used to calculate the cost associated with the full refinery population of each group. The future period costs were based on estimates developed for the average refinery in each of the nine size groupings.

The other Task Groups of the overall study required costing in the 13 geographic regions shown in Figure 2-10. Therefore, the cost from the nine size groupings were distributed into these regions as determined by the refinery size population in each region (Tables 2-5 and 2-6) and adjusted by location factors which were developed by the Task Group. Tables 2-7, 2-8, and 2-9 show the results. Location factors are discussed later in this chapter.

HISTORICAL COSTS (1986–1990)

To establish a reference point for evaluating the estimates of future costs of compliance with environmental regulations, data were needed on the costs for environmental facilities incurred over the recent past. A five-year period was selected as an appropriate reference time, with the belief that these past costs would be readily available for each facility and relevant to the study. Inclusion of historical data

TABLE 2-4

BECHTEL STUDY BASIS
U.S. REFINERIES – NINE SIZE GROUPINGS

Group	Capacity (MB/SD)	Number of Refineries	Tot. Cap. (MB/SD)	% of Total	Avg. Cap. (MB/SD)
a	0-10	26	175	1	7
b	10-25	24	400	2	17
c	25-50	40	1,545	9	39
d	50-75	28	1,730	11	62
e	75-100	12	1,060	6	88
f	100-150	24	3,025	18	126
g	150-200	11	1,935	12	176
h	200-300	14	3,545	22	253
i	300+	8	3,010	19	376
Total		**187**	**16,425**	**100**	**88**

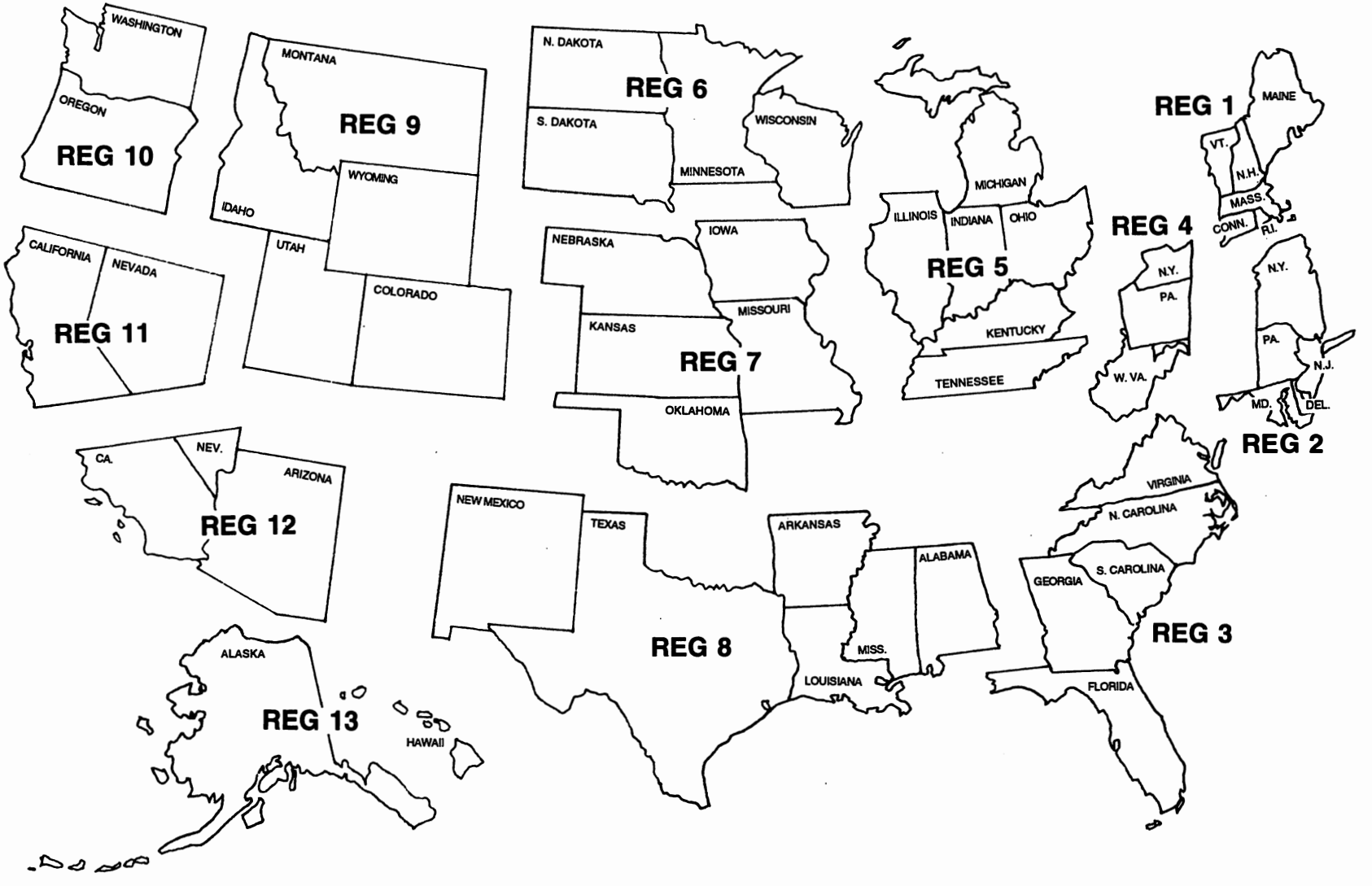


Figure 2-10. U.S. Regions–National Petroleum Council Refining Study.

TABLE 2-5

DISTRIBUTION OF REFINERY SIZES IN GEOGRAPHIC REGIONS
(Percentage of Size Volume in Region)

Size	Supply Region													
	1	2	3	4	5	6	7	8	9	10	11	12	13	Total
0-10			3	9	12			38	9		9	15	5	100
10-25				14	7		2	20	23			20	14	100
25-50		4			3	2	13	29	29	3		17		100
50-75			4	4	25	8	12	27	4		4	4	8	100
75-100		8					24	27		16	7	8	10	100
100-150		19			17		4	29		4	12	12	3	100
150-200		34			23			32		11				100
200-300					13	6		61			7	13		100
300+					16			84						100

TABLE 2-6

DISTRIBUTION OF REFINERY SIZES IN GEOGRAPHIC REGIONS
(Number of Refineries in Region)

Size	Supply Region													
	1	2	3	4	5	6	7	8	9	10	11	12	13	Total
0-10			2	2	4			8	2		2	5	1	26
10-25				3	1		1	6	4			6	3	24
25-50		1			1	1	5	13	12	1		6		40
50-75			1	1	7	2	4	8	1		1	1	2	28
75-100		1					3	3		2	1	1	1	12
100-150		4			4		1	7		1	3	3	1	24
150-200		4			3			3		1				11
200-300					2	1		8			1	2		14
300+					1			7						8
Total		**10**	**3**	**6**	**23**	**4**	**14**	**63**	**19**	**5**	**8**	**24**	**8**	**187**

TABLE 2-7

REFINERY FACILITIES COST – 1995
(1990 Dollars)

Capital: $ Million, 1991–1995
One-Time Expense (OTE): $ Million, 1991–1995
Operating And Maintenance Expense (O&M): $ Million per Year, 1995

NPC Region	Air	Water/ Waste	Safety/ Health	Total
Region 2				
Capital	460	405	134	999
OTE	56	182	59	297
O&M	152	149	31	332
Region 3				
Capital	32	20	8	60
OTE	6	14	4	24
O&M	5	5	1	11
Region 4				
Capital	38	36	13	87
OTE	9	24	10	43
O&M	9	13	2	24
Region 5				
Capital	1,026	667	209	1,902
OTE	151	379	94	624
O&M	277	241	38	556
Region 6				
Capital	171	96	28	295
OTE	43	80	12	135
O&M	42	34	6	82
Region 7				
Capital	277	186	92	555
OTE	57	132	40	229
O&M	60	62	14	136
Region 8				
Capital	3,352	1,950	601	5,903
OTE	521	1,207	290	2,018
O&M	929	730	97	1,756
Region 9				
Capital	186	135	95	416
OTE	44	125	44	213
O&M	48	48	10	106

1995 Continued				
Region 10				
Capital	166	147	52	365
OTE	29	72	25	126
O&M	53	51	13	117
Region 11				
Capital	355	223	69	647
OTE	71	156	32	259
O&M	101	99	12	212
Region 12				
Capital	568	365	136	1,069
OTE	132	288	65	485
O&M	165	156	22	343
Region 13				
Capital	135	101	38	274
OTE	26	61	19	106
O&M	29	36	7	72
Total				
Capital	6,766	4,331	1,475	12,572
OTE	1,145	2,720	694	4,559
O&M	1,870	1,624	253	3,747

TABLE 2-8

REFINERY FACILITIES COST – 2000
(1990 Dollars)

Capital: **$ Million, 1996–2000**
One-Time Expense (OTE): **$ Million, 1996–2000**
Operating And Maintenance Expense (O&M): **$ Million per Year, 2000**

NPC Region	Air	Water/ Waste	Safety/ Health	Total
Region 2				
Capital	195	551	152	898
OTE	2	120	13	135
O&M	53	135	20	208
Region 3				
Capital	13	38	13	64
OTE	0	3	1	4
O&M	3	13	2	18
Region 4				
Capital	25	86	19	130
OTE	1	5	2	8
O&M	7	26	2	35

2000 Continued

Region 5				
Capital	330	992	235	1,557
OTE	4	144	21	169
O&M	74	245	31	350
Region 6				
Capital	52	163	41	256
OTE	1	23	4	28
O&M	11	43	5	59
Region 7				
Capital	123	372	112	607
OTE	2	67	11	80
O&M	30	106	13	149
Region 8				
Capital	793	2,503	469	3,765
OTE	11	386	55	452
O&M	172	614	67	853
Region 9				
Capital	116	324	87	527
OTE	2	70	9	81
O&M	30	107	10	147
Region 10				
Capital	74	229	65	368
OTE	1	42	6	49
O&M	20	55	8	83
Region 11				
Capital	127	399	77	603
OTE	2	76	7	85
O&M	25	88	9	122
Region 12				
Capital	232	721	144	1,097
OTE	3	135	14	152
O&M	49	172	17	238
Region 13				
Capital	61	201	53	315
OTE	1	24	5	30
O&M	15	54	7	76
Total				
Capital	2,141	6,579	1,467	10,187
OTE	30	1,095	148	1,273
O&M	489	1,658	191	2,338

TABLE 2-9

REFINERY FACILITIES COST – 2010
(1990 Dollars)

Capital: $ Million, 2001–2010
One-Time Expense (OTE): $ Million, 2001–2010
Operating And Maintenance Expense (O&M): $ Million per Year, 2010

NPC Region	Air	Water/ Waste	Safety/ Health	Total
Region 2				
Capital	266	806	149	1,221
OTE	0	121	8	129
O&M	20	67	22	109
Region 3				
Capital	13	56	13	82
OTE	0	3	1	4
O&M	1	4	2	7
Region 4				
Capital	27	125	19	171
OTE	0	5	1	6
O&M	2	10	2	14
Region 5				
Capital	404	1,462	231	2,097
OTE	0	145	12	157
O&M	29	115	33	177
Region 6				
Capital	47	244	40	331
OTE	0	23	2	25
O&M	3	19	6	28
Region 7				
Capital	99	548	110	757
OTE	0	67	6	73
O&M	8	43	15	66
Region 8				
Capital	932	3,715	459	5,106
OTE	0	390	30	420
O&M	67	290	67	424
Region 9				
Capital	88	476	86	650
OTE	0	71	5	76
O&M	7	40	11	58

2010 Continued				
Region 10				
Capital	89	337	64	490
OTE	0	42	4	46
O&M	7	27	9	43
Region 11				
Capital	131	590	75	796
OTE	0	77	4	81
O&M	10	45	11	66
Region 12				
Capital	215	1,067	141	1,423
OTE	0	136	7	143
O&M	16	85	19	120
Region 13				
Capital	59	294	53	406
OTE	0	25	3	28
O&M	4	22	7	33
Total				
Capital	2,370	9,720	1,440	13,530
OTE	0	1,105	83	1,188
O&M	174	767	204	1,145

in the study analysis also helps to ensure continuity between actual and projected expenditures, especially for regulations and projects that have cost continuums.

Historical Expenditures

U.S. refining companies routinely record and report their expenditures made for environmental regulations in several ways; to employees, stockholders, and regulatory agencies. Considering the options and formats available, the Task Group decided to request historical spending information in a format similar to that which refineries already file annually with the U.S. Department of Commerce, Bureau of Census, on their MA-200 form, "Survey of Pollution Abatement Costs and Expenditures." This report requires disclosure of annual operating costs, capital expenditures, and payments for abatement of air pollutants, water pollutants, and solid waste management. This report was deemed to provide adequate detail to establish a reliable historical base of spending for environmental regulations. Use of the MA-200 report format facilitated a good survey response by using data that was readily available, and would also help ensure that the response data would be consistent across the refining industry.

Survey Questionnaire

The questions regarding information on the economic impacts of environmental regulations on refineries were included in Section IV of the NPC survey. Historical cost information was requested for the years 1986 through 1990 in actual year dollars.

Survey Results

The response from refiners regarding cost information was very good. Surveys were sent to all U.S. refineries, and 72 percent provided responses, representing almost 95 percent of U.S. crude oil processing capacity. The survey data were extrapolated to account for those refineries that did not respond to the survey.

When reviewing the survey data, it was observed that the number of survey respondents who supplied data for 1987 was lower

than that of the other years. It was surmised that low response might be related to the fact that the Department of Commerce did not request the MA-200 cost information for 1987. Nonetheless, the extrapolation process will tend to normalize the difference.

Significant Observations

Capital Expenditures

Extrapolated for non-respondents, U.S. refineries have expended approximately $5.6 billion of capital for emissions controls between 1986 and 1990. The breakdown by year and media is shown in Table 2-10.

Operating, Maintenance, and One-Time Expenses

Extrapolated for non-respondents, U.S. refineries have spent approximately $10.2 billion over the years 1986 through 1990 on O&M and one-time expenses for air, water, and solid waste emissions controls. The breakdown by year and media is shown in Table 2-11.

CURRENT COSTS (1991–1995)

The Refinery Facilities Task Group evaluated several options (as discussed earlier in this chapter) to obtain information on projected expenditures during the current period to comply with current and future environmental regulations. The Task Group sought to utilize data already available in the refining industry.

Planned Expenditures

Most companies annually develop plans for expected capital expenditures for the next five-year period. Some companies have ten-year capital plans, but regard the second five

TABLE 2-10

HISTORICAL CAPITAL EXPENDITURES TO MEET ENVIRONMENTAL REGULATIONS ($ Million in Actual Dollars)

Item	1986	1987	1988	1989	1990	Total
Air	591	1,036	324	220	528	2,699
Water	228	170	375	298	537	1,608
Solid Waste	68	98	664	268	150	1,248
Total	**887**	**1,304**	**1,363**	**786**	**1,215**	**5,555**

TABLE 2-11

HISTORICAL OPERATING AND MAINTENANCE EXPENSES AND ONE-TIME EXPENSES ENVIRONMENTAL REGULATIONS ($ Million in Actual Dollars)

Item	1986	1987	1988	1989	1990	Total
Air	868	869	1,084	1,178	1,317	5,316
Water	840	357	571	659	733	3,160
Solid Waste	186	178	294	417	626	1,701
Total	**1,894**	**1,404**	**1,949**	**2,254**	**2,676**	**10,177**

Note: Survey did not differentiate Operating & Maintenance and One-Time Expenses.

years in the plan as a look ahead rather than a more specific, tactical plan.

For annual expense forecasts, companies typically develop budgets for the upcoming year that account for increases in productivity, new and changed operations (e.g., due to capital projects), non-recurring "one-time" expenses (e.g., environmental remediation), inflation, etc.

The Task Group believed that, notwithstanding the accuracy limitations in spending forecasts, the operating refineries were the best source of spending forecasts for the current period.

Survey Questionnaire

The survey questionnaire requested information on planned expenditures for capital and OTE costs for the five-year period 1991-1995, and O&M expenses for the single calendar year 1995. All costs were to be supplied in 1991 dollars. Cost breakdowns were requested for air, water, solid waste emissions, as well as reformulated fuels and health and safety. These last two categories are not included in the MA-200 report.

Additional information was required for other purposes of the study. A detailed breakdown of capital investment expenditures for each of 23 different types of operating units, such as crude oil distillation, hydrotreating, hydrogen manufacturing, etc., was requested by other NPC Task Groups (Supply, Demand, and Logistics Task Group and Product Quality Task Group) for their studies.

Since there was a concern that the regulatory permitting process might jeopardize the timely construction of environmental facilities, the survey also requested information on the start-up dates and expected construction permit approvals for the unit-specific capital projects.

Finally, information was requested regarding the status of process hazards analyses (PHAs) and their corresponding corrective action, which companies had performed on the same 23 different types of refinery operating units.

Survey Results

The response from refiners regarding cost information was very good. Surveys were mailed out to all U.S. refineries. Seventy-two percent of the refineries returned data in Survey Section IV, representing almost 95 percent of the U.S. crude oil processing capacity. The survey data were extrapolated according to crude oil capacity, to account for non-respondents. The number of refineries responding to the survey, detailed according to the nine refinery size-complexity groupings, is shown in Table 2-12 along with the adjustments made to the survey responses.

In addition to extrapolating the survey data for non-respondents, costs were adjusted upward by 10 percent for California refineries to account for uncertainties in California environmental requirements.

Significant Observations

Capital Expenditures

For air, water, and solid waste emission controls (excluding reformulated fuels), refineries plan to spend approximately twice the average annual capital in the 1991-1995 period as they spent in 1990. Extrapolated for non-respondents, U.S. refineries expect to spend $12.6 billion for compliance with environmental regulations between 1991 and 1995, compared to $5.6 billion reported as spent between 1986 and 1990. A breakdown of the planned capital expenditures is shown in Table 2-13.

According to survey results, most of the capital expenditures for the benzene National Emission Standards for Hazardous Air Pollutants (NESHAP) rule will be made in refineries over 100 thousand barrels per stream day of crude oil capacity.

Based on survey results, individual components of the environmental (facilities and fuels) five-year capital plans (1991-1995) are ranked from greatest expenditure to least:

1. reformulated gasoline (fuels)
2. low sulfur diesel (fuels)
3. local air regulations (facilities)
4. oxygenated gasoline (fuels)
5. benzene waste NESHAP (facilities)
6. Clean Water Act/NPDES (facilities)
7. solid waste (facilities)

TABLE 2-12

REFINERY ENVIRONMENTAL FACILITIES AND PROGRAMS — 1991–1995 INVESTMENT AND COST DEVELOPMENT (1990 Dollars)

	Capital		One-Time Expenses		O&M Expenses	
	$ Million	%	$ Million	%	$ Million per Year	%
Survey	9,828	78	3,015	67	2,963	79
Adjust	2,772	22	1,485	33	787	21
Total	**12,600**		**4,500**		**3,750**	

SUPPORTING SURVEY RESPONSE

Refinery Size (MB/D)	Number of Refineries	Number Responding	% Responding
0-10	26	8	31
10-25	24	8	33
25-50	40	25	63
50-75	28	20	71
75-100	12	10	83
100-150	24	18	75
150-200	11	10	91
200-300	14	13	93
300+	8	7	88
Total	**187**	**119**	**64**

TABLE 2-13

CAPITAL EXPENDITURES REQUIRED TO MEET CURRENT ENVIRONMENTAL REGULATIONS ($ Million in 1990 Dollars)

Item	1991–1995
Air	6,800
Water & Solid Waste	4,300
Health & Safety	1,500
Total	**12,600**

Operating, Maintenance, and One-Time Expenses

The survey did not provide data for 1991-1994; however, if relatively smooth growth is assumed and if the information is extrapolated for non-respondents, U.S. refineries are projected to spend approximately $20 billion over the years 1991 through 1995 for O&M and OTE as compared to $10.2 billion spent over the years 1986 through 1990. The 1995 O&M and 1991-1995 OTE cost breakdowns are shown in Tables 2-14 and 2-15.

O&M expenses for air, water, and solid waste emissions controls (not including reformulated fuels projects) are expected to rise moderately (27 percent) between 1990 and 1995. The largest OTE in operating refineries

TABLE 2-14

OPERATING & MAINTENANCE EXPENSES REQUIRED TO MEET CURRENT ENVIRONMENTAL REGULATIONS ($ Million Per Year in 1990 Dollars)

Item	1995
Air	1,900
Water & Solid Waste	1,600
Health & Safety	250
Total	**3,750**

Note: These values include approximately $2.3 billion per year resulting from pre-1991 requirements.

TABLE 2-15

ONE-TIME EXPENSES REQUIRED TO MEET CURRENT ENVIRONMENTAL REGULATIONS ($ Million in 1990 Dollars)

Item	1991–1995
Air	1,100
Water & Solid Waste	2,700
Health & Safety	700
Total	**4,500**

over the next five years (1991 to 1995) is projected to be for solid waste management, primarily remediations.

Health and Safety

Process hazards analyses are still in their infant stage. Through 1991, $110 million had been spent for corrective action completed or resolved on a total of 173 units at 57 refineries. The budget for remaining corrective action is $317 million for the 155 units at 54 refineries that have unresolved corrective action on completed PHAs.

Extrapolated for non-respondents, U.S. refineries would be expected to spend $1.6 billion for corrective action related to PHAs.

Construction and Operating Permits

Obtaining construction permits does not appear to cause a problem with construction or revamps made to comply primarily with environmental regulations. The survey results showed, in general, that construction permits can be obtained and construction can be completed prior to the regulatory compliance dates. This does not, however, reflect difficulties that seem to be developing in obtaining *operating* permits, particularly in California.

FUTURE COSTS (1996–2010)

This section projects the costs to the refining industry of complying with both current and future stationary source and refinery facility environmental regulations for the 1996-2010 period. The methodology used was to premise a consistent set of environmental regulations. Survey information was utilized to define the state of refinery facilities at the end of 1995. For example, since a premise was that underground pipe will have to be replaced with above-ground pipe, an estimate of the amount of underground pipe was needed. The final steps were to (1) select the technology that would be used to satisfy the premised regulations and (2) determine the costs of implementation.

The premised regulations considered only items believed to have significant financial impact and thus, by omitting numerous small items, this approach tended toward conservative or low cost estimates. These regulations were developed by media. However, there are some allocations that must be made in developing the costs by media. For example, the cost of handling increased solid waste resulting from additional treatment at the waste water treatment plant could be displayed under either waste water or solid waste.

The Process for Projecting Costs

The regulations with which industry will have to comply are in various stages of development. Some regulations are final and the requirements are clear. The Clean Air Act Amendments of 1990 define a framework of regulation but the details of those regulations will be finalized over the next several years. For example, Maximum Achievable Control Technologies (MACT) for refineries is to be defined by the end of 1994. Over the time frame of 1996 to 2010, new regulations will be adopted and implemented.

To develop a realistic set of projections of the environmental regulations, a group of refinery environmental experts were assembled. These experts, knowledgeable in the current regulations, met in June of 1991 to develop a consensus forecast of future regulations. This work, which was done by media, was the basic building block of the premised regulations. The Task Group met with Bechtel, the contractor selected to quantify the future environmental costs, starting in mid-1991. The regulatory premises were reviewed with Bechtel's specialists over the next year. In an iterative process some of the premised regulations were modified. For example, one original premise was that since most refineries were in ozone nonattainment areas, the same controls would apply to all refineries. However, when Bechtel's model was developed to distinguish between the various levels of nonattainment, the premise was revised so that these areas would be treated differently. Another area where the initial premises were modified was in the effluent treatment system. There is an interrelation between the process sewer system, the storm water system, the size of the effluent treatment plant, and the amount of storage required. The premises were modified to give a consistent, integrated solution that would be cost-effective for the entire system.

The refinery survey was used as a tool to develop base-line information about facilities at refineries at the end of 1995. Examples of information from the survey are the amount of underground piping, number of pressure relief valves venting to the atmosphere, level of effluent treatment, and volume of contaminated soil. This type of information was not readily available from other sources.

Methodology — Bechtel Study

General Background

The principal task of the contractor, Bechtel, was to estimate the cost of environmental stationary source controls for domestic refineries from 1996 through 2010.

Bechtel's basic assignment was to translate the conceptual environmental control systems into detailed engineering solutions and provide consistent cost estimates for each air, water, ground water, solid waste, health and safety category. The NPC assumptions-premises are discussed later in this chapter. The NPC Task Group met frequently and conferred continually with Bechtel during the course of this work to ensure consistency and consensus agreement on the basis for cost estimating.

Bechtel Methodology for Cost Estimating Environmental Control Systems

Categorization

Bechtel categorized the U.S. refining system by nine groups based on size-complexity, which generally reflected technology breakpoints in processing and off-site complexity (see Table 2-16). The rationale for the selection

TABLE 2-16

BECHTEL SIZE CATEGORIES

Group	Crude Oil Capacity (Barrels per Stream Day)
a	1,000 – 10,000
b	10,001 – 25,000
c	25,001 – 50,000
d	50,001 – 75,000
e	75,001 – 100,000
f	100,001 – 150,000
g	150,001 – 200,000
h	200,001 – 300,000
i	300,001 – plus

of the nine groupings was to provide sufficient categorization so that "average" control equipment and systems would be representative for each group without further subdivision. This degree of refinement also served to ensure representative cost estimates for each category.

Bechtel developed facility costs for each environmental category in each of the nine refinery size groupings. The Task Group adjusted the Bechtel costs to account for location differences and distributed those costs by geographic region.

Basis

The contractor estimated environmental facility costs for the U.S. Gulf Coast as the Base Case. Mid-1990 Gulf Coast construction rates were used as the basis for capital investment costs. The O&M expenses were developed utilizing mid-1990 Gulf Coast unit costs for labor, utilities, and chemicals. Maintenance expenses were estimated as a percentage of capital investment. OTE were also developed based on mid-1990 Gulf Coast conditions.

Time Intervals Studied

The time intervals for analysis purposes in the future period were defined as:

- 1996 to 2000
- 2001 to 2010

All premises and subsequent Bechtel estimates were made on these intervals.

Bechtel Utilization of Survey Data

The contractor had full access to the *aggregated* response data. These data (Survey Sections III and IV) provided a useful benchmark for current expenditures and base line qualitative and quantitative data on existing refinery facilities, equipment, and above and below grade in-place systems, as well as data on exposure to future environmental requirements.

Bechtel Utilization of NPC Assumptions/Premises

As described in detail later in this chapter, the contractor based the study and derivative cost estimates on the premises supplied to them by the Task Group.

Bechtel Knowledge-Base

In addition to consultation with members of the NPC Task Group, Bechtel relied on:

- Public information sources, correspondence (published as well as unpublished), inquiries, technical papers, vendor material, etc.
- Critical evaluation of equipment vendor information. These representations were generally put to the test of "iron-clad" warranties before acceptance as an engineering "solution." In other words, technology had to be assured by full cost replacement by suppliers if "guaranteed" performance failed.
- Field experience by NPC-member companies.
- Consultation with relevant government agencies.
- Bechtel's past and current environmental projects for clients. The resources and knowledge base of Bechtel's Environmental subsidiary company were available throughout the study project.

Location Factors — Selection and Rationale

Capital Expenditures

Assigning a base case factor of 1.0 to the Gulf Coast, the Task Group developed the following geographic adjustment factors:

- Gulf Coast (Open Shop) — 1.0
- Balance of the U.S. (excluding California) — 1.2
- California — 1.4.

One-Time Expenses

A California escalation factor of 1.1 was assigned to reflect added ongoing burden as judged by Task Group members.

Operation and Maintenance Costs

O&M expenses related to capital were adjusted in the same fashion as the capital cost.

Summary of Geographic Adjustment Factors

All location factors are summarized in Table 2-17.

- The 1.1 California OTE factor reflects the ongoing added burden in the area.
- O&M factors reflect adjustments related to the capital.

Sensitivity Cases

Bechtel also developed costs estimates for a number of assumptions-premises control technologies that were not deemed appropriate for inclusion in the "base case" assumptions. These were considered as sensitivities in the interest of completeness. They are discussed in the Sensitivities section of this chapter.

Definitions (all costs in 1990 dollars)

- *Capital* costs were expenditures related to physical improvements which were depreciated over more than one year.
- *One-Time Expense* (OTE) costs were assigned to those implementation categories that tend to be remediation costs, and were accounted for as expense in the year incurred.
- *Operating and Maintenance* (O&M) costs were dollars accounted as expense during the year incurred. They were assumed to begin upon project completion and continue.

Premises

The individual premises-assumptions, which were developed by the Expert Panel and modified by the Task Group, where appropriate after discussion with the contractor, are displayed in Tables 2-18, 2-19, 2-20, and 2-21 and listed again in the Bechtel Report, in Appendix K, Section II. The discussion below identifies specific areas and assumptions for the study.

Air

The Clean Air Act Amendments of 1990 (CAAA) will impact the petroleum industry across all aspects of its operations. The product quality requirements mandated by the CAAA (TITLE II) are addressed in other chapters. The major impacts on refining facilities are attainment of ambient air quality standards (TITLE I), hazardous air pollutants (TITLE III), and permits (TITLE V).

Attainment of Ambient Air Quality Standards

The EPA determines which areas of the country do not meet the ambient air quality standards for the five criteria components—ozone, NOx, SOx, PM-10, and carbon monoxide. The states must then develop a

TABLE 2-17

GEOGRAPHIC ADJUSTMENT FACTORS
1996-2000 and 2001-2010

Region	Capital	One-Time Expenses	O&M Expenses
Gulf Coast	1.0	1.0	1.0
California	1.4	1.1	1.2/1.4*
Balance of U.S.	1.2	1.0	1.1/1.2*

* For 2001-2010.

TABLE 2-18

AIR CONTROL TECHNOLOGIES TO BE CONSIDERED FOR COST ANALYSIS

Subject (Limit/Scope)	Refinery Size (B/SD)	CONTROL TECHNOLOGY (Percent Implementation)*			
		Attainment	Nonattainment		
PM-10	All	High Efficiency Precipitator[a] (50-50-0)			
SOx	< 25,000	Sulfur Recovery Unit (SRU) (50-25-25)			
	25,000 - 50,000	SRU + TGU (Tail Gas Unit)(0-75-25)	SRU + TGU + SOx promoter (50-25-25)		
	> 50,000	SRU + TGU (0-75-25)	SRU + TGU + FCC stack gas scrubber (0-75-25)		
CO	All	b			
NOx[c]	< 100 MMBTU[d]	None	**Extreme**	**Severe**	**< Severe**
			Heater: ultra low-NOx burners[e] (50-50-0) FCC[f]: SCR (0-75-25)	Heater: ultra low-NOx burners[e] (25-75-0) FCC[f]: SCR (0-0-100)	Heater: ultra low-NOx burners[e] (0-50-50)
NOx[c] (20 ppm - FCC)	>100 MMBTU[d]	None	**Extreme**	**Severe**	**< Severe**
			Heater: SCR[g] (50-50-0) FCC[f]: SCR (0-75-25)	Heater: ultra low-NOx burners[e] (25-75-0) SCR[g] (0-0-100) FCC[f]: SCR (0-0-100)	Heater: ultra low-NOx burners[e] (0-50-50)

TABLE 2-18 (CONTINUED)

Fugitives (MACT) (pumps, valves, flanges, compressors)	All	Pumps: LO Tandem seals – 5% replacement/yr; Valves: 3% replacement/yr; Reciprocating Compressors: Box 10% of distance pieces and combust vapors[g] (75-25-0); Enhanced Inspection & Maintenance (I&M)[i]
Pressure Relief Valves	All	Vent to flare (25-50-0)[h,i] (excludes vents from very large towers)
Storage Tanks (MACT) (light products)	All	Internal floaters – no action; Tanks with single seals add double seals (25-75-0); Domes on 1/2 of external floaters (0-0-100)
Coker Vents	All	Scrubbers (25-75-0)
Coke Handling	All	Enclose conveyors and storage (25-25-50)
Waste Treatment System (MACT)	All	Cover and thermal oxidizer; primary separation (50-50-0); activated sludge (25-25-50)
Waste Handling (MACT)	All	Total enclosure (50-50-0)
H_2S	All	VOC Controls in place – no additional controls costed
Odor (MACT)	All	PSM and VOC Controls in place – no additional controls costed
Permits and Fees	All	$25/ton plus escalation; (limit 4000 tons/regulated pollutant/yr)
Offsets	All	No additional costing, included as capital cost of new units
Combustion/Toxics	All	Switch to clean fuel (25-75-0)
Unit Redundancy	All	Add capacity to handle shut-down of largest "control" units (i.e., precipitators, SRUs, TGUs, spares) (0-25-50)

a To control metals to comply with Maximum Achievable Control Technology (MACT).
b Proper operation of existing equipment (CO boiler and process heaters) will satisfy requirements.
c Based on ozone nonattainment.
d Heater size.
e Controlled to 0.05 pounds per million BTU.
f Independent of heater size.
g Controlled to 0.02 pounds per million BTU.
h One new flare will be costed per refinery to control emissions from pressure relief valves, process vents, fugitives, etc.
i Sensitivity analysis performed.

* Note: During periods 1991 through 1995, 1996 through 2000, and 2001 through 2010.

TABLE 2-19

WASTEWATER TECHNOLOGIES TO BE CONSIDERED FOR COST ANALYSIS

Subject	Limit/Scope	Technology	Percent Implementation During 1991 - 1995	1996 - 2000	2001 - 2010
Clean Water Act Reauthorization Process Wastewater Reuse	Maximum practical reuse of process wastewater	Use effluent as cooling tower makeup. Sidestream – treat to minimize blowdown.	0	0	50
New BAT (Best Available Technolgy) Mandated	Assume maximum organic/metals removal	Filtration of ASP/PACT Treatment. Two-stage activated sludge (ASP). Powdered activated carbon (PACT). Target heavy metal precipitation.	Capital, O&M, and One-Time Costs included in biomonitoring		
Water Quality Based NPDES Permits	Reduce toxicity of effluent (biomonitoring)	Filtration of ASP/PACT Treatment. Two-stage activated sludge (ASP). Powdered activated carbon (PACT). Target heavy metal precipitation.	0	50	50
	Reduce oil to sewer, storm water contamination	Exclude storage tanks drawoffs from storm sewers. Hard pipe tank drawoff to segregated sewer system.	Capital, O&M, and One-Time Costs included in groundwater		
	Reduce oil to sewer, storm water contamination	Exclude hydrocarbon samples from storm sewers. Install closed loop samplers.	25	50	25
	Reduce storm water contamination	Intercept process unit pad drains. Build segregated process pad drainage lift stations.	75	25	0
	Reduce runoff from unpaved process areas	Pave non-pad process areas to reduce total suspended solids	75	25	0
	Reduced discharge of suspended solids	Filtration of ASP/PACT Effluent. Pave non-pad process areas to reduce total suspended solids	75	25	0
		Route runoff to same segregated lift stations	75	25	0

TABLE 2-19 (CONTINUED)

Subject	Limit/Scope	Technology	Percent Implementation During 1991 - 1995	1996 - 2000	2001 - 2010
Sediments Criteria	Sediments discharged from waste water treatment plant	Develop estimate to quantify and remediate areas where sedimentation has occurred.	0	0	25
Stormwater Quality	Store and treat quantity of contaminated storm water from 10-year storm	Intercept process unit pad drains. Build segregated process pad drainage lift stations. Store and treat all stormwater runoff from process unit pads. Route runoff to same segregated lift stations.	25	25	50
Groundwater Issues Pollution Prevention – Tanks	Prevent groundwater pollution from storage tanks	Retrofit all storage tanks (not now covered by RCRA) with double bottoms.	25	25	50
	Prevent groundwater pollution from storage tanks	Install membrane liners and crushed stone inside tank farm diked areas. Route runoff to same segregated lift stations provided for tank drawoffs.	0	0	25
Pollution Prevention – Process Piping	Prevent groundwater contamination from underground process piping	Daylight (expose) below grade process piping, leak detection. Use survey data to quantify underground piping to be modified.	25	25	50
	Prevent groundwater contamination from underground process sewers	Hard pipe tank drawoff to segregated sewer system.	25	25	50

TABLE 2-20

HAZARDOUS AND NONHAZARDOUS SOLID WASTES TECHNOLOGIES TO BE CONSIDERED FOR COST ANALYSIS

Subject	Limit/Scope	Technology	Percent Implementation During 1991 - 1995	1996 - 2000	2001 - 2010
Groundwater Issues Pollution Prevention – Facility Wide	Remediation	Install and operate ground-water monitoring wells along two sides of the facility perimeter – 200 foot spacings	0	50	50
	Remediation	Install and operate ground-water recovery wells along two sides of the facility perimeter – 200 foot spacings	0	50	50
Above Ground Tanks	40 years old*	Demolish and replace with like capacity 1/2 tanks older than 40 years old. Light hydrocarbon tanks – double bottom, double seals – heavy hydrocarbon – double bottoms.	0	25	50
RCRA Reauthorization	Additional waste listings	Additional refinery wastes and waste like products may be listed as hazardous wastes in the future. These additional wastes which might include non-leaded tank bottoms, spent FCC catalyst, spent caustic, etc. will require additional handling expenditures for storage, transportation for disposal and disposal or treatment.	0	100	0
RCRA Toxicity Characteristic Land Disposal Restrictions	Surface impound-ments*	Most RCRA surface impoundments will be closed or retrofitted to meet RCRA minimum technology requirements prior to 1995. A few impoundments may require retrofit after that date. These impoundments may be newly listed waste facilities or units which are retrofitted.	100	0	0

TABLE 2-20 (CONTINUED)

Subject	Limit/Scope	Technology	Percent Implementation During 1991 - 1995	1996 - 2000	2001 - 2010
RCRA Corrective Action Pollution Prevention	Remediate contaminated soil*	As regulations become more stringent, non-SWMU contaminated soils will require monitoring to determine any threat to the environment and eventually treatment or disposal.	0	25	25
	SWMUs – non-hazardous	Solid Waste Management Units (SWMUs) which manage nonhazardous solid waste will be monitored to ensure that the materials do not pose a threat to the environment.	25	25	0
	SWMUs – inactive, hazardous*	SWMUs which managed hazardous waste and are now inactive will be monitored, closed or treated in place or closed by removal according to RCRA closure requirements.	25	25	25
	SWMUs – active, hazardous*	SWMUs which managed hazardous waste and are now active will be monitored, closed or treated in place or closed by removal according to RCRA closure requirements.	0	0	100
CERCLA Loss of the Petroleum Exclusion	Nonhazardous to hazardous	Issue item to discuss possible impacts of the loss of the petroleum exclusion on the refining industry.	—	—	—

* Upside sensitivity costs were developed.

TABLE 2-21

SAFETY AND HEALTH CONTROL TECHNOLOGIES TO BE CONSIDERED FOR COST ANALYSIS

Subject	Premises	Percent Implemented During 1991-1995	1996-2000	2001-2010
Permit to construct and operate based on result of probabilistic risk assessment of potential community impact from hazardous materials release.	Likely, for new facilities by 2000. Not as likely for modifications to existing facilities. Harmful to industry if process to obtain permit is lengthy.	25	75	0
Establishment of safety design requirements for refinery process computer control systems (redundancy levels, human factors considerations).	Moderately possible. Could involve significant limitations and restrictions.	100	0	0
Legislated phase out of materials regarded as highly hazardous (e.g., hydrofluoric acid, chlorine, anhydrous ammonia) where suitable, less hazardous substitutes exist.	Likely over a period of time to allow for unit modifications. More likely for some materials than others.	0	50	50
Establishment of performance criteria for the handling of ceramic fiber/calcium silicate materials.	Very likely.	25	50	25
Establishment of training and company certification requirements for various levels of refinery operators.	Likely. Will probably start as required training specifications.	100	0	0
Establishment of requirements for the control of worker exposure to toxics.	Existing regulations may be interpreted in a stricter manner to incorporate MACT/BACT. It may be phased in via new construction only.	100	0	0
Establishment of requirements that person/organization (owner) which utilizes the services of a contract employee must provide training similar to that provided to owner employees.	The trend will likely continue with contract employees required to have a certain basic training supplemented by site-specific training.	100	0	0
29 CFR 1910.119 Process Safety Management	Regulations currently under review.	100	0	0
Requirement for the development and maintenance of job toxic exposure profiles for job classification.	OSHA may present this as a record keeping requirement to document a healthy work place.	100	0	0
Residual Risk	Develop evaluation program.			

State Implementation Plan that brings the area into compliance by a specified date. Technologies were premised that will have to be implemented based on the area attainment status of the refinery, the degree of nonattainment for ozone, and the refinery size.

Ozone

The two primary precursors of ozone are volatile organic compounds (VOC) and nitrogen oxides (NOx). Reductions in VOC emissions were assumed to be achieved through the requirements of State Implementation Plans and air toxics regulations. Control devices were premised to reduce NOx emissions in ozone nonattainment areas. However, no controls were premised in the approximately 30 percent of refinery capacity that is located in ozone attainment areas.

For marginal, moderate, and serious ozone nonattainment areas it was premised that ultra low-NOx burners (0.05 pounds per million BTU) would be required. For severe ozone nonattainment areas, ultra low-NOx burners were required on all furnaces and selective catalytic reductions (SCRs) were required on all furnaces larger than 100 million BTU/hour and on fluid catalytic cracking (FCC) units. In the one extreme area (Los Angeles), the requirements were the same as for severe areas but the SCRs were required sooner.

Sulfur Oxides

About 92 percent of the U.S. refining capacity is located in areas that are in attainment for SOx. It was assumed that all refineries would have sulfur recovery units (SRUs) including those in attainment areas and refineries 25 MB/D or greater would also have tail gas units (TGUs). In nonattainment areas, an additional requirement was premised to be the use of SOx capture catalyst on the FCC unit for refineries of 25 to 50 MB/D and a stack gas scrubber on the FCC unit for refineries larger than 50 MB/D.

Hazardous Air Pollutants (MACT)

Under the CAAA, the EPA will promulgate Maximum Achievable Control Technology (MACT) standards for hazardous air pollutants, which will be as stringent as the best controlled 12 percent of similar sources. For refineries, most primary MACT standards should be defined by the end of 1994 and implemented within three years.

The following were premised to satisfy the MACT requirements at refineries. High efficiency electrostatic precipitators on FCC units will be required to control particulates. There will be an enhanced leak detection and repair program to control fugitive emissions from pumps, valves, flanges, and compressors. Pressure relief valves from all but the very largest fractionation columns will be routed to a flare system. External floating roofs on storage tanks for light products will have double seals and it is estimated that one-half of the tanks will have domes. Internal floaters on fixed roof tanks will be acceptable. The waste water treatment system through the activated sludge unit will have to be covered and vent controlled. Facilities for conveying solids were premised to be enclosed.

Permits

The CAAA require states to establish an operating permit system for all major sources of air emissions. Emission fees will be collected to cover the cost of this program. The premised fee is $25 per ton with a limit of 4,000 tons of regulated pollutants per year. It was assumed that total cost of this fee will be constant in constant dollars. The operating permit program will provide the states a mechanism to upgrade grandfathered units. This could be the mechanism that is used to require precipitators on FCC units in areas that are attainment for PM-10 or SRUs on refineries in attainment areas for SOx.

Other Premised Regulations

It was premised that control devices such as FCC precipitators, SRUs, and TGUs will always have to be operating. Therefore, redundant units will be required so that the largest control device can be shut down without impacting the refinery's ability to operate.

To control toxics from combustion sources, there will be a switch to clean fuels. Fuel oil will be replaced with plant fuel gas or natural gas as dictated by plant gas availability.

Facilities will have to be installed to minimize emissions to the atmosphere from coke drums. Also coke storage and handling equipment will have to be enclosed.

Facilities to control the emissions from loading tankers and barges were premised to be installed by 1995. Also facilities to comply with the Benzene Waste NESHAP regulations were assumed to be in place by 1995.

Waste Water

Discharges to receiving waters are limited by permits authorized by the Clean Water Act and enforced under the National Pollution Discharge Elimination System (NPDES). NPDES permits typically cover a five-year period and each time a permit is renewed the requirements are more stringent. The overriding concern in meeting the requirements of the most recently issued NPDES permits is meeting the acute-toxicity and chronic-toxicity biomonitoring standards.

The premises of the technology required to satisfy toxicity requirements determined the hardware required for future waste water treatment plants. With this base, it was premised that some marginal facilities will be added in order to reuse a significant portion of the water for water conservation. "Zero discharge" was not premised in the time frame of this study.

A consistent, integrated approach was used to estimate the cost of solving several interrelated issues. For example, the size of the effluent treatment plant is determined by how storm water is handled, which has implications for the cost of the sewer system.

An estimate of the industry implementation schedule was made. Except for remediation of sediments in receiving waters from waste water treatment plants (starts in 2001) and maximum practical reuse of process water (50 percent complete by 2010), the other projects are all implemented by 2010.

Process Water Treatment

All process water will have to be treated (including rain water that falls on the process pad). It was assumed that some refineries will have to add paving to the process pad area. The technology to meet the projected requirements of NPDES permits is a two-stage activated-sludge biological treatment with the addition of powdered activated carbon (PACT). Filtration is used to minimize the discharge of suspended solids.

The biosludge will contain PACT. The assumption was that 50 percent of the sludge will be incinerated in new on-site facilities and the remainder will be incinerated off-site.

A precipitation process was premised to remove heavy and other toxic metals from desalter water effluent and waste water from coker operations.

Process Water Reuse

Process water treated as described above will be used as make-up to cooling water towers in the refinery.

The next stage of maximum practical process water reuse will be installing sidestream softeners and filters treating cooling water tower blowdown. This was projected in 50 percent of all refineries by 2010.

Source Control

Closed loop process sampling systems are examples of expenditures required to keep sources of contamination out of the waste water treatment plant.

Storm Water

The premise was that storm water (not including rain water that falls on process pads) will be kept segregated from process water. There will be capacity to store a 10-year 24-hour storm event (can be in an earthen impoundment) before it becomes necessary to discharge untreated storm water.

Ground Water Protection

Future requirements were projected to protect ground water. These include retrofitting all storage tanks with double bottoms and a leak detection system (complete by 2010), installing impermeable liners inside tank dike areas (25 percent complete by 2010), and relocating below grade process piping above ground (complete by 2010). Consistent with this approach, the process sewers will be hard piped above ground to the waste water treatment facilities.

Solid Waste

The cost of remediating contamination that has occurred over the life of the refineries is potentially the most costly item facing the industry. This study includes only costs for contamination on the refinery site and does not include the remediation cost for off-site landfills or sites covered by the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA).

While only about 55 percent of the U.S. refineries have filed Resource Conservation and Recovery Act (RCRA) part B permit applications, it was assumed that essentially all refineries will eventually undergo some form of mandated corrective action.

Calculation of the cost to remediate contamination is not precise since both the extent of contamination and the target cleanup levels are significant variables.

Other costs considered were recovery and monitoring wells, the impact of listing additional refinery wastes as hazardous, and the cost of closing unlined impoundments. It was also premised that one-half of the tanks over 40 years old by 1995 will have to be replaced by 2010.

Corrective Action

Refineries with RCRA part B permits are currently being required to implement corrective action. Corrective action programs require assessment and possible remediation of all solid waste management units (SWMUs) releasing contaminants to the air, surrounding soils or to the ground water. Conditional remedies, such as on-site containment and monitoring, could significantly moderate the cost burden.

Contaminated Soil

The base case for contaminated soil was conditional remedies. This would not result in a significant increase from current costs. However, the cost of having to remove the contamination and either disposing of it in a hazardous waste landfill or incinerating it are displayed as sensitivities.

Solid Waste Management Units

For both active and inactive solid waste management units, the base case will close in place, provide a cap, and monitor. As with contaminated soil, sensitivity cases were evaluated where the contamination will be removed and either put in a hazardous waste land fill or incinerated.

Disposal Costs of Hazardous Waste

Industry is facing a significant increase in the cost of disposing of hazardous waste. Although refiners are working to reduce the amount of waste they generate, the definition of hazardous waste keeps expanding. In addition, waste that could previously be disposed of in a permitted hazardous waste landfill will have to be treated (incineration) before it can be land disposed.

Additional Listing of Hazardous Waste

The EPA is required to evaluate the listing of additional refinery wastes and waste like products as hazardous. It was premised that between 1996 and 2000 materials such as non-leaded tank bottoms, spent FCC catalyst, and spent caustic will become listed hazardous waste and require additional expenditures for storage, transportation and disposal.

Land Ban Restrictions

Existing land ban restrictions require extensive treatment of certain waste prior to placement on land (landfills or landfarms). Incineration is the technology normally utilized

to meet these requirements. By 1995, land disposal restrictions for toxicity characteristic wastes (greater than 0.5 ppm benzene) and primary solids (sludges from refinery process sewer systems) will be in effect.

Ground Water Monitoring/ Recovery Wells

It was premised that there will be ground water monitoring and recovery wells at 200-foot spacing along one-half the perimeter of the refinery.

Replacement of Old Above-Ground Tanks

It was assumed that one-half of the above-ground tanks that will be 40 years old by 1995 will be replaced by 2010. Of the tanks replaced, one-third will have to dispose of contaminated soil.

Upgrading Surface Impoundments to Minimum Technical Requirements

Surface impoundments that received either primary solids or toxicity characteristic hazardous waste will cease hazardous waste operations or be upgraded to meet the minimum technical requirements (double liner and leachate collection system) by 1995. The survey respondents indicated that there are some impoundments that will be upgraded after 1995.

Safety and Health

The two safety and health issues that were premised to have the largest impact on the refining industry are phasing-out of highly hazardous materials (hydrofluoric acid) and implementation of Process Safety Management. Other relative small costs were projected for process control safety systems, controlling worker exposure, operator training and certification, and regulation of ceramic fiber and calcium silicate.

Phase-Out of Highly Hazardous Materials (Hydrofluoric Acid)

It was premised that phase-out of materials regarded as highly hazardous will be legislated. Therefore, the cost was estimated to shut down and demolish all hydrofluoric acid alkylation plants and replace them with sulfuric acid alkylation plants. For this study half the plants were replaced between 1996 and 2000 and the remainder by 2010.

Process Safety Management

The survey associated with this study provided data on the costs of refineries doing process hazards analysis (PHA) and the costs of implementing changes determined to be appropriate as a result of PHA. The data from the refiners that responded were extrapolated to estimate the cost for the industry.

Bechtel Cost Estimates

The individual Bechtel cost estimates for each line item "assumption-premise" are found in the Bechtel Report in Appendix K, Section II, under each generic heading: Air, Water, Solid (and Hazardous) Wastes, Health and Safety. Summaries of the contractor's findings for capital, O&M, and OTE are as shown in Tables 2-22, 2-23, and 2-24.

TABLE 2-22

CAPITAL EXPENDITURES REQUIRED TO MEET THE NPC'S ENVIRONMENTAL PREMISES ($ Million – 1990 Dollars)

Item	1996–2000	2001–2010
Air	2,100	2,400
Water/Solid Waste	6,600	9,700
Safety & Health	1,500	1,400
Total	**10,200**	**13,500**

UNCERTAINTIES AND SENSITIVITIES

This study was undertaken recognizing that a degree of uncertainty surrounds the subject. It is realized that regulations and requirements included as premises may not come to

TABLE 2-23

ONE-TIME EXPENSES REQUIRED TO MEET THE NPC'S ENVIRONMENTAL PREMISES ($ Million – 1990 Dollars)

Item	1996–2000	2001–2010
Air	30	0
Water/Solid Waste	1,100	1,100
Safety & Health	150	100
Total	**1,280**	**1,200**

TABLE 2-24

INCREMENTAL OPERATING & MAINTENANCE EXPENSES REQUIRED TO MEET THE NPC'S ENVIRONMENTAL PREMISES ($ Million Per Year – 1990 Dollars)

Item	2000	2010
Air	500	150
Water/Solid Waste	1,600	800
Safety & Health	200	200
Total	**2,300**	**1,150**

Note: Capital and OTE costs are for the time periods indicated; O&M costs are per year and are incremental for premise implementation during the stated time period.

pass and that, certainly, implementation timing might be different. It is further realized that regulations and requirements will come to pass which were not anticipated and included, and it is recognized that many other variables such as the *actual* cost of doing things, the advent of new and unknown technology, and a changing refinery population all could affect the "answers." Even with this, however, the NPC believes the base case findings provide valid guidance.

In addition to the base case, several technical sensitivities were developed and grouped into two classifications. They were, for the most part, progressively severe extensions of items included as base case premises. They serve to illustrate the magnitude of the effect of apparently minor rules interpretations and/or alternative means of implementation.

While no quantitative downside sensitivities are presented, such possibilities were considered. Historically, incidences of actual cost being lower than forecast have been rare, primarily because the industry tends to underestimate the proliferation of new regulations while somewhat counterbalancing this with more imaginative, efficient, or effective implementation. Thus, while the Task Group recognizes the possibility of downside cost movement due to unanticipated technological developments, extensions of implementation timing, or significant changes in political direction, the Task Group cannot otherwise identify quantifiable downside sensitivities.

Sensitivities

Detail discussions of the sensitivities are in the Bechtel report in Appendix K, Section II, and a summary table (Table 2-25) is included in this chapter.

The first case contains the group with some likelihood of being required:

- $0.7 billion for venting all large fractionators to a flare. This is in addition to the $60 million base case requirement to route to flare all other pressure relief valves currently being vented to the atmosphere.

And then, four similar projects for handling contaminated soil:

- $2.7 billion to retrofit surface impoundments and remove the contaminated soil to landfills rather than leave as-is.
- $10.9 billion to remove contaminated soils to landfills rather than closure in place (capping).

TABLE 2-25

NPC SENSITIVITY STUDIES
($ Billion – 1990 Dollars)

	Capital	One-Time Expenses
First Case:		
Vent large fractionators, to flare	0.7	
Retrofit surface impoundments, landfill contaminated soil		2.7
Remove contaminated soil to landfill		10.9
Remove active hazardous SWMUs and incinerate soil		2.0
Remediate tank replacement contaminated soil in landfill		0.5
Total	**0.7**	**16.1**
Second Case:		
Retrofit surface impoundments, incinerate soil		7.5
Remove contaminated soil and incinerate		87.9
Remove inactive hazardous SWMUs and incinerate soil		85.1
Remediate tank replacement contaminated soil by incineration		2.4
Total		**182.9**

- $2.0 billion to remove active hazardous SWMUs and incinerate the contents rather then close in-place.
- $0.5 billion for landfill remediation of contaminated soil found during replacement of old tanks.

Recovery of this $17 billion expense over five years would increase light fuels cost 2 cents per gallon.

The second case is again the contaminated soil group and it seems prohibitively costly. But it must be considered because it generally represents a more severe extension of previous activities:

- $7.5 billion is required if soil from surface impoundment retrofits must be incinerated rather than moved to landfill.
- $87.9 billion to incinerate contaminated soils rather than landfill.
- $85.1 billion to remove inactive hazardous SWMUs and incinerate the contaminated soil rather than close in place.
- $2.4 billion to incinerate rather than landfill contaminated soil found during replacement of old tanks.

The $183 billion total cost of these items is equivalent to 20 cents per gallon of light fuel products costs over five years.

STUDY SUPPORT

Objective

A reconciliation among study participants was conducted to assure that capital costs and refinery operating costs would be compatible among the various task groups and contractors. The resulting document is in Appendix K, Section I, Attachment VII-1. Also, study support was provided in the form of miscellaneous cost estimates.

Cost Factors

To assure reasonable consistency among the study participants for estimating investment costs, capital, expense, and location fac-

tors were evaluated. Three study participants (Bechtel, Pace, and Turner-Mason) were surveyed for the following information: (1) inside battery limit (ISBL) costs for thirteen typical refining process units (U.S. Gulf Coast [USGC] location, design capacity, and pertinent operating parameters were specified), (2) corresponding factors to estimate off-site and other investment costs, and (3) operating cost for each process unit.

The process units examined included crude oil atmospheric and vacuum units, delayed coker, distillate desulfurizer, naphtha reformers (both high pressure semi-regeneration and low pressure continuous), fluid catalytic cracker, FCC gasoline desulfurization, hydro-cracker (2-stage), alkylation, methyl tertiary butyl ether (MTBE), isomerization (C_5/C_6), and sulfur recovery with tail gas unit.

This result was used to identify by consensus the most likely ISBL costs for the various process units, which then allowed the participants to make any final adjustments to their models for outliers (something outside of a reasonable range) before use of the models commenced. It was also recommended that all NPC study participants maintain consistency when factoring the battery limit capital cost estimates as follows: (1) off-sites were to be estimated by factoring the ISBL cost by 45 percent, and (2) other costs associated with the project cost (including site preparation, permitting, start-up costs, and other unanticipated on-site cost) were to be determined by factoring the ISBL cost by an additional 20 percent. Therefore, participants were instructed to increase USGC ISBL costs by 65 percent to reflect off-site and other costs associated with refinery capital projects for the USGC.

The off-site factor assumed installation in an existing refinery. Off-sites for a new unit as part of a "grassroots" refinery could be estimated using a factor of 90 percent of the ISBL cost.

Costs associated with initial catalyst fill and royalty were not included in the scope of the ISBL costs discussed above. These were handled separately, as required.

Geographic Factors

The methodology elected to accommodate worldwide refinery investment requirements was to estimate facility costs for the U.S. Gulf Coast—Houston open shop was assumed—and to apply geographic adjustment factors to facilitate relating this USGC base cost to other U.S. and foreign locations. This methodology was selected because the scope of this NPC project would not accommodate site specific cost estimating, and it was judged appropriate for providing investment cost information of sufficient accuracy.

Based on survey results provided by Turner-Mason, Pace, and Bechtel, as well as company information from two member companies, Table 2-26 presents factors determined to be appropriate relative to the USGC open shop base (Houston).

TABLE 2-26

GEOGRAPHIC ADJUSTMENT FACTOR

USGC (Houston, open shop) Base	1.0
Balance of U.S. (ex California)	1.2
California	1.4
Canada (Sarnia basis)	1.3
NW Europe (UK basis)	1.3
Med/North Africa (Italy Basis)	1.1
Middle East (Saudi Arabia basis)	1.2
Far East (Singapore/Taiwan basis)	1.0
Other Western Hemisphere (Venezuela basis)	1.3

The location differential for California reflects unique +20 percent treatment due to extraordinary environmental, permitting, and other complexities associated with projects in that state that are assumed to persist well into the future (i.e., to the end of the year 2010 time frame limit of this study). As an aside, the factor for a USGC closed shop basis was judged to be about 1.1 (or 10 percent higher) than the open shop basis assumed.

Areas selected to represent the six foreign sectors were based on a combination of data availability and judgment concerning probability of construction in that sector.

Operating Cost

Fixed and variable operating expenses associated with refining process units also received limited analysis using USGC cost as a basis. Fixed expenses included manpower, maintenance, taxes, and insurance, but excluded depreciation or amortization, which were handled separately. Variable expense included fuel, power, catalyst, and chemicals. Fuel price was set at a fixed value for all locations to accommodate reconciliation.

Potential limitations imposed by these assumptions were identified to the users prior to commencement of model use.

Maintenance expense associated with a new facility is commonly assumed to be about 4 to 5 percent of capital investment. That is the assumption for this study. Otherwise, except for fuel cost, the operating expense for a facility as a function of geography was assumed to be about constant. Fuel price is assumed to be site-specific.

Miscellaneous Support for Other Task Groups

The Refinery Facilities Task Group on occasion facilitated requests from other task groups to provide scoping quality estimates for various types of refining hardware. Three specific examples are hereby offered and include: (1) a 50,000 barrel gasoline storage tank, (2) a 20,000 barrels per stream day (B/SD) grassroots MTBE facility, and (3) a 150,000 B/SD grassroots refinery. Bechtel was the Engineering Contractor that provided the cost estimates for each of these.

A 50,000 barrel capacity gasoline tank that included a double bottom, double seals on an external floating roof and a dome cover, was estimated to cost $2 million (USGC location). The June 25, 1992 letter from Bechtel to the NPC Refinery Facilities Task Group provides additional detail, and is Attachment VII-2 in Appendix K.

The capital cost of a 20,000 B/SD grassroots MTBE facility for USGC, Saudi Arabia, and Venezuela was estimated by Bechtel at $286 million, $343 million, and $372 million, respectively. The June 25, 1992 correspondence from Bechtel to the NPC Refinery Facilities Task Group is Attachment VII-3 in Appendix K.

The capital cost for a 150,000 B/SD high conversion petroleum refinery, located in the Pacific Rim region, was estimated to approach $2.0 billion (U.S.). The forwarding letter from Bechtel to the NPC Refinery Facilities Task Group, dated August 25, 1992, is Attachment VII-4 in Appendix K.

CHAPTER THREE

SUPPLY, DEMAND, AND LOGISTICS

OBJECTIVES AND OBSERVATIONS OF THE SUPPLY/DEMAND/LOGISTICS EFFORT

The U.S. oil product supply, demand, and logistics system is a complex set of facilities that supplies petroleum products to meet regional demands. It involves geographically dispersed supply points not only in the United States but around the world. The logistics system includes many modes of transportation and a series of terminals. Overlaying these factors is a multiplicity of different oil products and regulations.

One of the major issues confronted in the refining study is the capability of this existing system, as modified by announced changes, to continue to operate effectively in the future. The system operates in a continuously changing environment which encompasses volume, quality, and number of products. There are also geographic, regulatory, and economic factors impacting the system.

A second issue addressed in the refining study is the future role of foreign sourced oil product supply. Foreign competition has been a major factor in many industries. The changing regulatory environment along with uncertainties concerning future U.S. oil product demand have raised questions concerning the long-term viability of the domestic refining industry.

A third major issue addressed in the refining study is the adequacy of the supply of oxygen containing components (oxygenates) for oxygenated motor gasoline blending needs. The Clean Air Act Amendments of 1990 (CAAA) require that under certain conditions motor gasoline will contain specific amounts of oxygen. Until recently, the United States has not had a large oxygenate production capability. Consequently, there are concerns surrounding the adequacy of future oxygenate supply to meet the demands for oxygenated motor gasoline on the timetable set forth in the CAAA.

For the study, a computer model was used to integrate the U.S. logistics system with the supply and demand geography. Contractors were used for the logistics work and to model U.S. refining regions (the five Petroleum Administration for Defense Districts [PADDs]) and six foreign regions. The refining models resulted in the development of cost-volume relationships. The product cost-volume approach relates costs of making products to the volume of products produced in a supply region (foreign regions and domestic PADDs) to simulate supply variability. Discussion of the product cost-volume approach can be found later in this chapter. Years chosen for modeling were 1989 for calibration; 1987 for validation; and 1995, 2000, and 2010 for future years.

The supply, demand, and logistics parts of the survey, discussed in Chapter Five, were used to obtain information, including capacity and utilization data on tanker, truck, barge,

rail, and pipeline movements. The survey was also used to obtain opinions on future foreign product quality requirements.

Three distinct projections of future U.S. product demand (Foundation Cases) prepared by demand region were adopted. The range of Foundation Case demand projections is believed to represent a reasonable U.S. petroleum product demand envelope from within which to address future U.S. refining issues. However, *none of the Foundation Cases described below are endorsed by the National Petroleum Council refining study as a primary projection of future U.S. petroleum product demand.*

- Foundation Case I represents a growing U.S. petroleum product demand projection scenario and is the EIA 1990 Annual Energy Outlook Reference Case.
- Foundation Case II represents a no U.S. demand growth projection using 1989 demands throughout, except for products for which the EIA projects a decline in demand between 1989 and 1995. Demands were held constant for the years thereafter.
- Foundation Case III represents a declining U.S. demand projection and is essentially the inverse image of Foundation Case I.
- Non-U.S. demands consistent with each Foundation Case were developed. The rationales for these demand projections are discussed later in this chapter.

Figure 3-1 presents the relative demands for the United States, OECD [Organization for Economic Cooperation and Development] (excluding the U.S.), and non-OECD countries for each of the Foundation Cases to show the ranges. Figure 3-1 illustrates that demand outside the United States is expected to grow at a greater rate than U.S. demand. For more details, see Appendix L, Sections I and III. The low near-term growth in demand for non-OECD countries is due to the reduction in demand in the former Soviet Union.

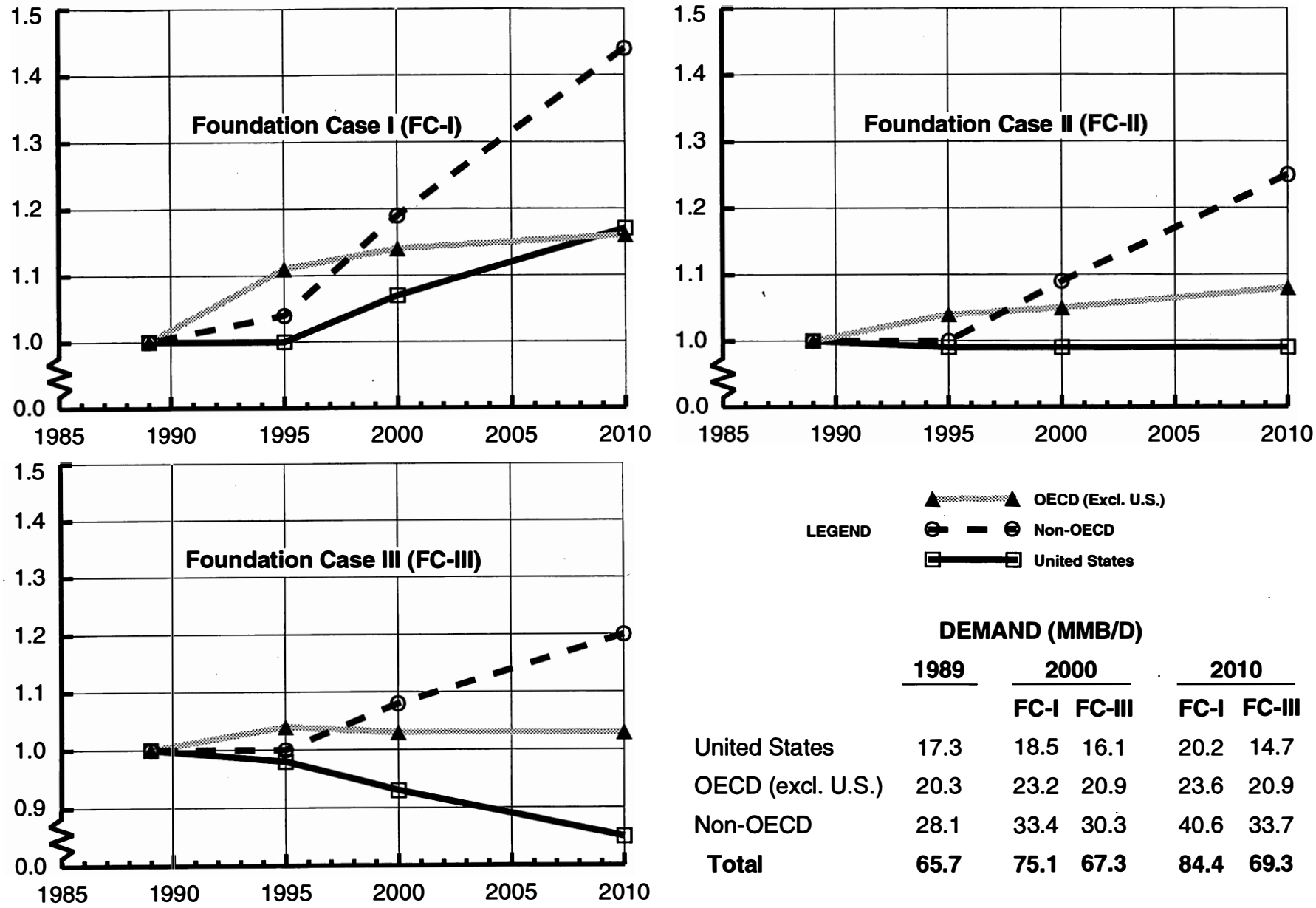
Several observations were made as a result of the supply, demand, and logistics effort.

- The U.S. logistics system will remain effective only if product specifications and specification enforcement procedures result in supply of compatible products. That is, one batch of a given grade and type product that is in compliance with appropriate regulations when blended with another batch of similar product and characteristics results in a total mixture that is in compliance. Today's product specifications and specification enforcement procedures allow effective use of the logistics system because minor commingling of products (i.e., product placed in a tank with existing material, interface of similar products moved via pipeline produced in different facilities, etc.) does not result in off-specification products.

  Environmental legislation requires production of more primary types of products. The NPC refining study survey results indicate that organizations involved in U.S. logistics operations are making preparations to accommodate an increase in number of primary products. These accommodations are likely to lower the overall capacity of the logistics system, but not below a level adequate for product movement required under the NPC refining study Foundation Case scenarios.

  However, a significant further increase in the number of product segregations would be required if a product blending and product quality enforcement system did not accommodate product compatibility. This would require segregating each batch from other batches of reformulated gasoline (RFG) to minimize the manufacturing cost increase. Such segregation would adversely impact the effectiveness of the U.S. product logistics system and some accommodations would have to be made. The effects would range from increase cost and sporadic runouts to complete failure of some systems. If complete segregation of individual batches is mandated, the logistics system as it exists today would be inoperable.

- Geographic noneconomic spillover of nonattainment quality products into attainment areas is expected to be less than one percent. Higher costs for



DEMAND (MMB/D)

	1989	2000		2010	
		FC-I	FC-III	FC-I	FC-III
United States	17.3	18.5	16.1	20.2	14.7
OECD (excl. U.S.)	20.3	23.2	20.9	23.6	20.9
Non-OECD	28.1	33.4	30.3	40.6	33.7
Total	**65.7**	**75.1**	**67.3**	**84.4**	**69.3**

Figure 3-1. Relative World Oil Demands (1989=1.0)

nonattainment quality products should encourage minimizing spillover. Terminal and tankage capability at nonattainment-attainment interface locations appears sufficient to allow appropriate product segregations. However, in some situations, suppliers may see no cost differences in supplying nonattainment quality products to attainment areas, resulting in some spillover.

- The U.S. refinery complex should generally be able to produce products that are lower cost than those produced in foreign refineries and exported to the United States. Foreign and U.S. refineries are both expected to have increased costs for environmental, health, and safety reasons. However, foreign refineries are expected to need to invest to meet growing demand and a shift to a lighter product mix. U.S. refineries already are capable of producing a light product mix and have surplus light product producing capability.

  In 1989, the U.S. refinery complex had a capability to produce 13.1 million barrels per day (MMB/D) of light products. In 1989, U.S. refinery light product production was 11.2 MMB/D. This results in a capability utilization rate for light products of 86 percent. Refining capacity additions that have been announced, anticipated operational changes, and addition of non-hydrocarbon material to the light products pool should increase light product output capability to 13.5 MMB/D in 1995, and 13.8 MMB/D in 2000 and 2010. The result of comparing light product output from the various Foundation Case studies with anticipated capability indicates increasing pressure for U.S. refinery capacity rationalization in a future where U.S. light product demand declines. The reverse is true under the situation where U.S. light product demand increases and there will be less pressure for U.S. refinery capacity rationalization.

  In all cases studied, refinery utilization decreased 3 to 4 percent in 1995. However, U.S. refinery output remained at the 1989 level.

  Projections of U.S. clean product supply under conditions of increasing demand indicated future clean product output from U.S. refineries higher than in 1989. Clean product imports decreased until refinery capacity in regions where clean products are imported or regions that supply these regions was fully utilized. At that balance point, clean product imports began to increase because it appears to be more cost effective to produce clean products in available foreign refinery capacity relative to the cost of producing clean products from new refinery capacity in the United States.

  Under conditions of decreasing clean product demand in the United States, U.S. refinery clean product output and imports decline. These estimates suggest that U.S. refinery operations will be impacted directly by future local demand conditions.

  The West Coast situation is somewhat different than for the United States as a whole. The difference is primarily in the near term because of increased environmental expenses compared to the rest of the United States. Projected imports increase in all Foundation Case evaluations through 1995. After 1995, the West Coast situation appears to be more like the situation in the rest of the United States where imports decline with decreasing or constant demand. As with the United States as a whole, West Coast imports begin to increase under growth demand conditions after local output capability is fully utilized.

- The increase in foreign refinery environmental, health, and safety costs relative to those of the refineries in the United States has been a significant issue throughout the study. The study participants developed a set of reasonable environmental, health, and safety costs associated with both U.S. refineries and foreign refineries for use in the study's base analyses.

  To test the significance of these assumptions and other cost related issues, an al-

ternate 2000 situation under growing U.S. demand conditions was analyzed. The alternate analysis incorporated a situation with no increase in foreign refinery environmental, health, and safety costs and with U.S. refinery costs increasing to levels supported by legislation that is currently in place. The net effect was to lower the 2000 foreign refinery cost increase relative to U.S. refinery cost increases about 2.8 cents per gallon (cpg). This analysis suggested that U.S. refinery output was essentially the same as in 1989. The increase in demand was met by an increase in imports. When assumed environmental, health, and safety costs were used, the demand increase was supplied from domestic refineries. This demonstrates the relative stability of the future U.S. refinery situation even under significant relative cost increase differences.

- Oxygenate availability should not limit production of oxygenated and reformulated motor gasoline required by the CAAA. There appears to be enough existing plus expected U.S. oxygenate capacity by 1995 to meet the minimum 1995 CAAA requirement for oxygenated and reformulated motor gasoline plus oxygenated motor gasoline for the entire state of California. If all existing plus announced oxygenate producing facilities are in operation in 2000, it is anticipated that domestically produced plus estimated available imported oxygenate will closely be in balance with maximum U.S. oxygenate requirements.

  There is a deficit supply on the West Coast requiring that oxygenate be imported or moved from east of the Rockies. This makes West Coast oxygenate the most expensive in the United States.

  Assuming the current federal subsidy is maintained, ethanol should be economically advantageous relative to ethers in the production of carbon monoxide (CO) nonattainment motor gasoline required under the CAAA. In states that provide additional subsidies, ethanol will be even more attractive for CO nonattainment gasolines.

GENERAL APPROACH

Subgroups were formed to address the major analytical components. The activities of the subgroups are described briefly below and are discussed in detail in later sections of this chapter.

Demand Subgroup

The Demand Subgroup provided three projections of future U.S. product demands (Foundation Cases).

Logistics Subgroup

The Logistics Subgroup developed a depiction of the future U.S. petroleum products logistics system that consists of pipelines, barges, tankers, rail cars, and trucks. Survey data and EIA data were used to develop current and future capacities and utilizations as well as plans for expansion. Estimates were made of transportation and distribution cost increases as a result of increased environmental regulations based on NPC survey results, reliable third party sources, and industry member expertise. These were all factored into projections of cost and future capacity for movement of products through the logistics system.

Ethanol Subgroup

The Ethanol Subgroup provided an assessment of U.S. ethanol supply capability and the supply/demand economics. An EIA survey of the ethanol industry was used to aid in these assessments. Possible consumption patterns were developed with the logistics integration model.

Other Oxygenates Subgroup

The Other Oxygenates Subgroup coordinated the development of current and future potential supply and consumption of oxygenates other than ethanol (methyl tertiary butyl ether, tertiary amyl methyl ether, or possibly ethyl tertiary butyl ether). This analysis was an effort to determine if oxygenate

demand requirements for U.S. motor gasoline identified in the CAAA could be fulfilled with both domestic and foreign oxygenate production in 1995 and beyond. EIA information served as a major input as did information from other sources.

Foreign Subgroup

The Foreign Subgroup effort was more broad based than the efforts of the above subgroups. The objective of the Foreign Subgroup was to develop the cost and availability of refined products for potential export to the United States. This included an assessment of the availability of the supply of both petroleum products and oxygenates.

A set of specifications for each modeled year was developed for products used within foreign regions. Details of the specifications development can be found later in this chapter.

The relationship between petroleum products cost and availability for each foreign export location was estimated using regional refining models, which were developed on a basis consistent with those used for the domestic PADDs and including new investment considerations. Details of the cost-volume relationship development are also discussed later.

A logistics analysis was used to estimate the non-U.S. interregional product flows and the potential for exports to the United States.

U.S. Supply Subgroup

U.S. PADDs were modeled in a manner similar to the Foreign Subgroup work by a subgroup of the Product Quality Task Group and used for development of the logistics model. This work is described later in this chapter. Other work done by the Product Quality Task Group is described in detail in Chapter Four.

Model Subgroup

The Model Subgroup tied all the above efforts together with the logistics model. The model was used to balance the interaction between the cost to supply U.S. quality products and the availability of those products from both the U.S. and foreign refining regions.

The model was calibrated using actual 1989 data provided by the EIA. The model was then validated using 1987 data. The calibration year of 1989 was chosen because it was the latest year for which complete foreign product supply and demand data were available when the refining study was begun.

Using the demands developed by the Demand Subgroup, the Foundation Cases were then run using the calibrated logistics model to estimate future (1995, 2000, 2010) U.S. related interregional movements of petroleum products. Many considerations such as demand, cost of production, cost of distribution, and limitations on distribution capacities determined which supply region would supply each demand region.

Various issues were then addressed using the output from the above simulations. These issues are discussed in the final section of this chapter.

Cost-Volume Relationship Buildup Methodology

A cost-volume relationship approach was used to simulate regional refining capability. Models of the U.S. refining system by PADD were developed along with models for the six foreign refining regions, most of which represent traditional or potential supplies of imports for the U.S. market. This included hydrocarbon-related costs as well as a cost component reflecting expanded refinery capacity was included in the models. Costs of added environmental requirements, process capital costs, and operating costs were then added in a layer fashion. This allowed assessment of the effects of new regulations on which supply regions, domestic or foreign, would supply products to the various demand regions.

General Assumptions

The supply/demand/logistics system within the United States is represented by thirteen domestic supply/demand regions. Six foreign regions from which products can move to the United States as imports are also represented. Details of the rationale of selecting the

regions are found in the next section of this chapter.

- Figure 3-2 is a map of the domestic regions as set out by the Demand Subgroup. These regions generally break the United States into major supply/demand regions. Table 3-1 describes these regions in terms of states and portions of states.

- The foreign regions used for the modeling analysis are also shown in Table 3-1. These regions were considered to be the most important in supplying petroleum products to the U.S. markets. Non-modeled regions were assumed to be self-sufficient or to have minor impact on the U.S. market. Figure 3-3 is a map of the foreign regions.

- The U.S. logistics system is assumed to behave in an economically rational fashion. This assumes that products move from the production locations to the consuming locations based on the cost of production and transportation within the constraints of the logistics system. Although at times there may be some dislocations, the modeling is based on the premise that the lowest cost product is the one ultimately supplied.

- An annual basis was chosen to model the supply/demand logistics system. To minimize model complexity, it was felt that even though seasonality will have an impact on refined product costs as well as storage and distribution logistics, it was beyond the scope of the study to attempt to model a summer/winter basis along with the inventory changes that take place as stocks are accumulated and depleted.

- All U.S. regional demands were based on population as of the 1990 census. U.S. product demands are published on a state basis. Future state shares of U.S. demands were assumed constant at their 1989 level. The regional demands were aggregated from state demands and where a state was divided between two regions, the state demands were apportioned to the regions on a county population basis (1990 Census).

- Each foreign supply region and U.S. PADD was modeled as though it were a single refinery. Thus, some refiners in a region would of necessity produce more or less of a particular product but the overall will match actual production capabilities. The U.S. PADDs were split into the various supply regions. Details of this modeling are given in later sections of this chapter and in Chapter Four.

- Only the major light products (motor gasoline, jet fuel, and distillate) were considered in the logistics model. Other products were assumed to be used locally or to move between regions as they had in the past or not affect light product flows.

- U.S. light product exports (about 1 percent of U.S. demand in 1989) to foreign regions were assumed to remain at 1989 levels.

- A rough attempt was made to balance worldwide demand and supply of residual fuel oil and the supply of swing crude oil to insure realism.

Costs for all products were developed by escalating 1989 prices to 1990 dollars to eliminate having to forecast various currency factors and inflation.

Base crude oil quality was assumed constant at estimated 1989 levels for the future and incremental crude oil was generally assumed to be Arabian light quality. Incremental crude oil for PADDs II and IV was assumed to be West Texas Intermediate and for PADD V was assumed to be Alaskan North Slope.

Delivered cost of crude oil was assumed to be constant at the 1989 level for future years.

For environmental reasons, premised motor gasoline geographic depiction varies with time.

- Reformulated motor gasoline with 2 percent by weight (wt%) minimum oxygen content, 1 percent by volume (vol%) maximum benzene content and reducing volatile organic compounds (VOC) during the summer VOC control season and toxic air pollutants (TAP) year-round by at least

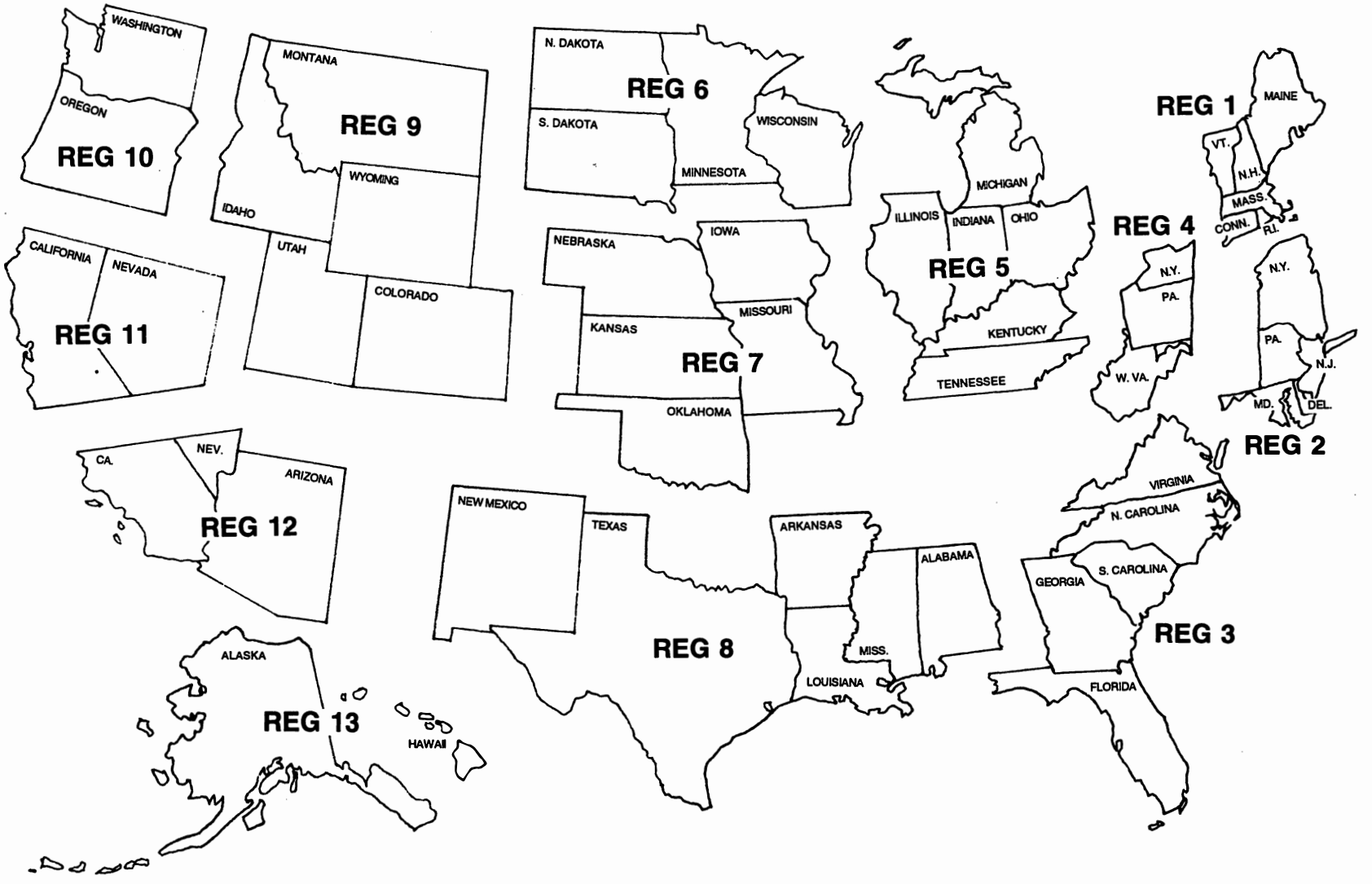


Figure 3-2. Map of U.S. Regions.

TABLE 3-1

SUPPLY/DEMAND REGIONS

U.S. Demand Regions (consistent with Figure 3-2)

PADD I

Region 1: New England: The states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont.

Region 2: Central Atlantic: The District of Columbia and the states of Delaware, Maryland, and New Jersey, together with the eastern portions of New York and Pennsylvania.

Region 3: Lower Atlantic: The states of Florida, Georgia, North Carolina, South Carolina, and Virginia.

Region 4: Appalachian No. I: The state of West Virginia and those parts of the states of Pennsylvania and New York not included in Region 2.

PADD II

Region 5: Indiana-Illinois-Kentucky: The states of Indiana, Illinois, Kentucky, Tennessee, Michigan, and Ohio.

Region 6: Minnesota-Wisconsin-North and South Dakota: The states of Minnesota, Wisconsin, North Dakota, and South Dakota

Region 7: Oklahoma-Kansas-Missouri: The states of Oklahoma, Kansas, Missouri, Nebraska, and Iowa.

PADD III

Region 8: PADD III: The states of Texas, Louisiana, Arkansas, Mississippi, Alabama, and New Mexico.

PADD IV

Region 9: Rocky Mountain: The states of Montana, Idaho, Wyoming, Utah, and Colorado.

PADD V

Region 10: Pacific Northwest: the states of Washington and Oregon.

Region 11: Central PADD V: The northern portions of California and Nevada.

Region 12: Southern PADD V: The state of Arizona and the portions of California and Nevada not in Region 11.

Region 13: Pacific: The states of Alaska and Hawaii.

Potential Supply Regions

Domestic: The same as the U.S. demand regions outlined above.

Foreign:
CAN - Canada
LAT - Caribbean/Central America/South America
NWE - Northwest Europe
MED - Mediterranean/North Africa
ME - Middle East
PAC - Far East

Note: The distribution centers for the above regions may be found in Appendix L, Section IV-1.

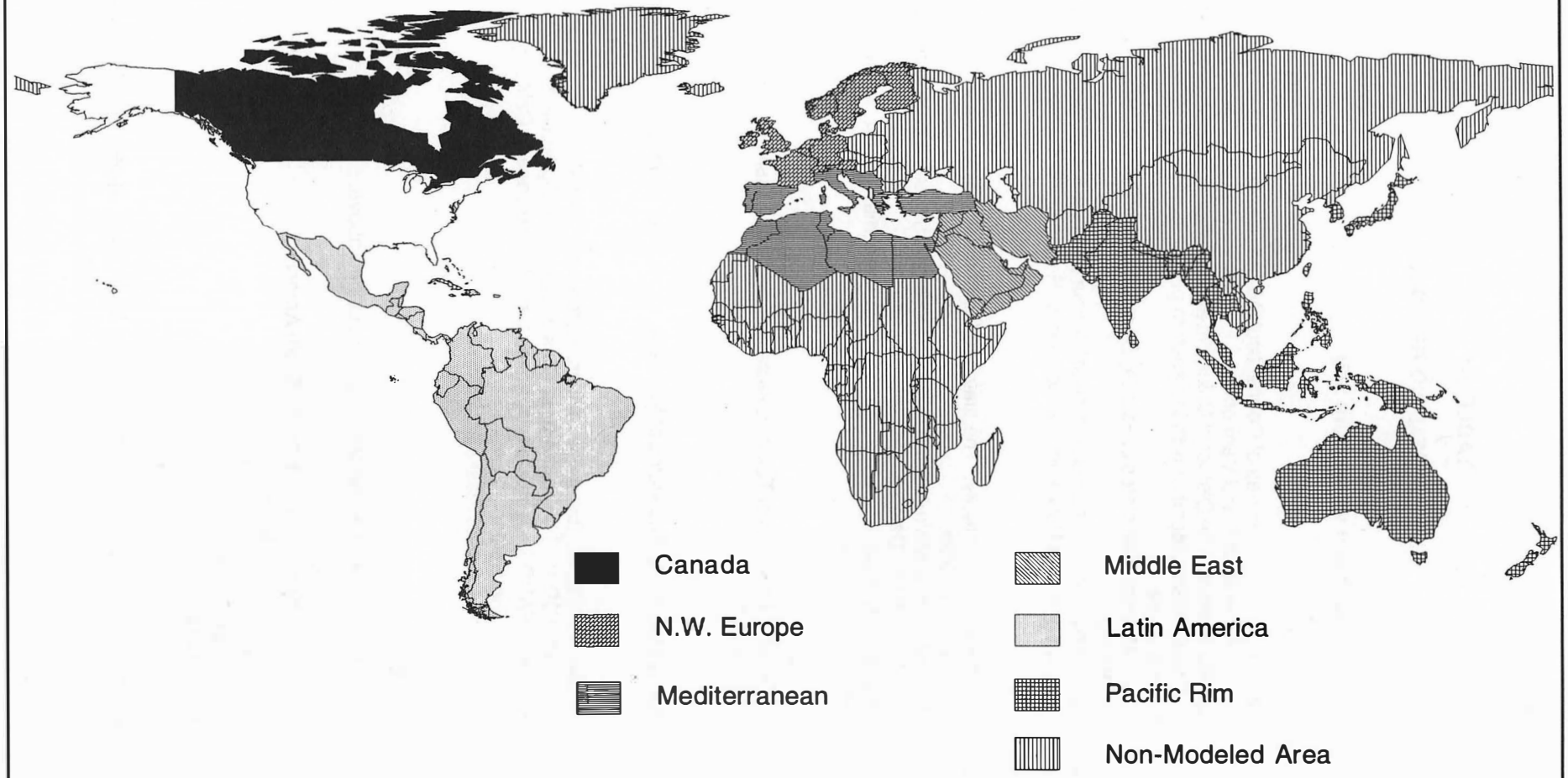


Figure 3-3. 1993 National Petroleum Council Refining Study Foreign Modeled Regions.

15 wt% on a per-gallon basis will be required in the nine worst ozone nonattainment areas (severe + extreme classifications) beginning in 1995. Although states can petition the EPA Administrator to "opt-in" to the RFG program, it was assumed that the necessary facilities to produce significantly more RFG than required in the nine worst areas would not be in place by 1995.

- Reformulated motor gasoline meeting a 25 wt% reduction on a per-gallon basis in VOC during the summer VOC control season and TAP year-round will be required in all ozone nonattainment areas (severe + extreme + serious + moderate + marginal classifications) and the Northeast Ozone Transportation Corridor in 2000 and 2010. It was assumed that this would give enough lead-time for refiners to install the necessary facilities to produce larger quantities of reformulated motor gasoline. In 1996, California Air Resources Board (CARB) Phase 2 gasoline, which is more severely reformulated and has more absolute specifications, will be required in all of California. California quality products were not specifically included, but were assumed to have the same delta cost relative to federal reformulated motor gasoline in all producing regions. Oxygenate requirements for California fuels were specifically accounted for.

- Starting in the winter of 1992-1993, motor gasoline with a minimum of 2.7 wt% oxygen content is required in 39 CO nonattainment areas during the winter CO control season. Thus, it was assumed for logistics modeling purposes, that motor gasoline requiring 2.7 wt% oxygen will be required in all CO nonattainment areas plus California during the winter of 1995-1996 and thereafter during the winter CO control seasons. California has requested a waiver reducing oxygen content to 2.0 wt% (1.8 to 2.2 percent) because of a possible increase in NOx emissions at the higher oxygen content. At the time of writing this report, the waiver had not been approved but was assumed in effect for modeling purposes.

Refinery stationary source emission requirements become increasingly more stringent with time, but are the same across all Foundation Cases in the same year.

New investment costs are adjusted for regional cost differentials, both U.S. and foreign. These investment cost differentials are discussed in this chapter and in Chapter Two.

Foreign regions' implementation of regulations for reducing stationary source emissions include catching up with those aspects of U.S. regulations that are expected to eventually migrate offshore. The gap with the U.S. emissions requirements decreases with time so that some of the cost advantage foreign regions may enjoy in this area vis-a-vis the United States diminishes.

U.S. production and import/export of minor products and feedstocks were held constant at 1989 levels. The same was done for the foreign regions with one exception where a significant growth trend was clearly identified. Naphtha production for ethylene manufacture was increased for the Pacific Rim in 1995 and then held constant for 2000 and 2010.

DEMAND DEVELOPMENT

None of the Foundation Cases described below are endorsed by the NPC as a most likely representation of future demand.

Foundation Cases – Domestic Demand

Three Foundation Cases, which represent distinct projections thought to provide a reasonable envelope of future demand possibilities, were adopted for study:

- FOUNDATION CASE I (FC-I), an increasing U.S. demand case, is based on the EIA Reference Case projection of U.S. demands to the year 2010, as published in the *1991 Annual Energy Outlook*. Demands for the various products and total demand for Foundation Case I are found in Table 3-2. Overall U.S. oil demand is essentially constant between 1989 and

TABLE 3-2

FOUNDATION CASE I – U.S. DEMAND
(Thousand Barrels per Day)

	1987*	1989*	1995†	2000†	2010†
Leaded Regular	1,702	740	—	—	—
Unleaded Regular	4,015	4,367	4,957	5,150	5,547
Unleaded Midgrade	—	497	801	832	897
Unleaded Premium	1,489	1,724	1,460	1,516	1,634
Total Motor Gasoline	7,206	7,328	7,218	7,498	8,078
Naphtha Jet Fuel	204	205	—	—	—
Kerosene Jet Fuel	1,181	1,284	1,609	1,819	2,219
Total Jet Fuel	1,385	1,489	1,609	1,819	2,219
On Highway Diesel	1,238	1,435	1,553	1,694	2,007
Off Highway Diesel	563	508	549	623	723
Other Distillate	1,232	1,259	1,201	1,216	1,168
Total Distillate	3,033	3,202	3,303	3,533	3,898
TOTAL Light Products	11,624	12,019	12,130	12,850	14,195
Fuel Oil #4	38	39	34	31	26
HFO < 0.31 %S	93	133	119	155	131
HFO 0.31-1.0 %S	392	438	391	508	433
HFO > 1.0 %S	780	799	745	835	879
TOTAL Heavy Fuel Oil	1,303	1,409	1,289	1,529	1,469
LPG	1,523	1,620	1,627	1,748	1,984
Other Products	2,229	2,260	2,269	2,391	2,586
TOTAL DEMAND	**16,679**	**17,308**	**17,315**	**18,518**	**20,234**

* Historical data as reported by Energy Information Administration (EIA).

† Consistent with EIA projections.

1995, with a somewhat higher growth rate of 1 percent per year between 1995 and 2010. More recent EIA projections of demands include modestly higher projections for 1995, 2000, and 2010.

Motor gasoline demand is projected by the EIA to decline at a rate of 0.2 percent per year between 1989 and 1995 and then grow at a rate of 0.8 percent per year between 1995 and 2010. Jet fuel demand is expected to grow at rates of 1.3 and 2.2 percent and distillate at rates of 0.5 and 1.1 percent. Heavy fuel oil remains fairly constant with an overall growth rate of 0.2 percent from 1989 to 2010.

State shares of the various demands were held constant at the shares described. Details of the state and regional demands may be found in Appendix L, Section III-1.

It should be noted that the EIA projections of demand growth embodied in Foundation Case I did not include the various energy efficiency initiatives in the

National Energy Strategy or possibly relevant legislation now being considered.

- FOUNDATION CASE II (FC-II) is based on no growth in U.S. demand. U.S. 1989 demands were used throughout except for products for which the EIA projects a decline in demand between 1989 and 1995. Those product demands were held constant after 1995 at 1995 levels. Overall demands for Foundation Case II are found in Table 3-3. As is obvious from the assumption, there is little difference in future demand levels relative to 1989. Again, state shares were held constant using the 1990 census and regional demands aggregated from state demands.
- FOUNDATION CASE III (FC-III) is based on a reduction in U.S. demand and is essentially the inverse of Foundation Case I. Overall demands for Foundation Case III may be found in Table 3-4. Again, state shares were held constant using the 1990 census and regional demands aggregated from state demands.

TABLE 3-3

FOUNDATION CASE II – U.S. DEMAND
(Thousand Barrels per Day)

	1987*	1989*	1995	2000	2010
Leaded Regular	1,702	740	—	—	—
Unleaded Regular	4,015	4,367	4,957	4,957	4,957
Unleaded Midgrade	—	497	801	801	801
Unleaded Premium	1,489	1,724	1,460	1,460	1,460
Total Motor Gasoline	7,206	7,328	7,218	7,218	7,218
Naphtha Jet Fuel	204	205	—	—	—
Kerosene Jet Fuel	1,181	1,284	1,489	1,489	1,489
Total Jet Fuel	1,385	1,489	1,489	1,489	1,489
On Highway Diesel	1,238	1,435	1,499	1,523	1,625
Off Highway Diesel	563	508	530	560	586
Other Distillate	1,232	1,259	1,163	1,096	950
Total Distillate	3,033	3,202	3,192	3,179	3,161
TOTAL Light Products	11,624	12,019	11,899	11,886	11,868
Fuel Oil #4	38	39	34	26	22
HFO < 0.31 %S	93	133	119	130	115
HFO 0.31-1.0 %S	392	438	391	428	380
HFO > 1.0 %S	780	799	745	705	772
TOTAL Heavy Fuel Oil	1,303	1,409	1,289	1,289	1,289
LPG	1,523	1,620	1,623	1,649	1,701
Other Products	2,229	2,260	2,265	2,253	2,219
TOTAL DEMAND	**16,679**	**17,308**	**17,076**	**17,077**	**17,077**

* Historical data as reported by Energy Information Administration (EIA).

TABLE 3-4

FOUNDATION CASE III – U.S. DEMAND
(Thousand Barrels per Day)

	1987*	1989*	1995	2000	2010
Leaded Regular	1,702	740	—	—	—
Unleaded Regular	4,015	4,367	4,957	4,765	4,366
Unleaded Midgrade	—	497	801	770	706
Unleaded Premium	1,489	1,724	1,460	1,403	1,286
Total Motor Gasoline	7,206	7,328	7,218	6,938	6,358
Naphtha Jet Fuel	204	205	—	—	—
Kerosene Jet Fuel	1,181	1,284	1,467	1,410	1,292
Total Jet Fuel	1,385	1,489	1,467	1,410	1,292
On Highway Diesel	1,238	1,435	1,476	1,443	1,411
Off Highway Diesel	563	508	522	530	508
Other Distillate	1,232	1,259	1,147	1,037	822
Total Distillate	3,033	3,202	3,145	3,010	2,741
TOTAL Light Products	11,624	12,019	11,830	11,358	10,391
Fuel Oil #4	38	39	34	21	18
HFO < 0.31 %S	93	133	119	106	94
HFO 0.31-1.0 %S	392	438	391	348	309
HFO > 1.0 %S	780	799	745	574	628
TOTAL Heavy Fuel Oil	1,303	1,409	1,289	1,049	1,049
LPG	1523	1,620	1,619	1,549	1,417
Other Products	2,229	2,260	2,260	2,116	1,849
TOTAL DEMAND	**16,679**	**17,308**	**16,998**	**16,072**	**14,706**

* Historical data as reported by Energy Information Administration (EIA).

Tables 3-5 through 3-7 present the demands for each Foundation Case by year to illustrate the variation in the envelope of demands. As indicated, 2010 U.S. oil product demand varies from a high of 20 MMB/D to a low of 15 MMB/D. In 1995, there is very little difference in demands between the three Foundation Cases.

No attempt was made to incorporate the effect of changing demographics on the various state shares of demands. Also, no attempt was made to adjust demands for the changing energy content of gasoline when oxygenates are added.

Foundation Cases – Foreign Demand

Estimates of growth outside the United States were used to project product demand outside the United States. Table 3-8 presents overall demands for the three foundation cases.

The foreign regional demand outlook for each of the three foundation cases was devel-

oped in the context of the assumptions underlying the U.S. demands.

As a starting point, individual country demands for 1989 were based on actual results published in the EIA *International Energy Annual 1990.*

- FOUNDATION CASE I: Overall foreign regional oil demands were based on the forecasts in the 1992 EIA International Energy Outlook (IEO) Reference Case. FC-I oil demands outside the United States grow from 48.4 MMB/D in 1989 to 64.2 MMB/D in 2010; an annual rate of 1.4 percent (Table 3-8). In contrast, U.S. growth is projected at 0.7 percent per year for the same period. Underlying economic growth in the world (excluding U.S.) from 1989 to 2010 is about 3 percent per year, with U.S. economic growth at slightly over 2 percent per year for the same period.

TABLE 3-5

1995 – U.S. DEMAND
(Thousand Barrels per Day)

	1989*	FC-I†	FC-II‡	FC-III‡
Leaded Regular	740	—	—	—
Unleaded Regular	4,367	4,957	4,957	4,957
Unleaded Midgrade	497	801	801	801
Unleaded Premium	1,724	1,460	1,460	1,460
Total Motor Gasoline	7,328	7,218	7,218	7,218
Naphtha Jet Fuel	205	—	—	—
Kerosene Jet Fuel	1,284	1,609	1,489	1,467
Total Jet Fuel	1,489	1,609	1,489	1,467
On Highway Diesel	1,435	1,553	1,499	1,476
Off Highway Diesel	508	549	530	522
Other Distillate	1,259	1,201	1,163	1,147
Total Distillate	3,202	3,303	3,192	3,145
TOTAL Light Products	12,019	12,130	11,899	11,830
Fuel Oil #4	39	34	34	34
HFO < 0.31 %S	133	119	119	119
HFO 0.31-1.0 %S	438	391	391	391
HFO > 1.0 %S	799	745	745	745
TOTAL Heavy Fuel Oil	1,409	1,289	1,289	1,289
LPG	1,620	1,627	1,623	1,619
Other Products	2,260	2,269	2,265	2,260
TOTAL DEMAND	**17,308**	**17,315**	**17,076**	**16,998**

* Historical data as reported by Energy Information Administration (EIA).

† Consistent with EIA projection.

‡ NPC premise.

TABLE 3-6

2000 – U.S. DEMAND
(Thousand Barrels per Day)

	1989*	FC-I†	FC-II‡	FC-III‡
Leaded Regular	740	—	—	—
Unleaded Regular	4,367	5,150	4,957	4,765
Unleaded Midgrade	497	832	801	770
Unleaded Premium	1,724	1,516	1,460	1,403
Total Motor Gasoline	7,328	7,498	7,218	6,938
Naphtha Jet Fuel	205	—	—	—
Kerosene Jet Fuel	1,284	1,819	1,489	1,410
Total Jet Fuel	1,489	1,819	1,489	1,410
On Highway Diesel	1,435	1,694	1,523	1,433
Off Highway Diesel	508	623	560	530
Other Distillate	1,259	1,216	1,096	1,037
Total Distillate	3,202	3,533	3,179	3,010
TOTAL Light Products	12,019	12,850	11,886	11,358
Fuel Oil #4	39	31	26	21
HFO < 0.31 %S	133	155	130	106
HFO 0.31-1.0 %S	438	508	428	348
HFO > 1.0 %S	799	835	705	574
TOTAL Heavy Fuel Oil	1,409	1,529	1,289	1,049
LPG	1,620	1,748	1,649	1,549
Other Products	2,260	2,391	2,253	2,116
TOTAL DEMAND	**17,308**	**18,518**	**17,077**	**16,072**

* Historical data as reported by Energy Information Administration (EIA).

† Consistent with EIA projection.

‡ NPC premise.

Total oil demands by region are shown in Table 3-9. On average, the modeled regions represent about 80 percent of total world oil demand (including U.S.). The growth in oil demand indexed relative to 1989 is shown in Figure 3-1. As indicated, the bulk of the world oil demand growth is in countries outside the OECD.

Overall, light product share of the demand barrel (percentage of motor gasoline, kerosene, jet fuel, and distillate) increases from 54.3 percent in 1989 to 58.3 percent in 2010 (Table 3-10). In the OECD countries (excluding U.S.), light product demands are assumed to increase modestly in share of the barrel relative to 1989 levels as a consequence of greater use of personal transportation vehicles, rapid airline growth, and modest economic growth. These driving forces are offset somewhat by increased efficiency of oil use. Heavy fuel

oil demand declines as a result of increased efficiency and natural gas penetration.

In the non-OECD countries (excluding former and current Centrally Planned Economies) light product shares are assumed to grow relative to 1989 levels boosted by rapid economic growth, increased industrialization, and greater demand for transportation fuels. Heavy fuel oil demand grows in absolute terms although limited somewhat by natural gas penetration.

- FOUNDATION CASE II: Overall, world oil demand growth (excluding U.S.) is assessed to be moderate, growing only 8.6 MMB/D from 1989 to 2010, versus the 15.8 MMB/D growth projected in FC-I. The lower demand growth relative to FC-II can be related to a combination of factors including lower economic growth and increased energy conservation in the

TABLE 3-7

2010 – U.S. DEMAND
(Thousand Barrels per Day)

	1989*	FC-I†	FC-II‡	FC-III‡
Leaded Regular	740	—	—	—
Unleaded Regular	4,367	5,547	4,957	4,366
Unleaded Midgrade	497	897	801	706
Unleaded Premium	1,724	1,634	1,460	1,286
Total Motor Gasoline	7,328	8,078	7,218	6,358
Naphtha Jet Fuel	205	—	—	—
Kerosene Jet Fuel	1,284	2,219	1,489	1,292
Total Jet Fuel	1,489	2,219	1,489	1,292
On Highway Diesel	1,435	2,007	1,625	1,411
Off Highway Diesel	508	723	586	508
Other Distillate	1,259	1,168	950	822
Total Distillate	3,202	3,898	3,161	2,741
TOTAL Light Products	12,019	14,195	11,868	10,319
Fuel Oil #4	39	26	22	18
HFO < 0.31 %S	133	131	115	94
HFO 0.31-1.0 %S	438	433	380	309
HFO > 1.0 %S	799	879	772	628
TOTAL Heavy Fuel Oil	1,409	1,469	1,289	1,049
LPG	1,620	1,984	1,701	1,417
Other Products	2,260	2,586	2,219	1,849
TOTAL DEMAND	**17,308**	**20,234**	**17,077**	**14,706**

* Historical data as reported by Energy Information Administration (EIA).

† Consistent with EIA projection.

‡ NPC premise.

TABLE 3-8

WORLD OIL DEMAND* — BY PRODUCT
(Million Barrels per Day)

	1989	1995 Foundation Cases			2000 Foundation Cases			2010 Foundation Cases		
		I	II	III	I	II	III	I	II	III
World (Excluding U.S.)										
Motor Gasoline	9.7	10.6	10.0	9.9	11.7	10.6	10.2	13.7	11.9	11.1
Kerosene/Jet Fuel	3.7	4.2	3.9	3.9	4.7	4.2	4.1	5.9	4.7	4.5
Distillate	12.9	14.0	13.2	13.1	15.4	13.9	13.5	17.9	15.3	14.4
Residual Fuel Oil	11.4	10.9	11.0	11.2	11.3	11.4	11.5	10.9	11.4	11.5
LPG	3.5	4.0	3.6	3.6	4.5	3.9	3.9	5.3	4.5	4.3
Other	7.3	8.0	7.6	7.6	9.0	8.2	8.0	10.5	9.2	8.8
Total	**48.4**	**51.8**	**49.2**	**49.2**	**56.6**	**52.1**	**51.2**	**64.2**	**57.0**	**54.6**
United States										
Motor Gasoline	7.3	7.2	7.2	7.2	7.5	7.2	6.9	8.1	7.2	6.4
Kerosene/Jet Fuel	1.5	1.6	1.5	1.5	1.8	1.5	1.4	2.2	1.5	1.3
Distillate	3.2	3.3	3.2	3.1	3.5	3.2	3.0	3.9	3.2	2.7
Residual Fuel Oil	1.4	1.3	1.3	1.3	1.5	1.3	1.0	1.5	1.3	1.0
LPG	1.6	1.6	1.6	1.6	1.7	1.6	1.5	2.0	1.7	1.4
Other	2.3	2.3	2.3	2.3	2.4	2.3	2.1	2.6	2.2	1.8
Total	**17.3**	**17.3**	**17.1**	**17.0**	**18.5**	**17.1**	**16.1**	**20.2**	**17.1**	**14.7**
TOTAL World Demand	**65.7**	**69.1**	**66.3**	**66.2**	**75.1**	**69.2**	**67.3**	**84.4**	**74.1**	**69.3**

* Data may not add to totals due to independent rounding.

TABLE 3-9

WORLD OIL DEMAND* — BY REGION
(Million Barrels per Day)

Region	1989	1995 Foundation Cases			2000 Foundation Cases			2010 Foundation Cases		
		I	II	III	I	II	III	I	II	III
Canada	1.7	1.8	1.8	1.8	1.9	1.8	1.7	1.9	1.8	1.6
Northwest Europe	8.9	9.4	8.9	8.9	9.5	9.0	8.8	9.6	9.1	8.8
Mediterranean/North Africa	5.2	5.7	5.4	5.4	5.9	5.5	5.4	6.3	5.7	5.5
Middle East	3.1	3.7	3.5	3.5	4.2	3.7	3.6	5.1	4.0	3.7
Latin America	5.2	6.5	6.0	6.0	7.3	6.3	6.2	8.9	6.9	6.4
Pacific Rim	10.7	12.6	11.6	11.6	13.8	12.0	11.7	15.4	12.9	12.0
Total Modeled Regions	34.9	39.6	37.2	37.2	42.6	38.3	37.4	47.2	40.4	38.1
Africa (Excluding North Africa)	1.0	1.2	1.2	1.2	1.4	1.2	1.2	1.7	1.3	1.2
USSR (Former)/E. Europe/ Other	10.2	8.2	8.2	8.2	9.5	9.5	9.5	11.6	11.6	11.6
China	2.3	2.7	2.7	2.7	3.1	3.1	3.1	3.7	3.7	3.7
United States	17.3	17.3	17.1	17.0	18.5	17.1	16.1	20.2	17.1	14.7
TOTAL World Demand	**65.7**	**69.1**	**66.3**	**66.2**	**75.1**	**69.2**	**67.3**	**84.4**	**74.1**	**69.3**

* Data may not add to totals due to independent rounding.

TABLE 3-10

LIGHT PRODUCT DEMAND SHARE* WORLD (EXCLUDING U.S.) (Percentage)

	1989	1995	2000	2010
FC-I	54.3†	55.7‡	56.2‡	58.3‡
FC-II	54.3†	54.9§	54.9§	55.9§
FC-III	54.3†	54.6§	54.2§	54.8§

* Motor Gasoline, Kerosene/Jet Fuel, and Distillate.

† Historical data as reported by the Energy Information Administration.

‡ Consistent with EIA projection.

§ NPC premise.

developed countries and less rapid industrial development in the Pacific Rim, Middle East, and Latin America. The lower overall oil use is mostly reflected as lower transportation fuel demand, thus light product share of the demand barrel is below FC-I levels.

It should be noted that the outlook for oil demand in the former USSR, Eastern Europe, and China in FC-I (based on the 1992 EIA-IEO) was assessed to apply as well for FC-II and FC-III. Given the uncertainty in the base projections for these countries, the NPC concluded that it was not meaningful to consider alternative demand scenarios. For simplicity, it was further assessed that the volume of net product flows from this group of countries to the rest of the world would return to 1989 levels by 1995 and remain the same in 2000 and 2010.

- FOUNDATION CASE III: In FC-III, a limited 1989-2010 demand growth of 6.2 MMB/D is projected for the World (excluding U.S.). Oil demands in the OECD countries (excluding U.S.) are essentially flat for 1989-2010 on the assumption that these developed countries now experience the pressures for conservation, efficiency increases, and limited alternative fuel use that the United States experienced in FC-II (lagged developments). Thus, nearly all of the world's oil demand growth is in the developing countries. The limited rate of economic development, a slower rate of natural gas penetration combined with gains in efficiency are assumed to maintain light product shares at about the same level that occurred in 1989.

In summary, the three cases provide a range of potential outcomes for evaluation of the cost and availability of foreign refined products for movement to the United States. FC-I is a high-demand case, with the highest percentage of light products in the demand barrel. FC-II is intermediate in total demand and product share. FC-III is a low-demand case with the highest percentage of heavy products.

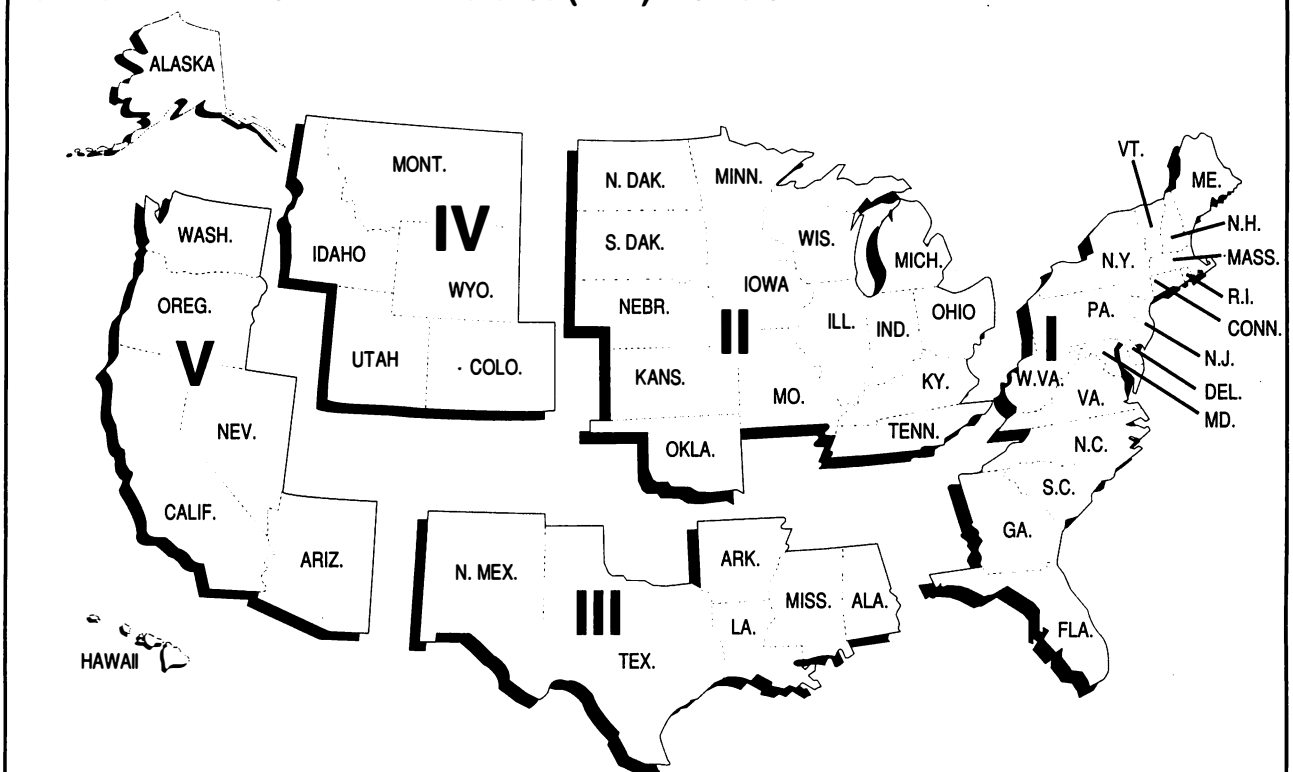
Region Development

Thirteen U.S. Regions

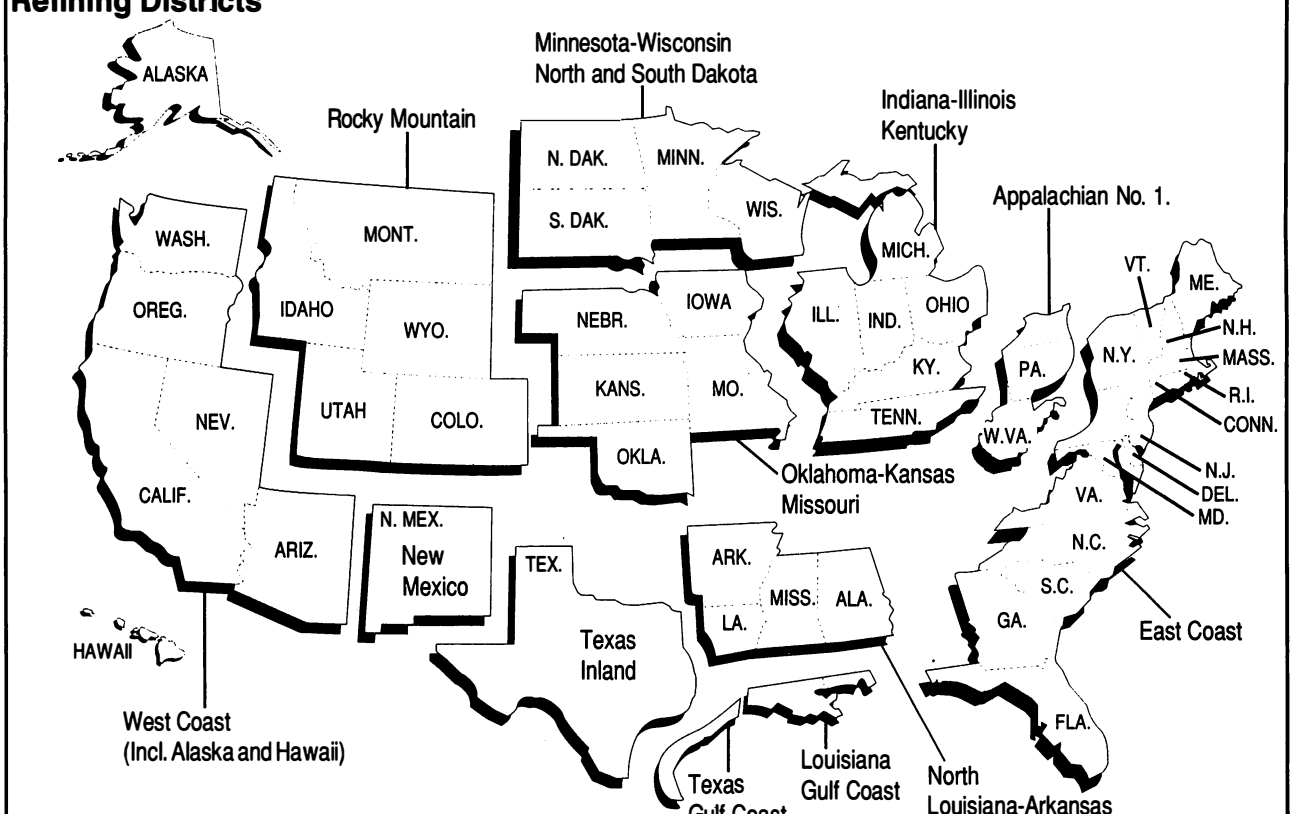
As noted earlier, the United States was divided into the 13 supply/demand regions shown in Figure 3-3 and listed in Table 3-1. The EIA often divides the United States into five Petroleum Administration for Defense Districts for reporting data. The PADDs are also divided by the EIA into refining districts as shown in the Petroleum Supply Annual (see Figure 3-4). The regions used for modeling were essentially the same as the EIA Refining Districts with some further subdivisions and aggregations as noted below.

PADD I is divided by the EIA into East Coast and Appalachian No. 1 refining districts. For the purpose of this study it was decided to further divide the EIA East Coast Refining District into three regions. Region 1, New England, has no refining capacity and limited pipeline supply access with most products moved by water from the Mid-Atlantic, Gulf Coast, and foreign regions. Region 2, Central Atlantic, is a major refining center supplying products for its own area and for surrounding areas such as Region 1 and Region 3. Region 3, Lower Atlantic, is a major demand region with little supply capacity. Region 4 is the same as the EIA Refining District Appalachian No. 1.

Petroleum Administration for Defense (PAD) Districts



Refining Districts



Energy Information Administration/Petroleum Supply Annual 1991, Volume 1

Figure 3-4.

NPC Regions 5, 6, and 7 are the same Refining District divisions of PADD II used by the EIA. Region 5 is Refining District Indiana-Illinois-Kentucky; Region 6 is Refining District Minnesota-Wisconsin-North and South Dakota; and Region 7 is Refining District Oklahoma-Kansas-Missouri.

PADD III (Region 8) was not subdivided since it is a major supply region for the surrounding regions.

PADD IV (Region 9) was not subdivided because it is generally self-sufficient with small refineries serving niche markets, only small amounts of products flowing into the region from other regions and little product flowing intra-regionally. PADD IV corresponds to the EIA Rocky Mountain Refining District.

PADD V (EIA West Coast Refining District) was subdivided into Regions 10, 11, 12, and 13 because of the unique supply requirements of California (especially in future years) versus the states of Oregon and Washington (Region 10), the major population centers located in northern and southern California (Regions 11 and 12), and the geographic isolation of Alaska and Hawaii (Region 13).

Where a state was split between regions, the boundaries used were county lines to allow apportionment of demands by county population.

Six Foreign Regions

Six supply/demand regions outside of the United States were chosen for modeling. These six regions, shown in Figure 3-3 and listed in Table 3-1 (with abbreviations used), were deemed to be the most important regions that have historically supplied products for the U.S. market or can be considered as a possible source of future supply. Region LAT is a long-standing supply source of products for the U.S. East Coast as well as occasional products supply for Europe and other areas in the world. Region CAN is closely allied with the United States geographically, politically, and economically. Region NWE is a major refining center with political and economic ties with the United States. Region MED is also a major refining center with political and economic ties with the United States. Region ME is a major crude oil production center with significant export refining capability and has historically supplied products to the U.S. market. Region PAC is also a major refining center, which is projected to undergo significant growth both in product demand and in refining capability and was considered a potential source of products for the U.S. market. The regions not modeled were assumed to have minor direct impact on the U.S. supply system.

1989, 1987 U.S. Demand For Calibration And Validation Runs

The demand data from 1989 that were used for calibration of the logistics model were taken from EIA published data. The year 1989 was used for calibration because at the onset of the study it was the most recent year for which complete worldwide demand data were available.

Where a state was split between regions, the state demands were apportioned to the regions on a county population basis using the 1990 census. Regional demands were then aggregated from the state data. Using a similar procedure and EIA data, demands were developed for the 1987 validation case. Overall demands for 1989 and 1987 may be found in Table 3-2. Details of the state and regional shares may be found in Appendix L, Section III-1.

Gasoline Grades

Based on the CAAA requirements, leaded gasoline was phased out by 1995 with its share apportioned between unleaded regular and unleaded midgrade. In areas where unleaded midgrade consumption was extremely low in 1987, midgrade share for 1995 was estimated by using the rate of change in share increase between 1987 and 1990. After 1995, midgrade share was held constant. Details may be found in Appendix L, Section III-2.

Gasoline Types

Five types of finished gasoline were considered:

- Reformulated Gasoline (RFG) for ozone nonattainment areas. The requirements for RFG were discussed earlier.

- Oxygenated Gasoline (OG) for CO nonattainment areas. The requirements for OG were also discussed earlier in this chapter.
- Oxygenated RFG (ORFG) for areas that are both ozone and CO nonattainment areas.
- Conventional Gasoline (CG) for areas that meet both ozone and CO standards for ambient air quality.
- Gasohol for areas in which ethanol has been blended at 10 vol% on an economic basis.

Ethanol was assumed to continue to be blended in attainment areas where it has been blended in the past for economic reasons. The demand for ethanol in OG and ORFG was determined on an economic basis using the logistics model. Because the potential demand for ethanol in these gasoline types is approximately twice current ethanol production capacity, ethanol was not considered in RFG. Further, these three gasolines have Reid Vapor Pressure (RVP) waivers or are winter type fuels (CO nonattainment).

Kerosene/Jet Fuel And Diesel

As has been announced by the U.S. Armed Services, naphtha-type jet fuel is assumed to be phased out. For this study, all future jet fuel was considered to be kerosene type.

In accordance with the CAAA, all on-highway diesel was considered to be low sulfur (<0.05 wt%) in October 1993 and thereafter. Off-highway diesel used for heavy mining equipment, road building equipment, cranes, fired turbines, drilling rigs, railroads, etc., was assumed to continue with the current sulfur specification which is <0.5 wt%. See Chapter Four for the costs of producing all diesel/distillate with lower sulfur specifications and for the costs of producing a low aromatics diesel fuel per California requirements.

Details of the breakdowns between the types and grades of gasoline, jet fuel, and diesel may be found in Appendix L, Section III-3. State maps showing the counties that require RFG, OG, and ORFG may be found in Appendix L, Section III-4. A listing of nonattainment and attainment counties may be found in Appendix L, Section III-5. To determine the share of the different types of gasoline, county populations (1990 Census) were used to determine their share of the total state demands. The rationale for changing from JP-4 to kerosene-type jet fuel may be found in Appendix L, Section III-6.

Foreign Products

Product type breakdowns may be found in Table 3-8 for 1989 and the three Foundation Cases. More detail of foreign product type breakdowns by region can be found in Appendix L, Section III-7.

Factors Affecting Demands

A number of factors could affect the demands for light petroleum products used in this analysis. Because of the difficulty in forecasting which factors will be predominant in the future, the NPC chose to study the range of demands embodied in the Foundation Cases instead of concentrating on one base case forecast. Some of the factors which can affect demand are:

- Alternative fuels (see Appendix E for an analysis of alternative fuels)
- Economic activity
- World crude oil prices and product prices
- Population growth
- Efficiency of facilities for producing light products
- Efficiency of the devices which use light products
- Government tax and fuel use mandate policies.

Most scenarios that can be developed either will cause an increase in demand leading to both higher imports and higher U.S. refinery output, thereby reducing pressures to rationalize U.S. refining capacity, or will cause a decrease in demand leading to lower imports and lower U.S. refinery output, thereby increasing pressure to rationalize U.S. refinery capacity.

THE NPC LOGISTICS MODEL

Introduction

The original request to the NPC from the U.S. Secretary of Energy (see Appendix A) to study the future viability of the U.S. refining industry was due in part to the concern about increased costs resulting from new legislation/regulation, e.g., the CAAA. The new regulations (for air, water, land, health/safety, and product quality) require new expenditures for both U.S. refineries and the product delivery system.

A viable U.S. industry was seen as needing to recover the increased costs. But there are also competitive forces at work. At the time of the study request, there was concern that foreign supply locations would not have similar large future expenditures. Without the need to recover new large expenditures, the cost of products from foreign refiners would not increase. The anticipated result was a major increase in product imports resulting in significantly lower U.S. refinery utilization.

Other chapters in this report address the modifications that are expected to be necessary within the fenceline of U.S. refineries. Similar foreign environmental and process costs for the non-U.S. refineries are discussed later in this chapter.

The delivery of products from U.S. and foreign refiners to the ultimate U.S. consumer utilizes an oil delivery system that is complex. This delivery system is comprised of various methods of moving oil in bulk from one geographic point to another. Hereinafter, this oil delivery system—comprised of pipelines, tankers (both U.S. and foreign flag), barges, railcars, and trucks—is referred to as the logistics system. The logistics system is also expected to incur increased future environmental, health, and safety costs. These additional logistics costs are discussed elsewhere in this chapter.

The NPC Logistics Model was used to integrate the future product supply costs from U.S. and foreign refineries with the appropriate product delivery costs. From a delivered product standpoint, the NPC Logistics Model minimized costs in providing the resultant supply/demand balance.

Product Supply and Delivery

The NPC chose to concentrate the study on the expected cost increases for light product (motor gasoline, jet fuel, and distillate) delivery to the ultimate consumer. Prior to the CAAA, light products could be divided into eight generic types as shown in Table 3-11.

TABLE 3-11

PRE-CAAA LIGHT PRODUCTS

Leaded Regular Gasoline
Unleaded Regular Gasoline
Unleaded Midgrade Gasoline
Unleaded Premium Gasoline
Naphtha Jet Fuel (Military)
Kerosene Jet Fuel (Civilian and Military)
Diesel (On-Highway and Off-Highway, e.g., Farm)
Other Distillates (Including Heating Oil)

The reader will note that regular, midgrade, and premium gasohols are not included in the table. Gasohol is the generic name for a gasoline containing 10 vol% ethanol. Because of the water solubility of ethanol, these gasohols are generally blended in the terminals instead of refineries. The EIA's historical data base through 1989 did not capture terminal blending of ethanol.

The CAAA requirements for oxygenates and reduced sulfur increases the generic forms to over sixteen. The generic product types expected by 1995 are shown in Table 3-12. The reader will note that two pre-CAAA products—leaded regular gasoline and military naphtha jet fuel—are assumed to disappear by 1995.

In addition to the three gasohols (containing 10 volume percent ethanol), the nine oxygenated, reformulated, and oxygenated-reformulated types of CAAA gasoline require an oxygen compound.

Table 3-12 shows the 19 generic light products that will be required by 1995 for dif-

TABLE 3-12

1995 (AND LATER) LIGHT PRODUCTS

Unleaded Regular Gasoline:	Conventional (pre-CAAA)
	Gasohol
	Oxygenated*
	Reformulated †
	Oxygenated-Reformulated ‡
Unleaded Midgrade Gasoline:	Conventional (pre-CAAA)
	Gasohol
	Oxygenated*
	Reformulated †
	Oxygenated-Reformulated ‡
Unleaded Premium Gasoline:	Conventional (pre-CAAA)
	Gasohol
	Oxygenated*
	Reformulated
	Oxygenated-Reformulated ‡
Kerosene Jet Fuel (Civilian and Military)	
On-Highway Diesel (0.05 weight % sulfur, maximum)	
Off-Highway Diesel (Farm, Construction, etc.)	
Other Distillates (including Heating Oil)	

* Winter fuel for carbon monoxide (CO) nonattainment areas.

† Required in ozone nonattainment areas. (The specific volume depends on the level of opt-in.)

‡ Winter fuel for areas in both ozone and carbon monoxide nonattainment.

ferent consumer areas/uses. But the logistics system considered additional types depending on the location of the oxygenate addition—refinery or terminal. There is an un-oxygenated counterpart to each of the nine possible CAAA gasolines that will contain oxygen compounds (regular/midgrade/premium and oxygenated/reformulated/oxygenated-reformulated). Thus, each refining region (both U.S. and foreign) could need to supply 28 different products versus the 8 prior to the CAAA.

The oxygen compounds add to the delivery complexity. Because of the water solubility of alcohols, the alcohol and ether oxygen compounds must be considered separately within the context of the logistics system. For the NPC study Logistics Model, ethanol and methyl tertiary butyl ether (MTBE) were used as representative of the two types of oxygen containing compounds.

As shown on Table 3-1, the NPC study considered thirteen U.S. regions and six foreign regions. The potential complexity of the future was kept in sight as the NPC began development of the Logistics Model.

Logistics Model Development

The previous material outlined the complexity of analyzing the delivery of future

product supplies. In summary, the part of the NPC study dealing with the deliverability of future product supplies considered 28 separate products from each of 18 possible supply locations, and utilized two oxygen compounds. The 19th region, New England, is not a supply region, only a product demand region.

Each refining center has a separate cost for each of the 28 products. These product costs increase with refining utilization (increasing throughput).

Past studies have frequently attempted to integrate the refining and logistics system in one model. The experience of the current study participants is that these integrated models add substantially to the complexity described above. This additional complexity hinders analyses and insights. The decision was to split the modeling effort between the refineries and the logistics system. This interface required more manual data handling in front of the logistics model; however, the analysis of the resultant model efforts (refining and logistics) were made simpler. The refining data provided for the logistics model are discussed subsequently.

Even with the split between the refining and logistics modeling efforts, the logistics model requires a large mathematical optimizing tool. The number of future products moving from the refining centers to the consumer demand locations were discussed above. The logistical links between supply and demand are the various methods of moving bulk oil—pipelines, tankers (U.S. and foreign flag), barges, railcars, and trucks. The logistical links may have capacity limits (e.g., pipelines) that become model constraints.

Model Contractor

After an interview period of possible contractors, Bonner and Moore Associates (B&M) was selected as the logistics model contractor. A major point in B&M's selection was that they had an existing system that could be modified for the NPC's logistics modeling effort. B&M had prior experience using their system to model smaller logistical (delivery) areas. A discussion of B&M's model and its adaptation and use for the NPC study can be found in Appendix L, Section IV-1.

Consumer Product Demand

The NPC Logistics Model was designed to satisfy the regional consumer demand for the particular products as specified. Historical U.S. and foreign demand data for 1989 and 1987 were used to calibrate and validate the model, respectively. These demand data were discussed earlier. Table 3-2 contains summarized U.S. data. In addition, Appendix L, Section III-1 contains the detailed state and regional data. The year 1989 was selected as the calibration year because, at the start of the study, it was the last historical year for which worldwide supply/demand volumetrics were available. Details on the 1989 calibration and 1987 validation of the model can be found in subsequent parts of this section.

The future was studied using three demand scenarios—for the United States—growth, no growth, and declining demand. For each scenario, product demand data were developed for 1995, 2000, and 2010. A complete discussion of all the U.S. regional and foreign demand data is in the Demand Development section of this chapter.

Refinery Supply

The development of the refinery product supply data used with the Logistics Model is involved. The section on Refining Industry Modeling contains the key assumptions, particularly product quality. Analyses of the refinery model runs are also found there. The subsequent section contains a discussion of the cost-volume relationships. What follows here is a summary of the cost-volume relationships as they were used with the Logistics Model.

As refinery throughput (utilization) increases, the conversion units fill toward capacity. It becomes more expensive to make each successive unit of gasoline and distillate. The change in cost (increasing) with increasing volume yields the cost-volume relationships referred to throughout this report. A particular base relationship is developed using a constant composition for the light products (Tables 3-11

or 3-12). Other relationships are developed at alternative compositions. Then, by comparing the relationships (which were developed on different compositions) at the same total volume of light products, the cost of changing the composition from the base relationship can be determined.

Logistics System

The Logistics section of this chapter contains a thorough discussion of the various aspects of moving bulk oil from one point to another. This includes the 1987 and 1989 transportation costs for pipelines, barges, railcars, and trucks which were taken from the NPC survey. Capacity limitations on the logistical transportation modes are also documented in that section.

Historical Product Costs

The previous discussion summarized the historical (1987 and 1989) product demand and logistical references as they occur in this report. The movement of products through the logistics system to the eventual consumer is dependent on a number of factors. Obviously, both logistical costs and capacity limitations are important. These logistical costs are related to both the distance from the refining supply point and the mode of delivery. However, the greater absolute cost is the cost to produce the products at the refinery point of supply.

Procedure

The development of historical refinery product costs can include many factors. For regional product costs, there are two cost buildup approaches. Obviously, the first is an aggregation (and weighting) of the costs for individual refiners in a supply region. An alternative buildup is for a single regional operation having the aggregated capacity of the individual operations in the region. Both approaches require a number of assumptions, some of which are outlined below.

- The first (and largest in absolute terms) is the delivered crude oil cost. What type of crude oil? Loading point costs (and discounts)? Delivery method and costs?
- Refinery operating costs (i.e., fuel inputs, chemicals, and catalyst). This will vary with the crude oil quality (e.g., sulfur and metals), severity of the refining operation (catalytic cracking and coking), and possible age of the equipment (heat integration).
- Refinery maintenance costs. These costs vary with age, refinery complexity, and the severity of the operation (determining the planned and unplanned downtimes).
- Refinery stationary environmental costs can be included in the prior two items, or developed separately.
- Refinery manpower costs (operating, maintenance, staff, etc.).
- Property taxes.
- Depreciation. Recovery of prior capital charges.
- Federal/state income taxes on profit/loss.
- Return on capital employed.

In addition to the foregoing, there is the need to have individual product costs. (One supply region could supply a particular product at less cost than another region.) How should the costs be allocated to the separate products? The final difficulty with both previous approaches is that there is a need for foreign detail equivalent to that in the United States.

While either buildup approach may be appealing, neither is practical or necessary for this study. The NPC Logistics Model is intended to capture major trends in the future level of U.S. refinery supply and the import levels. As discussed in other sections and chapters, the eventual product demand scenario will have the major impact on the combination of refinery utilization and imports. There is also uncertainty on the long-range environmental costs. Thus, the NPC judged that it was not necessary to complicate the study further

with the numerous assumptions discussed above.

Data Sources

There are several sources of historical product price data tabled by product and geography. Arguably, the best known of these sources is the Platt's (annual) *Oil Price Handbook and Oilmanac.* For some locations, both spot (refinery bulk) and terminal (rack) pieces are available from this source. The NPC chose to use annual averages created from these spot price assessment as proxies for annual average costs for bulk product delivery at the regional refinery locations. The data were supplemented with other information from EIA's *Petroleum Marketing Annuals.* In some cases, the foreign refinery products costs were calculated by netback from possible U.S. import locations. The details of the 1987 and 1989 product cost development are in Appendix L, Section IV-2.

The use of the average price data as a proxy for cost includes an unknown component of profitability. Some profitability component would have been included in the "buildup" approaches discussed earlier, but the buildup approach would have clearly stated the presumed level. The NPC procedure of accepting price as a proxy for cost results in the future analyses being built on the unstated level of 1989 historical profitability.

In the context of the current NPC study, the subject of profitability (return on capital employed) both historically and in the future is discussed in Chapter One. Still a few clinical comments on the use of the price data as a proxy for cost are helpful at this point. The industry as a whole operated in 1989, regardless of the level of profitability (positive, even negative). The marginal product suppliers (locally, or remotely through the logistics system) accepted the profit component included in the historical price. Since there were imports to the United States and the industry had spare capacity in 1989, the profit component was not "too high"—lower cost producers would have increased production. The profitability of the industry may have been "too low"—within a 12-month time frame, this could have been just prior to shutdown by the marginal product supplier.

The twin issues of specific refinery shutdown and the identification of individual marginal product suppliers (within a region as opposed to a whole region) are outside of the scope of the NPC study.

In building the future product costs on top of a historical cost, it is recognized that the absolute level of future cost may differ due to a change in the underlying historical profit component. Regardless, the NPC concluded that any variation should impact all regions approximately the same; and therefore, not impact the overall trends developed by the study.

As the reader will find elsewhere, here is another instance where caution should be exercised in using any particular absolute number from this study. The use of either trends or changes is preferred. Finally, the reader is again referred to Chapter One for a discussion of historical and future capital recovery.

Foreign Netback Adjustments

There were a number of instances where foreign price data for 1987 and 1989 were not published. In these cases, the missing data were created using netback calculations from other locations. For all products, the Canadian data were based on Boston; Latin American data were based on New York Harbor. The bases for the other foreign products are shown in Appendix L, Section IV-2.

As the first calibration case model runs were made, imports rarely occurred from foreign locations where the costs were not from U.S. netback sources. This does not suggest that the published foreign data are incorrect. It simply illustrates one of the problems the NPC knew it would have when it decided to base the logistics' modeling on annual average data.

The immediate step was to correct all foreign data to a netback basis relative to a probable U.S. import location. For 1987 and 1989, respectively, Tables 3-13 and 3-14 show the original published prices and, for the foreign locations, the netback revisions versus the data in Appendix L, Section IV-2.

TABLE 3-13

1989 NETBACK COST ADJUSTMENTS
(1987 Cents Per Gallon)

	U.S. Regions*													Foreign*					
	1	2	3	4	5	6	7	8	9	10	11	12	13	CAN	LAT	NWE	MED	ME	PAC
Leaded Regular:																			
Published Price	57.8	57.4	57.4	60.8	58.6	62.2	58.6	56.8	60.1	60.8	59.9	61.4	79.2	54.9	53.3	51.7	51.2	51.5	55.3
Netback	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(5.0)	(5.1)
Total	57.8	57.4	57.4	60.8	58.6	62.2	58.6	56.8	60.1	60.8	59.9	61.4	79.2	54.9	53.3	51.7	51.2	46.5	50.2
Unleaded Regular:																			
Published Price	57.0	56.6	56.6	58.8	57.2	61.7	58.4	55.7	60.1	60.9	59.9	61.4	76.7	54.1	52.5	52.3	51.8	52.1	56.0
Netback	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1.5)	(1.5)	(6.5)	(6.6)
Total	57.0	56.6	56.6	58.8	57.2	61.7	58.4	55.7	60.1	60.9	59.9	61.4	76.7	54.1	52.5	50.8	50.3	45.6	49.4
Unleaded Midgrade:																			
Published Price	59.3	58.9	58.9	62.4	60.9	64.8	60.6	58.0	64.4	63.5	62.3	63.8	78.8	-	-	-	-	-	-
Netback	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	59.3	58.9	58.9	62.4	60.9	64.8	60.6	58.0	64.4	63.5	62.3	63.8	78.8	-	-	-	-	-	-
Unleaded Premium:																			
Published Price	63.3	62.9	62.9	68.9	66.8	69.6	64.2	61.6	66.3	67.6	66.2	67.5	82.1	60.4	58.8	58.6	58.1	58.4	62.3
Netback	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1.5)	(1.5)	(6.5)	(6.6)
Total	63.3	62.9	62.9	68.9	66.8	69.6	64.2	61.6	66.3	67.6	66.2	67.5	82.1	60.4	58.8	57.1	56.6	51.9	55.7
Kerojet:																			
Published Price	58.9	58.5	58.1	59.2	57.6	59.6	56.9	55.5	57.3	59.3	59.8	59.8	61.0	55.9	54.3	54.6	53.2	53.6	57.4
Netback	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(2.1)	(1.3)	(6.7)	(6.8)
Total	58.9	58.5	58.1	59.2	57.6	59.6	56.9	55.5	57.3	59.3	59.8	59.8	61.0	55.9	54.3	52.5	51.9	46.9	50.6
Diesel/Distillate:																			
Published Price	55.2	54.8	54.4	57.0	53.4	55.1	53.8	52.1	54.1	57.2	56.3	55.7	57.4	52.9	51.5	50.9	50.2	49.9	54.2
Netback	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1.3)	(1.2)	(6.3)	(6.9)
Total	55.2	54.8	54.4	57.0	53.4	55.1	53.8	52.1	54.1	57.2	56.3	55.7	57.4	52.9	51.5	49.6	49.0	43.6	47.3

* The regional designations are shown on Table 3-1.

TABLE 3-14

1987 NETBACK COST ADJUSTMENTS
(1987 Cents Per Gallon)

	U.S. Regions*													Foreign*					
	1	2	3	4	5	6	7	8	9	10	11	12	13	CAN	LAT	NWE	MED	ME	PAC
Leaded Regular:																			
Published Price	52.9	52.5	52.5	54.7	52.7	55.8	52.7	51.3	54.6	52.9	52.1	54.6	66.1	50.0	49.0	47.7	47.3	50.8	55.3
Netback	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(10.2)	(11.0)
Total	52.9	52.5	52.5	54.7	52.7	55.8	52.7	51.3	54.6	52.9	52.1	54.6	66.1	50.0	49.0	47.7	47.3	40.6	44.3
Unleaded Regular:																			
Published Price	51.8	51.4	51.4	54.3	52.7	55.9	52.8	50.5	54.7	53.6	52.9	55.1	67.6	49.0	47.9	49.7	49.3	52.7	57.2
Netback	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(3.1)	(3.1)	(13.3)	(14.0)
Total	51.8	51.4	51.4	54.3	52.7	55.9	52.8	50.5	54.7	53.6	52.9	55.1	67.6	49.0	47.9	46.6	46.2	39.4	43.2
Unleaded Midgrade:																			
Published Price	53.8	53.4	53.4	56.7	54.7	57.9	54.5	52.2	56.8	56.2	54.8	56.9	69.0	-	-	-	-	-	-
Netback	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	53.8	53.4	53.4	56.7	54.7	57.9	54.5	52.2	56.8	56.2	54.8	56.9	69.0	-	-	-	-	-	-
Unleaded Premium:																			
Published Price	57.5	57.1	57.1	60.9	57.9	61.0	57.3	54.8	59.2	60.2	57.8	59.8	71.1	54.6	53.5	55.4	55.0	58.4	62.9
Netback	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(3.1)	(3.1)	(13.3)	(14.0)
Total	57.5	57.1	57.1	60.9	57.9	61.0	57.3	54.8	59.2	60.2	57.8	59.8	71.1	54.6	53.5	52.3	51.9	45.1	48.9
Kerojet:																			
Published Price	53.9	53.7	53.5	53.8	56.3	55.5	52.1	51.5	54.2	54.4	54.4	55.0	57.9	51.0	50.0	51.1	50.0	49.2	52.6
Netback	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(2.4)	(1.7)	(8.2)	(7.9)
Total	53.9	53.7	53.5	53.8	56.3	55.5	52.1	51.5	54.2	54.4	54.4	55.0	57.9	51.0	50.0	48.7	48.3	41.0	44.7
Diesel/Distillate:																			
Published Price	52.2	52.0	51.8	55.3	51.6	53.1	50.9	49.7	51.4	51.2	51.4	50.6	54.8	50.2	49.2	49.3	48.0	46.3	50.0
Netback	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1.5)	(0.6)	(6.7)	(6.7)
Total	52.2	52.0	51.8	55.3	51.6	53.1	50.9	49.7	51.4	51.2	51.4	50.6	54.8	50.2	49.2	47.8	47.4	39.6	43.3

* The regional designations are shown on Table 3-1.

Reference Point Calculation

Thus far, the discussion in this section has covered:

- Product cost buildup
- Use of published price data as a proxy for cost
- Netback corrections from U.S. import locations.

As mentioned earlier, the Logistics Model used cost-volume relationships to describe the increases in refinery costs as light product supply increased. A detailed discussion of the development of these relationships is in the section of this chapter entitled Cost of U.S. and Foreign Produced Products. These relationships need an anchor point, subsequently referred to as the "reference point." The cost-volume relationships then provide data on the variation in cost about a specific volume. For the 1989 model calibration effort, the reference point volume for each U.S. refining region was the 1989 production. For the foreign regions, the reference point was at the import level to the United States.

The historical data from the EIA provided information on only five of the eight generic products shown in Table 3-11. All the unleaded grades of gasoline are combined; so are all the distillates. The refinery modeling effort (the development of the cost-volume relationships) provided refining supply estimates to split the unleaded gasoline into grades—regular, midgrade, and premium. Similarly, the distillates were split into diesel and other (primarily heating oil). For 1987 and 1989, no additional split was made on the diesel pool—on-highway and off-highway. The calculation of the reference point cost is then the summation of the light product fractions times the respective cost for each product.

$$\sum [(\text{light product fraction}) \times (\text{cost of light product})]$$

Appendix L, Section IV-3 contains the calculations of the 1987 and 1989 reference point costs. There is a cost for each domestic region (except New England which is not a product supply source) and foreign region. Appendix L also contains the reference point cost calculations for all the Foundation Cases. A further discussion of the 1995/2000/2010 reference point costs can be found later in this chapter.

Regional Products

While the Logistics Model contained thirteen U.S. and six foreign regions (Table 3-1), the cost-volume relationships were developed for only six U.S. areas and the six foreign regions. The data for the six U.S. refinery modeled areas were distributed to the thirteen U.S. Logistics Model regions as described below.

Table 3-15 contains historical gasoline quality data that will be discussed later in this subsection. For the present, the table provides the reader with a pictorial match between the regions used with the Logistics Model and the geographic refining regions modeled to develop the cost-volume relationships. Where cost-volume relationships were applied to more than one logistics region, the refinery data were split based on the historical regional light product output share provided by the EIA. (Historical 1987 and 1989 refinery light product output data appear subsequently in Table 3-18.)

The refinery cost-volume relationships provided guidance on the increased cost of light products with increasing supply. The relationships also provided data on the changes in cost due to changes in composition among the major products—motor gasoline (M), kerosene jet fuel (J), and distillates (D). The "shorthand" of MJD is frequently used when discussing the cost-volume relationships. For the 1987-89 historical analyses on jet fuel and distillate, there were no additional costs at the refinery to move to other products within these major grades (e.g., from heating oil to diesel). At the refinery point of supply, shifts among the historical gasoline types could occur at an octane cost assumed to equal the difference in the corrected (netback and scaling factor) costs for the particular gasoline grades.

For jet fuel and distillates, no additional product cost adjustments were necessary as the product moved from the refinery to the consumer. However, the gasoline movements

TABLE 3-15

1987/1989 OCTANE AND RVP DATA

	Regional Consumer Demand					Refining Cost-Volume Modeling				
	Yearly Average Octane, (R+M)/2				Yearly Average RVP, psi	Yearly Average Octane, (R+M)/2				Yearly Average RVP, psi
Regions*	Unleaded Regular	Unleaded Midgrade	Unleaded Premium	Leaded	All Grades	Unleaded Regular	Unleaded Midgrade	Unleaded Premium	Leaded	All Grades
1	87.2	89.1	92.5	89.0	12.0					
2	87.2	89.1	92.5	89.0	12.0	87.2	89.1	92.2	89.2	11.5
3	87.2	89.1	92.5	89.0	11.0					
4	87.2	89.1	92.5	89.0	12.0					
5	87.2	89.1	92.1	89.0	12.0					
6	87.2	89.1	92.1	89.0	12.0	87.2	89.1	92.2	88.7	12.2
7	87.2	89.1	92.1	89.0	11.5					
8	87.2	89.1	92.1	89.0	11.0	87.1	89.1	92.2	88.8	11.0
9	85.4	88.1	91.1	87.0	11.0	85.8	87.9	90.8	87.3	11.8
11	87.2	89.1	92.1	88.5	10.0	87.2	89.1	92.0	88.4	10.9
12	87.2	89.1	92.1	88.5	10.0					
10	87.2	89.1	92.1	88.5	12.0					
13	87.2	89.1	92.1	88.5	11.5	87.2	89.1	92.0	88.4	11.5
Canada						87.2		92.2		11.5
Caribbean						87.2		92.2		11.5
NW Europe						87.2		92.2		11.5
Mediterranean						87.2		92.2		11.5
Middle East						87.2		92.2		11.5
Pacific Rim						87.2		92.0		10.9

* The regional designations are shown on Table 3-1.

could require both RVP and additional octane adjustments. The RVP of the refinery produced gasoline was corrected by the Logistics Model to the delivered regional consumer quality using normal butane at the refinery supply point. The costs of the normal butane are provided with the other product cost data in Appendix L, Section IV-2. The Logistics Model also corrected the refinery-produced octane to a delivered regional consumer quality. The adjustment again assumed the octane cost in a refining region could be derived using the premium-regular differentials from the adjusted (netback and subsequent scaling factor) respective product costs.

Model Calibration

Prior to using the NPC logistics model on the future demand scenario years (1995, 2000, and 2010), it was necessary to calibrate the model on historical data. This calibration (and the subsequent validation) was a necessary prerequisite to have any confidence the model could project future supply trends.

Summary

The Model Calibration involved determining cost correction factors that would modify the product flows such that historical refinery production and interregional flows were matched. Table 3-16 provides a comparison between the 1989 EIA historical data and the model results. In summary, with the minor adjustments discussed below, the model results closely approximated the 1989 actual data. The only difference of any significance was that the model chose to make most of the New England imports directly rather than transshipped through New York Harbor. Within the big picture, an additional constraint for imports into New England (e.g., a dock limit) was considered unnecessary.

Table 3-17 shows the scaling factors that were applied to the historical product costs discussed previously. Product cost scaling factors were required in nine of the thirteen domestic product supply regions; the largest was about 3 percent. All five foreign regions with significant 1989 exports to the United States required product cost scaling factors; the largest was about 4 percent. The sixth foreign region, the Pacific Rim, had minimal exports to the United States in 1989 (Table 3-16, Region PAC).

Outputs for the 1989 Calibration Case are available in the Appendices and Working Papers. The regional supply/demand balances by product are in Appendix L, Section IX-1. Pipeline, tanker, and barge data by product are in the Working Papers.

Constraints

The Calibration Case required twelve model constraints. Seven constraints were due to the regional nature of the NPC Logistics Model, as opposed to a state/sub-state model. The logistical flow was modeled by selecting centroids for the regions. One of the constraints prevented all of the distillates and jet fuel for the South Atlantic region from being supplied by tanker (Port Everglades) versus the pipeline centroid (Greensboro). Another constraint was to recognize the pipeline from El Paso to Arizona could not be used to supply gasoline directly to Southern California. Similarly, the pipeline from the Rocky Mountains to Spokane could not supply Western Washington. Three other constraints were also related to pipeline movements—North Texas to Denver, Oklahoma/Kansas to Denver, and Georgia to Tennessee. The seventh constraint, to match historical data, forced volume onto the more costly barges (versus pipelines) moving volume upriver from the Gulf Coast to the Ohio River area.

The remaining constraints limited product composition. These constraints were required because of the cheaper octane cost (premium minus regular) in the Gulf Coast. NPC survey data were utilized to limit the premium versus regular pipeline compositions. Detailed documentation on all of the 1989 model constraints are with the model computer output (Working Papers 3.IV-1).

Pipeline Throughput

The pipeline throughput data for the Calibration Case are with the Validation Case on Table 3-18.

TABLE 3-16

1989 REGIONAL REFINERY PRODUCT OUTPUT, PRODUCT IMPORT, AND DOMESTIC TANKER USE

	Calibration Case, Thousand Barrels/Day*			
	Refining Product Output		Product Imports	
Region†	Model	EIA‡	Model	EIA‡
1	—	—	507	276
2	1,016	1,031	81	307
3	49	69	118	80
4	75	76	5	8
5	1,675	1,694	20	7
6	269	277	5	7
7	637	607	—	—
8	5,169	5,125	—	42
9	360	401	3	3
10	351	342	13	9
11	555	556	—	4
12	933	917	16	6
13	137	150	8	8
Total	**11,226**	**11,245**	**776**	**757**

	Product Imports to U.S.	
	Model	EIA‡
CAN	121	117
LAT	489	434
NWE	49	79
MED	60	75
ME	55	50
PAC	2	2
Total	776	757

Domestic Tankers	Model	Availability
(Clean ex Chemicals)	27	38

* Total of modeled products—gasoline plus jet fuel plus distillates.

† The regional designations are shown on Table 3-1.

‡ Estimated after correcting for exports, inventory change, distillate No. 4 in distillate, and non-modeled imports.

TABLE 3-17

CALIBRATION CASE (1989) SCALING FACTORS
(1989 Cents Per Gallon)

	U.S. Regions*													Foreign*				
	1	2	3	4	5	6	7	8	9	10	11	12	13	CAN	LAT	NWE	MED	ME
Leaded Regular:																		
Cost	57.8	57.4	57.4	60.8	58.6	62.2	58.6	56.8	60.1	60.8	59.9	61.4	79.2	54.9	53.3	51.7	51.2	46.5
Scaling Factor	-	0.7	0.7	-	(0.5)	(1.9)	(1.5)	-	(0.8)	(0.7)	(1.0)	(1.2)	-	2.0	1.1	0.5	-	(1.2)
Percent	-	1.2	1.2	-	(0.9)	(3.1)	(2.6)	-	(1.3)	(1.2)	(1.7)	(2.0)	-	3.6	2.1	1.0	-	(2.6)
Unleaded Regular:																		
Cost	57.0	56.6	56.6	58.8	57.2	61.7	58.4	55.7	60.1	60.9	59.9	61.4	76.7	54.1	52.5	50.8	50.3	45.6
Scaling Factor	-	0.7	0.7	-	(0.5)	(1.9)	(1.5)	-	(0.8)	(0.7)	(1.0)	(1.2)	-	2.0	1.1	2.0	1.5	0.3
Percent	-	1.2	1.2	-	(0.9)	(3.1)	(2.6)	-	(1.3)	(1.1)	(1.7)	(2.0)	-	3.7	2.1	3.9	3.0	(0.7)
Unleaded Midgrade:																		
Cost	59.3	58.9	58.9	62.4	60.9	64.8	60.6	58.0	64.4	63.5	62.3	63.8	78.8	-	-	-	-	-
Scaling Factor	-	0.7	0.7	-	(0.5)	(1.9)	(1.5)	-	(0.8)	(0.7)	(1.0)	(1.2)	-	-	-	-	-	-
Percent	-	1.2	1.2	-	(0.8)	(2.9)	(2.5)	-	(1.2)	(1.1)	(1.6)	(1.9)	-	-	-	-	-	-
Unleaded Premium:																		
Cost	63.3	62.9	62.9	68.9	66.8	69.6	64.2	61.6	66.3	67.6	66.2	67.5	82.1	60.4	58.8	57.1	56.6	51.9
Scaling Factor	-	0.7	0.7	-	(0.5)	(1.9)	(1.5)	-	(0.8)	(0.7)	(1.0)	(1.2)	-	2.0	1.1	2.0	1.5	0.3
Percent	-	1.1	1.1	-	(0.7)	(2.7)	(2.3)		(1.2)	(1.0)	(1.5)	(1.8)	-	3.3	1.9	3.5	2.7	(0.6)
Kerojet:																		
Cost	58.9	58.5	58.1	59.2	57.6	59.6	56.9	55.5	57.3	59.3	59.8	59.8	61.0	55.9	54.3	52.5	51.9	46.9
Scaling Factor	-	0.7	0.7	-	(0.5)	(1.9)	(1.5)	-	(0.8)	(0.7)	(1.0)	(1.2)	-	-	0.6	2.1	1.3	0.5
Percent	-	1.2	1.2	-	(0.9)	(3.2)	(2.6)	-	(1.4)	(1.2)	(1.7)	(2.0)	-	-	1.1	4.0	2.5	(1.1)
Diesel/Distillate:																		
Cost	55.2	54.8	54.4	57.0	53.4	55.1	53.8	52.1	54.1	57.2	56.3	55.7	57.4	52.9	51.5	49.6	49.0	43.6
Scaling Factor	-	0.7	0.7	-	(0.5)	(1.9)	(1.5)	-	(0.8)	(0.7)	(1.0)	(1.2)	-	0.2	2.0	(2.0)	(0.1)	0.1
Percent	-	1.3	1.3	-	(0.9)	(3.4)	(2.8)	-	(1.5)	(1.2)	(1.8)	(2.2)	-	0.4	3.9	(4.0)	(0.2)	(0.2)

* The regional designations are shown on Table 3-1.

TABLE 3-18

REGIONAL REFINERY PRODUCT OUTPUT, PRODUCT IMPORT, AND DOMESTIC TANKER USE
(Thousands of Barrels per Day)

	1989 Calibration Case*				1987 Validation Case*			
	Ref. Product Output		Product Imports		Ref. Product Output		Product Imports	
Region†	Model	EIA‡	Model	EIA‡	Model	EIA‡	Model	EIA‡
1	–	–	507	276	–	–	392	217
2	1,016	1,031	81	307	1,016	1,034	124	322
3	49	69	118	80	49	53	100	43
4	75	76	5	8	70	76	5	5
5	1,675	1,694	20	7	1,532	1,699	-	8
6	269	277	5	7	293	245	5	5
7	637	607	–	–	669	583	–	-
8	5,169	5,125	–	42	5,103	5,004	–	24
9	360	401	3	3	346	385	–	4
10	351	342	13	9	340	318	1	9
11	555	556	–	4	555	571	–	4
12	933	917	16	6	850	833	–	7
13	137	150	8	8	137	135	2	5
Total	11,226	11,245	776	757	10,960	10,936	629	653

	Product Imports to U.S.		Domestic Tankers Clean ex Chemicals		Product Imports to U.S.		Domestic Tankers Clean ex Chemicals	
	Model	EIA‡	Model	Availability	Model	EIA‡	Model	Availability
CAN	121	117			73	78		
LAT	489	434			279	342		
NWE	49	79			90	83		
MED	60	75			130	106		
ME	55	50			55	42		
PAC	2	2			2	2		
Total	776	757	27	38	629	653	32	38

* Total of modeled products—gasoline plus jet fuel plus distillates.

† The regional designations are shown on Table 3-1.

‡ Estimated after correcting for exports, inventory change, distillate No. 4 in distillate, and non-modeled imports.

Model Validation

The objective of the Model Calibration was to develop both the scaling factors and the minimum number of constraints necessary for the model to reproduce the historical 1989 U.S. supply/demand balance for light products. The objective of the Model Validation process was to demonstrate the model could reproduce the supply/demand results for another historical year. The year 1987 was chosen.

Summary

Table 3-16 compared the 1989 model results for U.S. refinery production and imports to the historical EIA data. Table 3-18 presents the same 1989 data and includes a similar comparison for 1987.

The validation effort on the 1987 consumer demands used the identical scaling factors developed in the 1989 calibration effort (Table 3-17). Consumer demands and product costs were adjusted to 1987 actuals. The results on Table 3-18 validate the use of the Logistics Model for the study of future scenarios.

Constraints

Using the different state/regional product demand data in 1987, the constraints were modified as necessary. The 1987 constraints and the model computer outputs for the Validation Case are in Appendix L, Section IX-1, and the Working Papers.

Pipeline Throughput

Table 3-19 provides the pipeline data for both the 1989 Calibration Case and the 1987 Validation Case. The EIA data are for inter-PADD movements; unsupplied data are due to the flow not crossing a PADD boundary. The NPC Logistics Model flows are one-directional; hence, they can be less than the EIA data where flows occurred in both directions (e.g., see EIA 7 to 8 and 8 to 7 flows).

Foundation Cases (1995/2000/2010)

Following the calibration and validation of the NPC Logistics Model, the Model was used to develop the supply/demand trends and interregional flows for the Foundation Cases. The consumer product demands for these cases are discussed in an earlier section of this chapter. The results of the Cases (and other issue Cases) are discussed in a later section. The remainder of this section provides other specifics about the model revisions for these future years.

Products

Table 3-12 provided the 19 consumer light products considered for each of the Foundation Cases. To simplify the development of the refinery cost-volume relationships, the midgrades were blended from regular and premium by the Logistics Model. The Logistics Model also blended the gasohols from sub-octane conventional gasoline streams. Hence, the cost-volume relationships provided guidance on only 12 of the products; the other 7 were blended by the Logistics Model.

The gasoline octane and RVP adjustments were procedurally the same as discussed earlier in this chapter.

Oxygenates

The refinery cost-volume relationships for gasolines that contained oxygen compounds (oxygenated, reformulated, and oxygenated-reformulated) were provided with the assumed MTBE removed. Refinery produced (captive) MTBE was required to be blended at the regional refinery source of production. The Logistics Model provided guidance on refinery versus terminal blending of the non-refinery (merchant) MTBE.

After satisfying the required regional consumer demands for gasohol, excess ethanol was allowed to compete with the merchant MTBE. The competition was limited to the wintertime oxygenated types of gasoline. Even with this limitation, potential ethanol consumption could be approximately twice current supply capability. The Logistics Model selected the oxygenate (ethanol or MTBE) based on the lowest combinations of producer and logistics costs.

TABLE 3-19

PIPELINE DATA
(Thousands of Barrels per Day)

Regional† Flows		EIA Pipeline Movements‡		Logistics Model			
				Capacities		Utilization	
From	To	1987	1989	1987	1989	1987	1989
2	4			359	359§	270	269
3	2			1,278	1,278§	600	737
3	5	222	235	299	299§	199	200
4	2			—	—	—	—
5	4	54	40	126	126§	—	7
5	6			291	291§	—	—
5	7			123	123	—	—
5	8			—	—	—	—
7	5			840	840§	—	1
7	6			237	237§	165	224
7	8	67	78	45	45§	—	—
7	9	67	60	100	100	27	23
8	3	2,013	2,032	2,546	2,546§	1,763	1,972
8	5	*	*	280	280	146	87
8	7	555	612	993	993§	285	416
8	9			43	43	43	43
8	12	56	54	58	58	52	58
9	6	26	30	45	45§	10	—
9	7	*	*	16	16	—	—
9	10	41	43	67	67	34	42
12	11			—	—	—	—

* Inter-PADD movements shown elsewhere—see 7 to 8, 8 to 7, and 9 to 6.

† The regional designations are shown on Table 3-1.

‡ Energy Information Administration data for pipeline movements between PADDs, where available. Revised 1/12/93: Gasoline components, Gasoline, Jet Fuel, Kerosene, and Distillate.

§ Pipeline capacities are NPC refining study survey data, where noted. Other capacities are estimated.

The reader is referred to the Oxygenates section later in this chapter for a detailed discussion of oxygenate supply/demand and costs.

Product Costs

The Foundation Case analyses were done in constant 1990 dollars. The conversions from other years were done with the Gross Domestic Product Deflator. These factors are shown in Appendix L, Section IV-4.

The 1989 conventional unleaded regular gasoline cost was converted to 1990 dollars and became the basis for the development of the oxygenated, reformulated, and oxygenated-reformulated unleaded regular gasolines. Conventional premium evolved in a like manner. The eight gasolines together with kerosene jet fuel, on-highway diesel, off-highway diesel, and other distillates comprised the twelve products contained in the cost-volume relationships.

A later section of this chapter contains a discussion of the future costs of these products. The detailed cost buildups are in Appendix L, Section VIII-1. Future environmental and process capital expenditures increase the costs of the products. A constant dollar 10 percent return was used in the calculation. The details are in Appendix L, Section IV-5.

Reference Point Calculation

The reference point calculation for the future years was procedurally the same as described earlier for the historical years. However, there were a couple of minor differences. Obviously, there were more products in the calculation, twelve versus seven historically. (Historically, on- and off-highway diesel were combined, reducing the total from eight to seven.) The historical calculation was of a known, actual composition. For the future, the composition was estimated as that which might be required from the refinery supply source. With that anchor point, the cost-volume relationships were developed. These relationships needed some additional flexibility to allow freedom for the Logistics Model. The reference point calculations are in Appendix L, Section IV-3. In summary, those volumes and compositions are not the final regional refinery supply data developed by the Logistics Model. The final regional supply data for the Calibration, Validation, Foundation, and Environmental Sensitivity Cases are in Appendix L, Section IX-1 and in the Working Papers.

Logistics Costs

The Logistics section of this chapter provides the details on the future changes expected for logistics costs and capacity limitations.

Model Constraints

The Logistics Model constraints, developed for the 1989 Calibration Case, were modified for the increased number of products in the future scenarios. The numerical level of the constraints was a function of the consumer demand, which varied by Foundation Case and year. The specific constraints are available in the Working Papers with the computer output from the Logistics Model for the same case.

Pacific Rim

Much of the future growth in product demand is in the Pacific Rim. The regional refinery simulations for the cost-volume relationships indicate that a substantial volume of products has moved and will continue to move from the Middle East to the Pacific Rim. In this environment, the Pacific Rim cost-volume relationships for export to the United States were judged less likely to occur. More likely, the potential Pacific Rim exports will stay local backing Middle East movements back into the Middle East. The future year studies with the NPC Logistics Model were made by moving the potential Pacific Rim export volumes back to the Middle East with the appropriate netback adjustment to the product costs.

California Quality Products

The Logistics Model was used to develop refinery production and interregional flow trends as a function of demand (the Foundation Cases). The investments associated with meeting new environmental regulations and *federal* product quality were included. The costs associated with unique California product qualities were excluded in the Logistics

Model studies on the assumption that the incremental costs of these products over EPA quality products would, on average, be the same in all production locations. This means that some limited volume of California product could be produced at some locations at lower cost.

OXYGENATES

Introduction

Oxygenates (alcohols and ethers) are oxygen-containing compounds. When oxygenates are blended with gasoline, the presence of oxygen enables the fuel to be more completely combusted in a fuel-rich mixture engine environment. The results of more complete combustion are the reduction of CO emissions and the reduction of unburned hydrocarbon molecules, which is one of the two precursors (nitrogen oxides, or NOx, is the other precursor) that react in the presence of sunlight to form smog. The degree of emissions benefit depends on the specifics of the vehicle.

Historical Overview

Refiners have been blending oxygenates in gasoline for many years. As part of the policy response to the oil price shocks of 1979-1980, the federal government and some state governments passed legislation with tax and financial incentives to promote the production and use of alcohol in transportation fuels. This legislation was designed to supplement gasoline production using renewable sources (such as agricultural products) to reduce U.S. oil imports. Some refiners in the 1980s used oxygenates in their gasoline to replace octane benefits lost with both lead phasedown and higher consumer demand for unleaded premium gasoline. Alcohols (primarily ethanol) and ethers (primarily MTBE) provided a competitive source of octane to help boost gasoline pool octane. In addition, starting with Denver, Colorado in 1988, some metropolitan areas have required oxygenates in gasoline during the winter months to reduce their atmospheric CO levels.

With the passage of the CAAA, oxygenate blending will play an expanded role in gasoline. The CAAA require the blending of oxygenates to meet federal air emissions standards in almost all CO nonattainment areas in the winter months and in certain ozone nonattainment areas year-round. Up to 39 geographic metropolitan areas of the United States will be required to blend oxygenates in gasoline for a minimum of four months in the winter (some areas up to six months and New York/Northern New Jersey metropolitan area for seven months) to help meet CO attainment standards beginning in the 1992-1993 winter season. Nine ozone nonattainment geographic metropolitan areas will be required to blend oxygenates in gasoline year-round beginning January 1, 1995. Beginning in 1995, additional ozone nonattainment areas are eligible to opt-in to the CAAA requirements for reformulated gasoline, gasoline that contains oxygenate.

Study Objectives

A key objective of this study is to determine if there is expected to be enough oxygenate in the years 1995, 2000, and 2010 to meet the projected CAAA oxygenate demand requirements. The study identifies available options to balance oxygenate supply with demand. Finally, the study estimates the capital investment required to support the projected growth in both domestic and foreign supply capability.

Summary of Results

Domestic production potential and demand estimates for oxygenates for the years 1995, 2000, and 2010 are shown in Table 3-20. The major assumptions used to develop the data in Table 3-20 are:

- Oxygenate production, reported in MTBE equivalent barrels, are based on the October 1992 EIA supply update. One barrel of ethanol (pure basis) is oxygen equivalent to 2.03 barrels of MTBE.
- NPC study Foundation Cases I, II, and III for motor gasoline assume that the annual change in gasoline demand for the 1995-2010 period are as follows:
  - Foundation Case I +0.8% / Year
  - Foundation Case II 0% / Year
  - Foundation Case III (0.8)% / Year

TABLE 3-20

DOMESTIC OXYGENATE PRODUCTION AND DEMAND
MTBE EQUIVALENT BARRELS
(Thousands of Barrels per Calendar Day)

	1995			2000			2010		
	Foundation Case			Foundation Case			Foundation Case		
	I	II	III	I	II	III	I	II	III
Domestic Production*	442	442	442	566	566	566	566	566	566
Domestic Demand									
CAAA	276	276	276	571	550	529	615	550	485
Gasohol	69	69	69	43	43	41	47	43	37
Total	345	345	345	614	593	570	662	593	522

* January 1, 1993, production capability = 285,000 barrels per day.

- In the years 2000 and 2010, the study assumes nonattainment areas eligible to opt-in to the federal RFG program choose to do so. This is a key assumption that significantly increases oxygenate demand. In addition, the study assumes the Northeast Ozone Transportation Corridor (NOTC) states opt-in to the CAAA ozone nonattainment gasoline requirements and California uses both reformulated gasoline and CO nonattainment gasoline statewide.
- The oxygen content of CO nonattainment gasoline in California is limited to 2.0 percent by weight (wt%) oxygen. This reduction for California from 2.7 to 2.0 wt% must still be approved by the EPA. The impact of this assumption is a reduction of 19 thousand barrels per calendar day (MB/CD) in oxygenate supply requirements.
- Idle ethanol capacity in 1992 is assumed to be available for start-up by 1995.
- Respondents to the EIA ethanol production survey in October 1992 reported no plans for the construction of green field facilities. Total capacity in 1995 is assumed to remain identical to the 1992 capacity, which is 88 thousand barrels per stream day (MB/SD) (pure ethanol basis).
- Per the October 1992 EIA production survey, U.S. MTBE production capacity of 170 MB/SD in 1992 is expected to grow to 353 MB/SD in 1995. MTBE from fluid catalytic cracking (FCC) isobutylenes is expected to grow from 68 MB/SD in 1992 to 119 MB/SD by 1995. MTBE from petrochemical and new green field facilities is expected to grow from 101 MB/SD in 1992 to 234 MB/SD by 1995.

Based upon the study assumptions for the Foundation Cases in 1995, Table 3-20 shows domestic oxygenate potential annual production exceeds demand by 97 MB/CD. Balance between 1995 supply and demand could be achieved through either a delay in the start-up of some production facilities, accelerating opt-ins by other nonattainment areas, or blending additional volumes of oxygenates as octane enhancers in conventional gasoline.

Gasohol demand in Table 3-20 declines over time as areas eligible to opt-in to the CAAA requirements for RFG choose to do so. About half of the 66 MB/CD annual ethanol production is anticipated to be used in attainment areas of both the Midwest producing states and other states that provide tax credit incentives for gasohol. The remaining ethanol is projected to be used in CO nonattainment areas.

Significant uncertainty surrounds the out year (2000 and 2010) balance between oxygenate supply and demand. The study assumes California, the NOTC states, and all ozone nonattainment areas opt-in to the CAAA requirements for RFG by year 2000. In this scenario, about 65 percent of U.S. gasoline is required to contain oxygenates. Table 3-20 shows that with the addition of the premised domestic supply capacity, demand will marginally exceed supply in most cases studied (4 to 96 MB/CD). Several options available to balance supply with demand could be:

- Additional investment in domestic oxygenate facilities
- Foreign oxygenate imports
- Lower level of opt-ins to the CAAA.

Costs

Table 3-21 shows a summary of the costs projected for new oxygenate facilities. Fuel ethanol costs are based on a minimum 40 million gallon per year producing facility. The U.S. Department of Agriculture (USDA) 1988 study is the primary source of information used for ethanol costs. Several minor adjustments were made to include USDA updated information and make the costs consistent with the NPC study basis. Ethanol costs include the 54 cpg federal excise tax exemption but exclude any state tax credits. MTBE costs are based on a nominal 2.0 MB/SD refinery FCC isobutylene feedstock facility and a 12.5 MB/SD green field facility. All costs in Table 3-21 are production and capital recovery based costs only. They exclude transportation, import fees, and other logistical costs. Capital recovery was based on an NPC study criteria of a 10 percent real return on investment after tax.

The data in Table 3-21 indicate that MTBE produced in facilities processing FCC isobutylenes would be preferred versus MTBE produced in green field dehydrogenation facilities since MTBE costs from FCC isobutylenes are substantially lower. Green field MTBE facilities are expected to come on stream by 1995 since oxygenate demand exceeds the potential FCC sourced isobutylene MTBE supply capability by as much as 200 MB/CD.

TABLE 3-21

OXYGENATE PRODUCTION COSTS FROM NEW FACILITIES (Cents per Gallon, 1990 Dollars)

Ethanol		
Dry Milling	148	94*
Wet Milling	138	84*
MTBE		
Refinery Isobutylenes:		
U.S. Gulf Coast	77	
Green Field: †		
U.S. Gulf Coast	88	
Saudi Arabia	86	
Venezuela	93	

* After deducting 54 cents per gallon federal excise tax exemption.

† Plants include isomerization/dehydrogenation facilities.

Depending upon transportation costs and region logistics, ethanol produced from new, energy efficient green field plants may compete with green field MTBE capacity and play a more significant role as an oxygenate in CO nonattainment areas to meet the provisions of the CAAA assuming the continuation of the federal excise tax exemption. All of the existing available ethanol capacity has been utilized to provide both gasohol and oxygenated gasoline in CO nonattainment areas. The study economics would favor blending more ethanol into CO nonattainment gasoline if more ethanol capacity was available. The use of ethanol in RFG is considered elsewhere in the NPC study. The premise of this section is that no ethanol is used in summer RFG.

A detailed discussion of the refining industry's ability to supply sufficient oxygenates to comply with the CAAA is presented below.

Oxygenate Properties

The four primary oxygen compounds used today as oxygenates for blending with gasoline are ethanol, MTBE (methyl tertiary butyl ether), TAME (tertiary amyl methyl ether), and

ETBE (ethyl tertiary butyl ether). Table 3-22 shows typical physical properties for these oxygen containing compounds. TAME and ETBE are ethers similar to MTBE. See Appendix L, Section V-1 (Typical Properties of Oxygen Compounds) for additional information.

Other oxygen-containing compounds such as methanol and isopropyl alcohol could be blended into gasoline. Methanol is a high octane, high oxygen content stream. However, the blending vapor pressure of methanol is extremely high relative to competing oxygenates and gasoline vapor pressure specifications. This physical characteristic along with its high affinity for water, severe corrosion characteristics, and high formaldehyde emissions is expected to limit direct blending of methanol into gasoline. Therefore, this study assumes that no methanol will be blended as an oxygenate directly into gasoline. Rather, the study assumes that methanol is much more attractive and economical as a raw material in the MTBE and TAME production processes. Isopropyl alcohol has a gasoline blending vapor pressure of 13 to 14 pounds per square inch (psi), which significantly exceeds gasoline RVP specifications and, therefore, virtually eliminates it from being economical as an oxygenate.

Ethers are attractive oxygenates for blending with gasoline because they are high octane, low vapor pressure streams that are not soluble in water. Ethanol has an oxygen content twice that of ethers, but a gasoline blending vapor pressure significantly higher than both ethers and neat gasoline. Ethanol also has a high affinity for water that is characteristic of alcohols. This limits ethanol to splash blending at distribution terminals to avoid water contamination in refinery systems and common carrier pipelines. On the other hand, ethers can be handled at a refinery and blended directly into gasoline for shipping on common carrier pipelines. Excluding cost considerations, these differences in physical properties along with reasons discussed later should result in ethers being the primary oxygenates used to meet the CAAA oxygen requirements.

Gasohol (90 percent gasoline, 10 percent ethanol) has been primarily marketed in the Midwest agricultural states where corn conversion to ethanol is economical and considered beneficial to individual states' economies. Several states subsidize ethanol for gasoline blending. Gasohol demand will decline over time after 1995 when some of the existing ozone nonattainment areas opt-in to the CAAA. Gasohol sales are expected to continue in attainment areas where economics will remain favorable. The oxygenate demand for gasohol will be additive to the CAAA oxygenate demand.

Ethanol

Over 95 percent of ethanol produced in the United States for gasoline is made from corn. On a dry basis, corn is composed of

TABLE 3-22

GASOLINE RELATED PROPERTIES OF OXYGENATES

	Ethanol	MTBE	TAME	ETBE
Blending Octanes ((R+M)/2)*	115	110	105	111
Blending RVP (psi)*	18	8	1.5	4
Boiling Point (degrees F)	173	131	187	163
Density (lb/gal @60 degrees F)	6.62	6.22	6.47	6.29
Energy Density (MBTU/Gal)	76.1	93.5	100.6	96.9
Oxygen Content (wt%)	34.73	18.15	15.66	15.66

* Blending octanes and RVP (Reid Vapor Pressure) vary significantly depending on the oxygenate concentration and the properties of the hydrocarbon gasoline blendstock.

about 72 percent starch, 10 percent protein, 5 percent oil, 6 percent hemicellulose, 3 percent cellulose, 2 percent sugar, 1.4 percent ash, and 1 percent lignin. Enzymes convert starch in the corn kernel to sugar by hydrolysis and then yeast ferments the sugars to ethanol. While little of the corn kernel is wasted, only about one third of it can be converted to ethanol with the remainder ending up as carbon dioxide, animal feed, and corn oil. The first step in the process is to separate the starch from the rest of the corn. There are two processes that are used today: dry milling, which produces 2.6 gallons of ethanol per corn bushel; and wet milling, which produces about 2.5 gallons of ethanol per bushel of corn. In dry milling, the grain is ground to produce a mash that is mixed with water and then cooked prior to fermentation to alcohol. In wet milling, the grain is ground wet and the starch is separated prior to fermentation and conversion to alcohol. By separating the starch first, the wet milling process is capable of shifting production in the spring and summer months from ethanol to fructose corn sweeteners for use in the soft drink industry. The three by-products from the wet milling process are corn gluten feed, corn gluten meal, and corn oil. In the dry milling process, the ethanol is separated from solids which are dried and sold as dried distillers grain (DDG). Both processes can produce carbon dioxide as a by-product. The wet milling process (per the National Corn Growers Association) accounts for 85 percent of U.S. ethanol production.

This study is based on ethanol being produced from grain feed sources. Research and development of ethanol produced from biomass or cellulose feedstocks continues to be studied and evaluated. Since this technology will not be commercially possible for at least several years, the study excludes these sources from contributing to ethanol production capacity.

MTBE

MTBE is produced from two primary sources. Refiners produce isobutylene streams from their FCC units that are reacted with methanol to produce MTBE. The petrochemical industry ethylene cracking and propylene oxide production processes also produce a significant quantity of isobutylene that is then reacted with methanol to produce MTBE. Isobutane dehydrogenation is also used to produce isobutylene, which is also reacted with methanol to produce MTBE.

TAME

TAME is produced by reacting methanol with isoamylene streams from FCC units. Because isoamylenes have one more carbon molecule than isobutylenes, isoamylenes have higher boiling points than streams used to produce MTBE. TAME technology is less developed and more costly than MTBE and will most likely be implemented on a limited and refiner specific basis.

ETBE

ETBE process technology is almost identical to MTBE except isobutylene-rich streams are reacted with ethanol instead of methanol. Because ETBE has a significantly lower gasoline blending vapor pressure than either ethanol and MTBE, producers may design their new ether plants to produce either MTBE or ETBE. Minor plant modifications or capacity reduction is required to produce ETBE from MTBE facilities.

Tertiary amyl ethyl ether (TAEE) may also be used as an oxygenate for blending into gasoline. The study assumes TAEE may be used on a minimal basis and has, therefore, been excluded from the supply volumetrics.

Supply Assumptions

Regulatory Requirements

Beginning in 1995, nine ozone nonattainment areas (extreme and severe classifications) in the United States will be required to blend oxygenates year-round into reformulated gasoline. RFG must contain a minimum 2.0 wt% oxygen content. This study assumes refiners will target for 2.1 wt% oxygen to comply with the RFG regulation. Oxygenate blending will continue in the winter months (primarily November through February, with some states extending the enforcement period to include October and/or March) in the 39 CO nonattainment areas. In addition, the New

York/Northern New Jersey metropolitan area requires oxygenate blending for 7 months for CO emissions compliance. The study assumes a 14-day average pre-blending period of oxygenates prior to November 1 to turnover the refinery to distribution terminal system to meet oxygen content requirements. A further 21-day period is required to turn over the terminal to service station system. The CAAA require a 2.7 average wt% oxygen content for gasoline sold in these areas. The only exception is the state of California regulation for oxygen content, which is to be capped at 1.8 to 2.2 wt%. California regulators claim that NOx emissions are a significant contributor to the California ozone situation. By capping oxygen content, California expects to limit NOx emissions. This exception must still be approved by the EPA.

Also beginning in 1996, *all* gasoline sold in California year-round will be reformulated per the California Air Resources Board (CARB) Phase 2 RFG regulations. Gasoline oxygen content will be capped at 1.8 to 2.2 wt%.

By the year 2000, the study assumes that all areas in the marginal, moderate, and serious ozone nonattainment classifications and the NOTC states will opt-in to the CAAA RFG program and require oxygenated gasoline year round.

Excluding ethanol, oxygenate imports are assessed a 5.6 percent import duty, which reduces their economic competitiveness versus domestic supply. The countries of Canada and Venezuela are the only exceptions where no import duty is assessed. By comparison, oxygenates in mixture with gasoline incur only the 52 cents per barrel (1.2 cpg) motor gasoline import duty. Imported ethanol is eligible for the federal excise tax exemption, if produced from renewable sources, but is assessed a 54 cpg import fee if it is used as a transportation fuel. Therefore, ethanol imports are essentially economically noncompetitive with domestic ethanol.

Ethanol Legislation/Regulatory Environment

The blending RVP of ethanol (18 psi) is significantly above the RVP specifications of gasoline. When ethanol is blended with gasoline at concentrations greater than 5 percent by volume ethanol, the gasoline vapor pressure increases by about 1 psi. Therefore, gasohol blends containing 10 percent by volume ethanol have been given a 1 psi RVP allowance waiver in a number of states. The use of ethanol in RFG is considered elsewhere in the NPC study (see Chapter Four). The premise of this section is that no ethanol is used in summer RFG.

In addition to the RVP waiver, most states allow gasohol a waiver to lower the mid-point (50 percent point) boiling specification versus neat (hydrocarbon only basis) gasoline. This waiver enables gasohol blenders to minimize octane giveaway and avoid an economic penalty that would otherwise result from compliance with the neat gasoline specification.

Even with state-of-the-art technology, ethanol production for use in transportation fuels is not economical without receiving government financial support. For this reason, the federal government recently extended the 54 cpg excise tax exemption for ethanol to September 30, 2000. The Comprehensive Energy Policy Act of 1992 was signed on October 24, 1992. The legislation contains an excise tax exemption of 54 cpg for ethanol blended in gasoline at volumetric concentrations of 5.7 percent, 7.7 percent, and 10 percent beginning January 1, 1993. By allowing a three tier tax subsidy, the government is permitting blenders to optimize the use of ethanol by lowering oxygen content in gasohol from 3.5 wt% (10 percent by volume equivalent) to 2.7 wt% (7.7 percent by volume) and 2.0 wt% (5.7 percent by volume).

Ethanol imports have not undergone any new rule changes. All ethanol imports are charged a duty with the exception of the 27 Caribbean Basin Initiative (CBI) countries and Canada as part of their trade agreements with the United States. Imports from the CBI countries with no feedstock provisions are restricted to either 60 million gallons annually or 7 percent of the domestic ethanol market, whichever is greater. Beyond this constraint, additional imports are levied a portion of the import duty per defined feedstock requirements in the Steel Trade Liberalization

Program Implementation Act of 1990. All ethanol produced in a full fermentation facility in a CBI eligible country is imported duty free in unlimited quantities.

Distribution Logistics

"Spillover" of oxygenated gasoline is defined as gasoline produced for nonattainment areas being sold in attainment areas. Spillover is caused by limitations in terminals, pipelines, and the overall supply distribution systems. Uneconomic spillover has been assumed to be minimal (<1 percent). A detailed discussion of "spillover" is included in the Logistics section of this chapter.

The most significant problem to overcome with ethanol blending is its solubility in water. For this reason, ethanol is usually shipped to a distribution terminal by truck or railcar and stored in separate tanks to avoid contamination with water. Ethanol is then "splash blended" into gasoline at the distribution terminal.

Supply Volumetrics

1995

Oxygenate supply information is reported in various publications by a number of refining industry and government sources. This study has used information from two of these sources, the Energy Information Administration and DeWitt & Company, Inc. The EIA tracks and reports U.S. production, capacity, capacity utilization, and inventories of oxygenates. They recently published an October 1992 update of oxygenate information. The survey information was reviewed and adjusted to provide the best current estimate of the 1995 supply capability. Data from DeWitt & Company was used to compare with the EIA survey information for MTBE and TAME. Other than differences in highly speculative future capacity, the estimates are very similar. See Appendix L, Section V-2 (EIA MTBE Capacity Survey) for additional information.

Respondents to the EIA ethanol production survey in October 1992 reported no plans for the construction of green field ethanol facilities. Thus, total capacity in 1995 is assumed to remain identical to the current 1992 capacity. See Appendix L, Section V-3 (EIA Fuel Ethanol Capacity Survey) for additional information. New green field capacity can come on stream in future years depending upon oxygenate demand and competing economics with green field MTBE facilities.

Survey Data Methodology

The DeWitt & Company surveys characterize MTBE and TAME production capacity in one of five classifications: Operating, Under Construction, Very Probable, Probable, and Possible. These classifications were used in conjunction with EIA terminology (Operating, Under Construction, or Planned) to categorize capacity as being available before or after 1995. Table 3-23 shows how supply capacity has been categorized in this study.

While ETBE can currently be produced in existing MTBE facilities, very little production has occurred to date. Since only one MTBE facility is known to be currently producing ETBE, this study assumes ETBE will not be a significant oxygenate source until after 1995. In reality, this may change depending upon legislation or EPA adopting additional ETBE/ethanol rules for implementing the CAAA. Results of such action may substantially alter oxygenate blending economics and favor ETBE over MTBE and TAME. MTBE plants can be modified to produce ETBE with minor investment. If future economics favor ETBE versus MTBE, this should result in increased ETBE production and decreased MTBE production. The volumetric impact of a no ETBE production basis versus a shift from MTBE to ETBE would be fairly minimal on the overall oxygenate supply volumetrics.

Oxygenates Supply Volumetrics

Based on the supply category methodology in Table 3-23, the anticipated supply capacity for 1995 is shown in Table 3-24. See Appendix L, Section V-4 (U.S. Oxygenate Capacity by Supply Region) for additional information.

Table 3-24 identifies both stream and calendar day capacity. Stream day capacity typically represents the design capacity of a facility or 100

TABLE 3-23

MTBE/TAME SUPPLY CAPACITY CATEGORIES

	Refinery MTBE	Other MTBE	TAME
Operating	X	X	X
Under Construction	X	X	X
Very Probable (Permitted)	X	Y	X
Probable/Possible/Planned	Y	Y	Y

Note: X = On stream by 1995, Y = On stream after 1995.

TABLE 3-24

1995 U.S. OXYGENATE PLANT CAPACITY MTBE EQUIVALENT BARRELS (Thousands of Barrels per Day)

	Capacity (MB/SD)	Capacity Factor	Production (MB/CD)
Ethanol From Corn	178*	0.75	134
MTBE from FCC Isobutylenes	119	0.70	83
MTBE from Other Production	234	0.90	211
TAME from FCC Isoamylenes	20†	0.70	14
Total	**551**		**442‡**

* Ethanol production (pure basis) 88 MB/SD x 2.03 (ratio of ethanol to MTBE oxygen content by weight).

† TAME production 23 MB/SD x 0.89 (ratio of TAME to MTBE oxygen content by weight).

‡ January 1, 1993, production capability = 285,000 MB/CD.

percent of capacity. The year-round average is a calendar day utilization that refiners historically achieve, and is significantly less than a facility's stream day capacity. Calendar day capacity reflects the impact of feedstock availability, planned turnarounds, unplanned shutdowns, oversized plants, and other capacity constraining events. Based on historical calendar day capacity data from the EIA, Table 3-24 includes the capacity factors being used in this study.

As the demand for oxygenates increases, refiners will be challenged to improve the operability of their FCC, alkylation, and oxygenate facilities to increase production of MTBE and TAME. This study recognizes that a number of variables, including feedstock availability, are responsible for the historical 0.7 calendar day capacity factor. As oxygenate demand continues to rise, refiners are expected to improve their operations to help maximize MTBE and TAME production. The study assumes capacity utilization will improve from 0.7 to 0.8 by year 2000. Economics favor this improvement since refinery produced MTBE is less costly than MTBE produced from dehydrogenation facilities as shown previously in Table 3-21.

Oxygenate supply is not limited to the domestic refining and petrochemical industries.

Some oxygenate producing facilities are already operating and others are under construction in foreign regions. The United States is currently a net importer of MTBE and will continue to import some MTBE depending upon economics, distribution logistics, and region location. Table 3-25 shows 1995 oxygenate supply capacity outside the United States. See Appendix L, Section V-5 (Foreign Oxygenates Supply/Demand Balances) for MTBE supply/demand information by supply region. Capacity methodology for foreign supply is identical to the domestic supply methodology shown in Table 3-23.

The NPC study assumes that capacity factors for MTBE and TAME facilities outside the United States are identical to FCC calendar day actual capacity factors and are included in Table 3-25. While foreign capacity factors for refinery produced MTBE is higher (0.89) than U.S. capacity factors (0.7 in 1995, 0.8 in 2000+), reducing the foreign capacity factors to the U.S. historical capacity factors would have less than a 10 MB/CD supply impact. Thus, the capacity factor differences are insignificant to the study observations.

Oxygenate Volumetric Equations

The cost of ethanol production varies considerably with the price of corn, plant capacity, and technology utilized. The wet milling process is considered the most flexible and therefore economical to process ethanol despite fluctuations in corn prices. The wet milling production equation is as follows:

- **Ethanol From Corn (Wet Milling Process):**

  Equation 1: 1 Bushel Corn = 2.5 gal Ethanol + 14 lbs Gluten Feed + 3 lbs Gluten Meal + 1.5 lbs Corn Oil + CO_2

MTBE and TAME production occur by reacting isobutylenes and isoamylenes respectively with methanol. The volumetric yield equations associated with these processes are as follows:

- **MTBE From FCC Isobutylenes:**

  Equation 2: 0.79 gal Isobutylene + 0.34 gal Methanol = 1.0 gal MTBE

- **MTBE From Other Sources (Butane Dehydrogenation):**

  Equation 3: 0.95 gal NC_4 + 0.34 gal Methanol = 1.0 gal MTBE

- **TAME From FCC Isoamylenes:**

  Equation 4: 0.82 gal Isoamylene + 0.30 gal Methanol = 1.0 gal TAME

MTBE production from the butane dehydrogenation process requires an intermediate processing step. Normal butane (NC_4) is first isomerized to yield isobutane (IC_4) before dehydrogenating IC_4 to isobutylene. Isobutylene is then reacted with methanol to produce MTBE. Much of the future MTBE capacity from other sources shown in Tables 3-24, 3-25, 3-27, and 3-28 will be produced via the isomerization/dehydrogenation process.

Methanol Volumetrics

U.S. methanol supply capacity in 1992 was 106 MB/SD. EIA data show U.S. methanol production of 91 MB/CD in 1992. Capacity is projected to increase to 137 MB/SD by 1995. Table 3-24 previously showed domestic MTBE and TAME supply capacity. Based on those capacities and equations 2, 3, and 4 above, methanol supply requirements in 1995 are shown in Table 3-26.

Methanol has a number of uses in the chemical industry and potentially as an alternative transportation fuel and is therefore not exclusively available for MTBE and TAME production. The United States currently imports a sizable volume of methanol to meet existing demand. For the past five years, methanol imports have averaged about 30 MB/D. Methanol capacity outside the United States in 1991 was estimated at roughly 122 MB/SD. The study assumes that the additional methanol availability is not limiting to meet the domestic MTBE and TAME demand requirements.

Butane/Butylene Volumetrics

The NPC study assumes there is adequate supply of butanes and FCC and petrochemical isobutylene to support the production of MTBE. The refining industry is currently a net producer of butanes. Lower gasoline vapor pressures will increase this net production.

TABLE 3-25

1995 FOREIGN OXYGENATE PLANT CAPACITY
MTBE EQUIVALENT BARRELS
(Thousands of Barrels per Day)

	Capacity (MB/SD)	Capacity Factor	Production (MB/CD)
MTBE from FCC Isobutylenes	41	0.89	37
MTBE from Other Sources	158	0.90	142
TAME from FCC Isoamylenes	4*	0.89	4
Total Supply Capacity†	203		183
Foreign Demand† (FC-1/FC-3)	102/93		102/93
Supply-Demand (Export Avails)	101/110		81/90

* TAME production 5 MB/SD x 0.89 (ratio of TAME to MTBE oxygen content by weight).

† Excludes 11 MB/D of Supply and Local Demand in China/CIS States.

TABLE 3-26

1995 METHANOL SUPPLY CAPACITY
MTBE EQUIVALENT BARRELS
(Thousands of Barrels per Day)

	Total Oxygenates		Methanol Required	
	MB/SD	MB/CD	MB/SD	MB/CD
MTBE Supply Capacity	353	294		100
TAME Supply Capacity	20	14		4
Total				104
1995 Methanol Domestic Supply Capacity			**137**	**123**

In any individual plant, MTBE production from FCC isobutylene is frequently limited by isobutylene availability. That is, the MTBE plant is sized for more isobutylene than the refinery's FCC unit makes. Isobutylene is a minor part, typically about 3 percent, of a FCC unit's production. In the laboratory, new FCC catalyst technology can increase isobutylene production up to 4-5 percent of FCC product; however, the economics of the commercial use of such catalysts are dominated by the remaining 95-97 percent of the FCC product. The implementation of catalyst changes is also severely limited by the hardware and operating conditions of the FCC unit. Therefore, the NPC expects a modest increase in MTBE production from refinery FCC units as reflected in the use of a 0.8 capacity factor by year 2000.

FCC source MTBE can provide about one fourth of a gasoline requirement for oxygenates. Sufficient butanes are expected to be available to support additional plants for manufacturing MTBE from butane via the isomerization and dehydrogenation route. This technological option is more expensive than FCC source MTBE but some will be required to provide the volume of oxygenate required by regulation.

While this study did not perform a detailed analysis of the butane/butylene supply/demand future, a review of a number of

independent studies suggest the NPC study assumptions are reasonable.

Years 2000/2010

Oxygenate supplies need to grow after 1995 to comply with additional regulatory requirements. Specifically, California will require oxygenated gasoline year-round throughout the state beginning in April 1996. With an even greater impact, the NPC study assumes that all geographic metropolitan areas currently classified as marginal, moderate, or serious ozone nonattainment areas and all the NOTC states will opt-in to the CAAA by year 2000. Based on the category methodology described in Table 3-23, oxygenate supply capacity for the year 2000 and beyond is shown in Tables 3-27 (domestic) and 3-28 (foreign).

Tables 3-27 and 3-28 indicate supply potential from currently operating and announced oxygenate facilities. No announcements have been made for new facilities after 1996. Without any additional announcements, oxygenates potentially available to the United States equal 587 to 645 MB/CD (566 MB/CD domestic, 21 to 79 MB/CD foreign) in year 2000. Oxygenate supply could be further increased by building additional MTBE and/or TAME facilities that have not been announced. Sufficient feedstocks are available to support additional oxygenate production. In the year 2010, demand growth for oxygenates in the foreign regions indicates an 89 MB/CD shortfall (FC-I) versus an 80 MB/CD surplus (FC-III) available for export. Without the availability of imports in 2010 (FC-I), the United States would be short of oxygenates to meet demand. Sufficient time exists and feedstocks would be available to increase U.S. oxygenate supplies by building additional facilities.

Demand Volumetrics

Oxygenate demand for the foundation cases for the years 1995, 2000, and 2010 are shown in Tables 3-29 and 3-30. Table 3-29 shows an annual average oxygenate demand for the entire United States in MTBE equivalent barrels. Table 3-30 breaks down the type of oxygenated gasoline required by the CAAA. The four categories of oxygenates in Table 3-30 are defined as follows:

- CO nonattainment oxygenates are blended in the winter only in areas that are CO nonattainment.
- RFG oxygenates are blended year round in areas that are ozone nonattainment only.

TABLE 3-27

YEAR 2000+ U.S. OXYGENATE PLANT CAPACITY MTBE EQUIVALENT BARRELS (Thousands of Barrels per Day)

	Capacity (MB/SD)	Capacity Factor	Production (MB/CD)
1995 Supply Capacity	551		442
Add'l MTBE from FCC Isobutylenes	49	0.8	39
Add'l MTBE from Other Sources	76	0.9	68
Add'l TAME from FCC Isoamylenes	4*	0.8	3
Increased Calendar Day Capacity	—		14†
Total Supply	**680**		**566**

* TAME production 5 MB/SD x 0.89 (ratio of TAME to MTBE oxygen content by weight).

† MTBE from FCC Isobutylenes and TAME from FCC Isoamylenes Plant Capacity factor rises from 0.7 to 0.8 for existing 1995 capacity.

TABLE 3-28

YEAR 2000+ FOREIGN OXYGENATE PLANT CAPACITY MTBE EQUIVALENT BARRELS (Thousands of Barrels per Day)

	Capacity (MB/SD)	Capacity Factor	Production (MB/CD)
1995 Supply Capacity	203		183
Add'l MTBE from FCC Isobutylenes	13	0.89	11
Add'l MTBE from Other Sources	206	0.90	185
Add'l TAME	5*	0.89	4
Total Supply†	**427**		**383**
Foreign Demand (FC-I/FC-III)			
Year 2000	362/304		362/304
Year 2010	472/303		472/303
Supply-Demand (Export Avails)			
Year 2000	65/123		21/79
Year 2010	(45)/124		(89)/80

* TAME production 5 MB/SD x 0.89 (ratio of TAME to MTBE oxygen content by weight).

† Excludes 46 MB/D of Supply/Local Demand in China/CIS States.

These areas are in compliance with CO air emissions standards.

- CO reformulated oxygenates are blended in the winter in areas that are both ozone nonattainment and CO nonattainment.
- Gasohol contains 10 percent by volume ethanol (expressed as equivalent MTBE volume) and is only blended in areas that do not require RFG or CO nonattainment gasoline.

As previously indicated in Table 3-20, domestic oxygenate supply exceeds 1995 U.S. minimum demand (without opt-ins). In years 2000 and 2010, Foundation Case III estimated oxygenate demand is nearly equal to or less than the potentially available oxygenate supply. Only Foundation Case I oxygenate demand would require additional new supply capability beyond 1995.

A detailed discussion of the methodology to develop the demand data is presented in the Demand Development section of this chapter.

Cost Assumptions

Overview

The overall cost assumptions and economics were completed using 1989 actual prices and inflating these numbers to 1990 dollars. The entire economic analysis for oxygenates excludes any price projections with one exception. Methanol prices were forecast as part of an Auto/Oil economics committee study that was completed by Robert Hahn on "The Economics of Methanol" in September 1991.

TABLE 3-29

U.S. OXYGENATE ANNUAL DEMAND MTBE EQUIVALENT BARRELS (Thousands of Barrels per Day)

	Foundation Case		
Year	I	II	III
1995	345	345	345
2000	614	593	570
2010	662	593	522

TABLE 3-30

U.S. OXYGENATE ANNUAL DEMAND BY GASOLINE TYPE
MTBE EQUIVALENT BARRELS
(Thousands of Barrels per Day)

	1995			2000			2010		
	Foundation Case			Foundation Case			Foundation Case		
	I	II	III	I	II	III	I	II	III
CO Nonattainment	80	80	80	18	18	17	20	18	16
Reformulated	105	105	105	394	379	365	424	379	334
CO Reformulated	91	91	91	159	153	147	171	153	135
Gasohol	69	69	69	43	43	41	47	43	37
Total Demand	**345**	**345**	**345**	**614**	**593**	**570**	**662**	**593**	**522**

The study projects future methanol prices which were adjusted to a 1990 dollar basis.

The capital estimates for refinery and green field MTBE facilities are also reported in 1990 dollars. All capital investments assume a required 10 percent real return on investment after taxes, which translates to an annual capital charge of 17.1 percent of investment. See Appendix L, Section V-6 (MTBE Facility Capital Investment Costs) for additional details of these assumptions.

Ethanol Production Costs

Ethanol production costs vary considerably with corn prices, plant size, and the technology utilized in the process. Economics favor the wet milling process. Using information from the USDA study completed in April 1988, the capital investment cost for ethanol facilities is shown below in Table 3-31. The investment costs have been inflated to 1990 dollars using the NPC study inflation factors.

The production costs of ethanol for current production, per the 1988 USDA study, and for new green field facilities is shown in Table 3-32.

The bases and assumptions used to develop these costs are included in Appendix L, Section V-7 (Ethanol Cost Assumptions).

The NPC study assumes the ten year average corn and by-product prices from the USDA are representative of average ethanol feedstock costs. The averages shown in Table 3-33 eliminate a potential cost bias that could result from a drought or surplus corn production in any single year. These costs have been included in Table 3-32.

TABLE 3-31

ETHANOL INVESTMENT COSTS
(1990 Dollars)

	Wet Milling	Dry Milling
Minimum Capacity (Gallons/Year)	100 Million	40 Million
Capital Investment ($/Annual Gallon)	2.45	2.45
Capital Recovery ($/Gallon)*	0.55	0.55

* Based on calendar day production and NPC study capital recovery basis.

TABLE 3-32

ETHANOL PRODUCTION COSTS
(1990 Dollars per Gallon)

	Wet Milling		Dry Milling	
	Current*	New Facilities†	Current*	New Facilities†
Corn	1.01	1.01	0.97	0.97
By-Product Credit	(0.59)	(0.59)	(0.45)	(0.45)
Operating Costs	0.51	0.41	0.51	0.41
Capital Recovery	0.55	0.55	0.55	0.55
Total	**1.48**	**1.38**	**1.58**	**1.48**

* Based on 1988 U.S. Department of Agriculture study.

† For new green field facilities.

TABLE 3-33

ETHANOL COMMODITY FEEDSTOCK PRICES 1981–1990 AVERAGE COST (Then Spent Dollars)

Corn ($/bushel)	2.53
Gluten Feed ($/ton)	105.13
Gluten Meal ($/ton)	250.20
Corn Oil ($/lb)	0.24
Dried Distillers Grain ($/ton)*	131.41

* Assumes dried distillers grain price is 125 percent of gluten feed price.

Source: U.S. Department of Agriculture.

Other than improvements in energy efficiency, ethanol production technology has not appreciably changed since the 1988 USDA study. The energy efficiency enhancements are anticipated to reduce production costs from $0.47 to $0.38 per gallon per the USDA study. The NPC study assumes that all new green field ethanol facilities will include this technology to improve ethanol's economics and compete more favorably with ethers as an oxygenate source. Therefore, in 1990 dollars, the $1.48 per gallon wet milling production cost would be reduced by 10 cpg to $1.38 per gallon (as shown in Table 3-32). By including the 54 cpg federal tax credit, ethanol costs will be predicted to be $0.84 per gallon (excluding transportation). Similarly, Table 3-32 shows dry milling facilities production costs would be reduced to $1.48 and $0.94 per gallon (includes federal tax credit), respectively.

While this study excludes state tax credits from the cost analysis, several states offer tax subsidies, which further improves ethanol economics. Appendix L, Section V-8 (Ethanol State Subsidies) shows a list of states that currently provide these tax subsidies.

Since ethanol provides a significant market for corn sales, the study weighs in the effect of higher ethanol demand. Per the USDA study, corn costs are estimated to increase by $0.35 per bushel (one bushel is defined as 56 pounds) with an 800 million bushel increase in corn demand. Assuming corn costs increase linearly with demand, this results in an additional 1 cpg for each 150 million gallon increment of ethanol production.

Based on current market share and seasonal production flexibility, wet milling technology incorporating the energy efficiency enhancements will most likely be utilized in the future for green field capacity.

MTBE Facility Capital Investment Costs

A number of public sources have evaluated the investment costs associated with constructing oxygenate facilities. Two investment options were selected for building new MTBE facilities. Purvin & Gertz completed a study for the Coordinating Research Council of the Auto/Oil Task Group in December 1990, which estimated the costs of building a refinery FCC MTBE unit. The Bechtel Corporation completed capital estimates for MTBE green field facilities for both domestic and foreign supplied MTBE in June 1992 for the NPC. Costs can vary significantly depending upon the geographic location for investment. Location factors, or investment capital factors, are shown below in Table 3-34 to represent these differences.

Using the factors in Table 3-34 and the Purvin & Gertz and Bechtel studies, Table 3-35 shows the capital investment estimates for new MTBE facilities. The bases and assumptions used to develop these estimates are included in Appendix L, Section V-6 (MTBE Facility Capital Investment Costs).

TABLE 3-34

INVESTMENT CAPITAL FACTORS

U.S. Gulf Coast	1.0 Base
Middle East (Saudi Arabia)	1.2
Latin America (Venezuela)	1.3

Feedstock Costs

Feedstock costs used in the study are the 1989 actual average spot prices adjusted to 1990 dollars. The only exception is methanol cost, where the study has chosen the Hahn study to predict future methanol costs.

Operating & Maintenance Costs

Facility operating and maintenance (O&M) costs for refinery and green field MTBE facilities were included in the estimates from Purvin & Gertz and Bechtel. These costs include utilities, catalyst and chemicals, and O&M labor and overhead. Operating days are assumed to be 330 days per year to reflect planned turnarounds, unscheduled shutdowns, and other events.

Transportation Costs

The NPC study for oxygenates assumes the U.S. Gulf Coast is the base domestic location for comparison with potential foreign sourced oxygenates.

MTBE Production Costs

Table 3-36 shows a summary of the predicted costs for MTBE in the U.S. Gulf Coast, Middle East, and Latin America. The detailed assumptions and bases used to calculate these costs are included in Appendix L, Section V-9 (MTBE Facility Production Costs).

Table 3-36 shows that MTBE produced from refinery FCC isobutylene feedstocks is significantly lower in cost than from green field dehydrogenation facilities. As indicated in Tables 3-24, 3-29, and 3-30, MTBE production

TABLE 3-35

MTBE FACILITY CAPITAL INVESTMENT COSTS

	Thousands of Barrels per Stream Day	Millions of 1990 Dollars
U.S. Gulf Coast FCC MTBE Unit	2.0	17
U.S. Gulf Coast Dehydrogenation Unit	12.5	216
Middle East Dehydrogenation Unit	12.5	259
Latin America Dehydrogenation Unit	12.5	280

TABLE 3-36

MTBE FACILITY PRODUCTION COSTS
(1990 Cents per Gallon)

	U.S. Gulf Coast		Saudi Arabia	Venezuela
	Refinery	Green Field	Green Field	Green Field
Feedstocks *				
Butylenes	50	—	—	—
Butanes	—	30	21	30
Methanol	61	61	65	59
MTBE				
Feed Cost	60	50	43	49
Operating Cost	6	12	12	11
Capital Recovery	11	26	31	33
Production Cost	**77**	**88**	**86**	**93**
Transportation †	—	—	15	7
Total Delivered Cost‡	**77**	**88**	**101**	**100**

* Costs used in Equations 2&3 to calculate feedstock costs.

† Average transportation cost to U.S. Gulf Coast.

‡ U.S. Gulf Coast destination.

from FCC isobutylenes built by 1995 is well below expected oxygenate demand. Therefore, MTBE dehydrogenation green field capacity is necessary to help meet expected oxygenate demand beginning in 1995.

Table 3-36 also shows foreign MTBE production facilities costs about the same as domestic green field facilities. Since the foreign costs exclude any transportation or import duty fees, imports will likely be minimized.

A comparison of the ethanol and MTBE production costs shows that ethanol should be able to compete with MTBE as an oxygenate source with the continuation of the 54 cpg federal subsidy. States that provide tax credits in addition to the federal subsidy will make ethanol even more competitive. This study does not include regional transportation costs in the production economics. These costs and the logistics of shipping and storing ethanol to avoid water contamination will determine where ethanol economics are more attractive than MTBE or other ethers. The indication of this analysis is that ethanol should compete in CO nonattainment areas when gasoline RVP is at winter specification levels. The Bonner and Moore logistics model used all the available ethanol capacity to supply gasohol and oxygenated gasoline. Additional economic incentive exists to blend additional ethanol supply into CO nonattainment gasoline if the capacity is constructed and brought on stream after 1995. See Appendix L, Section V-10 (Ethanol Incentives) for a discussion of the economic incentives for blending additional ethanol.

During the course of this study, a number of changes concerning data and information have occurred. Appendix L, Section V-11 (Oxygenate Issues — Data Revisions, Changes, and Updates) discusses these changes. None of these changes affect the conclusions and findings of the Oxygenates section of the NPC study.

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LOGISTICS

General

The U.S. Petroleum Logistics System is a complex network of facilities and equipment that moves petroleum products from the producers to the consumers of the United States. The system consists of terminals of all sizes, deep draught ocean-going tankers, large ocean-going barges, smaller river barges, a vast net-

work of pipelines, railroad tankcars, and trucks of all sizes. The system includes crude oil gathering and transportation systems that transport crude oil from domestic as well as foreign oil fields to refineries. Across the nation, refineries make products to meet the nation's demand for various forms of energy. In addition to domestic refinery produced products, product imports are received into the system. Products move from refineries and import points to a series of distribution terminals by tanker, barge, pipeline, rail tankcar, and truck.

The study of the logistics system was confined to the distribution of gasoline, jet fuel, distillates (diesel fuel and heating oil) and oxygenate blending components. The transportation cost of crude oil will increase as a result of various environmental legislation and regulations, especially the Oil Pollution Act of 1990. A basic premise for the study is that the delivered crude oil costs will remain constant.

In each of the 13 supply and demand regions, the logistics system was represented by a single distribution point that shipped and received products. The shipping and receiving points represented a hypothetical center of gravity for that region. Product transportation costs were estimated for the various possible transportation modes (pipelines, tankers, etc.) from each of the supply regions to each of the demand regions. The supply and demand points selected for each region are shown in Appendix L, Section VI-1. Costs were not estimated for supply routes that were unrealistic or infeasible, e.g., tanker movement from New York to Seattle. In certain cases, it was necessary to use specific transportation routes because routes to the generalized demand centers were not representative of a particular product flow. For example, products can move from Region 8 on the Gulf of Mexico (Houston) to Region 12 (Southern California, Southern Nevada, and Arizona). The feasible product flows include ocean-going U.S. flag (Jones Act) tankers from Gulf Coast Ports to Los Angeles, pipeline from El Paso to Tucson and Phoenix, and rail tankcar delivered oxygenates. Since the pipeline route represented an actual means of moving product between the regions, it had to be included, even though a pipeline did not exist between the two centers of gravity (Houston to Los Angeles). In this case, an exception was made to use the actual pipeline tariff for the El Paso-to-Arizona route. However, it was necessary to limit the volume of flow to the specific pipeline capacity in order to prevent all product from flowing on this least cost mode.

Transportation costs and specific capacity limitations were developed for the model and will be discussed for each transportation mode below. Transportation costs and capacity limits for historical periods used to test the model were estimated from actual data. However, forecasts of future transportation rates required an assessment of the factors leading to cost changes. Future cost estimates were based on three sources:

- An NPC industry survey
- An assessment by industry experts
- Cited expert sources.

The NPC surveyed industry members to determine estimates of cost increases. In order to protect the confidentiality of the survey replies, fields of less than three respondents were not reported. Thus, some information was not available to the NPC report writers.

In order to confirm surveys and interpret data, NPC study participants reviewed the aggregated information. Knowledge of the industry economics and procedures enabled NPC committees to reach a consensus on the transportation costs. Where possible, these opinions were further substantiated from expert sources.

Logistics System Environmental Cost

The Clean Air Act Amendments of 1990 and other environmental legislation will lead to regulations that will have a major effect on the petroleum logistics system operations and costs. The cost to the logistics system has been estimated for each element in that system. The cost of product specifications has been addressed in Chapter Four. While the specific cost and cost changes will vary for each source and destination, overall average costs are summarized in Table 3-37. The table shows the nationwide geographic and seasonal historical

TABLE 3-37

ENVIRONMENTAL REGULATIONS COST IMPACT ON LOGISTICS

Transportation Mode	1987	1989	1995	2000	2010
			Costs in Future Years Expressed in Constant Dollars		
			Increase Over 1989		
U.S. Flag (Jones Act) (Expressed in 1991 ATRS)	AR130	AR145	+AR15 (10%)	+AR30(21%)	+AR40(28%)
Foreign Flag (Expressed in 1991 Worldscale)					
Sources except PG	W145	W190	+W12 (6%)	+W20 (11%)	+W30 (16%)
PG loadings	W215	W190	+W12 (6%)	+W20 (11%)	+W30 (16%)
Pipeline Tariffs	1989 Tariffs for Selected Routes		+10%	No Increase over 1995	
Barges	Committee Survey Estimate		+22.5%	+32.5%	+42.5%
Rail	Survey $/Gal-Mile		Insignificant increase		
Product Terminals	Survey $/MB/CD				
Tank Truck	Survey $/Gal-Mile		+10-15%	No Increase over 1995	

Note: Worldscale and ATRS tanker rate schedules described in Appendix L, Section VI-4.

average cost for each transportation mode in 1987 and 1989 as well as estimates of how those average costs will change in the future. In the following sections, each of the transportation and storage modes will be discussed in detail. The causes for the environmental cost increases will be enumerated and the methodology used by the study participants will be outlined. The summary of actual transportation costs used in the Logistics Model is provided in Appendix L, Section VI-2. The expanded cost matrix is shown in Working Paper 3.VI-1.

The anticipated cost and cost changes for moving gasoline from Houston and Rotterdam to New York are shown in Table 3-38 for 1990 and 1995. Logistics cost (not product cost) is estimated to increase over that five year period by 0.75 cpg from both sources to New York. The increase of slightly less than one cpg seems inconsequential, but it is considerable in relative terms. The percentage increase is less from Rotterdam (14 percent) than from Houston (19 percent) because of its higher base. The major segment of the cost increase is for terminal modifications and expenses. Individual components of cost are shown. The pipeline costs are based on published pipeline tariffs and remain constant throughout the year. The Ocean freight cost from Northwest Europe is an annual average which may differ considerably during the year depending on the seasonal tonnage supply/demand balance. Pipeline is the primary means of moving clean fuel products from Houston to New York. U.S. flag tankers could also be employed, but are generally not competitive with pipelines to New York. Normally, tankers are employed from the Gulf Coast to coastal Florida and the southern Atlantic states as well as to and along the West Coast. As with the foreign flag movements from Europe, U.S. flag costs are more volatile and tankers are employed where and when their use is economic.

TABLE 3-38

1990 &1995 LOGISTICS COST
(Cents per Gallon – Constant 1990 Dollars)

	Houston/New York			Rotterdam/New York			1990 cpg per 100 Statute Miles
	1990	1995	Difference	1990	1995	Difference	
Primary Distribution							
Tanker, Foreign Flag				4.02	4.25	0.23	0.102
Pipeline Tariff	2.46	2.69	0.23				0.160
Subtotal	2.46	2.69	0.23	4.02	4.25	0.23	
Secondary Distribution							
Terminal Cost	0.50	0.90	0.40	0.50	0.90	0.40	N/A
Tank Truck Delivery (25 Miles)	0.91	1.03	0.12	0.91	1.03	0.12	3.500
Subtotal	1.41	1.93	0.52	1.41	1.93	0.52	
Total Logistics Cost to New York	**3.87**	**4.62**	**0.75**	**5.43**	**6.18**	**0.75**	
Reference Transportation Cost for Other Modes							
U.S. Flag (Jones Act) Tanker							0.135
Barge (Inland Waterway)							0.273
Rail Tankcar							1.146

Product Compatibility

One fundamental characteristic of the transportation fuels manufactured in petroleum refineries and marketed by oil companies is product compatibility. Product compatibility means being able to mix separate batches of a specific product necessary for the effective operation of the logistics system. For example, when one batch of on-specification product of a given grade, Batch A, is mixed with another batch of on-specification product of the same grade, Batch B, the resulting mixture, Batch C, will always be on-specification. If there must be absolute batch segregation, the logistics system as it exists today would be inoperable.

Every industry has its product distribution system. Goods are generally produced at a central location and transported to bulk warehouses located near retail demand centers. From the warehouses, products are shipped to retail outlets which directly supply consumers. However, petroleum products have a distribution system that is quite distinct from package goods because petroleum products are shipped in bulk to common facilities. Television sets or cases of string beans can be stacked in a warehouse and maintained as separate units. In contrast, petroleum products must be stored in tanks and the number of segregations is limited to the number of tanks at each location. Commingling some amount of the previous batch is inherent in the system.

Tanks are rarely empty when a product batch is received. In order to reduce evaporative emissions, light products such as gasoline are stored in floating roof tanks. The roof of the tank actually floats on the product to eliminate the air space above the product. In order for the floating roof design to function properly, the tank must contain a minimum volume of product that is called *bottoms* or *heels*. The normal minimum inventory level for a product tank employing floating roof design would be about 10 percent of its capacity. If a tank is permitted to empty below the level at which the roof design functions properly, the EPA will generally impose a fine on the terminal operator. A requirement to have a tank completely empty prior to receipt of a product batch is infeasible. In addition to the heels, the terminal must maintain an operating inventory to minimize the outages resulting from fluctuations in supply and demand.

The problem of mixing received product with the previous batch is not limited to pipeline terminals. Products are loaded on top of the remains of previous batches throughout the entire logistics system. Terminals extend to refinery tankage, deep water terminals for shipping and receiving ocean-going tankers and barges, river terminals receiving and dispensing products on the inland waterways, distribution terminals, and local distributor bulk plants. In addition to terminals of all types, products may come in contact with previous batches in ship and barge tanks, in tank trucks and rail tankcars, at retail service stations and ultimately in consumers' vehicle fuel tanks. Cleaning facilities such as found in retail service stations between delivered batches would be extremely expensive and would require operational shutdowns to accomplish.

The following example of a pipeline/terminal interaction illustrates the problem as it relates to the logistics system.

A 50,000 barrel unleaded premium gasoline batch is to be received at a company terminal from a major pipeline. The terminal has two unleaded premium gasoline tanks of 40,000 barrel capacity each. One currently contains 10,000 barrels of gasoline and the other is at the 15,000 barrel level. It will not be possible to receive the new 50,000 barrel batch without commingling at least part of it with existing product. In addition, part of the pipeline batch will contain the pipeline interface between two adjacent products. Mixing at the interface is small, usually less than 1 percent, but is another source of product commingling. The pipeline shipment is normally arranged 25 to 30 days prior to shipment. If sales are less than expected during the intervening time, the unfilled tankage may not be adequate to accommodate the pipeline batch when it arrives. Under this circumstance, it may be necessary to send some part of the batch up the line to another terminal that has capacity. Pipeline flows would not be stopped

to allow sales to make more tankage available for product receipt.

Regulations proposed by the Environmental Protection Agency on February 23, 1993 could preclude mixing even small or incidental amounts of different gasoline batches. As noted from the example shown above, it is not feasible to segregate each gasoline batch to make certain that even a small percentage of other complying gasolines are not included. The gasoline composition from batch to batch produced by a single refiner may differ considerably depending on specific processing and input material processed during a given period. Gasoline composition from different refiners will probably differ to an even greater extent.

As part of the NPC survey, pipeline companies were asked to evaluate the impact of increasing gasoline segregations by six and increasing distillate segregations by one. The question was based on the concern that shipping an unleaded regular grade, an unleaded medium grade and an unleaded premium grade for each CO and for RFG gasoline types as well as the combination of CO-RFG grades and blendstocks would cause disruption in pipeline operations. The response that is described in the following section of this chapter indicated that pipelines could accept the additional seven segregations with approximately 10 percent increased costs and a 15 percent capacity reduction. The capacity reductions also appear within the current capacity surplus. Increasing the additional segregations beyond seven by restricting or eliminating product compatibility will increasingly reduce the ability of the pipelines and terminals to function as transportation/distribution systems. If the number of segregations exceed what can be practically accommodated, the expected consequences would range from increased manufacturing and distribution costs and sporadic runouts to complete failure of some systems. Rules that effectively mandate complete batch segregation would render the logistics system inoperable.

For the above reasons, product compatibility is vital to the function of the logistics system. Requiring total isolation of each shipper's product is not feasible. The industry is preparing for the increased segregations required by the Clean Air Act Amendments of 1990 through facilities construction and capacity sharing exchange arrangements. However, the preparation is based on the assumption that individual grades of each gasoline reformulation type will be compatible. Under current operating practices, commingling small amounts of similar products from other sources that meet general specifications will not alter the quality of a shipment and does not limit the capability of the logistics system. The same situation is assumed by the NPC to exist following implementation of the CAAA requirements.

Pipeline Transportation Costs

A large percentage of the interregional clean product movement is accomplished through the vast array of U.S. product pipelines. The pipeline system is the backbone of the product distribution system. A 1987 map of the product pipelines in the United States is shown as Figure 3-5. Capacities and routes have changed little since 1987. It was important to the NPC study to determine whether implementation of the Clean Air Act Amendments of 1990 would be expected to create significant disruptions in the product pipeline distribution system through logistics limitations or dramatic cost escalation. Specifically, the adequacy of the existing system to handle a significant number of additional product grades needed to be addressed.

Only two announced capacity changes are recognized for the 1995 pipeline system. The Diamond Shamrock line from the Texas Panhandle to the Colorado Springs area is expected to be completed in 1993 with a capacity of 32 MB/D. In addition, the Santa Fe Southern Pipeline from El Paso to Arizona is being increased to 95 MB/D from 58 MB/D.

In order to establish base costs for the Calibration (1989) and Validation (1987) cases, study participants reviewed published tariffs. Where necessary, pipeline company representatives were contacted to assure a uniform comparison. Prior DOE and NPC studies and other industry data were reviewed to establish representative base pipeline transportation

costs and capacities from the selected "center of gravity" for product sources to the selected geographic demand centers. Where pipeline tariffs include terminal and truck loading service, adjustments were made in an effort to provide a common basis for pipeline transportation cost separate from the terminal services at a destination.

To assess the effect of possible changes imposed by the Clean Air Act Amendments of 1990, carriers were asked in the NPC survey to estimate the impact on transportation capacity and tariffs expected to result from increasing the number of product grades to be carried. When asked to evaluate the impact of increasing the number of gasoline grades by six and the number of distillate grades by one, respondents representing more than 80 percent of the interregion carrying capacity forecast less than 15 percent impact on the interregional carrying capacity. The survey also indicated that the pipeline system as a whole is operating at an annual average utilization rate of 50 to 60 percent. However, this statistic is an annual average across a system of hundreds of product pipelines. During certain periods throughout the year, some pipelines are at full capacity. At other times, some lines are at an even lower utilization than 50 to 60 percent. Considering the current pipeline 50 to 60 percent capacity utilization rate, the increases in segregations should not fully disrupt operations. However, periods of full capacity will be extended and times of higher required inventories will be prolonged.

Table 3-39 shows the pipeline utilization between supply/demand regions in 1989 and projections for 1995, 2000, and 2010 under various case assumptions. In all cases for 1995, annual average utilization taken from model runs appears at the current average level. The model does not account for reduced pipeline capacity attributable to increased number of segregations. In years beyond 1995, utilization is projected in these ranges except for low demand scenarios for which utilization drops into the 40 to 50 percent level. It appears that pipelines will have adequate capacity in future periods under the range of demand cases. As long as product segregations do not go well beyond the seven grade increase, pipeline capacity should not constrict the logistics system.

Full segregation of each pipeline batch goes far beyond increasing segregations by 6 or 7 products. If pipelines and terminals are required separate each product batch, segregations would increase by 15, 20, or even more. Attempting to contain product in terminals at this level of segregation would result in an inoperable system.

The change in tariff required to maintain 1990 carrying capacity under this increased seven grade scenario was forecast by carriers representing the same 80 percent of capacity to be less than a 10 percent increase. Only 8 percent believed that there would be no change. Thus, for purposes of the study, a nominal 10 percent increase in pipeline rates was used for the 1989-1995 period. This increase should represent the upper-end of expected increased pipeline tariffs resulting from the various environmental regulations.

In most common carrier pipeline systems, alcohol and gasoline-alcohol blends have been prohibited in the past. Alcohols include ethanol and methanol. (The use of methanol as a gasoline blending octane enhancer and oxygenate has been reduced to 3 MB/D in this country.) Most pipeline systems are not totally free of water contamination. With petroleum fuels, water will separate from the fuel in storage and can be easily removed by separately pumping from the two layers. However, water goes into solution with alcohols and must be removed through costly distillation. Further, alcohol/gasoline blends that are contaminated with water tend to separate into gasoline and an alcohol-water solution. For this reason, the current practice is to "splash blend" alcohols with gasoline from separate tankage at distribution terminals to avoid water contamination. In addition, alcohols and ethers require special seals in pipelines and pumps.

Ethers that include MTBE, ETBE, and TAME when blended with gasoline do not cause the water problems associated with the alcohols. Texas Eastern is a common carrier pipeline that has agreed to ship unblended MTBE. In addition, the Explorer Pipeline has

Figure 3-5. Petroleum Products Pipeline Capacities* as of December 31, 1987 (Thousands of Barrels Daily).

SOURCE: National Petroleum Council, *Petroleum Storage & Transportation*, 1989.

TABLE 3-39

PIPELINE DATA
(Thousands of Barrels per Day)

Regional Flows		EIA Pipeline Movements‡	Logistics Model								
			Capacities		Utilization						
From	To	1989	1989	1995	1989	1995-I	1995-III	2000-I	2000-I(E)	2010-I	2010-III
2	4	*	359§	322§	269	257	262	174	191	298	112
3	2	*	1,278§	1,278§	737	788	739	675	348	668	532
3	5	235	299§	299§	200	182	184	198	198	201	201
4	2	*	—	—	—	—	—	—	—	—	—
5	4	40	126§	118§	7	10	—	118	97	15	117
5	6	*	291§	291§	—	—	—	—	—	—	—
5	7	*	123§	164§	—	—	—	—	—	—	—
5	8	†	—	—	—	—	—	—	—	—	—
7	5	*	840§	854§	1	9	—	5	22	22	15
7	6	*	237§	237§	224	177	187	185	185	200	156
7	8	78	45§	53§	—	—	—	—	—	—	—
7	9	60	100	100	23	—	—	47	13	—	14
8	3	2,032	2,546§	2,546§	1,972	2,030	2,057	2,158	1,718	2,414	1,933
8	5	†	280	280	87	138	96	84	84	81	84
8	7	612	993	996§	416	332	311	421	404	481	353
8	9	0	43	75¶	43	68	62	93	93	91	93
8	12	54	58	95	58	95	95	95	95	87	95
9	6	30	45§	54§	—	22	26	37	37	54	27
9	7	†	16	16	—	—	—	—	—	—	—
9	10	43	67	67	42	39	39	38	38	49	60
12	11	*	—	—	—	—	—	—	—	—	—

* Not available; flow does not cross PADD boundary.

† Inter-PADD movements shown elsewhere, see 7 to 8, 8 to 7, and 9 to 6.

‡ Energy Information Administration data for pipeline movements between PADDs, where available. Gasoline components, Gasoline, Jet Fuel, Kerosene, and Distillate.

§ Pipeline capacities are NPC refining study survey data, where noted. Other capacities are estimated.

¶ Expanded to 93 thousand barrels per day by 2000.

shipped MTBE from Texas to Oklahoma and Kansas. ARCO North Pipeline has shipped unblended MTBE. The economics of pipelining MTBE, in part, is dependent on the interface volume. For large diameter pipelines, the interface volume may become cost prohibitive. However, there are a number of options available to reduce the interface losses that may increase the use of the MTBE pipeline transportation mode.

Barge Transportation

Barge rates for river transport between U.S. regions were developed primarily from survey results. Ocean-going barge rates were assumed to be effectively the same as tanker rates because barges must compete in ocean transport between two U.S. deep water ports. For that reason, this section refers primarily to river system and inland waterway barge operation.

Barge capacity is not considered limiting for this study. Barge construction time is less than a year and additional barges can be quickly built to offset capacity shortages as recognized.

Environmental cost increases are driven by the requirements of the 1990 Oil Pollution Act (OPA'90), 1990 Clean Air Act Amendments, and pertinent state environmental laws. While not subject to all of the vessel replacement regulations of OPA'90, owner/operators of the relatively smaller inland barges still expect substantial future rate increases, particularly in the 1990-1995 time frame, due to increased personnel, training, and operating requirements to meet environmental requirements. Anticipated increased costs will stem specifically from legal support, training staff and facilities, emergency response teams, vapor recovery systems, stack emissions controls, increased financial responsibility burdens, and disposal cost for shipyard stripped product.

As noted above, unblended (neat) oxygenate component transportation is not permitted in most pipelines. Oxygenates, both alcohols and ethers, are regularly transported by barge where supply and demand points are accessible to navigable rivers and inland waterways.

Tanker Transportation

Ocean-going tankers are the only means of moving petroleum products from one continent to another. In addition, tankers are used to move products between and along the coasts of the United States.

The tanker markets have evolved with brokers arranging for contracts between ship operators and cargo owners. Ships are available for hire, or charter, for a single spot voyage from one supply port to one demand port. Tonnage is a commodity and the price of tonnage fluctuates with the demand for and the supply of a particular vessel class. A free and open system has developed to provide cargoes for ships and transportation for oil product owners.

Rather than attempt to speculate on the long-term tonnage supply/demand ratio and the resulting volatile spot rates, the cost of future years has been estimated at the 1989 level plus incremental environmental costs. All future cost estimates are based on constant dollars and do not reflect anticipated inflation.

Environmental costs are based on the requirements expected from the OPA'90 and other federal and state environmental regulations. In addition, the International Maritime Organization (IMO) will impose vessel retirement conventions similar to OPA'90. Although regulations have not been completed, anticipated requirements include a vessel life limiting program that will phase out existing tankers and, if replaced, require major hull design modifications including some form of double hull construction. In addition, other regulations will require more frequent inspections, low sulfur fuel while operating in port, vapor recovery systems, tank overfill alarms, Marine Preservation Association dues which fund marine spill response efforts, cooperative spill response training, drills, and dues, and increased financial responsibility insurance premiums. The average spot charter market component for an average size clean product tanker was selected because it represents an incremental transportation cost which is appropriate for analytical use. Estimated costs of these mandated programs will be added to the base spot market costs.

U.S. Flag (Jones Act) Tankers

The Merchant Marine Act of 1920 (Jones Act) requires that all marine transportation from one U.S. port to another U.S. port be carried in a U.S. built, U.S. manned, U.S. flag ship. Jones Act tonnage moves products and crude oil from a U.S. supply port to a U.S. demand port. Foreign flag and non-Jones Act U.S. tonnage is not permitted to trade between U.S. ports, and a small number of U.S. flag ships continue to operate in this unique niche market. In developing the transportation model, a list of 38 clean product carriers from 25 to 50 thousand deadweight tons (MDWT) was assumed to be available for transporting gasolines, jet fuels, and distillates between various U.S. ports. This list which is included as Appendix L, Section VI-3 is not an exclusive list of only ships available because ships move in and out of clean product service from dirty and chemical trading. Ships may be unexpectedly retired. Large barges move into clean product ocean trading. Some larger and smaller vessels may also be employed as clean product carriers. However, the ships selected were in clean product service at the time and are a representative feasible clean product fleet. Further references to U.S. flag ships will apply only to those ships that can operate between U.S. ports within the Jones Act definition.

Model runs indicate that 30 average size (35 MDWT) vessels with a total 1,059 MDWT capacity will be required to meet U.S. flag ocean transport needs in 1995. Under Foundation Case I, this requirement increases to 1,236 MDWT in 2000 and then declines to 635 MDWT in 2010 as imports to New England and increased pipeline deliveries to the Lower Atlantic back out U.S. flag deliveries.

All tankers entering U.S. waters will be subject to the OPA'90 retirement conventions. All tankers that operate worldwide will be subject to the IMO requirements. The retirement requirements for all clean product carriers used for the study are shown on the vessel list in Appendix L, Section VI-3. Table 3-40 summarizes the tonnage required and the amount to be scrapped for each of the next five-year increments. It has been assumed that since U.S. flag ships operate exclusively in U.S. trading that OPA'90 will apply. Under OPA'90 none of the clean service ships used in the model will require retirement by 1995. However, by the year 2000, 60 percent of the represented tonnage will need to be scrapped. The tonnage short-fall calculated for 2000 is 700 MDWT. If the ships required to move domestic products are to be available in the last half of this decade, new construction will be required. The projected decline in requirements forecast in Foundation Case I for 2010 may discourage the required number of vessels to be built for turn of the century tonnage requirements.

Major petroleum companies and independent tanker owners operate U.S. flag ships. The value of the ships and consequently the cost of tanker deliveries between U.S. ports is determined by the tanker market in which ships are freely offered and hired. Tanker charters can be made for a single voyage, a number of consecutive voyages or for a period of time such as one or more years. The Shipping Cost Analysis Corporation (New York) collects the U.S. charter data, analyzes them, and publishes the United States Average Freight Assessment (USFRA). USFRA is an average of component costs for spot charters and term charters of various time periods.

The U.S. flag marine transportation costs used were based on the 30 to 39 MDWT size spot charter component of USFRA. The reported averages were AR145 and AR130 for 1989 and 1987, respectively, and are expressed in the 1991 American Tanker Rate Schedule (ATRS). The ATRS book provides rates for the U.S. flag trades and is used for virtually all single voyage chartering. With the AR rate, it is possible to calculate the dollar per ton transportation cost for each product in each trade considered. The ATRS system to those unfamiliar with it should be considered a method of pricing tonnage. ATRS is described in more detail in Appendix L, Section VI-4, in a paper presented by Bruce R. Bishop to the Northern California Section of The Society of Naval Architects and Marine Engineers in March 1990.

Incremental 1995 environmental U.S. flag transportation costs are forecast at 15 points of ATRS (+AR15) (expressed in 1991 ATRS) over 1989 base costs or about a 10 percent increase.

TABLE 3-40

EXISTING CLEAN FLEET EMPLOYMENT (25 TO 50 MDWT SIZE RANGE)

	Tonnage MDWT Must be Retired By			
	1995	2000	2005	2010
Tonnage Assigned to Model				
# Vessels (Actual)	38	14	9	7
MDWT	1,344	536	363	294
Tonnage Required (Based on Model Runs) – Foundation Case 1				
# 35 MDWT Vessels	30	35	Year not	18
MDWT	1,059	1,236	run	635
Long/(Short) MDWT	285	(700)		(341)

EXISTING CLEAN FLEET RETIREMENT REQUIREMENTS

	Tonnage MDWT Must be Retired By				Later Than
	1995	2000	2005	2010	2010
Under OPA'90	0	808	981	1,050	1,344
Cumulative %	0.0%	60.1%	73.0%	78.1%	100.0%
Under IMO	878	954	1,016	1,050	1,344
Cumulative %	65.3%	71.0%	75.6%	78.1%	100.0%

Notes:

1. U.S. clean product fleet retirements based on vessel list in Appendix L, Section VI-3.
2. Because U.S. Flag Jones Act vessels operate exclusively in U.S. trading, it is assumed that ships will comply with U.S. OPA'90 legislation and not the more strenuous IMO international regulations.

All future cost estimates are based on constant dollars and do not reflect inflation. The causes for the cost increase include those items listed above for OPA'90 and its associated state laws and regulations. It does not include the cost of double-hulls because that provision requires an orderly phase-out over time. By 1995, only a few ships will have been replaced.

By 2000, the incremental environmental U.S. flag transportation cost is projected to increase 30 points of ATRS (+AR30) over 1989 rates, for an increase of 21 percent. The incremental amount reflects the items for 1995 plus a partial recognition of the required double hull construction cost. By 2010, the cost will increase by 40 points of ATRS (+AR40) over 1989 rates in recognition of the full double hull construction costs. The increase represents a 28 percent increase over 1989 average spot charter cost levels.

These rate estimates are considered conservatively low because the 1989 spot market rate of AR145 only covered out-of-pocket operating cost, plus a modest contribution toward capital recovery and return on investment. Thus, this market level will not support new ship construction investments. If owners and operators are to receive an adequate return on investment to provide the incentive for reinvestment in replacement tonnage construc-

tion, charter market rates must be higher than this level.

Foreign Flag Tankers

The foreign flag tanker market is considerably larger than the U.S. flag tonnage market in terms of number of ships and worldwide trading. The clean product marine transportation costs for foreign flag ships moving three products (motor gasoline, diesel/heating oil, and jet fuel) to the United States were based on the average spot charter rates in 1989 and 1987 for 25-40 MDWT size clean ships. The rate averages for these two years are W190 and W145, respectively, expressed in 1991 Worldscale. Worldscale is a rate schedule that published rates for most trades (origin to destination) around the world. It is the tonnage pricing system used for virtually all single voyage chartering. Market rates are expressed in a percentage of that number. Using Worldscale permits the determination of a dollar per ton spot charter transportation cost in any trade required. Worldscale is further described in Appendix L, Section VI-4, in Mr. Bishop's paper.

Capacity for foreign tankers was assumed to be adequate for tonnage requirements. Foreign ships have been historically abundant and the product imports into the United States are a relative small percentage of overall worldwide clean tonnage usage.

Estimating long-term foreign tanker market rates is difficult for the same reasons explained for U.S. flag ships. Rate levels are determined by the relative tonnage supply for a given vessel class to the demand for it. Again, rather than attempt to speculate on the future tonnage supply/demand ratio balance, the incremental environmental capital and operating costs have been estimated and applied for future years.

For 1995, incremental environmental cost for clean foreign flag tonnage is estimated to result in a rate increase 12 points of 1991 Worldscale (W12) or a 6 percent increase in constant dollars over 1989 spot market rates. The costs consist of the same items required by the OPA'90 and other federal and state environmental regulations. The requirement for double-hulls will have little if any effect on the 1995 costs and are not included. By 2000, the incremental cost should increase by +W20 or about 10 percent over 1989 spot market rates to account for some double-hull tonnage entering the market. By 2010, full recognition of double-hull cost will cause rates to increase by +W30 or about 16 percent over 1989 levels in constant dollars.

As with U.S. flag ships, the cost is based on the single voyage (spot) charter market because it represents the incremental transportation cost. The incremental environmental costs are added to base average spot charter rates to estimate future foreign flag clean product tanker costs.

Almost half of all tankers on order specify double-hull construction. A large percentage of the remaining orders have double-hull options that may be exercised.

The 1989 spot market rate of W190 is considered conservatively low because it covers out-of-pocket operating costs, but does not produce an adequate return on investment to create the required investment incentives to build double-hull ships. If the tanker owners and operators do not have the prospect of adequate future rates that support proper returns, investment in new tonnage may be inadequate. The tonnage supply/demand ratio will be unbalanced and rates will increase until added tonnage is constructed. On the other hand, if product imports were to increase sufficiently to justify terminal modifications, the trend toward employment of larger vessels would reduce transportation rates. Larger ship rates would be somewhat offset by increased tankage requirements and higher stationary and in-transit inventory costs.

Import Duties And Fees

Import duties and fees are assessed by the federal government on imports of various petroleum raw materials and products. The duties depend on the type of product, its intended use as well as its source. Table 3-41 lists the current duties in effect in 1992 for typical petroleum products. The current duties are assumed to remain in effect throughout the

TABLE 3-41

UNITED STATES IMPORT DUTIES
(Cents per Barrel)

Imported Item	Favored Nations	Non-Favored Nations
Oils		
Crude Oil, <25° API	5.25	21.00
Crude Oil , >25° API	10.50	21.00
Distillate & Resid, < 25° API	5.25	21.00
Distillate & Resid, > 25° API	10.50	21.00
Motor Fuels (Avgas, Mogas, Diesel, Jet)	52.50	105.00
Motor Fuel Blending Stock	52.50	105.00
Kerosene (except motor fuel or motor fuel blending stock)	10.50	21.00
Naphthas (except motor fuel or motor fuel blending stock)	10.50	21.00
Chemicals		
Ethanol for motor fuel and any motor fuel containing ethanol	See Note 3	See Note 3
MTBE for motor fuel blending	235.00	235.00

Notes:

1. Duties applied to Canadian sourced crude oils and products but were phased out at the end of 1992.
2. Chemical duties are based on 5.6 percent of imported value for MTBE (based on $1.00 per gallon).
3. Imported ethanol is treated identically with U.S. produced ethanol and is eligible for the 54 cents per gallon federal excise tax exemption if produced from renewable sources. However, it is assessed a 54 cents per gallon import fee if it is used as a transportation fuel. Therefore, ethanol imports are essentially economically noncompetitive with domestic ethanol. The exceptions include ethanol imports from 22 countries covered by the Caribbean Basin Economic Recovery Act of 1989 and Canada. Ethanol imports are duty free from these countries, but are restricted to 60 million gallons or 7 percent of the domestic ethanol market, whichever is greater.

1990-2010 period of the study with the exception of the duties on imports from Canada. Canadian import duties are being phased out and will drop to zero by 1993.

In addition to the duties, the following other fees and taxes on imports are required. It is assumed that these fees and taxes will remain in effect throughout the period covered by the study.

- **Merchandise Processing Fee.** Formerly called the Customs User Fee, this fee is 0.17 percent *ad valorem* on all oil imports into the United States. It is based on the import's value reported in the commercial invoice. Duty-free imports are not exempt from this fee, but Customs has placed a maximum of $400 per entry fee and $240 for imports from Canada.
- **Superfund Tax.** A tax imposed to fund hazardous waste site cleanup, the tax is 9.7¢ per barrel on imported crude oil, imported products and domestically produced crude oil.

- **Harbor Maintenance Fee.** A 0.125 percent *ad valorem* fee on all loading or unloading of cargo at U.S. ports. It is assessed only once as long as the cargo remains aboard one ship.
- **Oil Spill Liability Fund.** A tax of 5¢ per barrel on all imported crude oil, imported products, and domestically produced crude oil is imposed in order to create a spill cleanup fund. It will not be imposed after the fund reaches $1 billion in value, but can be re-imposed if the fund falls below that level.

Rail Tankcar Transportation

Rail rates used in the study were based on 1989 public waybill sample average costs for all chemical commodities. These rates were validated by NPC survey results. The survey also verified that only negligible volumes of gasoline, jet fuel, and distillate were transported by rail from one region to another. The study conclusion that rail is a non-competitive mode of transportation over long distances for all fuels except oxygenates (primarily ethanol) was substantiated by the NPC survey results. As noted above, all product pipelines permit gasoline containing ethers to be shipped. Few pipelines permit neat ethers to be shipped and, as of this writing, no common carrier pipelines permit alcohols or even products containing alcohols to be accepted. Therefore, all ethanol and some MTBE must move by marine, rail, or truck. Rail is the primary transportation mode for ethanol between areas not accessible by barge.

Increased cost of low sulfur diesel locomotive fuel would be the most likely environmental cost increase for rail tankcar delivery. A railroad diesel locomotive moves an average 400 to 800 ton-miles of freight per gallon of diesel fuel consumed. At that rate, moving one gallon of ethanol 1,000 miles would expend approximately 0.004 to 0.008 gallons of diesel. For an incremental cost of 5 cpg for low sulfur diesel, the increased cost of moving ethanol 1,000 miles would be 0.02 to 0.04 cpg. The level of this incremental cost change would not be significant in the logistics model. Therefore, it is assumed that rail tankcars do not have a significant incremental environmental cost effect.

If, as a result of the Clean Air Act Amendments of 1990, rail transported oxygenate volumes increase dramatically, the economies of scale leading from unit-train and other special handling efficiencies could result in reduced rail freight costs. Conversely, if other pipelines are modified to accept neat oxygenates and ethanol blended gasolines, the rail mode share of oxygenate transportation could be reduced significantly.

Tank Truck Transportation

Tank trucks serve as the last link in the petroleum distribution chain between the refinery and the retail gasoline outlet. The cost of trucking is higher over long distances than pipeline or forms of marine freight. Therefore, trucks are generally used for short-distance hauls.

Truck rates were derived from the NPC survey. The survey indicated that refiners' trucking cost over their most frequently used route were 0.04 cpg-mile in 1990. The respondents also verified that trucks are seldom used to transport light fuel products over the longer distances between regions.

The respondents estimated that environmental regulations would increase trucking cost. The level of the estimated increase from 1990 to 1995 ranged from less than 1 to 78 percent, with a median of 18 percent and a mean of 23 percent. The cost increase reflects anticipated higher fuel costs associated with new low sulfur diesel specifications, more rigorous driver training and certification, and higher liability insurance costs. Truck design changes may also have led to the wide range of estimates. In discussions with NPC study participants, the range of 10 to 15 percent appeared more appropriate as a cost increase resulting from new regulations on tank truck transportation. A 12.5 percent increase would result in an increase of 0.005 cents per mile per gallon.

Terminals

Terminals are major facilities located near the terminus of the petroleum product

distribution chain. They serve to receive large parcels or "batches" of product from pipelines or marine vessels for redelivery by truck or rail transports to wholesale jobbers and retail outlets. The predominant features of a terminal are the tanks needed for product storage and grade segregation. Ancillary equipment at a terminal includes the piping, pumps, valves, meters, etc., necessary for bulk receipts as well as loading rack for small quantity deliveries. Terminals must also include the necessary equipment to measure and account for the product delivered.

Like refiners, terminal operators are faced with additional environmental and safety expenditures over the next several years, including:

- Vapor recovery facilities at all marine terminals
- Additional volatile organic compound and toxic emission controls on floating roof tanks
- Vapor recovery on fixed roof systems
- Reduced throughput capacity as a result of increased tank inspection requirements
- Increased cost due to more stringent handling of rain water run-off and tank water bottoms
- OSHA programs for Process Safety and Hazardous Operation training.

Terminal operators responded to the NPC survey that these environmental and safety programs would increase terminal throughput mean costs about 1 cpg in 1995 from 1990 cost levels of 0.4 cpg. However, the range in the responses was so wide that study participants questioned the validity of the mean. The wide range in the cost estimates and high end results may have been caused by the respondents misinterpretation of rather complex questions in this section of the survey. The details of the reported terminal environmental investments and operating costs are shown in Table 3-42.

After considering the responses, the Logistics Subgroup believes that a more realistic incremental environmental terminal cost increase estimate would be 0.4 cpg from 1990 to 1995. The adjusted level will be reported and used in this study. Increased terminal costs will not affect the selection of the supply source or transportation mode because the costs will apply equally to all products' throughput, irrespective of their source.

Spillover

A major concern to the industry was the degree of spillover that would be experienced near nonattainment areas that will require environmental fuels such as oxygenated gasoline and reformulated gasoline. Spillover of two types may occur. The first type is a chronological spillover in which an environmental product that is seasonally mandated is distributed before or after it is required in order to meet distribution scheduling. Chronological spillover is not discussed here, but is considered in the product demand section above. The second type is geographic spillover, in which environmental product is distributed to those areas not requiring it by law. The introduction of such environmental fuels will increase the number of segregations traditionally handled by the product distribution system. Geographic spillover defines the situation in which environmental fuels are consumed in the conventional product area due to the lack of available terminal tankage necessary to provide for these additional segregations.

The Logistics Subgroup considered the question of how much increased demand for environmental products would be attributable to geographic spillover. Maps of each nonattainment area were compared with terminal and pipeline information reported in the NPC *Petroleum Storage & Transportation* April 1989 study. Most nonattainment areas are located in major population centers. In virtually all cases examined, these centers are served by numerous nearby product terminals, each containing multiple tanks. Few of these individual terminals would likely be equipped with sufficient numbers of tanks to segregate all of the environmental products from conventional products. However, two adjacent terminals with four tanks each could accommodate eight segregations. It is believed that the manufactured cost differential between environmental fuels

TABLE 3-42

TERMINAL ENVIRONMENTAL INVESTMENTS & OPERATING EXPENSES

	NPC Survey Results (1990 Dollars)				Participants' Consensus	
	Mean		Range (Cents/Gallon)			
1990	**$/MB/CD**	**Cents/Gallon**	**Low**	**High**	**$/MB/CD**	**Cents/Gallon**
Environmental Capital Expenditures	$60,000	0.067	0.0003	1.199	$14,000	0.02
Environmental Operating & Maintenance Expenses	$50,000	0.326	0.0007	5.627	$5,200	0.03
Total		**0.393**	**0.0010**	**6.826**		**0.05**
1991-1995						
Environmental & Process Safety Related Capital Expenditures	$284,800	0.318	0.0008	3.193	$165,000	0.18
Environmental One-Time Expenses	$156,000	0.174	0.0002	2.130	$60,000	0.07
Subtotal	**$440,800**	**0.492**	**0.0009**	**5.323**	**$225,000**	**0.25**
1995						
Environmental Operating & Process Safety Maintenance Expenses for 1995	$77,200	0.504	0.0007	6.624	$30,000	0.20
Total Annual Terminal Environmental Costs for 1995 & Beyond		**0.995**	**0.0016**	**11.947**		**0.45**
INCREMENTAL ENVIRONMENTAL COST INCREASE OVER 1990						**0.40**

Notes:
1. Cap. Alloc. Factor 10%A/T ROI = (0.171x 100)/(1000 x 365 x 42) = 0.00000112
2. Expense Allocation Factor = 100/(1000 x 365 x 42) = 0.00000652

and conventional fuels will serve as a sufficient incentive for terminal operators to utilize and exchange their facilities in an effort to minimize spillover.

Supply of southern New Jersey, which is in the Philadelphia area, is used as an illustration. Nearby Atlantic and Cape May counties are attainment areas and do not require environmental fuels. However, more than 40 product terminals are located in the area.

Considering the incentive of a high cost differential for environmental products, it is difficult not to believe that terminal owners will make exchanges and supply agreements for those areas not requiring the more expensive products. Even today, without the product cost differential, companies routinely exchange product and share joint terminal operations. The spillover is estimated to be no more than 1 percent. In some situations, individual suppliers may find it economic to distribute oxygenated products to areas where they are not required. For example, if the oxygenate value reaches its octane value as a gasoline blending component, it becomes economic to blend it into gasoline, even without the CAAA requirement to do so.

In Chapter Four, the cost increases of requiring common specifications for all heating oils and both on-highway and off-highway diesel fuels are addressed. Requiring universally more rigid specifications will most certainly increase the costs and prices of middle distillate products. However, specifications changes that combine product groupings with the same specifications will reduce the number of product segregations and to some degree reduce the logistical complexity and costs. The reduced logistics segregations and complexity would not compensate for the additional manufacturing costs.

Logistics Section References

1. *Transporting U.S. Oil Imports: The Impact of Oil Spill Legislation on the Tanker Market,* Petroleum Industry Research Foundation, Inc., June 1992, prepared for the U.S. Department of Energy, page 91.
2. *Rail vs. Truck Fuel Efficiency: The Relative Fuel Efficiency of Truck Competitive Rail Freight and Truck Operations Compared in a Range of Corridors,* Abacus Technology Corporation, Chevy Chase, MD, April 1991, prepared for the U.S. Department of Commerce.
3. *Petroleum Supply & Transportation, Petroleum Liquids Transportation,* National Petroleum Council, April 1989, Volume V.

REFINING INDUSTRY MODELING

Introduction and Summary

This section of the report describes the development of the refining data for the logistics model described earlier. These data are the competitively costed U.S. and foreign light products. Because a great deal of material is covered in this section, Appendix L, Section VII-1 provides additional noncritical information as well as more detail in specific areas.

Background Study Development

U.S. and Foreign Refining Industry

The NPC recognized that a study to evaluate the supply of U.S. petroleum products for future years would not be complete without considering both U.S. refinery capability and light product imports from foreign refineries. Two NPC work groups developed models representing both the U.S. and foreign region refineries. The results, in the form of incrementally costed light products in future years became input to the logistics model. The year 1989 was taken as the base year for establishing the refining models.

Modeled Areas

United States

The concept of refining industry capability modeling with one model per Petroleum Administration for Defense District was selected as a practical way to represent U.S. manufacturing capability. The entire refining industry in a PADD was mathematically modeled in a computer as a single aggregated refinery.

The PADD models demonstrated that it was possible to represent regional product production, by matching crude oil input with historical product yields. This approach, evaluating the capability of the refining industry by aggregated industry modeling, has been used by previous NPC and other studies; e.g., lead phasedown, the Auto/Oil Air Quality Improvement Project, etc.

The federal government divides the United States into five petroleum supply/consumption PADDs:

PADD I = U.S. East Coast.

PADD II = U.S. Midwest.

PADD III = U.S. Gulf Coast.

PADD IV = U.S. Mountain states.

PADD V = U.S. West Coast.

For this study, the U.S. West Coast was divided into two refining sectors:

VC = PADD V - California sector = CA, NV, and AZ.

VOC = PADD V - outside California = WA, OR, HI, and AK.

A refining industry capability model was developed for each of the six defined PADD areas.

Foreign (See Appendix L, Section VII-1)

To effectively evaluate the impact of global supply and demand on future U.S. supply, six major foreign supply regions were selected. The six foreign regions covered in the study are defined early in this chapter, and given the following designations: Canada (CAN), Northwest Europe (NWE), Mediterranean (MED), Middle East (ME), Latin America (LAT), and Pacific Rim (PAC).

The concept of regional modeling with one model per region was selected as a practical way to represent foreign manufacturing capability. The regional models were calibrated based on estimates of actual regional crude oil and feedstock runs and refinery productions for 1989.

Model Contractor

The NPC selected Pace Consultants as its contractor to perform the linear programming (LP) studies for the U.S. and foreign refining industry capability, under NPC direction.

The model simulates the refining processing capability by minimizing costs within the boundaries and constraints identified, and calculates the cost of producing the next barrel of that product, i.e., the marginal value. (See Appendix L, Section VII-2, and Working Paper 3.VII-1.)

Expert Panel

An expert advisory panel was convened in Washington in early 1992 to discuss issues that were expected to apply to the evaluation of the impact of overseas refining on the domestic market. Among topics addressed were opinions on future product quality requirements and the impact of new environmental regulations on stationary facilities and the time frame for implementation. Product quality information was used in the development of the foreign regional models. Summaries of this panel discussion are contained in Appendix L, Section VII-3, and the detailed transcript is included in Working Paper 3.VII-2 for this NPC study.

Refining Survey

United States

The NPC used a variety of public sources for data on capabilities, product yields, and operations, etc., needed to model the industry's capability. Section II of the NPC survey was used to verify these data, supplement areas where data were inadequate, and tune the model for the calibration cases.

Foreign

The NPC refining study survey included Section X for operators of refineries outside the United States. The objective of the survey section was to gain information on the future product specification requirements in other countries. Specifically, perspectives for motor gasoline, distillate (for transportation fuels),

and residual fuel oil (for stationary users) were requested. Base line country average product quality information for 1989 was also requested.

The survey results revealed that significant tightening of foreign product specifications is likely during the 1990s. The specific trends for product specifications are highlighted on a region by region basis in Appendix L, Section VII-4. According to the survey responses, in many cases the foreign product quality requirements will be close to those of the United States by 2000-2010. Unleaded, oxygenated, and other low emission gasolines will be phased in at different rates over this time period by countries within the foreign regions. Sulfur reduction in distillate and residual fuels (on land usage) will proceed in Northwest Europe and the Mediterranean regions in approximately the same time frame as in the United States.

A key finding from the survey was the diversity of specification requirements sometimes found in the regional markets. This was particularly true for the Pacific Rim and Latin America where distillate sulfur, gasoline RVP, and gasoline octane indicated wide ranges in property values between countries. However in the single region representation used for the study, average specifications were estimated and used in the refinery modeling.

Development of Key Study Assumptions

Crude Oil

United States

The 1989 crude oil volumes used in the regional models were taken from historical information using EIA and other publicly available data. It was agreed to represent a fixed volume base crude oil mix by preparing a composite of crude oils at the approximate rates known to have been run in the region during 1989. Each PADD model has an incremental crude oil in the model whose volume varied as required to meet variable light product production volumes. Based on historical data, incremental crude oils selected were:

- Arabian Light quality in PADD I and PADD III.
- West Texas Intermediate quality in PADD II and PADD IV.
- Alaskan North Slope quality in PADD VC and PADD VOC.

Base crude oil volume and quality, and incremental crude oil quality, were the same in all years studied (see Appendix L, Section VII-2). The cost used for the incremental crude oil was the published 1989 price, which reflected market conditions at that time.

Foreign

Crude oil run volumes in 1989, which were used in the regional models, were taken from historical information provided by the EIA and supplemented by the contractor. It was agreed to represent a fixed volume base crude oil mix by preparing a composite of crude oils and approximate rates known to have been run in the region during 1989. The last increment of crude oil to be run in the regions, swing crude oil, was assumed to be Arabian Light quality as representative of general incremental industry crude oil mix. The incremental crude oil was allowed into the model for all foreign regions as required to meet variable requirements for light products. Base crude oil volume and quality, and swing crude oil quality, was assumed the same in all years except when it was necessary to segregate low sulfur crude oil (see Appendix L, Section VII-2). The cost used for the incremental crude oil was the published 1989 price, which reflected market conditions at that time. In addition, it was necessary to segregate low sulfur crude oils within the regional base crude oil mix. These were used as segregated crude oils to achieve reasonable blends of low sulfur fuel oil.

Other Inputs

United States

The volumes of miscellaneous refinery feedstocks, e.g., FCC feed, gasoline blendstocks, olefins, and residual fuel oil imported into the PADD from other PADDs of the United States or from foreign refineries, are

taken from EIA data for 1989, and are assumed to be constant for all years and not a function of the total crude oil run in a PADD. Butane, used to adjust gasoline vapor pressure, floated within limits; the input of isobutane for alkylation plant feed did not exceed the volume input in the 1989 reference case. Natural gas for fuel or hydrogen plant feed varied as required. MTBE was assumed available to meet product blending requirements including those for reformulated and oxygenated gasolines in 1995, 2000, and 2010. It was assumed that all refinery produced MTBE and TAME would be blended within the refining PADD in which it is produced.

The 1989, 1995, and 2000 reference cases assumed no change of inter-PADD product movements in the United States from the 1989 volumes reported by the EIA. For development of cost-volume relationships, the starting point assumed imports and exports at 1989 levels. Product qualities for transfers were taken to be the same as that of the producing region.

No oxygenate was used in the modeling for 1989. In 1995 and 2000, oxygenate was assumed to be added only to the regulated grades, oxygenated and reformulated gasolines, and not to conventional gasolines. Ethers were the only oxygenates used in this LP modeling.

Low aromatics diesel for 1995 and 2000 and CARB Phase 2 RFG for 2000 for California were not produced except in PADD VC.

Foreign

FCC unit feed, gasoline blendstocks, butane, olefins, and residual fuel oil mixtures imported into the region, and natural gas consumed in refineries in the region, were based on EIA data for 1989. All but natural gas, which varied as a fuel, were assumed to be constant for all years.

Refining Capacity

United States

The rated 1989 refining capacity per stream day for each of the PADDs was taken primarily from historical records compiled by the EIA and the *Oil & Gas Journal*. The listing was modified where specific industry information indicated otherwise. Assumptions have been made about the nature and use of certain units, particularly hydrodesulfurization and hydrocracking units. No public information was available about the size of some processing units in individual refineries; e.g., chemical treating, H_2S recovery, fractionation, etc. The process unit capacities for each individual refinery in a PADD was composited into single process units for the single refinery of the refining industry capability model.

Capacity in 1989 was established by adding announced capacity changes to the 1989 base data. The NPC's adjustments include all increments/decrements announced (prior to April 1992 cut-off) in the *Oil & Gas Journal* and other public industry information. No capacity creep, i.e., no unannounced capacity increase at no cost, has been added to 1989 U.S. capacities.

Certain process capacity changes from 1989 to 1995 were not based on announcements:

1. Some existing distillate aromatics saturation units were not capable of producing 0.05 percent sulfur diesel fuel in 1989. Additional hydrodesulfurization reactor or catalyst volume or catalyst changes or other modifications could increase desulfurization to meet lower diesel fuel sulfur specs. In the United States, this hydrodesulfurization upgrade has been given the investment costs equal to that of new hydrodesulfurization units for 10 percent of ultra low sulfur diesel production in the region.
2. In the VC model for 1995, aromatics saturation processing capacity additions were allowed for production of low aromatics diesel meeting the California state requirements for that product.

The U.S. refining process capacity for 2000, before modifications required to produce reformulated gasoline, was premised to be the same as that in the 1995 models. For the year 2000 reference cases, the LP modeling of the U.S. PADDs allowed for new process capacity to be built only for making reformulated

gasolines not to make more light products. "Minor" process additions, primarily for fractionation, to produce Phase II reformulated gasoline were included at an investment of $400 per daily barrel of RFG production.

Additional volumes of light products beyond that which can be produced from the existing refining system were manufactured at a cost corresponding to the addition of a major residual fuel oil conversion project in the PADD.

Foreign (See Appendix L, Section VII-1)

The rated 1989 refining capacity for each of the foreign regions in 1989 was taken primarily from historical records compiled in the *Oil & Gas Journal*. The listing has been modified where other industry information is judged to be more reliable. Where there was no announced capacity additions, a 5 percent capacity creep was allowed above nameplate capacity for units to reflect minor debottlenecking between 1989 and 1995. Capacity in 1995 was established by incorporating announced capacity expansions to the 1989 base data, adjusted with a probability factor. (See Appendix L, Section VII-2.)

For 2000 onwards, the regional LP model allowed for new capacity to be built as required and economic with the capital charge imposed for the new facilities in order to meet the demand within the region. Capacities are summarized for the foreign regions in Appendix L, Section VII-5.

United States and Foreign

The Refinery Facilities Task Group developed investment costs for the various refinery process units based on capacity for world scale units. Capital cost adjustment factors were established for each region to convert from U.S. Gulf Coast to local conditions for the region. While process technologies are expected to develop during the period covered in this study, none were specifically identified for inclusion in the regional models for future years. (See Appendix L, Section VII-6.)

Adjustments were made to the stream day capacity calculated above to derive the maximum processing capacity available in the model. This capacity took into account scheduled turnaround shutdowns, unscheduled plant shutdowns due to equipment malfunction, as well as feedstock interruptions, market lapses, product quality and transportation problems.

Oxygenate manufacture and supply, including refinery produced material, is discussed elsewhere in this chapter.

Product Quality and Demand

Product qualities for light products are expected to change over the duration of the study. This is illustrated in Table 3-43, which compares 5 critical light product properties for the U.S. and foreign regions and how they are expected to change for the future years.

United States

U.S. average product qualities were used for modeling specifications for imports to United States. This maintains consistency with U.S. product specification philosophy, using "manufacturing specifications" in the refining industry capability model that corresponded to U.S. average product quality. The specifications for products imported to the United States were assumed to be the same as that of the importing U.S. region. Products exported from the United States were assumed to have average U.S. quality for that PADD.

Detailed petroleum product specifications for the United States in 1989 are given in Chapter Four. Since the modeling was done on a yearly average basis, yearly average product specifications were developed and used.

The 1989 product specifications used in the PADD model by the NPC in the 1989 cases were intended to reflect the actual average product quality in the marketplace during 1989. On an annual-average industry-average basis, product qualities were and are not generally limited by ASTM or legal specifications. A grade of gasoline meets certain specs based on average gasoline properties rather than ASTM or legal minimums or maximums. Examples for 1989 modeling include: winter RVP, sulfur content, distillation specs, and pool aromatics

TABLE 3-43

KEY FOREIGN PRODUCT SPECIFICATION GUIDELINES

	Oxy Mogas % Pool	Mogas RVP Max	Mogas S, ppm	Mogas 90%Dist	Diesel S, %
United States	0/30/62/62	11.5/10/ 9.5/9.5	500/350/ 225/225	335/335/ 330/330	0.28/0.1/ 0.1/0.1
Canada	0/25/30/30	15.5/10/ 9.5/9.5	1500/1500/ 500/500	375/375/ 350/350	0.2/0.2/ 0.05/0.05
NW Europe	0/10/20/20	14.5/10.5/ 10/10	1000/500/ 250/250	360/NR/ 350/350	0.2/0.2/ 0.05/0.05
Mediterranean	0/10/20/20	12/10.5/ 9.5/9.5	2000/500/ 250/250	375/NR/ 350/350	0.28/0.2/ 0.05/0.05
Middle East	0/0/0/0	10.9/9.5/ 9.5/9.5	NR/1000/ 500/250	NR/NR/ 350/350	0.9/0.5/ 0.3/0.2
Latin America	0/35/35/35	10.9/9.5/ 9.5/9.5	NR/1000/ 500/250	NR/NR/NR/ 350	NR/0.5/ 0.3/0.2
Pacific Rim	0/10/20/20	10.9/10/ 10/10	NR/1000/ 250/250	NR/NR/NR/ 350	0.37/0.3/ 0.2/0.15

Notes:

1. Values in table represent model average specification used for 1989/1995/2000/2010 respectively. 1989 values are representative of pool estimates.
2. RVP is annual average for the region.
3. NR is not required.
4. U.S. specifications are average of conventional and reformulated.

content. These were modeling specifications. Similar average specifications for gasoline were applied for 1995, 2000, and 2010. (See Appendix L, Sections VII-2 and VII-4.)

The NPC premised no significant degradation in quality of any product from 1989 to 1995:

- No change in the octane of a gasoline grade.
- No change in gasoline grade split.
- Leaded gasoline to be replaced by unleaded gasoline by 1995; the unleaded grade split has been estimated by the NPC for this study.
- Naphtha-jet, JP-4, to be replaced by kero-jet by 1995.
- U.S. jet fuel production to remain low sulfur compared to maximum allowed by current specifications.
- Marine bunkers to remain high sulfur fuel oil (e.g., 3.5 percent sulfur) throughout the period studied.
- No significant degradation in quality of any product from 1989 to 2000.
- No additional change of diesel or distillate quality or specifications between 1995 and 2000.
- No new petroleum fuel light products of significance between 1989 and 2010 and no product specification changes after 2000. (This assumption removed the need for cost-volume relationships to be developed for 2010.)

Demand for the U.S. regions for the future years and three demand scenarios studied are shown elsewhere in this chapter and in Appendix L. This information covers grade splits: regular, midgrade, and premium gasoline;

reformulated and oxygenated gasolines; diesel fuel; and home heating oil; etc.

Demand for propane, butane, coke, and high sulfur fuel oil were assumed variable, and dependent upon crude oil run and unit operating severity. All of these products are basically fuel. Production of these products in excess of U.S. demand were assumed to be exported. All other products were fixed at the forecast production levels established for each foundation case. As noted earlier in this section, base crude oil run was fixed for all reference cases, and the incremental crude oil was allowed to vary.

Foreign (See Appendix L, Section VII-4)

The following assumptions were considered important in establishing the foreign regional models. In all cases, specifications reflected average annual qualities.

- **Gasoline.** Clear pool octane would increase as lead is phased out of gasoline. There would be no degradation of gasoline quality over the study period and would be fixed based on the NPC survey. Aromatics were not shipped between foreign regions to satisfy octane demands. All European (including N. Africa) specifications would be uniform by 2000. Pool splits between regular and premium grades would be held constant at historical (1989) levels.
- **Kerojet.** Sulfur specification of 0.05 wt% would apply by 2000 worldwide (except the United States).
- **Distillate.** Home heating oil and automotive diesel would both have the same sulfur specification in the foreign regions by 1996. Home heating oil demand was held constant at 1989 levels. All increases in demand were to be for automotive diesel product.
- **Fuel Oil.** Residual fuels would have the same global sulfur specification. Four grades would be considered—high sulfur fuel oil at 3.5 wt% sulfur primarily used as bunker fuel, medium sulfur fuel oil at 2.0 wt% sulfur, low sulfur fuel oil at 1.0 wt% sulfur, and very low sulfur fuel oil at 0.3 wt% sulfur—and were based on sulfur ranges from the NPC survey and were held constant for the study years. Forecasts of stationary fuel oil demands by sulfur grade was based on the survey. Refer to Appendix L, Section VII-4, for a complete discussion of the procedure used in interpreting survey results to obtain product specifications for 1995 and future years.

The results of the survey were interpreted to apply only to production for foreign local demand and not for export markets. The specifications for export products were assumed to be the same as that of the importing region. Changes in local demand in the foreign regions were assumed to be met by production within the region and not be increasing imports.

The 1989 reference cases were based on EIA and International Energy Agency (IEA) historical data for imports and exports of motor gasoline (mogas), kerojet (jet), distillate (diesel and heating oil), and residual fuel oil (resid) between foreign regions, and between foreign regions and the United States. (Note: Light product refers to total motor gasoline, kerojet, and distillate, with or without chemical feedstock naphtha). These same import/export quantities were also used as the initial basis for development of the 1995 reference cases. Only individual product movements exceeding the lesser of 20 MB/D or 2 percent of exporting regional production of the individual product were included in the regional refinery model studies.

In order to balance residual fuel oil supply and optimize the regional models with respect to sulfur and conversion capacity, an estimate of global bunker oil (3.5 percent sulfur) demand was prepared by region for each year. (It should be noted that a detailed worldwide fuel oil supply/demand analysis was outside the scope of the study). Summaries of these balances for the six modeled regions are included in Appendix L, Section VII-7.

Where no movements to the United States were shown for 1989, small volumes of gaso-

line, jet, and distillate for export to the U.S. were included in all foreign regional models in order to provide LP marginal values for such production. For simplicity, oxygenate was assumed to be added only to the reformulated but not the conventional gasolines exported to the United States. Low aromatics diesel fuel and CARB Phase 2 gasoline for California were not specifically modeled in foreign regions as exports to the United States. It was felt that foreign region cost differences relative to similar federal quality products would be the same as in the United States. The logistics balance was conducted under this assumption.

Refinery production of individual products in 1989 was obtained from the EIA, supplemented by other published sources. For 1995 onwards, historical (or modified) interregional product movements then were added to, or subtracted from, regional demands to obtain actual regional refinery production requirements.

Demand for propane, butane, coke, and high sulfur fuel oil were assumed variable, and dependent upon crude oil run and unit operating severity. All other products were fixed at the future production levels established for each foundation case. Base and segregated sweet crude oil run was fixed for all reference cases, and the incremental crude oil was allowed to float, provided that the LP crude oil run and high sulfur fuel oil production were within modeling guidelines.

United States and Foreign

A summary of the interregional light product movements for 1989, based on EIA data, which were used in establishing the 1989 foreign region base cases for the LP models, is given in Table 3-44. These movements were the basis for all future years and foundation cases for product movements.

Process Plant Investment

United States and Foreign

Investment cost for process units installed before 1996 was not optimized in the refining industry capability model, but calculated external to the model for announced additions. Plant investment for 1995 was based on the unit investment costs developed by the Refinery Facilities Task Group and included in Chapter Two. For 2000 onward, investment in new facilities was optimized. New capacity was assumed added in the form of world-scale units. The major units added in the foreign regions in 2000 and 2010 are summarized in Appendix L, Section VII-7.

Refinery Stationary Emissions, Health & Safety Facility Costs

United States

Costs for emission controls on refineries as stationary sources as well as costs for compliance with health and safety regulations are discussed in Chapter Two.

Foreign

Key resources in developing foreign region environmental assessments included Expert Panel comments (January 1992); the "Government Energy Policy Analysis" paper prepared by Pace for the Foreign Subgroup (see Appendix L, Section VII-8); and estimates of U.S. environmental costs provided by the Refinery Facilities Task Group, API reported historical cost data, and NPC survey results.

The approach in generating foreign environmental costs has assumed:

- Foreign regions currently lag the United States in environmental regulations by between 5 and 20 years.
- Environmental investments borne by the U.S. refiners carry higher development costs associated with leading the effort, and foreign government participation can be expected to lessen the impact on foreign refiners.
- Foreign regions may not choose to adopt and implement as rigorous environmental regulations as the United States on existing facilities.

In Appendix L, Section VII-9, the estimated annualized environmental costs for compliance with regulations for air, water, solids, and health and safety are presented.

TABLE 3-44

1989 ESTIMATED INTERREGIONAL LIGHT PRODUCT FLOWS
(Thousand Barrels per Day)

Exporter	Importer							
	CAN	NWE	MED	LAT	PAC	Un-modeled*	U.S.	Total Exports
Gasoline								
Canada	—	—	—	—	—	—	45	45
NW Europe	20	—	20	—	—	—	60	100
Mediterranean	—	65	—	—	10	20	50	145
Middle East	—	20	5	—	55	—	35	115
Latin America	—	10	—	—	—	—	170	180
Pacific Rim	—	—	—	—	—	—	—	—
Unmodeled	—	35	—	—	40	—	10	85
United States	5	—	—	30	5	—	—	40
Total Imports	**25**	**130**	**25**	**30**	**110**	**20**	**370**	
Jet								
Canada	—	—	—	—	—	—	10	10
NW Europe	—	—	—	15	10	20	0	45
Mediterranean	—	10	—	10	10	15	10	55
Middle East	—	5	—	—	150	20	10	185
Latin America	—	—	—	—	—	—	75	75
Pacific Rim	—	—	—	—	—	—	5	5
Unmodeled	—	—	—	—	—	—	—	—
United States	5	—	—	5	15	—	—	25
Total Imports	**5**	**15**	**—**	**30**	**185**	**55**	**110**	
Distillate†								
Canada	—	—	—	—	—	—	60	60
NW Europe	—	—	15	30	—	—	20	65
Mediterranean	—	45	—	—	45	15	10	115
Middle East	—	65	25	—	175	50	5	320
Latin America	—	25	—	—	15	15	185	240
Pacific Rim	—	—	—	—	—	—	—	—
Unmodeled	—	270	90	—	30	—	10	400
United States	15	5	—	45	30	—	—	95
Total Imports	**15**	**410**	**130**	**75**	**295**	**80**	**290**	

* Unmodeled represents areas not covered in the regional models such as PRC, the former USSR, Eastern Europe and much of Africa.

† Estimated after correcting for distillate No. 4 in distillate.

Import/Export Assumptions (See Appendix L, Section VII-1)

United States and Foreign

This study has assumed that there are no transportation or handling limits in the foreign regions on their ability to ship exports to the United States. Therefore there are no increases in shipping infrastructure costs to account for any additional docks, pipelines etc. to handle increased exports to the United States.

The U.S. logistics model was set up to analyze imports of light products to the United States, not exports of products or blending components from the United States. Exports from the U.S. for this study were set at the 1989 levels.

Analysis Results

United States

General Comments on Model Results

A summary comparison of final model runs for 1989 for the six U.S. PADDs is included in Appendix L, Section VII-2. These runs matched the PADD actual volumetrics reported by the EIA as closely as practical.

The U.S. reference cases were run on a constant crude oil run and, as far as possible, light product production basis for 1995 and 2000. Other than announced changes, no new refineries nor any refinery shutdowns were premised in the modeling.

See Appendix L, Section VII-2, for light product grade splits, and proportions of oxygenated gasoline and reformulated gasoline produced in the reference case for each PADD.

The U.S. reference cases produced the same volume of total jet fuel (naphtha jet plus kerojet) as in 1989; and the same volume of total No. 2 oil (diesel fuel plus home heating oil, etc.) as in 1989. The demand for propane, butane, coke, and high sulfur fuel oil were assumed variable, and dependent upon crude oil run and unit operating severity. Both base and swing crude oil runs was fixed for all reference cases.

Model Output

The following observations are drawn from an aggregated industry model simulating annual average operation under the NPC study premises.

PADD I – NPC Regions 1, 2, 3, 4

Refineries are concentrated in New Jersey, Pennsylvania, and Delaware. Compared to national average refineries, PADD I refineries have proportionately more FCC and less coking capacity and produce more distillates and less kerojet.

1989

At the actual 1989 crude oil run, crude oil capacity is spare but conversion capacity is fully utilized. Alkylation plant utilization is limited by isobutane availability. PADD I is close to maximum gasoline production capacity.

The cost-volume relationship below 1989 crude oil run has a high slope, and a moderate slope above. The slope of the cost-volume relationship is indicative of changing refining mode as crude oil run and light product production is increased. Low slope (i.e., a cost change of up to about $0.10 per barrel for an 8 percent change in light product make) indicates little change in refinery yield structure over the volume range. High slope (i.e., a cost change of over about $0.30 per barrel for an 8 percent change in light product make) indicates a significant change in refinery yield structure; such as from coking yields to cracking yields or cracking yields to topping-reforming yields. Although FCC capacity is full above the 1989 crude oil run, the fuel oil production:crude oil run ratio is held near that of cracking mode operation by cracker feed optimization.

1995

Based on announced projects, there are minimal refinery process capacity changes from 1989 to 1995; plus some C5/C6 isomerization and MTBE capacity and minus some crude oil capacity.

At 1989 crude oil run, conversion capacity is fully utilized and gasoline production is

shifted toward RFG. The impact of RFG production is to unload FCC capacity and thus increase economic gasoline production capability.

The cost-volume relationship has a high slope throughout the volume range. The increase in environmental costs per gallon of light product is about U.S. average except for Region 4, which exhibits costs higher than average.

2000

At 1989 crude oil run, conversion capacity is fully utilized. The impact of Phase II RFG is to increase FCC utilization compared to 1995. The required refinery changes from 1995 for production of premised Phase II RFG are to add butane isomerization, TAME facilities, and gasoline component fractionation.

The cost-volume relationship has a high slope throughout the volume range. The increase in environmental costs per gallon of light product is somewhat higher than U.S. average.

PADD II – NPC Regions 5, 6, 7

Compared to national average refineries, PADD II refineries run crude oil that is somewhat lighter and lower sulfur. Compared to national average, PADD II refineries have less distillate hydrodesulfurization and produce more gasoline and less kerojet and fuel oil.

1989

At actual 1989 crude oil run, coker capacity is full but FCC capacity is spare. There is capacity to produce additional gasoline.

The cost-volume relationship has a low slope over the entire volume range modeled.

1995

Based on announced projects, there are significant refinery changes from 1989; plus distillate hydrodesulfurization, continuous catalytic regeneration reforming, FCC, alkylation, hydrogen, and MTBE capacity and also plus some crude oil capacity.

The cost-volume relationship has a low slope throughout the volume range. The increase in environmental costs per gallon of light product is about U.S. average.

2000

At 1989 crude oil run, coking capacity is fully utilized and FCC capacity is spare. The impact of increased proportion of RFG in total gasoline production is to decrease FCC utilization compared to 1995. The required refinery changes from 1995 for production of premised Phase II RFG are to add butane isomerization, TAME facilities, and gasoline component fractionation.

The cost-volume relationship has a low slope throughout the volume range. The increase in environmental costs per gallon of light product is slightly higher than U.S. average.

PADD III – NPC Region 8

PADD III refineries produce about 45 percent of U.S. light products. PADD III refineries are, on average, typical of average U.S. refinery, except they have proportionately more distillate hydrodesulfurization capacity.

1989

At actual 1989 crude oil run, some cracking capacity is spare.

The slope of cost-volume relationship is low below the 1989 crude oil run, and high above. Production of additional gasoline is relatively higher cost than additional distillate or jet.

1995

Based on announced projects, there are significant refinery changes from 1989; plus distillate hydrodesulfurization, FCC, alkylation, hydrocracking, coking, hydrogen, MTBE capacity, and some crude oil capacity.

At 1989 crude oil run, there is more spare cracking capacity than in 1989.

The slope of cost-volume relationship is moderate over the entire volume range. The increase in environmental costs per gallon of light product is about U.S. average.

2000

At the 1989 crude oil run, both cracking and coking capacity is fully utilized. The required refinery changes from 1995 for production of premised Phase II RFG are to add TAME facilities, and gasoline component fractionation capacity.

The slope of the cost-volume relationship is high below 1989 crude oil run, and moderate above. The increase in environmental costs per gallon of light product is significantly below U.S. average.

PADD IV – NPC Region 9

Compared to national average refineries, in PADD IV crude oil is lighter and lower sulfur, refineries have less conversion facilities, less hydrocracking and coking, less distillate hydrodesulfurization and reforming. PADD IV refineries produce more distillates and less kerojet and fuel oil. PADD IV cracking refineries are much smaller than in the rest of the United States.

1989

At actual 1989 crude oil run, coker capacity is full but spare FCC capacity.

The slope of the cost-volume relationship is low throughout the volume range.

1995

Based on announced projects, there are minimal refinery process capacity changes from 1989; plus some distillate hydrodesulfurization and FCC feed hydrotreating capacity.

At 1989 crude oil run, coking capacity is fully utilized and FCC capacity is spare. There is very little RFG production in PADD IV.

The slope of the cost-volume relationship is high below 1989 crude oil run (because spare coking capacity exists at this point and the incentive to fill this capacity is large); and low above. The increase in environmental costs per gallon of light product is below U.S. average.

2000

At 1989 crude oil run, coking capacity is fully utilized and FCC capacity is spare. The impact of increased proportion of RFG in total gasoline production is to increase FCC utilization compared to 1995. Even in 2000, RFG production in PADD IV is low. The required refinery changes from 1995 for production of premised Phase II RFG are to add some alkylation, TAME facilities, and gasoline component fractionation capacity.

The slope of the cost-volume relationship is low in PADD IV. The increase in environmental costs per gallon of light product is above U.S. average.

PADD V - California Sector – NPC Regions 11, 12

Compared to national average refineries, California refineries run much heavier crude oil on average and have more distillate hydrodesulfurization, hydrocracking, and coking, and less FCC capacity. California refineries produce proportionately more kerojet and fuel oil and much less distillates than U.S. average.

1989

At actual 1989 crude oil run, cracking and coking capacity is fully utilized. There is some capacity to produce additional gasoline.

The cost-volume relationship has a high slope since turndown spares cracking capacity.

1995

Based on announced projects, there are significant refinery changes from 1989; plus distillate and FCC feed hydrodesulfurization, alkylation, conversion facilities (FCC, hydrocracking, and coking), hydrogen and MTBE capacity and less crude oil capacity.

At the 1989 crude oil run, both cracking and coking capacity is fully utilized.

The slope of the cost-volume relationship is moderate to low over the volume range modeled. The increase in environmental costs per gallon of light product is about U.S. average.

2000

At the 1989 crude oil run, both cracking and coking capacity is fully utilized. The required

refinery changes from 1995 for production of California Phase 2 RFG are extensive.

The slope of the cost-volume relationship is high throughout the volume range because of the cost of making California's reformulated products.

The increase in environmental costs per gallon of light product is slightly higher than U.S. average.

PADD V - Non-California Sector – NPC Regions 10, 13

Compared to national average, PADD V non-California refineries run heavier crude oil and have less processing downstream of the crude oil units. They have proportionately more hydrocracking and less FCC; produce much more kerojet and much less gasoline, and produce more fuel oil.

The non-California part of PADD V has a high portion of refineries with unique processing, e.g., several refineries with hydrocracking but without FCC units, a cracking refinery without a reformer, and refineries producing primarily straight run jet fuels and distillates. There are also a high portion of geographically isolated refineries, i.e., those in Alaska and Hawaii.

1989

Conversion capacity is completely utilized.

Incremental/decremental crude oil run gives topping mode type of yields.

Cost-volume relationship is very flat throughout the volume range.

1995

Based on announced projects, there are significant refinery process capacity changes from 1989 including plus distillate hydrodesulfurization, continuous catalytic regeneration reforming, cracking facilities, hydrogen, and MTBE capacity as well as some plus crude oil capacity.

The increase in environmental costs per gallon of light product is higher than U.S. average.

At the 1989 crude oil run, PADD V - non-California refineries continue to have conversion facilities completely utilized.

The slope of the cost-volume relationship for the PADD V - non-California refinery regions is high because of insufficient process facilities downstream of the crude oil units to produce the required proportions of gasoline and jet fuel.

2000

Since very little RFG is produced in PADD V refineries outside of California, new process facilities are not required. Therefore, in the decreasing or no growth demand cases, the 1995 cost-volume relationships are also used for 2000.

The increase in environmental costs per gallon of light product is higher than U.S. average.

In an increasing demand case, the model finds it economic to add a conversion project (FCC unit and FCC feed hydrotreating plus associated alkylation and ether production) to convert FCC feed currently going to fuel oil in the model into additional light products. Given the wide geographic spread and unique features of these refineries, it is not clear that this potential FCC feed is available at a suitable location. In this case the slope of the costvolume relationship for the PADD V - non-California refinery regions is high.

Foreign

General Comments on the Model Results

In any modeling study, it is important to maintain a consistent methodology from case to case. Hence the models were calibrated against 1989 actual results, which set certain key parameters for all subsequent runs.

Because the six foreign regional models represent an aggregation of many individual refineries that are geographically separated and diverse in their capabilities, it was necessary to apply certain constraints to ensure reasonableness of results.

A discussion of specific constraints and assumptions follows.

- **High Sulfur Fuel Oil Production.** High sulfur fuel oil production was constrained for most regions and years to a level similar to the local demand forecast, since high sulfur fuel oil was assumed to be demand limited. Without this constraint where spare crude oil distillation capacity was available in any given region, the LP solution would have been to use incremental swing crude oil in a topping mode to produce the required distillate, resulting in the production of high sulfur fuel oil that exceeded forecast demand, and lower gasoline marginal values.
- **Investment Cases (2000 and 2010 Only).** LP cases for volumes above the reference U.S. light product export level were run at fixed reference high sulfur fuel oil production volume in order to avoid a situation where incremental crude oil was processed in a topping mode to produce the required incremental light products. With this constraint the LP solution reflected investment in residue destruction. The NPC believes that this constraint provided a more realistic result, in as much as there is a need for a global balancing of high sulfur fuel oil production.
- **Sweet Crude Oil Segregation.** In order to meet the increasing demand for low sulfur fuel oil, it was necessary (except for the Middle East) to segregate up to 50 percent of low sulfur crude oil components in the base crude oil mixture. This was done even for the 1989 base year to match low sulfur fuel oil production with demand. It was not considered appropriate in the foreign regional models to segregate all of the low sulfur crude oil, since this would represent a significant overoptimization of the regional model concept. In three regions, Canada, Mediterranean, and Latin America, even with a 50 percent segregation of sweet or low sulfur crude oil, it was not possible to match the demand for low sulfur fuel oil without generating unrealistically high marginal values for distillate product. This was due to the model blending distillate to fuel oil to meet fuel oil sulfur limits. In these three regions the sulfur specifications for low and medium sulfur fuel oil grades were relaxed to 2 wt% and 2.5 wt%, respectively. Results were checked in off-line calculations to validate that there was sufficient low sulfur crude oil in the base mix for that region in order that actual specifications (and not the relaxed LP specifications) could be achieved.
- **Atmospheric Residue Distillation Cut Point.** The LP utilized constant cut points for both atmospheric and vacuum distillation for all years. The cut point varied region by region based on estimated operating practices.
- **Export of Light Products to the United States.** The 1989 models were developed to reproduce actual export volumes of motor gasoline, kerojet, and distillate (light products) from foreign regions to the United States. In the foreign regions, capacity was added in 2000 and 2010 to meet local demand, and to maintain U.S. light product exports and interregional movements at their 1989 levels.

Model Output

Specific results of the LP modeling studies for each region and comments regarding unique regional features are listed below. The comments apply to all foundation cases.

A summary comparison of final LP model runs for the six foreign regions is included in Appendix L, Section VII-7. These summaries present a comparative tabulation of pertinent data taken from the LP reports generated for the study. The tables compare the changes in crude oil capacity, use of swing crude oil, light product production for export and local demand, conversion capacity, additional processing requirements for future years, and key marginal values for each region's production. Cost comparisons are on an F.O.B. basis at the point of manufacture.

Canada

- Small increase in local light product demand.
- Highest percentage of gasoline production of any foreign region.
- Minimal process unit investment to meet future assumed local demand.
- Spare crude oil distillation capacity through 2010.
- Refinery operation limited by production of low pour point distillates, which required lower than typical atmospheric residue distillation cut points.

With low transportation costs to the United States and the phase-out of the import duty of 52.5 cents per barrel of fuel product in 1993, Canada is a viable source for additional U.S. quality petroleum products and also a possible outlet for product flows from the United States. There may be economic incentive for export of an increased quantity of gasoline and higher pour distillate components to the United States.

Northwest Europe

- Small growth in local light product demand.
- High local demand for distillate.
- Relatively low process unit investment in future years reflects the higher quality gasoline and diesel already produced in the region.
- Spare crude oil capacity through 2010.
- Increasingly severe product specifications are seen in the region. The region is constrained by octane demand.

Mediterranean

- Small growth rate in local light product demand.
- Highest percentage of distillate demand of any foreign region.
- Low process unit investment while greater than Northwest Europe, again reflects prior investment to meet high quality gasoline and automotive diesel oil requirements. Year 2000 model shows that added atmospheric residue desulfurization is required to meet the low/medium sulfur fuel oil demand, due to low sulfur fuel oil constraints. Refinery operation generally limited by gasoline production. High unit cost of meeting restrictive environmental requirements.

Middle East

- High growth rate in local light product demand, but absolute demand is relatively small.
- High distillate local demand.
- Additional crude oil distillation not required before 2010 to meet local demand and historical export levels.
- High investment to meet distillate and local gasoline demand. Residual desulfurizing needed to meet low/medium sulfur fuel oil demand.
- Highest percentage of kerojet demand for any region primarily due to large export volumes. Increasingly restrictive product specifications. Refinery operation generally limited by kerojet and distillate production.

Products from this region have been traditionally low cost reflecting the fact that refineries have operated incrementally with local crude oil. The incremental products have been supplied into the spot market to meet seasonal swings and local shortages. In some cases refined products are sold as higher value alternatives to incremental crude oil sales. The model showed that, based on 1989 costs with reduced worldwide demand for high sulfur fuel oil, the region has to invest heavily in conversion capacity, in order to maintain high sulfur fuel oil balance globally. Additionally more restrictive specifications for sulfur cause heavy investment in desulfurizing capacity. These investments result in large increases in product costs for future years.

Latin America

- High regional demand for light products in all case scenarios.
- Second highest percentage of gasoline in the foreign regions.
- High process unit investment to meet gasoline demand and the quality improvements required for gasoline and distillate.
- Crude oil distillation capacity required by 2010 under high growth scenario.
- Increasingly restrictive product specifications, led by Mexican environmental regulations. Refinery operations are maximized to produce gasoline.

This region historically has been the most attractive supply source for U.S. light products. The assumed large rate of increase in local light product demand, coupled with the increasingly stringent requirements for product specifications, make the region's product costs increase significantly.

Pacific Rim

- Largest percentage of increase in light product demand of all regions.
- High demand for distillate and a high percentage of kerojet in the product mix.
- Largest regional unit investment in conversion capability as light product increases without increases in high sulfur fuel oil demand. Extensive use of residue destruction to reduce high sulfur fuel oil production.
- Crude oil distillation capacity is needed by 2010 in all scenarios.
- Widest variation in product specifications, with specifications for developed countries approaching or exceeding those of the United States, and less developed countries selectively implementing specifications for gasoline and automotive diesel. Refinery operations are maximized for kerojet production to meet demand (followed by distillate). Anticipated automotive diesel production costs are higher than gasolines.

With the highest rate of increase in local light product demand, and limited capital availability, the region is assumed to remain a net importer through 2010. The refining economics improved with increased chemical naphtha demand in 1995. Recovery of the large investment will increase the cost of all light products. The study for 2000 and 2010 indicates a strong incentive to convert existing, or install new, gas oil hydrocrackers designed to operate in the maximum distillate production mode.

Exports from the United States (See Appendix L, Section VII-1)

The NPC concluded that it was reasonable to assume that exports from the United States would not change dramatically from historical levels. In Table 3-45, exports for the past ten years are summarized. It will be noted that individual years showed large variations in movement that can be rationalized on the basis of political or climatic swings, but there is no discernible trend for either growth or reduction in exports from the United States.

Issues

Issue cases were evaluated by the NPC in analyzing the refining models and their relationships to the costs and availability of product supply. They are briefly summarized here and detailed in Appendix L, Section VII-1.

- The refining industry in each foreign region was represented in the Pace model as a single, fully integrated refinery. This inherently leads to some overoptimization, as the model presumes the ability for free flow of intermediate streams between refineries to maximize utilization of available conversion unit capacity. In the real world, however, logistics, national boundaries, structural limitations, freight economics, local product needs, etc., often inhibit such flows. To assess the potential economic effect of such overoptimization, utilization of conversion capacity was downrated from 100 percent to the

TABLE 3-45

SUMMARY OF HISTORICAL U.S. EXPORTS TO FOREIGN REGIONS
TOTAL LIGHT PRODUCTS
(Thousand Barrels per Day)

Exports	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992
Pacific Rim	26	27	18	22	54	57	50	54	60	98	125
Latin America	38	19	21	25	42	37	43	75	74	131	158
Canada	0	9	22	18	27	21	21	25	25	19	18
NW Europe	25	17	0	14	22	5	1	4	32	64	30
Mediterranean	10	6	3	10	7	5	1	2	16	13	6
Other Countries	2	3	2	1	1	1	3	5	7	17	28
World	101	81	66	91	152	126	120	165	213	343	365
Imports-From Worldwide	332	463	645	628	643	723	813	788	733	581	601
Net Imports-Worldwide	231	382	579	537	491	597	693	623	520	238	236

Notes:
1. Source of data—EIA published (see Appendix L, Section VII-11).
2. Totals may not equal sum of components due to independent rounding.
3. Data include No. 4 fuel oil in distillate.

80 percent (Pacific Rim) to 90 percent (Mediterranean and Latin America) range, as these regions were expected to show the greatest impact.

Comparing the impact of such overoptimization in the forward years vs. the impact of this same optimization in 1989, indicated that it might have resulted in underestimating the true cost by up to 0.3 cpg in the Mediterranean and Latin America, which was not enough to materially impact the level of U.S. imports from these areas. In the Pacific Rim, this cost would have increased by up to 1.0 cpg. However, as the Pacific Rim cost was adjusted to be at parity with the Middle East import costs to the United States as a premise of this study, this would not have altered the level of imports to the United States from this region either.

The effects of overoptimization in the other foreign regions and the U.S. regions would have been a much lower level, and in addition to have essentially the same level of overoptimization in the forward years as they did in the 1989 base year. This reflects generally better integration of refineries and smaller geographic areas than the regions tested.

- Use of 1989 product prices for all years, particularly the approximately $2 per barrel spread between crude oil and heavy fuel oil (high sulfur fuel oil), may not be reflective of future scenarios that are characterized by a lighter demand barrel than 1989. This is evidenced by announced construction of new fuel oil to light product conversion facilities that would not be justified by 1989 price differentials. The effect of using 1991-92 pricing differentials of about $4 per barrel between crude oil and high sulfur fuel oil was tested for selected foreign regions where it was judged its impact on regional costs would be most sensitive. While the larger cost differential would have resulted in increased residue conversion capacity being built, it is estimated

that the resulting effective costs of the average import product mix would have increased on the order of 0.5 cpg from Latin America, the Pacific Rim, and by extension, the Middle East. Cost increase of this magnitude would not be expected to have significant impact on the overall level of U.S. imports.

- The reference cases and cost-volume relationships have all been developed on the assumption that there will be no change in allowable bunker fuel sulfur levels. However, there have been proposals made in some quarters (e.g., International Maritime Organization) for global reductions in bunker fuel sulfur levels. If adopted, this would tend to reduce markets for high sulfur fuel oil and reduce value of high sulfur fuel oil relative to light products and crude oil. This would be expected to lead to higher cost light products than the high sulfur fuel oil price sensitivity discussed above, with the magnitude of this cost depending on the extent and severity of such a bunker fuel sulfur reduction.

- Because adequate distillate desulfurizing capacity is already in place, a smaller reduction in European sulfur levels by 2000 for home heating oil than assumed in the study did not appear to significantly affect the cost of potential distillate products to the U.S. based on the methodology used in the study.

- Less restrictive specifications in aromatics and benzene levels in the foreign regions than assumed in the study were analyzed by reference to the foreign model LP incentives. The effect of such reductions was not expected to impact the cost of potential exports to the United States.

- Under the proposed NAFTA agreement it is economically attractive to import oxygenates and possibly other light product blending components into Canada, blend them into finished products, export the finished product to the United States, and avoid current U.S. tariffs on the oxygenate component. Under Foundation Case I in the year 2000, the Logistics Model demonstrates this economic advantage by importing 3,000 barrels per day of MTBE oxygenated gasoline to the United States without any duty assessed. If the MTBE had been imported directly into the United States and then blended with imported Canadian gasoline, duties would have been collected on the imported MTBE. Although tariff avoidance is not in the spirit of the proposed NAFTA, current wording does not specifically prohibit this practice. From a practical perspective, should this practice become prevalent, there is a likelihood that changes would be sought to the agreement to prohibit the practice.

- The United States, and to a greater extent California, plan to implement by 2000 stringent product specifications due to environmental concerns. Although other countries are also instituting more stringent product specifications, i.e., unleaded and lower VOC gasolines, and lower sulfur distillates and fuel oil, these countries may not adopt the complex reformulated fuels proposed for the United States. In this circumstance, the United States would have a unique set of stringent product specifications. This would place the U.S. product supplies at risk in the event of a supply disruption, whether due to political, natural, or operational causes.

- There was no analysis of the financial ability of foreign refineries to meet regulatory costs. In some cases, the situation could be similar to that projected for U.S. refineries.

COST OF U.S. AND FOREIGN PRODUCED PRODUCTS

Introduction

This section outlines the methodology and output generated that describe the cost changes associated with producing incremental U.S. quality products in each region to satisfy the future demand scenarios. A similar procedure was used for both the U.S. PADD and six

foreign regions based on the refining models described earlier.

Approach

As a starting point for this work, published product prices for 1989 for each PADD and foreign region were established as the reference price (see Appendix L, Section IV-2). This assumed that in 1989 the logistics system was in balance. The fundamental assumption of the logistics study is that the factors that resulted in the 1989 balance (e.g., tariffs, quotas, embargoes, etc.) remain the same through the study years. Therefore the product supply changes are driven by relative cost changes from region to region. All differences in costs from the reference value are a result of changes in the logistics systems or the cost of product supply (noted in this section) and are built into the logistics model.

In this study, it has been assumed that light products (MJDN), representing 70 percent of U.S. refining output, and the bulk of the product traded in world markets, are the products affecting the drivers in the logistics model. Residual products are not significant to U.S. refining since they represent less than 7 percent of the output (based on crude oil intake).

In describing the generation of cost-volume relationships, the following definitions will be used in this text and the Appendices. All grades of gasoline are described by M (Mogas); all grades of jet fuel, including naphtha jet, and kerosene by J (Jet); and all distillates, on- and off-highway diesel, home heating oil, and No. 2 oil by D (distillate). N describes naphtha produced for petrochemical feedstock. MJDN defines the sum of those components.

In the cost buildup work every new investment was assumed to garner a return. Investment costs were included using a ten percent real rate of return.

Costs were expressed in 1990 U.S. dollars. Published price data from 1989 were adjusted to 1990 values using the GDP deflator (1.045) (see Appendix L, Section IV-3).

Structural Costs

As the study moved forward from the 1989 reference year, there were cost changes associated with changes in processing facilities and operations to meet product quality and volume, and changes in facilities to meet health, safety, and environmental requirements.

These cost changes were significant in magnitude, location, and time frame. To illustrate this, Figures 3-6 and 3-7 depict these structural cost changes for reformulated gasoline for Foundation Case I and on-highway diesel for Foundation Case I, respectively, for representative areas. The development of these structural cost changes is described below and the actual structural cost layering for all products is detailed in Appendix L, Section VIII-1.

As indicated in Table 3-46, 1989 published prices were used as a starting point for the analysis. These prices were adjusted to 1989 Reference Values to create a value structure that provided product flows in a model context that met 1989 EIA reported conditions. More detail is available on this subject elsewhere in this chapter.

In Table 3-46, future cost changes associated with structural component changes for each product are defined. The approach was the same for each product and each region. PADD III on-highway diesel costs are shown as illustrative of the cost buildup structure. The following expands on the description in Table 3-46.

- "A" represents process related capital amortization and fixed operating costs.
- "AA" is the specific capital investment charge assignable to a specific product requiring additional capital investment and fixed operating costs to meet new specification requirements—e.g., low sulfur automotive diesel. This is in addition to A.
- "B" represents the cost changes associated with additional health, safety, and environmental requirements in a refining region. These include capital, one-time expenses, and operating costs.

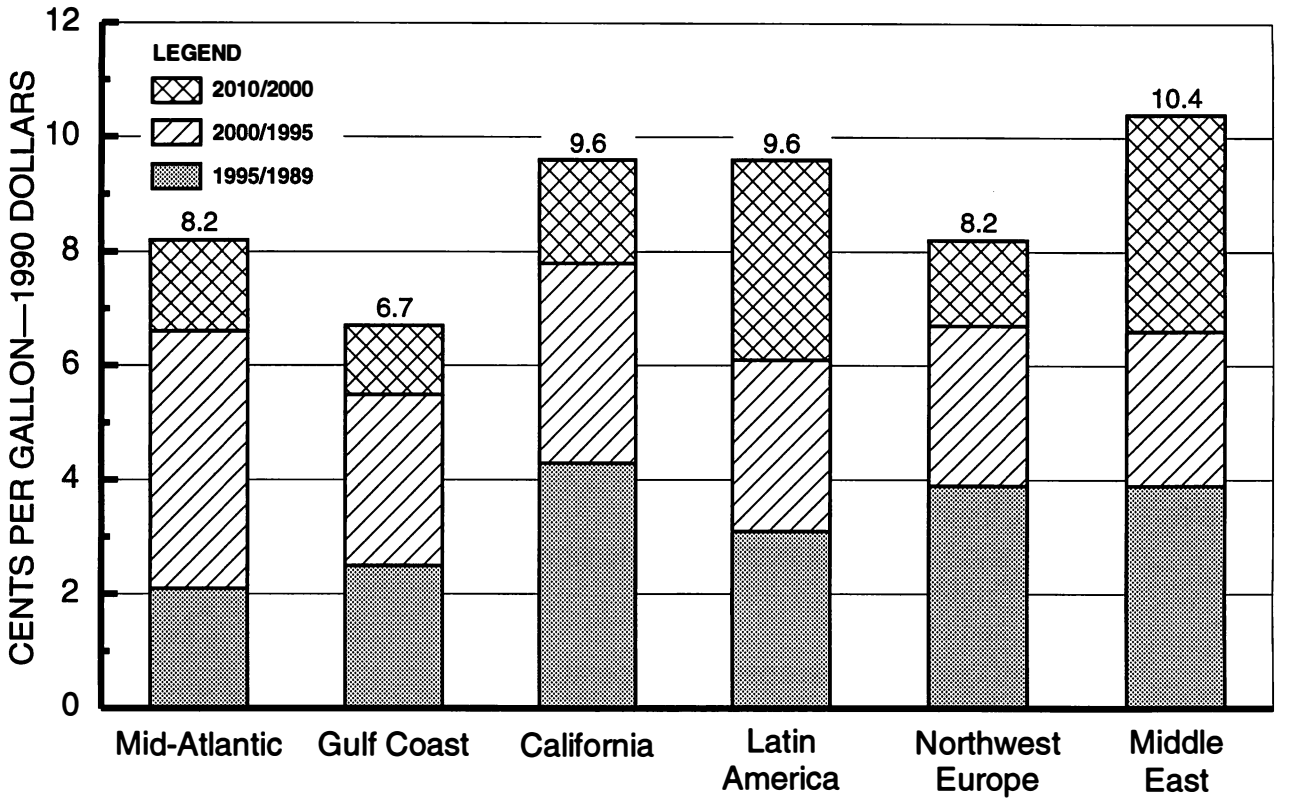


Figure 3-6. Regional Cost Increase
Reformulated Motor Gasoline Ex Oxygenate—1989 to 2010.

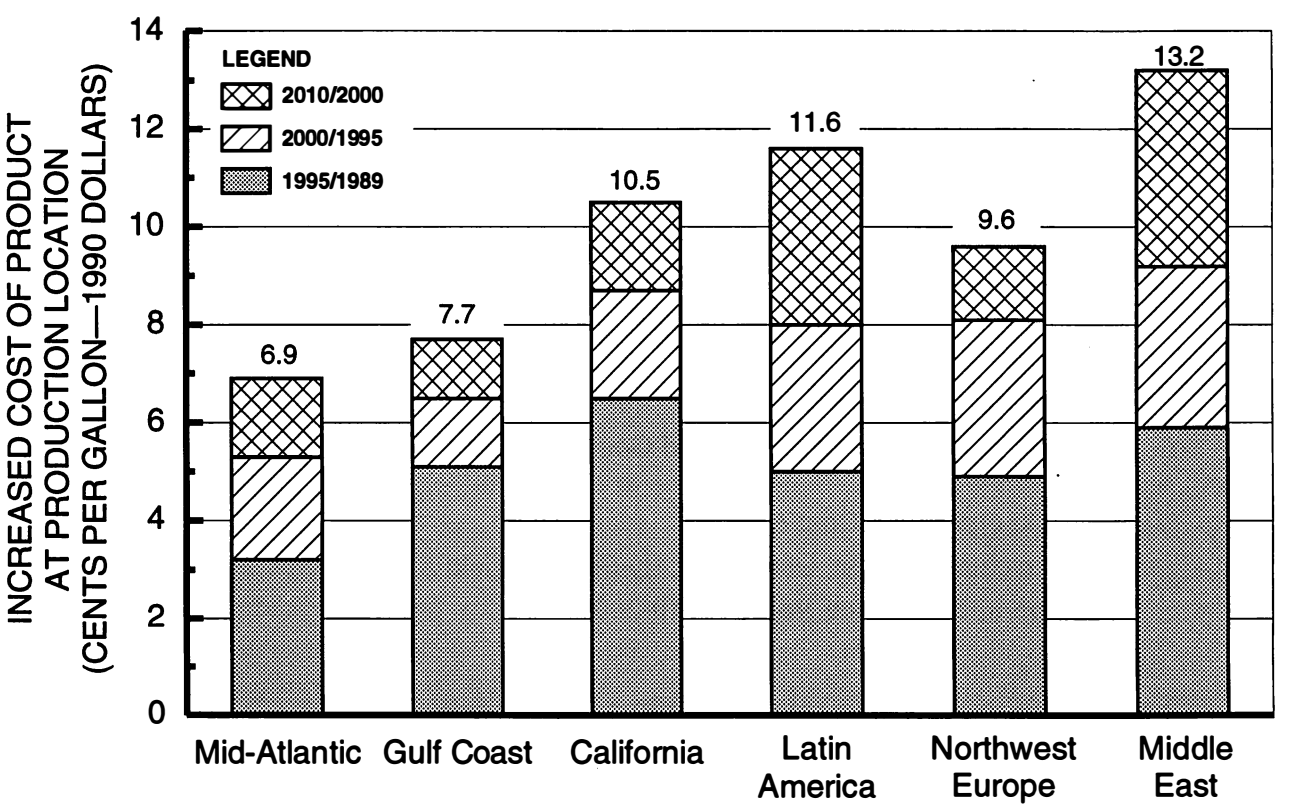


Figure 3-7. Regional Cost Increase
On-Highway Diesel Fuel—1989 to 2010.

TABLE 3-46

STRUCTURAL PRODUCT COST BUILDUP

		Row Designation	On-Highway Diesel Fuel PADD III cpg in 1990 Dollars
1989:	Published Price	V	54.26
	Scaling Factor	S	0
	Reference Value*	**W**	**54.26**
1995:	Process Related Capital Cost Δ	A (AA)	0.85 (0.85)
	Fixed and Related (Maintenance, Manpower, Property Tax, ...)		
	Environmental Cost Δ	B	2.70
	Capital; One-Time Expense; and Operating and Maintenance		
	Variable Operating Cost Δ	C (CC)	-0.34 (1.00)
	Chemicals, Catalyst, Utilities, ...; By-Product Yield Δ		
	Change in Reference Value (1995-1989)	**X**	**5.06**
2000:	Process Related Capital Cost Δ	D (DD)	0 (0)
	Fixed and Related (Maintenance, Manpower, Property Tax, ...)		
	Environmental Cost Δ	E	1.43
	Capital; One-Time Expense; and Operating and Maintenance		
	Variable Operating Cost Δ	F (FF)	0 (0)
	Chemicals, Catalyst, Utilities, ...; By-Product Yield Δ		
	Change in Reference Value (2000-1995)	**Y**	**1.43**
2010:	Process Related Capital Cost Δ	H (HH)	0 (0)
	Fixed and Related (Maintenance, Manpower, Property Tax, ...)		
	Environmental Cost Δ	I	1.23
	Capital; One-Time Expense; and Operating and Maintenance		
	Variable Operating Cost Δ	J (JJ)	0 (0)
	Chemicals, Catalyst, Utilities, ...; By-Product Yield Δ		
	Change in Reference Value (2010-2000)	**Z**	**1.23**

* See section of this chapter entitled The NPC Logistics Model.

Note: ( ) indicates cost changes assignable to specific products (see text).

- "C" represents the changes in process related variable operating costs such as feedstock costs, by-product costs, chemicals, catalyst, etc.
- "CC" represents the specific process related variable operating cost changes associated with given product such as low sulfur diesel.
- "X" is the total cost change for the time period 1989-1995.

Similar factors were generated for the 1995-2000 (D, DD, E, F, FF, Y) and 2000-2010 (H, HH, I, J, JJ, Z) time frames as indicated in Table 3-46 (see Appendix L, Section VIII-2).

The development of the specific cost changes for each category (A, B, C, etc.) for each time period was carried out by assessing the total cost in changes for the category from 1989 to the target years (1995, 2000, and 2010). The change in cost for the prior period(s) was then subtracted to remove the possibility of double counting. The cost changes apply to all light products except in the defined special cases (AA, CC, etc.).

The 1995 costs for both U.S. and foreign refineries were established using announced changes in facilities. For 2000 and 2010, foreign region processing capacity was added in a fashion consistent with regional demand projections. No additional processing capacity was necessary in the U.S. to meet 2000 demand projections. U.S. processing capacity was held at 2000 levels in 2010.

In establishing the layered factors for adjusting product values for future years, one additional factor was added to the buildup for the Pacific Rim products only. It is not shown in Table 3-46, but appears as "Other Costs" in Appendix L, Section VIII-2. This factor brings the product values in the Pacific Rim back to parity with the Middle East for future years. It was applied in the belief that not only is there a net import of Middle East products to the Pacific Rim in 1989, but, due to continued high growth in the region, this shortfall would continue for future years, and that the product value in the Pacific Rim should reflect the netback value from its principal supplier.

Cost-Volume Relationships

In this description, the notation "reference point" is used. For foreign regions, the reference point is the light product demand for the region consistent with the Foundation Case being evaluated plus 1989 exports from the region. The "reference point" for the U.S. cost-volume relationships in 1989 was established by matching actual PADD crude oil runs with refinery production. In the 1995 and 2000 U.S. reference cases, the same volume of crude oil as in 1989 was run. The 2000 results were used for 2010 in the U.S. analysis. Both foreign and U.S. refining models were modified to include announced process facility changes. The "reference point" is the anchor point for developing the cost-volume relationship that permits volume balancing in the logistics model described earlier in this chapter. The balancing in the logistics model was accomplished without changing the refining facilities in the region from the "reference point" configuration.

The cost-volume relationships were developed by starting at the "reference point" volume for the region. Using the regional models, the volume of light products was varied over a specified range. That range was established using different parameters for the domestic and foreign regions.

U.S. cost-volume relationships were developed by adjusting operations both above and below the "reference point." This was done because there is estimated to be more U.S. capability available at the 1995 and 2000 "reference point." The U.S. 2010 cost-volume relationship was assumed to be equal to that of 2000. Costs are higher above the "reference point" and lower below.

Foreign cost-volume relationships for 1995 were established using the same approaches in the United States. As the volume of product was increased from the "reference point," foreign refining capacity was added (in years 2000 and 2010) to satisfy demand. Consequently this additional product had a higher cost than at the reference point. Similarly, as volumes were reduced below the "reference point" foreign processing facilities were used

more effectively lowering cost below reference point levels.

Figure 3-8 depicts light product cost-volume relationship for PADD III in 1995 and Figure 3-9 illustrates the Latin America case for 1995 (Foundation Case I). Appendix L, Section VIII-3, contains all the cost-volume relationships used in the study. If Figures 3-8 and 3-9 are compared with Figures 3-6 and 3-7, it can be seen that the relative change in cost associated with changing light product volumes is small compared to the cost change associated with structural factors.

For each cost-volume relationship, prime (M', J', D') cases were developed to reflect the value of increasing the manufacture of one product while keeping the total MJD production constant and with the secondary products in the same volumetric ratio as in the base (reference) case. The development of these additional relationships is described in the contractor's report (Appendix L, Section VII-2) and was used as an input to the logistics model as MJD pool with a new MJD ratio. Values of M', J', and D' for foreign regions are summarized for each modeled case in Appendix L, Section VII-8. It should be noted that the prime cases represent non-optimal LP solutions and result in higher product value for the prime product but with lower secondary product values. However, typically the overall value of the total MJD pool increases for M' cases and decreases for D' cases.

J' and D' were allowed to extend by 5 to 10 percent beyond the range of the cost-volume relationship at the expense of gasoline. This was allowed in certain foreign and domestic regions to determine if low limits on mid-range products had artificially constrained the logistics model to suboptimal limits. The need for relaxation on J' and D' recognized that gasoline was not the major growth product in most regions.

Each cost-volume relationship developed has a back-up spreadsheet calculation that shows how the values are derived. These values were adjusted to estimate the effect of small differences in individual product volumes. This permitted balancing of individual product needs in the logistics model runs used for estimating costs associated with individual product volume adjustments. Details of the methodology are included in Appendix L, Section VII-2.

New Capacity

There was a concern that the cost-volume relationships for U.S. light products would not cover the range of demand in some Foundation Case scenarios. Therefore, an option to build additional capacity to meet this possibility in 2000 and 2010 was included. No such option was provided for 1995 because only announced additions were used in the analyses.

In the United States, it was assumed that in 2000 and 2010 no investment would be needed until all conversion capacity was fully committed. Beyond that point, a cost of $6.15 per barrel was added to the cost-volume relationship, representing the operating and recovery costs for new conversion capacity (assumed to be a delayed coker complex). (See Appendix L, Section VIII-3.)

Foreign regions were treated in a similar fashion to the United States. However, in order to meet 2000 and 2010 foreign demands, it was generally necessary to construct new capacity. Consequently, the cost of new capacity was required for added incremental volume above the high end of the cost-volume relationship. A limited number of evaluations were made (Latin America and Pacific Rim). In 2000, the range of cost increase for new capacity was $1 to $1.50 per barrel. For 2010, the range was between $2 and $3 per barrel. (See Appendix L, Section VIII-1.)

Other Costs

Light product structural costs and cost-volume relationship costs are exclusive of oxygenates and based solely on hydrocarbon components. This approach was necessary since the logistics model was designed to utilize the lowest cost source of oxygenate in each region. Therefore all refinery produced MTBE and TAME (as MTBE equivalent on an oxygen basis) was backed out of gasoline in the domestic and foreign region cost treatment of U.S. quality

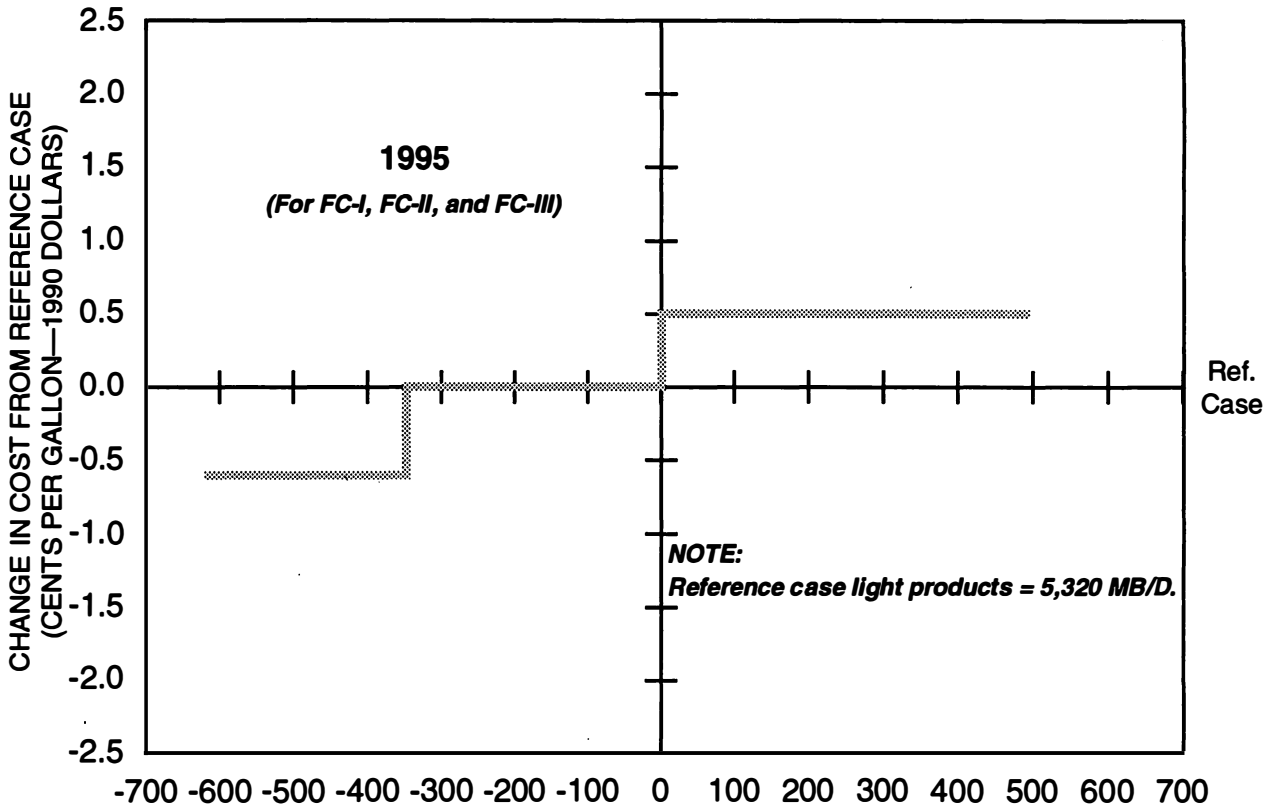


Figure 3-8. Cost-Volume Relationship—PADD III (1995).

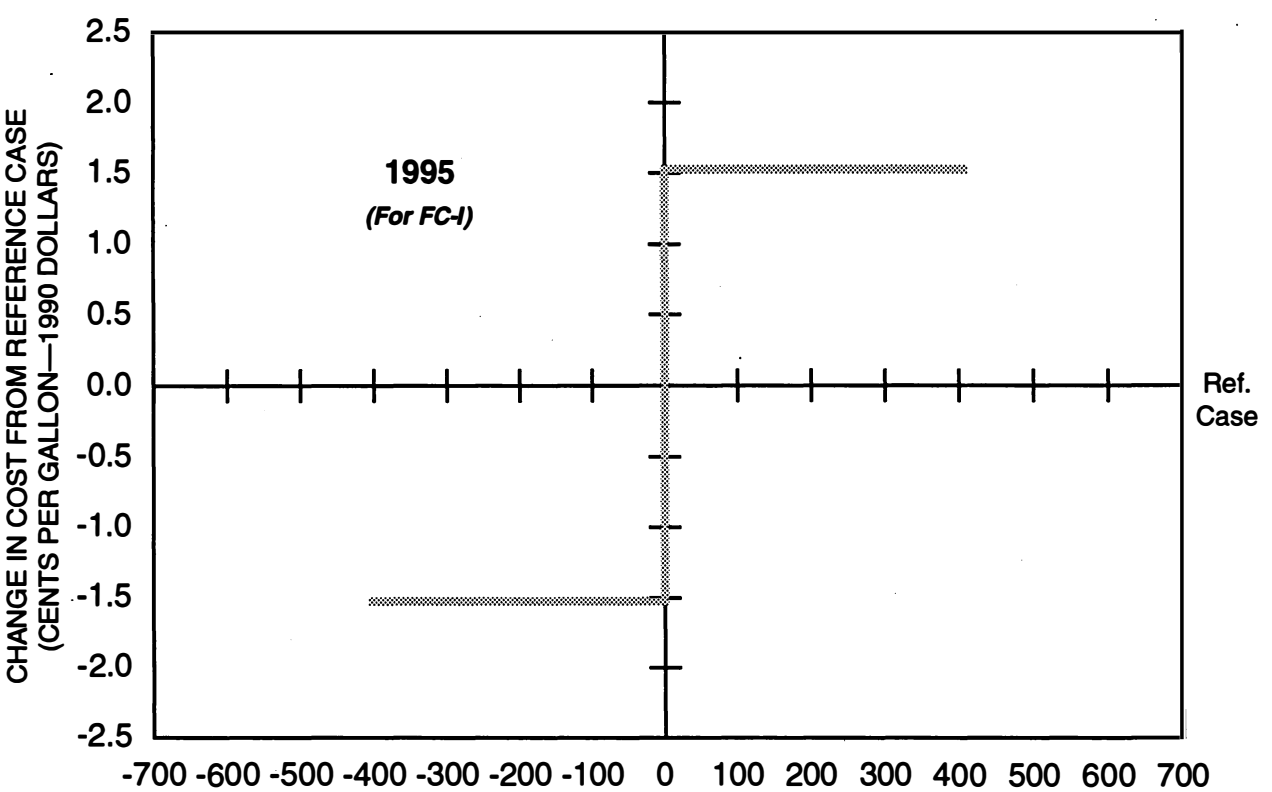


Figure 3-9. Cost-Volume Relationship—
Latin America Foundation Case I (1995).

product. All purchased MTBE is included in input cost where necessary to make oxygenate containing gasoline for local foreign markets when there is insufficient refinery-produced MTBE available. Since MTBE is also an octane enhancer, the back-out for U.S. quality material lowers pool octane.

Issues

With all the announced capacity included in the Pacific Rim regional model for 1995, this region still required imports to balance demands under all foundation cases. Should all announced capacity increases not be realized, as a result of financial or other constraints, the Pacific Rim regional demand balance would be satisfied by greater imports from those regions supplying products. This would raise the cost of products to be imported to the United States because refineries would operate in higher cost modes to produce the demand volume. Conversely more added Pacific Rim capacity would lower the cost of imports to the United States. Additional capacity would be spurred by higher product values within the region, driven by increasing demand. The effects of this type of scenario on the logistics model were not examined.

Documentation

The Pace reports for the domestic and foreign regional models are included in Appendix L, Section VII-2. The reports include cost-volume relationships, individual product cost differentials supporting spreadsheet calculations, explanation of relationship patterns, tabulations of unit capacities for the regions in 1989 and 1995, and supporting volume and specification material.

FOUNDATION CASE FINDINGS

Introduction

In order to evaluate more global issues such as the viability of U.S. refineries over the next 20 years, a series of Foundation Case studies were conducted. The purpose of these studies was to identify the potential for directional change in the U.S. oil product supply pattern. In a strategic planning setting, what is presented here should be considered as a starting point. The reader is encouraged to consider his own opinions concerning the bases that are used in determining the study results and evaluate their impact on the output.

Of necessity, the primary report discussion of the Foundation Case studies reverts to summary data and use of relevant examples. The entire output from the various analyses can be found in Appendix L, Section IX-1, and Working Paper 3.IX-1. The reader is encouraged to take the opportunity to review these detailed materials before accepting or rejecting the trends and observations that are presented.

The views that are held by the NPC study participants concerning the Foundation Case studies are based on the primary assumption that there are no major aberrations in the way in which oil product flows are accommodated in the future relative to the past situation. A major assumption is that the world oil product flows were balanced in 1989 and that the relevant philosophies in place then would continue into the future. Consequently, published 1989 oil product prices were used as a starting point. Anticipated cost changes were incorporated to reflect future economic conditions. At one point, the study participants observed that with the assumptions laid out in the orderly fashion required for a complete supply, demand, and logistics exercise such as the Foundation Case studies, the directional trends are obvious without the use of a logistics model. Therefore, one can view the Foundation Case studies output as verification of logical estimation techniques.

Bases

These studies were carried out using the logistics model discussed earlier in this chapter. There are a great number of specific assumptions that provide part of the underpinning for a complex analysis such as that completed in the Foundation Case studies. Product specifications, refinery capability, regulation impacting U.S. oil product imports, regulation impacting product quality requirements, and regulations affecting refinery and logistics system configurations are a few of the basic factors that have an effect on the outcome of this effort. These input factors relate to the cost of

supplying oil products to the U.S. market. The Foundation Case studies include analyses that show the impact of relative cost variability.

Perhaps the most important factor that will affect the U.S. refinery complex is U.S. oil product demand. As indicated earlier in this chapter, the NPC developed three Foundation Case projections to use as demand platforms for analysis of various issues. The three Foundation Case demand profiles are summarized in Table 3-47. As was also indicated earlier, none of the demand profiles is an NPC projection. Foundation Case I is a depiction in which future U.S. demand grows. Foundation Case II is a view where there is no U.S. demand growth. Finally, Foundation Case III is a future with declining U.S. oil demand.

Another significant input assumption is the one that depicts the extent to which reformulated motor gasoline will be utilized in the United States in response to the 1990 Clean Air Act Amendments. The assumptions used throughout this study concerning this factor are (1) minimum use in 1995 and (2) maximum use as permitted by the 1990 CAAA in 2000 and 2010.

The impact of these assumptions on the need for oxygenate is discussed elsewhere in this chapter. These assumptions also directly impact the estimated utilization of U.S. refineries in the Foundation Case studies. In 1995, about 300 thousand barrels per day of oxygenate is added to the U.S. motor gasoline pool. This reduces the need for production of "hydrocarbon" motor gasoline (motor gasoline without the oxygenate required by the CAAA assumptions) by essentially the same amount. Relative to 1989, U.S. refinery light product output under the 1995 reformulated motor gasoline conditions assumed in this study would be reduced about 3 percent assuming all of the oxygenate is supplied from outside the U.S. refinery complex. The assessment of supply indicates that about one third of 1995 supply is expected from U.S. refineries. The refinery oxygenate output is not expected to increase significantly beyond 1995. However, the 2000 and 2010 reformulated motor gasoline penetration assumption adds another 300 thousand barrels per day of oxygenate input, further reducing the need for "hydrocarbon" motor gasoline from the demand projection indicated for each Foundation Case.

TABLE 3-47

TOTAL WORLD OIL DEMAND
(Millions of Barrels per Day)

	1989	1995			2000			2010		
		FC-I	FC-II	FC-III	FC-I	FC-II	FC-III	FC-I	FC-II	FC-III
United States										
Light Products*	12.0	12.1	11.9	11.8	12.8	11.9	11.4	14.2	11.9	10.3
Other Products	5.3	5.2	5.2	5.2	5.7	5.2	4.7	6.0	5.2	4.4
Total Products	17.3	17.3	17.1	17.0	18.5	17.1	16.1	20.2	17.1	14.7
Modeled Foreign Regions	34.9	39.6	37.2	37.2	42.6	38.3	37.4	47.2	40.4	38.1
Other Foreign Regions	13.5	12.2	12.0	12.0	14.0	13.8	13.8	17.0	16.6	16.5
Total World	**65.7**	**69.1**	**66.3**	**66.2**	**75.1**	**69.2**	**67.3**	**84.4**	**74.1**	**69.3**

*Light products equal the sum of motor gasoline, jet fuel, and distillate.

Finally, the costs associated with unique California product qualities were not specifically included in the Foundation Case effort. This was done on the assumption that the incremental costs of these products over EPA quality products would, on average, be the same in all production locations. Some limited volume of California product could be produced at some domestic or foreign locations at lower cost.

Seven of the nine Foundation Cases were studied to evaluate the global issues relating to the future U.S. refinery situation. All of the study years (1995, 2000, 2010) for Foundation Case I and Foundation Case III were investigated, as was Foundation Case II in 2010. This pattern provided information along the edge of the NPC refining study demand envelope.

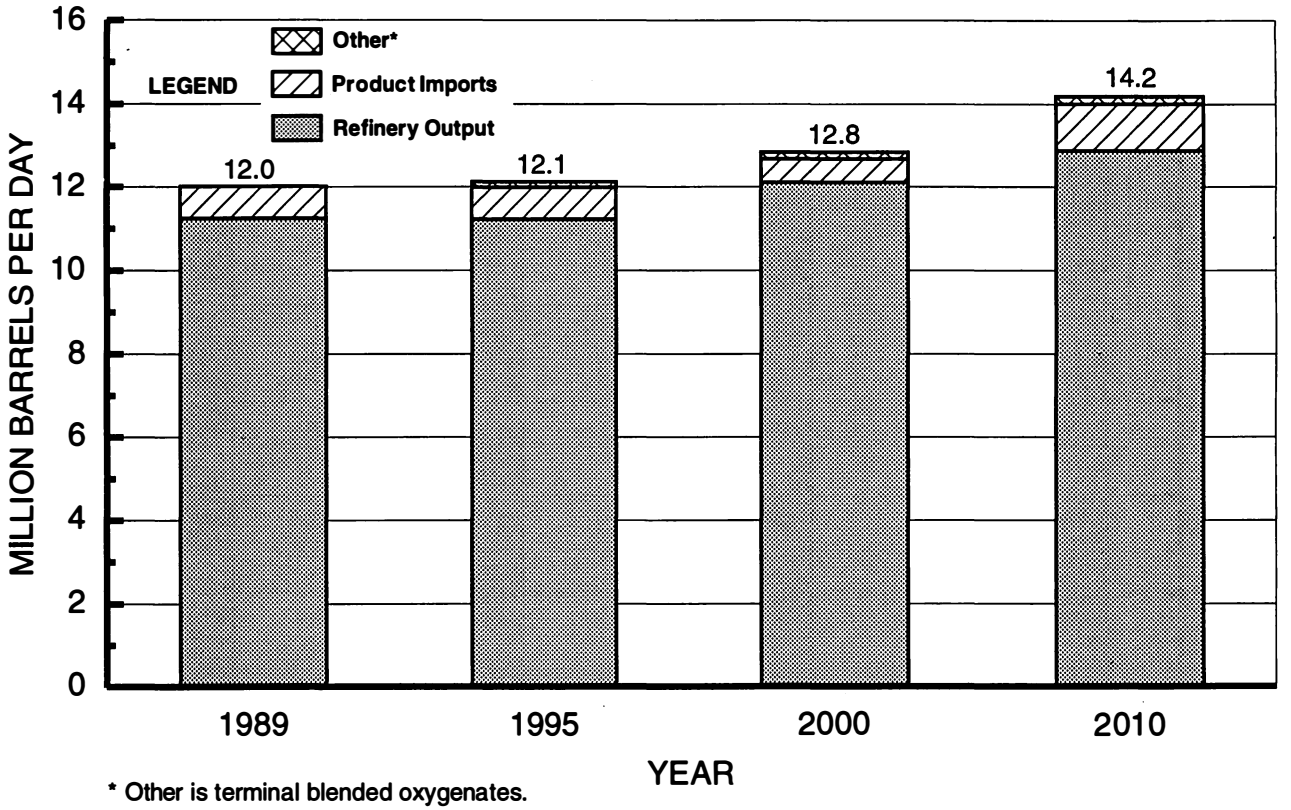
The Foundation Case studies were carried out looking at light products (motor gasoline, jet fuel, distillate). Light products are about 70 percent of the U.S. demand barrel. Other than heavy fuel oil, light products are the major products traded on the world oil market. Heavy fuel oil was not included in the logistics analysis because of its relatively minor effect on U.S. refinery operations. The remaining U.S. products are not heavily traded on world markets and are individually relatively small volumes. All products were captured in refinery cost assessments for light products discussed in other sections of this chapter and in other report chapters.

U.S. exports of light products were assumed to remain at 1989 levels in future years. There is the expectation that U.S. light product exports will vary in the future as relative light product costs change between the U.S. and foreign regions. The U.S. light product import results of the Foundation Case studies should be viewed as net import trends. The issue of exports is discussed elsewhere in this chapter.

U.S. Oil Product Supply Trends

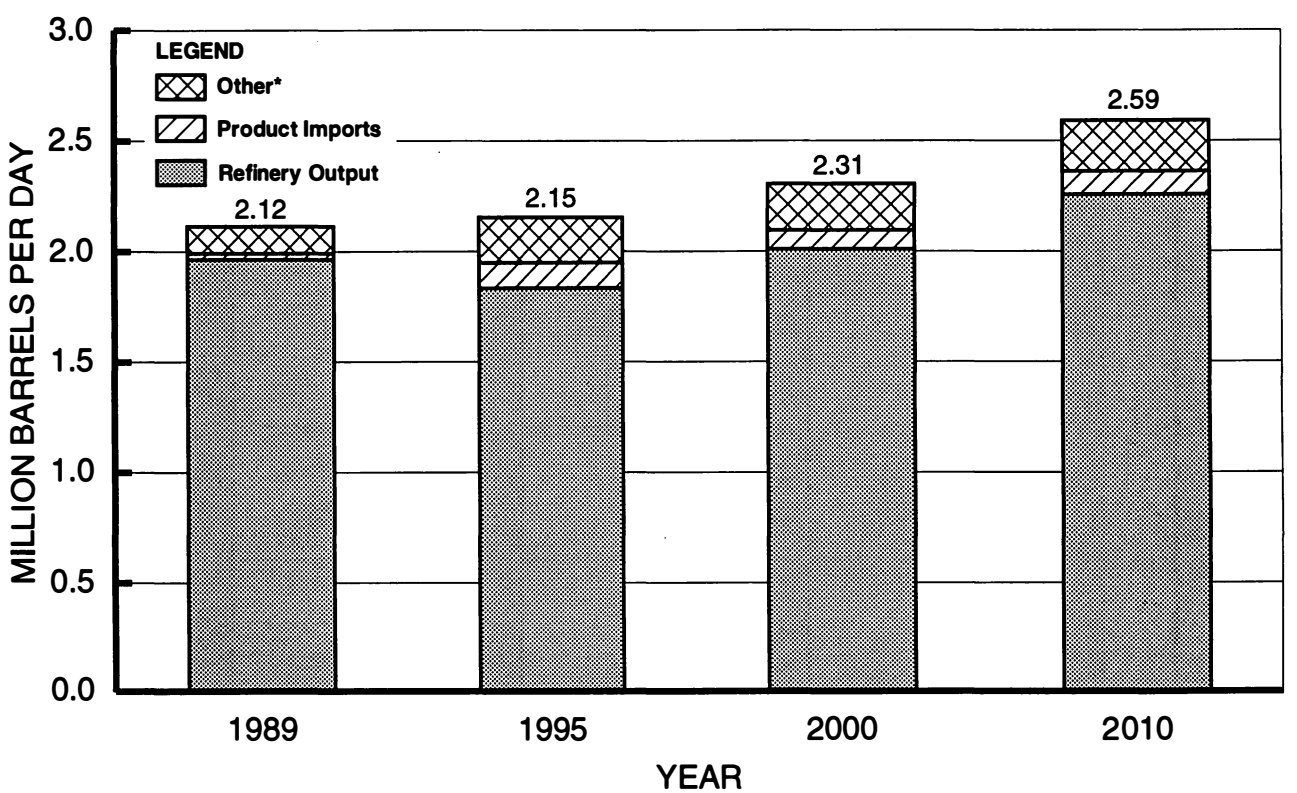
From an overall perspective, it appears that the U.S. refinery complex, under relevant 1989 philosophies, is likely to operate at future levels reasonably close to 1989 levels. However, there are variations to this theme under varying demand conditions and product cost increase estimates.

- Increasing U.S. light product demand future (Figures 3-10 and 3-11):
  - U.S. refinery light product (hydrocarbon fraction plus refinery blended oxygenate) output appears to grow toward the limits of U.S. refinery capability as demand increases.
  - U.S. light product imports appear to decline with time until U.S. refinery output reaches logistically sustainable maximums.
  - After U.S. refinery capacity is effectively used, it appears that light product imports, produced in underutilized foreign refineries, increase to fill the demand need.
  - Foundation Case I demand levels do not cause "grass roots" refinery capacity to be added in the United States or in foreign regions specifically to supply U.S. clean product needs.
  - The West Coast situation between now and 1995 is slightly different than for the United States in that imports under Foundation Case I appear to increase and West Coast refinery light product output appears to decline.
  - After 1995, the West Coast situation appears to be the same as the U.S. situation relative to light product refinery output and imports.
- Decreasing U.S. light product demand future (Figures 3-12 and 3-13):
  - U.S. light product imports appear to decline with time to a minimum level in the future.
  - U.S. light product refinery output appears to remain relatively stable until clean product imports reach low levels in response to declining demand.
  - West Coast light product refinery output appears to decline as clean product imports increase to 1995.



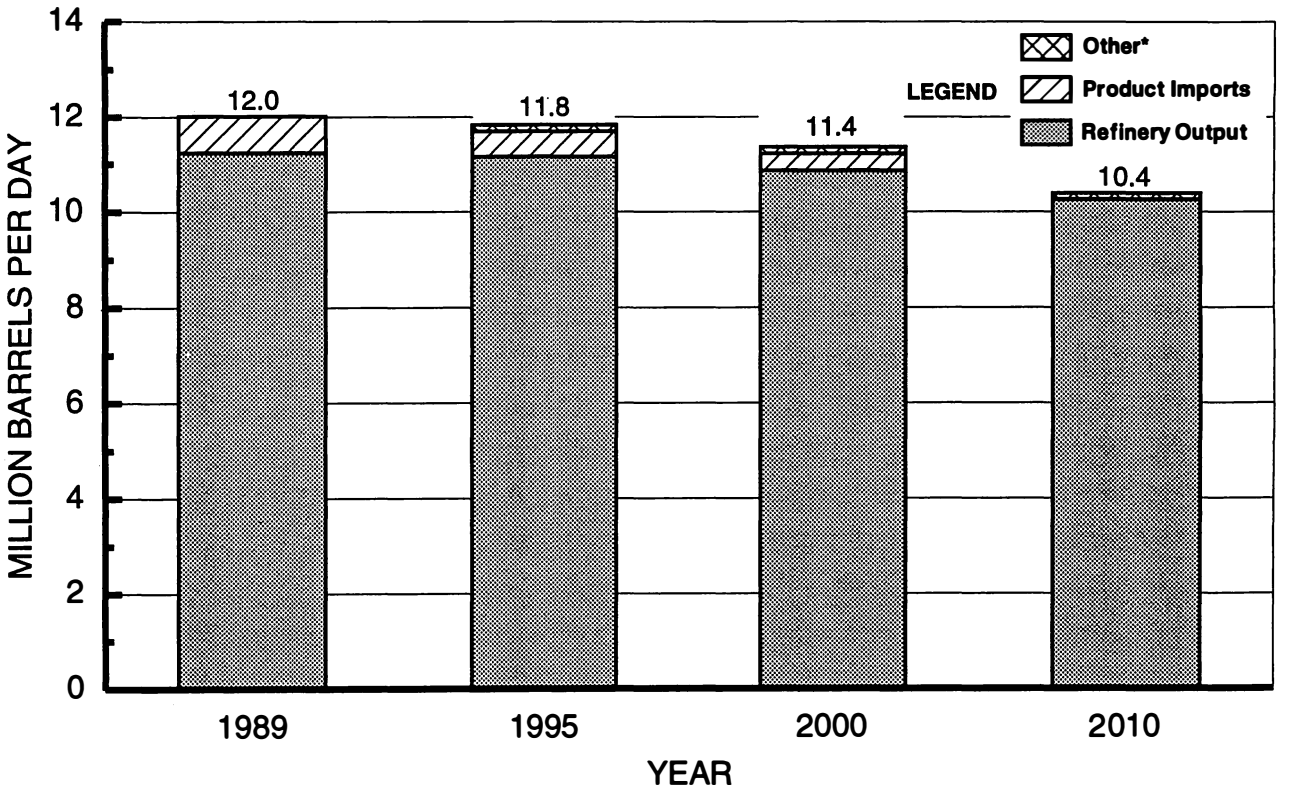
* Other is terminal blended oxygenates.

Figure 3-10. Foundation Case I—United States.



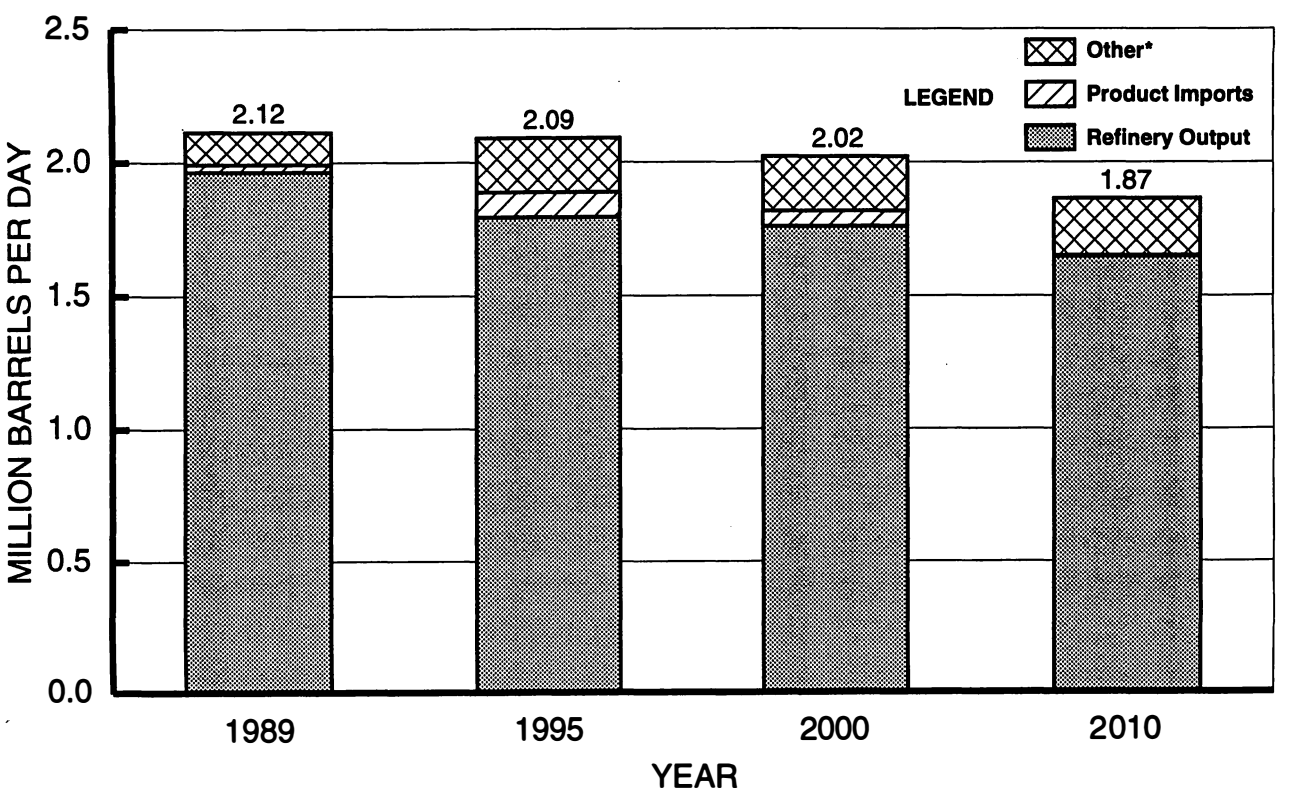
* Other is net of terminal blended oxygenates and other District flows.

Figure 3-11. Foundation Case I—West Coast.



* Other is terminal blended oxygenates.

Figure 3-12. Foundation Case III—United States.



* Other is net of terminal blended oxygenates and other District flows.

Figure 3-13. Foundation Case III—West Coast.

- After 1995, West Coast light product imports appear to decline to a minimum level with refinery output declining thereafter.

- No growth in U.S. light product demand future (Figures 3-14 and 3-15):
  - U.S. light product refinery output appears to be relatively stable, with oxygenates added to the U.S. motor gasoline pool replacing imports.
  - The Foundation Case study does not provide enough detail to evaluate the near term West Coast situation under Foundation Case II conditions, but longer term the West Coast situation appears to be similar to the U.S. situation.

- Under Foundation Case I demand conditions, anticipated foreign light product cost increase between 1989 and 2000 was reduced about 50 percent and anticipated U.S. light product cost decreased about 20 percent. The net impact is to increase the U.S. cost almost 3 cents per gallon relative to foreign costs, which results in a foreign light product cost increase that is two-thirds of the U.S. increase. The logistics model output under these conditions suggests 2000 U.S. light product output slightly above 1989 levels and imports increasing between 1989 and 2000 to fill 50 to 60 percent of demand growth. Relative to the primary case output, about 700 MB/D of supply shifts from U.S. refinery output to imports (Figure 3-16). In this situation, U.S. refinery output provides 89 percent of U.S. supply. U.S. refinery output provides 94 percent of U.S. supply in Foundation Case I for 2000 and for the historical year 1989.

- Under the same product cost conditions as described above, West Coast Foundation Case I imports increase between 1989 and 2000 to fill 60 to 70 percent of the growth in demand while refinery output is slightly below 1989 levels reflecting the increase in terminal oxygenate blending. There is a shift of about 70 MB/D between refinery output and imports from the primary case results (Figure 3-17).

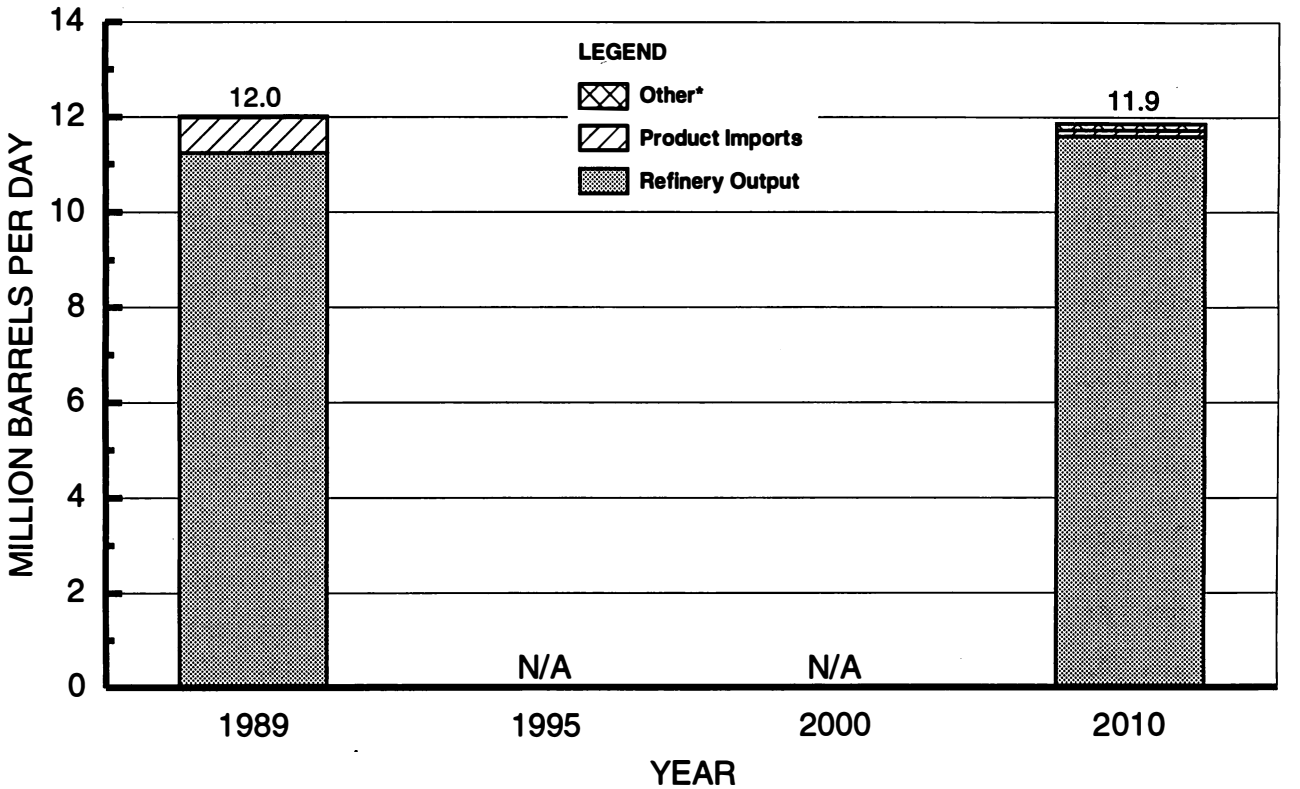
The data for the above charts are summarized in Tables 3-48 and 3-49. More detailed summary tables are included in Appendix L, Section IX-1. The detail product flow output is included as Working Paper 1.

As the study progressed, there were discoveries of factors omitted and inaccurate calculations as well as rethinking concerning various basic assumptions. Analyses were done to test the robustness of the general observations. A comparison of the outputs from these analyses indicates that the directional results are stable (Appendix L, Section IX-2, and Working Paper 3.IX-2).

U.S. Oil Product Cost Buildup

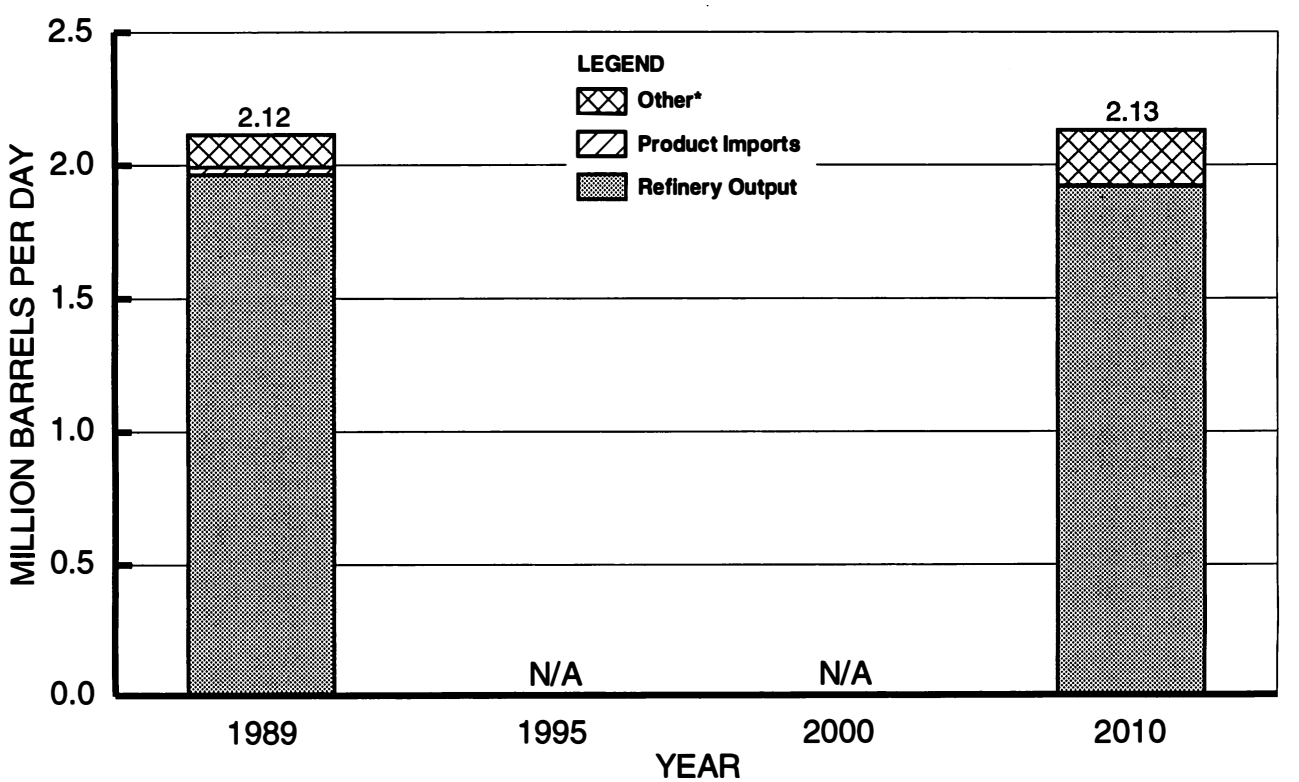
Obviously anticipated light product cost increases have a significant impact on the future U.S. supply situation. As indicated earlier, both U.S. and foreign transportation costs are expected to increase. There is a discussion of anticipated foreign and U.S. refinery cost increases related to various factors elsewhere in this chapter. However, the anticipated cost increases for U.S. refineries relative to those of foreign refineries is the most significant factor in the analysis for estimating the balance of oil product supply between U.S. refinery output and imports. Additional discussion of the cost factors is provided here for perspective regarding the Foundation Case studies results.

Most of the anticipated U.S. cost increase is a function of future implementation of refinery fixed facility health, safety, and environmental regulations. This subject is discussed in some depth in Chapter Two. The remaining cost increase for the United States is primarily related to processing for environmental products (i.e., reformulated motor gasoline and low sulfur on-highway diesel) and is discussed in Chapter Four. Foreign cost increases are expected in these areas. First, health, safety, and environmental costs are expected to increase in all foreign locations. Second, product consumption is expected to increase outside the United States and product quality is expected to shift toward environmental fuels, making processing costs increase significantly more than in the United States. Finally, the cost of moving products from foreign supply points to



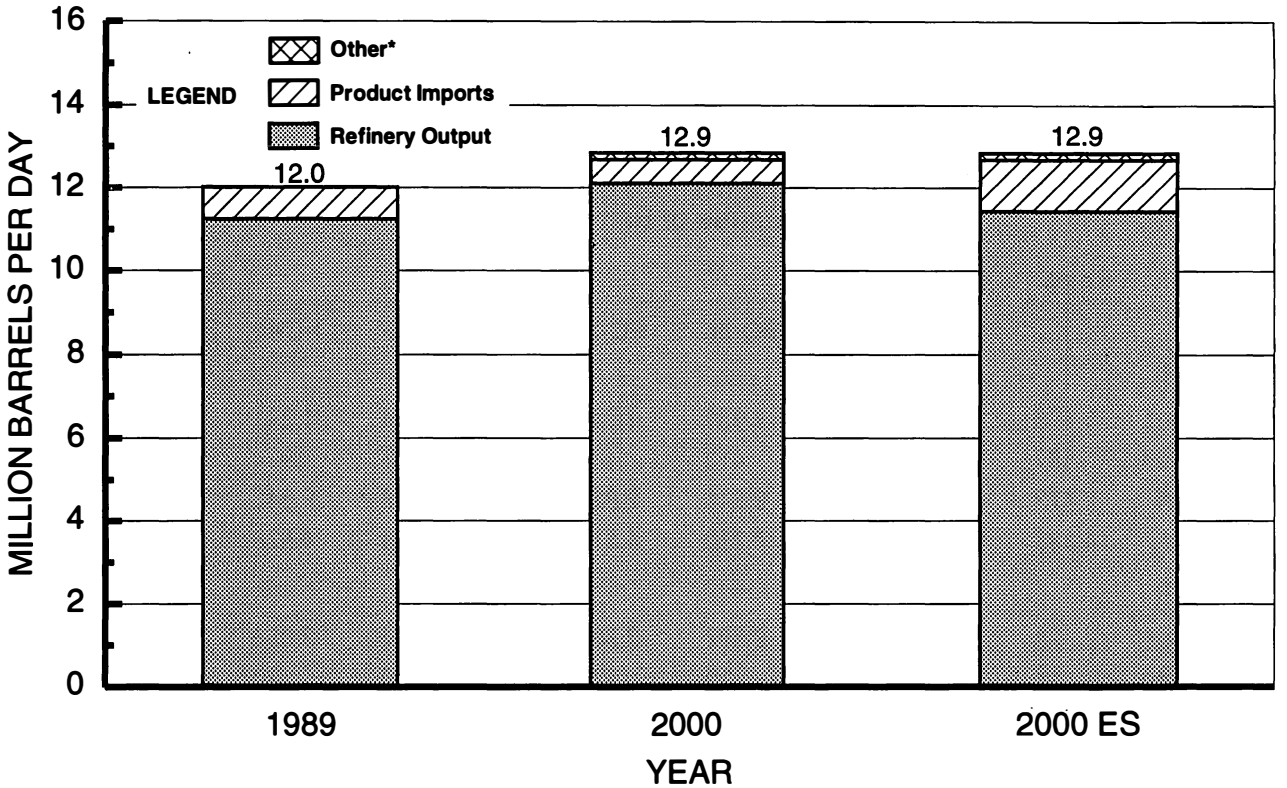
* Other is terminal blended oxygenates.

Figure 3-14. Foundation Case II—United States.



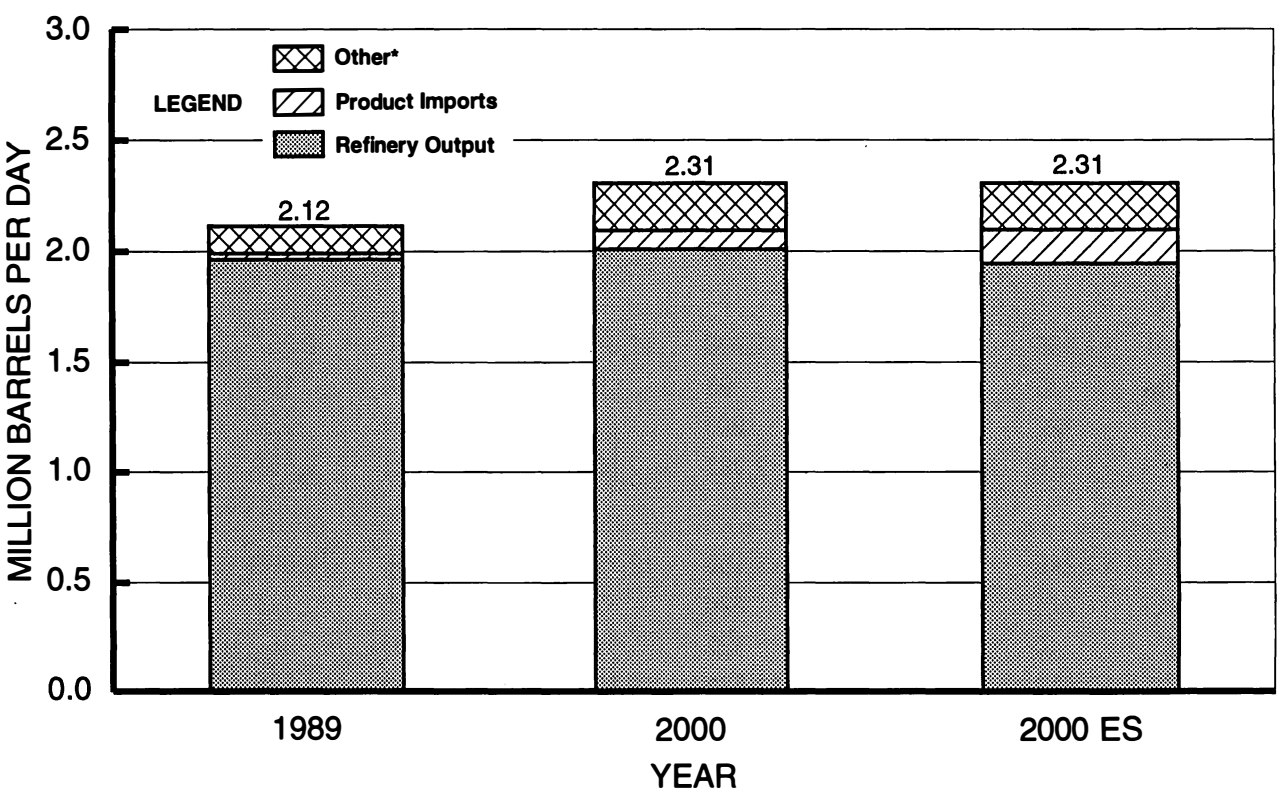
* Other is net of terminal blended oxygenates and other District flows.

Figure 3-15. Foundation Case II—West Coast.



* Other is net of terminal blended oxygenates.

Figure 3-16. Environmental Sensitivity Case—United States.



* Other is terminal blended oxygenates and shipments from other Districts.

Figure 3-17. Environmental Sensitivity Case—West Coast.

TABLE 3-48

U.S. LIGHT PRODUCT REFINERY OUTPUT, IMPORTS, OTHER SUPPLY
(Thousands of Barrels per Day)

	1989	1995			2000			2010		
		FC-I	FC-II	FC-III	FC-I	FC-II	FC-III	FC-I	FC-II	FC-III
PADD I										
Output	1,176	1,151	N/A	1,151	1,234	N/A	1,174	1,241	1,184	1,090
Imports	687	633	N/A	418	464	N/A	298	994	125	3
Other*	2,473	2,530	N/A	2,641	2,814	N/A	2,522	2,643	2,780	2,490
Total	**4,336**	**4,314**	**N/A**	**4,210**	**4,512**	**N/A**	**3,994**	**4,878**	**4,089**	**3,583**
PADD II										
Output	2,578	2,615	N/A	2,592	2,906	N/A	2,624	3,056	2,704	2,344
Imports	14	20	N/A	20	20	N/A	0	20	0	0
Other*	767	766	N/A	715	679	N/A	583	922	676	617
Total	**3,359**	**3,401**	**N/A**	**3,327**	**3,605**	**N/A**	**3,207**	**3,998**	**3,380**	**2,961**
PADD III										
Output	5,125	5,237	N/A	5,237	5,610	N/A	4,968	5,849	5,455	4,856
Imports	42	0	N/A	0	0	N/A	0	0	0	0
Other*	(3,345)	(3,372)	N/A	(3,422)	(3,609)	N/A	(3,208)	(3,599)	(3,585)	(3,222)
Total	**1,822**	**1,865**	**N/A**	**1,815**	**2,001**	**N/A**	**1,760**	**2,250**	**1,870**	**1,634**
PADD IV										
Output	401	383	N/A	383	355	N/A	340	487	340	325
Imports	3	3	N/A	3	3	N/A	0	0	0	0
Other*	(17)	10	N/A	0	68	N/A	35	(9)	58	23
Total	**387**	**396**	**N/A**	**386**	**426**	**N/A**	**375**	**478**	**398**	**348**
PADD V										
Output	1,965	1,835	N/A	1,796	2,010	N/A	1,760	2,257	1,920	1,648
Imports	28	115	N/A	93	85	N/A	58	107	3	3
Other*	122	204	N/A	203	211	N/A	204	227	208	214
Total	**2,115**	**2,154**	**N/A**	**2,092**	**2,306**	**N/A**	**2,022**	**2,591**	**2,131**	**1,865**
U.S.										
Output	11,245	11,221	N/A	11,159	12,115	N/A	10,866	12,890	11,603	10,263
Imports	774	771	N/A	534	572	N/A	356	1,121	128	6
Other*	0	138	N/A	137	163	N/A	136	184	137	122
Total	**12,019**	**12,130**	**N/A**	**11,830**	**12,850**	**N/A**	**11,358**	**14,195**	**11,868**	**10,391**

* Other is net of terminal blended oxygenate and other District flows.

TABLE 3-49

U.S. LIGHT PRODUCT REFINERY OUTPUT, IMPORTS, OTHER ENVIRONMENTAL SENSITIVITY CASE (Thousands of Barrels per Day)

	1989	2000	
		FC-I	FC-I (E)
PADD I			
Output	1,176	1,234	1,254
Imports	687	464	1,071
Other*	2,473	2,814	2,187
Total	**4,336**	**4,512**	**4,512**
PADD II			
Output	2,578	2,906	2,865
Imports	14	20	20
Other*	767	679	720
Total	**3,359**	**3,605**	**3,605**
PADD III			
Output	5,125	5,610	4,989
Imports	42	0	0
Other*	(3,345)	(3,609)	(2,988)
Total	**1,822**	**2,001**	**2,001**
PADD IV			
Output	401	355	388
Imports	3	3	3
Other*	(17)	68	35
Total	**387**	**426**	**426**
PADD V			
Output	1,965	2,010	1,946
Imports	28	85	151
Other*	122	211	209
Total	**2,115**	**2,306**	**2,306**
U.S.			
Output	11,245	12,115	11,442
Imports	774	572	1,245
Other*	0	163	163
Total	**12,019**	**12,850**	**12,850**

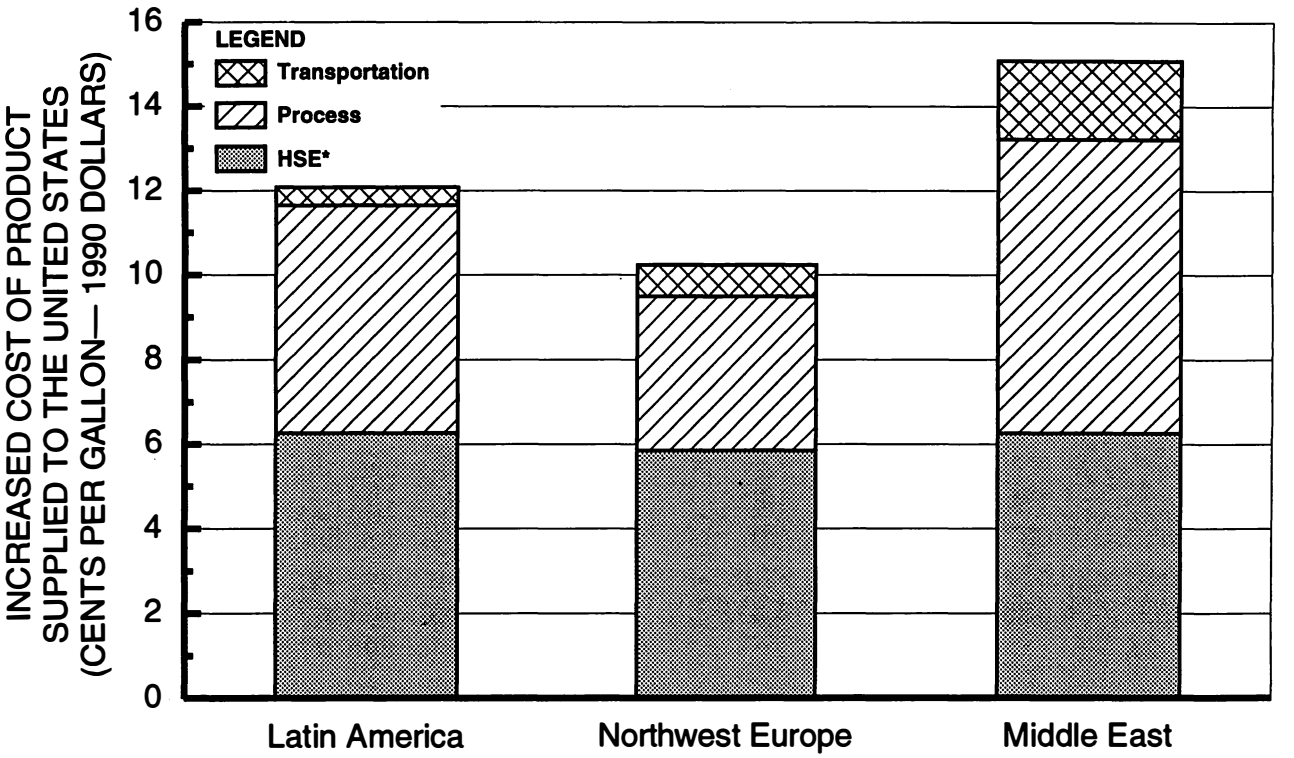
* Other is net of terminal blended oxygenate and other District flows.

U.S. demand centers is expected to increase. The relative impact of these individual factors can be seen in Figure 3-18.

Figures 3-19 and 3-20 depict anticipated cost increases for reformulated regular motor gasoline exclusive of oxygenate costs and on-highway diesel, respectively. Both are at point of manufacture and do not include transportation costs to point of consumption. The figures show the cost increases for coastal regions of the United States and for major foreign regions where U.S. oil product imports originate. In a general sense, the European and Latin American locations provide supplies to the U.S. Gulf Coast and East Coast, while the Middle East provides supplies to the U.S. West Coast. When looking at the figures from this perspective, foreign refinery product cost increases are equal to or greater than those in the relevant U.S. regions in 2010. When considering the assessment that foreign shipping costs are expected to increase, it is not surprising that imports are projected to provide less U.S. supply in the future than they have in the recent past under Foundation Case conditions.

Table 3-50 shows the expected regional cost increase by time period. Examination of these trends provides insight as to the reason for the West Coast supply situation being different in the earlier years from that of the United States as a whole. Simply put, California refinery cost increases are expected to be greater than those in the rest of the United States and are expected to materialize sooner.

A major part of the cost increase is the cost associated with health, safety, and environmental (H/S/E) changes required for refinery stationary sources. As indicated earlier in this chapter, the H/S/E cost increases are significant. Figure 3-21 shows the relationship between on-highway diesel H/S/E and total cost increase for 2010. The significance is that anticipated U.S. H/S/E costs are a greater share of the total anticipated cost increase than are those in foreign regions. The U.S. H/S/E cost increases are a direct output from the facilities work reported on in Chapter Two. Foreign H/S/E cost increases are discussed elsewhere in this chapter.



* HSE is health, safety, and environmental cost increase for fixed facilities.

Figure 3-18. Foreign Region Total Delivered Increase Cost EPA On-Highway Diesel Fuel—1989 to 2010.

TABLE 3-50

RELATIVE COST INCREASE FROM 1989 (Cents per Gallon – 1990 Dollars)

	1995/1989	2000/1989	2010/1989
Reformulated Motor Gasoline (excluding oxygenates)			
Mid-Atlantic	2.1	6.6	8.2
Gulf Coast	2.5	5.6	6.8
California	4.3	7.8	9.6
Latin America	3.1	6.1	9.6
Northwest Europe	3.9	6.7	8.2
Middle East	3.9	6.6	10.4
On-Highway Diesel Fuel			
Mid-Atlantic	3.2	5.4	6.9
Gulf Coast	5.1	6.5	7.7
California	6.5	8.7	10.5
Latin America	5:0	8.0	11.7
Northwest Europe	4.9	8.0	9.5
Middle East	5.9	9.2	13.2

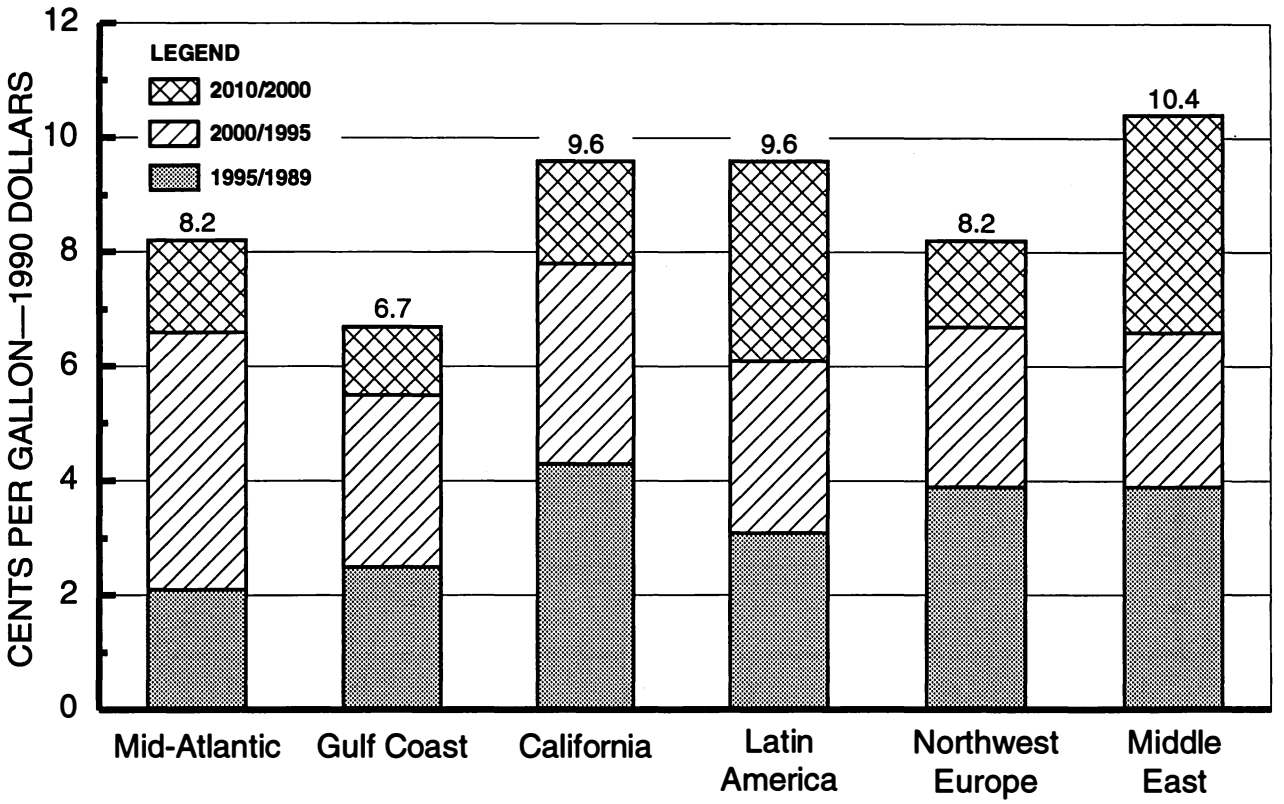


Figure 3-19. Regional Cost Increase
Reformulated Motor Gasoline Ex Oxygenate—1989 to 2010.

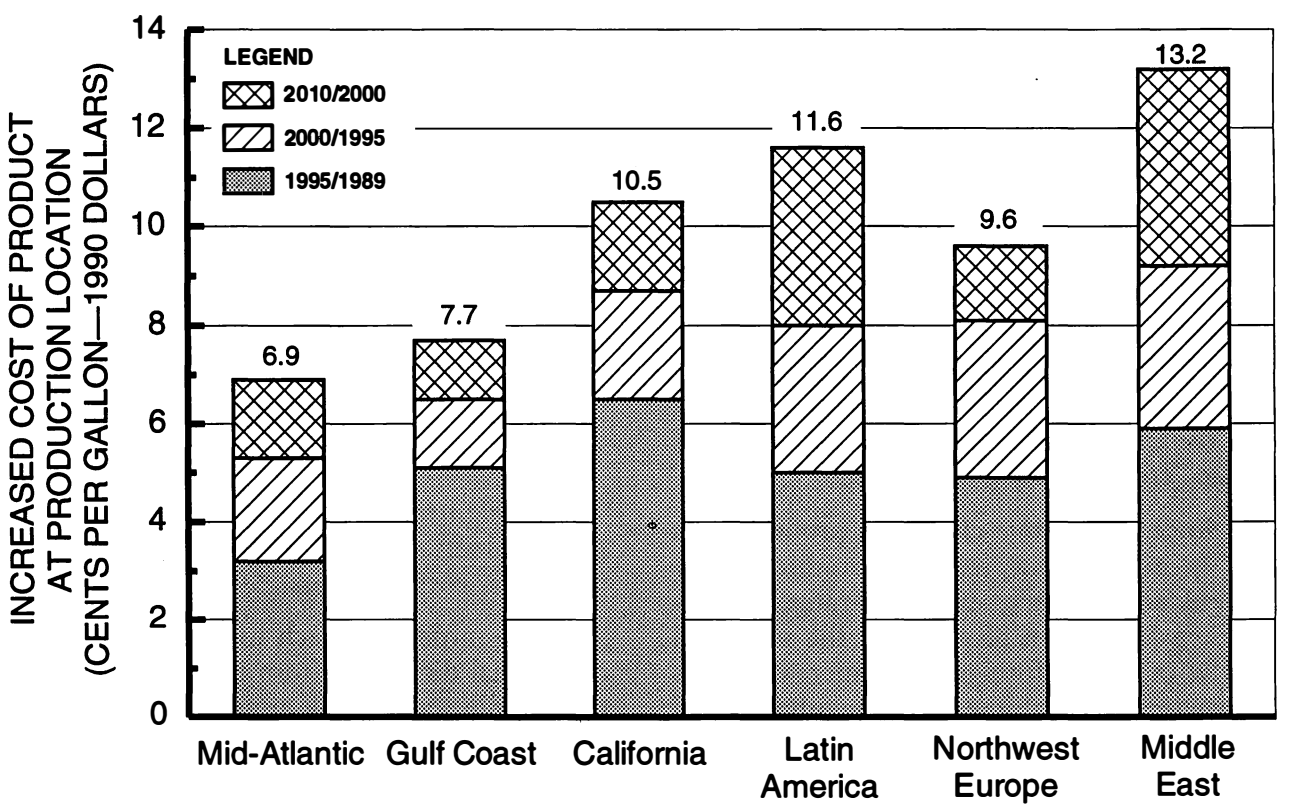
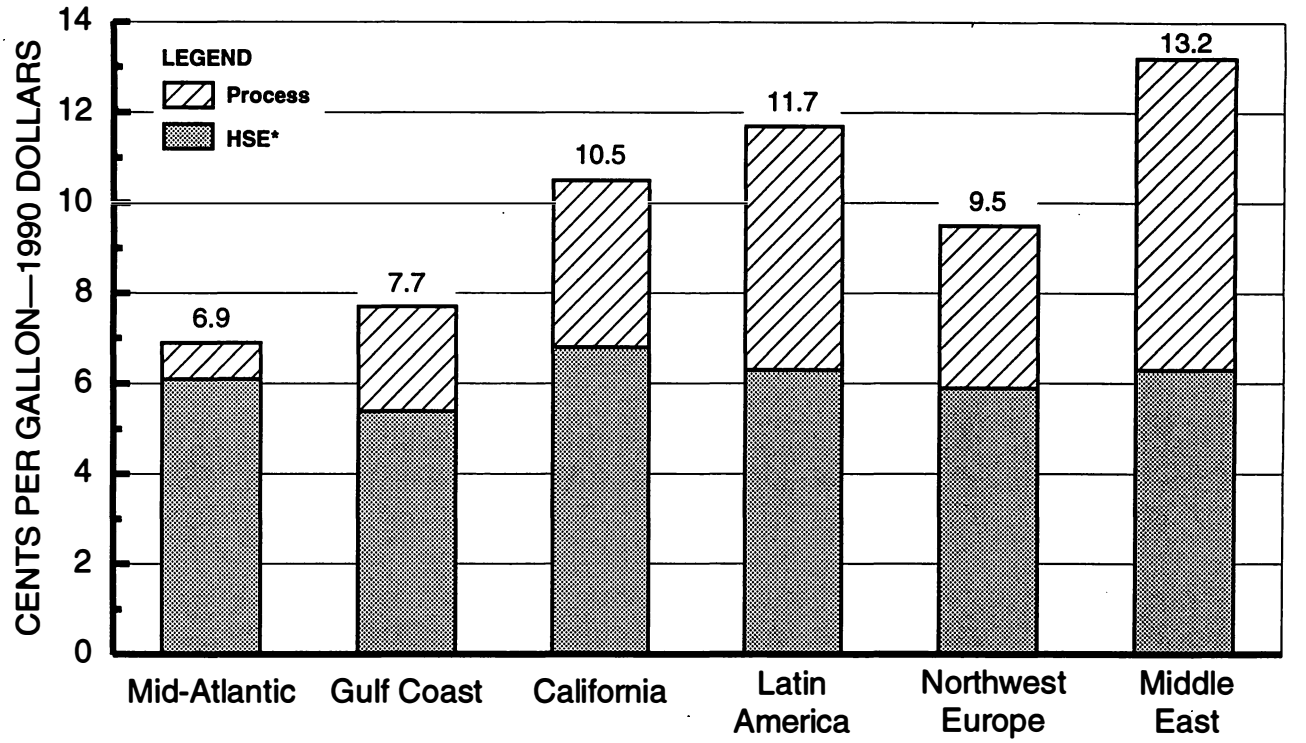


Figure 3-20. Regional Cost Increase
EPA On-Highway Diesel—1989 to 2010.



* HSE is health, safety, and environmental cost increases for refinery facilities.

Figure 3-21. 2010/1989 Total Cost Increases On-Highway Diesel.

It is important to recognize that there is less certainty concerning the cost increase estimate for foreign facilities. The foreign cost increase estimate was tempered to the low side in several places. First, health, safety, and environmental cost increases were reduced by 10 to 30 percent. Second, it was assumed that foreign locations would overbuild capacity to maintain 1989 U.S. product export capability, which resulted in foreign cost increase estimates at the lower average level rather than the higher incremental level. A third factor was the use of "creep" (increase in existing capacity with no apparent investment) in foreign areas and no "creep" in the United States.

Since the relative change in product costs directly impact anticipated U.S. product supply patterns and refinery utilization rates, a sensitivity case was run to evaluate the potential supply impact of foreign costs increasing less relative to U.S. cost increases. The fundamental concern in early deliberations was the H/S/E cost, consequently the case is called the Environmental Sensitivity Case. Later the concern widened to encompass other possible variations on cost increases. These ideas were wide in variation and covered a gamut of concerns.

- The United States as a whole adopts California refining facility regulations.
- U.S. terminal and/or pipeline regulation becomes more stringent, which results in more costly local transportation.
- Lower foreign transportation costs.
- Foreign governments desiring internal industrial development encourage refinery construction through any of a number of potential incentive packages.
- Foreign refineries producing U.S. quality products such as CARB motor gasoline at lower cost than possible in U.S. refineries.

The initial approach to evaluating a cost differential difference from the study assumption profile was to look at anticipated refinery facility H/S/E costs in the context of certainty. Since it was a new idea that foreign refineries would bear H/S/E costs, it was thought that an analysis that removed all foreign H/S/E cost in-

creases and those in the United States not supported by existing legislation or regulation would be severe enough to test the resilience of the U.S. refinery complex.

As mentioned earlier, the results of this analysis indicated that there would be a minor shift in U.S. oil product supply. In 2000 (the year selected for this analysis), U.S. light product supply shows added reliance on imports relative to base projected 2000 conditions. However, U.S. refinery light product output does not diminish from today's levels.

Figures 3-22 and 3-23 show the relative cost increases between 1989 and 2000 for the base estimate and that under the severe conditions imposed by the test assumptions.

The Environmental Sensitivity Case costs are shown on Table 3-51. The table also contains the percent change in costs relative to the primary cost increase assessment brought about by the assumed H/S/E conditions. As indicated in the table, the U.S. refinery cost increase delta to 2000 was about 20 percent. The foreign refinery cost increase delta was around 50 percent.

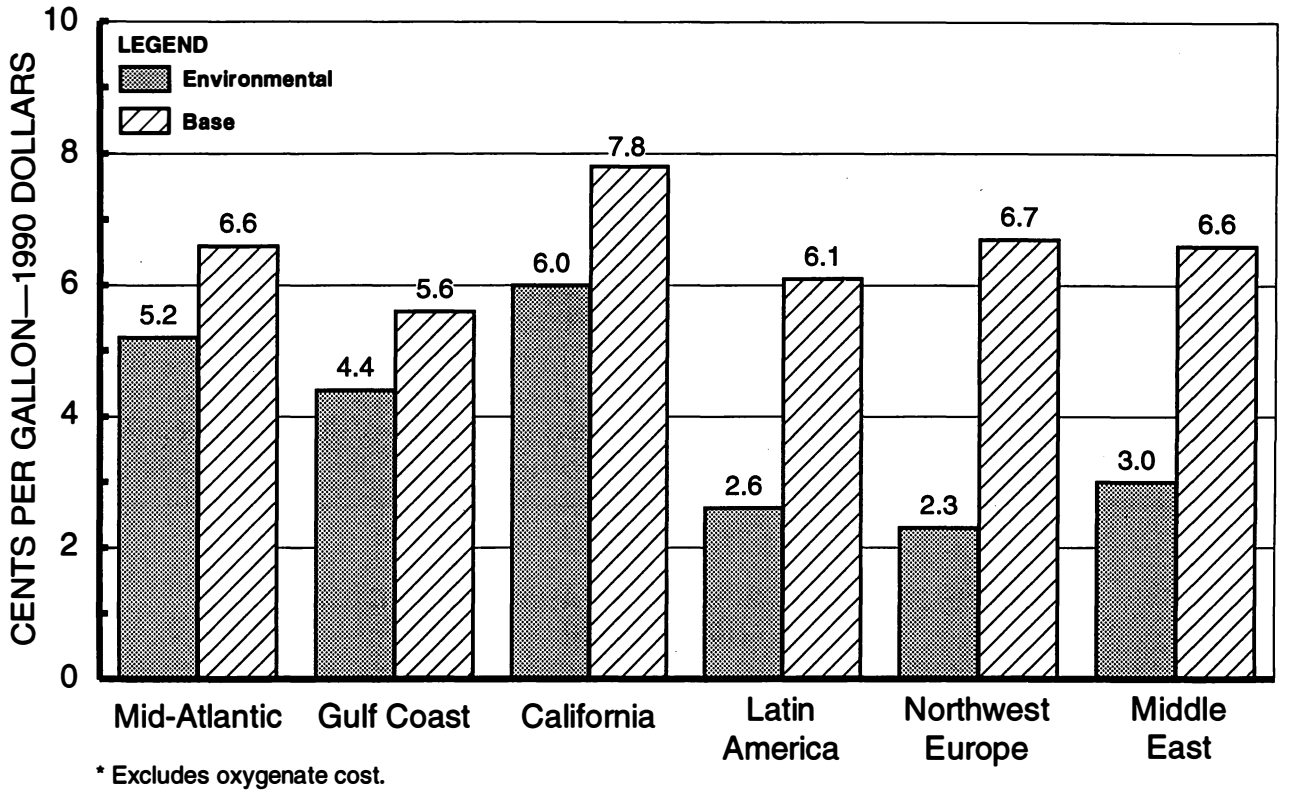
TABLE 3-51

ENVIRONMENTAL SENSITIVITY ANALYSIS FACTORS (1990 Dollars)

	Cost Increase	
	1995/1989	2000/1989
Reformulated Motor Gasoline (Excluding Oxygenates)		
Mid-Atlantic	2.1	5.2
Gulf Cost	2.5	4.4
California	4.3	6.0
LatinAmerica	1.5	2.6
Northwest Europe	1.4	2.3
Middle East	2.3	3.0
On-Highway Diesel Fuel		
Mid-Atlantic	3.2	3.9
Gulf Coast	5.1	5.3
California	6.5	6.9
LatinAmerica	3.5	4.5
Northwest Europe	2.4	3.7
Middle East	4.4	5.7

COST DIFFERENCE FROM BASE (1990 Dollars)

	Reformulated Gasoline (excluding oxygenates)		On-Highway Diesel Fuel	
	cents/gallon	percent	cents/gallon	percent
Mid-Atlantic	(1.5)	22.4	(1.5)	27.8
Gulf Coast	(1.2)	21.0	(1.2)	18.0
California	(1.8)	22.6	(1.8)	20.2
LatinAmerica	(3.5)	57.6	(3.5)	43.5
Northwest Europe	(4.4)	65.5	(4.4)	54.4
Middle East	(3.6)	54.0	(3.6)	38.5



* Excludes oxygenate cost.

Figure 3-22. 2000 Reformulated Motor Gasoline Cost Comparison* Environmental Sensitivity versus Base.

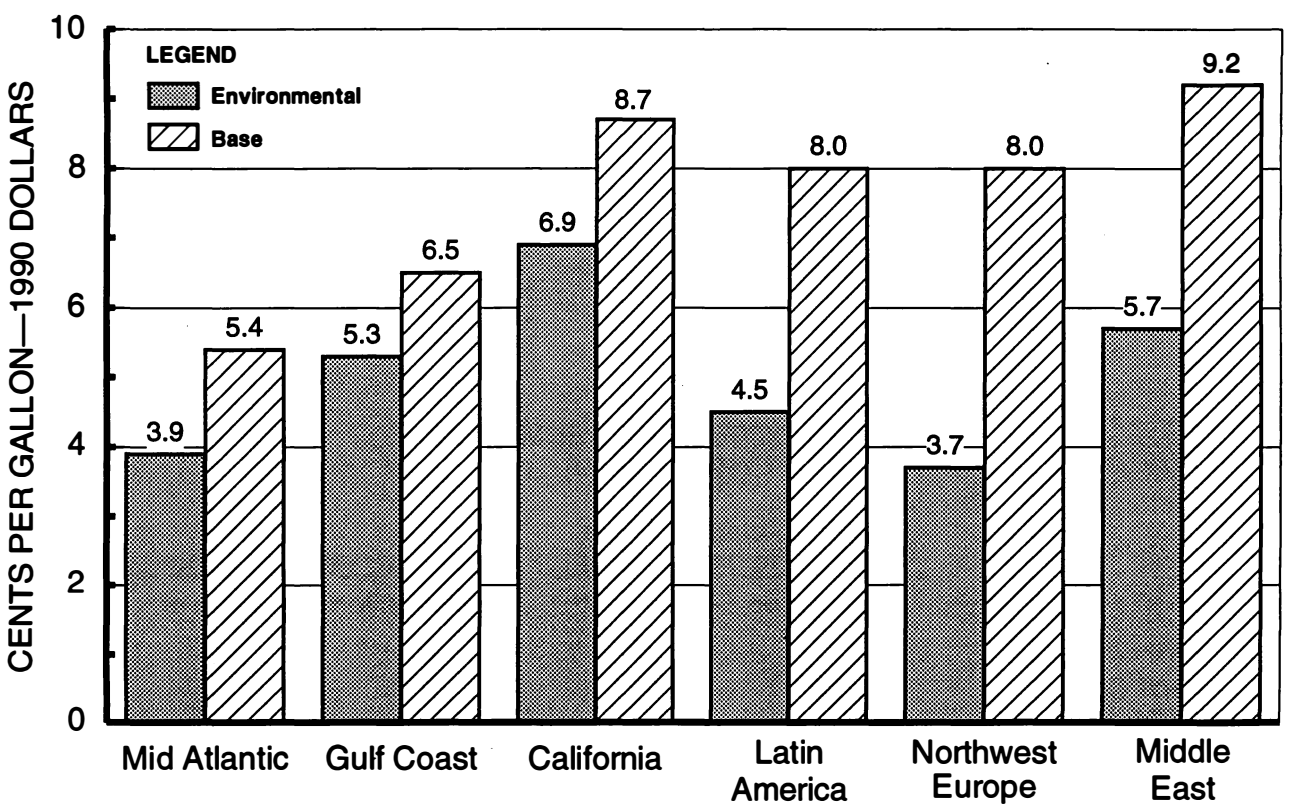


Figure 3-23. 2000 On-Highway Diesel Cost Comparison Environmental Sensitivity versus Base.

The magnitude of the shift was deemed sufficient to cover most situations where foreign refinery costs increased less than assumed in the base assessment. Study participants agreed that there would be an increase in cost associated with foreign H/S/E concerns. Rather, the uncertainty surrounding both the assessment of cost associated with H/S/E factors and their relationship to either U.S. or foreign refineries created the desire to evaluate a situation of such severity. The participants derived the feeling that the U.S. refinery complex would be resilient relative to foreign supplies under all but the most unusual circumstances.

U.S. Refinery Capability Utilization

A concern that pervades many organizations is that of significant future rationalization of U.S. refining capability. The refining study analysis was limited to the production of light products. This part of the product barrel represents more than seventy percent of the output from U.S. refineries. Consequently, evaluating the capability to produce light products should provide a reasonable basis to comment on the possible rationalization of U.S. refinery capacity.

Table 3-52 shows light product output under the various Foundation Case scenarios and the estimated capability to produce light products. The estimated capability to produce light products does not include any announced or actual shutdown that has occurred since 1989 and is based on the EIA crude oil runs to operable crude oil capacity estimates of 85.6 percent in 1989. The table also shows percent utilization under various Foundation Case conditions. While no interior studies were done (Foundation Case II for 1995 and 2000), it was observed that the results of these evaluations would have fallen between the reported results and no additional insights would be gained from specific evaluation.

One's view of whether or not refinery capacity rationalization will occur depends on many factors. Prominent among these is the concern that exists in the 1989 time frame for viability of some refineries under prevailing conditions at the time. A view of future U.S. oil product demand is also paramount in grappling with the issue of U.S. refinery capacity rationalization in the future.

The following assessment is based on an estimate of directional pressures relative to the

TABLE 3-52

U.S. LIGHT PRODUCTS*
REFINERY OUTPUT — REFINERY CAPABILITY
(Million Barrels per Day)

	1989	1995			2000			2010		
		FC-I	FC-II	FC-III	FC-I	FC-II	FC-III	FC-I	FC-II	FC-III
Refinery Output	11.2	11.2	N/A	11.2	12.1	N/A	10.9	12.9	11.6	10.3
Operable Capacity	13.1	13.5	13.5	13.5	13.8	13.8	13.8	13.8	13.8	13.7
Utilization, %	86%	83%	N/A	82%	88%	N/A	79%	93%	84%	75%

* Light Products = motor gasoline, jet fuel, and distillate.

† Derived from 1989 U.S. refinery operable crude oil capacity and crude oil input as reported by the Energy Information Administration equaling a utilization rate of 85.6 percent, which is rounded to 86 percent in the table. It is assumed that 1989 light product operable capability is directly related to this utilization and is calculated at 13.1 million barrels per day. Capability is increased in 1995 by 0.1 million barrels per day of announced U.S. refinery additions plus 0.3 million barrels per day of oxygenate blended in refineries. After 1995, capability changes reflect changes in refinery blending of oxygenate.

N/A = Not analyzed.

1989 situation. There is a slight decline in capability utilization in all of the scenarios evaluated for 1995. This suggests pressure to remove capacity from the total complex in the near term. The reduction in utilization results from three factors. First, all Foundation Case demand projections are relatively flat to 1995. Second, the infusion of oxygenates (non-hydrocarbon derived material) into the U.S. product mix reduces the need for hydrocarbon product output from U.S. refineries. Finally, there is announced capacity expansion equivalent to about 200 MB/D of light product output, all of which is expected on-stream by 1995.

After 1995, U.S. demand increases under Foundation Case I conditions. Even when recognizing the increased infusion of oxygenates (about 0.3 million barrels per day post-1995) brought about by the assumed level of ozone nonattainment area use of reformulated motor gasoline, there is a projected increase in U.S. refinery capacity utilization in 2000 and 2010. As indicated earlier in this section, U.S. refinery light product capability use approaches effective maximum after 2000 with the demand increase postulated in Foundation Case I. Under these circumstances there is little pressure to rationalize U.S. refinery capacity.

In the Foundation Case III demand assessment there is a demand decline post 1995. With this situation, even when imports decline as discussed earlier in this section, U.S. refinery light product capability utilization declines markedly. This suggests increased pressure to rationalize U.S. refinery capacity.

As mentioned earlier, U.S. exports are assumed constant at 1989 levels. Exports may vary, changing the refinery utilization situation from that shown in Table 3-52.

The major factor impacting the future viability of the U.S. refinery complex is future oil product demand. The reader should contemplate this issue in depth before reaching an individual conclusion regarding future U.S. refinery capacity rationalization.

CHAPTER FOUR

U.S. REFINING CAPABILITY AND COSTS

The purpose of this chapter is to report NPC findings concerning the impact of the Clean Air Act Amendments of 1990 (CAAA) on motor fuel quality requirements, the cost of making motor fuel products, and the capability of the U.S. refining industry. Costs of compliance with stationary source regulations are covered in Chapter Two.

Study of the motor fuel quality and performance changes is focused on gasoline requirements that begin in 1995 and diesel fuel requirements that begin in 1993. Phase I reformulated gasoline (RFG) will be required for, at least, nine primary ozone nonattainment areas beginning in 1995. More stringent emission reduction requirements for Phase II RFG must be met starting in 2000. In addition, starting in 1992, the CAAA requires oxygenated gasoline (OG) for carbon monoxide (CO) nonattainment areas in the winter. Conventional gasoline (CG) will have to meet antidumping requirements, also beginning in 1995.

To estimate changes in the manufacturing cost of fuels and the capability of the U.S. refining industry, the NPC established representative premises and a comprehensive methodology for study. All study data are from public sources, including aggregated NPC survey data. Two consultants' proprietary refining computer models, one by Turner, Mason & Company and another by The Pace Consultants, were used for evaluating aggregated industry refining costs and performance using NPC input. Exhaust and non-exhaust emissions models were taken from EPA and API public proposals pending a final EPA promulgation expected after the close of the NPC study. The years 1995, 1997, 2000, and 2010 were chosen for the analyses.

This chapter describes the CAAA quality changes for fuels, study methodology, and the impacts on cost and refining capability from changes in each fuel type and time period. Also, information concerning a number of associated issues is provided.

SUMMARY OF MAJOR CONCLUSIONS

Key Premises

The conclusions developed concerning the capability of the U.S. refining industry and the costs to meet the CAAA requirements are valid within the bounds of the premises used for this study. The analysis and results presented are based on the following key premises:

- **Compatibility.** Final RFG rule making will set enforcement procedures, including test tolerances and conditions for product compatibility such that impacts on refining costs are negligible.

- **Cost-Effectiveness.** Gasoline modifications that have an incremental cost-effectiveness of up to $10,000 per ton of volatile organic compound (VOC) emissions reduced in a six month summer (equivalent to $5,000 per ton of VOC on an annual basis, and corresponds to the EPA definition of control decision benchmark) will be required for Phase II RFG.

- **Emissions Performance Standards.** Final EPA rule making will set emissions performance standards for Phase II RFG that enable refineries to produce compliant RFG when operating at this incremental cost-effective level for VOC reduction.

- **Refinery Model.** The refinery model, Turner, Mason & Company's aggregated industry model run for each Petroleum Administration for Defense District (PADD) separately, reasonably represents both the average and incremental cost of manufacturing industry average reformulated products (reformulated gasoline and ultra-low sulfur diesel fuel).

- **Simple Emissions Model.** RFG meeting the requirements of the EPA simple model complies with the EPA requirements for Phase I in 1995-1996.

- **Complex Emissions Model.** The 4/92 complex model for emissions that is embedded in the refinery model provides a suitable approximation for production of RFG meeting the EPA emissions performance standards for Phase I RFG in 1997-1999 and Phase II RFG in 2000 and after. The EPA's MOBILE4.1 model provides the basis for calculation of the mobile source emission inventory and statutory baseline gasoline emissions for this complex model. The 4/92 complex model is similar to the EPA's most recent complex emission model made public in May 1993. A June 1993 version is expected.

- **Conventional Gasoline.** Gasoline meeting the antidumping requirements of the simple model in 1995 and the 4/92 complex model in 1997 and thereafter complies with the EPA requirements for CG.

- **Product Demand and Crude Oil Quality.** Most of the study results reported in this chapter make a central assumption of no U.S. demand growth for motor fuels on a heating value adjusted basis and no significant change in crude oil quality throughout the study period. Some study of a growing U.S. petroleum product demand and a declining U.S. demand was also performed.

- **Reformulated Products Supply.** For this study, it is premised that in 1995 simple model Phase I RFG will be supplied only to the nine severe and extreme ozone nonattainment areas and that in 2000 complex model Phase II RFG will be supplied to all ozone nonattainment areas and the Northeast Ozone Transport Corridor. It is assumed that ultra-low sulfur diesel fuel will be used for all on-highway consumption beginning in 1993. California will be using low aromatics diesel fuel starting in 1993 and California Air Resources Board (CARB) Phase 2 RFG starting in 1996.

Results

Results of this study, based on the premises used, indicate that the U.S. refining industry will be technically capable of manufacturing fuels that meet the CAAA requirements for diesel fuel in 1993, and for RFG in 1995 (Phase I) and 2000 (Phase II). Meeting the CAAA requirements for fuels will result in significant added costs.

RFG Emissions Performance

In 1995 under the simple model, reduction of emissions with RFG will be achieved through required reduction in Reid Vapor Pressure (RVP), benzene, and aromatics, and mandated oxygen addition.

With the complex model in 2000, the levels of emission reduction calculated for a given processing cost are very dependent on the complex emissions model used. Table 4-1 shows percent emission reduction from the 1990 statutory summer baseline calculated for the same RFG with the 4/92 and two later pro-

TABLE 4-1

PHASE II RFG AVERAGE SUMMER EMISSIONS REDUCTION IN PADD III (Percent)

	CAAA Minimum Requirement	Complex Model* 4/92†	1/93 API‡	2/93 EPA‡
Volatile Organic Compounds	20	45	32	31
Toxic Air Pollutants	20	35	33	25
Oxides of Nitrogen	≥0	3	8	(1)

* All three models use CAAA statutory summer baseline gasoline RVP (8.7 psi).

† This complex emissions model uses a MOBILE4.1 mobile source emission inventory basis.

‡ These complex emissions models use a MOBILE5.0 basis.

posed complex models plus the CAAA minimum requirement for the target PADD III (U.S. Gulf Coast)[1] case in 2000.

Achieving these 2000 Phase II VOC reduction levels from 1990 statutory baseline levels is the result of additional changes from Phase I RFG; further reduction of RVP to the 6.5 pounds per square inch (psi) minimum allowed in this study as well as nominal reductions in sulfur and olefin properties. The differences between calculated emissions reduction is less from one PADD compared to another[2] than the differences between one complex model calculation compared to another.

Cost of Motor Fuel Reformulation

In 1995, the increased refining cost over the cost of conventional gasoline, for Phase I RFG to supply the 9 ozone nonattainment areas is estimated to be 5.5 cents per gallon (cpg) on a U.S. average basis in the summer. The increased refining cost varies from 3 cpg in PADDs II and III to 7 cpg in PADD I and California. On a U.S. basis, this increased refining cost is primarily for oxygen addition with a smaller amount for benzene and RVP reduction.

In 2000, the increased refining cost over the cost of conventional gasoline for Phase II RFG to supply all ozone nonattainment areas, except California, is estimated to be about 7.6 cpg on a U.S. average basis in the summer. The increased refining cost varies from 6.9 cpg in PADD III to 8.9 cpg in PADD II. The additional 2.1 cpg in 2000 over the 5.5 cpg in 1995 is for the increased portion of RFG in the gasoline pool, the further RVP reduction, and other Phase II property changes. This increased refining cost in 2000 is for Phase II RFG meeting cost-effective emissions requirements with the 4/92 complex model where VOC reduction is controlling. Increased annual average refining costs for making RFG would be about 1 cpg less than summer RFG because VOC is not the controlling emission in the winter.

The increased refining cost over the cost of CG for CARB Phase 2 RFG to supply California is estimated to be 15.1 cpg. If CARB Phase 2 gasoline were required nationwide, the increased refining cost would be about 17 cpg over the cost of CG and would range from 14.3 cpg in PADD III to 25.3 cpg in PADD IV.

The average increased refining costs given above for making RFG in the summer might be understated. Actual costs will be very dependent on the EPA regulations promulgated and any EPA requirements not studied in the modeling. These EPA requirements

[1] See Table 3-1 in Chapter Three for PADD listing.

[2] See Appendix M for other PADD data.

might include more stringent certification and enforcement requirements, such as inadequate testing tolerances, property ranges, property caps, compliance allowances, or enforcement policies that result in more product segregation than current practices. Because each refinery is unique in its processing capability, feedstocks, and product slate, individual refinery costs to produce RFG will be higher for some and lower for others.

Toxic air pollutants (TAP) are the controlling emission in the winter. Since the EPA has determined that incremental TAP reduction is not cost-effective, no additional processing or costs to achieve winter TAP reduction beyond that achieved with Phase I winter RFG have been included. The final complex emissions model selected could result in non-cost-effective additional processing to satisfy the TAP performance standard in the CAAA.

The reduction in oxides of nitrogen (NOx) was not specifically studied. However, estimates were made by analyzing refining model runs for sulfur and olefin reduction. For example, if significant summer NOx reductions (on the order of 4 to 6 percent reduction) were required in 2000, NOx reduction would become limiting for RFG instead of VOC reduction. In this case, the added refining cost on a U.S. average basis of Phase II RFG over CG would be about another 2 cpg over the 7.6 cpg.

If, as proposed in the 2/93 EPA Notice of Proposed Rulemaking (NPRM), additional VOC reduction for RFG containing MTBE were required in 2000 to offset the use of ethanol in 30 percent of the total northern RFG pool, the added refining cost would be about 9.0 cpg instead of 7.6 cpg because of additional refinery processing required. When evaluated on the basis of increased cost per gallon of ethanol used, the increase in direct refining cost is 75 cpg of ethanol used.

The consumer using RFG or OG instead of CG can expect to see an additional effective increase in overall gasoline cost of about 2 to 3 cpg because the lower energy content of gasolines with oxygen will require more gallons to travel the same distance.

Introduction in 1993 of on-highway ultra-low sulfur diesel fuel will add refining costs of about 3.8 cpg of diesel fuel on a U.S. average. If all U.S. diesel fuel were produced to meet CARB low aromatics diesel fuel requirements, the added cost would be about 14.5 cpg over current diesel fuel costs.

The foregoing cpg refining cost increases do not include added costs for stationary source environmental controls or added costs for transportation and marketing environmental controls.

Cost-Effectiveness of Summer VOC Reduction in Phase II RFG

The particular complex emissions model used and any requirements for NOx reduction will influence incremental cost-effectiveness substantially.

The CAAA require that cost be considered in setting Phase II RFG performance standards. Incremental cost-effectiveness (the cost for reducing the next incremental ton of VOC) is important in comparing the value of more costly gasoline reformulation to the value of other available alternative non-fuel strategies for ozone control. Fuel economy cost is included with refining cost in making cost-effectiveness calculations.

Starting from Phase I RFG, RVP reduction is the most cost-effective approach to reducing summer VOC emissions further. Following RVP reduction are the modest but more costly reductions in sulfur and T_{90}. These more costly steps to VOC reductions would be utilized by individual refineries with the complex emissions model to achieve the most economic solution for its specific situation. Deeper reductions of these properties are not incrementally cost-effective methods for reducing VOC. Depending on the final complex model and the emissions reduction required, modest olefins and aromatics reductions could also be necessary. Further oxygenate addition or benzene reduction are not incrementally cost-effective methods for reducing VOC.

Refining costs developed for this study are determined at the break point where incre-

mental refining and fuel economy costs for further VOC reduction are higher than the $10,000 per summer ton limit. This concept is illustrated for PADD III in Figure 4-1. This break point and incremental cost-effectiveness will vary from PADD to PADD. The reader should also be aware that costs for manufacturing RFG are the lowest in PADD III. The percent VOC reductions shown in Figure 4-1 are calculated with the 4/92 complex model used in this study as a surrogate for the eventual complex model. Other complex models evaluated resulted in smaller calculated percent VOC reductions for a given average gasoline but the break points are expected to occur at about the same cost. If emission performance standards are not set lower than the break point level to allow for testing tolerance, the incremental cost per ton of VOC removed will not be within the acceptable level.

Serious, moderate, and marginal ozone nonattainment areas that have not opted into the RFG program can achieve significant VOC reduction by RVP reduction alone. VOC reduction by this control may be particularly cost-effective.

Capital Expenditures for Refining

Refining capital expenditures to meet CAAA or CARB requirements as appropriate for reformulated fuels are estimated to be $11.2 billion in the 1991-1995 time period and $2.5 billion from 1996 to 2000. No changes to

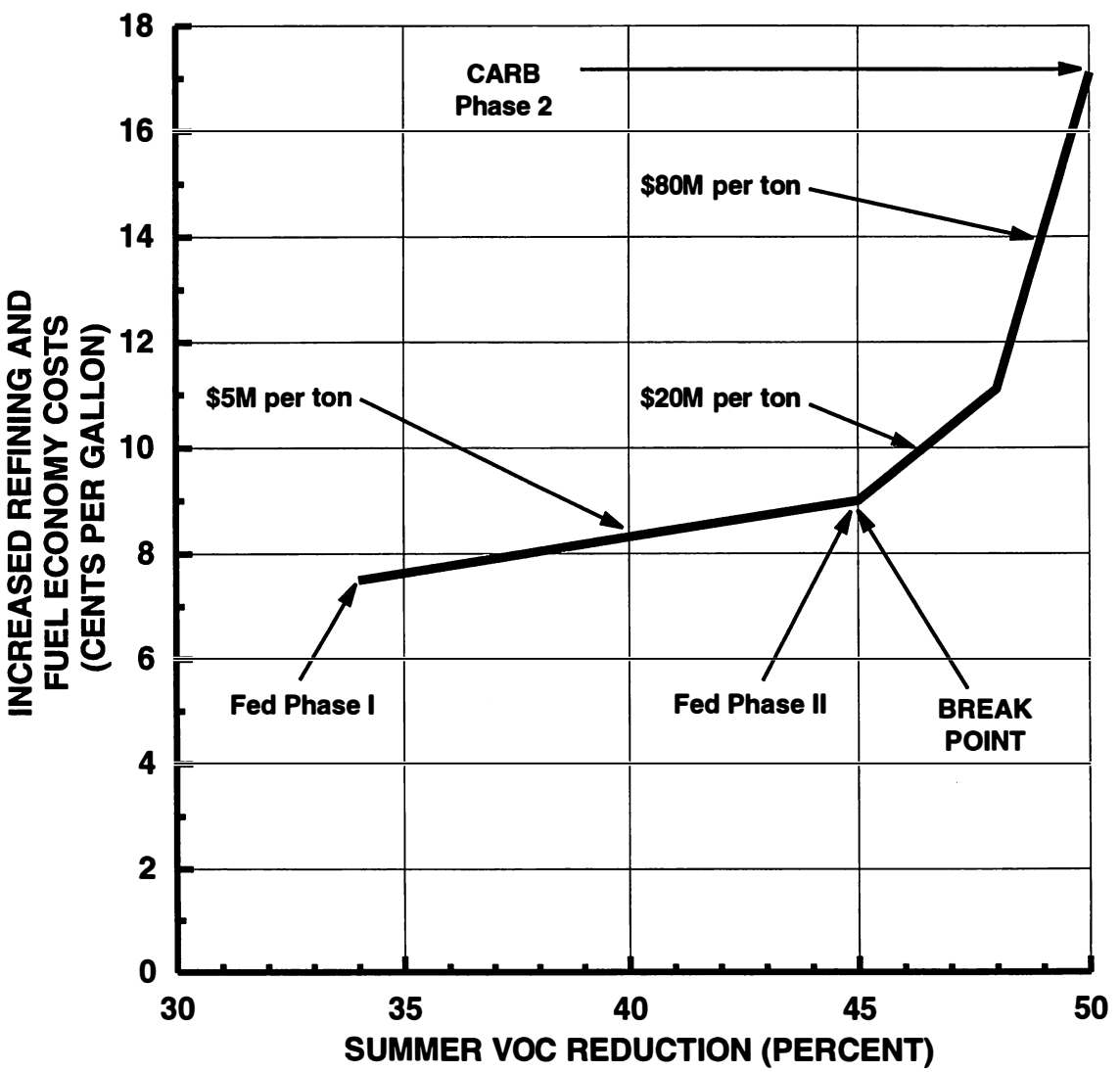


Figure 4-1. Incremental Cost-Effective Break Point Illustration for Reformulated Gasoline, PADD III, 4/92 Complex Model.

product quality were premised for diesel fuel after 1993 or for gasoline after 2000.

The majority of the refinery processing investment in the 1991-1995 time period is for facilities for hydrotreating diesel fuel, benzene reduction, refinery MTBE production, and gasoline component fractionation. In the 1996-2000 time period, these investments are primarily for fractionation, benzene saturation, desulfurization, and refinery MTBE and TAME production. No investment costs for facilities to produce merchant MTBE, methanol, or ethanol are included here but the cost of those investments are captured in the purchase cost estimated for MTBE.

Motor Fuel Production Rates

If no capacity is shut down, volumes of gasoline and diesel fuel the U.S. refining industry can produce will increase because of oxygenate addition, processing changes, and other investments needed to meet the CAAA product quality requirements (for RFG, OG, CG, and ultra-low sulfur diesel fuel).

Gasoline production capability of U.S. refineries compared to 1989 will increase by about 8 percent in 1995 and 14 percent in 2000 when running the same crude oil charge rate as run in 1989-1990.

In the reformulated product era, if crude oil charge rates were constant, the U.S. refining industry could supply up to an additional 1 million barrels per day of mixed light products including unleaded gasoline, jet fuel, and distillate compared to 1989-1990. This surplus capacity could result in significant refining industry rationalization. Alternatively, the additional product could be used for reducing imports or increasing exports, if economic. Imports of light products were 780 thousand barrels per day in 1989. Also, certain intermediate process streams that are not now generally marketed, could be exported for blending to light product outside the United States or used as petrochemical feedstock.

Based on modeling results, the U.S. refining industry would be able to produce a short-term maximum (for one month) of 12.6 million barrels per calendar day (MMB/CD) of light products in 1995 and 13.0 MMB/CD in 2000 compared to an estimated maximum of 12.0 MMB/CD in 1989-1990. Actual production of light products in 1989-1990 was 11.2 MMB/CD.

The U.S. industry is expected to retain its historical flexibility to produce, as needed, an additional 600 thousand barrels per calendar day (MB/CD) or more of distillate at the expense of gasoline production. Excess capability to make kerosene-type jet fuel (kerojet) will be reduced from about 300 MB/CD in 1989 to 200 MB/CD due to the shift of 200 MB/CD of military naphtha-type jet fuel to kerojet.

Production capabilities could be lower than reported here. This would depend upon individual refineries' capabilities rates, process interruptions, feedstocks, and product slate variations, and the need to reprocess noncomplying products resulting from too little flexibility in requirements for property ranges, caps, compliance allowances, or enforcement measures that limit compatibility.

Regional and Size Impacts on Refining

The impact of the CAAA requirements for reformulated fuels will vary regionally and with refinery size. This study was done using aggregated PADD models. Impacts on individual refineries will vary more than described herein.

In 1995, PADD I refineries will be affected the most, because of their location within an area requiring a large percentage of RFG.

PADD III refineries will require the greatest total investment due to their larger capacity, but can manufacture reformulated products at a lower per-gallon cost than other regions.

Small PADD IV refineries will face the greatest per-gallon cost increase for CAAA RFG (about 150 percent of U.S. average) and for ultra-low sulfur diesel fuel (about 200 percent of U.S. average). If Salt Lake City opts into the RFG program, it is likely that local refineries would produce RFG at unit cost greater than in other PADDs.

Northwest refineries in PADD V are minimally impacted by RFG requirements since no demand for RFG is expected in the Northwest. Part of this area will use OG in the winter time.

California refineries must meet CAAA RFG Phase I requirements in 1995 as well as CARB Phase 1 requirements. Starting in 1996, except for the small refineries, California refineries must meet much more stringent CARB Phase 2 RFG requirements. CARB low aromatics, ultra-low sulfur diesel fuel requirements start on October 1, 1993, for all vehicular diesel fuel used in California.

In general, small refineries will face the greatest cost increase in cpg for RFG and ultra-low sulfur diesel fuel if high proportions of their products are required to be reformulated.

Regulatory Uncertainties and Concerns

There are a number of areas in this study where uncertainties and concern exist over future regulatory requirements and the impact on the refining industry. Key premises (described earlier) and a large number of modeling assumptions discussed later in this chapter were established to "resolve" the uncertainties and allow the analysis to proceed. In a few situations, sensitivity cases around the uncertainties were conducted.

Many of the premises and the analytical approach itself (i.e., use of industry aggregate models) as well as developments in the regulatory process since the study was designed may lead to an optimistic or more favorable view of what is really a wider range of possible outcomes. The NPC cautions the reader to consider these uncertainties when reviewing the results presented here.

- The 4/92 complex emissions model and the underlying vehicle emission inventory model (MOBILE4.1) allow significant VOC control through relatively low-cost RVP reduction. A different model such as the EPA 2/93 complex model using MOBILE5.0 instead of MOBILE4.1 would require more costly property changes (e.g., olefin or sulfur reductions) to achieve the same target VOC benefits or NOx compliance. Conversely, use of the latter model could result in a lower target for compliance.
- The cost-effectiveness criterion (control decision benchmark) in determining the VOC reduction requirement is not well-defined. The cost-effectiveness of RFG should be evaluated on an incremental cost, incremental effect basis. If a higher cost-effectiveness target is used or if incremental cost-effectiveness is not used to determine the VOC requirement (e.g., the renewable oxygenate proposal of the 2/93 NPRM) costs and investment requirements could be higher than indicated by this report, and the industry's capability more strained. Enforcement costs, including costs incurred by refineries to insure compliance in practical gasoline manufacture, blending, and transportation are an integral part of the cost of RFG and the calculation of cost-effectiveness.
- The NOx emission performance standard used in this study assumed a requirement of "no NOx increase" on an average basis. The EPA subsequently suggested no NOx increase on a per-gallon basis or a standard requiring a substantial NOx decrease. Either would increase the cost of RFG.
- Compatibility and interchangeability of RFGs in the distribution system might not be possible or might be substantially constrained. This might result in increased cost for emission performance give-away, greater logistic system costs, and/or reduced flexibility.
- If enforcement requirements are not consistent with needed measurement tolerances, pipeline practices, and other industry requirements, more severe reformulations might be required.
- This study limits the 1995 RFG demand to the nine cities' mandatory use. Significantly higher demand for RFG in 1995 would raise costs and early investment needs. It could also strain industry's

physical capability. Current opt-in requests submitted to the EPA include the Northeast Ozone Transport Corridor and Dallas-Fort Worth. Several other areas eligible to opt-in have elected not to do so.

- Aggregate modeling results may not be equally applicable to all members of the industry. Clearly some refiners and refineries will have a more difficult time complying with the requirements than indicated for the industry as a whole.
- The complex emissions model might not be suitable for refinery operation, enforcement, and compliance purposes. Two complex model specification RFGs when blended together might not yield an acceptable RFG. The model should be scientifically as well as statistically correct. The acceptable gasoline property ranges in the complex model might not cover all expected RFGs and CGs, both summer and winter, past, present, and future and OGs.
- The transition from the simple model to the complex model for Phase I RFG might not be useful to refiners since it could result in higher cost RFG rather than the expected lower cost from increased flexibility.

MOTOR FUEL QUALITY CHANGES FOR THE CAAA

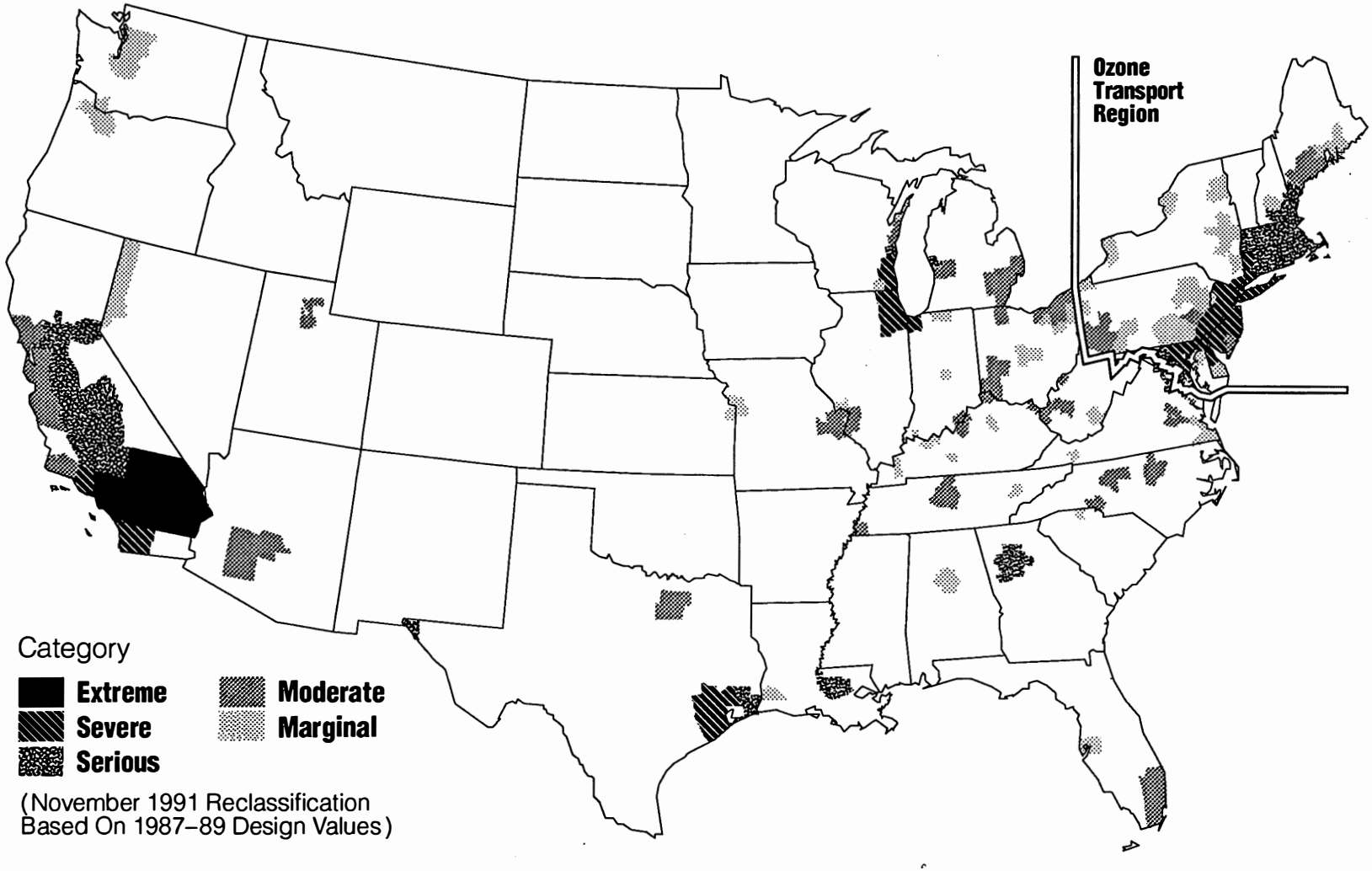
Reformulated Gasoline and Low Sulfur Diesel Fuel Overview

The reformulation of gasoline (that is, the changing of its physical and chemical properties) and the reduction of sulfur and aromatics levels in diesel fuel are currently being pursued by both the Environmental Protection Agency and the California Air Resources Board as methods of reducing vehicle emissions of carbon monoxide, toxic air pollutants, volatile organic compounds, oxides of nitrogen, and particulates. In response to specific provisions contained in Title II of the Clean Air Act Amendments of 1990, the EPA is implementing an RFG program that will go into effect in 1995 (Phase I) in the nine worst ozone nonattainment cities and, potentially, other ozone nonattainment areas (see Figure 4-2). States with ozone nonattainment areas (an additional 89 urban areas) may opt into this program. RFG requirements will be stricter in the year 2000 (Phase II). Regulations requiring diesel fuel sulfur reductions and controlling aromatics levels will take effect in October 1993. California, which has the worst air-quality problems in the country, has developed a similar but separate set of gasoline reformulation and diesel fuel requirements, with an accelerated timetable and greater stringency.

In addition to the reformulation requirements, the CAAA also require gasoline sold during winter months in 39 cities that are CO nonattainment areas to contain at least 2.7 percent (by weight) oxygen, starting in November 1992. This oxygenated gasoline program, covers 37 percent of total U.S. winter gasoline demand. Starting in 1995, this program significantly overlaps the RFG program, meaning that in many areas oxygenate program reformulated gasoline, i.e., RFG with 2.7 percent oxygen, will be supplied for part of the year. However, states can (and some have) petitioned the EPA to lower the oxygen requirement to less than 2.7 percent, if the higher level is shown to interfere with attaining other air quality requirements.

Based on 1989 consumption patterns, it is anticipated that RFG will account for about 25 percent of U.S. gasoline demand to meet the needs of the nine specified RFG cities in 1995. The combined effect of the EPA RFG program, the California reformulation program, and the pressure created on states by the other provisions of the CAAA to reduce emissions and opt into the RFG program could result in about 65 percent of gasoline being reformulated by the year 2000. Alternatively, many states with ozone nonattainment areas might choose other VOC control strategies and not opt into the RFG program.

Although 65 percent of gasoline could be reformulated by 2000, its impact is not geographically uniform. Except for surrounding suburban areas that are within a designated ozone nonattainment area and a small amount of "spillover" (i.e., unavoidable distribution of



Source: U.S. EPA, "Air Quality Designations and Classifications", 56 Federal Register 56694, 1991.

Figure 4-2. Ozone Nonattainment Areas.

RFG outside nonattainment areas due to limitation of the distribution system), RFG will be used only in urban/suburban areas and not rural areas. The exceptions to this are the states of the Northeast Ozone Transport Corridor that are to use RFG statewide, including rural areas.

Under the NPC premise of full opt-in, the Northeast, Midwest, and California will be the predominant users of RFG. Some cities in the south (including the major urban areas in Texas) will also use RFG. This means that refineries supplying PADD I and California in PADD V will face the heaviest within-PADD demand (essentially 100 percent of gasoline produced) for RFG. PADD IV refineries will, on average, face only 13 percent demand (assuming Salt Lake City opts-in). Demand for RFG in PADDs II and III will depend on the degree of opt-in, but refineries supplying both regions could be required to produce over half of their gasoline as RFG by 2000 to meet within-PADD and PADD I.demand.

This does not mean that gasoline in rural areas and the smaller urban areas will not be affected. All gasoline not reformulated, i.e., conventional gasoline, must meet certain "antidumping" requirements (i.e., avoiding the addition of blend components to conventional gasoline that were removed from RFG). This will practically limit conventional gasoline, on average, to 1990 properties or cleaner.

Similarly, the ultra-low sulfur diesel fuel changes will affect all on-highway diesel fuel beginning October 1993. While there are no opt-in type provisions, there may be spillover to non-highway diesel fuel and other distillate markets such as No. 2 heating oil.

Taken together, the CAAA product quality requirements will change the characteristics of almost half of the volume of all products produced in U.S. refineries.

The changes in gasoline and diesel fuel required by the CAAA are not the first product quality changes imposed by government and met by the refining industry. In 1971 the EPA required the introduction of unleaded gasoline. By 1975 all new cars needed unleaded fuel to protect the emissions control system, and refiners were required to supply greater quantities. Later the EPA also required reductions in the lead level of leaded gasoline grades. Other product quality changes included mandatory reductions in summer gasoline vapor pressure in 1989 and again in 1992.

Status of Rule-Making Activity

As of this writing (June 1993), the EPA has completed the initial phase of the process of developing the proposed rules governing RFG. This includes what characteristics will meet the EPA and CAAA fuel property requirements, emission performance standards, how gasoline reformulations will be approved (including the Phase I simple model for relating fuel properties to estimated vehicle emissions), and how the rules will be enforced. The EPA initially conducted a "regulatory negotiation" with the interested parties. In August 1991, an agreement was signed by members of the regulatory negotiation and, in April 1992, the EPA published a Supplemental Notice of Proposed Rule Making (SNPRM) reflecting that agreement. The EPA supplemental proposal contained a "simple [emissions] model" compliance specification for 1995 and 1996, and guidance on an initial "complex [emissions] model" that might be used for 1997 and later. This complex model, which was described in material in the docket and not the notice itself, was intended to offer refiners more flexibility than the simple model (allowing trade-offs between fuel properties within the complex model). The SNPRM also contained two options for use of the complex model as early as 1995, if refiners elect to do so.

A second NPRM was published in February 1993. This proposed rule contained proposals for a complex model, Phase II RFG VOC and TAP performance standards, proposed NOx reduction standards, a proposal for the use of ethanol or ETBE in RFG and more specific enforcement rules for use with the complex model prior to and after 1997. A final rule is expected later in 1993.

On November 22, 1991, the California Air Resources Board adopted its requirements for CARB Phase 2 RFG, which become effective in 1996. In contrast to the federal approach, eight

fuel properties are controlled separately. CARB is engaged in an ongoing effort to develop its own emissions model so that NOx, VOC, and toxic equivalent performance requirement may be substituted for the specific gasoline property specifications now contained in the CARB Phase 2 RFG requirements.

Product Quality Changes

The specific provisions of the CAAA and CARB requirements are described in detail later in this chapter. From a product quality perspective, the important changes necessary to meet the federal and California requirements for RFG will generally include some or all of the following:

- RVP Reduction
- Benzene Reduction
- Oxygenate Addition
- Olefin Reduction
- Sulfur Reduction
- T_{50} and T_{90} Distillation Point Reductions
- Aromatics Reduction

The reasons for and nature of these changes in product quality are discussed below. Their impacts on refinery investment needs, product costs, and refinery output capabilities are reported in the following sections of this chapter. However, these results must be viewed within the context of the limitations of a study of this type:

- The analyses conducted for this study focus on changes required by the refining industry to produce products with certain average properties.
- The analysis is dependent on aggregate, annual (or seasonal) modeling of a PADD level industry average refinery. Variations among refineries, in crude oil input, specific product output, or equipment availability are not determined.
- The study does not consider the impact of enforcement and compliance schemes associated with the required product specifications, nor the impact on refinery operations of post-refinery compliance program requirements that may limit product variability or compatibility.
- It was conducted at a time, as noted above in the discussion of the rule-making status, when key elements of the RFG regulatory program (such as the complex model, ethanol use program, and enforcement schemes) were not finalized.

Federal Reformulated Gasoline

For 1995-1997 reformulated gasoline, the EPA is concentrating on four parameters—RVP, benzene, aromatics, and oxygen—to achieve the required level of emission control. Under the simple model contained in the EPA proposed rule, the initial 15-percent reduction of VOCs will be met almost entirely by RVP reduction. Volatility requirements in place since 1992 will limit RVP to 9.0 psi in northern areas and to 7.8 psi in southern ozone nonattainment areas. Based on the MOBILE4.1 version of the EPA's emissions inventory model, the EPA determined that lowering RVP to 8.1 psi and 7.2 psi will result in VOC reduction of over 15 percent in northern and southern areas, from their respective baseline gasolines. The 15 percent TAP reduction will be determined with an emissions model; compliance will be achieved primarily by benzene and RVP control, which indirectly cut TAP (because the toxic air pollutants are, in part, a subset of the vehicle's VOC emissions, and benzene is the primary TAP). The simple model does, and the complex model likely will, allow some trade-off between aromatics reduction and benzene reduction.

Other gasoline parameters (olefin and sulfur levels, T_{50} and T_{90} distillation points) influence the NOx, VOC, and TAP emission levels. Implementation of the complex model for 1997 (or earlier optional use in 1995 or 1996), will allow refiners to optimize these parameters to achieve the CAAA's performance standards. For the more strict Phase II RFG (year 2000) performance requirements, a greater degree of reformulation, involving some or all of the parameters mentioned above, will be required. The impacts of those changes will depend on individual refinery situations, the complex

model adopted by the EPA, the severity of Phase II VOC, NOx, and TAP performance standards, and enforcement requirements.

Based on the work performed for this study and a review of the EPA February 1993 NPRM, the quality changes beyond the compulsory oxygenate required for summer VOC-controlled Phase II RFG are likely to include some combination of RVP reductions to as low as 6.5 psi, aromatics reductions to less than 25 percent, benzene reductions to 0.95 percent or less, sulfur reductions to less than 200 parts per million (ppm), and possibly reductions in olefin content (to less than 10 percent), and in T_{50} and T_{90} distillation points. Winter RFG will also have quality changes beyond the compulsory oxygenate addition, most likely in terms of lower benzene, aromatics, sulfur, and possibly olefins levels, to achieve TAP and NOx performance requirements.

Of particular interest are the factors affecting the possible need to reduce olefins. The cost of achieving olefin reductions, the low olefin level in the CAAA baseline and the strong relation between olefin level and NOx emissions in the 2/93 EPA complex model all make this quality change of particular concern.

Conventional Gasoline

While conventional gasoline must meet only limited "antidumping" (no emission increase) requirements, control of its quality and, under certain circumstances, some changes in quality will be required. As refineries adjust the quality of their RFG pools, efforts must be made to hold the quality of the conventional gasoline pool to its 1990 baseline properties or performance limits.

California Reformulated Gasoline

For 1992, California established requirements for Phase 1 gasoline including statewide RVP and olefin limits. In 1996 more severe specific fuel property specification limits (as opposed to emission performance standards) are set for RVP, sulfur, aromatics, benzene, oxygenate, and olefin content, and for T_{50} and T_{90} points.

Table 4-2 shows a comparison of possible properties of federal Phase I RFG for southern simple model gasoline, CARB Phase 2 gasoline and the CAAA 1990 summer baseline. Note the significantly lower sulfur, T_{90}, and olefin properties in the CARB Phase 2 gasoline.

TABLE 4-2

COMPARISON OF CALIFORNIA GASOLINE WITH FEDERAL SUMMER REFORMULATED GASOLINE

	CARB Phase 2 (per gallon specifications)	Federal Phase I, Southern (per gallon, possible properties)	CAAA Summer Baseline
Oxygen (wt%), Min.	2.0	2.0	0.0
Sulfur (wt%), Max.	40	339	339
RVP (psi), Max.	7.0	7.2	8.7
T_{50} (° F), Max.	210	218	218
T_{90} (° F), Max.	300	330	330
Aromatics (vol%), Max.	25.0	26.2	32.0
Olefins (vol%), Max.	6.0	9.2	9.2
Benzene (vol%), Max.	1.0	1.0	1.5

Source: *Federal Register*, Vol. 58 No. 37, Friday, February 26, 1993, p. 11, 746, "Regulation of Fuel and Fuel Additives: Standards for Reformulated Gasoline: Proposed Rule."

Diesel Fuel

In addition to the RFG requirement, the CAAA required that the EPA issue rules requiring that all on-highway diesel fuel have a maximum sulfur content of 0.05 percent (by weight) and a minimum cetane index of 40 (deemed equivalent to a maximum aromatics level of 35 percent). These CAAA requirements mirrored actions that the EPA had already taken in promulgating ultra-low sulfur diesel fuel (and minimum cetane index) requirements on August 21, 1990. The effective date for these changes in diesel fuel quality is October 1, 1993.

The 0.05 percent sulfur requirement is designed primarily to help reduce diesel engine particulate emissions impact both by the direct reduction of particulate emissions (primarily hydrated sulfur oxides) and by allowing more effective use of exhaust catalysts. The minimum cetane index requirement is a proxy for an aromatics limit and is also designed to aid in particulate and toxic emission control.

Separately, California has adopted vehicular diesel fuel requirements for reduction in sulfur levels to 0.05 percent and reductions in aromatics levels to 10 percent or less (or the "equivalent performance" by other fuel property modifications).

Ethanol and Reformulated Gasoline

While the CAAA do not contain specific requirements regarding the use of ethanol (as opposed to oxygenates in general) in RFG, there has been a long-standing interest by a number of parties to ensure that ethanol plays a significant role in meeting RFG oxygen content requirements. To this end, the February 1993 NPRM contained a proposal to allow a 1 psi RVP waiver for the use of ethanol in up to 30 percent of RFG consumed in northern cities. Increased VOC emissions resulting from this ethanol use would be offset by requiring the RVP of a RFG that does not contain renewable oxygenates (e.g., ethanol or ETBE) to be 0.3 psi lower than would otherwise be required in those cities (i.e., RFG not using ethanol or ETBE would have to be 7.8 psi instead of 8.1 psi under the simple model standards in 1995). The maximum RVP of RFG using ethanol or other renewable oxygenate in the 30 percent program is 8.8 psi. Southern cities would be able to opt into the RFG with ethanol program with a waiver applying to up to 20 percent of the market and by reducing RVP of all gasoline by 0.2 psi to 7.0 psi.

The NPRM also includes proposals for the use of ethanol and ETBE ("renewable oxygenates") under the complex model, more stringent performance standards for RFG with MTBE, and an enforcement scheme that encourages ethanol use by economically penalizing refiners who do not choose to use ethanol or ETBE in 30 percent of their summer RFG. In addition, the number of RFG products and extent of record keeping required, increase significantly. There is substantial uncertainty surrounding the final form of these requirements. As a result, analysis of the impact of this proposal on product quality was handled as an alternative case.

The product quality changes required by the proposal will depend on the final form of any "renewable oxygenate" rule, the complex model, the VOC and NOx performance standards, and refiner's choice between ethanol and ETBE. For 1995-1999 Phase I RFG, the proposed rule can be met by reducing RVP. For 2000 and later, the additional VOC reductions required under the program will require processing changes, e.g. further reductions in olefin, T_{90}, and sulfur. In both periods, ETBE may have unique advantages under the proposal because of its low RVP.

Segregations and Handling Requirements to Maintain Product Quality

In addition to the required changes in product quality, the EPA NPRMs contain enforcement and compliance requirements that will necessitate changes in product handling. These requirements are designed to assure maintenance of RFG properties as the products pass throughout the logistics system to the final consumer. Some of the requirements also are designed to provide the EPA, refiners, and product handlers (e.g., terminal operators) the data and documentation needed to

avoid product quality violations or to determine how they occurred. These requirements are focused on individual refiners or refineries and on the individual nonattainment areas.

The primary impact of those requirements outside the refinery will be to require a greater number of *segregations* (e.g., RFGs certified with the simple emissions model vs. complex emissions model) of similar products than has been the case in the past.

In addition, a much greater degree of *testing* of product properties, and *documentation* of product characteristics, origin, and destination will be required. Because of variability in testing methods, the cost of increased segregation and the difficulty in predetermining the destination of product shipments refiners may make additional (or more severe) changes in product quality than those discussed above in order to meet the full range of the EPA requirements. This is discussed in more detail later in this chapter.

OVERVIEW OF METHODOLOGY

Study Strategies

The impact of government regulations on the U.S. refining industry's product quality is extensive. A list of product quality issues was developed by the DOE and by the NPC to define the scope of the study. Each issue was analyzed in terms of data needed, analytical tools employed, premises required, time frame of interest, geographical differences to be considered, and the impact on refineries of differing size and complexity.

As a result of this review, the following decisions were made:

- Geographical areas would conform to PADD descriptions.
- Two types of refineries would be considered—simple and conversion.
- A refinery survey would be used to inquire as to future refinery operating plans and to obtain historical and forecast operating data that could be aggregated on regional and size bases. These data would be used as a check on the modeling results.
- Aggregate linear program (LP) mathematical models of a number of regional refinery groups would be employed rather than using a number of models of individual refineries with differing process equipment and crude oil handling capability. Two types of LP models would be required—one that would provide cost data as a function of refinery throughput and one that would provide investment, costs, gasoline emissions performance, and refinery capability information.
- The models of PADDs III and IV would be used as surrogates for large and small refineries.
- When studying the increased cost of RFG quality changes, the objective of the model runs would be to minimize the cost of manufacturing average RFG satisfying a target emissions reduction. A small number of runs would optimize operations to meet individual gasoline property constraints.
- LP modeling results would be compared to those of base cases that reflected operations without the CAAA. Results would be developed for the primary implementation dates of the CAAA—1995, 1997, and 2000.
- Not all issues would be studied in all PADD regions. Where necessary, estimates of U.S. industry impacts would be developed from the results of a limited number of PADDs.
- Seasonal results would be developed as required by individual issues.

Refinery and Emission Models

Refinery Model

The study objectives require analyses of refinery capability, product quality, and the costs of reformulating products under differing conditions of regulatory severity, cost-effective limits, current refining complexity, and refinery size and location. These analyses required

a sophisticated modeling system that could provide quantitative assessments of these differences. The intent of such a model would be to provide a tool for analyzing the above differences with constant demand of light products.

Turner, Mason & Company was selected as a consulting contractor to utilize its proprietary LP refinery modeling system for these studies and to assist in developing assumptions, premises, study case designs, and analyses to meet the needs of the refining study. The option of using a consultant's model was chosen over development of one by the study team, as has been done in past studies, out of consideration of timeliness, cost-effectiveness, the consultant's industry expertise and ready data base, and a skilled staff to supplement the expertise of the study participants.

The U.S. industry was simulated through the use of LP models of six regional industry conversion refineries supplemented by a single material balance simulation used to portray the simple refineries of all the geographical regions except for the Rocky Mountain region (PADD IV) where simple refineries were included with the conversion refineries. The total grouping represents the U.S. refining industry. This division into smaller groupings was done to lessen the over-optimization that tends to occur with the use of aggregate models. The Turner-Mason refinery model also reduced this over-optimization through extensive calibration and adjustment to historical data. A complex emissions model has been added to the refinery model as part of the LP optimization for meeting emission constraints.

Optimization of the refinery model provided a minimum cost solution to meet the constraints of emission standards or product properties. Constraints were met in both reformulated and conventional products. Solutions were demand driven to meet fixed light product demand with only the manufacture of high sulfur fuel oil, coke, butane, and lighter gases allowed to vary. Other variables were process unit utilization, addition of process unit capacity, process unit severities, and limited selection of raw material inputs.

Emission Models

The refinery model was used to estimate the gasoline composition, cost, and refinery investment required to achieve specific emission reduction targets and property limits. The emission performance of gasolines was defined using several proposed emissions models. For Phase I (1995), a "simple emissions model" was used to estimate VOC and TAP emissions. For Phase II (2000 and a singular 1997 case), a "complex emissions model" was used.

For 1995, the simple model defines VOC emissions as a function of RVP and oxygen content provided that other properties that might affect VOC emissions remain at or below 1990 levels. TAP emissions are defined as a function of RVP, oxygen, benzene and aromatics levels. NOx is deemed to meet the "no NOx increase" requirement as long as oxygen levels are at or below 2.1 percent or, in the case of MTBE, 2.7 percent by weight. Under the simple model, conventional gasoline is assumed to be in compliance as long as relevant properties are capped at 125 percent of 1990 refinery averages. Taken together, these simple model requirements were used to define property limits for RFG and CG within the refinery industry models.

Starting four years after a final rule is established (year 1997 for the purposes of this study), a final EPA complex model will be used to certify gasoline VOC, TAP, and NOx emission performance. At the time this work started (Spring 1992), a formal EPA-approved complex emissions model was not available and a surrogate complex model called the 4/92 complex model was used in this study. This 4/92 complex emission model estimates VOC, TAP, and NOx emissions as a function of oxygen, sulfur, aromatics, olefin, and RVP levels, as well as T_{50} and T_{90} (and benzene content for TAP). The VOC, TAP, and NOx reduction portions of the complex model were incorporated into the refinery LP model. In this way, emission reduction requirements could be treated as additional model constraints, and optimization could take place among all parameters in terms of cost and emission reduction benefit. Using this model, the emission benefits and cost effectiveness (dollar per ton

of VOC reduction) could be calculated from the properties of the several types of gasolines (RFG, conventional gasoline, etc.) produced by the optimal refinery model solution.

Key Premises For Modeling

Cost Basis

The cost estimates presented in this study of U.S. refining capability are incremental production costs from those of a base case representing refinery operations in the same time frame and season but without federal CAAA product quality regulations in place. The base case operations were premised in a fashion to isolate the incremental costs as much as possible to the reformulated product of interest.

The product quality analysis focused on the change in two major products—gasoline and diesel fuel/distillate fuels. Study premises assumed constant product quality for the balance of the refinery products, with the exception of the shift to the use of JP-8 grade for military jet fuel and the removal of lead from the gasoline pool.

The only regulations represented in these costs are those associated with product quality environmental requirements. Other regulatory categories affecting refineries are considered in Chapter Two and do not affect product quality.

Capital recovery for added investment assumes 10 percent rate of return. (See Appendix M, Table B-6 for a detailed description.)

Reformulated Gasoline

The base case used to study incremental costs for RFG for nearly all of the study assumed the U.S. no demand growth case on a heating value adjusted basis. This constant demand base was used throughout the 1995-2000 period for consistent comparisons. The annual product demands for this base case were seasonalized to six month "summer" and "winter" periods based on historical seasonality factors.

In order to estimate the total refining cost of various requirements in the CAAA, it was necessary to develop a case for the year 2000 without these regulations. Two cases were needed to separate the cost of RFG issues from low sulfur diesel fuel issues. One of these cases assumed no reformulated gasoline in the year 2000 but did include ultra-low sulfur diesel fuel. The other case assumed neither reformulated gasoline nor ultra-low sulfur diesel fuel to provide a basis for calculating the cost of ultra-low sulfur diesel fuel.

Distillate Fuels

The basis for consideration of the distillate fuels cases was the U.S. no demand growth case assuming that the Clean Air Act was not in effect. Only annual cases were done. The various cases assumed ultra-low sulfur for on-highway diesel fuel, all diesel fuel, and all distillate fuel, respectively. Another case studied the effect of manufacturing low aromatics distillate fuel throughout the United States (rather than just California).

Refinery Product Demand Levels

Refinery product demand for use in this modeling was developed from the consumer supply and demand scenarios prepared by the Supply, Demand, and Logistics Task Group. Three product demand scenarios were provided; U.S. demand growth, no demand growth, and declining demand relative to the 1989-1990 time frame. In all cases, world demand increased for this refinery model. Refinery demands for this modeling work were calculated by assuming product imports and exports remaining constant at 1989 levels.

Refinery Capacity Basis

The capacity basis for the refinery model was all operable refineries as of January 1, 1991, as reported by the DOE in the 1990 *Petroleum Supply Annual* plus announced projects and restarts as of October 1991.

Constant Crude Oil Quality

To simplify the modeling and focus on the effects of product quality specifications changes, crude oil qualities of refinery inputs were assumed to remain comparable to 1989 crude oil qualities for model runs. Survey results concerning anticipated crude oil qualities are discussed later in this chapter.

Current Refinery Technologies

While the 1990s will surely see further technological change, the nature of this change cannot be predicted. Refinery technologies were assumed to remain comparable to current technologies, although capacities were allowed to change.

Octane

The octane ratings of motor gasoline are assumed to remain constant at 1989 levels.

GASOLINE

RFG Program Requirements

This section addresses the changes in gasoline composition and quality that will occur due to the air emission legislation contained in the Clean Air Act Amendments of 1990. Studies are provided for the years of 1995, 1997, and 2000, which are the implementation dates of important changes required by the CAAA.

The emissions reduction estimated with reformulated gasoline depend on the properties of both the RFG and of the baseline gasoline and the procedure used for estimating the emissions. The emissions calculation procedure has two major components: non-exhaust emissions estimates based on the mobile source emissions inventory models (MOBILE4.1 or MOBILE5.0) and exhaust emissions estimates (based on the simple model or the complex model). The MOBILE model incorporates the EPA's assumptions about vehicles and their use (fleet age and composition, vehicle miles traveled, fuel economy, on-board controls and effectiveness, inspection and maintenance, high emitters, etc.) and other bases of the emission calculations (e.g., ambient conditions). The non-exhaust and exhaust emissions estimates are combined to provide total emissions. The same procedure is used to estimate emissions from the baseline gasoline and the reformulated gasoline. The models (MOBILE4.1 and MOBILE5.0) give significantly different estimates of emissions from the baseline gasoline and of the portion of total VOC emissions attributed to evaporative emissions relative to exhaust emissions.

Figure 4-3 is a timeline based on the EPA February 1993 NPRM from 1995 through 2000 describing the baseline gasoline, vehicle emissions model, compliance emissions model, and emission performance standards for reformulated and conventional gasolines. Note that the EPA will change the mobile source emissions inventory model it uses from MOBILE4.1 to MOBILE5.0 in the year 2000.

The 4/92 complex model used for this NPC work assumed the use of MOBILE4.1 as the mobile source emissions inventory model. As discussed later in this chapter in connection with 2000 case studies, results with the 2/93 EPA complex model which uses MOBILE5.0 are compared with results using the 4/92 complex model and MOBILE4.1. The difference in the results illustrates the influence of the emission and MOBILE models on the total emission estimates.

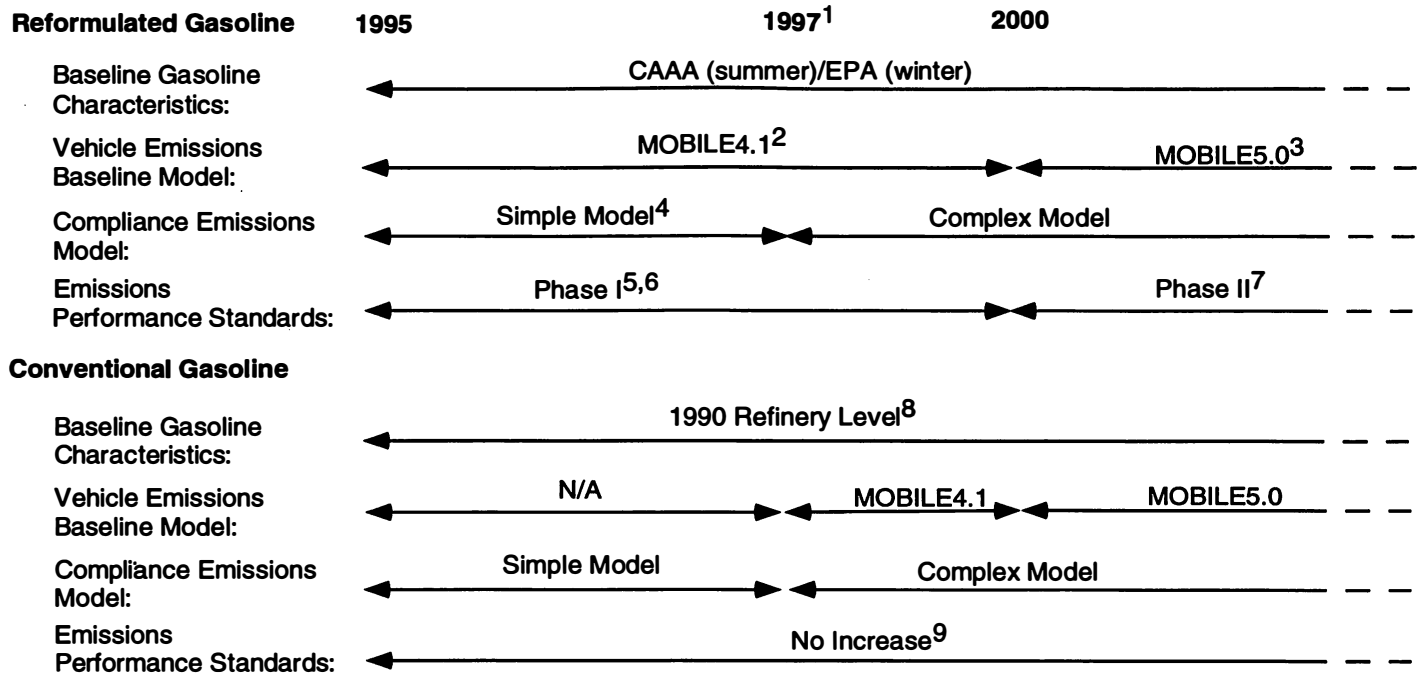
Phase I RFG Under the Simple Model

The CAAA performance requirements for RFG beginning in 1995 include:

- Volatile organic compounds: Requires a reduction of at least 15 percent during the summer high-ozone season, compared to the calculated VOC emissions from the refiner's 1990 baseline fuel.
- Toxic air pollutants: Requires a reduction of at least 15 percent of air toxics during the entire year, compared to the calculated TAP emissions from the refiner's 1990 baseline fuel.
- NOx: No increase.

As a result of the Regulatory Negotiations, the EPA has proposed that RFG produced under the simple model, meeting the following composition requirements (on each gallon of RFG), will meet the CAAA performance requirements.

- Oxygen: 2.0 wt% minimum (2.7 wt% MTBE maximum)
- Reid Vapor Pressure: 7.2 psi RVP maximum in southern areas and 8.1 psi RVP



[1] Four years after EPA promulgation of the complex model. Earliest possible date is 2nd half 1997.

[2] Refers to EPA MOBILE Source Emission Inventory model which define 1990 baseline emissions values from which reductions must be achieved. Of critical importance is the relative weighting of exhaust and non-exhaust VOC emissions. MOBILE 4.1 heavily weights (65%) non-exhaust (e.g. evaporative) VOCs.

[3] Heavily weights (60%) exhaust VOCs.

[4] Proposed EPA rules allow for optional use of complex model.

[5] Percent Reductions (every gallon)
VOC: 15% to 28% (northern and southern cities) plus ethanol accomodation
NOx: No increase
TAP: 15%

[6] These emission reductions requirements may change in 1997 with the shift in the complex model.

[7] Percent Reductions (every gallon)
VOC: >25% to "cost effective" level, plus ethanol accomodation
NOx: No increase to 15%
TAP: 20% to 25%

[8] Refinery or Refiner's Average with heirarchy of procedures for establishing values.

[9] In 1995-1997, no increase in sulfur, olefin and T_{90} levels is allowed above 125% of baseline, except for calculated exhaust benzene which is held to 100% 1990 baseline in all years. Under the complex model compliance is determined on the basis of TAP and NOx performance, not gasoline property levels.

Figure 4-3. Federal Reformulated Gasoline Proposed Program Requirements. (Based on February 1993 NPRM).

maximum in northern areas, in the summer only

- Benzene: 1.0 vol% maximum
- Sulfur, T_{90}, and olefins are capped at 100 percent of the 1990 refinery average baseline.
- Toxic air pollutants: Assume at least 15 percent reduction will be achieved with control of benzene, oxygen, and aromatics content.
- The CAAA also prohibits lead anti-knock compounds beginning on January 1, 1996, and in January 1995 requires use of additives to reduce engine and fuel supply deposits. This applies to all gasoline, both conventional and reformulated.

In addition, the antidumping regulations require that conventional gasoline produce no more exhaust benzene emissions than the refiners' 1990 average (baseline) and that sulfur, T_{90}, and olefins be capped at 125 percent of the refiners' baseline.

In 1995, RFG is needed to supply at least the nine cities whose ozone nonattainment status is severe or greater. In addition to supplying these cities, there will be some "spillover" to areas that do not need RFG. Early estimates of this spillover were about 10 percent of the required RFG. This spillover estimate was used in the refinery modeling work. A later, more detailed estimate of spillover, only 1 percent, was used for the logistics analysis. The difference between 1 percent and 10 percent spillover estimates is about 2 percent of the total 1995 summer gasoline production by U.S. refiners. This variance does not appear significant because of the large uncertainty surrounding the actual increase in RFG demand that will result from opt-ins over time. The cost of RFG on a "per-gallon" basis will not be significantly affected by the different spillover levels.

The requirement to supply RFG to the nine cities with serious ozone problems creates areas of the country where the production of RFG is high while other areas produce none. Figure 4-2 shows the primary need for RFG in 1995 to be in California and the East Coast. Table 4-3 shows the assumed refinery production of RFG needed to supply the nine cities by PADD. Note that PADD I and the California sector of PADD V have the most production (about two-thirds of the total) while other PADDs produce little or none. To simplify the modeling work, PADD I refineries were assumed to make all their gasoline as reformulated because of the large expected demand in this PADD. The remainder of PADD I's supply of RFG is assumed to be produced in PADD III.

TABLE 4-3

ASSUMED SUMMER 1995 REFINERY PRODUCTION OF GASOLINE BY PADD
Based on Supplying the 9 Mandated Cities with RFG
(Thousand Barrels per Calendar Day)

	Conversion Refineries							
	PADD I	PADD II	PADD III	PADD IV	PADD VC*	PADD VOC†	Simple Refineries	Total
Reformulated	692	276	359	0	575	0	0	1,902
Conventional	0	1,414	2,803	245	390	222	72	5,146
Total	**692**	**1,690**	**3,162**	**245**	**965**	**222**	**72**	**7,048**

* PADD VC is PADD V California only.

† PADD VOC is PADD V Outside of California.

The investment for producing the above volume of RFG in 1995 will be about $3 billion for refinery equipment. These investments (Table 4-4) are for the additional equipment needed over the base case. The added refining cost to produce summer RFG in the United States is about 5.5 cpg of RFG. The total U.S. investment and the per-gallon cost are estimates based on extrapolating PADD studies.

Reformulated gasoline production at low portions of the pool can be produced for about 3 cpg. Above 75 percent reformulation, such as in PADD I, the refining costs rise to the 6 to 7 cpg range primarily because of the greater share of MTBE purchased rather than internally produced. The added cost is sensitive to the price of MTBE.[3]

A model of PADD III was used to estimate the added refinery equipment, its investment cost, and operating cost to produce 11 percent RFG in the summer. Although the quantity of RFG was small, the aggregate PADD III refinery model indicated difficulty in achieving the benzene limit of 0.7 vol% and meeting the antidumping regulations that prevent blending of the displaced components into conventional gasoline. The 0.7 vol% benzene specification for modeling rather than the statutory 1 percent specification level is in recognition of analytical test tolerances. Table 4-5 shows the necessary added equipment assuming PADD III

[3] This refinery modeling work premised that a 10 cpg premium over 1990 prices would be required for MTBE purchases in 1995 and 2000. If the premium does not develop as premised, the refining cost for the high reformulation cases would be in the 5 to 6 cpg range.

TABLE 4-5

1995 PADD III GASOLINE PRODUCTION ADDITIONAL EQUIPMENT AND INVESTMENT TO PRODUCE SUMMER SIMPLE MODEL RFG (9 CITIES ONLY)

Production, Thousands of Barrels per Calendar Day	
Conventional Gasoline	2,803
Reformulated Gasoline	359
Unit, Thousands of Barrels per Stream Day	
Reformer Feed Fractionation	608
Reformate Fractionation	237
Benzene Separation	12
MTBE Unit	19
Refinery Investment, Millions of 1990 Dollars	825

TABLE 4-4

ESTIMATED 1995 INCREASED COSTS OVER BASE CASE* FOR 1995 SUMMER SIMPLE MODEL RFG (1990 Dollars)

	PADD I	PADD II	PADD III	PADD IV	PADD VC	PADD VOC	Total U.S.
RFG % of Pool	100	16	11	0	59	0	27
Refinery Investment, $Billions	1	0.5	0.8		0.5		3.0
Refining Cost of RFG, cpg†	7.0	3.0	3.0		7.1		5.5

* Base cases are 1995 with no CAAA – summer season.

† Refining costs include:
1. Capital charges for new facilities.
2. Raw material upgrading costs.
3. Fixed cost for new facilities.

TABLE 4-6

U.S. AVERAGE REFINING COST OF SUMMER REFORMULATED GASOLINE USING THE 1995 SIMPLE MODEL

	Percent RFG	Volume RFG (MB/CD)	Refining Cost (cpg, 1990 dollars)
Nine Cities Only	27%	1,902	5.5
Full Opt-in	65%	4,628	6.0

refineries make at least 11 percent RFG. The model built 608 thousand barrels per stream day (MB/SD) of reformer feed fractionation capacity and 237 MB/SD of reformate fractionation to get benzene down to the 0.7 vol% level in RFG while not increasing the benzene content of conventional gasoline.

Since there is considerable variability between individual refineries, it is likely that some refineries will produce RFG with little additional investment while others will elect not to produce it at all. The likely result of this is some reduction in capital cost.

Because of the difference in vapor pressure between the two types of gasoline, it is possible to move higher vapor pressure components into conventional gasoline from RFG and eliminate the capital needed to control vapor pressure by more expensive means. For this case, the RVP of 1995 RFG produced in PADD III refineries was 7.2 psi.[4]

An additional level of summer RFG production was analyzed for 1995 that represented full opt-in by other ozone nonattainment areas. The full opt-in case requires RFG for 65 percent of the U.S. production or 4,628 MB/CD. Table 4-6 summarizes the refining cost and volumes of RFG under the base case and full opt-in scenarios for the total U.S. The required volume for oxygenates was assumed to be available for purchase.

PADDs II and III were studied using the refinery models to determine the extent of investments required to produce sufficient RFG to satisfy demand assuming full opt-in. Table 4-7 summarizes both capital investment and required equipment. In PADD III the investment required for full opt-in increases by about 2.8 times the level of just supplying the nine cities. The RFG production, however, increases about 5.6 times. As in the nine cities' cases, nearly all the investment is for benzene removal. Benzene removal has no effect on reducing VOCs, but is effective in reducing toxics.

Survey Results

In the NPC survey, refiners were asked whether new facilities would be needed in 1995. The respondents indicated that most of these new facilities would be required to produce RFG meeting a benzene specification of 1 percent while complying with the antidumping requirement. These survey results agree qualitatively with the conclusion from the PADD III refinery modeling work—benzene reduction will be the main driving force for refiners' new capital equipment for simple model Phase I RFG. Table 4-8 highlights, from the survey, the expected changes to many of the facilities used to modify gasoline properties. For a full discussion of the survey, see Chapter Five.

With the exception of alkylation and oxygenate production all the processes in Table 4-8 significantly affect the quantity of benzene in gasoline.

While aromatics saturation units as a means of destroying benzene will be relatively unattractive in 1995, the capacity is expected to increase from 11 to 44 MB/SD during this period.

[4] This assumes 40 percent Northern gasoline; 60 percent Southern gasoline; and a 0.3 psi RVP compliance margin.

TABLE 4-7

1995 PADD II AND III GASOLINE PRODUCTION ADDITIONAL EQUIPMENT AND INVESTMENT TO PRODUCE SUMMER SIMPLE MODEL RFG (FULL OPT-IN)

	PADD II	PADD III
Production, Thousands of Barrels per Calendar Day		
Conventional Gasoline	750	1,176
Reformulated Gasoline	950	2,014
Unit, Thousands of Barrels per Stream Day		
Reformer Feed Fractionation	822	1,476
Reformate Fractionation	97	267
Aromatic Extraction		66
Benzene Saturation	48	85
MTBE Facilities		34
Refinery Investment, Millions of 1990 Dollars	1,124	2,352

TABLE 4-8

NPC SURVEY DATA ANTICIPATED CHANGES TO GASOLINE-RELATED PROCESS UNITS 1991 THROUGH 1995

Process Unit	Actual 1/1/91 Capacity (MB/SD)	Number of Responses	Anticipated 1/1/96 Capacity (MB/SD)	Number of Responses	Anticipated Change in Capacity (MB/SD)
Aromatic Saturation	11	3	44	10	33
Catalytic Reforming					
High Pressure (>225 psig)	1,484	76	1,174	63	(310)
Low Pressure (<225 psig)	1,591	57	1,665	59	74
Continuous Catalyst Regen.	574	19	783	26	209
Isomerization	382	26	524	41	142
Alkylation	1,037	100	1,115	100	79
Oxygenates					
MTBE	40	19	161	55	121
TAME	0	0	63	24	63
Secondary Gasoline Fractionation	2,381	44	3,574	58	1,193

Note: 154 of 199 refineries responded to the NPC Survey. The responding refineries represent almost 95 percent of 1990 U.S. crude oil inputs. However, not every refinery responded to every question.

Source: NPC Survey Section II, Part A.

Isomerization of pentanes and hexanes appears to be a very popular route to prevent benzene production while at the same time increasing the octane of the gasoline pool. The respondents anticipated an increase in capacity from 1991 to 1996 of 142 MB/SD.

Some high pressure reformers are expected to be replaced with new low pressure units. Low pressure units produce less benzene, have better yields, and produce more hydrogen at the same octane as a high pressure unit. In addition, respondents anticipated that reformers will operate at slightly lower octane levels in 1995. Reducing octane will reduce both benzene and aromatics.

Respondents are planning a large increase in oxygenate capacity. MTBE production capacity increased from 40 to 161 MB/SD from 1990 to 1996. TAME capacity increased from 0 to 63 MB/SD in the same period.

Respondents anticipate building 1,193 MB/SD of secondary gasoline fractionation doubling the capacity of these units. This likely anticipates further processing or component sales.

1996 California Air Resources Board (CARB) Phase 2 Gasoline

California RFG in 1996 and beyond must meet CARB Phase 2 regulations, which are more stringent than required by the federal CAAA. The NPC did not study the cost or capability for manufacture of reformulated gasoline for use in California. However, to complete U.S. industry balances for the NPC study, estimates for California RFG were made by incorporating publicly available studies prepared for the Western States Petroleum Association (WSPA) in 1991.[5] Those studies analyzed the effect of CARB Phase 2 regulations on RFG cost and manufacturing capability. These prior cost estimates were made consistent with the NPC study by adjusting return on investment to 10 percent per year and by amortizing the investment for VOC emission reduction solely in the summer ozone period.

The CARB Phase 2 specifications, on a per-gallon basis, are shown in Table 4-2. The regulations also permit compliance on an average gallon basis as follows: 22 percent aromatics content, 4 percent olefin content, 6.6 psi RVP summer maximum, 30 ppm sulfur content maximum, 1.8 to 2.2 percent oxygen content, 200°F T_{50} maximum, and 290°F T_{90} maximum. Emission reduction performance for the adjusted WSPA results were computed using the complex models assumed in the NPC study based on the California gasoline composition.

CARB Phase 2 gasoline provided the highest emission reduction of any reformulated gasoline analyzed in the NPC study, providing high reductions of VOC, TAP, and NOx emissions from the 1990 statutory baseline. The added refining cost of CARB Phase 2 RFG in California is estimated to be 15.1 cpg over conventional gasoline. The estimated added refining cost for the U.S. on a 100 percent basis is 17 cpg. The estimated cost of manufacture is the highest developed in the study and its incremental cost-effectiveness the highest cost per ton of VOC reduction.

Phase I RFG Performance Under the Complex Model

Beginning four years after final promulgation of the complex model, the same emissions reduction performance standard as in the 1995-1997 time frame will apply, but the new complex model will be utilized to determine RFG compliance. The baseline gasoline that is used to determine percent emission reductions for RFG also changes in 1997 from the 1990 refinery baseline gasoline to the CAAA summer baseline and the EPA winter baseline gasolines. In addition, the specifications for gasoline deemed to be in compliance with the simple model will have to be proven in compliance using the EPA complex model.

Switching to the EPA Complex Model in 1997

A PADD III refinery model, producing 63 percent (full opt-in) summer (VOC con-

[5] Adapted from WSPA Study of the Cost Impacts of Potential CARB Phase 2 Gasoline Regulations, WSPA Contract No. DF 206-46, Phases I, II, III, November 18, 1991, Turner Mason & Company.

trolled) RFG, was used to compare the added refinery facilities and the refinery cost to produce RFG using the 4/92 complex model and the EPA simple model at the same VOC reduction level. PADD III was selected because it represents the largest gasoline producing PADD. The 4/92 complex emissions model predicted that both NOx and TAP reductions would be satisfied as well as the VOC reduction. This produced a straightforward comparison of adding four more properties to the emission equation.

Table 4-9 shows the PADD III refinery capital and RFG production cost under both the simple and 4/92 complex model. The gasoline produced using the complex model reached the same percent VOC reduction as the simple model yet reduced the refinery capital cost about $392 million. This reduced RFG production cost in the PADD III refinery by about 0.5 cpg.

Table 4-10 shows the difference in facility requirements between the two cases. The differences are relatively minor because most of the added equipment results from meeting the benzene specification. Switching to the complex model did eliminate the need for benzene extraction equipment. The complex model allowed variations in sulfur, T_{90}, and olefins that produced a complying RFG while meeting antidumping regulations for the rest of the gasoline pool. The studies do show that a complex model can give more blending flexibility and thus can lower the cost of VOC reductions for refiners if TAP and NOx reductions are also satisfied.

The case using the 4/92 complex model reduced the sulfur content in RFG by about 30 ppm and raised the T_{90} about 5°F. Across the gasoline pool of both CG and RFG, there was a small increase in benzene content (0.1 vol%) and decrease in sulfur content (24 ppm).

Implications of Different Complex Model Forms for 1997

Certification of Phase I RFG using the complex emissions model is based on emission performance relative to 1990 statutory baselines determined by Congress (for summer) and the EPA (for winter). Since gasoline pools of many refineries are over these statutory baselines in some properties, it will be more difficult for such refineries to make RFG with the complex model. Furthermore, the summer statutory baseline described in the CAAA was not the actual 1990 summer U.S. average gasoline quality. Rather it was the base fuel used in the Auto/Oil Air Quality Improvement Research Program to represent the 1990 average fuel. This Auto/Oil fuel was lower in olefin content than the 1990 national average. This difference has potentially serious implications for cost of compliance which will depend on the actual complex model promulgated and its sensitivity to olefin levels.

Under the 4/92 complex model, the difference in olefin content was not very significant to any of the emission target reductions. However, under the EPA 2/93 complex model this difference in olefins caused the simple model gasoline to be non-compliant in NOx in some cases. Thus refiners with olefins near

TABLE 4-9

COST COMPARISON OF THE EPA SIMPLE MODEL AND THE 4/92 COMPLEX MODEL AT FULL OPT-IN PRODUCTION RATES (1990 Dollars)

	PADD III Simple Model	PADD III Complex Model	PADD III Savings
Added Refinery Investment, $Millions	2,352	1,960	392
Operating Costs, $Millions	2,424	2,277	147
RFG Upgrade Cost, cents per gallon	5.8	5.3	0.5

TABLE 4-10

PADD III FACILITY ADDITIONS NEEDED TO SUPPLY RFG UNDER THE SIMPLE AND COMPLEX MODEL AT FULL OPT-IN PRODUCTION RATES (Thousands of Barrels per Stream Day)

Unit	Simple Model	4/92 Complex Model
Reformer Feed Fractionation	1,476	1,425
Reformate Fractionation	267	257
Aromatic Extraction	66	0
Benzene Saturation	85	89
MTBE	34	25

or above the U.S. average would find that switching to the complex model in 1997 would require more capital and operating costs to reduce NOx emissions. Such costs are discussed later in connection with Phase II RFG.

Phase II RFG

Complex Emissions Model

Background and Relationship to Product Quality Analysis

The CAAA require that gasoline sold in ozone nonattainment areas after January 1, 2000 must meet stricter performance standards. They include the following requirements:

- **Volatile Organic Compounds.** An emission reduction of at least 25 percent from a CAAA defined statutory baseline 1990 fuel must be achieved during the summer high ozone period. The Act provides for a lesser (but at least 20 percent) or greater reduction based on technical feasibility and costs.
- **Toxic Air Pollutants.** The requirement is similar to that of VOCs except the reduction is required for the entire year.
- **Oxides of Nitrogen.** NOx emissions are not to increase above those of the baseline fuel in any batch. (Note: At the time of writing this report, the EPA is considering a requirement to reduce NOx emissions.)
- **Antidumping.** Antidumping requirements are placed on conventional gasolines to prevent increased emissions in those areas not mandated to use reformulated gasoline.

The summer baseline gasoline is defined in the CAAA; the EPA has established the winter baseline.

The regulatory negotiation participants agreed to develop a mathematical emissions model (or models) based on available data (and updated as warranted by new data) linking gasoline properties and vehicle emissions. The use of a complex emissions model was determined, by the regulatory negotiation participants, to be the most effective and flexible approach to carrying out the RFG program requirements. A complex model provides (1) the basis for determining the emissions performance of a wide range of gasolines (many more than could be practically tested), (2) a nearly instantaneous evaluation of how blending changes in a refinery affect calculated emissions for gasoline (and, thus, compliance status), (3) a practical enforcement tool for the EPA, and (4) flexibility to refiners to meet RFG requirements in the most efficient manner for individual refineries. This model will establish the relationship between important gasoline properties (currently judged to include aromatics, olefin, oxygen, sulfur, and benzene content, RVP, T_{90}, and T_{50} points) and emissions of TAP, VOC, and NOx. This model, which is currently under development,

has become known as the "complex model," reflecting the complicated nature of the gasoline property/emission relationships, and to distinguish it from the "simple model" used to define gasoline emission performance for the early years (1995, 1996, and part of 1997) of the RFG program.

Work began separately within EPA and the API in 1991 to develop a complex emissions model for nationwide application building on the work of the Western States Petroleum Association and the Auto/Oil Air Quality Improvement Research Program data base. That effort is still ongoing. At the time this work started (Spring 1992), a formal EPA-approved complex model was not available. The NPC study uses a complex emissions model based on the best public information available at that time. This model, referred to as the 4/92 complex model, is based primarily on information published in the *Federal Register* by the EPA through the April 16th, 1992 Supplemental Notice of Proposed Rulemaking. This model is a series of equations, which are described in Tables A3-13 through A3-17 in Appendix M. The non-exhaust equations of this model assume the EPA MOBILE4.1 emissions inventory model. EPA and API complex model development efforts have continued. The 4/92 complex model has been compared with these later models—referred to as the 10/92 EPA complex model, 1/93 API complex model, and the 2/93 EPA complex model. The results of these comparisons are provided throughout this chapter. The final EPA model is not expected until later in 1993.

Table 4-11 shows the estimated VOC, TAP, and NOx emission changes, as compared to the CAAA summer baseline, for four specific gasoline blends studied in the NPC analysis. The estimated emission changes (as a percentage of the baseline gasoline emission) are presented for the 4/92 complex model, 1/93 API model, and the 2/93 EPA model. For TAP, the predictions of the various models are in reasonable agreement. For VOC and NOx emissions, there are large differences among the models, with the 2/93 EPA model generally predicting lower VOC and NOx reductions than the other models.

Figure 4-4 shows the estimated change in VOC, TAP, and NOx, respectively, from one-at-a-time changes from a target Phase II RFG case in the eight gasoline properties used in three complex models. The relative sizes of the property changes shown in the figures were chosen to reflect approximately equal refinery cost increments of about 1 cpg. These illustrations provide a rough indication only since the cost of a step is very dependent on the starting point for that step. The case from which the changes are made is the NPC Phase II RFG 2000 cost break target case (2000CBT case) for PADD III, which achieves approximately 45 percent VOC reduction from the Statutory Baseline computed with the 4/92 complex model.

The importance of these figures is the direction and relative size of emission changes for the given set of gasoline property changes. The differences in predicting emissions among the models are considerable. The complex model ultimately adopted by EPA could be different than the ones used in the study. The cost of RFG and the difficulty the refining industry will have in complying with reformulated and conventional gasoline requirements might be different than that reported here.

Figure 4-5 presents a similar comparison of the 4/92 complex model used in this study with the EPA's most recent complex model, that of July 1993 Option #2. For all three emissions, VOC, NOx, and TAP, the emissions change for most of the specific RFG property changes are similar for both models, both in sign and magnitude. Neither T_{50} nor E200, the 50 percent distillation temperature and percent evaporated at 200°F, which were variables in Option #2, were variables in the 4/92 complex model. The most significant differences are for oxygen content, which has not been varied in this study. Therefore, the approach and general implications of the incremental cost-effectiveness analysis in this chapter should be valid for the EPA's May 1993 version of the complex model.

Complex Model Property Ranges

Because the complex model is basically a regression model of emissions as a function of

TABLE 4-11

COMPARISON OF EMISSION REDUCTION ESTIMATES FROM DIFFERENT COMPLEX EMISSION MODELS FOR VARIOUS NPC GASOLINE BLENDS (Reduction from 1990 Statutory Baseline Gasoline)

	Complex Emission Model		
	4/92	EPA 2/93*	API 1/93
Blend A (Q6)†			
PADD III 1995 RFG			
Emission Reduction			
VOC, % reduction	34	35	37
NOx, % reduction	(4)	(5)	(1)
TAP, % reduction	30	28	33
Blend B (Q6N)			
PADD III 2000 RFG			
Emission Reduction			
VOC, % reduction	45	31	32
NOx, % reduction	3	(1)	8
TAP, % reduction	35	25	33
Blend C (Q6)			
PADD I 2000 RFG			
Emission Reduction			
VOC, % reduction	41	28	30
NOx, % reduction	(1)	(9)	4
TAP, % reduction	33	17	29
Blend D (Q6N)			
PADD III 2000 CG‡			
Emission Reduction			
VOC, % reduction	31	8	19
NOx, % reduction	4	(7)	6
TAP, % reduction	13	18	1

* For comparison purposes, the results shown here for this model are based on Statutory Baseline RVP. They differ from corresponding values in Appendix M which assume adjusted statutory baseline RVP in Southern Regions in accordance with the 2/93 NPRM.

† See Appendix M Table A4-9 for case identity.

‡ From 1989 PADD III average as baseline. CG = conventional gasoline.

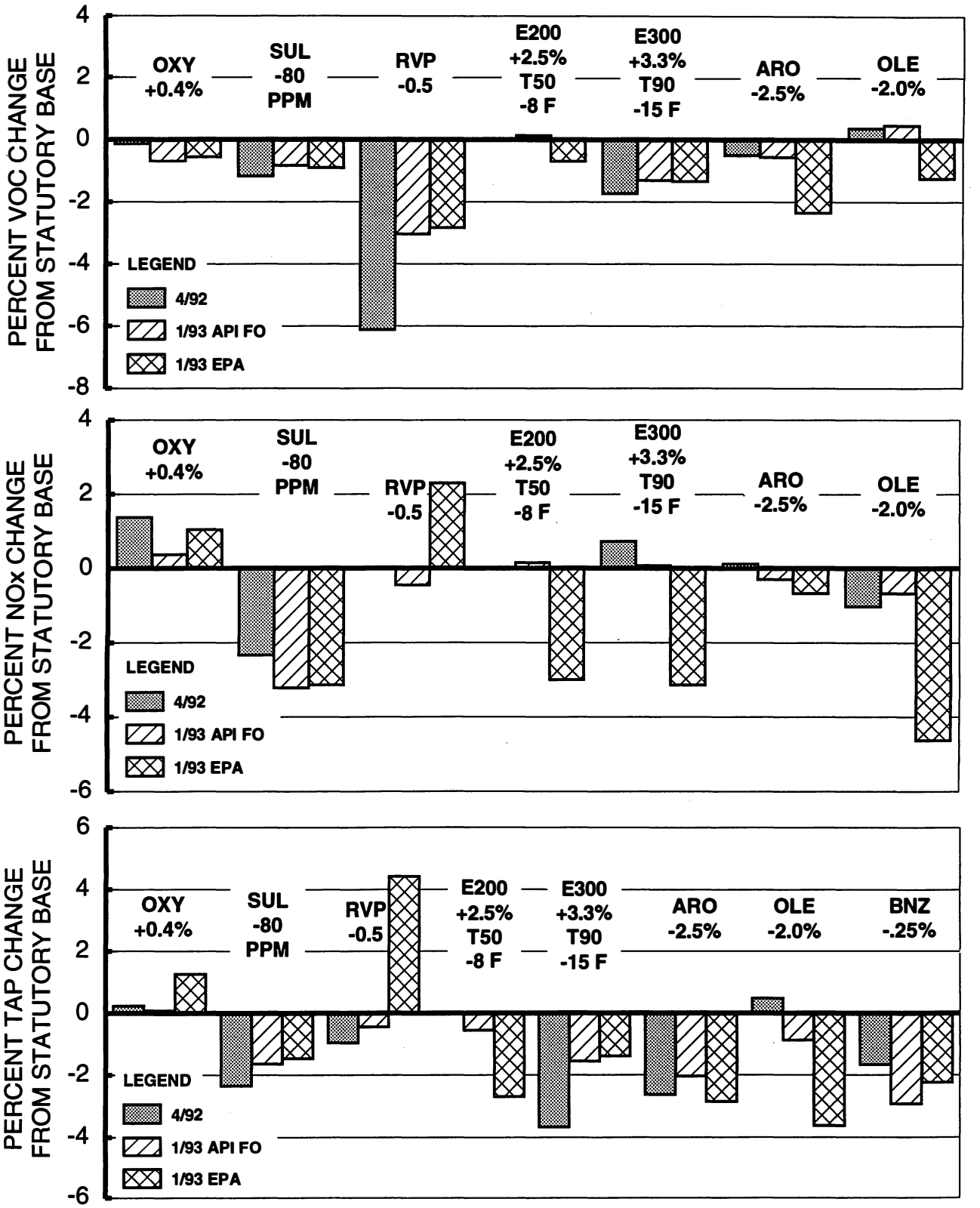


Figure 4-4. Comparison of Alternative Emissions Models. Change in Emission Performance as a Function of Individual Gasoline Property Change* (Base Case is NPC 2000CBT Cost Break Point Case).

* Gasoline property changes are equal cost increments of 1 cpg in the PADD III Q6 case.

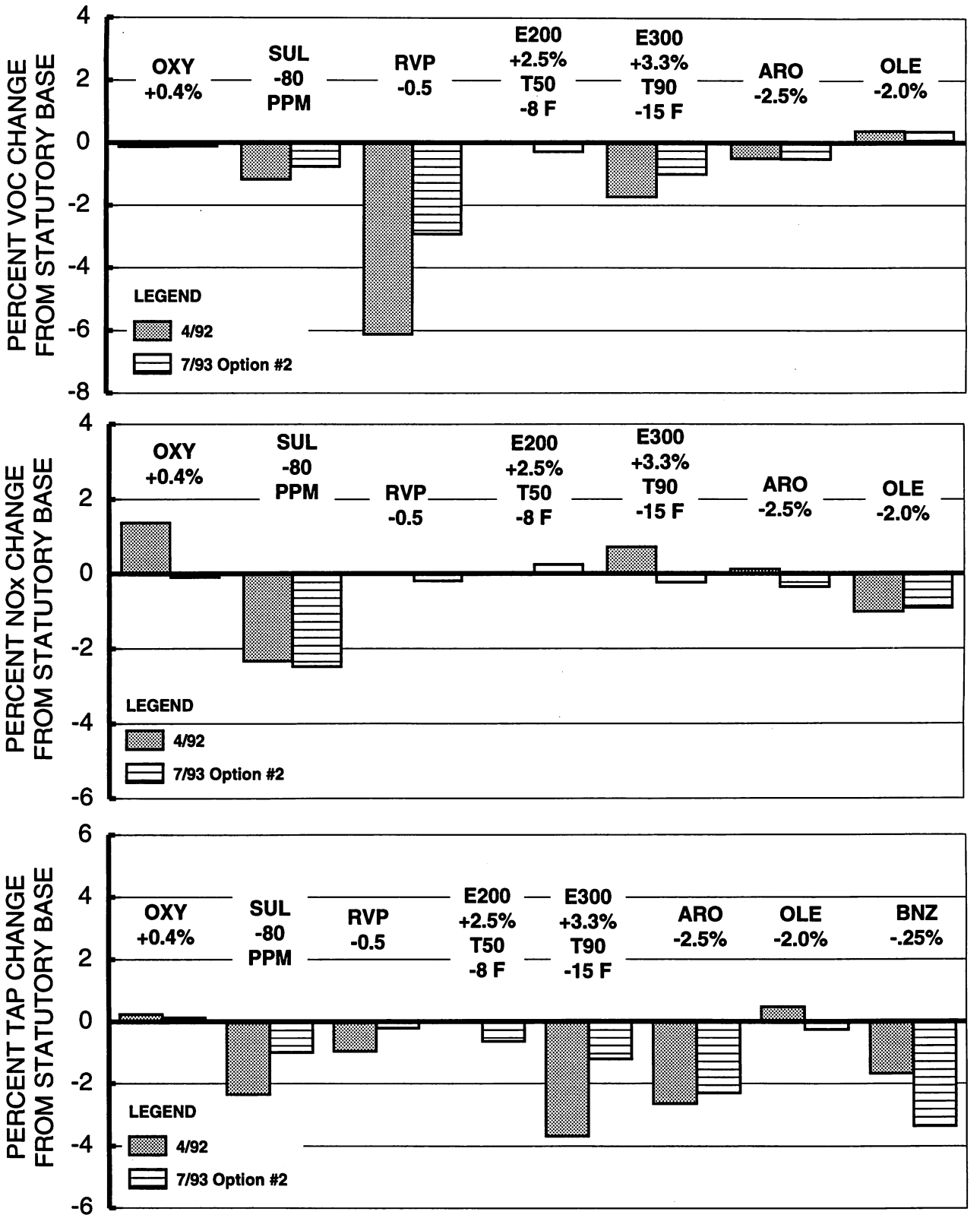


Figure 4-5. Comparison of 4/92 and EPA's 7/93 Option #2 Emissions Models. Change in Emission Performance as a Function of Individual Gasoline Property Change* (Base Case is NPC 2000CBT Cost Break Point Case).

* Gasoline property changes are equal cost increments of 1 cpg in the PADD III Q6 case.

test vehicle and test fuel parameters, the underlying data limit the range of validity of the model. Although a wide variety of vehicles and fuels are represented in the complex model data base, the actual range of fuel properties is limited when compared to real world fuels.

The EPA has proposed limiting the applicability of the model to reflect this limited data base. The 2/93 EPA complex model was proposed to be valid only for fuels with properties that fall within the ranges shown in Table 4-12. Actual National Institute for Petroleum and Energy Research (NIPER) 1991 survey data for gasolines show that recent normal ranges for most of these properties were over twice as wide as EPA's proposed valid ranges. These proposed ranges, if not expanded, will represent a severe limitation on either the use of the complex model or allowable gasoline properties for individual refiners certifying RFG or CG with the model. Particularly notable limitations are on RVP for winter gasoline, sulfur, aromatics, olefin, and benzene levels for both RFG and CG.

Analysis for Cost Effective Solution for Emissions Reduction

During the course of the NPC study, the EPA standards for VOC and TAP emission reductions were yet to be defined. Based on indications from the EPA staff and the judgment of the NPC study team, the study for the year 2000 focused on VOC reductions at or above the 25 percent CAAA requirements and achievement of the minimum (20 percent) TAP reduction standard. While a number of different VOC performance standards were evaluated for the year 2000, the study focused on determining the maximum VOC reduction level that coincided with the highest limit of incremental cost effectiveness of $10,000 per summer ton of VOC reduction when determined by the 4/92 complex emissions model used in this study. The solution meeting this criteria has been designated as the 2000CBT case described below. Reductions greater than this level required processing changes that were significantly more costly and judged not to be likely to meet the CAAA requirement for consideration of reasonable cost.

Results presented here are highly dependent on the 4/92 complex model. A different model could cause the cost of achieving a given emission performance and the characteristics of a "cost-effective" Phase II RFG to be different.

Selection of the 2000 Cost Break Target Case (2000CBT)

The base case assumes that "business as usual" in 2000 is the same as in the 1995 case with no CAAA. The costs of the RFG cases are incremental to this base case.

Conversion refinery[6] models for PADD geographic regions were used to develop the regional 2000CBT cases and to analyze additional costs of reducing VOC emissions with reformulated gasoline during the summer control period. The 2000CBT case represents the maximum VOC emission reduction point above which incremental costs increase greatly. The choice of this "cost break point" should not be viewed as a recommendation for performance standards, but is used to illustrate that processing costs escalate rapidly when certain processing steps are exhausted.

Refining Investment, Cost, and Regional Variation

The illustrative cost break point 2000CBT case using the 4/92 complex model and a 6.5 psi RVP minimum shows the summer pollutant reductions in RFG from baseline gasoline shown in Table 4-13. Results for PADD V are not shown nor included in the U.S. totals. (California gasoline must meet state regulations in 2000 and the rest of PADD V does not require RFG.)

These reductions exceed the CAAA targeted goals of 25 percent for VOC and TAP with no increase in NOx (except for PADD I). They are presented as typical of the upper limit of a technically feasible, cost effective processing case for VOC reduction. The choice of a 6.5 psi RVP minimum assumes it to be the lowest technically feasible level. Should factors such as cold starting, explosion limits, drivabil-

[6] The study assumes that simple refineries, which currently produce about one percent of U.S. gasoline, will not produce RFG.

ity, etc., require a higher RVP, the VOC reductions will decrease from those shown by about 5 percent per 0.5 psi RVP increase.

The estimated incremental refining investments and per-gallon costs (above the 2000 Base Case without the CAAA) for Phase II summer reformulated gasoline taken at the cost break point (2000CBT cases) are shown in Table 4-14. Refining investment is the highest in PADD III and PADD II due to the greater refinery production of Phase II RFG in those areas.

The refinery cost per gallon of Phase II RFG is higher in PADDs I, II, and IV than in PADD III. The latter has considerable flexibility for making RFG due to the size and complexity of its refineries. PADD I has higher costs since it produces 100 percent RFG and does not have the flexibility of optimizing the blending of gasoline components into several pools. PADD II requires a relatively greater amount of new fractionation processing to make RFG. PADD IV requires a considerable amount of additional processing to make more of the low aromatics, saturated components needed for RFG. The refinery configurations of PADD IV are characteristic of smaller refineries.

The increase in costs with time as the regulatory requirements for reformulated gasoline become more stringent is shown in Table 4-15;

TABLE 4-12

COMPARISON OF PROPOSED EPA PROPERTY RANGES WITH ACTUAL RANGES

		EPA Proposed Ranges	Actual 1991 NIPER Ranges
Oxygen	weight percent	0.0 - 3.7	0.0 - 3.7
Sulfur	parts per million by weight	50 - 450	10 - 1,000
RVP	pounds per square inch	6.5 - 10.0	6.1 - 16.0
T_{50}	° F	170 - 235	142 - 239
T_{90}	° F	280 - 360	275 - 363
Aromatics	volume percent	20 - 45	3 - 65
Olefins	volume percent	2 - 20	0 - 36
Benzene	volume percent	0.5 - 2	0.1 - 4.9

TABLE 4-13

PHASE II RFG AVERAGE EMISSION FROM STATUTORY BASELINE 4/92 COMPLEX MODEL AT COST BREAK POINT

	Percent Reductions—Summer				
	PADD I	PADD II	PADD III	PADD IV	U.S.*
VOC	41	41	45	45	43
NOx	(1)	0	3	6	1
TAP	33	32	35	30	32

* Does not include PADD V.

TABLE 4-14

ESTIMATED ADDITIONAL COSTS* FOR SUMMER PHASE II RFG AT COST BREAK POINT — 2000CBT (1990 Dollars)

	PADD I	PADD II	PADD III	PADD IV	PADD V outside California	U.S. without CARB	Calif.†	U.S. with CARB
RFG Refinery Production, % of Total	100	56	63	13	0	65	91	65
RFG, MB/CD	682	945	2,008	32	0	3,667	913	4,580
Refining Invest., $Billion‡	0.9	1.6	2.7	0.2	0	5.5	3.3	8.7
Added Refining Costs, cpg§	8.2	8.9	6.9	7.8	0	7.6	15.1	9.2

* Incremental costs above 2000 Base Case without CAAA.

† California model assumes CARB Phase 2 regulations.

‡ Does not include investment for non-refinery oxygenate manufacturing units. Results do not add to total due to rounding.

§ Cents per gallon based on conventional gasoline upgraded to RFG.

PADD III model summer values are used to illustrate the progression. The cases described are those discussed in the previous sections. All costs are in 1990 dollars and values are not cumulative.

Comparison of Gasoline Properties.

Table 4-16 compares average properties of the PADD III 2000CBT reformulated gasoline with those of the 1989-1990 average pool for the total U.S. less PADD V (East of Rockies). Also shown are properties of the 1990 statutory baseline gasoline.

Refinery Facilities Changes and Capability for Cost-Effective Solution (2000 Cost Break Target Cases)

This section reviews aggregate industry refining capability in each PADD in the year 2000, with a focus on gasoline manufacture in the summer period. Capability of the industry to meet the requirements for RFG manufacture and antidumping requirements in 2000 is analyzed in terms of what new process units must be built and of the utilization of individual process units as they differ in scenarios with and without the CAAA requirements for gasolines. (See Appendix M, Analysis Cases Q6S, C-Tables, and Q9S, B-Tables.) The cases described for PADDs I, II, III, and IV are the 2000CBT cases for which costs were presented in the previous section.

Gasoline Pool Description

The extent of RFG manufacture and selected RFG properties at the cost "break point" for the PADDs are shown in Table 4-17. (For reference, the cost curve illustrating the "break point" for variations in RFG performance in PADD III is shown later in this chapter.)

The properties marked as model input limits in Table 4-17 are CAAA or CARB specifications, e.g., oxygen content, benzene content (with compliance margins), etc., or those required to achieve the cost-effective solution using the 4/92 model. The LP model was driven to produce RFG with properties that achieved a specified target VOC reduction as calculated by the 4/92 complex model. Reduction of RVP to

TABLE 4-15

INCREASED COSTS (NON-CUMULATIVE) OF PHASE II RFG PADD III — 4/92 COMPLEX MODEL (1990 Dollars)

	Conventional Gasoline		Reformulated Gasoline				
Summer Period	**1990**	**1995**	**1995**	**1995**	**1997**	**2000**	**2000**
Case Description*	**A**	**B**	**C**	**D**	**E**	**F**	**G**
RFG, % of Pool	**0**	**0**	**11**	**63**	**63**	**63**	**100**
RVP	8.7	7.9	7.2	7.2	7.2	6.5	6.5
VOC Reduction %	0	19	34	35	34	45	45
TAP Reduction, %	0	5	30	30	32	35	34
NOx Reduction, %	0	2	(4)	1	2	3	4
Refining Investment, $Billion		Base	0.8	2.4	2.0	2.7	3.2
Added Refining Costs, cents per gallon		Base	3.0	5.8	5.3	6.9	7.2

* A = SB=Statutory Baseline Case.
B = Q9=Base Case, Business as Usual, without Clean Air Act Amendments (CAAA).
C = Q6=With CAAA, with simple model.
D = S5=1995 with CAAA, with simple model, with full opt-in.
E = S19=With CAAA, shift to 4/92 complex model from simple model with full opt-in.
F = Q6N=With CAAA, 4/92 complex model at cost break point with full opt-in.
G = S6=With CAAA, 4/92 complex model at cost break point with 100 percent RFG.

TABLE 4-16

COMPARISON OF AVERAGE SUMMER GASOLINE PROPERTIES

	Average East of Rockies 1989-90	1990 Statutory Baseline Gasoline	PADD III 2000CBT*
RVP, psi			
Summer – Class C (North)	9.9	8.7	6.5
– Class B (South)	9.4	8.7	6.5
T_{50} Distilled, ° F	209	218	203
T_{90} Distilled, ° F	337	330	342
Benzene, vol%	1.72	1.6	0.7
Aromatics, vol%	31.3	32.0	23.7
Olefins, vol%	13.2	9.2	10.7
Oxygen, wt%	0.1	0.0	2.1
Sulfur, ppm, wt.	336	339	141

* 4/92 complex model (assumes MOBILE4.1 model for non-exhaust emissions).

TABLE 4-17

AVERAGE REFORMULATED GASOLINE POOL PROPERTIES PHASE II SUMMER 4/92 COMPLEX MODEL RESULTS 2000 CBT CASES*

	PADD I	PADD II	PADD III†	PADD IV	Calif.‡
RFG, % of Pool	**100**	**56**	**63**	**13**	**91**
(R+M)/2 Octane, Clear§	88.9	88.1	88.6	86.6	88.5
Aromatics, vol%	24.4	22.2	23.7	28.9	22.0§
Ethers, vol%	11.7	11.7	11.7	11.7	11.1
Oxygen, wt%	2.1	2.1	2.1	2.1	2.0
Olefins, vol%	13.1	10.7	10.7	7.1	4.0§
Benzene, vol%	0.7	0.7	0.7	0.7	0.8
Sulfur, ppm	233§	273	141	100	30§
Reid Vapor Pressure, psi§	6.5	6.5	6.5	6.5	6.6
Distillation T_{10}, ° F	132	134	134	131	135
Distillation T_{50}, ° F	206	203	203	205	196
Distillation T_{90}, ° F	338	348	342	337	290§
VOC – % Reduction	41§	41§	45§	45§	49
NOx – % Reduction	(1)	0	3	6	8
TAP – % Reduction	32	32§	35	31§	48

* Appendix M, Table C-10A, Issue Case Q6S. Note: No Phase II reformulated gasoline is produced in PADD V outside of California.

† Issue Case Q6NS.

‡ CARB Phase 2 gasoline.

§ Input limit.

a floor of 6.5 psi attained the target reduction in PADDs II and III. PADD IV required reduction of the sulfur content as well, while PADD I required reductions in sulfur and olefin contents.

New Facilities Required

Table 4-18 provides estimates from refinery LP modeling runs of the additional process unit capacities required for RFG manufacture. The additions for PADDs I through IV are for process units required only for RFG manufacture. PADD V outside California does not add any facilities for RFG processing. The additions for California are those required by CARB Phase 2 regulations.

The bulk of the additional processing capacity is for improved or additional fractionation units to provide closer control of gasoline components and their properties. The units are not common to current refinery flow schemes but their addition is evidence that the increased control of gasoline properties will require much greater separation of current day gasoline components. Benzene control also requires additional processing. Some refinery manufacture of ethers is provided in this analysis. In California, CARB Phase 2 RFG and improved diesel fuel requires extensive hydrogenation and gasoline component manufacturing units as well.

Process Unit Utilization

Table 4-19 provides a comparison of selected gasoline-related process unit utilization

rates for the two 2000 scenarios of summer operations with the CAAA (Issue Case Q6S) and without the CAAA (Issue Case Q9S).

Several observations can be made from this comparison of the two modes of operation. (Identification of the two modes is by Issue Case Number—Q6 represents operations in 2000 with the CAAA in place, and Q9 represents operations in 2000 as they would be without the CAAA.)

- CAAA regulations apply in all geographic areas. However, PADD V outside California does not manufacture RFG. In California, RFG manufacture is regulated by CARB. Utilization includes any effect of manufacturing ultra-low sulfur or low aromatics diesel fuel in this region.
- Gasoline component fractionation for RVP control for the Q6 cases is extensive in East of the Rockies refineries.

TABLE 4-18

PHASE II REFORMULATED GASOLINE NEW PROCESS FACILITIES REQUIRED 2000 SUMMER 4/92 COMPLEX MODEL RESULTS: ISSUE CASE Q6S LESS Q9S 2000 CBT CASES*

(Thousands of Barrels per Stream Day)

New Capacity	PADD I	PADD II	PADD III†	PADD IV	Calif.‡	Total U.S.
Heavy Naphtha Splitter					93	93
FCC Gasoline Splitters	96		135	10	333	574
Coker Light Gasoline Desulfurizer/Splitter	2	15	24			41
Hydrotreating – FCC/Coker C6s					29	29
Reformer Feed Fractionation	250	756	1,463	103	344	2,916
Reformate Fractionation	80	71	255	7	177	590
Benzene Saturation	27	34	62	4	60	186
FCC Gasoline Hydrodesulfurizer					14	14
Alkylation					17	17
MTBE	8		26	2		36
TAME					3	3
Isomerization – C5/C6					57	57
Isomerization – C5/C6, Recycle					32	32
Isomerization	5				4	9
C4 Rerun – Saturates	36	101	203	4	78	422
C4 Rerun – Unsaturates	115	260	501	10		886

* Appendix M, Tables C-6 and B-6: Issue Case Q6S = with CAAA; Issue Case Q9S = without CAAA. Note: No Phase II reformulated gasoline is produced in PADD V outside of California.

† Case Q6NS, less Case Q9S.

‡ CARB Phase 2.

TABLE 4-19

PROCESS UNIT UTILIZATION†
PHASE II SUMMER 4/92 COMPLEX MODEL RESULTS FOR 2000 CBT CASES WITH AND WITHOUT CAAA‡

	PADD I		PADD II		PADD III		PADD IV		PADD V Outside California	California
	Q6S	Q9S	Q6S	Q9S	Q6NS	Q9S	Q6S	Q9S	Q6S	Q6S
RFG, % of Pool	100	0	56	0	63	0	13	0	0	91
Crude Oil Distillation – Atmospheric	83.2	87.7	84.8	86.7	84.0	85.7	90.0	90.0	82.5	85.1
Catalytic Cracking§	84.7	85.9	85.0	84.2	81.7	84.2	87.0*	87.0*	94.0*	87.5
Catalytic Cracking¶	77.0	80.1	77.9	77.3	75.9	78.3	79.8	80.0	85.5	87.8
FCC Gasoline Splitters	94.0*				94.0*		87.0*		84.5	94.0*
FCC Gasoline Fractionation	37.8	84.6	79.7	75.7	81.9	81.9	77.8	77.8	87.0*	
Hydrocracking – High Conversion	59.7	87.0*	83.0*	83.0*	82.9	87.0*	83.0*	83.0*		87.0*
Hydrocracking – Low Conversion	87.0*	78.4	83.0*	58.5	58.5	58.5	83.0*	66.4	87.0*	87.0*
Hydrocrackate Fractionation										
Coker Lt. Gasoline DS/Splitter	92.0*		86.0*		92.0*				92.0*	
Catalytic Reforming – Combined¶	61.5	69.0	59.6	69.0	72.7	79.8	76.1	71.6	81.8	69.7
Hydrotreating – Naphtha	58.6	59.2	62.8	73.2	71.3	73.5	71.0	68.3	92.0*	67.9
– Heavy Gas Oil	92.0*	83.5	87.0*	81.1	86.6	86.6	79.1	79.1	87.4	90.5
Reformer Feed Fractionation	92.0*		87.0*		92.0*		87.0*			92.0*
Reformate Fractionation	92.0*	92.0*	87.0*	87.0*	92.0*	85.0	87.0*			92.0*
Aromatics Extraction	92.0*	87.3	87.0*	87.0*	92.0*	92.0*				
Benzene Saturation	92.0*		87.0*		92.0*		87.0*			92.0*
Alkylation	89.0*	84.3	77.4	72.1	65.9	69.5	84.0*	84.0*	74.1	89.0*

* Unit Maximum Capacity

† Calendar day rates divided by stream day capacity.

‡ Appendix M, Tables C-8 and B-8, Issue Case Q6 = with CAAA; Issue Case Q9 = without CAAA.

§ Include effects of nonunitary capacity for some feedstocks and severities.

¶ Based on actual feed rates, ignoring severity effects.

- Crude oil distillation utilization is lower for the Q6 (with CAAA) cases than for the corresponding Q9 (without CAAA) cases. This reflects the substitution of oxygenates for hydrocarbon components.
- The use of catalytic cracking diminishes with high proportions of RFG in the total gasoline pool. Reducing the use of catalytic cracking reduces the amount of olefins and aromatics in gasoline. Catcracked gasoline splitting for further processing reduces the amount of light catcracked component for RVP and olefin content reductions.
- The use of hydrocracking is less in the Q6 high RFG manufacture PADDs and the same in the others. Less hydrocracker naphtha is required for catalytic reformer feed as reformate is a less desirable RFG component due to its higher benzene and aromatics contents. Utilization of low conversion hydrocracking is higher for the Q6 cases driven by its use to produce reformulated distillate products.
- Use of coker gasoline fractionation and desulfurization is shown for the Q6 cases. The addition of the coker gasoline splitter desulfurizer process unit reduces gasoline sulfur and provides coker amylenes for alkylation.
- Catalytic reforming utilization is considerably reduced in the high RFG content gasoline pools. The need for reformate as a gasoline octane enhancers is reduced due to the mandated use of oxygenates. Light reformer feed with benzene precursors is by-passed to gasoline blending to reduce benzene content. Reformates are less desirable components of RFG because of their aromatics content.
- Aromatics extraction and added benzene saturation units operate at maximum utilization in the Q6 cases, as required to reduce the benzene content to the 1 percent maximum allowable (0.7 percent with compliance margin).
- The use of alkylation units that provide a preferred gasoline component for RFG is higher for the Q6 cases. An exception is utilization of alkylation in PADD III in which the reduction of the use of catcracking reduces olefin feedstock for alkylation after increased isobutylene feed to MTBE manufacture.

RFG Composition

Table 4-20 illustrates the changes in the content of major components in the RFG created by the CAAA requirements. Reduction of RVP is the lowest cost processing option employed in the 2000CBT "cost break point" case Q6 for meeting the performance requirements of the CAAA is to reduce RVP. Comparing Q6 with Q9 (the base case) in all regions illustrates the marked reduction of the butane component that is the principal contributor to higher RVP.

Control of RFG emissions is favored by lower olefin and aromatics and higher saturates contents in the gasoline pool. The lower olefin content of the Q6 RFG is reflected by the reduced FCC gasoline portion of the total pool from the reduced utilization of Catalytic Cracking noted above. Similarly, the reduced reformate content of the RFG pool from the lower utilization of catalytic reformers decreases the aromatics content. The large increase in saturated component content is mostly attributable to the large increase of oxygenates in the pool. The increased use of oxygenates also reduces the FCC gasoline and reformate portions of the pool by dilution. The California CARB Phase 2 gasoline has very high saturates and very low FCC gasoline contents.

Alternative Scenarios

Variations in the Amount of RFG Produced

Basis of Analysis

This section looks at shifts in refining cost (including capital recovery) for increasing the amount of RFG produced (holding the RFG specifications constant). For each case analyzed, comparisons are made for the *average* production cost per gallon of all RFG. In addition, the types of equipment changes required

TABLE 4-20

PHASE II REFORMULATED VERSUS CONVENTIONAL GASOLINE COMPOSITION (VOL%) PADD AVERAGE REFINERIES, 4/92 COMPLEX MODEL – 2000 CBT CASES SUMMER RESULTS WITH AND WITHOUT CAAA

	PADD I		PADD II		PADD III		PADD IV		PADD V Outside California	California
Gasoline Type	**RFG**	**CG**	**RFG**	**CG**	**RFG**	**CG**	**RFG**	**CG**	**CG**	**RFG**
Issue Case*	**Q6S**	**Q9S**	**Q6S**	**Q9S**	**Q6NS**	**Q9S**	**Q6S**	**Q9S**	**Q6S**	**Q6S**
RFG, % of Pool	**100**	**0**	**56**	**0**	**63**	**0**	**13**	**0**	**0**	**91**
Gasoline Component										
Butanes	1.9	4.4	2.0	5.2	2.0	3.7	1.9	4.0	5.2	1.7
FCC Gasoline	36.2	42.0	32.5	33.7	31.2	37.1	15.4	35.1	30.2	15.0
Olefinic	1.0	1.9	0.8	1.3	1.6	1.9	3.2	3.0	2.2	0.2
Reformate	22.4	27.2	17.8	34.2	22.2	30.1	39.4	28.4	36.5	28.0
Oxygenates	11.8	2.0	11.7	2.0	11.8	2.0	11.6	2.0	1.7	11.1
Other Low Aromatic, Saturated	26.7	22.5	35.2	23.6	31.2	25.2	28.5	27.5	24.2	44.0
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

* Appendix M, Tables B, C-9, and C-9A: Issue Case Q6S = with CAAA; Issue Case Q9S = without CAAA.

are compared along with required capital investment.

Average Cost Comparison

The cases analyzed for 2000 include full opt-in (Q6) and 100 percent reformulation (S6). The full opt-in case represents 65 percent of U.S. demand excluding California, or about 3.7 MMB/CD of RFG. The 100 percent RFG case represents about 6.0 MMB/CD of RFG. Average cost comparisons for PADD III, PADD IV, and the U.S. excluding California are presented in Table 4-21. Increasing PADD III RFG production from 63 to 100 percent of the total gasoline pool, has a small impact (0.3 cpg) on RFG cost. However, increasing PADD IV RFG production from 13 to 100 percent increases RFG costs 2.4 cpg. Costs of producing RFG in PADD IV are greater than in PADD III by 1 to 3 cpg, because of the smaller size and lower complexity of the PADD IV refineries.

The total U.S. figures in Table 4-21 show that the average per-gallon cost of RFG is not highly sensitive to production rate at higher percentages of RFG in total gasoline.

New Process Investments and Costs

Investments in PADDs III and IV, as representative of the range of needs, are also shown in Table 4-21. The full opt-in case would require refinery investment for PADD III of $2.7 billion, or $1,400 per B/CD of RFG. The 100 percent RFG case will require a refinery investment for PADD III of $3.2 billion, or $1,000 per B/CD of RFG. For PADD III, refinery capital investments increase by about 17 percent when going from 63 to 100 percent RFG production. The significant refinery equipment changes in both cases are similar. The amount of added investment for the significant changes in millions of 1990 dollars for the two cases (Q6/S6) are shown in Table 4-22.

For PADD IV, the full opt-in case will require an investment of $0.2 billion, or $4,800 per B/CD. This is triple the PADD III cost per

TABLE 4-21

IMPACT OF INCREASED RFG PRODUCTION IN SUMMER OF 2000 AVERAGE COST AND CAPITAL INVESTMENTS REQUIRED

	PADD III		PADD IV		U.S. w/o California	
	Q6 Full Opt-In	S6 100% RFG	Q6 Full Opt-In*	S6 100% RFG	Q6 Full Opt-In	S6 100% RFG
RFG Produced, MB/CD†	2,008	3,207	32	250	3,667	5,971
% of Total Gasoline	63	100	13	100	65	100
RFG Added Refining Cost, cpg‡	6.9	7.2	7.8	10.2	7.6	7.6
Investments, Billions of 1990 dollars, Refinery‡	2.7	3.2	0.2	0.5	6.0	8.0
Investment, 1990 Dollars per B/CD	1,400	1,000	4,800	2,000	1,700	1,300

* PADD IV cost estimates here may be low. Model assumes RFG production throughout PADD, while actual case will concentrate RFG production in Salt Lake area only.

† From Appendix M, Tables C-2, D2-3, G1-3, and A-31.

‡ From Appendix M, Exhibit 15 (5/20/93).

TABLE 4-22

ADDED INVESTMENT — PADD III (Millions of 1990 Dollars)

	Full Opt-In	100% RFG
FCC Gasoline Splitters	128	230
Reformate Fractionation	274	377
Benzene Saturation	218	392
TAME	0	61
MTBE Storage	111	177
Other	1,988	1,982
Total	**2,719**	**3,219**

unit of capacity for the same case. For the 100 percent RFG case, PADD IV capital investment rises to $0.5 billion, or $2,000 per B/CD. This unit investment is double that needed for PADD III refineries with 100 percent RFG. The types of equipment investments in PADD IV are similar to those in PADD III. However, because PADD IV refineries are smaller and have less of the needed capacity to begin with, investments are higher.

RFG Performance Variation; Alternative Complex Emissions Models

This section presents a comparison of RFG performance for the four complex models discussed previously. Emission estimates of the four models for the baseline gasolines (40 percent northern baseline; 60 percent southern baseline) are shown in Table 4-23.

The two mobile source emissions inventory models (MOBILE4.1 and MOBILE5.0) give significantly different estimates of the portion of total VOC emissions attributed to evaporative emissions relative to exhaust emissions. Since evaporative emissions are primarily a function of gasoline RVP and exhaust emissions are primarily a function of fuel properties other than RVP, this creates significant uncertainty in the required properties and cost of RFG required to meet a given performance standard.

The uncertainty of the complex model itself creates similar uncertainty in the required properties and cost of RFG. Clearly, the performance standard cannot be set until the complex and MOBILE models are finally established. Other EPA rule making uncertainties include:

- What are acceptable cost levels (dollars per ton) for emission reduction goals?
- What is the definition of baseline conventional gasoline?
- What is the NOx emission performance standard?
- What are the acceptable ranges of reformulated and conventional gasoline properties for use in the model?
- What are the enforcement and compliance regulations?

Strategy for Analysis

The analysis of manufacturing Phase II RFG was done by using the 4/92 complex model embedded in the refinery LP models as a surrogate for the final complex emissions model. Exhaust emissions are estimated from a correlation of available data and the EPA mobile source emission inventory model, MOBILE4.1 is used for baseline non-exhaust and exhaust emissions. Since each of the complex models is derived from the same basic data set, exhaust emission predictions should not change radically. Further, the change in predicted performance exhaust emissions between reformulated gasolines of differing composition should be similar when calculated by complex models derived from the same data.

The non-exhaust model portion of any subsequent complex model was assumed to use the MOBILE4.1 model. The non-exhaust section of the complex model affects refinery processing primarily through fuel RVP. Its influence varies in importance with the weighting applied by the EPA to the emission predictions from the exhaust and non-exhaust

TABLE 4-23

COMPARISON OF COMPLEX EMISSION MODELS*
FOR PADD III FOR BASELINE GASOLINES WITH 60/40 SOUTHERN/NORTHERN GASOLINES

Complex Model	4/92		10/92 EPA		1/93 API		2/93 EPA †	
Phase	I	II	I	II	I	II	I	II
Mobile Source Emissions Model	4.1	4.1	4.1‡	4.1‡	4.1	5.0	4.1	5.0

Reformulated Gasoline	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
Non-Exhaust VOC, gm/mile	0.824		0.429		0.824		0.541		0.665		0.450	
Exhaust VOC, gm/mile	0.460		0.417		0.446		0.907		0.444		0.900	
Total VOC, gm/mile	1.284		0.846		1.270		1.448		1.109		1.350	
TAP, mg/mile	52.65	40.11	39.31	30.44	45.45	32.09	79.28	65.26	42.14	31.89	75.03	64.81
NOx, gm/mile	0.660	0.670	0.660	0.660	0.660	0.660	1.34	1.313	0.659	0.647	1.338	1.313

* Based on auto/oil, EPA, and WSPA data. Assumes enhanced inspection and maintenance programs. Summer emissions for CAAA statutory baseline and winter emissions for EPA baseline.

† Summer statutory baseline adjusted to 7.8 RVP for Region I (South).

‡ Adjusted to intermediate level for volatile organic compounds.

sources. This weighting is largely a function of the MOBILE model status and EPA assumptions when the final complex model is generated.

The relationship of gasoline reformulation and VOC reduction (controlling variable) using the 4/92 complex model should be indicative of other complex models. Curves expressing this relationship should be similarly shaped when calculated using any complex model on a given series of reformulated gasolines. Guidance as to the level of cost effective reformulation should be valid in deciding acceptable values.

Although the shape of the curves from similar models is expected to be the same, optimal solutions and absolute refining costs could differ if another complex model were to be used in the refinery LP model. The NPC judgment is that the refining cost could vary moderately but cost-effectiveness (i.e., the slope of the VOC reduction cost curves—dollars per VOC summer ton) could be quite different due to differences in prediction of VOC reduction by the four models.

Basis for Analysis

The 4/92 complex model is the NPC basis for analysis of 2000 summer RFG performance. The controlled variable for summer operations was VOC reduction. Benzene reduction and oxygenate addition were fixed. The TAP and NOx reductions for these base studies were computed at the control VOC reduction levels. Cost estimates, gasoline pool compositions, and refinery operation characteristics shown in this section are those obtained when using this complex model.

Emission predictions using three other proposed complex models assumed the reformulated and conventional gasoline pool compositions derived from these refinery model LP solutions. These emissions estimates were done off-line for each of the three other complex emission models studied.

Scope of Analysis

Costs of RFG manufacture as a function of summer VOC emission reduction were estimated using the aggregate PADD III refinery model for conversion refineries. Because of the size of the industry in this PADD, per-gallon cost changes are indicative of those of the total U.S. industry outside of California. However, cost changes in other PADDs will be somewhat larger.

Other case studies estimated the costs of specific RFG pool property reductions of sulfur and olefin contents. To provide analysis of geographical and of refinery size and complexity differences, case studies for reducing sulfur content to 30 ppm were done in the Turner-Mason refinery models for PADDs I, III, and IV. Two levels of olefin content reduction were studied in the PADD I model and one level of olefin reduction in PADD III. The selection of PADD I for additional olefin studies was made because the base case gasoline pool olefin content, 15.9 percent, is the highest of any of the geographic areas.

Another set of defined property limit studies was done in which the controlled properties associated with CARB Phase 2 regulations were applied to RFG manufacture in the refinery models for PADDs I, III, and IV. Property limits for RVP, T_{50}, T_{90}, benzene, aromatics, oxygen, and sulfur create much more demanding processing steps and higher costs.

Analysis of the Cost of RFG as a Function of Emission Reduction using the 4/92 Complex Model

Table 4-24 presents the results of 11 PADD III cases covering a wide range of potential RFG manufacturing severities—from the low severity 1997 initial complex model case under the CAAA up to the stringent CARB Phase 2 requirements. This table shows the calculated emission reductions from the statutory base using four complex models—4/92, EPA 10/92, EPA 2/93, and API 2/93. It also shows the most pertinent RFG properties, the refining investment, and added cost for making RFG.

Figure 4-6 shows summer RFG refining costs for the PADD III aggregate conversion refinery as a function of VOC reduction from

TABLE 4-24

REFORMULATED GASOLINE ALTERNATIVE SEVERITIES INCREASED COSTS VS. EMISSIONS REDUCTIONS PADD III SUMMER CASES* – U.S. NO DEMAND GROWTH CASE

	S19 SF Alt	C40VL VL Δ VOC	Q40L L Δ VOC	Q6 T Δ VOC	Q6N Q6 + Cap Chg	QN2 Q6 + 10.7% OL	S10 Q6 + 30 S	S6 Q6 + 100% RFG	Q40H H Δ VOC	SN1 Q6 + 7 RVP	S21 CARB 2
RFG, % of Pool	**63**	**63**	**63**	**63**	**63**	**63**	**63**	**100**	**100**	**100**	**100**
Complex Model Designation †, %											
4/92											
VOC	33.8	35.4	40.0	44.7	44.7	44.7	44.7	44.7	47.8	44.7	50.2
NOx	(2.6)	1.5	1.8	3.0	3.4	3.6	8.9	3.9	4.9	4.3	7.5
TAP	31.6	31.0	31.6	33.0	35.4	33.5	38.0	50.0	41.1	50.6	48.7
10/92 EPA											
VOC	28.0	28.3	33.1	35.6	37.0	36.7	39.7	36.5	39.3	36.0	41.1
NOx	(2.3)	(2.9)	(3.5)	(3.2)	0.3	(0.5)	14.1	0.5	8.0	16.4	17.9
TAP	28.2	28.2	28.1	25.1	28.5	27.7	39.3	27.4	33.6	42.8	44.1
1/93 API											
VOC	37.1	26.0	29.5	31.4	31.9	31.6	31.8	31.5	34.0	32.4	34.7
NOx	6.2	5.5	6.3	8.0	8.4	8.5	14.3	9.0	11.2	11.6	14.3
TAP	37.1	–	–	–	–	–	–	–	–	–	–
1/93 EPA ‡											
VOC	26.3	18.7	22.7	24.5	26.5	26.0	30.6	25.7	29.5	27.9	32.9
NOx	(2.6)	(3.1)	(3.7)	(3.6)	0.2	(0.6)	14.0	0.3	7.9	16.3	17.7
TAP	27.6	24.1	24.1	21.1	24.8	24.0	35.6	23.7	30.0	39.0	40.4

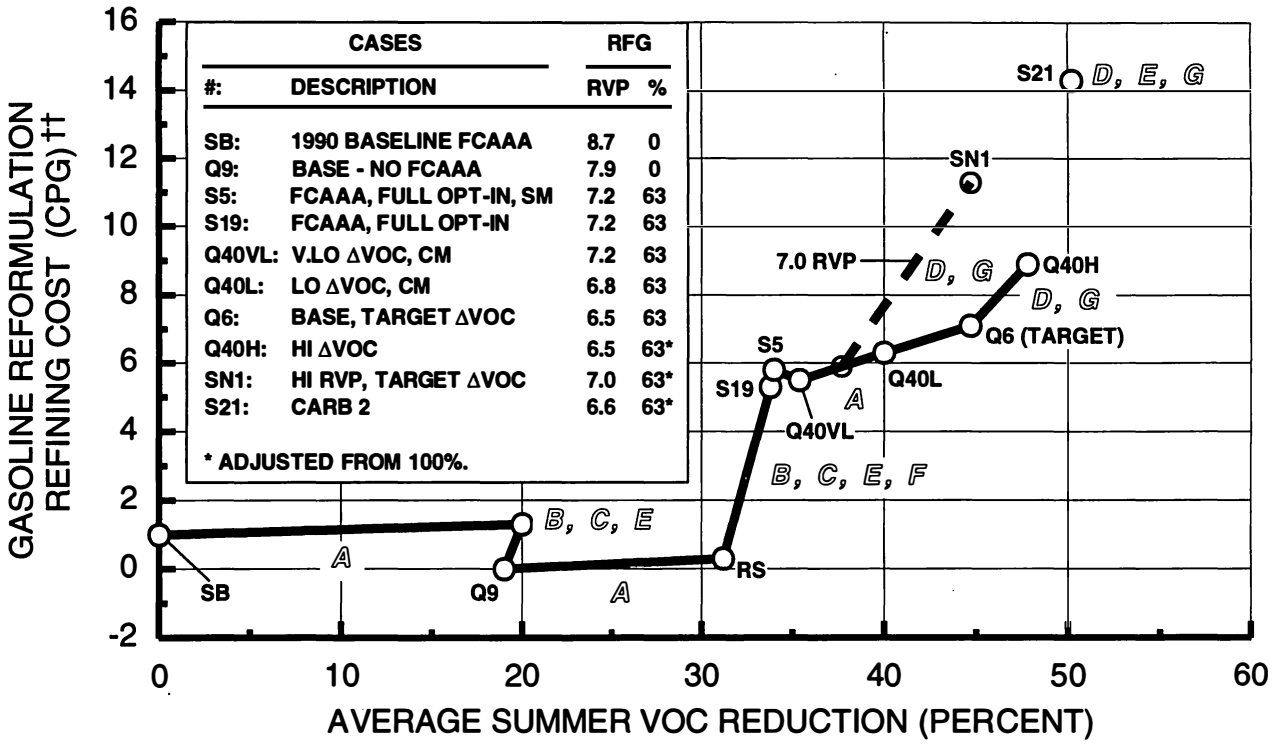
TABLE 4-24 (CONTINUED)

	S19 SF Alt	C40VL VL Δ VOC	Q40L L Δ VOC	Q6 T Δ VOC	Q6N Q6 + Cap Chg	QN2 Q6 + 10.7% OL	S10 Q6 + 30 S	S6 Q6 + 100% RFG	Q40H H Δ VOC	SN1 Q6 + 7 RVP	S21 CARB 2
RFG, % of Pool	**63**	**63**	**63**	**63**	**63**	**63**	**63**	**100**	**100**	**100**	**100**
Properties, RFG											
Aromatics, %	24.7	24.1	23.8	24.7	23.7	24.0	24.5	24.7	23.1	20.5	22.0
Olefins, %	13.1	13.0	12.3	11.6	10.7	10.7	5.2	10.7	9.7	8.9	4.0
Sulfur, ppm	151	171	173	144	141	137	30	125	76	58	30
RVP, psi	7.2	7.2	6.8	6.5	6.5	6.5	6.6	6.5	6.5	7.0	6.6
T_{90}, ° F	344	344	346	344	342	344	329	341	325	295	292
Refining Δ Investment, $Billion	2.0	2.0	2.4	3.0	2.7	3.2	3.6	3.2	4.5	6.4	10.2
Added Costs, cents per gallon											
Refining	5.3	5.5	6.3	7.1	6.9	7.7	8.2	7.2	8.9	11.3	14.3
Fuel Economy	2.2	2.2	2.1	1.9	1.9	1.8	1.9	1.9	2.2	3.1	2.8
Total	7.5	7.7	8.4	9.0	8.8	9.5	10.1	9.1	11.1	14.4	17.1

* See Figure 4-8 for case description.

† RFG emissions reduction from Statutory Baseline.

‡ From adjusted statutory base with 7.8 RVP for Class B (8.2 RVP for PADD III).



† Case S5 uses simple model.

†† Refining costs of conventional gasoline upgraded.

Processing Step

A - Reduce RVP	D - Reduce S
B - Add OX	E - Reduce OL
C - Reduce AR	F - Reduce BZ
	G - Reduce T90

Figure 4-6. Gasoline Reformulation Cost vs. VOC Reduction 1995-2000 PADD III Summer Results with 4/92 Complex Model.†

the statutory base gasoline. Sharp breaks occur at several points in the processing severity progression. The range covered starts with the CAAA 1990 statutory base gasoline having zero VOC emission reduction and extends to the most severe case at 50 percent reduction when CARB Phase 2 regulations are applied (Case S21). The small refining cost at very low VOC reduction is due to the NPC's selection of the cost base to be one without the CAAA RFG regulations in place (Case Q9). This Q9 base case has (1) a lower RVP (by 0.8 psi) as it has the lower RVP limit imposed in 1992, (2) a higher MTBE content (by 2 percent), and (3) a higher olefin content (by 4 percent) than the 1990 CAAA statutory baseline fuel. The net cost of these debit and credit cost items result in a CAAA baseline gasoline refining cost that is more than the selected NPC base without the CAAA.

In Figure 4-6, the next portion of the curve to the right of Q9 (RS) illustrates the low cost of VOC reduction by reducing RVP. About 12 percent VOC reduction from the Q9 base case can be gained by reducing RVP from 7.9 psi to 7.2 psi.

The steep cost increase in the next section of this curve occurs due to the mandated addition of oxygen to 2.1 wt% content and benzene content reduction to 1.0 vol% (0.7 vol% with 0.3 percent compliance factor) in accord with the CAAA. Negligible costs are required to decrease aromatics content for TAP control because aromatics decrease synergistically with the high octane oxygenate addition. Refining

costs increase about 5.5 cpg but VOC reduction is only about 3 percent.

The study found that any prescribed RVP minimum creates a sharp cost break in the VOC cost curve at that minimum. The NPC study team selected a minimum RVP of 6.5 psi as a pragmatic basis but acknowledge some uncertainty considering engine starting, RVP control in the refinery, drivability, safety risks, etc. The movement to the 6.5 psi RVP level was studied in the increments shown as points Q40VL and Q40L to establish the cost inflection point and the associated VOC reduction. The point Q6 is the target inflection point case (2000CBT) providing 45 percent VOC reduction with the 4/92 complex model at an additional refining cost above base of about 7 cpg.

Further VOC reduction requires more severe processing and correspondingly higher costs. The case Q40H increased the VOC target to 48 percent with RVP at the 6.5 psi minimum. Increased processing severity sharply decreased the sulfur content of the reformulated gasoline with accompanying moderate decreases in the T_{90}, olefin, and aromatics properties. Refining costs increase to 9 cpg above base.

Figure 4-6 shows results of other sensitivity studies: (1) increasing the RVP minimum to 7.0 psi and (2) assuming CARB Phase 2 regulations in PADD III. The choice of the minimum RVP is arguable. To provide analysis of the choice, a parallel case to Q6 was structured assuming a minimum of 7.0 psi. Although 6.5 psi now falls in the range of product properties proposed for use in the EPA complex models, its use may create some instability as very little experimental work on emissions exists at that level. The cost disadvantage with the higher minimum can be observed by comparing Q6 point with the intersection of the 7.0 psi line with that connecting Q6 and Q40VL—a difference of about 1 cpg and about 7 percent VOC reduction. To re-establish a VOC reduction of 45 percent, the 7.0 psi case (SN1) invokes much more stringent processing to reduce the olefin, sulfur, and aromatics content and the T_{90} point of the RFG. The additional refining cost is about 11 cpg above base or about 4 cpg more than the 6.5 psi case at 45 percent VOC reduction.

CARB Phase 2 regulations set RFG property specifications that require extremely severe refinery processing. Most of the property levels are about the same as the 7.0 psi RVP case, except sulfur content is lower at 30 ppm by weight and olefin content lower at 4.0 vol%. This severity increases VOC reduction to 50 percent at an additional refining cost of 14 cpg above the base case. The CARB case for PADD III provides 5 percent additional VOC reduction at a cost of about 7 cpg more than the 2000CBT case Q6.

Not shown in the figure but provided in Table 4-24 are results of sensitivity studies of (1) the effect of lowering RFG sulfur content on VOC reduction and (2) the effect of lowering olefin content. The two cases that set RFG product single property limits for sulfur (S10) and olefins (QN2) provided the same VOC reduction of 45 percent as the target case 2000CM at costs of about 1 cpg more. Although the VOC reductions are the same for the three cases, differences occur in NOx reduction. These are discussed later in this chapter.

Investment estimated for PADD III additional to the base case Q9, ranges from $2 billion for the low severity case S19, to $10 billion if CARB Phase 2 regulations were applied to PADD III producing 100 percent RFG. For the cost-effective RVP-based VOC reductions, refining investments for PADD III range from $2.0-3.2 billion. Refining investment increases to $3.6-4.5 billion for the lower cost NOx reduction cases, S10 and Q40H. They further increase to $6.4 billion for the more severe reformulation cases SN1 (7 psi RVP).

Figure 4-7 arrays the same cases as discussed above but plots average TAP reduction as a function of average VOC reduction. The TAP reductions were computed at the control VOC reduction levels using the 4/92 complex model. TAP reductions computed with this complex model are above 30 percent for the possible Phase II RFG summer VOC reductions which exceed the CAAA required performance standard of 20 or 25 percent VOC reduction. Discussions with the EPA indicate

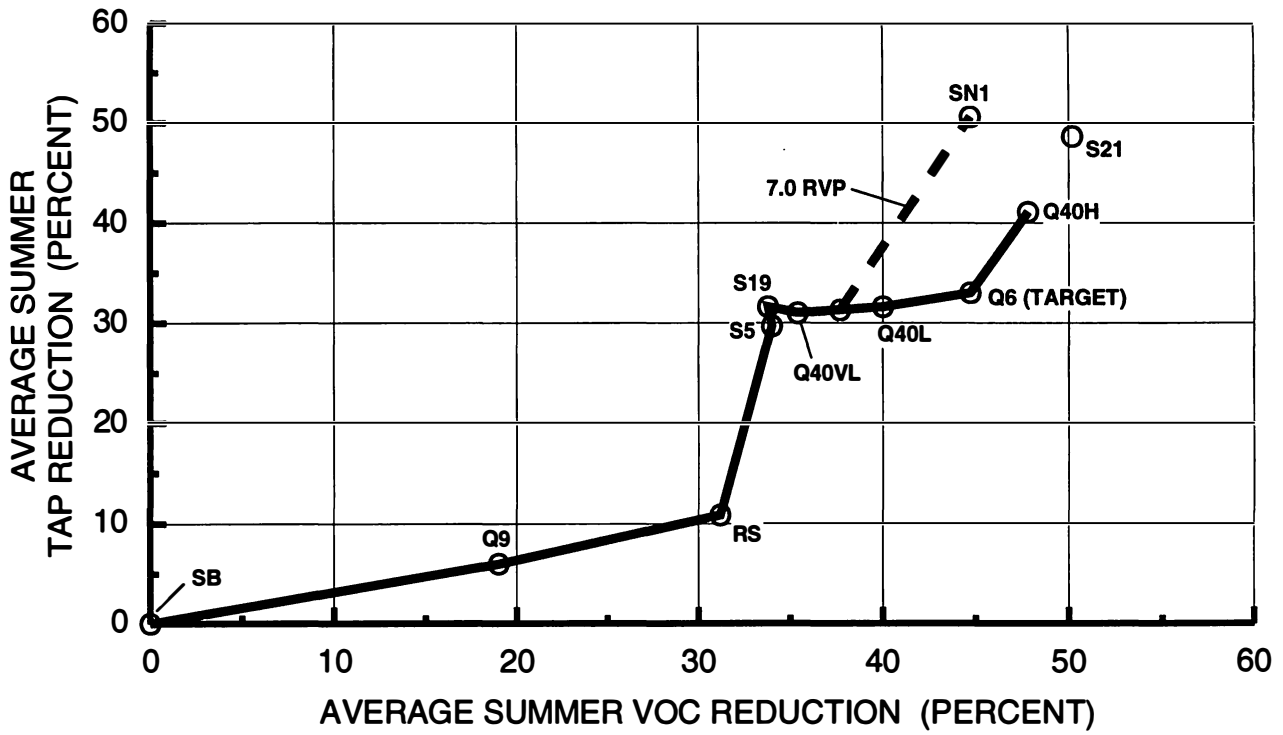


Figure 4-7. TAP Reduction vs. VOC Reduction*
1995-2000 PADD III Summer Results with 4/92 Complex Model.†

* Controlled by VOC reduction limits.
† Refer to Figure 4-6 for description of cases.

that it is unlikely that a higher TAP reduction standard than the CAAA required will be promulgated in the final rule.

Figure 4-8 portrays the same cases as the prior figures but show average NOx reduction as a function of average VOC reduction. All of the cases shown exceed the CAAA performance standard of no increase in NOx emissions when computed using the 4/92 Complex Model. The highest severity cases, which generally provide for sulfur and olefin content reductions, yield the highest NOx reductions (up to 8 percent for the CARB Phase 2 gasoline).

Computed Variation in Average Emission Reductions with Alternative Complex Models

The impact of other proposed complex models on average VOC reductions is shown graphically in Figure 4-9, using data from Table 4-24. (For simplicity, the individual case identifiers and the 10/92 EPA complex model results are not shown.)

The general effect of the more recent equations is to decrease the percent VOC reduction from that computed with the 4/92 complex model. The 2/93 EPA complex model provides the most extreme decrease of the series, amounting to values ranging from 8 to 19 percent depending on whether the model is applied to Phase I or Phase II gasoline. This model and the corresponding 1/93 API model exhibit discontinuities in their VOC reduction curves between the cases applying to Phase I and to Phase II RFG. These are created by two changes in the 2/93 NPRM proposal from prior versions, which apply to Phase II. First, is the use of the MOBILE5.0 model in place of MOBILE4.1 for the non-exhaust portion of the complex model. Second, is an adjustment of the Statutory Baseline RVP for Class B (South) areas to 7.8 psi from the 8.7 psi base stated in the CAAA. The first change is the more dominant of the two regarding VOC reduction and is created by the change in weighting applied to the exhaust and non-exhaust portions. These changes

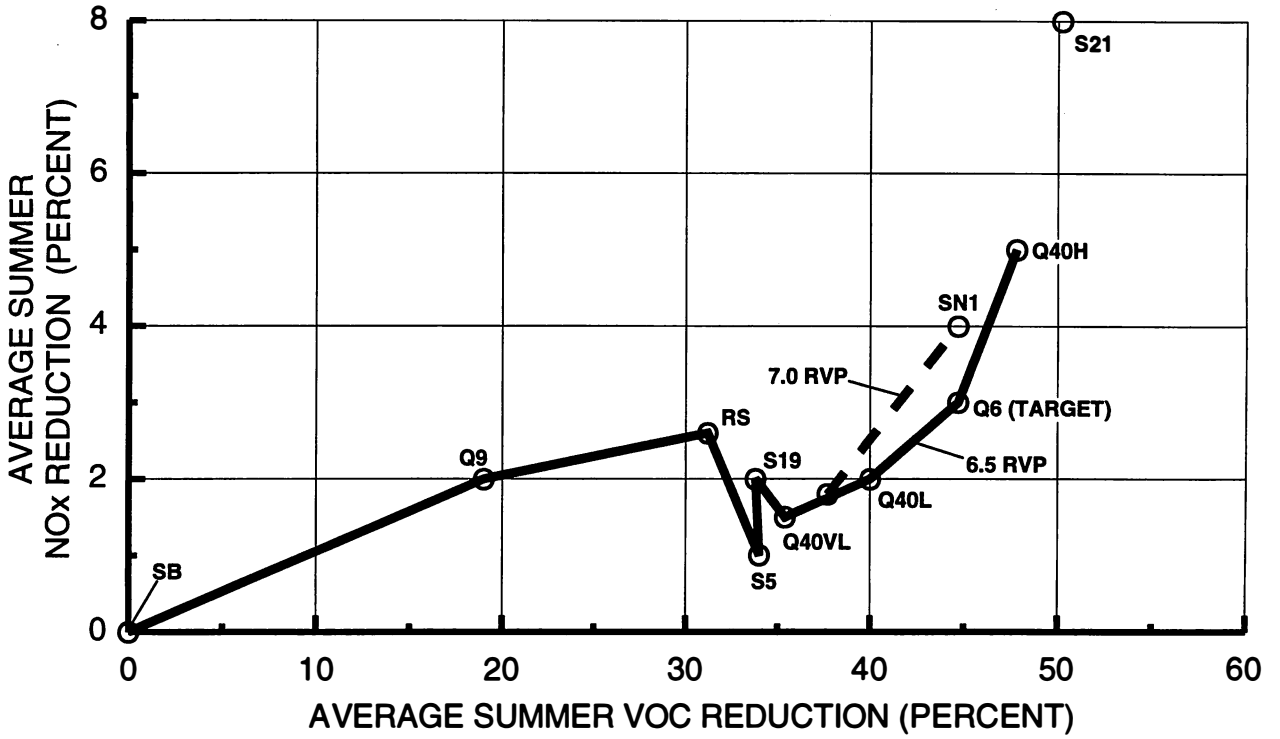
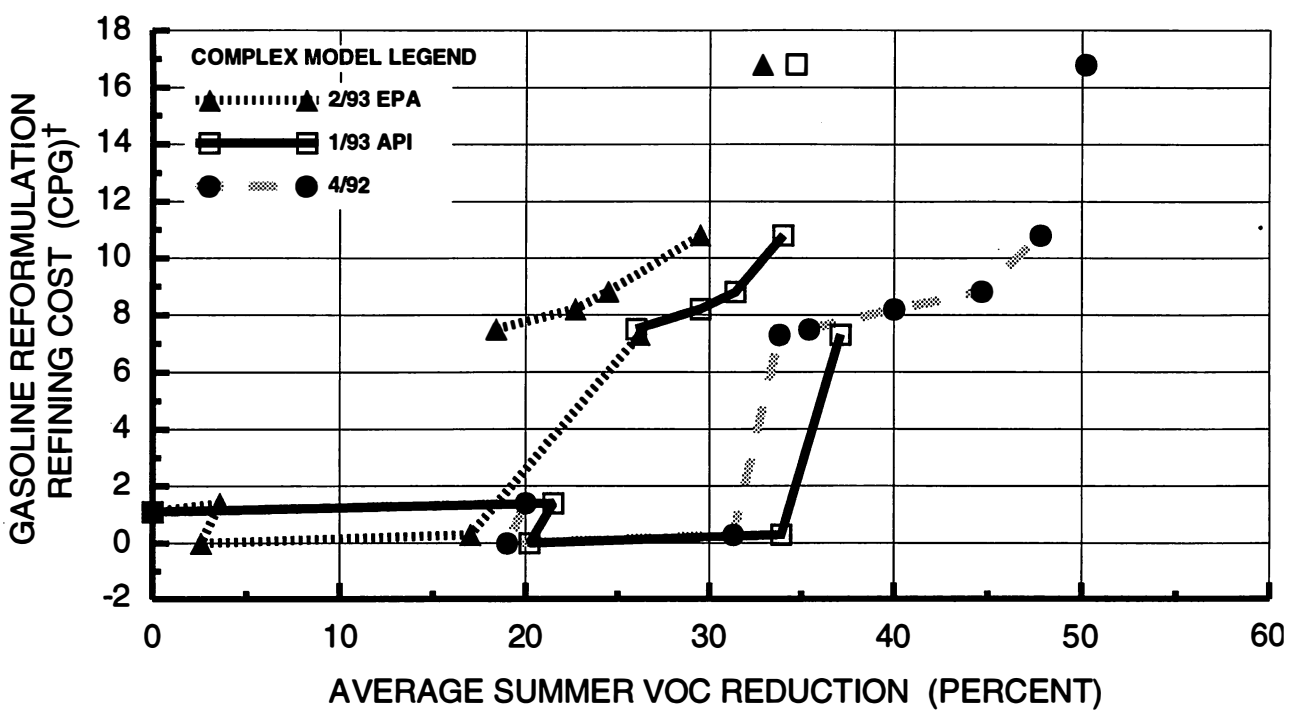


Figure 4-8. NOx Reduction vs. VOC Reduction 1995-2000 PADD III Summer Results with 4/92 Complex Model.*

* See Figure 4-6 for description of cases.



* Excludes cases S5, SN1, and Q6N (shown on Figure 4-5) to simplify comparison.

† Refining cost of conventional gasoline upgraded.

Figure 4-9. Impacts of Alternative Complex Models on VOC Reductions 1995-2000 PADD III Summer Results.*

have the combined effect of diminishing VOC reduction by about 5 to 6 percent at the discontinuity, which is equivalent to added costs of about 1 to 2 cpg to maintain the same level of VOC reduction.

From this figure, it is apparent that average VOC reductions at constant RFG costs are subject to significant change with different complex models. The Phase II cost inflection point (Q6 on prior curves) moves over wide ranges and is somewhat less distinguishable with the 2/93 EPA complex model than with the others. It is the only complex model in which the inflection point falls below a VOC performance standard of 25 percent, suggesting that a lower standard (with the adjusted statutory base) would be required when the reasonable cost criterion is applied. Further, southern RFG may require a lower performance standard than one for northern gasolines due to the lower adjusted Statutory Baseline RVP for southern areas.

Figure 4-10 illustrates the impact of complex models on average TAP reductions. As with the prior analysis for average VOC reduction, the more recent models result in less average TAP reduction. The 1993 models show the same discontinuity as the VOC curves for the same reasons. The slight dip in the 2/93 EPA complex model curve is due to interaction between the many terms of this model and illustrates the instability of this version.

Adoption of the 2/93 EPA complex model could result in a lowering of the performance standard for VOC reduction, as discussed above. A concomitant lowering of the TAP performance standard would also be suggested by the relationship of TAP and VOC shown in this figure. The 2/93 NPRM proposes a minimum of 21.5 percent average TAP reduction for Phase II. The cost break point case could achieve this level but not the co-proposed maximum average reduction of 26.5 percent. If the proposed limits of reasonable incremental cost-effectiveness are increased, average TAP performance could become controlling with a corresponding increase in processing severity. This relationship is more clearly shown for the 2/93 EPA complex model in Figure 4-11.

The impacts of the complex models on average NOx reduction is shown in Figure 4-12. The 4/92 and the API 1/93 complex

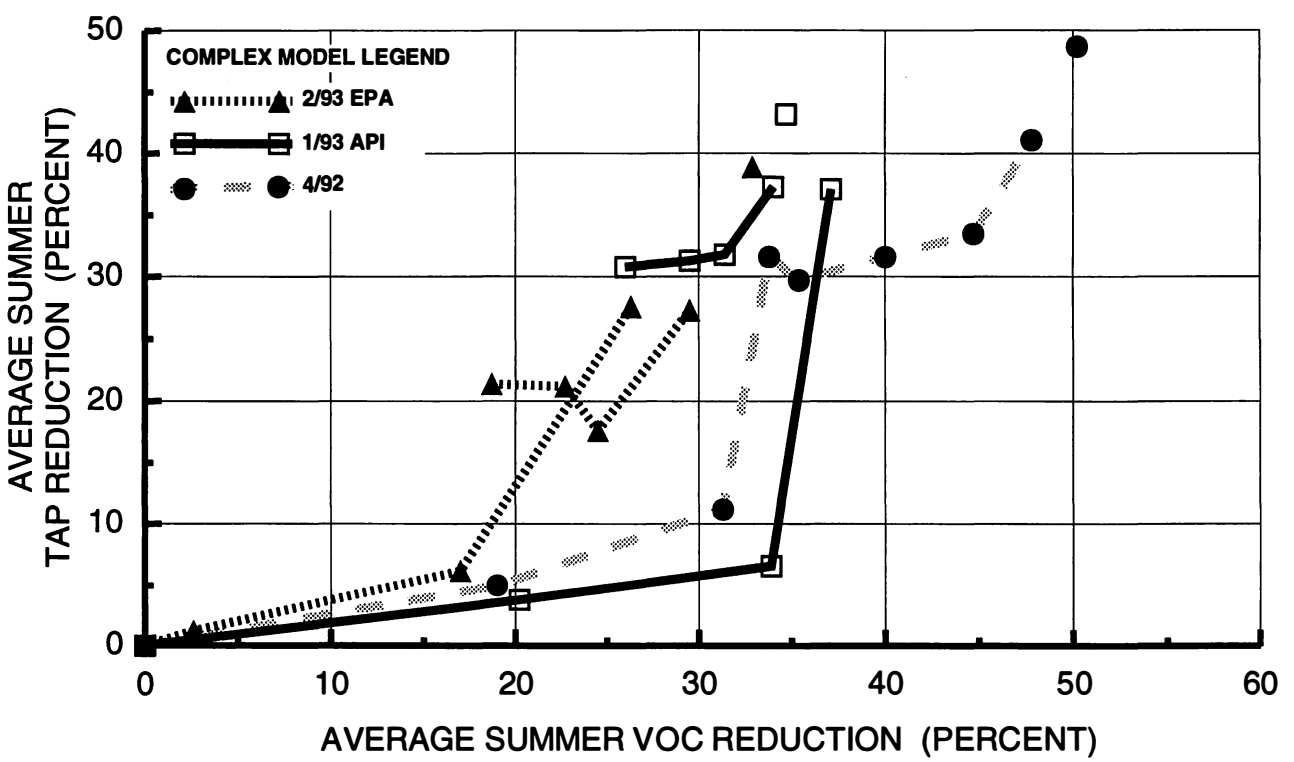


Figure 4-10. Impacts of Alternative Complex Models on TAP Reductions 1995-2000 PADD III Summer Results.

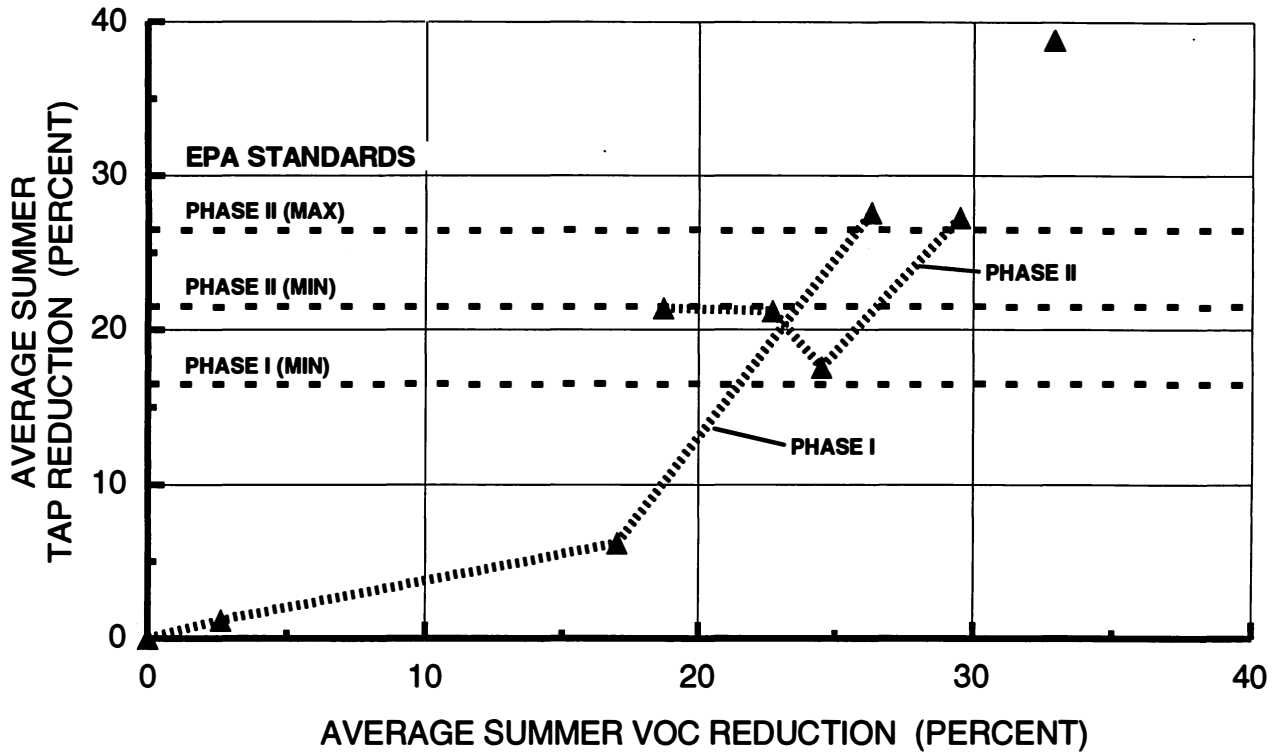


Figure 4-11. Impact of 2/93 EPA Complex Model on TAP Reductions 1995-2000 PADD III Summer Results.

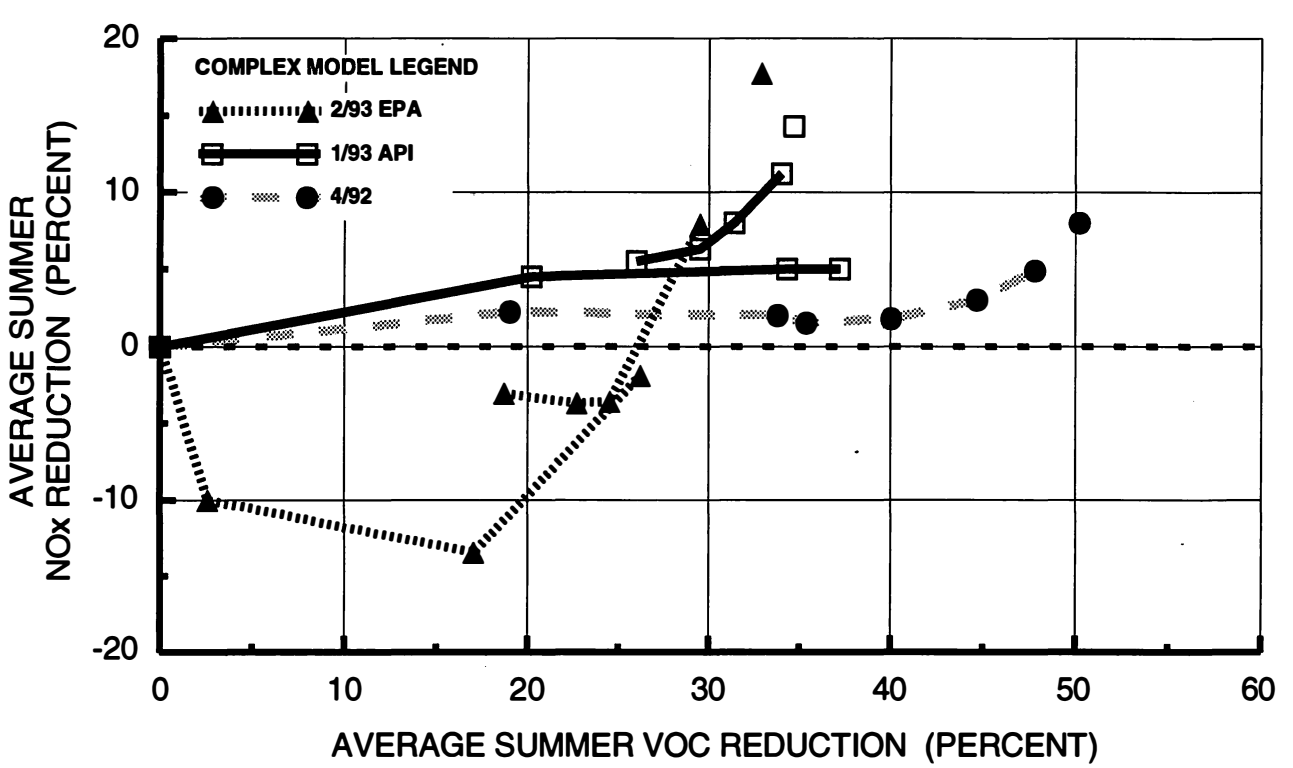


Figure 4-12. Impacts of Alternative Complex Model on NOx Reductions 1995-2000 PADD III Summer Results.

models provide average NOx reductions which meet the performance standard of no increase at all levels of average VOC reduction performance. The EPA 2/93 complex model meets this standard only with the highest processing severity cases, which provide a significant amount of sulfur and moderate olefin reductions.

Control of NOx emissions is part of the strategy for lowering ozone concentrations in most nonattainment areas. The NOx to VOC ratio is a variant in the different air sheds of the nonattainment areas and affects the chemistry of the ozone reaction. Control of NOx emissions is more or less important dependent on the ratio in the air shed. The ratio is a function of all of the pollutant sources, not just those from light vehicles. The CAAA provides that the NOx emissions of RFG are not to exceed that from the Statutory Baseline gasoline. The February 1993 NPRM, however, proposes as much as 15 percent NOx reduction from baseline.

This maximum reduction proposal and the current CAAA performance standard of no increase are shown in Figure 4-13 along with the average NOx/VOC relationship computed using the EPA 2/93 complex model. To achieve either of these average NOx performance standards clearly makes NOx reduction the controlling variable with this complex model. The corresponding VOC and TAP reductions achieved at the processing severities required for NOx performance exceed the performance standards for those pollutants as well as the limits proposed as reasonable costs for combined average VOC plus average NOx reduction.

Sulfur Reduction

Experimental data show that reducing the sulfur concentrations to low levels in RFG is effective in lowering NOx emissions. All complex models (lowering olefins significantly lowers NOx only with the 2/93 EPA complex model.) variants studied confirm this assertion. However, severe refinery processing is required to reduce sulfur in RFG and costs are high.

Cases were developed to study the cost, cost relationship with other solutions, and

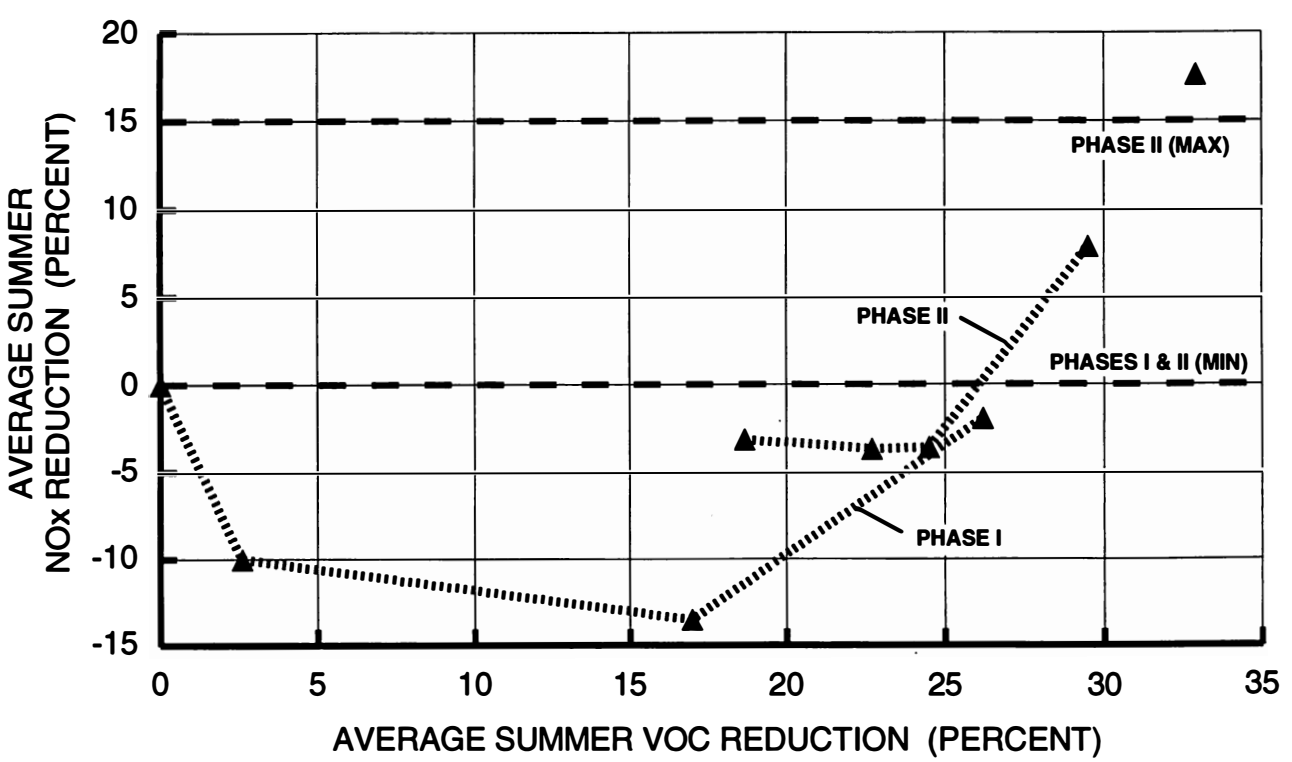


Figure 4-13. Impact of 2/93 EPA Complex Model on NOx Reductions 1995-2000 PADD III Summer Results.

refinery capability for reducing sulfur to 30 ppm.[7] The refinery LP model run objective for these cases was to reduce sulfur to this level. In the other cases discussed previously, the LP objective was to achieve a VOC reduction target. Model runs were completed for the PADD I, III, and IV conversion refinery models. Costs, properties, and emission reductions for these runs are shown in Table 4-25. Also provided is an extrapolation of the cost data from these regional cases to provide an estimate of the cost of providing low sulfur content gasoline for total U.S. RFG requirements in 2000. For comparison, costs for Case Q6, the cost break point target case 2000CBT are also given for each PADD.

Reducing RFG sulfur content to 30 ppm increased the refining investment in the United States by about $8 billion and the refining cost by about 9 cpg over the base case without the CAAA. The added cost over the target case is about $2 billion investment and 1.4 cpg added refining cost. This difference between the sulfur reduction and the target case ranged from 1.3 cpg in PADD III to 4 cpg in PADD IV. The cost of sulfur reduction is likely to vary considerably in different refineries.

Refining costs are higher in PADD I and PADD IV than in PADD III, as illustrated in Table 4-26. This is due to economy of scale and to the higher initial sulfur content in PADD I and PADD IV gasolines. Reducing sulfur content to this extreme level also reduces olefin content, as may be observed by comparing the S10 and Q6 cases in Table 4-25. Processing options are much the same, particularly treatment of cat-cracked gasoline.

Low sulfur RFG emission reductions for VOC, TAP, and for NOx equaled or exceeded those of the target reduction case Q6 when computed by any of the four complex models. As expected, NOx reduction is clearly enhanced over the target case with increases of 5 to 14 percentage points in the various models and PADDs. Noteworthy is that the 2/93 EPA complex model indicates NOx reductions in all of the low sulfur cases versus increases for lower severity target reduction Q6 case. On the other hand, the 1/93 API complex model also computes NOx reductions for the low sulfur case *and* for the target reduction case. The target case is the one found in these NPC studies to have the maximum processing severity at a reasonable cost for VOC reduction. One complex model requires severe processing to achieve the NOx increase performance target while another predicts this performance at lower severities and costs. The choices of (1) the final complex model, (2) NOx reduction limits, and (3) what is a reasonable cost, need to be finalized in order to judge the merits of higher severity processing such as reduction of sulfur content for reducing NOx emissions.

Olefin Reduction

Single property reduction studies using the PADD I and PADD III models were also done assuming olefin reduction as the variable. Processing severity levels were selected to be greater than those of the Q6 cases so as to achieve additional reductions in NOx emissions.

Costs, properties, and emission reductions for these runs are shown in Table 4-27. Extrapolated U.S. costs are also provided. For an approximate 2 percent olefin reduction, refining investment for the United States is about $7 billion and the refining cost is about 8.5 cpg over the base case without the CAAA. The added cost over the target case is about $1.5 billion investment and 1 cpg added refining cost for a 2 percent olefin reduction. The PADD I results for the approximate 5 percent olefin reduction case indicates additional refining costs of 2 cpg over the target case.

Added refining and unit investment costs are higher in PADD I than PADD III for the 11 percent olefin reduction at 9.3 and 7.7 cpg and $1,750 and $1,000 per B/CD RFG, respectively. This is due to economy of scale in PADD III and to the higher initial olefin content in PADD I.

All emissions are maintained or reduced compared to the target cases for these reduced olefin cases when computed by the four complex models, with the exception of the TAP

[7] The RFG sulfur reduction costs were developed assuming that sulfur would be reduced year-round, not just in the summer. These costs would increase for summer only sulfur reduction due to higher capital charge.

TABLE 4-25

LOW SULFUR CONTENT REFORMULATED GASOLINES
INCREASED COSTS VS. EMISSION REDUCTIONS WITH ALTERNATIVE COMPLEX MODELS
2000 SUMMER CASES – U.S. NO DEMAND GROWTH CASE

	PADD I			PADD III			PADD IV			U.S.*	
	Q9	Q6	S10	Q9	Q6	S10	Q9	S6	S10	Q6	S10
	Base Case†	Target Case	Sulfur 30 ppm	Base Case†	Target Case	Sulfur 30 ppm	Base Case†	Target Case‡	Sulfur 30 ppm	Target Case	Sulfur 30 ppm
RFG, % of Pool	**0**	**100**	**100**	**0**	**63**	**63**	**0**	**100**	**100**	**65**	**65**
Northern Gasoline, %	**80**	**90**	**90**	**40**	**40**	**40**	**40**	**40**	**40**		
Added Refining Investment, $Billion		0.9	1.1		2.7	3.6		0.5	0.8	6.0	8.0
Added Refining Costs, cpg, RFG		8.2	11.3		6.9	8.2		10.2	14.1	7.6	9.0
RFG Properties											
Aromatics, vol%	31.2	24.4	27.0	30.9	24.7	24.5	28.0	21.9	20.8		
Oxygen, wt%	0.4	2.1	2.1	0.4	2.1	2.1	0.4	2.1	2.1		
Olefin, vol%	15.9	13.1	10.2	13.6	11.6	5.2	14.6	11.3	10.4		
Benzene, vol%	1.8	0.7	0.7	1.8	0.7	0.7	1.9	0.7	0.7		
Sulfur, ppmw	341	233	30	206	144	30	287	196	30		
RVP, psi	8.2	6.5	6.7	7.9	6.5	6.6	7.9	6.6	6.8		
T_{50}, ° F	212	206	205	211	205	206	206	205	206		
T_{90}, ° F	354	340	346	347	344	329	344	340	328		

TABLE 4-25 (CONTINUED)

	PADD I			PADD III			PADD IV			U.S.*	
	Q9	Q6	S10	Q9	Q6	S10	Q9	S6	S10	Q6	S10
	Base Case†	Target Case	Sulfur 30 ppm	Base Case†	Target Case	Sulfur 30 ppm	Base Case†	Target Case‡	Sulfur 30 ppm	Target Case	Sulfur 30 ppm
Complex Model Designation§, %											
4/92											
VOC	9	41	41	19	45	45	19	45	45		
NOx	(3)	(1)	7	2	3	9	(1)	1	6		
TAP	(3)	33	35	5	34	37	7	35	43		
10/92 EPA											
VOC	(1)	31	30	9	36	40	12	37	38		
NOx	(21)	(9)	5	(9)	(3)	14	(8)	(2)	9		
TAP	3	19	28	8	25	39	9	29	37		
1/93 API											
VOC	8	30	29	20	31	32	21	31	32		
NOx	(2)	4	12	5	8	14	1	6	13		
TAP	(6)	29	32	4	32	38	2	33	38		
2/93 EPA¶											
VOC	(5)	27	27	(3)	24	31	2	26	29		
NOx	(21)	(9)	5	(10)	(4)	14	(9)	(2)	9		
TAP	2	17	26	1	18	33	4	22	32		

* Extrapolated from PADD results shown. Does not include CARB (California Air Resources Board) gaoline.

† No 1990 Clean Air Act Amendments.

‡ At 100 percent RFG.

§ RFG emissions reduction from Statutory Baseline.

¶ From adjusted emission reduction Statutory Baseline with RVP adjustment from 8.7 to 7.8 for psi for southern gasoline.

TABLE 4-26

REPRESENTATIVE COSTS OF LOW SULFUR REFORMULATED GASOLINE (1990 Dollars)

	PADD I	PADD III	PADD IV	U.S.*
Reformulated Gasoline, MB/CD	680	2,013	251	3,885
Investment, $ per B/CD RFG	1,600	1,780	2,980	2,060
Refining Cost, cpg, RFG	11.3	8.2	14.1	9.0

* Estimated from PADD values without California CARB Phase 2 gasoline. Includes PADD IV at 100 percent RFG.

emission (2 percent increase) in PADD I computed with the 4/92 complex model. NOx reductions ranged from 0 to 6 percent for the 2 percent olefin decrease from the target case. With the use of the 2/93 EPA complex model, a further olefin reduction would be required to obtain no NOx increase in PADD III.

Neither the sulfur nor olefin study cases are to be viewed as optimal for meeting potential NOx reduction requirements. The similarity of the costs suggests that optimization studies are required to pick the correct processing scheme for any individual refinery, should the final complex model and standards require severe processing for NOx reduction.

CARB Phase 2 Standards Outside California

CARB Phase 2 regulations impose very extreme limits on gasoline properties as a control strategy for reducing ozone. If states other than California were to adopt CARB gasoline standards, some refineries supplying such states would face significant capital investments to produce CARB gasoline. These limits were assumed for PADDs I, III, and IV models to assess the regional and national impact on cost to manufacture this highly reformulated gasoline. Costs, RFG properties, and emission reduction computed with the four complex models are given in Table 4-28 for these PADDs. Also shown are results for California adapted from WSPA studies to the financial standards of the NPC study.

Investment is the highest in PADD III due to the large volume requirements of this region. The unit investments in PADDs I and IV are higher than PADD III and California, as many of the initial properties are higher, e.g., olefins, sulfur, etc., and these regions have less economy of scale. Table 4-29 compares investment on a dollars per daily barrel of RFG manufacture to illustrate this point.

Refining costs of 17 cpg in the United States are also significantly higher in PADDs I and IV for the same reasons. Emission reductions are the highest studied ranging from 5 to 20 percent higher for the CARB Phase 2 cases than for the Q6 target cases.

Processing Severity Impact on Refinery Capability

The D1 series of tables provided in Appendix M present the Q40 set of runs for PADD III, which study the effect of increasing processing severity to achieve higher levels of VOC reduction for reformulated gasoline. The following observations result from a review of these tables.

- The fractionation of gasoline components is increased greatly as severity increases. RVP control requires a great deal of fractionation, as does increased property control for benzene, sulfur, aromatics, T_{90}, etc.
- Diesel fuel and gas oil, hydrotreating, hydrogen manufacture, aromatics extraction,

TABLE 4-27

LOWER OLEFIN CONTENT REFORMULATED GASOLINES
INCREASED COSTS VS. EMISSION REDUCTIONS WITH ALTERNATIVE COMPLEX MODELS
2000 SUMMER CASES – U.S. NO DEMAND GROWTH CASE

	PADD I				PADD III			U.S.*	
	Q9	Q6	QN2M	QN2H	Q9	Q6	QN2	Q6	QN2
	Base Case†	Target Case	Olefin 11.1%	Olefin 8.6%	Base Case†	Target Case	Olefin 10.7%	Target Case	Reduced Olefins and NOx
RFG, % of Pool	**0**	**100**	**100**	**100**	**0**	**63**	**63**	**65**	**65**
Northern Gasoline, %	**80**	**90**	**90**	**90**	**40**	**40**	**40**		
Added Refining Investment, $Billion		0.9	1.2	1.4		2.7	3.2	6.0	7.5
Added Refining Costs, cpg, RFG		8.2	9.3	10.3		6.9	7.7	7.6	8.5
RFG Properties									
Aromatics, vol%	31.2	24.4	24.3	24.3	30.9	24.7	24.0		
Oxygen, wt%	0.4	2.1	2.1	2.1	0.4	2.1	2.1		
Olefin, vol%	15.9	13.1	11.1	8.6	13.6	11.6	10.7	11	9
Benzene, vol%	1.8	0.7	0.7	0.7	1.8	0.7	0.7		
Sulfur, ppmw	341	233	239	214	206	144	137		
RVP, psi	8.2	6.5	6.5	6.5	7.9	6.5	6.5		
T_{50}, ° F	212	206	205	205	211	205	204		
T_{90}, ° F	354	340	339	337	347	344	344		

TABLE 4-27 (CONTINUED)

	PADD I				PADD III			U.S.*	
	Q9	Q6	QN2M	QN2M	Q9	Q6	QN2	Q6	QN2
	Base Case†	Target Case	Olefin 11.1%	Olefin 8.6%	Base Case†	Target Case	Olefin 10.7%	Target Case	Reduced Olefins and NOx
Complex Model Designation ‡, %									
4/92									
VOC	9	41	41	41	19	45	45		
NOx	(3)	(1)	0	2	2	3	4		
TAP	(3)	33	31	33	5	34	34		
10/92 EPA									
VOC	(1)	31	32	33	9	36	37		
NOx	(21)	(9)	(3)	2	(9)	(3)	0		
TAP	3	19	24	29	8	25	28		
2/93 API									
VOC	8	30	30	30	20	31	32		
NOx	(2)	4	4	6	5	8	9		
TAP	(6)	29	30	32	4	32	33		
2/93 EPA §									
VOC	(5)	27	28	30	3	24	26		
NOx	(21)	(9)	(4)	2	(10)	(4)	(1)		
TAP	2	17	21	26	1	18	21		

* Extrapolated from PADD results shown assuming Case QN2M in PADD I and no change in conventional gasoline olefin content. Does not include CARB (California Air Resources Board) gasoline.

† No 1990 Clean Air Act Amendments.

‡ RFG emissions reduction from Statutory Baseline.

§ From adjusted Statutory Baseline with RVP adjustment from 8.7 to 7.8 for psi for southern gasolines.

TABLE 4-28

CARB PHASE 2 REFORMULATED GASOLINES
INCREASED COSTS VS. EMISSION REDUCTIONS WITH ALTERNATIVE COMPLEX MODELS
2000 SUMMER CASES – U.S. NO DEMAND GROWTH CASE

	PADD I			PADD III			PADD IV			California	U.S. Total
	Q9	Q6	S21	Q9	Q6W	S21	Q9	Q6	S21	S21	S21
	Base Case*	Target Case	All CARB2	Base Case*	Target Case	All CARB2	Base Case*	Target Case	All CARB2	All CARB2	All CARB2
RFG, % of Pool	**0**	**100**	**100**	**0**	**63**	**100**	**0**	**100**	**100**	**100**	**100**
Northern Gasoline, %	**80**	**90**	**80**	**40**	**40**	**40**	**40**	**40**	**40**	**0**	
Refining Investment,† $Billion		0.9	3.7		2.7	10.2		0.5	1.2	3.5	24
Added Refining Costs, cpg, RFG		8.2	21.3		6.9	14.3		10.2	25.3	15.1	17
RFG Properties											
Aromatics, vol%	31.2	24.4	22.0	30.9	24.7	22.0	28.0	21.9	18.0	22.0	
Oxygen, wt%	0.4	2.1	2.0	0.4	2.1	2.0	0.4	2.1	2.0	2.0	
Olefin, vol%	15.9	13.1	4.0	13.6	11.6	4.0	14.6	11.3	4.0	4.0	
Benzene, vol%	1.8	0.7	0.8	1.8	0.7	0.8	1.9	0.7	0.8	0.8	
Sulfur, ppmw	341	233	29	206	144	30	287	196	30	30	
RVP, psi	8.2	6.5	6.6	7.9	6.5	6.6	7.9	6.6	6.6	6.6	
T_{50}, ° F	212	206	193	211	205	193	206	205	193	196	
T_{90}, ° F	354	340	290	347	344	292	344	340	290	290	

TABLE 4-28 (CONTINUED)

	PADD I			PADD III			PADD IV			California	U.S. Total
	Q9	Q6	S21	Q9	Q6	S21	Q9	Q6	S21	S21	S21
	Base Case*	Target Case	All CARB2	Base Case*	Target Case	All CARB2	Base Case*	Target Case	All CARB2	All CARB2	All CARB2
Complex Model Designation ‡, %											
4/92											
VOC	9	41	48	19	45	50	19	45	51	52	
NOx	(3)	(1)	8	2	3	8	(1)	1	7	8	
TAP	(3)	33	48	6	34	49	7	35	53	49	
10/92 EPA											
VOC	(1)	31	38	9	36	41	12	37	42	44	
NOx	(21)	(9)	18	(9)	(3)	18	(8)	(2)	19	17	
TAP	3	19	43	8	25	44	9	29	48	45	
2/93 API											
VOC	8	30	34	21	31	35	14	31	35	35	
NOx	(2)	4	14	4	8	14	1	6	15	15	
TAP	(6)	29	43	2	32	43	2	33	46	42	
2/93 EPA §											
VOC	(5)	27	36	3	24	33	2	26	33	30	
NOx	(21)	(9)	18	(10)	(4)	18	(9)	(2)	19	17	
TAP	2	17	41	1	18	39	4	22	43	39	

* No 1990 Clean Air Act Amendments.

† Additional to Base Case, 1990 dollars.

‡ RFG emissions reduction from Statutory Baseline.

§ From adjusted Statutory Baseline with RVP adjustment from 8.7 to 7.8 psi for southern gasolines.

TABLE 4-29

COSTS OF CARB PHASE 2 SPECIFICATION GASOLINE (1990 Dollars)

	PADD I	PADD III	PADD IV	California	U.S.
Reformulated Gasoline, MB/CD	682	3,235	252	973	7,180
Investment, $ per B/CD RFG	5,500	3,200	4,800	3,600	3,400
Investment, $Billions	3.7	10.2	1.2	3.5	24.0
Refining Cost, cpg, RFG	21.3	14.3	25.3	15.1	17.0

benzene saturation, and isomerization process units tend to stay fully utilized.

- New investment is concentrated in fractionation units and benzene saturation.

Other case studies tend to show these same characteristics. Other geographic regions would be expected to behave similarly.

Impact of Alternative Complex Models on Conventional Gasoline

Emissions from conventional gasoline were controlled in the LP model runs using the 4/92 complex model to not exceed those of the refiners baseline gasoline as specified in the CAAA. The 2/93 EPA complex model computes nonperformance for several of the conventional gasoline pools with respect to NOx reduction. Noteworthy among these are the conventional gasoline pools resulting from the application of the simple model in the 1995 period. Many of the 2000 cases computed by this model also show increases in NOx emission from conventional gasolines. Details are presented in Appendix M, Exhibits 21 through 27. Should this version of the complex model be adopted, additional processing and additional costs will be required to achieve NOx compliance even for refineries producing no RFG.

Ethanol Use In RFG

One of the basic premises for this study was that MTBE would be the predominant oxygenate chosen to meet summer (VOC-controlled) RFG oxygen requirements. This premise reflected the favorable blending characteristics of MTBE (e.g., RVP, octane, miscibility, suitability for pipeline shipping) and the large commitment of refiners and others to construction of MTBE manufacturing facilities.

Nonetheless, there is substantial interest in the use of ethanol in summer RFG and a decision was made to analyze the effect of doing so as part of this study. A case was modeled around current and proposed practices for using ethanol in gasoline. The primary case considered was the use of ethanol, blended in RFG (RFG-E) at the 5.7 percent (2.1 percent oxygen) level, in lieu of MTBE, in 30 percent of the summer RFG pool. The base gasoline in the RFG-E and MTBE-blended RFG (RFG-M) was adjusted so that VOC performance of the whole RFG pool was held constant at the refinery. This case was designed to analyze the ethanol-related proposal made in the EPA February 1993 NPRM.

Geographic and Seasonal Scope

PADD II was chosen since almost all U.S. ethanol is produced within this PADD. Given the current cost and difficulty (water solubility) of transporting ethanol long distances, it was viewed as the most likely place where ethanol could economically compete. This choice of study areas is supported by EPA draft proposed rules. These rules would establish a mandatory ethanol use program in all northern ozone nonattainment areas, while allowing "renewable oxygenate use" trading with the express purpose of allowing the maximum amount of ethanol use close to the production locations (i.e., PADD II).

Summer RFG for the year 2000 (meeting Phase II RFG requirements) was chosen as the appropriate time frame. In 1995, the impacts of ethanol use on RFG cost and refinery investment are less, given the lower Phase I RFG requirement and refiners' ability to reduce RVP to achieve equal VOC performance. In the year 2000, RFG-M is being produced at the minimum RVP level (6.5 psi for this study) and at the inflection point in the VOC/cost curve (consistent with the EPA draft proposed rule). Achieving the needed additional VOC reduction, to offset ethanol's effect in RFG-E, will have significant cost and investment impacts.

One hundred percent RFG production within PADD II was chosen as the basis for the analysis because of limitations in the LP model to handle multiple grades of conventional gasoline in addition to RFG-M and RFG-E and to avoid over-optimization when producing only a small percent of RFG-E.

Results

For the cases studied, 1.7 MMB/CD of reformulated gasoline are produced. In the ethanol use case, 0.5 MMB/CD are RFG-E using 30 MB/CD of ethanol, while 1.2 MMB/CD of RFG-M are produced. The RFG, as a pool, achieves a VOC reduction of 41 percent (computed with the 4/92 complex model), the same as the 100 percent RFG-M base case. The RFG-E and RFG-M pools, separately, achieve 31 percent and 45 percent VOC reduction, respectively. The no NOx increase and TAP reduction requirements are also met. This added VOC emission performance of RFG-M was achieved through sulfur and T_{90} reductions.

Under the 2/93 EPA complex model, all requirements are met but the VOC reductions are about 10 percent less for both RFG-E and RFG-M, and the RFG-E produced greater NOx reduction benefits because of its higher RVP and lower olefins. Overall, the combined RFG-E and RFG-M pool had substantially better NOx performance than the base case 100 percent RFG-M pool, due to the sulfur and T_{90} reductions. To achieve the needed VOC reductions (to offset the higher RVP level of RFG-E) and to make up for the loss in RFG volume and energy content (due to a shift from 11.8 percent ether to 8.2 percent ether, and 1.7 percent ethanol), several changes occur in refinery operation, including:

- Processing additional crude oil to make up for lost RFG (ether) volume and provide part of the needed increases in plant fuel
- Increasing hydrotreating and hydrocracking to lower sulfur levels in gasoline and distillate streams
- Increasing fractionation of FCC and reformer streams to allow processing and blending changes to permit components with lower sulfur and T_{90} properties to be moved to gasoline
- Decreasing catalytic cracking and increasing reforming to produce an increased volume of lower sulfur gasoline blendstocks
- Increasing alkylation and decreasing internal MTBE production.

To achieve these processing changes in PADD II, additional refinery investment of $0.8 billion is required, primarily for fractionation and desulfurization units. Changes in raw material usage include an additional 78 MB/CD (or 3 percent) of crude oil, and additional natural gas and electricity purchases equal to about 7 MB/CD of fuel oil equivalent (FOE). Ethanol use increases 30 MB/CD while MTBE purchases fall 45 MB/CD and methanol purchases (for internal MTBE production) fall 5 MB/CD. Overall plant energy consumption within the refinery increases about 22 MB/CD FOE. This increase in energy consumption is more than the energy content of the ethanol used.

The refining cost impact (of using ethanol in 30 percent of the RFG pool in lieu of MTBE) is estimated to be an additional 1.4 cpg of RFG (over the total combined pool). This does not include additional fuel economy loss of about 0.3 cpg and ethanol subsidy costs. When evaluated on the basis of increased cost per gallon of ethanol used, the increase in direct refining cost amounts to 75 cpg of ethanol used.

Observations

- Producing RFG-E will require two additional RFG types.
- The results of this analysis, when viewed in terms of increased cost per gallon of ethanol used, suggest that an alternative, lower cost strategy for using ethanol would and should be sought. Production of ETBE in lieu of MTBE is an obvious possibility.
- Constraints on the analysis, in particular limiting diesel fuel and jet fuel production to a fixed level, may have resulted in some overstatement in the crude oil usage and costs.
- Evaluating the impact of using ethanol in lieu of MTBE when there is no room to adjust RVP (i.e., operation at the "break point" in the cost curve) may overstate the difficulty. However, this is the specific nature of the current EPA proposal.
- Refinery energy usage increased by about 150 percent of the blended ethanol energy usage.

Regulatory Concerns

- The use of ethanol as the oxygenate component in RFG has a disadvantage of increasing RVP with a corresponding increase in VOC emissions. Additional processing is required to reduce this emission back to the comparable level associated with the use of MTBE as the oxygenate. An alternative to the ethanol initiative using ETBE might be a more attractive option.

Performance Standard

Because of compliance allowances or averaging, the emissions calculated for industry average RFG will be lower than the emissions level implied by the performance standards the gasoline meets. The cost of producing the industry average gasoline may be higher or lower than the industry aggregated PADD refinery model estimates.

Lower costs might occur because of:

- The use of subsidized ethanol instead of MTBE and TAME as the oxygenate.
- The use of ETBE, subsidized or not, instead of MTBE and TAME as the oxygenate.
- At lower penetrations of RFG, only the most efficient producers would invest to manufacture RFG.

Higher costs might occur because of:

- Increased specification giveaway required for satisfactory use of refinery blendstocks for oxygenate blending and terminal blending.
- Enforcement procedures that don't make adequate allowance for testing compliance; given the normal variability of laboratory tests, a high proportion of batches don't meet the performance standard. It is impractical to have more than a very small percentage of batches that require retesting or adjustment.
- Meeting several constraining standards simultaneously on an every-gallon-meets-the-standard basis or an averaging basis leads to specification giveaway for one or two of the specifications and hence cost increases compared to the refining industry aggregate model which, on average, over many refineries and a long period of time and all octane grades, can meet all the standards simultaneously. Potential simultaneous standards:
  - No NOx increase requirement
  - The VOC reduction standard
  - The TAP reduction standard.
- Ranges eliminate otherwise qualifying RFG. May not be a qualifying RFG if any fuel property is outside its range.
  - Ranges create lower limits on fuel properties that reduce refineries' flexibility in producing RFG because of the tolerance allowance required to avoid being out of compliance on the lower limit.

- Ranges eliminate credit for being better than range allows, if fuel property is below the lower limit of the range.

- The EPA or possibly the individual states or nonattainment areas may apply different RFG requirements, such as baseline gasolines, or baseline emissions, or complex model coefficients for RFG, or performance standards. Additional or different constraints on RFG and different RFGs for different areas may reduce RFG producibility or increase number of RFG segregations and RFG cost.

- The EPA may elect to make different requirements for RFG blended with ethanol than for RFG blended with ethers when setting the overall RFG performance standard. This may require a greater reduction of emissions from the overall RFG performance standard for RFG blended with MTBE.

- In the aggregated industry model the refining industry also produces summer conventional gasoline, with average properties constrained to prevent an increase in the targeted emissions from the appropriate conventional gasoline baseline (i.e., meets the antidumping requirements). Caps and ranges for the applicability of equations for calculating estimated emissions to comply with antidumping requirements may make it more difficult and costly to meet these requirements.

Seasonality

Geographic and Seasonal Scope

Conversion refinery models were used to analyze costs of reducing VOC emissions from reformulated gasoline during the summer control period specified by the CAAA. The corresponding reductions of TAP and NOx in this period achieved at least the reduction requirements of the CAAA but otherwise were allowed to float at levels resulting from the processing changes required to meet the VOC target reduction. Because the CAAA reduction requirements for TAP and NOx are annually based, a limited number of cases were developed for the winter period for PADDs II and III to provide data for estimating costs for reformulated gasolines in this season. The results for winter can be averaged with corresponding summer data to estimate annual costs and emissions. Other PADDs were not studied for winter conditions; results from PADD II and PADD III studies are believed to be representative of the total U.S. industry outside of California.

Flexibility

The studies of these two PADDs indicate that the refining system has flexibility to meet the different seasonal variations. Table 4-30 compares summer/winter gasoline demand, added process units and investment required in the two seasons over the base case without CAAA, total gasoline pool composition, and NOx emissions for the several gasoline types in the two periods.

Added process unit requirements for the two seasons are similar, with the summer period requiring some added capacity. Both seasons require considerably more fractionation units than the no CAAA case. Investment is higher for summer requirements. Emission reduction performance computed with the 4/92 complex model meets requirements except for NOx emission in the winter for nearly all of the types of gasolines. These values when combined with the summer values computed with this complex model would about average to no annual increase in NOx. Other complex models in general predict better NOx performance than the 4/92 model for the winter gasolines whereas they predict poorer performance for summer RFG as noted previously.

Annualized Results

Annual emission performance and added costs for PADDs II and III are provided in Table 4-31 for the 2000 cost break point target cases Q6. Also shown are the cost estimates for the U.S. excluding California, which were obtained by extrapolating the results for these two regions. Annual results were calculated by combining the results of the summer and winter cases.

Annualized U.S. added refining cost (excluding costs in California) is estimated to be

TABLE 4-30

COMPARISON OF SEASONALITY FACTORS PADD II AND PADD III 2000 SUMMER/WINTER Q6 CASES – U.S. NO DEMAND GROWTH CASE

	PADD II		PADD III	
	Summer Q6S	Winter Q6W	Summer Q6WS	Winter Q6W
Process Unit Additions, MB/SD*				
FCC Gasoline Splitter	0	0	135	248
Coker Light Gasoline Desulfurizer/Splitter			24	0
CRU Feed Fractionator	756	726	1,463	1,359
Reformate Fractionator	71	39	255	247
Benzene Saturator	34	18	62	33
MTBE	0	0	26	18
C4 Rerun – Saturates	101	0	203	0
C4 Rerun – Unsaturates	260	0	501	0
Distillate HDs		18		
Investment, $Millions (1990 Dollars)*				
Added Capacity	1,428	842	2,446	1,598
MTBE Storage/Blending	64	64	111	111
C4 Fractionation Upgrade	113	0	162	0
Total	**1,605**	**906**	**2,719**	**1,724**
Gasoline Demand, MB/CD				
Conventional	752	657	1,173	1,017
Reformulated	945	836	2,006	1,428
Oxygenated		99		84
Reformulated-Oxygenated		88		536
Total	**1,697**	**1,680**	**3,182**	**3,063**
NOx Emission Reduction, 4/92 Complex Formula, %				
Reformulated†	0	(3)	3	(5)
Conventional‡	5	(2)	3	0
Oxygenated†		(2)		(1)
Reformulated-Oxygenated†		(4)		(5)

* Additions above 1990 base case without Clean Air Act Amendments.

† Reduction from statutory base.

‡ Reduction from 1989 base.

TABLE 4-31

ANNUALIZED GASOLINE RESULTS SUMMARY
EMISSIONS PERFORMANCE AND INCREASED COSTS OVER BASE CASE RESULTS
2000 CASES – U.S. NO DEMAND GROWTH CASE

	PADD II				PADD III				U.S.*		
	Q9	Q6S	Q6W	Q6A	Q9	Q6S	Q6W	Q6A	Q6S	Q6W	Q6A
	Annual Base Case†#	Summer Target	Winter	Annual#	Annual Base Case†#	Summer Target	Winter	Annual#	Summer Target	Winter	Annual#
RFG, & RFG-OG % of Pool	**0**	**56**	**55**	**56**	**0**	**63**	**64**	**64**	**65**	**65**	**65**
Northern Gasoline, %	**80**	**80**	**80**	**80**	**40**	**40**	**40**	**40**			
Added Refining Investment, $Billion ‡		1.6	0.9	1.6		2.7	1.6	2.7	6.0	3.8	6.2
Added Refining Costs, cpg, RFG		8.9	4.4	6.7		6.9	5.1	6.1	7.6	5.5	6.6
RFG Properties											
Aromatics, vol%	29.6	22.2	18.2	20.0	29.3	24.7	20.3	22.8			
Oxygen, wt%	0.4	2.1	2.1	2.1	0.4	2.1	2.1	2.2			
Olefin, vol%	11.7	10.7	8.4	9.4	13.0	11.6	9.5	10.7			
Benzene, vol%	2.0	0.7	0.7	0.7	1.7	0.7	0.7	0.7			
Sulfur, ppmw	284	273	239	255	196	144	153	147			
RVP, psi	10.4	6.5	12.5	9.5	9.8	6.5	11.9	9.2			
T_{50}, ° F	205	203	182	193	206	205	186	195			
T_{90}, ° F	342	348	336	342	343	344	334	339			

TABLE 4-31 (CONTINUED)

	PADD II				PADD III				U.S.*		
	Q9	Q6S	Q6W	Q6A	Q9	Q6S	Q6W	Q6A	Q6S	Q6W	Q6A
	Base Case†#	Summer Target	Winter	Annual#	Base Case†#	Summer Target	Winter	Annual#	Summer Target	Winter	Annual#
Complex Model Designation **, %											
4/92											
VOC	6	41		41	19	41		45			
NOx	2	0	3	1	3	0	4	4			
TAP	(6)	31	19	26	3	31	20	28			
10/92 EPA											
VOC	1	34		34	9	34		36			
NOx	(5)	(4)	9	3	(5)	(4)	12	4			
TAP	(4)	26	21	24	6	26	20	23			
2/93 API											
VOC	5	29		29	13	29		31			
NOx	1	3	3	3	5	3	7	7			
TAP	(6)	31	28	30	3	31	28	30			
2/93 EPA											
VOC	(3)	29		29	(2)	29		24			
NOx	(4)	(4)	9	3	(6)	(4)	10	3			
TAP	(5)	22	21	22	3	22	22	19			

* Extrapolated from PADD results shown. Does not include CARB (California Air Resources Board) gasoline.

† No 1990 Clean Air Act Amendments.

‡ Additional to Base Case, 1990 dollars.

§ From adjusted Statutory Baseline with RVP adjustment from 8.7 to 7.8 psi for southern gasolines.

Combined summer and winter cases.

** RFG emissions reduction from Statutory Baseline.

about 6.6 cpg. On a U.S. total average basis, increased refining cost is about 2 cpg higher for summer than for winter. Winter and annual RFG costs are less than those of summer primarily due to the higher RVP associated with winter gasolines. Investment required for RFG in the U.S. excluding California is estimated to be about $6 billion.

Emission performance requirements of the CAAA for no increase in NOx and at least a 15 percent reduction in TAP emissions are met in all of the winter and annual cases as computed by any of the four complex emission models.

Beyond 2000

The CAAA established no additional or more stringent requirements for gasoline beyond that which becomes effective in calendar year 2000. Although the time frame for this NPC refining study extends out to 2010, no basis for setting additional requirements for study could be determined. As new scientific knowledge is gained and technology is developed, it is reasonable to expect an impact on future gasoline qualities. This impact could result in gasoline either more or less expensive to produce.

Cost-Effectiveness of Reformulated Gasoline

Under the Clean Air Act, reformulated gasoline is required only in the nine urban areas with the greatest ozone nonattainment problems, but other ozone nonattainment areas can come into the program through state action and EPA concurrence. Many states are considering RFG as a measure for achieving the ozone ambient standard. As one of many control options which a state can choose, its cost-effectiveness relative to alternative VOC control strategies needs to be considered.

In a purely analytical sense, the "cost-effectiveness" of RFG should be measured in dollars per unit of ozone level reduction. However, such an analysis requires the detailed emissions inventories and air quality modeling of the specific area in question. That type of analysis is beyond the scope of this study. However, incremental cost-effectiveness is more generally considered on the basis of dollars per ton of emissions reduced. That approach is taken here to show the relative cost of emissions reduction through various gasoline reformulations. Also, this approach allows for a *general* comparison of the incremental cost-effectiveness of RFG to other VOC and NOx control measures such as enhanced vehicle inspection and maintenance programs, past RVP reductions, retrofit of stationary sources with low NOx burners or catalytic controls, and control of other types of VOC and NOx sources in general.

RFG can affect VOC, NOx, and TAP emissions. For a given RFG blend, it is difficult to separate the costs attributable to each. In this analysis, cost-effectiveness as an ozone precursor control is emphasized. Both VOC and NOx are important to ozone formation. The expected effect of reformulation on NOx emissions is often small and the Clean Air Act requires only that there be "no increase" relative to the CAAA baseline gasoline. However, EPA is now considering (under the general authority of Section 211 of the Clean Air Act) a requirement for a NOx reduction in the Phase II RFG performance standards.

Toxic air pollutant reductions through gasoline reformulation can be significant, but RFG is being considered in ozone nonattainment areas primarily, if not exclusively, as an ozone attainment strategy. This study maintained, as a constraint, the minimum TAP reduction, relative to the CAAA baseline, of 15 percent in Phase I and 20 percent in Phase II. To avoid attributing TAP control costs to VOC and NOx reductions, the cost of RFG production is adjusted in the incremental cost-effectiveness analysis by backing out the cost of benzene reduction measures with the remaining cost attributed to VOC or VOC plus NOx reductions. Given the mandated benzene content reduction to 1 percent (0.7 percent used in this modeling) and VOC reduction requirements, the TAP reduction standard is met with no additional cost and thus its cost-effectiveness is not considered here.

Lastly, in comparing VOC and NOx reductions due to RFG with reductions due to

other measures, it is important to recognize that the RFG VOC reduction occurs in the ozone season while many other measures create year-round VOC reductions. However, only those in the ozone season are of value in solving ozone nonattainment problems.

The VOC maximum incremental cost-effectiveness target suggested by the EPA and used in this study was $10,000 per ton of VOC reduced during the six-month summer period (equivalent to $5,000 per ton control decision benchmark for annual VOC control costs). RFG VOC incremental cost-effectiveness above $10,000 per ton (of summer VOC) is viewed as being beyond a justifiable level.

Basis of the Calculations

Several assumptions have been used in analyzing emission reductions and costs. The emission reductions are based on the 1990 model year baseline vehicle emissions as represented by the EPA in the RFG rule making. They also reflect the impact of inspection and maintenance before the RFG effect is calculated. Future actual emission reductions due to RFG will differ from these estimates to the extent that different vehicle emissions inspection programs are used and the population of vehicles on the road in 1995, 2000, or 2010 have emissions that are different from typical 1990 autos. Also, future vehicles may include technologies which respond differently to RFG.

The costs used here are the consumer costs, which include both refinery costs (including capital recovery and operating) and the cost (including taxes) of additional gallons of fuel needed to make up for the lower fuel economy caused by changes in energy content per gallon due to reformulation. The fuel economy cost for the PADD III examples shown later in the section vary from 1.9 to 2.8 cpg (see Table 4-24). This approach (i.e., consumer cost vs. refining cost only) is different from that used and reported in other parts of this chapter, but is viewed as appropriate for evaluating and comparing national incremental cost-effectiveness of RFG. The costs attributed to RFG production reflect the cost of producing RFG while also complying with antidumping limits on conventional gasoline. Nonetheless, all these costs are attributed to the volume of RFG. Capital recovery for equipment needed to meet RFG VOC requirements is allocated to the gallons produced for the VOC control period (summer) because such equipment is only used to meet summer requirements.

The costs considered in this analysis are based on case studies using the Turner-Mason refinery model, the 4/92 complex model, and MOBILE4.1. Subsequently, the performance and cost-effectiveness of gasolines created in these studies were analyzed using the EPA 2/93 complex model. Since the final complex model(s) is(are) not yet completed, the gasoline parameters used to evaluate emissions performance may change, the incremental effectiveness may change and therefore associated incremental costs for a given emission reduction may also change.

Cost-Effectiveness of Changing Individual Parameters

The refinery modeling of changes to meet RFG requirements specifically looked at the VOC reduction effectiveness but also considered the cost of changes to individual gasoline characteristics. The results of these analyses and other referenced studies (see Appendix M) are as follows:

- Reducing gasoline vapor pressure (RVP) was the most cost-effective means of controlling VOCs over the entire range of RVPs (down to about 6.5 psi) considered in this study. The absolute cost-effectiveness of RVP reductions, however, are sensitive to the relative importance of the exhaust and evaporative VOC emissions, which can change with different complex models.
- Reducing gasoline sulfur content down to as far as 80 ppm was the next most cost-effective approach to reducing VOCs.
- Reducing T_{90} down to about 320°F was the next most cost-effective measure and similar in cost-effectiveness to sulfur reduction.
- Reducing olefins to about 9 percent was the next most cost-effective measure but only with the 2/93 EPA complex model.

- Increasing oxygen content and reducing aromatics (including benzene) were the least cost-effective ways of reducing VOCs.

Reducing RVP is an attractive VOC control strategy because of the significant effect it has on evaporative emissions. Other property changes such as sulfur and T_{90} reductions generally lower VOC exhaust emissions by improving combustion and automobile catalytic converter efficiency.

Average Cost-Effectiveness of Various RFG Formulations

The average cost and emission reduction effectiveness of specific RFG formulations were examined to identify the apparent cost-effectiveness of different formulations. *Average* cost-effectiveness is used here as the appropriate representation of the overall benefits of the RFG program and the value which states, in deciding whether to opt-in to the federal RFG program, must compare to other VOC control strategies. *Incremental* cost-effectiveness is addressed separately in the next section.

Tables 4-32 through 4-34 show the costs, effectiveness, and average and incremental cost-effectiveness of various formulations for gasolines made in PADD III. Both the 4/92 and 2/93 EPA complex models[8] are used to assess performance. All comparisons are against the expected characteristics of

[8] To understand these cost-effectiveness results, the reader should remember that, as explained earlier, the baseline emission values for RFG produced under the complex model changes in 2000 such that the estimated emission reduction benefits for a given RFG blend will be less in the 2000 and later period.

TABLE 4-32

COST AND VOC & NOx PERFORMANCE OF VARIOUS REFORMULATIONS (PADD III SUMMER)*

Year	Case Description	% RFG	Cost† cpg	% VOC Reduction‡ 4/92	% VOC Reduction‡ 2/93§	% NOx Reduction‡ 4/92	% NOx Reduction‡ 2/93§
1995	conventional gasoline (Q9)	0	0.0	19	3	2	(10)
1995	full opt-in, simple model (S5)	63	8.0	34	26	1	(2)
1997	full opt-in, switch to complex model (S19)	63	7.5	34	26	2	(3)
2000	complex model base case (Q6)	63	9.0	45	24	3	(4)
2000	low sulfur and olefin RFG (S10)	63	10.1	45	31	9	14
2000	complex base case with all RFG (S6)	100	9.1	45	26	4	0
2000	formulation w/hi VOC and NOx reductions (Q40H)	100	11.1	48	30	5	8
2000	California Phase II RFG (S21)	100	17.1	50	33	8	18

* Data taken from Appendix M Exhibit 12 (2/11/93), Exhibit 13 (4/15/93), Exhibit 14 (4/15/93) and Exhibit 21 (4/16/93) and Exhibit 22 (4/15/93).

† Cost per gallon of RFG includes refinery costs and consumer cost for extra gasoline used due to lower BTU content, all costs relative to conventional gasoline under the pre-1990 CAAA. 1990 Dollars.

‡ Percent change in emissions relative to the performance of the statutory baseline gasoline under the 4/92 complex model and the 2/93 EPA complex model.

§ The change in emissions is relative to the statutory baseline adjusted to 7.8 psi RVP for southern gasoline.

TABLE 4-33

AVERAGE COST-EFFECTIVENESS OF VARIOUS RFG FORMULATIONS (PADD III, SUMMER)

Case	Cost (cpg)*	Model†	Change in % VOC Reduction‡	Change in % NOx Reduction‡	Cost-Effectiveness Thousands of Dollars per Ton (summer)	
					VOC	VOC + NOx
Simple model RFG (S5)	8.0	4/92	14	(1)	19	18
		2/93	23	8	10	8
Complex model in 1997 (S19)	7.5	4/92	15	0	16	16
		2/93	23	7	10	8
2000 RFG (Q6)	9.0	4/92	26	1	11	11
		2/93	21	6	13	10
Low sulfur & olefin RFG (S10)	10.1	4/92	26	7	13	11
		2/93	28	24	11	6
2000 specification to obtain more VOC and significant NOx reduction under 2/93 model (Q40H)	11.1	4/92	29	3	13	12
		2/93	27	18	12	7
2000 specification to match Calif. Phase 2 (S21)	17.1	4/92	31	6	18	17
		2/93	30	28	17	9

* Cost over conventional gasoline under the pre-1990 Clean Air Act (Q9).

† The two complex models also include different baseline emissions. For the 4/92 model, VOCs are about 1.25 grams/mile; NOx 0.66 grams/mile. For the 2/93 EPA model, VOCs are about 1.35 grams/mile and NOx is 1.34 grams/mile. Average MPG of 22.1 for conventional gasoline was used.

‡ Versus performance of conventional gasoline without the CAAA (Q9).

conventional gasoline in the absence of RFG requirements (Q9). Cost-effectiveness is analyzed in dollars per ton of *summer* VOC reduction and per summer ton of NOx plus VOC. While the relative importance of NOx and VOC for ozone attainment is not known in general, and it will vary regionally, this convention is sometimes used.

Some general observations are:

- The computed average cost-effectiveness of the various formulations is extremely sensitive to the form of the complex model.
- The inclusion of NOx reduction effects would be very important to the assessment of cost-effectiveness of RFG alternatives.
- Average cost-effectiveness of all RFG formulations (all costs attributed to summer VOC or VOC plus NOx emissions) is consistently over or near $10,000 per ton except for instances where both VOC and NOx reductions are included in the tonnage credit and the EPA 2/93 model is used. For those cases, cost-effectiveness is in the $5,000 to $10,000 per summer ton range and the average cost-effectiveness is

TABLE 4-34

INCREMENTAL COST-EFFECTIVENESS OF VARIOUS RFG FORMULATIONS (PADD III, SUMMER)

Case	Change in Cost (cpg)*	Model†	Incremental % VOC Reduction	Incremental % NOx Reduction	Incremental C/E, Thousands of Dollars per Ton (summer)	
					VOC	VOC + NOx
Introduction of simple model RFG (S5 vs. Q9)	+6.0	4/92	14	(1)	13	14
		2/93	23	8	8	6
Switch to complex model from simple model in 1997 (S19 vs. S5)	–0.5	4/92	0	1	NA‡	NA‡
		2/93	0	(1)		
Tightening of specifications between 1997 and 2000 (Q6 vs. S19)	+1.5	4/92	11	1	5	4
		2/93	NA§	NA§	NA§	NA§
Tightening 2000 specifications with low sulfur and low olefin (S10 vs. Q6)	+1.1	4/92	0	6	NA	11
		2/93	7	18	5	1
Tightening of 2000 specifications to obtain more VOC and significant NOx reduction under 2/93 model (Q40H vs. S6)	+2.0	4/92	3	1	20	19
		2/93	4	8	12	5
Tightening of 2000 specifications to match California Phase 2 (S21 vs. S6)	+8.0	4/92	5	4	50	35
		2/93	7	18	35	10
Tightening of 2000 specifications to California Phase 2 from low VOC and NOx (S21 vs. Q40H)	+6.0	4/92	2	3	80	55
		2/93	3	10	60	14

* Cost over conventional gasoline excludes 2 cents per gallon attributed to investments specific to meeting the benzene specification.

† The two complex models also include different baseline emissions and emission inventory models. For the 4/92 model, VOCs are about 1.25 grams/mile; NOx 0.66 grams/mile. For the 2/93 model, VOCs are about 1.35 grams/mile and NOx is 1.34 grams/mile. Average MPG of 22.1 for conventional gasoline was used.

‡ The switch saves about 0.5 cents with no real change in effectiveness; reducing the cost of the 1995 RFG specification by about 20 percent or $1,000 to $1,500 per ton VOC.

§ Comparison of the VOC reductions between Phase I and Phase II RFG is not possible with the 2/93 EPA complex model because of a change in the baseline.

not particularly sensitive to the type or degree of stringency of RFG specifications considered here.

- PADD IV average cost-effectiveness (for the 100 percent RFG case) is poor, over $14,000 per ton, because of the relatively large number of low complexity, smaller refineries in PADD IV.
- The average cost-effectiveness of CARB Phase 2 RFG as a VOC control is always over $17,000 per ton but may be below $10,000 if NOx reductions are included in the tonnage credit and the 2/93 EPA complex model is used.
- RVP control alone is a more cost-effective VOC control measure than any of the RFG formulations, in large part because of the added costs and lesser effectiveness of the requirements to limit benzene and add oxygenates. Therefore, designing a gasoline specifically to control VOCs alone would result in a specification different from that in the Clean Air Act for RFG, and probably emphasize reductions in RVP and perhaps include reductions in sulfur content and T_{90} depending on their incremental cost-effectiveness.
- Average cost-effectiveness of reformulated gasoline can vary significantly from area to area. Figure 4-14 shows the variation among the four areas that may produce federal Phase II RFG. While PADD III has the lowest cost of achieving a given VOC reduction level, PADD II has the most attractive average cost-effectiveness when Phase II RFG (S6) is compared to what would have been produced in the absence of the CAAA RFG requirements (Q9).

Incremental Cost-Effectiveness of Tightening RFG Specifications

The incremental cost analysis looks at the cost-effectiveness of progressive moves to tighten specifications which influence NOx and VOC emissions. As with average cost-effectiveness, the complex model used and the inclusion or exclusion of NOx reduction effects

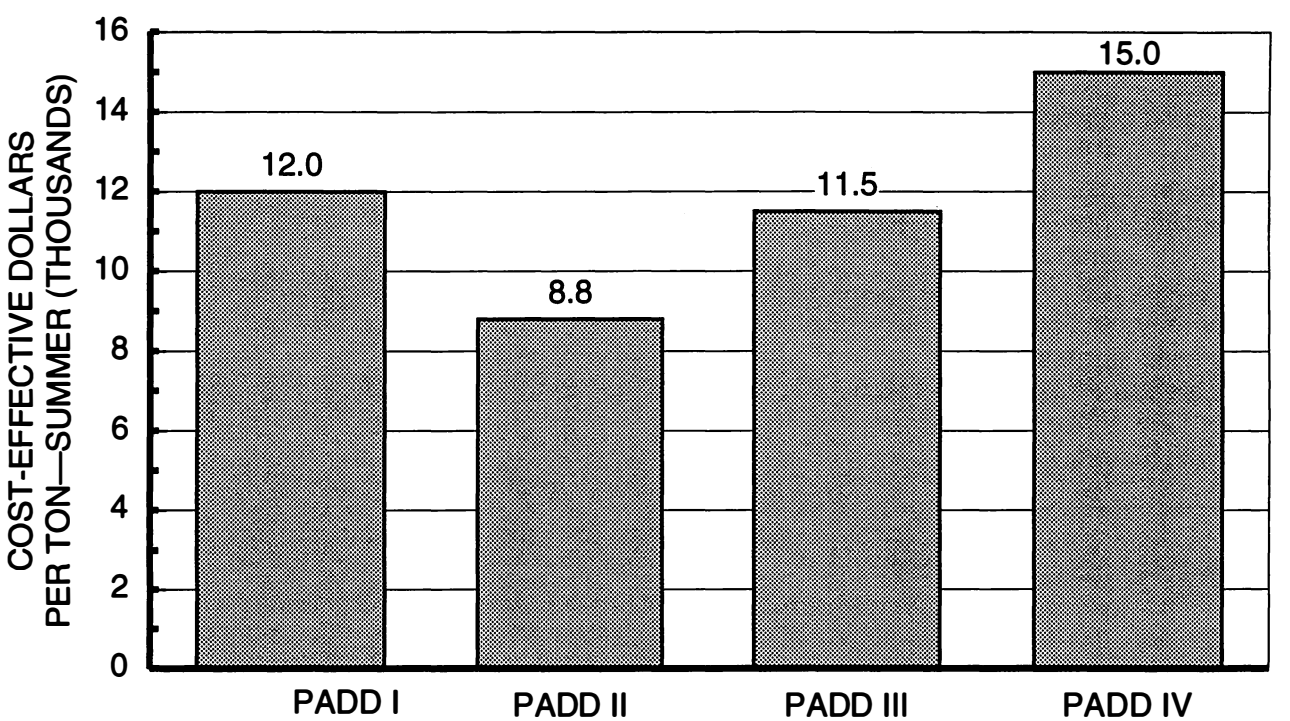


Figure 4-14. Average Cost Effectiveness* of RFG Formulations Variations Among Various PADDs—Phase II (S6) RFGs.

* Based on 4/92 Complex Model. 100 percent RFG for each PADD.

influences incremental cost-effectiveness substantially.

- Incremental cost-effectiveness as reported in Table 4-34 is generally better when the 2/93 EPA complex model is used or when NOx reduction is included.
- Moving from the Phase I (1995) RFG to the Phase II (2000) RFG when the Phase II gasoline is designed with the 4/92 model appears to be an attractive alternative as incremental cost-effectiveness is estimated to be below $10,000 per summer ton for VOC alone or for both VOC and NOx.
- The least attractive incremental cost-effectiveness comes when moving beyond the VOC level achieved at the break point in the cost curve. The criterion of cost below $10,000 per summer ton is exceeded in all cases except for when both VOC and NOx are counted and the analysis is based upon the 2/93 EPA complex model. A possible exception to this in some refineries could be the use of sulfur reduction to low levels for VOC control. Moving beyond the break point to a formulation with low olefins or California Phase II RFG increases incremental cost dramatically no matter which model is used.
- The incremental cost-effectiveness of using the CARB Phase 2 specification in place of a low VOC or low VOC plus NOx alternative is consistently over $10,000 per ton.

Comparisons to the Cost-Effectiveness of Other Measures

Two other ozone control measures related to motor vehicle emissions that have been or are being implemented are the first phase of the gasoline volatility program and the enhanced vehicle inspection and maintenance program. The EPA estimated Phase I RVP cost-effectiveness at a maximum cost of about $600 per ton VOC controlled in the summer. The estimated cost of an enhanced inspection and maintenance program is roughly on the same order, at $500 to $1,600 per ton VOC controlled, but reflects year-round VOC reductions value, equivalent to $1,000 to $3,200 per ton of VOC reduced in the summer. Also under the Clean Air Act, large boilers and process heaters are required to retrofit NOx controls, and new units are expected to install the best controls. Retrofit low NOx burners have an expected cost-effectiveness of about $500 to $2,000 per ton annually and catalytic controls for new units would cost approximately $2,000 to $5,000 per ton annually of NOx control. The cost-effectiveness of these measures and those presented by the EPA as a possible basis for RFG, targets of $300 to $600 per annual ton for NOx and $1,250 to $5,000 per annual ton for VOC, should be compared to the incremental cost-effectiveness of RFG presented here. The cost-effectiveness of RFG as a VOC control or VOC plus NOx control measures beyond RVP and mild olefin, sulfur, and T_{90} reductions are clearly much less attractive.

Regulatory Concern

The basis of this analysis is that the RFG requirements of the CAAA and the agreement resulting from the regulatory negotiation focus on using RFG to achieve VOC reductions while maintaining NOx emissions at a "no increase" level.

While the above sections present the computed average and incremental cost-effectiveness of reductions in VOC plus NOx, this was done *ex post facto* and was not a constraint in the analyses. A simultaneous and constraining NOx limit may change the cost and cost-effectiveness of a given VOC reduction. While cost-effective VOC reduction steps will generally take gasoline to the no NOx increase limit, further VOC reductions can face difficult simultaneous NOx constraints under a requirement for RFG NOx reduction. This is particularly significant if the complex model used shows that some property changes that reduce VOC emissions will increase NOx emissions. This causes the additional VOC reductions to be more costly than would be the case without the NOx constraint. Under these circumstance the cost-effectiveness of these property changes will be poorer and the ranking of cost-effective

gasoline property changes different than reported here.

Incremental gasoline property changes that reduce both VOC and NOx will have particularly good cost-effectiveness. However, analyzing on a NOx plus VOC basis may not be an appropriate way to measure incremental cost-effectiveness, depending on how the cost-effectiveness maximum targets were derived.

- There are additional unresolved questions regarding the techniques and standards for analyzing cost-effectiveness of emission reduction regulations. These include: the appropriate basis for comparing stationary source, motor vehicle, and motor fuel controls; the correct basis for comparing controls with different operating time frames (e.g. seasonal vs. annual); and the basis for cost-effectiveness analysis of controls achieving reduction in more than one pollutant.

- Determining the cost-effectiveness benchmark for setting the RFG performance standard will have a marked effect on the attractiveness of that RFG as a control strategy for different ozone nonattainment areas. If a high control decision benchmark, one that is cost-effective and appropriate for severe ozone nonattainment areas, is used for setting Phase II RFG performance standards, then that performance standard is not likely to be cost-effective and appropriate for serious and moderate ozone nonattainment areas. In addition, not all nonattainment areas will benefit from NOx reductions. Urban airshed modeling is needed to determine the benefit of NOx reductions relative to VOC reductions.

- In Section 211 (k) (1) of the CAAA, RFG requirements include consideration of the energy security impacts of RFG, in addition to cost, other environmental impacts and technical feasibility. Incremental *energy-effectiveness* as well as cost-effectiveness should be considered in setting performance standards.

Product Compatibility and Segregations

Product Compatibility

The NPC study assumes that finished gasolines, RFG, OG, and CG, are compatible within a given type and grade. Refinery blendstocks for oxygenate blending (RBOBs) used to produce RFG by oxygenate addition at terminals are also assumed to be compatible within a given grade and type. This assumption could be at variance with the EPA proposed rules in the February 1993 NPRM.

The U.S. logistics system will remain effective only if product specifications and enforcement proceedings, including testing tolerances, allow product compatibility throughout the manufacturing and distribution chain. Product compatibility, being able to mix separate batches of a specific product, is necessary for the effective operation of the logistics system. Without compatibility, the system would require much more tankage, be less efficient, and would supply products at higher cost. To avoid the costs of segregation, refineries could elect to increase product specification giveaway to provide additional compatibility. Pipelines may adopt specifications that require giveaway to increase compatibility. For RFG, refineries could elect to use per-gallon compliance standards rather than averaging.

In 1991, the participants in Phase I of this NPC study expressed their optimism that the RFG certification requirements would be based on a simple straight-forward emissions model. Based on their knowledge of the impact of fuel parameters on emissions, they expected that the CAAA's requirements for RFG could be met by:

- A significant, but practical, reduction of RVP.

- The use of sufficient oxygenate to achieve a 2 percent oxygen content, on a pool average basis.

- The reduction of aromatics, on a pool average basis, obtained when refinery pro-

cessing is adjusted to compensate for the octane and volume provided by the oxygenate.

- The reduction of benzene in RFG, on a pool average basis.

The subsequent Regulatory Negotiation, and the NPRMs describing the complex model and the Phase II RFG standards tempered that optimism; hence, refiners now have concerns regarding performance standards, compliance certification, testing tolerance, enforcement policies, and product compatibility.

"Product compatibility" refers to being able to mix complying batches of a given type and grade of certified product (e.g., reformulated gasoline) when expedient for distribution. When one batch of compliant (i.e., on specification) product, Batch A, is mixed with another batch of compliant product of the same type and grade, Batch B, the resulting mixture, Batch C, is a compliant product of the same type and grade. Product compatibility does not refer to interchangeability (generally referred to as fungibility), that is, common specifications for a product used by several suppliers to permit the exchange of product without differentiating the source. Current product specifications and enforcement procedures allow effective use of the logistics system because commingling of products does not result in off-specification products at the final point of sale.

Compounding the compatibility issue is the wide number of types of gasoline. The primary types of gasoline products are: conventional gasoline, reformulated gasoline, oxygenated gasoline, and gasohol. There may be several further types of gasoline, for example:

- Northern and southern vapor pressure CG.
- Gasoline for states with unique specifications, CG, RFG, or OG.
- In the VOC control period, RFG blended with a renewable oxygenate (e.g., ethanol and ETBE) and RFG blended with MTBE or TAME.
- OG blended with ethanol and OG blended with ethers.
- Northern and southern RFG.
- In 1995 and 1996, both simple and complex model gasolines for all of the above RFGs and RBOBs.

There are also several octane grades of each type of gasoline: regular, midgrade, and premium. Therefore, there is the potential for many segregations of gasolines to be required by a refiner.

Further segregations may be caused by RFG program requirements. RFG, from one source (i.e., oxygenate or emissions model) may be incompatible, from an enforcement perspective, with RFG from another source (different oxygenate or emissions model) of the same octane grade. Incompatibility means a mixture of the two types fails to meet the specifications and regulations for either type; therefore, the two gasolines must be kept segregated. In the summer VOC control season, RFG of one type and grade is generally not compatible with RFG of any other type and grade. This requires each type and grade of summer RFG to be segregated from each other. This segregation could be further compounded if the source of a RFG type and grade creates incompatibility.

Product compatibility is required for efficient transportation via pipelines. Much of the nation's gasoline is distributed from refineries to bulk terminals via pipelines; and most gasoline shipped on pipelines does not retain an individual company identity throughout the distribution system. Refineries produce gasolines meeting mutually agreed upon pipeline specifications. A company delivers compatible gasoline to the pipeline at one point and receives compatible gasoline, not necessarily the same barrels it delivered, at another point. Compatibility permits the pipeline system to transport and distribute gasolines without segregating one company's product of a given gasoline type and grade from another company's product of the same type and grade; i.e., without proprietary batches and tankage.

Without compatibility, transportation and distribution—by pipeline, tanker, and barge—would require much more tankage, more interface stocks would have to processed,

and the transportation system would be less efficient.

These concepts also apply to RBOBs. RBOB is used to produce RFG by oxygenate addition at terminals. RBOB is assumed to be compatible within a given grade and type; but, RBOBs of different types may be incompatible. In the summer VOC control period, RBOB intended for blending with MTBE and TAME is generally a different RBOB than that intended for blending with ethanol. The same may be true for ETBE RBOB. In fact, RBOB intended for blending with TAME may not be suitable for blending with MTBE or vice versa. Hence, RBOBs are additional product types requiring additional segregations.

Implications of Product Compatibility

An RFG supplier in a given nonattainment area can meet the requirements for RFG on either an *every gallon meets the standard* (per-gallon) basis or on an averaging basis. Averaging allows for the real differences between types and grades of gasoline produced by a single refinery. Averaging also allows flexibility for continued production of RFG, within bounds, for process unit shutdowns, planned or unexpected. For example, shutdown of a refinery's benzene reduction facilities could lead to a complete shutdown of the refinery if *each* gallon of gasoline shipped had to meet a 1 percent maximum benzene requirement, rather than an average over time.

The RFG a refinery ships has to be in compliance for the type and grade of RFG intended, either on a per-gallon basis or an averaging basis. If a refinery ships RFG from two different tanks into a single barge or pipeline batch, the refinery must confirm compliance with applicable RFG regulations. Since this practice is common and efficient, refineries need presumption of linear blending of inspections, sampling techniques and timing appropriate to refineries' blending and shipping practices.

Historically, since products have been compatible and have met conventional per-gallon specifications, there has been no need to retain a detailed record of the history and origin of each batch of product. However, to allow compliance on average, the enforcement procedures and requirements proposed for RFG require a detailed documentation and paper trail. This is because a non-linear complex model creates the possibility that the mixture of two compliant RFGs of a given type and grade—even on a per-gallon compliance basis—would not be compliant RFG. Normal testing variance creates a similar possibility. Hence, RFG compliance checking at points downstream of the mixture of two complying batches of RFG could find RFG that appeared to be non-complying. Then, the source or sources of that RFG must be established to confirm that the RFGs were compliant when they left the refinery. If the EPA's RFG enforcement policies in practice do not take the non-linear nature of the complex model *and* testing tolerances into account, commingling of different batches of RFGs would not be practical and extensive segregation of different batches of RFG would be required. As discussed above, this would greatly reduce the efficiency and effectiveness of the gasoline supply and distribution system. A more costly and less flexible alternative which reduces some of these concerns is for the refinery to use the per-gallon standards.

In general, RFG will be produced by blending a variety of process components with known properties, together in predetermined proportions to produce a batch of the desired gasoline. RFG will not be produced by refining conventional gasoline, either imported or produced in the United States, to remove components that have high levels of properties limited in RFG. It is neither practical nor economical to produce a suitable blendstock for producing Phase II RFG (only needing the addition of the required oxygenate) by reducing the olefin or aromatics content or the T_{50} or T_{90} of conventional gasoline by additional processing. However, except for the dye, it should be possible to produce summer Phase I RFG for northern ozone nonattainment areas by adding oxygenate to a low RVP conventional gasoline (such as that required in southern ozone nonattainment area) that has a suitably low benzene content.

The cost and strategy for reprocessing off-test RFG to produce compliant RFG or other gasoline will be highly dependent upon the circumstances. Typical alternative strategies include:

- Downgrading the off-test RFG to conventional gasoline or export gasoline.
- Adding components, such as alkylate, whose properties significantly exceed RFG requirements.
- Blending off with large volumes of compliant RFG that has some giveaway compared to minimum RFG requirements.
- Holding off-test summer RFG until the VOC season is over, and the RFG can be used directly or blended into winter RFG.

All of these would require increased costs compared to current practices for handling off-test gasoline and could result in tying up enough product tankage to restrict refinery output.

Other costs increases beyond the refining cost to produce the reformulated products would be created directly in proportion to the increased number of product segregations required. These would occur because of:

- The increased number of tanks that may be required in an individual refinery.
- Increased giveaway to minimize the number of segregations by making a dual purpose product meeting both products specifications and regulations.
- Increased giveaway when providing a single RBOB for use with either ethanol or ethers.
- Reduced ability to minimize transportation costs by means of product exchanges.
- Refiners opting to make more costly product to maintain product compatibility or to minimize the number of grades of gasoline they distribute to a given area.

RFG Cost Adjustment to Annualized 1989 Time Basis

Most of the RFG per-gallon costs developed and reported in this chapter assume summer operations and incremental costs above a base of 1995 gasoline manufacture without the CAAA. Product prices used in the chapter are those of the 1989-1990 period with the exception of that for MTBE, which was increased by 10 cpg over the 1989 price to reflect spot and contract prices that were at this level when the cost assumptions were made.

Table 4-35 develops the RFG increased refining costs to a basis that is consistent with other parts of this report and which can be used for the financial calculations in Chapter

TABLE 4-35

ANNUALIZED 1989 TIME BASE AND MTBE COST ADJUSTMENTS TO RFG INCREASED AVERAGE REFINING COSTS (Cents per Gallon—1990 Dollars)

	Chapter Four Basis	Property Adjustment 1989 to 1995	MTBE Price Adjustment	Summer to Annual Adjustment	Chapter One Basis
U.S. without Calif.					
1995	5.5	0.5	(0.2)	(1.0)	4.8
2000	7.6	0.5	(0.7)	(1.0)	6.4
2010	7.6	0.5	(0.7)	(1.0)	6.4
U.S. with 100% CARB Phase 2	17.0	0.5	(0.8)	(1.0)	15.7

One. The Chapter Four costs shown are for the 1995, 2000, and 2010 summer target cases. Adjustment factors are shown for the cost of adjusting gasoline RVP and oxygenate properties that occurred in the period from 1989 to the 1995 case without the CAAA, for the MTBE price reversion to the 1989 basis, and for the cost differences estimated for summer and annual operations. Annual operations include the costs for oxygenated gasoline for CO nonattainment areas. Costs are shown for the United States without California. Also shown is the estimate annual cost for California CARB Phase 2 gasoline.

Included in these adjusted refining costs is an investment cost of $1.5 billion, which has been made or is committed to be made to bring U.S. refineries from 1989-1990 to the 1995 basis used in this chapter.

DISTILLATE

Results

Table 4-36 provides a summary of results for the various ultra-low sulfur and low aromatics distillate cases studied. Included are volumes of product upgraded, processing investments needed, and increased product costs as compared to current distillate production.

In the first three cases, capital costs are approximately 46 percent of the per-gallon cost. For the low aromatics case, capital costs account for about 53 percent of increased product cost. Costs on a per-gallon basis tend to be lower for PADD III and higher for PADD IV. Larger, more complex refineries should see lower costs than smaller, less complex refineries.

1993 Diesel Fuel Quality Requirements

In the American Petroleum Institute Standard Definitions for Petroleum Statistics, distillate fuel oil is defined as follows: "A general classification for one or more distilled petroleum fractions used for domestic heating and industrial burners, or for power generation in compression-ignition engines." There are four fractions listed: No. 1 fuel oil, No. 2 fuel oil, diesel fuel, No. 4 fuel oil. The No. 1 fuel oil and the No. 4 fuel oil represent relatively small volumes of product. As such, they have not been included in the analysis. For this evaluation, two classifications have been used: diesel fuel and other distillate (No. 2 fuel oil).

Diesel fuel includes that portion of the distillate which is burned in diesel engines. Diesel fuel may be further divided into on- and off-highway. On-highway diesel fuel includes both truck and passenger car use. Off-highway includes farm, construction, railroad, military, and marine diesel fuel. In most of the United States, diesel fuel and other distillate fuels are marketed from the same refinery, terminal, or bulk plant tankage. The distillate product is thus distinguished by end use rather than by properties. The other distillate includes product used for home heating, power generation, and other industrial uses. A large portion of the home heating oil is marketed in the Northeast U.S. area of PADD I where some product segregation does occur.

Under the CAAA, the EPA requires that all on-highway diesel fuel have a sulfur content of no greater than 0.05 wt% beginning October 1, 1993. The average U.S. on-highway diesel fuel sulfur content in 1990 and 1991 was approximately 0.25 wt% with PADD IV higher at about 0.35 wt%. In California's South Coast Air Basin, diesel fuel has had a 0.05 wt% maximum sulfur content since 1989. Also required for October 1, 1993 is a minimum cetane index of 40 or a maximum aromatics content of 35 percent. This aromatics content is approximately equal to current national average levels. The major reasons for this regulation are the reductions of sulfur oxides and particulate emissions from diesel engines.

Some areas of the country produce a *premium* diesel fuel product with a sulfur level of approximately 0.25 wt% and a 45 cetane index. It was assumed, for purposes of this study, that all ultra-low sulfur diesel fuel would be premium diesel fuel with a 45 cetane index.

Premises

The pie chart (Figure 4-15) provides a summary of the various pieces of distillate

TABLE 4-36

DISTILLATE CASE SUMMARY
U.S. TOTAL BASIS
(1990 Dollars)

	1993 On-Highway Diesel Fuel Ultra-Low Sulfur	All Diesel Fuel Ultra-Low Sulfur	All Distillate Ultra-Low Sulfur	All Distillate Ultra-Low Sulfur Low Aromatics
Distillate Upgraded, MB/CD	1,366	2,068	2,899	2,899
Added Investment,* $Billions	2.4	3.5	5.0	19.0
Increased Product Cost,* cpg, Upgraded	3.8	4.0	4.5	14.5

* Base is 1990 diesel fuel quality and 1990 refinery capacity.

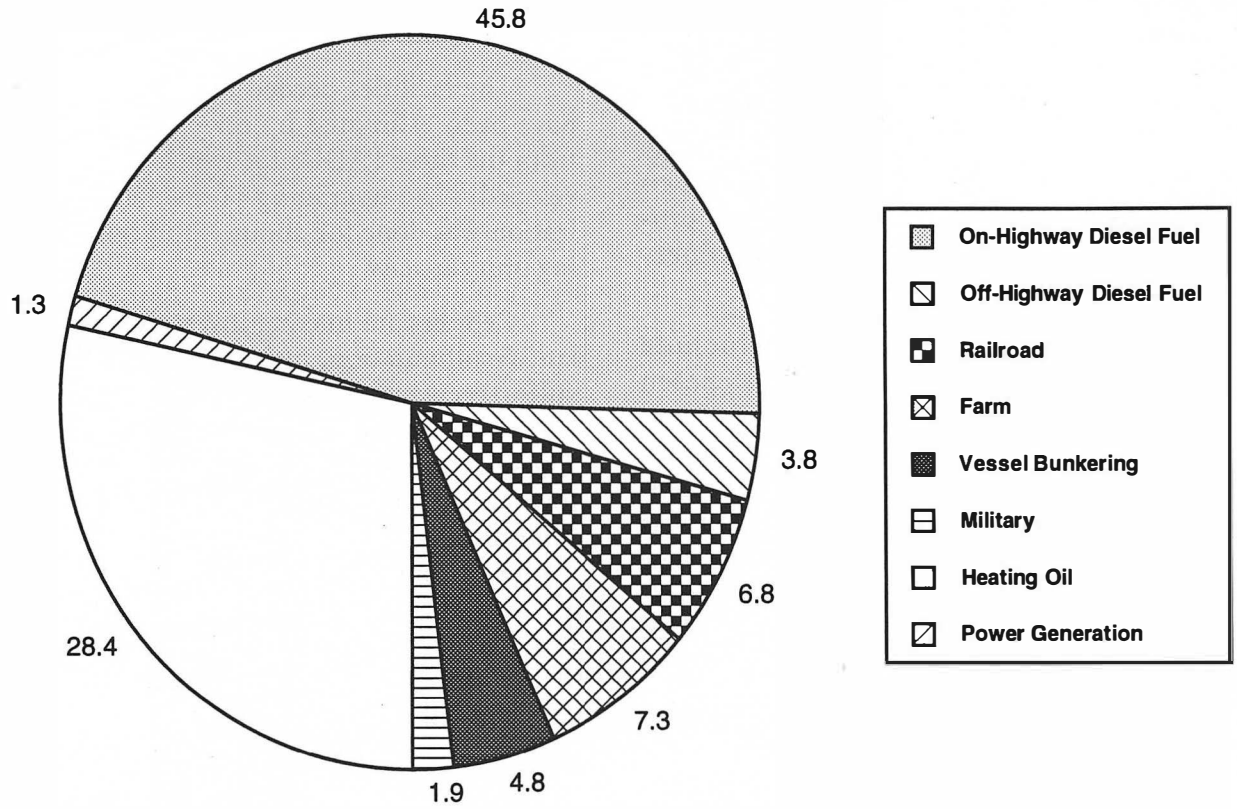


Figure 4-15. 1991 Distillate Fuel Sales (Percent).

demand based on the most recent data available from the Energy Information Administration. From this chart, on-highway diesel fuel is seen to comprise almost 46 percent of the total U.S. distillate demand pool. Off-highway, railroad, and farm diesel fuels make up another 18 percent of total demand. Similar demand proportions were premised for the *no growth* product demand case for 1995. This is shown in the bar chart (Figure 4-16), which also illustrates the diesel fuel demand breakdown by PADD. Notice that the total demand for diesel fuel on a percentage basis is the lowest in PADD I at just over 51 percent (41 percent for on-highway) due to the large home heating distillate demand in this area.

As a basic economic premise, distillate demand is taken as equal to distillate supply. Distillate supply under a *no growth* demand scenario was then divided into U.S. refinery supply and foreign supply via imports, using historical supply figures. The volumes of the various distillate products supplied by U.S. refiners on a PADD basis reflect typical inter-PADD transfer rates. The largest product movements historically have been from PADD III to PADDs I and II. The result was a set of refinery supply figures by PADD. These refinery supply volumes were then used to generate the adjusted cost data provided below from the Turner-Mason refinery model runs.

The areas chosen for study include PADDs I, III, and IV. PADD III was chosen due to its large production of distillate fuels. It was also used as a surrogate for large, complex refineries. PADD IV was selected to represent smaller, less complex refineries. PADD I was included to provide for a more complete view of the industry. From these three PADD studies, the effect on various segments of the U.S. refining industry was determined. A scale-up of the results was also made to estimate the impact on the entire U.S. refining industry.

For this study, 1995 was chosen as the year to study 1993 ultra-low sulfur diesel fuel requirements. Since a no growth demand scenario was used, the costs developed for 1995 would apply to any future year.

For ease of presentation, the costs of producing the Los Angeles Basin (LA Basin) ultra-low sulfur diesel fuel have been included in the costs for 1993 ultra-low sulfur diesel fuel. On a nation-wide basis, LA Basin costs are approximately 6 percent of the total U.S. costs shown.

Unlike the analysis explained in the gasoline section for RFG, no attempt has been made to evaluate cost-effectiveness for any of the distillate cases.

Facility Changes and Investment Costs

Table 4-37 lists the new facilities estimated by the study as being required for 1993 ultra-low sulfur diesel fuel on a U.S. total basis. Also included is the total volume of diesel fuel upgraded and the investment needed. New distillate desulfurization facilities were assumed to remove 95 percent of distillate sulfur. The upgrade of existing distillate desulfurization facilities consists of modifications to allow for increasing the level of sulfur removal from the current level of 75-85 percent to 95 percent removal.

The facilities needed on a U.S. total basis have been estimated by reviewing the results from the three PADDs for which data were developed. The upgrading of distillate desulfurization was done for about 38 percent of existing unit capacity.

Refiners are making investments in distillate desulfurization, hydrogen generation, and sulfur recovery in order to comply with the ultra-low sulfur diesel fuel requirements. Those refiners with predominantly sweet or low sulfur crude oil slates will need to have *mild* distillate desulfurization. Mild desulfurization is considered to be removal of 75 to 85 percent of the feedstock sulfur similar to the desulfurization in place in most refineries. Those refiners with sour or high sulfur crude oil slates will need to have *deep* distillate desulfurization. Deep desulfurization is considered to be about 95 percent sulfur removal. Many refiners with existing mild desulfurization will be able to convert their process units to deep desulfurization by modifying existing units for a lower cost than constructing new units. This

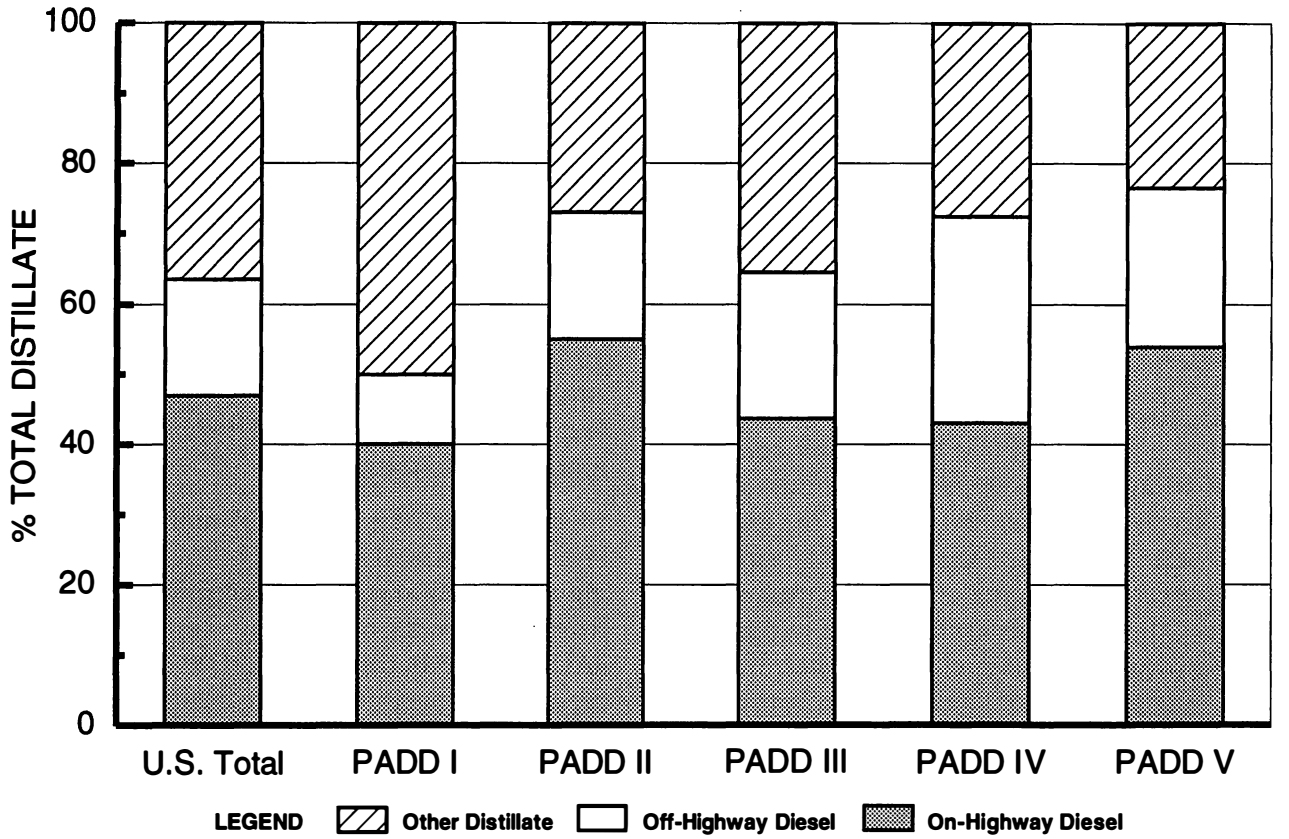


Figure 4-16. Premised 1995 U.S. Distillate Demand Summary.

TABLE 4-37

1993 ULTRA-LOW SULFUR DIESEL FUEL FACILITIES AND INVESTMENTS* U.S. TOTAL BASIS

	U.S. Total
Total Refinery Distillate Supply, MB/CD	2,899
1993 Ultra-Low Sulfur Diesel Fuel, MB/CD	1,366
1993 Diesel Fuel, percent of Total Distillate	47
New Distillate Desulfurization, MB/SD	250
Upgrade Existing Distillate Desulfurization, MB/SD	1,300
New Hydrogen Production, MMCF/SD†	180
New Sulfur Removal, LT/SD‡	700
Total Investment, $Billions (1990 dollars)	2.4

* Base is 1990 refinery capacity and diesel fuel quality.

† MMCF/SD = million cubic feet per stream day.

‡ LT/SD = long ton per stream day.

has been reflected in the investment figures provided. Some refiners may choose to serve only the higher sulfur distillate markets and to forego the investments required to provide the desulfurization facilities. Other refiners may elect to supply only the ultra-low sulfur diesel fuel markets. Thus, investments and costs may vary significantly from refinery to refinery depending upon their crude oil slate, existing desulfurization facilities, and marketing strategies.

In theory, some sweet crude oils might have low enough sulfur levels on their kerosene and distillate to allow for the production of ultra-low sulfur diesel fuel without the expense of desulfurization facilities. In reality, supplies of these very low sulfur crude oils are limited, and few, if any, refiners will be able to produce ultra-low sulfur diesel fuel without desulfurization. The logistics of crude oil transportation also limits the segregated delivery of very low sulfur crude oils to inland refineries.

Cost in Cents per Gallon and Regional Variation

Table 4-38 illustrates the regional variation in 1993 diesel fuel production and investment requirements. Also shown is the estimated increased product cost in each region on a cents per gallon of 1993 ultra-low sulfur diesel fuel produced basis. PADD II and PADD V were estimated based on results from the other PADDs.

The increased product costs per gallon of diesel fuel upgraded are fairly similar in PADDs I, II, and V. They range from 4.4 to 4.5 cpg, relatively close to the U.S. average. The costs for PADDs III and IV, however, are much different. In general, PADD III refineries tend to be larger and contain more sophisticated processing than the average U.S. refinery. Thus, they will have economies of scale in the building of new process units which tend to lower their per-gallon costs. They also have added flexibility in product blending and disposition, again tending to provide lower costs. Investment costs per barrel of diesel fuel produced for PADD III tend to be the lowest in the United States.

PADD IV refiners tend to be smaller, less complex refineries with less flexibility in crude oil processing and product blending. As such, they also may be used as a surrogate for small, less complex refineries located throughout the United States. Thus, size and location will each play a role in determining cost advantages for the production of ultra-low sulfur diesel fuel. PADD IV investment costs run approximately 20 percent higher than PADD III for a given project due to location. PADD IV refiners also currently produce a higher average sulfur content diesel fuel than PADD III so they will have more sulfur to remove.

A listing of 1993 diesel fuel facilities by PADD is provided in Table 4-39. The upgrading of existing distillate desulfurization varied from 35 percent of existing unit capacity in PADD I to 45 percent in PADD IV. New desulfurization capacity of 7 percent of existing capacity was required on a total U.S. basis. PADD IV required additional capacity of 40 percent of existing capacity. PADD IV has had the lowest desulfurization level in the United States historically and is forecast to increase to sulfur removal by almost 20 percentage points by 1995 over 1990 levels.

Comparisons to Survey

Table 4-40 shows survey data, summarizing refiners 1995 plans for distillate desulfurization. Thus, the Turner-Mason computer runs mirror the PADD IV refiners' plans for increased desulfurization.

A further comparison can be made by looking at refiners' replies to Section II of the survey. While not 100 percent complete, the survey certainly can provide a guidance to comparing industry plans to computer modeled facilities. Table 4-41 shows a summary of survey data. Making the assumption that the facilities planned per the survey responses approximates the industry totals, a comparison can be made on both a U.S. total and a PADD basis.

The survey data are consistent with the production of 62 percent of the distillate pool as ultra-low sulfur. The computer generated facilities shown in Table 4-39 are based on 47 percent of the pool as ultra-low sulfur representing

TABLE 4-38

1993 ULTRA-LOW SULFUR DIESEL FUEL INVESTMENT AND COST SUMMARY

	U.S. Total	PADD I	PADD II	PADD III	PADD IV	PADD V
Total Distillate Supply, MB/CD	2,899	361	687	1,301	122	428
Diesel Fuel Upgraded, MB/CD	1,366	178	338	564	50	236
Diesel Fuel Upgraded, %	47	49	49	43	41	55
Investment,* $Billions (1990 dollars)	2.4	0.3	0.6	0.9	0.2	0.4
Increased Product Cost,* cpg (1990 dollars), Upgraded	3.8	4.4	4.5	2.4	8.2	4.5

* Base is 1990 refinery capacity and 1990 diesel fuel quality.

TABLE 4-39

1993 ULTRA-LOW SULFUR DIESEL FUEL FACILITIES*

	U.S. Estimate	PADD I	PADD III	PADD IV
New Distillate Desulfurization, MB/SD	250	25	85	35
Upgrade Existing Distillate Desulfurization, MB/SD	1,300	130	560	40
New Hydrogen Production, MMCF/SD†	180	5	95	0
Sulfur Removal, LT/SD‡	700	50	310	35

* Base is 1990 refinery capacity.

† MMCF/SD = million cubic feet per stream day.

‡ LT/SD = long tons per stream day.

TABLE 4-40

1995 DISTILLATE DESULFURIZATION PLANNED PER NPC SURVEY

	U.S. Total	PADD I	PADD II	PADD III	PADD IV	Calif.	PADD V Outside California
1990 % Sulfur Removal	83.2	79.7	79.2	83.2	70.7	92.3	N/A
1995 % Sulfur Removal	91.2	80.0	93.5	91.9	89.3	93.7	93.8

TABLE 4-41

ADDITIONAL FACILITIES PLANNED FOR CONVERSION REFINERIES PER NPC SURVEY, BY JANUARY 1, 1996

	U.S. Total	PADD I	PADD II	PADD III	PADD IV	Calif.	PADD V Outside California
New Distillate Desulfurization, MB/SD	825	30	428	332	59	(47)	23
New Hydrogen Production, MMCF/SD*	425	0	91	72	NA	228	33
Sulfur Removal, LT/SD†	3,062	68	1,462	1,146	117	240	29

* MMCF/SD = million cubic feet per stream day.

† LT/SD = long tons per stream day.

on-highway diesel fuel volumes. Thus the survey is useful only for directional guidance. For the three PADDs studied, the survey facilities indicated for new distillate desulfurization are certainly directionally consistent with the computer model predicted facilities for new and upgraded desulfurization capacity.

The survey figures for PADD V vary greatly between conversion facilities inside California and outside California. Inside California, distillate desulfurization capacity is reported to be declining while both hydrogen production and sulfur recovery show increases. Certainly, at least a partial reason for the distillate desulfurization figures is that refiners supplying California's South Coast Air Basin have supplied ultra-low sulfur diesel fuel since 1989. Thus, no expansion of facilities is needed in this area to provide 1993 ultra-low sulfur diesel fuel. There has also been some conversion of distillate desulfurization to distillate dearomatization capacity.

While the survey figures for hydrogen production and sulfur recovery have been provided they are not comparable to computer model data. The computer model facilities are those directly associated with 1993 ultra-low sulfur diesel fuel. The survey facilities for hydrogen and sulfur include associated facilities for crude oil changes, other products changes, and regulations as well as for 1993 ultra-low sulfur diesel fuel.

Other Ultra-Low Sulfur Distillate Cases

Two additional ultra-low sulfur distillate cases have been considered. In the first, federal 1993 diesel fuel regulations were assumed to be extended to include off-highway diesel fuel. In the second, all distillate production was required to be ultra-low sulfur. Table 4-42 shows the progression of distillate volumes, investments, and costs for comparison.

The product cost to desulfurize, on a per-gallon basis, in any PADD is relatively insensitive to the percent of distillate supply desulfurized in the ranges studied here. Interpolation will allow for the calculation of the investment required for any volume desulfurized. Thus any level of "spillover" may be analyzed using the figures presented in this section. The capital investments required are shown graphically in Figure 4-17.

On a total U.S. basis, the increased product cost is also relatively insensitive to the level of ultra-low sulfur distillate production. Ultra-low sulfur distillate will cost 4 to 4.5 cpg more

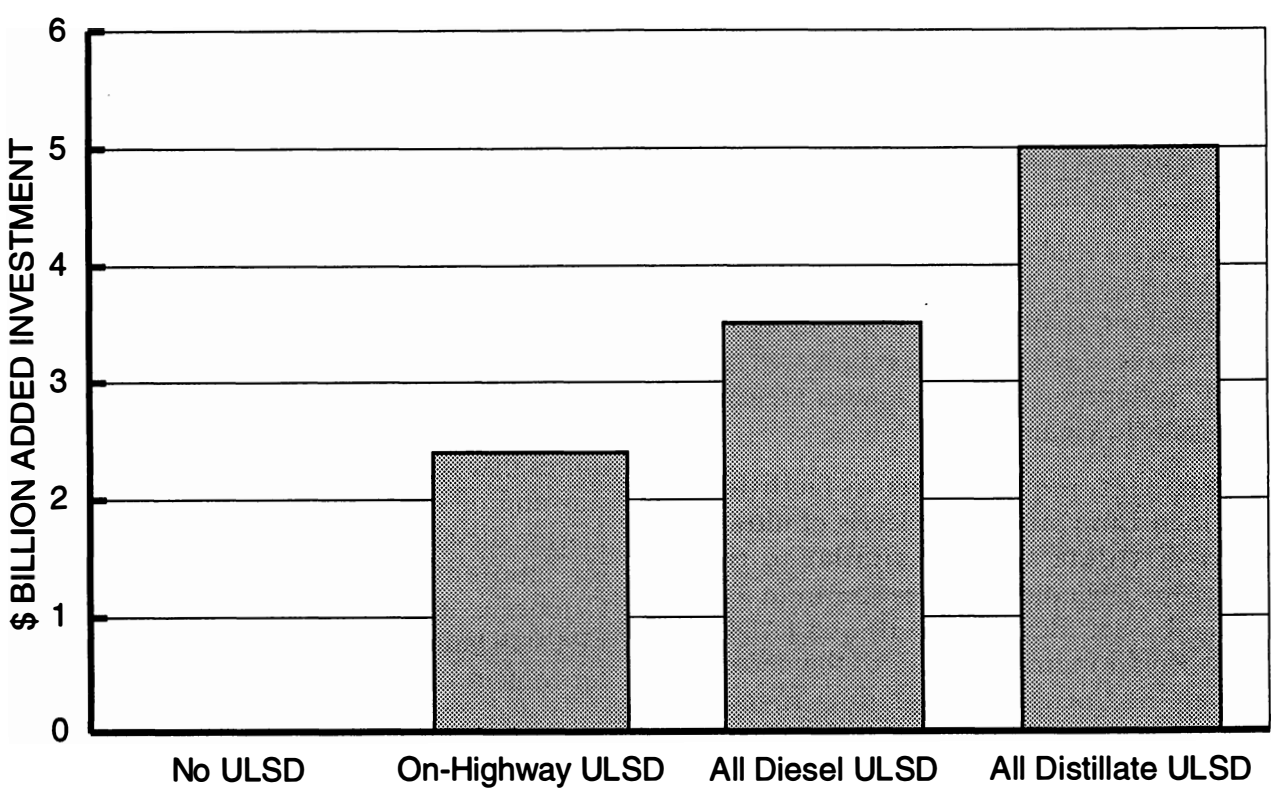
to produce than the current sulfur level product at 50 to 100 percent of the distillate pool being ultra-low sulfur. The investment increases almost linearly with the volume produced, ranging from $2.4 billion for 47 percent to $5.0 billion for 100 percent ultra-low sulfur. Investment and product cost results for PADDs III and IV are shown in Tables 4-43 and 4-44.

The cost-per-gallon figures for PADD III indicate that this area would have a cost advantage of approximately 1.4 cpg over total U.S. refiners in the production of ultra-low sulfur

TABLE 4-42

DISTILLATE CASE SUMMARY — U.S. TOTALS

	No Diesel Ultra-Low Sulfur	1993 On-Highway Diesel Ultra-Low Sulfur	All Diesel Ultra-Low Sulfur	All Distillate Ultra-Low Sulfur
Current Sulfur, MB/CD	2,899	1,533	831	0
Ultra-Low Sulfur, MB/CD	0	1,366	2,068	2,899
Total Distillate, MB/CD	**2,899**	**2,899**	**2,899**	**2,899**
Total Investment, $Billions (1990 dollars)	Base	2.4	3.5	5.0
Increased Product Cost, cpg (1990 dollars)	Base	3.8	4.0	4.5



ULSD = Ultra-Low Sulfur Diesel.

Figure 4-17. Diesel Fuel/Distillate Investments.

TABLE 4-43

INVESTMENT AND PRODUCT COST — PADD III
(1990 Dollars)

	No Diesel Ultra-Low Sulfur	1993 On-Highway Diesel Ultra-Low Sulfur	All Diesel Ultra-Low Sulfur	All Distillate Ultra-Low Sulfur
Total Investment, $Billions	Base	0.9	1.4	2.1
Increased Product Cost, cpg	Base	2.4	2.4	4.3
% Ultra-Low Sulfur Distillate	0	43	70	100

TABLE 4-44

INVESTMENT AND PRODUCT COST — PADD IV
(1990 Dollars)

	No Diesel Ultra-Low Sulfur	1993 On-Highway Diesel Ultra-Low Sulfur	All Diesel Ultra-Low Sulfur	All Distillate Ultra-Low Sulfur
Total Investment, $Billions	Base	0.2	0.3	0.4
Incremental Investment, $Billions	Base	0.2	0.1	0.1
Increased Product Cost, cpg	Base	8.2	8.2	8.4
% Ultra-Low Sulfur Distillate	0	41	67	100

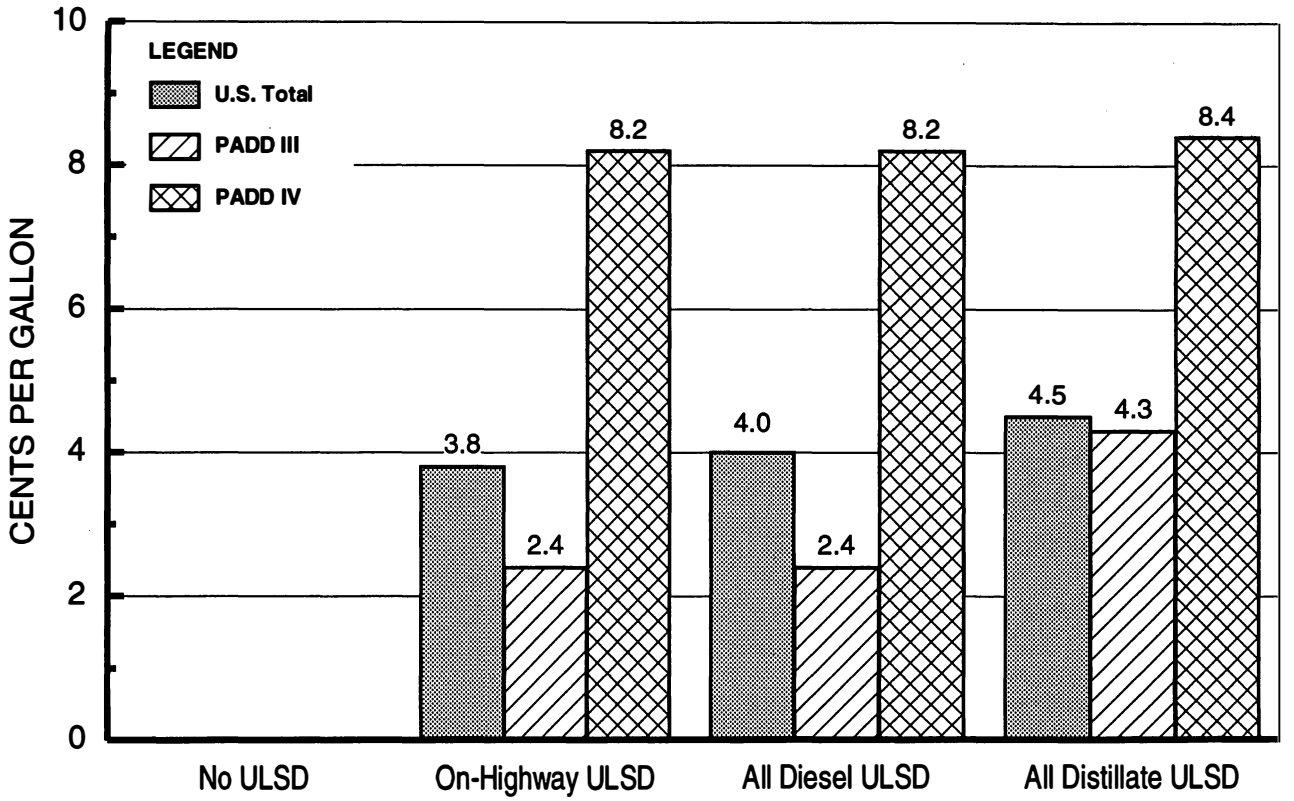
diesel fuel. PADD III refineries also show a higher current level of distillate sulfur removal than PADDs I, II, or IV. PADD IV shows a cost disadvantage of about 4 cpg as compared to the total U.S. figures. The cost figures are shown graphically in Figure 4-18.

Refiners' requirements in facilities to meet increasing production levels of ultra-low sulfur distillate are very similar to those needed for 1993 diesel fuel as shown in Tables 4-45 and 4-46. Both PADD III and PADD IV results would indicate that all of the necessary distillate hydrotreating upgrading is accomplished at about 70 percent of the distillate pool being ultra-low sulfur. The remaining 30 percent of the pool would require new unit capacity. Some minimal diesel fuel aromatics saturation is shown to be needed in PADD IV to maintain distillate cetane quality when producing all ultra-low sulfur distillate.

CARB Diesel Fuel

The California Air Resources Board requires that vehicular diesel fuel, both on-highway and off-highway (excluding railroad and marine diesel fuel), have a maximum aromatics content of 10 percent beginning October 1, 1993. They also require the federal EPA standard of a maximum of 0.05 wt% sulfur content.

The California regulations for low aromatics, ultra-low sulfur vehicular diesel fuel allow certification of an alternative diesel fuel formulation. The manufacturer has to demonstrate that the alternative formulation has



ULSD = Ultra-Low Sulfur Diesel.

Figure 4-18. Diesel Fuel/Distillate Product Costs.

TABLE 4-45

ESTIMATED ULTRA-LOW SULFUR DISTILLATE FACILITY NEEDS
PADD III

	1993 On-Highway Diesel Ultra-Low Sulfur	All Diesel Ultra-Low Sulfur	All Distillate Ultra-Low Sulfur
New Distillate Hydrotreating, MB/SD	85	135	477
Upgraded Distillate Hydrotreating, MB/SD	560	894	894
Hydrogen Production, MMCF/SD*	95	154	154
Sulfur Recovery, LT/SD†	310	502	502
Product Volume, MB/CD	564	913	1,301

* MMCF/SD = million cubic feet per stream day.

† LT/SD = long tons per stream day.

TABLE 4-46

ESTIMATED ULTRA-LOW SULFUR DISTILLATE FACILITY NEEDS PADD IV

	1993 On-Highway Diesel Ultra-Low Sulfur	All Diesel Ultra-Low Sulfur	All Distillate Ultra-Low Sulfur
New Distillate Hydrotreating, MB/SD	35	56	90
Upgraded Distillate Hydrotreating, MB/SD	40	68	68
Hydrogen Production, MMCF/SD*	0	0	0
Sulfur Recovery, LT/SD†	35	65	67
Diesel Aromatics Saturation, MB/SD	0	0	6
Product Volume, MB/CD	50	82	122

* MMCF/SD = million cubic feet per stream day.

† LT/SD = long tons per stream day.

equivalent, or better, emissions performance of the standard 10 percent aromatics, 0.05 percent sulfur diesel fuel. To date the California Air Resources Board has certified four fuels. One example of a certified diesel fuel is shown in Table 4-47.

Certified fuel can be considered an approximately 50-50 mixture of ultra-low sulfur diesel fuel and low aromatics diesel fuel with the addition of sufficient cetane improver to raise its cetane number to the required level. The cost of producing this alternative formulation diesel fuel has not been considered in this study.

Parts of California are recognized to have some of the most severe environmental problems in the United States. For example, the Los Angeles Basin is the only area in the United States which is not in compliance on NOx. In the area of diesel fuel, CARB has a more stringent regulation than the rest of the states. The CARB goal is to decrease not only SO_2 but also particulates and NOx emissions.

TABLE 4-47

SPECIFICATIONS FOR CARB CERTIFIED DIESEL FUEL FORMULATION

Fuel Property	Fuel Specification	Test Method
Aromatic Hydrocarbons	≤19 percent by weight	ASTM D5186-91
Sulfur	≤196 ppm by weight	ASTM D2622-82
Polycyclic Aromatic Hydrocarbons	≤4.68 percent by weight	ASTM D2425-83
Nitrogen Content	≤466 ppm by weight	ASTM D4629-86
Cetane Number	≥59	ASTM D613-84

Note: The candidate fuel was tested without the addition of any additives other than additives having the sole effect of enhancing cetane. Therefore, no minimum additive concentration is required.

Aromatics removal would cost the U.S. refining industry an additional $14 billion over the $5 billion expenditure required for all ultra-low sulfur distillate. The cost of product would increase by 10 cpg for the aromatics reduction alone. Table 4-48 indicates the costs of low aromatics distillate in relation to the 100 percent ultra-low sulfur distillate case studied. The increased product cost is 14.5 cpg when compared to current distillate costs.

These figures have been estimated based on PADD III data. PADD III costs would be projected to be $4.5 billion of the $14 billion total. Increased PADD III distillate costs would be 8.3 cpg. As with the other distillate issues studied, PADD IV refineries would be expected to face costs much above the U.S. average.

The required PADD III facilities to produce 100 percent low aromatics distillate from 100 percent ultra-low sulfur distillate would include 165 MB/SD added distillate hydrotreating capacity, 278 million cubic feet per stream day (MMCF/SD) additional hydrogen production, and a new capacity of 1,259 MB/SD of diesel fuel aromatics saturation. The diesel fuel aromatics saturation comprises 85 percent of the PADD III investment increase for low aromatics distillate production.

Figures 4-19 and 4-20 provide a graphical indication of the progression of investment and product cost increases for all of the distillate cases considered.

The cases in this study evaluated CARB diesel fuel on a U.S. basis. Figures were not developed for the cost of producing medium aromatics diesel fuel that met CARB fuel specifications like the type of fuels that are now being certified by CARB. Other industry studies have estimated the capital expenditures for CARB diesel fuel in California to be $1.0 billion and the increased refining cost for it to be about 10 cpg of low aromatics diesel fuel.

Implications, Concerns, and Strategies

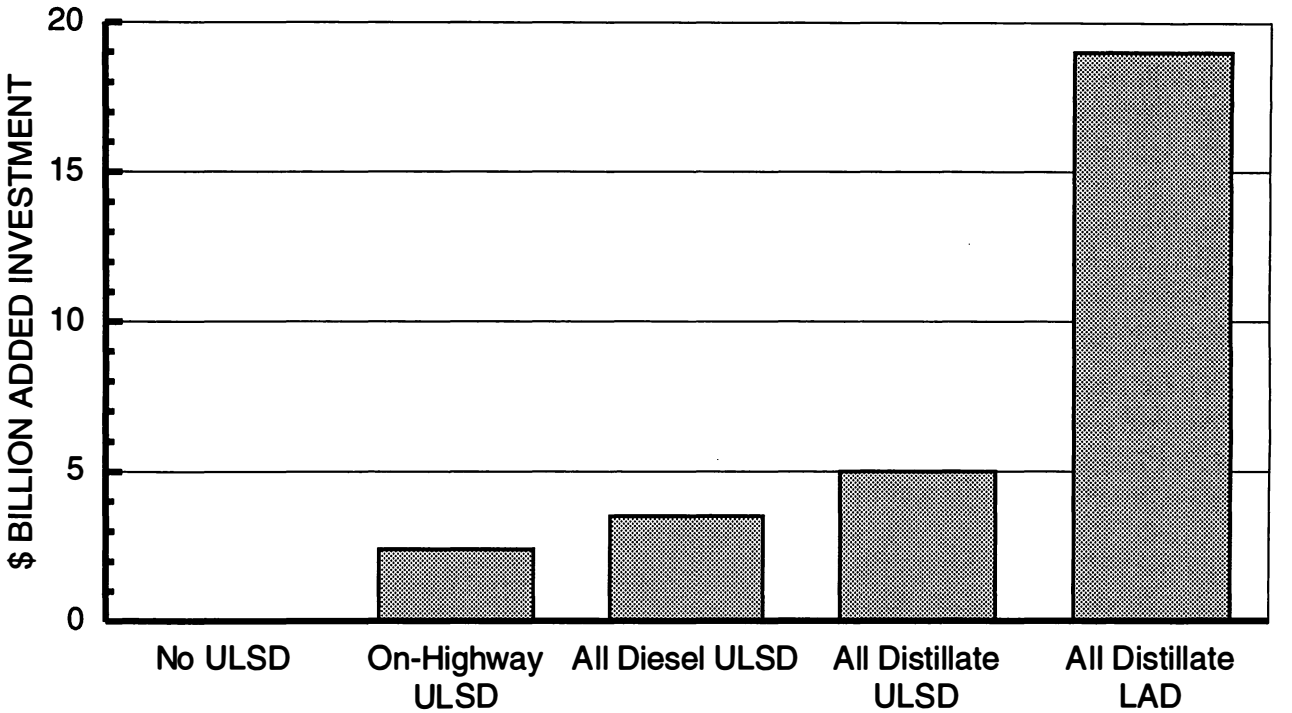
Future regulations may force changes in the quality of U.S. diesel fuel that is sold outside of California. In order for diesel engine manufacturers to meet lower NOx exhaust emission standards in 1998, it may be necessary to improve the quality of diesel fuel. Studies have shown that modern, prototype engines operating on diesel fuel with cetane numbers higher than today's typical levels produce lower emissions than when using lower cetane quality fuel. The increased cetane number can be obtained through processing or by chemical cetane improvers.

A second concern of the industry focused on the way to meet the new sulfur specification. Survey data imply that U.S. refiners plan to construct more facilities than will be needed to satisfy on-highway diesel fuel requirements. The NPC survey of the industry indicated that

TABLE 4-48

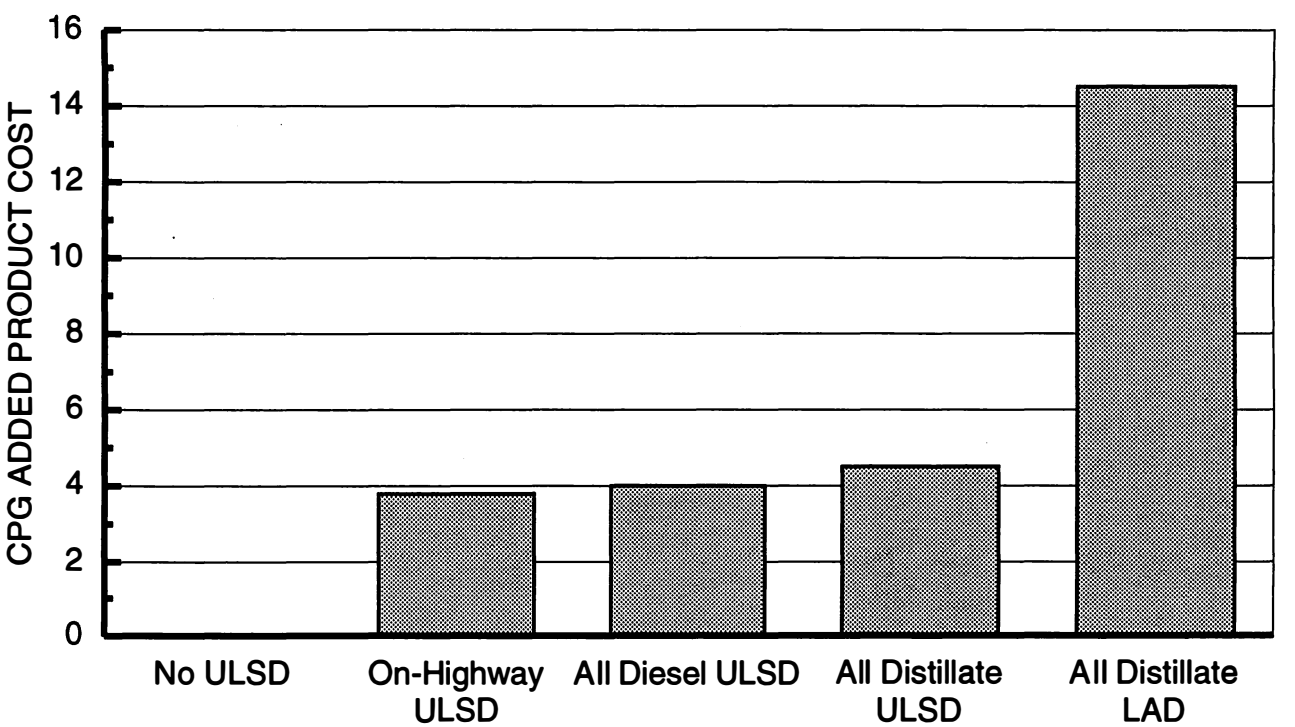
CARB DIESEL FUEL SUMMARY — U.S. TOTALS

	All Distillate Ultra-Low Sulfur	All Distillate Low Aromatics
Ultra-Low Sulfur, MB/CD	2,899	0
Low Aromatics, MB/CD	0	2,899
Total Distillate, MB/CD	**2,899**	**2,899**
Total Investment, $Billions (1990 Dollars)	5.0	19.0
Incremental Investment, $Billions (1990 Dollars)	Base	14.0
Increased Product Cost, cpg (1990 Dollars)	Base	10.0



ULSD = Ultra-Low Sulfur Diesel.
LAD = Low Aromatics Diesel.

Figure 4-19. Diesel Fuel/Distillate Investments (Billions of Dollars).



ULSD = Ultra-Low Sulfur Diesel.
LAD = Low Aromatics Diesel.

Figure 4-20. Diesel Fuel/Distillate Investments (Cents per Gallon).

refiners planned to produce a total of 62 percent of their distillate product as ultra-low sulfur in 1995. Another 23 percent would be between 0.05 and 0.20 wt% sulfur. Full data by PADD are not available. It does appear that refiners in PADD II plan to supply almost 67 percent of their distillate production at a sulfur level at or below 0.05 wt%. PADDs' III and IV comparable figures are 60 percent and 66 percent. In each of these PADDs, the planned supply figure is more than 10 percentage points above the estimated no growth demand requirements for ultra-low sulfur on-highway diesel fuel alone. Many refiners will be desulfurizing 100 percent of their distillate to take advantage of economics of scale by building larger desulfurization facilities, for product exchange with other refiners, and to avoid the cost of handling dual products throughout the distribution systems. There is no legal requirement forcing entry into the ultra-low sulfur diesel fuel program and markets for higher sulfur distillate material may still exist.

Of concern to refiners is the possibility of oversupply of the ultra-low sulfur diesel fuel markets. This could lead to under-recovery of upgrading costs by some refiners.

While the average diesel fuel sulfur content is 0.25 wt%, some refiners produce product up to the current specification of 0.50 wt% sulfur maximum. It is also assumed in this study that refiners will produce ultra-low sulfur diesel fuel to an actual sulfur level of 0.042 wt% maximum. This will allow a compliance margin to allow for the most accurate lab test repeatability. The compliance margin for aromatics was assumed to be 3 percent by volume.

PRODUCTION CAPABILITY AND FLEXIBILITY

This section provides an assessment of industry production capability and flexibility based upon the NPC survey and mathematical modeling of the industry using The Pace Consultants and Turner-Mason proprietary models. First, an overview and summary of key results is presented. Following that, additional details are discussed concerning industry demand scenarios, survey results, and modeling results.

Overview

Industry production capability and flexibility were assessed by utilizing information from NPC survey results as well as results from industry linear programming models. Key results are summarized in Table 4-49, which provides estimates of production capability and flexibility at 95 percent operable stream day crude oil unit capacity utilization. Utilization is defined as calendar day throughput divided by operable stream day capacity. This utilization level was judged to be the *maximum practical short-term* level of capacity utilization and is useful as an approximation to emergency demand capabilities. Table 4-49 volumes can be reduced by about 3 percent for estimates of longer-term industry capabilities, since maximum sustained industry crude oil unit capacity utilization has not historically exceeded about 92 percent.

Summary of Key Results

Key results from Table 4-49 are:

- Using the Pace cost-volume model estimates of short-term gasoline production capability at 95 percent crude oil capacity utilization increase from 7.3 MMB/CD in 1989 to 7.9 MMB/CD in 1995 and 8.3 MMB/CD in 2000-2010. Under the premised no growth in consumer demand, this represents 110 percent of demand in 1995 and about 115 percent in 2000-2010. Much of the increase will be due to oxygenates along with process equipment additions.

  Modeling estimates also indicate that industry has the flexibility to produce an additional 0.5 to 0.6 MMB/CD of gasoline at the expense of decreased Jet-A/kerosene and No. 2 distillate yields.

- No. 2 distillate production capability at 95 percent crude oil unit utilization is estimated at 3.1 MMB/CD in 1989 through 2010. This is 100 percent of recent consumer distillate demand. Flexibility exists to produce at least an additional

TABLE 4-49

U.S. MAXIMUM PRACTICAL SHORT TERM PRODUCTION CAPABILITY
(Million Barrels per Calendar Day)

SURVEY AND MODELING RESULTS VS. 1989-1990 CONSUMER PRODUCT DEMAND

	1989-1990	1995	2000	2010
Total Light Products[2]				
Survey results, at 95% crude capacity[3]	11.6	12.8	—	—
Modeling results, at 95% crude capacity	12.0	12.6	13.0	13.0
Consumer demand	12.0	—	—	—
Gasoline				
Survey results, at 95% crude capacity	7.1-7.2	8.2	—	—
Modeling results, at 95% crude capacity	7.3-7.8	7.9-8.5	8.3-8.8	8.3-8.8
Consumer demand	7.3	—	—	—
Diesel Fuel/No. 2 Distillate Fuel Oil				
Survey results, at 95% crude capacity	3.0-3.2	2.8	—	—
Modeling results, at 95% crude capacity	3.1-3.5	3.1-3.5	3.1-3.5	3.1-3.5
Consumer demand	3.2	—	—	—
Jet-A/Kerosene				
Survey results, at 95% crude capacity	1.6-1.8	1.5	—	—
Modeling results, at 95% crude capacity	1.6-1.8	1.6-1.8	1.6-1.8	1.6-1.8
Consumer demand	1.5	—	—	—

Notes:

1. When a range is given for modeling results, the lower number reflects production at a base case gasoline to distillate to Jet-A/kerosene product ratio. The higher number reflects increased production of the desired product (e.g., gasoline) at the expense of other light products.
2. Total light products after addition of all required oxygenate as MTBE (or TAME) including oxygenate blended at terminals.
3. Percent of operable calendar day capacity.

0.4 MMB/CD of distillate by reducing yield of gasoline.

- Jet-A/kerosene production capability at 95 percent crude oil unit utilization is estimated at 1.6 MMB/CD in 1989 through 2010. This is 100 percent of premised no growth in consumer jet fuel demand. Flexibility exists to produce at least an additional 0.2 MMB/CD of Jet-A/kerosene by reducing yield of No. 2 distillate and gasoline.
- This increased production capability is a result of increased oxygenate use, increased utilization of existing capacity, and future announced process unit additions.

It should be stressed that these are estimates representing capability only; actual production levels will be determined by industry economics. Additional details concerning the survey and modeling results are discussed below.

Survey Results of Production Capabilities

NPC survey results pertaining to U.S. production capability are summarized in Table 4-50. Presented in Table 4-50, from left to right, are survey results for actual 1990 production, 1990 production capability with 5 percent incremental and decremental crude oil, and short-term production capability when maximizing one product at the expense of another (flexibility). Respondent data are shown in the upper half of the table. In the lower half of the table these data are adjusted to include non-respondents. Survey results reinforce the increased industry gasoline capacity indicated in modeling results.

- **Total Light Products.** Adjusted survey data indicate that in 1990 industry delivered a total of 11.2 MMB/CD of light products at a crude oil unit utilization capacity of about 89 percent (13.5 MMB/CD crude oil and 15.0 MMB/CD capacity). Maximum short-term light product production capability in 1990 can be estimated by extrapolating the 5 percent incremental crude oil run survey data to 95 percent crude oil unit capacity utilization. This gives a maximum extrapolated light product production at 95 percent utilization of 11.6 MMB/CD, or about 96 percent of the 12.0 MMB/CD consumer demand. Adjusted refiners' projections for 1995 indicate a production capability of 12.0 MMB/CD light products at 92 percent crude oil utilization. Extrapolating to 95 percent utilization (14.5 MMB/CD crude oil and 15.2 MMB/CD capacity) gives a light product production capability of 12.6 MMB/CD.
- **Gasoline.** For gasoline, adjusted survey data indicate that in 1990 industry delivered a total of 6.9 MMB/CD of gasoline at a crude oil unit utilization capacity of about 89 percent. As with the light product estimate, maximum gasoline production capability in 1990 can be estimated by extrapolating the 5 percent incremental crude oil run data to 95 percent crude oil unit capacity utilization. This results in a maximum short-term extrapolated 1990 gasoline production at 95 percent utilization of 7.1 MMB/CD, or about 98 percent of the 7.2 MMB/CD consumer demand for gasoline, assuming the same nominal product ratio is maintained. Survey data indicate that refiners have the short term flexibility to increase gasoline production to about 7.2 MMB/CD if they reduce distillate and Jet-A/kerosene production. For comparison, monthly production reported by the EIA, which shows a maximum of about 7.4 MMB/CD, as seen on Table 4-51. The 7.4 MMB/CD includes oxygenates required after October 1, 1992.

For 1995, adjusted survey data show a production capability of 7.7 MMB/CD gasoline at 92 percent crude oil utilization. Extrapolating to 95 percent utilization (14.5 MMB/CD crude oil and 15.2 MB/SD capacity) gives a maximum short-term gasoline production capability of 8.2 MMB/CD.

- **Distillate.** Adjusted survey respondent data show that in 1990, industry could produce 2.8 MMB/CD of No. 2 distillate at a crude oil unit utilization of 89 percent. Extrapolating to 95 percent crude

TABLE 4-50

NPC SURVEY RESULTS—U.S. PRODUCTION CAPABILITY
(Million Barrels per Calendar Day)

		1990 U.S. Annual Production Capability		1991 Projected U.S. Short-Term Production Capability [4]			
Respondent Data	**1990 Actual U.S. Annual Production [1]**	**With 5% More Crude Oil [2]**	**With 5% Less Crude Oil [3]**	**Maximizing Gasoline**	**Maximizing Jet-A/ Kerosene**	**Maximizing No. 2 Distillate**	**1995 Projected U.S. Annual Production Capability [5]**
Crude Oil Inputs	12.48	13.00	11.92	—	—	—	13.08
Motor Gasoline	6.48	6.59	6.34	6.77	5.91	5.93	7.28
Jet-A/Kerosene [6]	1.36	1.41	1.30	1.31	1.69	0.95	1.41
No. 2 Distillate	2.53	2.65	2.40	2.39	2.36	2.97	2.54
Total	**10.37**	**10.65**	**10.05**	**10.47**	**9.97**	**9.85**	**11.23**
Residual Fuel [7]	0.75	0.79	0.70	0.69	0.77	0.69	0.58
Adjusted Data to Include Non-respondents [8]							
Crude Oil Inputs	13.49	14.01	12.93	—	—	—	14.09
Motor Gasoline	6.89	7.00	6.75	7.18	6.32	6.34	7.69
Jet-A/Kerosene	1.48	1.53	1.42	1.43	1.81	1.07	1.51
No. 2 Distillate	2.79	2.91	2.66	2.65	2.62	3.23	2.82
Total	**11.16**	**11.44**	**10.83**	**11.26**	**10.75**	**10.64**	**12.02**
Residual Fuel	0.86	0.91	0.82	0.81	0.88	0.81	0.69
Key Process Unit Capacity Utilization, % [9]							
Crude Oil Unit	89	93	86	—	—	—	92

Notes:

1. Survey questions II-C-1-f, i, j, k, l, n, and II-B-1-a-7
2. Survey question II-C-8-a-1, 3, 4, 5, 6
3. Survey question II-C-7-a-1, 3, 4, 5, 6
4. Survey questions II-C-6-a-1, 2, 3; b-1, 2, 3; c-1, 2, 3
5. Survey questions II-C-1-f, i, j, k, l, n, and II-B-1-b-7
6. Includes naphtha-jet
7. Does not include asphalt and road oils
8. Source EIA Petroleum Supply Annual Data
9. Percent of operable calendar day capacities

TABLE 4-51

U.S. TOTAL PRODUCTION: FINISHED MOTOR GASOLINE
(Million Barrels per Calendar Day)

Month	1987	1988	1989	1990	1991	1992
January	6.71	6.73	6.94	6.75	6.72	7.04
February	6.36	6.74	6.65	6.99	6.57	6.75
March	6.57	6.71	6.61	6.61	6.65	6.69
April	6.85	6.91	6.82	6.78	6.74	6.96
May	6.99	6.85	6.93	6.61	7.06	7.10
June	7.09	6.98	7.29	7.10	7.35	7.20
July	7.04	7.16	7.36	7.24	7.27	7.20
August	6.93	7.21	7.16	7.33	7.25	6.82
September	6.92	6.95	7.07	7.27	7.03	7.08
October	6.67	6.86	6.84	6.89	6.75	7.20*
November	6.91	7.06	7.05	6.94	7.02	7.30*
December	7.01	7.30	6.88	6.89	7.35	7.40*
Average	6.84	6.95	6.97	6.95	6.98	7.06

* Includes oxygenates mandated by the Clean Air Act Amendments.

Source: EIA *Petroleum Supply Annual.*

oil utilization using the 5 percent more incremental crude oil column information gives a maximum short-term distillate production capability of about 3.0 MMB/CD, or about 94 percent of the 1989-1990 consumer demand of 3.2 MMB/CD. Survey data also show that refiners have the short term flexibility to increase distillate production to about 3.2 MMB/CD, provided they do so at the expense of producing less gasoline and Jet-A/kerosene. Extrapolating refiner survey data for 1995 estimated distillate production gives a distillate production capability of 2.8 MMB/CD distillate. However, survey flexibility data show that refiners could shift the product slate to produce additional distillate at the expense of gasoline production.

- **Jet-A/Kerosene.** The premised no growth consumer demand for Jet-A/kerosene is 1.6 MMB/CD. Extrapolation of survey results to 95 percent crude oil unit capacity utilization gives a maximum short-term industry Jet-A/kerosene production capability of about 1.6 MMB/CD, or 100 percent of demand. Survey data show that industry has the short-term flexibility to produce up to 1.8 MMB/CD of Jet-A/kerosene, provided less gasoline and No. 2 distillate are made. Similar extrapolation of 1995 results to 95 percent crude oil utilization results in a 1995 maximum short-term production capability of 1.5 MMB/CD, although this too could be increased at the expense of less gasoline production.

Modeling Results for 1989

Models of the U.S. refining industry were developed for input to the supply and logistics modeling portion of the NPC study. Information from this modeling was also utilized to develop insights into industry production capabilities.

Table 4-52 compares 1989 modeling results using the Pace model for two levels of crude oil throughput:

- 89 percent crude oil unit utilization (13.4 MMB/CD crude oil) at a fixed product distribution corresponding to 1989 actual product distribution. Additional cases were also developed at this crude oil throughput, but with increased gasoline, Jet-A/kerosene, or No. 2 distillate production.
- 97 percent crude oil unit utilization (14.6 MMB/CD crude oil) at a fixed product distribution corresponding to 1989 actual product distribution. Additional cases were also developed at this crude oil throughput, but with increased gasoline, Jet-A/kerosene, or No. 2 distillate production.

Several observations can be made with regard to 1989 production capability from these modeling results:

- The calibration of the model to 1989 NPC survey results is very close. For example, at the equivalent crude oil utilization of 89 percent, both modeling estimates and survey results indicate production of 11.2 MMB/CD of light products.
- At 89 percent crude oil utilization, modeling verifies the ability of refiners to produce at least 11.3 MMB/CD of total light products by emphasizing gasoline or distillate production. Modeling indicates that at least 7.3 MMB/CD of gasoline can be produced when the excess production is at the expense of other products. This is reasonably close to the adjusted survey results for 1991 short-term gasoline maximization capability shown in Table 4-51 (7.2 MMB/CD).

Modeling Results for 1995

Table 4-53 compares 1995 modeling results for the same two levels of crude oil throughput as in the 1989 modeling, 13.4 MMB/CD of crude oil and 14.6 MMB/CD of crude oil. However, crude oil capacity additions scheduled for 1995 completion raised the total U.S. crude oil unit capacity slightly to 15.25 MMB/CD from 15.03 MMB/CD in 1989. This results in 1995 crude oil capacity utilization rates of 88 percent and 96 percent for modeling purposes. Several observations can again be made:

- Results of model projections compare reasonably well with survey projections for 1995. The Table 4-50 survey results indicate that industry could provide about 12.0 MMB/CD of total light products in 1995 at a crude oil unit utilization of about 92 percent (14.0 MMB/CD crude oil). Interpolating from Table 4-53 results at 88 and 96 percent gives a model projection of 12.3 MMB/CD at 92 percent crude oil unit utilization crude oil utilization. Again, this is slightly larger than survey results, reflecting the over-optimization inherent in linear programming models.
- The above survey and model results indicate that the industry could supply the 1995 no demand growth scenario without imports, provided no additional shutdowns occur. This is a physical supply capability, not an economic capability. Economics of domestic production cost vs. imports will set actual production and import levels.
- Modeling results from Table 4-53 were extrapolated to 95 percent crude oil unit utilization, which is a reasonable upper limit for short-term crude oil throughput. A crude oil unit utilization of 95 percent would imply a crude oil throughput of 14.5 MMB/CD. Assuming no downstream limits, extrapolated total light products production would be about 12.6 MMB/CD, with a maximum gasoline production of about 7.9 MMB/CD.

Modeling Results for 2000

Table 4-54 summarizes year 2000 modeling results, again at 13.4 and 14.6 MMB/CD of crude oil. Several observations can again be made:

- Even with stricter product specifications, year 2000 modeling results indicate that the industry will be able to supply more

TABLE 4-52

MODELING RESULTS
U.S. REFINERY PRODUCTION CAPABILITY—1989
(Million Barrels per Calendar Day)

	Base Case Crude Oil Run				Short-Term at High Crude Oil Run*			
	At Base Case Product Ratio	At Increased Gasoline Production	At Increased Jet-A/ Kerosene Production	At Increased No. 2 Distillate Production	At Base Case Product Ratio	At Increased Gasoline Production	At Increased Jet-A/ Kerosene Production	At Increased No. 2 Distillate Production
Crude Oil Inputs	13.42	13.42	13.42	13.42	14.64	14.64	14.64	14.64
Motor Gasoline	6.93	7.34	6.81	6.58	7.49	7.96	7.39	7.12
Jet-A/Kerosene	1.41	1.36	1.68	1.44	1.63	1.47	1.84	1.56
No. 2 Distillate	2.90	2.61	2.84	3.31	3.14	2.83	3.07	3.57
Total	**11.24**	**11.31**	**11.33**	**11.33**	**12.26**	**12.26**	**12.30**	**12.25**
Residual Fuel	0.72	0.73	0.73	0.73	1.01	1.05	1.06	0.99
Crude Oil Unit Capacity Utilization, % †	89	89	89	89	97	97	97	97

* Increased gasoline, Jet-A/kerosene, and No. 2 distillate production at high crude oil run assume same percentage increase as at base crude oil run.

† Percent of operable calendar day capacity. Operable calendar day capacity = 15.03 MMB/CD in 1989.

TABLE 4-53

MODELING RESULTS
U.S. REFINERY PRODUCTION CAPABILITY—1995
(Million Barrels per Calendar Day)

	Base Case Crude Oil Run				Short-Term at High Crude Oil Run*			
	At Base Case Product Ratio	At Increased Gasoline Production	At Increased Jet-A/ Kerosene Production	At Increased No. 2 Distillate Production	At Base Case Product Ratio	At Increased Gasoline Production	At Increased Jet-A/ Kerosene Production	At Increased No. 2 Distillate Production
Crude Oil Inputs	13.42	13.42	13.42	13.42	14.64	14.64	14.64	14.64
Motor Gasoline	7.38	7.89	7.23	7.00	8.00	8.55	7.83	7.59
Jet-A/Kerosene	1.50	1.35	1.70	1.43	1.63	1.46	1.84	1.55
No. 2 Distillate	2.90	2.60	2.83	3.29	3.14	2.81	3.06	3.56
Total	**11.78**	**11.84**	**11.76**	**11.72**	**12.77**	**12.82**	**12.73**	**12.70**
Residual Fuel	0.53	0.55	0.54	0.54	0.79	0.81	0.80	0.80
Crude Oil Unit Capacity Utilization, % †	88	88	88	88	96	96	96	96

* Increased gasoline, Jet-A/kerosene, and No. 2 distillate production at high crude oil run assume same percentage increase as at base crude oil run.

† Percent of operable calendar day capacity.

TABLE 4-54

MODELING RESULTS
U.S. REFINERY PRODUCTION CAPABILITY—2000
(Million Barrels per Calendar Day)

	Base Case Crude Oil Run				Short-Term at High Crude Oil Run*			
	At Base Case Product Ratio	At Increased Gasoline Production	At Increased Jet-A/ Kerosene Production	At Increased No. 2 Distillate Production	At Base Case Product Ratio	At Increased Gasoline Production	At Increased Jet-A/ Kerosene Production	At Increased No. 2 Distillate Production
Crude Oil Inputs	13.42	13.42	13.42	13.42	14.64	14.64	14.64	14.64
Motor Gasoline	7.72	8.22	7.54	7.31	8.35	8.89	8.16	7.90
Jet-A/Kerosene	1.50	1.34	1.70	1.43	1.63	1.45	1.84	1.56
No. 2 Distillate	2.90	2.58	2.83	3.28	3.14	2.79	3.06	3.54
Total	**12.12**	**12.14**	**12.07**	**12.01**	**13.12**	**13.14**	**13.06**	**13.00**
Residual Fuel	0.49	0.49	0.49	0.49	0.72	0.72	0.72	0.72
Crude Oil Unit Capacity Utilization, % †	88	88	88	88	96	96	96	96

* Increased gasoline, Jet-A/kerosene, and No. 2 distillate production at high crude oil run assume same percentage increase as at base crude oil run.

† Percent of operable calendar day capacity.

light product. From the same amount of crude oil, the industry could provide about 7-8 percent more light products than in 1989.

- Maximum short-term gasoline production capability at 95 percent crude oil capacity utilization is estimated from model results at about 8.3 MMB/CD. Flexibility to increase gasoline production at the expense of other products is estimated at 8.8 MMB/CD.

Modeling Results for 2010

Additional modeling was not developed for the year 2010, since product specifications and refining capacity were premised to be the same as in the year 2000.

Varying Gasoline Versus Distillate Demand

To study the impact of the increasing use of alternative fuels on the U.S. refining industry, Turner-Mason model runs were created on the PADD III model using the demand growth case for all products except gasoline. These cases show the effects of replacing some of the gasoline produced in refineries with alternative fuels produced outside of refineries. A scale-up of the results was made to allow for a prediction of the impact on the entire U.S. refining industry. Gasoline demand was taken from either the no growth demand case or the declining demand case, providing two scenarios with gasoline replacement of approximately 11 percent and 22 percent, respectively. This reduced gasoline demand was then a surrogate for increased penetration of alternative fuels. While reductions in both gasoline and diesel fuel may result from the various programs, the largest impact on refineries would arise from a scenario in which jet fuel and diesel demands are increasing while gasoline demand declines.

Refiners face two adjustments with increasing alternative fuels penetration. The first is the need to produce a much different mix of refinery products. The second is the possibility of additional rationalization of capacity due to decreased demand for refinery-produced products.

An increase in the alternative fuels portion of the U.S. gasoline demand would change the product mix for U.S. refiners. Gasoline has traditionally accounted for almost half of the product supplied by U.S. refiners with the kerosene/jet fuel/distillate pool approximately one-fourth. These figures would be revised as shown in Figure 4-21 using the two cases considered.

In reviewing the impact on U.S. refiners of increasing penetration of alternative fuels, one of the key issues is the amount of lead time that refiners would have to react to demand changes. The two extremes will be examined below.

Assuming refiners would have little or no lead time (i.e., the development of alternative fuels is rapid or mandated under a tight schedule), several impacts could be expected. First, refiners will have spent money to upgrade conventional gasoline to RFG only to see those new facilities idled because the RFG would be replaced with alternative fuels. This would provide no return on the investment. The same situation will occur for MTBE plants built outside of refineries because there will be a reduced demand for oxygenates at lower RFG demand.

In addition, refiners will face still more investment to meet a changing product mix. If a refiner is faced with decreasing gasoline demands and decides to alter the refinery to produce other light products, investments will be needed to change a portion of the gasoline fraction to distillate/jet fuel. Some of the process equipment needed would be: (1) a naphtha-splitter to rework gasoline fractions to distillate; and/or (2) a distillate hydrocracker to increase distillate yields. An estimate of the refinery facilities idled by increased alternate fuel demands is shown below. Table 4-55 shows the crude oil distillation and MTBE production capacity which would be idled under this scenario in PADD III. For a 22 percent penetration, as much as 971 MB/SD of crude oil capacity would be affected, or over 13 percent of the expected 2010 capacity under this demand scenario.

Not included in this study are the processing, distribution, and refueling facilities and

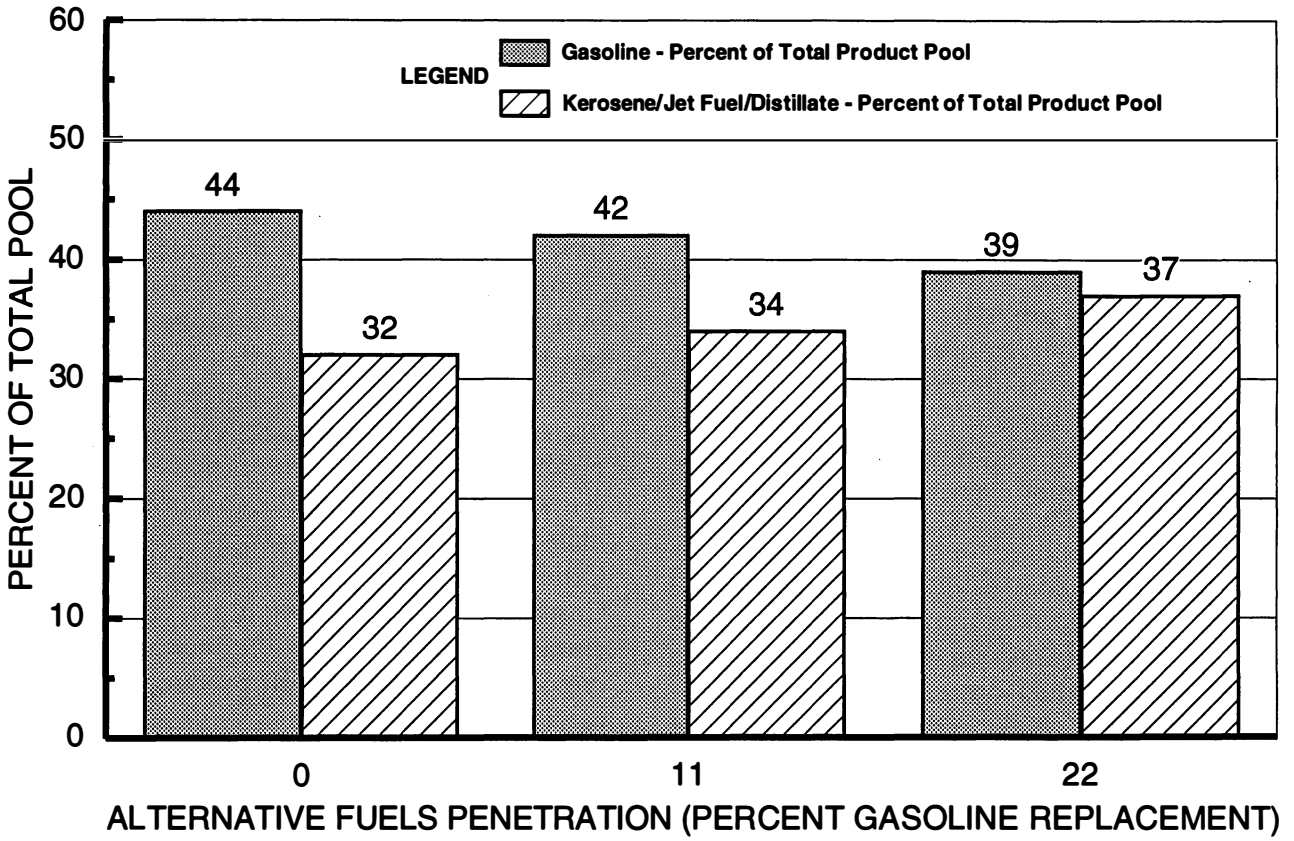


Figure 4-21. Alternative Fuels Penetration Effects on Product Mix.

investments needed to provide the alternative fuels. The costs for these facilities should be included in an overall cost comparison with petroleum-based fuels. Also not included is higher overall production costs for gasoline if refiners try to recover their investment in idled facilities on other fuels. The cost of these idled facilities may be expressed as 3.3 cpg of remaining refinery produced gasoline for the 11 percent penetration case and 7.4 cpg for the 22 percent case. These costs include the outside MTBE facilities idled and the cost for added facilities to meet the product mix changes.

Assuming refiners would have enough lead time to react to the alternative fuels impact, they would be able to avoid the investment in idle facilities noted above but would still be faced with the added investments due to product mix changes. This added investment

TABLE 4-55

COST OF REFINERY FACILITIES IDLED IN PADD III BY INCREASED ALTERNATIVE FUELS DEMAND IN 2000

Alternative Fuels Penetration	11%	22%
Idled Refinery Investment Producing No Economic Return, $Billions (1990 dollars)	0.9	1.7
Additional Investment Needed, $Billions (1990 dollars)	0.1	0.4
Crude Oil Distillation, Idled, MB/SD	488	971
MTBE Capacity Idled, MB/CD	12	20

could be on the order of $2 billion for the U.S. refinery industry with a 22 percent penetration of alternative fuels. This equates to approximately 2 cpg of remaining gasoline.

While not studied specifically using computer modeling, the impact is also significant on the U.S. refinery industry of increasing alternative fuels use under a constant demand scenario. Only slightly smaller volumes of crude oil capacity would be idled than discussed above in the decreasing demand case. On a U.S. total basis, up to 1.9 MMB/SD of crude oil capacity would be idled or almost 15 percent of the total expected capacity in 2010 under a constant demand scenario.

Refineries best suited to handle the expected change in product mix would include those with hydrocrackers with the flexibility to swing their product output from gasoline toward distillates. Refiners with only catalytic cracking might be less adaptable to the product mix swing. In the high alternative fuels penetration case, utilization of cat-cracking units would drop from 92 percent to 65 percent. Utilization of alkylation capacity would also fall, going from 79 percent to 46 percent. Additional processing needed would include heavy virgin naphtha splitting and hydrocracking with maximum middle distillate yields.

The full impact of alternative fuels penetration cannot be measured without considering the location of the demand for alternative fuels. Table 4-56 shows the January 1, 1996, anticipated cat-cracking and hydrocracking capacity by PADD as a percent of crude oil capacity based on survey data.

These figures would indicate that conversion refiners in California are best equipped to respond to changes in refinery product resulting from high levels of alternative fuels penetration. PADDs I and II are the least able to respond because of their low percentage of hydrocracking capacity. Not including alternative fuels processing, distribution, and refueling facilities costs, it would appear that PADD I and II refiners could be facing higher relative costs than the rest of the United States to meet product mix swings caused by high alternative fuels penetration.

Impact of Refinery Size and Complexity

The competitiveness of most U.S. refineries is related to their cost of producing light products. Light products (gasoline, jet fuel, diesel fuel and home heating oil, and naphtha) have high values relative to crude oil. In the United States, the refining industry produces over 85 barrels of these light products from every 100 barrels of crude oil. Historically, the cost to produce incremental light products has been tied to the complexity of the processing producing the incremental product. As a percentage of output basis, the cost of incremental light products is: Cost = (Cost of Incremental Crude Oil + Incremental Variable Operating Costs – Value of Incremental By-Products)/Incremental Light Product Production. Any incremental residual fuel oil produced is valued as a by-product.

Refining Complexity

Refining complexity is determined by the types of process equipment at each site. Simple refineries produce light products utilizing only crude oil distillation, i.e., topping columns, reforming capacity, and hydrotreating. These refineries are limited to a low yield of light products; basically that present in the crude oil itself. More complex, or conversion, refineries have catalytic cracking units to increase light product output. The most complex refineries have coking or equivalent residual conversion facilities plus catalytic cracking units to maximize production of light products from a barrel of crude oil.

Complex refineries that have invested in coking and cracking units are able to convert lower value residual fuel oil and heavy materials to higher value light products. Typically, this enables complex refineries to produce incremental light products at lower costs than simple refineries can with only topping and reforming units. An example of this capability is shown in Table 4-57. It illustrates the relative amount of crude oil needed to produce one additional barrel of light product, along with the amount of residual fuel oil that is produced from that crude oil.

TABLE 4-56

CATALYTIC CRACKING AND HYDROCRACKING CAPACITY BY PADD AS A PERCENT OF CRUDE OIL CAPACITY

	U.S. Totals	PADD I	PADD II	PADD III	PADD IV	Calif.	PADD V No Calif.
% Catalytic Cracking	35	48	38	39	39	33	19
% Hydrocracking	9	6	5	9	N/A	23	11

Source: NPC Survey Section II, Part A.

TABLE 4-57

REFINING YIELD STRUCTURE TO PRODUCE ONE ADDITIONAL BARREL OF LIGHT PRODUCTS

	Cracking + Coking Mode	Cracking Mode	Topping/ Reforming Mode
Crude Oil	1.10	1.27	1.97
Motor Gasoline, Jet Fuel, & Diesel	1.00	1.00	1.00
Residual Fuel Oil	0.05	0.25	0.88
Relative Light Products Cost*	Base	+ 2 cpg	+ 12 cpg

* Based on Pace model runs, with the cost of crude oil and value of products the same for each refinery type.

When refineries operate in an optimal manner, the crude oil processed in a cracking and coking mode provides incremental light products at the lowest costs per barrel, while cracking only mode operations have intermediate costs. The topping/reforming mode of operation produces the highest cost incremental light products.

However, when refineries operate at unusually high throughputs, the relative cost of light products shown in Table 4-57 may not apply. For example, a coking refinery may run more crude oil than required to completely utilize its coking capacity. Under the circumstances, a portion of its crude oil is run in the coking mode and the balance in the cracking mode. Similarly, a cracking refinery may run more crude oil than required to completely utilize its cracking capacity so that a portion of its crude oil is run in the cracking mode and the balance in the topping/reforming mode. The cost of incremental light products shifts from its normal operating to the next, less efficient mode, with higher costs for producing incremental light products.

Topping/reforming refineries have remained competitive by supplying specialty products to the market, while limiting their capital investments and their operating and maintenance (O&M) expenses. Thus, simple refineries have lower fixed costs than complex coking and cracking refineries. Typical simple refinery specialty products are lubricants, asphalts, naphtha-jet fuel, and cracking feedstocks.

Refinery Size

Large refineries may have an advantage over smaller ones due to economies of scale. This affects not only initial capital costs, but also O&M costs when figured on the basis of dollars per barrel of unit feed.

Small refineries, such as those in PADD IV, have remained competitive by utilizing strategies that lowered overall costs. Generally, they have limited investments in capital projects, which reduced capital charges and O&M costs. Additionally, small refineries often are located where they can serve niche markets with a minimum of competition from larger, more efficient refineries. In some circumstances, lower hourly wages in these remote locations enable small refineries to operate with lower manpower costs than larger refineries in metropolitan areas.

Some of the smaller refineries produce naphtha jet fuel for the Department of Defense. This enables them to dispose of low octane naphtha. However, as the military converts its aircraft and other equipment to JP-8, a kerosene-type jet fuel, these refineries will have to find alternative uses for their naphtha.

Under the CAAA, small and simple refineries may continue their practice of limiting capital investment. Thus, they may prefer to produce only conventional gasoline and conventional middle distillates rather than ultra-low sulfur distillate. This would eliminate the need for new processing to meet RFG and on-highway diesel specifications. However, the demand for conventional off-highway diesel fuel and home heating oil may be limited in their marketing area. They may have to install desulfurization units and supporting facilities to produce low sulfur diesel.

The effect of these potential investments was explored in the survey. About 42 percent of the respondents from refineries under 50 MB/CD thought that the financial impact for sulfur reduction in diesel fuel would be "Quite a Bit" or "A Great Deal." This indicates that the cost of capital investments for most of the small and simple refineries will be important to their competitiveness.

Small refineries may have additional capital investments if they market gasoline in nonattainment areas with 100 percent RFG. This would force them to install processing to upgrade their conventional gasoline to RFG or to sell subgrade blendstocks.

OTHER CONSIDERATIONS

Other variables impacting refining industry capabilities include: crude oil quality and the potential for technological advances.

Crude Oil Quality

While there are many important qualities of crude oil, sulfur content and density (expressed as API gravity) are two characteristics readily identifiable and widely recognized throughout the world. Virtually every crude oil stream in the world is known by its sulfur content and API gravity. The sulfur content of crude oil is important because it may limit its potential processing alternatives. Refined product specifications, equipment metallurgy, air emissions, and other considerations may limit which type of crude oil can be processed at a particular refinery. Heavier crude oils (lower API gravities) generally have more residua and less gasoline and distillate fractions. Unless a refinery has bottoms upgrading capacity, such as coking, the volume of gasoline and distillate fuel oil will be limited.

Refineries that have the ability to process a wide variety of crude oils find it economically attractive to process higher sulfur, lower gravity crude oils because they generally are less expensive than low sulfur, high gravity crudes. However, processing high sulfur crude oil requires more capital investment for desulfurization equipment, special metallurgy to resist corrosion, amine and sulfur units to recover sulfur as a product, and additional costs to reduce air and water emissions.

In recent years, on average, crude oils processed in U.S. refineries have become heavier and higher sulfur. Most low sulfur crude oils come from the United States, Africa, Asia, and the North Sea. Within the United States, many of the lower sulfur crude oil reserves have been exhausted and refiners have turned to higher

sulfur Alaskan North Slope or imported crude oil. A predominance of the newly developed crude oil fields in the world have been high sulfur. In response to changing crude oil sources, many U.S. refiners have added or modified their equipment to process available crude oils. Table 4-58 shows the trend in the average sulfur level and average API gravity of crude oils processed in the United States.

As can be seen in Table 4-58, between 1985 and 1992, average sulfur in the U.S. crude oils increased about 24 percent and average API gravity declined nearly 3 percent. This trend in crude oil quality is expected to continue. If crude oil inputs continue to become heavier and higher sulfur, some refiners will need to invest in additional bottoms upgrading and sulfur removal. Unless they make these investments, some refiners will be limited to the use of lower sulfur crude oil or face reduced processing options as the refinery becomes constrained by sulfur removal or bottoms upgrading capacity.

Section II of the NPC survey requested information on actual crude oil types and qualities processed in 1990 and those anticipated to be processed in 1995. Crude oil slates for all of the survey responses are summarized in Table 4-59. The average change over this five year period in anticipated crude oil quality for the whole United States is a 0.7°API gravity decrease and a 0.1 percentage point increase in

TABLE 4-58

U.S. REFINERY INPUTS
(Thousands of Barrels per Calendar Day)

	1985	1986	1987	1988	1989	1990	1991	1992
Crude Oil Inputs	12,002	12,716	12,854	13,246	13,401	13,409	13,301	13,411
% Imported	24.0	31.3	34.6	37.0	42.1	42.9	42.6	44.6
% Low Sulfur*	46.3	39.8	39.0	35.5	33.7	35.8	35.3	35.5
Avg Sulfur, wt%	0.91	0.96	0.99	1.04	1.06	1.10	1.13	1.16
Avg Gravity, API	32.5	32.3	32.2	31.9	32.1	31.9	31.6	31.3

* Low Sulfur Crude Oil = < 0.5 weight percent sulfur. NPC estimate.

Source: EIA, *Petroleum Supply Annual*, yearly, 1985-1992, except where noted.

TABLE 4-59

CRUDE OIL QUALITY FROM NPC SURVEY

	Actual 1990	Anticipated 1995
Total Crude Oil Rate , MB/CD	12,480	13,085
Low Sulfur, %	40	36
Gravity, ° API	31.7	31.0
Sulfur, wt%	1.2	1.3
1050+ Resid Content, vol%	17.1	17.8

Source: NPC Survey Section II, Part B. 154 of 199 refineries responded. These refineries represent almost 95 percent of total U.S. 1990 crude oil inputs.

sulfur. These trends are consistent with the crude oil slate changes in the past. Consistent with these projected trends in changes in crude oil slates are anticipated increases in process unit capabilities. Table 4-60 shows the aggregated NPC survey responses concerning related process unit capacities.

U.S. refiners anticipate adding a modest amount of bottoms upgrading capability in delayed coking. The data in Table 4-60 also show anticipated increases in sulfur handling capacity. The increases in hydrotreating and sulfur plant capacity are likely due to production of ultra-low sulfur diesel fuel, reformulated gasoline, and other environmental requirements, as well as the higher sulfur level in the crude oil processed. One of the other environmental regulations that is requiring additional sulfur plant capacity is the need for redundant capacity to avoid SOx emissions in case of a shutdown of one of the units. Additional capacity may also be required to improve the efficiency of older sulfur plants or to recover sulfur from sources in the refinery that do not currently have sulfur recovery equipment.

Ability to Substitute High Sulfur Crude Oils for Low Sulfur Crude Oils

Refiners were asked in the survey how much crude oil of approximately 33°API gravity and 1.5 percent sulfur could be substituted for light sweet crude oil with existing facilities in 1990. The respondents indicated that about 403 MB/CD of additional higher sulfur crude oil could be processed. It was necessary to remove about 464 MB/CD of sweet crude oil to make room for this high sulfur crude oil. Responses were grouped into size categories (crude oil distillation capacity) and by region. Table 4-61 describes the survey results by refinery size. Refineries with crude oil distillation capacity of 50 to 100 MB/CD generally require more sweet crudes. Table 4-62 shows crude oil flexibility by PADD. About 3.2 percent more high sulfur crude oil could be substituted by all responders as replacement for 3.7 percent of their light sweet crude oil.

Refiners were asked about restrictions to the amount of high sulfur crude oil that could be processed. Respondents were asked to rate seven potential restrictions on a subjective scale from "No Effect" to "A Great Deal." Table 4-63 summarizes the responses aggregated for the total U.S.

The most significant response was the required sulfur content of refined products. About 43 percent of respondents felt that this restriction affected the amount of high sulfur crude oils they could process "A Great Deal." Only 13 percent felt that product specifications had "No Effect." The number of respondents indicating that sulfur content of crude oils had an effect on processing was relatively uniform across all PADDs. As expected, those refineries

TABLE 4-60

SELECTED UPGRADING PROCESS UNIT CAPACITY FROM NPC SURVEY (Thousand Barrels per Stream Day)

	1/1/91 Total Operable Capacity	1/1/96 Total Operable Capacity	Anticipated Additions
Gasoil/Catalytic Cracker Feed Hydrotreating	1,745	2,022	277
Delayed Coking	1,329	1,434	105
Sulfur Plants, LT/SD	19,235	22,394	3,159

Source: NPC Survey, Section II, Part A. 154 of 199 refineries responded to the survey. Refineries responding to the above capacity questions represent almost 95 percent of 1990 crude oil inputs.

TABLE 4-61

HIGH SULFUR CRUDE OIL FLEXIBILITY BY REFINERY SIZE
(Thousands of Barrels per Calendar Day)

	<50,000	50,000-100,000	100,000-150,000	>150,000	Total
1990 Total Crude Oil Runs	1,149	2,148	2,428	6,753	12,480
% of Refineries Running Some Sweet Crude Oil	61%	91%	68%	83%	74%
Increased High Sulfur Crude Oil	28	72	95	207	403
Decreased Low Sulfur Crude Oil	27	88	126	223	464

Source: NPC Survey Section II, Part C. 154 of 199 refineries responded to the survey. These refineries represent almost 95 percent of 1990 crude oil inputs.

TABLE 4-62

HIGH SULFUR CRUDE OIL FLEXIBILITY BY PADD*
(Thousands of Barrels per Calendar Day)

	Simple	PADD I	PADD II	PADD III	PADD IV	PADD V-CA	PADD V-OC	Total U.S.
1990 Total Crude Oil Runs	498	1,038	2,743	5,468	447	1,644	642	12,480
% of Refineries Running Some Low Sulfur Crude Oil	45%	87%	96%	84%	87%	40%	86%	74%
Increased High Sulfur Crude Oil	N/A	64	127	158	17	27	6	403
Decreased Low Sulfur Crude Oil	3	89	139	170	17	32	14	464

* In each PADD, only those refineries with conversion equipment were aggregated. Simple refineries, those with NO conversion equipment were aggregated in a U.S. total. The U.S. total is the sum of all responses.

Source: NPC Survey Section II, Part C. Refineries responding to the questions represent almost 95 percent of U.S. crude oil inputs in 1990.

with crude oil capacities greater than 150 MB/CD appeared to have less problem with higher sulfur crude oils than those less than 50 MB/CD. Larger refineries tend to have multiple processing trains and more flexibility in processing options.

Modeling Methods and Results

To corroborate survey data, the Turner-Mason model was used to determine refinery equipment needs to process more high sulfur and heavy crude oils. PADD III and PADD IV refinery models were used to study the effect of

TABLE 4-63

REASONS THAT LIMIT HIGH SULFUR CRUDE OIL RUNS
(Percent of Respondents)

	None	Some	Quite a Bit	A Great Deal
Required Sulfur Content of Products	13	23	21	43
Sulfur Content of Refinery Fuels	34	27	21	18
Stationary Source Air Emission	14	28	26	32
Effluent Water Quality Requirements	29	39	21	7
Metallurgy	29	26	18	27
H_2S Recovery or Sulfur Plant Capacity	30	26	12	30
Residua Processing Capacity	25	21	17	34

Source: NPC Survey Section II, Part B. Refineries that responded to the survey represent almost 95 percent of 1990 U.S. crude oil inputs.

refinery size on investments required. Refineries in these PADDs are likely to make the investment if there is a strong economic driving force to run additional high sulfur heavy crude oils. Model runs can estimate the capital cost for desulfurization of products and conversion of heavy cuts into lighter products. They cannot reflect site specific environmental costs however. In all cases the product demand was based on full opt-in to reformulated gasoline in the year 2000 with no increase in demand. These model runs are shown in Appendix M.

In PADD III both light and heavy fuels products were held constant as the crude oil slate changed to heavier and higher sulfur. When 636 MB/CD of heavy Arabian crude oil was substituted for 580 MB/CD of light sweet domestic crude oil (about 10 percent of crude oil runs), marketable coke yield increased by 48 MB/CD, about 61 MB/CD additional vacuum residua was processed with existing coker capacity and 69 MB/CD was processed with new coking capacity. Another 20 MB/CD of cat-cracker gasoline splitting and 25 MB/CD of coker gasoline splitting were needed for further processing. The cost of this added equipment for PADD III was about $590 million. No additional hydrotreating, hydrogen, or sulfur capacity was needed. Hydrogen plants were operating at their maximum capacity. Extrapolating this result to the total U.S., the investment cost of a similar 10 percent crude oil change would be about $3 billion.

The PADD IV refinery model was forced to replace 50 MB/CD (10 percent of crude oil runs) of Montana Rebeki/Wyoming Sweet with Wyoming Platte/Sour. The processing of this additional high sulfur heavy crude oil required about 104 long tons per stream day (LT/SD) of sulfur recovery capacity to remove the additional sulfur. This is a 31 percent increase in capacity. Sulfur capacity was limiting in the base case also so additional equipment was needed to process the additional high sulfur crude oil. Existing coking throughput increased from 29 MB/CD to 38 MB/CD. No additional coking capacity was allowed due to the poor economics of very small units. The total investment cost was $69 million. However, high sulfur residual fuel oil production increased from 1 MB/CD to 4 MB/CD. Kerosene decreased from 34 MB/CD to 29 MB/CD.

California Refiners

Another crude oil quality issue is the potential decline in Alaskan North Slope (ANS) crude oil production in coming years. In recent years, almost 1.2 MMB/CD of the 1.7-1.8 MMB/CD Alaskan production has moved to U.S. West Coast refineries; small volumes were processed in Alaskan refineries, about 100 MB/CD moved to Hawaiian refineries and the remaining Alaskan crude oil moved to U.S. Gulf Coast and U.S. Caribbean refineries. Moving Alaskan crude oil to the Gulf Coast refineries requires high transportation cost, and consequently Gulf Coast refineries tend to be the marginal outlet.

In the *Annual Energy Outlook, 1990*, the EIA predicted that by the end of the decade, Alaskan oil production will fall to about 1 MMB/CD. The remaining crude oil production will most likely go first to the Alaska and Puget Sound refineries and then to Hawaii and California refineries. Therefore, as ANS crude oil volume declines, the California refineries which have processed significant amounts of ANS crude oil will likely replace those volumes with California crude oil to the extent available and imported crude oils. Existing California crude oils tend to be heavier (lower API gravity) than ANS crude oil, while some of the imported crude oil will be of a higher API gravity and lower sulfur levels than ANS.

In Section II of the NPC survey, California refineries responded to the question concerning crude oil types processed in 1990 and crude oils expected to be processed in 1995. Table 4-64 summarizes their responses. These data show that California refiners anticipate processing heavier, more sour crude oils in the future. Per the NPC survey, California refiners anticipated changes in process unit facilities consistent with the above expected changes in crude oil types. As shown in Table 4-65, some additional hydrotreating, bottoms upgrading, and sulfur handling capacity are anticipated.

Strategic Petroleum Reserve

The Strategic Petroleum Reserve (SPR), a crude oil stock pile, was created by the Energy Policy and Conservation Act of 1975 to reduce the vulnerability of the United States to the effects of a severe energy supply interruption. The SPR crude oil is stored in salt caverns in six locations along the Texas-Louisiana Gulf Coast. These sites have access by pipelines and marine terminals to the major refining centers in the country. Current inventory is shown in Table 4-66. If the United States were experiencing a severe energy supply interruption, the President could release the crude oil for sale. The Energy Policy Act of 1992 allows drawdown in emergency situations involving a supply reduction coupled with a severe price increase likely to cause a major adverse impact on the national economy. The SPR has developed storage capacity for a full 750 million barrels. At the end of 1992, there were over 575 million barrels in storage. This is equivalent to about 82 days of 1992's net crude oil

TABLE 4-64

CALIFORNIA REFINERY CRUDE OIL SURVEY RESULTS

	Actual 1990	Anticipated 1995
Total Crude Oil Input Rate, MB/CD	1,644	1,647
API Gravity	24.0	23.1
Sulfur, wt%	1.11	1.26
1050+ Resid Content, vol %	25.0	25.7

Source: NPC Survey Section II Part B for California refineries. These respondents represent over 90 percent of 1990 crude oil inputs for California conversion refineries.

TABLE 4-65

CALIFORNIA PROCESSING SURVEY RESULTS
(Thousands of Barrels per Calendar Day)

	Actual 1990	Anticipated 1995
Gas Oil Hydrotreating Capacity	499	582
Delayed Coking, Capacity	353	362
Hydrocracking Capacity	364	406
Sulfur Plant Capacity, LT/CD	3,958	4,197

Source: NPC Survey Section II, Part B. These respondents represent over 90 percent of 1990 crude oil inputs in California.

TABLE 4-66

SPR SITES AND INVENTORY AS OF DECEMBER 31, 1992

Site	Crude Oil Type*	Inventory (MMB)	API ° Gravity	Percent Sulfur
Bayou Choctaw	Sweet	15	36.1	0.39
	Sour	36	33.2	1.47
Weeks Island	Sour	72	28.9	1.41
Bryan Mound	Sweet	62	36.0	0.34
	Sour	144	33.1	1.51
	Maya	11	22.8	3.28
Big Hill	Sweet	3	36.9	0.31
	Sour	25	33.7	1.44
Sulfur Mines†	Sour	0		
West Hackberry	Sweet	105	36.9	0.31
	Sour	1000	33.7	1.44
Tanks And Pipeline Fill		3		
Total Inventory		**575**		
Total Sweet Crude		**184**		
Total Sour Crude		**391**		

* Sweet crude oil is <0.5 percent sulfur.

† Sulfur Mines is being decommissioned, and oil stored there is being moved to Big Hill.

Source: U.S. Department of Energy, Office of Strategic Petroleum Reserve.

imports. Currently, SPR distribution capability is about 3.9 MMB/CD for the first two months of a disruption, or over half of net imports. Over the course of a six-month disruption, the SPR could replace about 3 MMB/CD of lost oil supplies.

The SPR crude oil in the salt caverns is similar to the quality of crude oil currently processed in U.S. refineries. About 32 percent of SPR crude oil is sweet crude; in 1991, about 34 percent of U.S. crude oil runs were sweet crude (see Table 4-58). The nominal sulfur and gravity of SPR crude oils are similar to typical U.S. crude oil slates.

Technology Trends

Processing

Current technology can be used for the refining processing needed to make reformulated fuels. However, technology improvement is a continuous process and future incremental improvements will occur. Research and development have been ongoing for decades to identify methods for improving fuels performance and reducing cost of fuels manufacture. This effort is driven by competitive interests as well as out of concern for improving the environment. These interests will ideally result in more effective methods for the cleaner production and use of motor fuels.

Fuel Additives

Additives have been used in fuels for decades to enhance their performance. The CAAA require, beginning in 1995, that all gasolines contain additives to prevent the accumulation of deposits in engines and fuel supply systems. Additive technology breakthroughs may be possible which would improve gasoline emission performance at a lower cost than alternative processing.

Fuel Components

Ethanol and MTBE have been used in gasoline in increasing amounts over the past decade. Although the initial use of these components was beneficial to offset part of the gasoline octane decrease following the mandated lead-phasedown, it was later determined that, through their use, an environmental benefit of CO emission reductions for older cars could also be realized. To the extent that these components are independent from petroleum source inputs, the U.S. dependence on imported crude oil might be reduced. It is possible that other economically competitive non-petroleum based fuels might be developed and commercialized which are compatible with gasoline or diesel fuel and might help the United States further reduce its dependence on imported crude oil.

For a discussion of alternative fuels, see Appendix E.

Vehicle Improvements

Technology improvements in fuels and vehicle systems will yield the greatest benefit to the environment and the economy if developments consider both the fuel and the vehicle at the same time. Vehicle system improvements which should be considered in harmony with fuel improvements might include:

- Improved vehicle inspection and maintenance and on-board diagnostics
- Preheated catalyst system for cold start and relocation of catalyst closer to the engine
- Enclosed vehicle fuel and refueling systems
- "Cleaner burning" engines
- Scrappage or retrofit of older high emitting vehicles.

Economic Considerations

Although change is inevitable, steep or too frequent changes in performance requirements also can be economically inefficient. Performance requirement changes or rapid technology changes may result in the construction and abandonment of production facilities in far less time than past capital recovery practices would allow. This situation points to the need for a complete integration of establishing performance requirements based on sound science and economics in harmony with the transportation system and its fuels. This integration will have the best chance of using the nation's limited transportation and refining resources

for the most benefit at the least economic and environmental costs.

METHODOLOGY

Introduction

Four models were used to analyze U.S. refining capability. Two models are linear programming (LP) computer models used to study the U.S. refining industry's capability under varying scenarios. These are proprietary models developed by The Pace Company and Turner, Mason & Company. The Pace cost/volume model is described in Chapter Three. Its purpose was to develop light product cost and availability data for the domestic and foreign refining industries for input to the U.S. supply logistics model used by the Supply, Demand, and Logistics Task Group. The Turner-Mason refining model was used to derive most of the facility, investment, and incremental product cost information provided in this chapter.

Two additional models have been used in conjunction with both of the LP models mentioned above. These models predict the emissions performance of given gasolines based on gasoline properties. These models have been referred to as the Simple Emissions Model and the Complex Emissions Model. The simple model, described earlier in this chapter, sets limits on specific properties of reformulating gasoline for use in the 1995-1997 era. The complex model, also described earlier, is a correlation of experimental data for prediction of emissions for use primarily in the post 1997 period.

The study objectives required analyses of refinery capability and the costs of reformulating products relative to differing conditions of regulatory severity, cost effective limits, current refining complexity, and refinery size and location. A sophisticated modeling system was needed which could provide quantitative assessments of these variables. Whereas the Pace model developed the relationship of light product cost to changes in manufacturing volumes at constant product quality, the intent of the Turner-Mason model was to provide refining capability and costs for the above variables at constant demand.

Turner, Mason & Company was selected as a consulting contractor to provide its sophisticated LP refinery modeling system for these studies and to assist in developing assumptions, premises, study case designs, and analyses to meet the needs of this portion of the study. The option of selecting a consultant's model over development of a model by the study team (as has been done in some past NPC studies) was more desirable due to timely results, being cost-effective, incorporating the consultant segment of industry expertise, starting with an up-to-date base, and having continuous availability of skilled personnel to run a familiar model while incorporating the expertise of the study participants.

Modeling

Assumptions and Premises

Major assumptions and premises used for the Turner-Mason refinery model listed below.

Investment

The investment cost figures provided are based on mid-1990 dollars. Ranges were calculated for each investment case to include capital investment sensitivities from 15 percent below to 35 percent above the base investments. A 15 percent return on investment was required for any added investment in all of the refinery model cases. The capital charges (investment payback) provided in this chapter were then determined based on a 10 percent rate of return.

Existing process units were allowed to be expanded by up to 20 percent of capacity based on the same (up to 20 percent) percent of its replacement cost. This approach allows for expansions of existing capacity at a lower cost than the installation of small units as new capacity. Exceptions to this approach include MTBE units and PADD IV units. MTBE units were assumed to be new units with no expansion of existing units allowed. Due to the generally smaller size of PADD IV refineries, some sharing of units was permitted to provide for units to be of economical size. This assumption results in a lower investment than would

be the case if each refinery were to build their own smaller units.

Summer gasoline quality and quantity demands determine the refining investment required rather than winter or year-average requirements. Based on public gasoline studies (1987 API lower RVP and 1991 WSPA CARB Phase 2 gasoline studies) plus initial NPC summer and winter LP cases, facilities required to lower RVP and to meet a very low T_{90} property for reformulated summer gasoline are neither required nor used in the winter. Facilities were included in the refining model for improved gasoline debutanizing, depentanizing, TAME, C_5 alkylation, butane isomerization, and heavy gasoline hydrocracking. Required capacities of another group of units for initial T_{90} reductions and for benzene reduction are significantly larger in the summer than in the winter. The other added units are required at close to uniform capacity year round.

Refinery Product Demand Development

The approach in developing refinery product demand was to begin with U.S. consumer supply and demand scenarios prepared by the NPC Supply, Demand and Logistics Task Group. They provided three demand scenarios; demand growth, no demand growth, and declining demand relative to the 1989-1990 time frame. By assuming product imports and exports remained constant at 1989 levels, the refinery demands could then be calculated. These three refinery demand scenarios were used as the bases for all of the refinery modeling work. In all cases, ethanol was assumed constant at about 60 MB/CD blended outside of the refinery models with the exception of cases set up to study high ethanol use.

The API gravity and sulfur content of the crude oil slate were held relatively the same as 1989 actual qualities. This assumption resulted in some slack capacity in conversion units such as cat-cracking units and cokers. Sensitivity cases were used to examine changes to a heavier crude oil quality.

The Turner-Mason computer models were run to produce a required volume of all major products rather than have production based on product pricing or feedstock cost. Thus, they were "demand driven" as opposed to "cost driven." Gasoline volume was constant after adjusting for heating value. For products whose volumes were variable, 1989 *Platt's Oil Price Handbook and Oilmanac* pricing escalated to 1990 was used.

MTBE costs for 1989 were adjusted upward by 10 cpg for 1995 and 2000 to reflect current spot and five-year contract levels. These costs were readjusted back to 1989 levels for the year 2010.

Capacity Basis

To develop the capacity basis for this work, the starting point was all operable refineries as of January 1, 1991 as reported by the DOE in the *1990 Petroleum Supply Annual.* Refineries were excluded in the aggregate if they reported no inputs to the DOE in 1990. Announced shutdowns were also taken into account. In addition, capacity under construction in October 1991 or completed in 1991 was included in the base capacity figures used for 1995.

Capacity Creep

From a review of past year-to-year capacity changes of major process units, it is estimated that some of the increase is due to capacity creep, i.e., unannounced increases in capacity. For the most part, these changes result from low-cost modifications in hardware or operating procedures. Often these hardware modifications are associated with the additions of new process technologies to an existing unit. As part of the unit upgrade, some modest capacity debottlenecking is made that is not publicly announced.

In addition to unannounced additions to process unit capacities, there have been gradual increases over time in light product yields per barrel of charge at the expense of by-products. These have come about primarily due to advances in technology: process, hardware, better catalysts, and more efficient operating procedures. Increased light product yields have the same effect as capacity increases, at

constant demand, capacity utilization decreases.

With the advancing age of most refineries, this trend of capacity creep has slowed down in recent years and most units have already undergone any potential low-cost debottlenecking. In addition, there will likely be some unannounced unit shutdowns in the future. It was assumed for this study that any future capacity creep will be offset by future shutdowns.

Reformulated Gasoline Specifications

There are two basic sets of specifications or limits concerning reformulated gasoline. For 1995, limits were set on specific items such as benzene content and RVP. The 1997 and beyond emissions guidelines were set for volatile organic compounds, toxic air pollutants, and oxides of nitrogen. Equations, i.e., the complex emissions model, are to be provided by the EPA to allow refiners some flexibility to meet these guidelines. The complex emissions model used for the bulk of the work is based on work published at the time of the EPA 4/92 SNPRM. Later versions of the complex model were published, the most recent in February 1993. These were evaluated outside the computer model structure using gasoline properties driven by the 4/92 complex model. As of this writing, a final complex emissions model has not been published by the EPA.

For the simple model, compliance margins were included to assure that each specification would be met when considering the test method involved. For example, if an RVP specification was set at a level of 8.0 psi, maximum, then the model would blend to a level of 7.7 psi to assure product compliance. The difference in these two figures, 0.3 psi, is the compliance margin.

Spillover

For estimating the volume of reformulated gasoline to be produced by the U.S. refining industry, a 10 percent spillover figure was used in the Turner-Mason model runs. That is, in areas requiring reformulated gasoline, the RFG volume was increased by 10 percent to allow for imperfect ability to supply specific markets.

For 1993 on-highway diesel fuel, a spillover of 50 percent was used in the Turner-Mason computer runs to account for possible underreporting of on-highway diesel volumes and for those refineries that choose to sell a single product rather than deal with two products throughout their distribution systems. Subsequent to the computer runs, a decision was made to present the 1993 ultra-low sulfur diesel fuel results using no spillover volumes. The completed refinery model results were adjusted for use in the final presentation.

JP-8

In all cases, 1989 volumes of JP-4 jet fuel were assumed to be replaced by JP-8 by 1995 and beyond.

Leaded Gasoline

For purposes of this study, it was assumed that no leaded motor gasoline remained in the United States by 1995 and beyond.

Additional Detail

Additional detail on these and other assumptions/premises may be found in the Turner-Mason "A" tables in Appendix M.

Seasonality

Summer and winter were assumed to be 6 months each. Most of the analysis was done on summer cases.

Modeling Specifications

For the Pace model, the NPC established modeling specifications for gasoline and diesel fuel that represent average product quality manufactured by an aggregate of refineries to meet the CAAA requirements. Tables 4-67 and 4-68 detail the NPC modeling specifications for 1995 and 2000. For Phase II RFG in 2000, the gasoline specifications used were developed using the Turner-Mason refining models by determining the break point in the cost/VOC emission reduction curve at which the incremental cost per ton of VOC emission reduction was equal to the proposed cost-effective limit of $10,000 per summer ton.

California Air Resources Board Phase 2 RFG specifications are summarized in

TABLE 4-67

NPC GASOLINE SPECIFICATIONS FOR PACE MODELING PURPOSES — 1995

	NPC Premised Compliance Margins*	U.S. Specifications†		
		Reformulated Gasoline	Conventional Gasoline	Oxygenated Gasoline
RVP, psi, max				
Summer – Northern	0.3	8.1	9.0‡	–
– Southern	0.3	7.2	9.0‡	–
– California	0.3		7.8	
Winter	0.3	B§	B§	B§
Benzene, vol%, max	0.3	1.0	B§	B§
Oxygen, wt%, min	0.1	2.0	–	–
wt%, min/max	0.2	–	–	2.7
Olefins, vol%, max	2.5	B§	125%B¶	125%B¶
Aromatics, vol%, max	2.7	27.9#	B §	B§
Sulfur, ppm, max	20	B§	125%B¶	125%B¶
T_{50} ° F, max	5	-	-	-
T_{90} ° F, max	5	B§	125%B¶	125%B¶
Octane, [(R+M)/2], min	0.1	B§	B§	B§

* Compliance margins are not included in the specifications, but were used to set LP modeling targets.

† Compliance margins not included in Reformulated Gasoline, Conventional Gasoline, and Oxygenated Gasoline columns.

‡ RVP specification is 9.0 psi max for Southern and Northern in attainment areas. Southern gasoline specification is 7.8 psi in nonattainment areas; Northern is 9.0 psi.

§ B = Base 1989-90 property levels.

¶ Antidumping (does not apply to exported gasoline but does apply to imports). Average levels of sulfur, olefins, and T_{90} in the non-RFG pool shall not exceed 125 percent of base year. In addition, there shall be no increase in non-RFG pool benzene exhaust emissions from the base year. For modeling purposes, the base year is 1989 rather than 1990.

\# Maximum aromatics content assuming RVP, oxygen, and benzene are met on a per-gallon basis; with averaging for aromatics and toxics reduction. Based upon EPA 1991 draft complex model toxics equation. Compliance margin does not apply.

TABLE 4-68

NPC GASOLINE SPECIFICATIONS FOR PACE MODELING PURPOSES 2000-2010

	NPC Premised Compliance Margins*	U.S. Specifications†			
		Reformulated Gasoline	Conventional Gasoline§	Oxygenated Gasoline§	CARB Phase 2‡
RVP, psi, max					
Summer – Northern	0.3	6.9	9.0¶	-	-
– Southern	0.3	6.9	9.0¶	-	-
– California	0.3	-	-		7.0
Winter	0.3	B#	B#	B#	B#
Benzene, vol%, max	0.3	1.0	B#	B#	0.8
Oxygen, wt%, min	0.1	2.0	-	-	
wt%, min/max	0.2	-	-	2.7	2.0
Olefins, vol%, max	2.5	B#	B#	B#	4.0
Aromatics, vol%, max	2.7	25.0	B#	B#	22.0
Sulfur, ppm, max	20**	200	B#	B#	30
T_{50} ° F, max	5	210	-	-	200
T_{90} ° F, max	5	330	B#	B#	290
Octane, [(R+M)/2], min	0.1	B#	B#	B#	B#

* Compliance margins are not included in the specifications, but were used to set LP modeling targets, depending on the particular case evaluated.

† Compliance margins not included in Reformulated Gasoline, Conventional Gasoline, Oxygenated Gasoline, and CARB Phase 2 columns.

‡Specifications shown are for averaging. If refiner meets requirements on a per-gallon basis, then specifications are: olefins = 6.0 vol%, sulfur = 40 ppm, aromatics = 25.0 vol%, benzene = 1.0 vol%, T_{50} = 210 ° F, and T_{90} = 300 ° F.

§ Antidumping (does not apply to foreign gasoline supplies). There shall be no increase in the non-RFG pool exhaust toxics and NOx as determined by the complex model, relative to the base year. For modeling purposes, base year is 1989.

¶ RVP specification is 9.0 psi max for Southern and Northern in attainment areas. Southern gasoline specification is 7.8 psi in nonattainment areas; Northern is 9.0 psi.

B = Base 1989-90 property levels.

** Sulfur compliance margin drops to 10 ppm with the CARB 2 limit of 40 ppm for every gallon.

Table 4-68. The specifications for CARB Phase 2 gasoline in the 2000-2010 time period are significantly lower for olefins, aromatics, sulfur, and T_{90} than those used for the NPC modeling of federal Phase II RFG.

Refinery Linear Program Models

The assessment of refinery capability and costs included the use of mathematical models of the refining industry as a means of quantifying differences under a variety of operating conditions. The U.S. industry was simulated through LP models of six regional conversion refineries. These were supplemented by a single material balance simulation to portray the simple refineries of all the geographical regions except for those simple refineries in the Rocky Mountain region (PADD IV), which were included with the PADD IV conversion refineries. This division was done to lessen the over-optimization that tends to occur with the use of aggregate models due to the logistically improper transfer of intermediate product streams. The selection of the Turner-Mason modeling system also reduced this over-optimization in that this system has been extensively calibrated and adjusted to historical standards in a number of recent industry studies.

It has been the practice in previous similar NPC studies to calibrate the refinery models to validate their use. Validation was curtailed for this portion of the current NPC study as a review of recent validations of the Turner-Mason models—Auto/Oil Study, WSPA Study, API RVP Reduction Study and the previous 1986 NPC study—coupled with an industry capacity review that portrayed only slight changes in refinery capacities indicated that validation would not significantly improve the study's results. Process unit investment estimates and stream factors were updated for this study through a review of the contractor data. Process unit investment was also checked and coordinated with the values proposed by The Pace Consultants and the Bechtel Corporation, two other contractors participating in the total NPC study.

New to the contractor's modeling system for this study has been the addition of both the simple and complex emissions models as part of the Turner-Mason LP optimization. All year 2000 optimizations were done with the 4/92 complex emissions model as part of the solution.

This complex model has two parts that include a correlation of the available data on exhaust emissions and assume the use of the EPA MOBILE4.1 model for non-exhaust emissions. The logic of using the 4/92 exhaust model as a surrogate for subsequent models is that later models would be based on the same basic data and further statistical analysis should not change the emission predictions radically. Further, the change in predicted performance between reformulated gasolines of differing severities should be consistent when calculated by complex models derived from the same data. The non-exhaust model portion of subsequent complex models used MOBILE5.0.

Case studies were done on specific gasoline properties to reflect changes seen when going from the 4/92 to the 2/93 EPA complex model proposal. Gasoline olefin content in particular was studied due to its greater role in NOx emissions when using the EPA 2/93 complex model.

Optimization of the LP refinery models provided a minimum cost solution to meet the set constraints of emission standards or product properties and to meet fixed light product demand. Variables were process unit utilization including additional capacity, process unit severities, and limited crude oil selection. Crude oil slates were set to match the historical quality and sources for each PADD model by mixing representative crude oil assays from the contractor library. Flexibility was provided by allowing input of limited amounts of specific crude oils to vary, along with MTBE, methanol, natural gasoline, purchased butanes, and natural gas feed for hydrogen manufacture. All other raw materials were held constant at 1989-1990 levels. Because the solutions were demand-driven, the 1989 crude oil and product prices (mid-1990 dollars) supplied to the models were considered in the solution but the results were relatively insensitive to product price. The use of the prices provided reasonable levels of LP shadow values used for evaluating constraints.

Also new to the modeling system were a number of additional processing options for

control of gasoline properties which affect emission performance. A list of these is provided in Table A-4 of Appendix M.

Regions were selected for the aggregate LP models and correspond to the Petroleum Administration for Defense Districts defined by the DOE. The six individual LP refinery models were named to agree with the PADD region plus an indication that only conversion (C) refineries were included. The West Coast (PADD V) refineries were split into two models, one for California and one for the West Coast outside of California. California refinery operations are unique because of its heavy, high-nitrogen naphthenic crude oil slate and because in this period of analysis California refineries are regulated by the more stringent CARB requirements rather than those of the CAAA. On the other hand, the West Coast aside from California has relatively few nonattainment areas, particularly for ozone and correspondingly less product regulation.

The geographical relationship of the PADD models is as follows:

PADD IC	East Coast
PADD IIC	Midwest
PADD IIIC	Gulf Coast
PADD IV	Rocky Mountains
PADD VCC	California
PADD VCOC	Outside California (Northwest)

Because individual refinery flow schemes and raw material supplies differ from the aggregate average refinery, some reservations regarding absolute values should be assumed in reviewing results. However, the geographical models do provide some insight as to differences due to configuration or supply. The PADD IIIC model is more complex than other East of Rockies models. PADD VCC is most complex due to product slates and to crude oil quality. PADD IV is typical of a small refinery. PADD IC operations represent a high percentage of reformulated product demand.

Base Case Development

The NPC survey provided guidance for development of some of the data base for the LP models. However, baseline 1990 operations were the 1989 and 1990 actual DOE detailed U.S. refinery supply and demand information sorted into the specific PADD model groupings. Forecast refinery product demand assumed the consumer demands of the Supply, Demand, and Logistics Task Group less the import/export amounts provided by the DOE data. Gasoline type demand, e.g., RFG, OG, CG, etc., was developed for each regional model using API research study #58, "Meeting the Oxygenate Requirements of the 1990 Clean Air Act Amendments." Initial gasoline demand estimates by types assumed conventional gasoline energy content. Finished gasoline manufacture was adjusted to maintain constant vehicle miles traveled with the lower BTU content, higher or lower specific gravity, and higher oxygen content RFG and OG. Individual model gasoline component properties were those provided by a 1989 National Petroleum Refiners Association survey. This data source also provided 1990 summer individual base gasoline properties used for measuring conventional gasoline performance in forecast years. The industry statutory baseline summer gasoline properties of the CAAA were used for measuring RFG performance.

Time Frames Studied

Case studies using the various regional refinery models were developed for CAAA analysis:

- 1995 assuming low sulfur and low aromatics diesel and No. 2 fuel oil. Application year, 1993.
- 1995 using the simple model for gasoline and RFG supplied to the nine cities classified as severe in ozone nonattainment.
- 1997 using both the simple and complex models for gasoline and full opt-in for RFG.
- 2000 using the complex model for gasoline and full opt-in for RFG.
- 2000 using CARB Phase 2 regulations for gasoline.
- 2010 using the complex model for gasoline.

CHAPTER FIVE

NPC SURVEY

In 1990, the U.S. Secretary of Energy requested the National Petroleum Council to assess the effect of changing conditions on the U.S. refining industry. In response to this request, the NPC undertook a comprehensive, industry-wide study. The overall purpose of the study was to assess the U.S. refining industry's capability to meet future product demand when considering environmental trends of the 1990s. The impact of the Clean Air Act Amendments of 1990, other legislation, and current and anticipated future regulations affecting both the composition of motor fuels, air, water, and solid waste emissions from refineries, and refinery safety and health have all been considered. A major component of the study was a comprehensive survey of industry operations.

SURVEY DEVELOPMENT

In 1979 and 1985, the NPC conducted surveys of U.S. refining industry operations. These early surveys focused primarily on process unit capabilities, throughputs, product yields, energy consumption, and financial data. In order to obtain a better understanding of the potential impact of the Clean Air Act Amendments and other regulations on the U.S. refining industry, the NPC determined that a more extensive survey was necessary for this study.

The survey was designed to include all U.S. refineries, including refineries located in U.S. territories in the Caribbean, pipeline operators, terminal operators, motor gasoline blenders, and companies with U.S. offices doing business in foreign countries. The aggregated survey results provided data for industry modeling and analysis for both 1990 and 1995. Survey results from pipeline and terminal operators and blenders were used to evaluate the effects of regulatory requirements and changes in product mix and quality on the logistical systems, including terminals, used to supply petroleum products. Survey results from companies doing business in foreign countries were used to assess the future product quality and major refined product production in foreign countries. This is the first time that the NPC has surveyed foreign companies on their operations in other countries.

Questionnaire Development

The NPC retained SRI International (SRI) to format the survey questionnaires, and to protect the confidentiality of the survey data by collecting and tabulating the survey data and providing only aggregated data to the NPC study participants. Questionnaire development took place in the summer of 1991. The task groups were responsible for determining the data needed. Data requirements were then put into questionnaire format. The questionnaires were reviewed and revised by the respective task groups and then pretested with seven refining companies. The questionnaires were

revised as a result of the pretests to resolve any ambiguities that were found.

Survey Description

The final questionnaire consisted of 10 sections, each bound separately, covering the issues outlined below. (Copies of the questionnaire are included as Appendix N to this report.)

I. Perceptions of Regulatory Impacts on Individual Refineries (Perceptions) *in 1995 and 2000.*

II. Refinery Facilities — Capabilities and Utilization, Feedstocks, and Product Yields (Refinery Capabilities), *actual 1990 data and projected for 1995.*

III. Refinery Emission Sources and Controls (Emissions), *including waste sources and quantities.*

IV. Economic Impacts of Environmental Regulation on Refineries (Economic Impact), *both historical and anticipated costs.*

V. Distribution and Transport Mode of Products from Refineries (Distribution), *actuals for 1990 and projected for 1995.*

VI. Corporate Supply and Distribution of Oxygenates (Oxygenates) *expected in 1995.* (Slightly different versions of this section were produced for refiners and for blenders.)

VII. Issues Concerning Terminals for Terminal Operators (Terminals), *including supply of product, capacity, and environmentally related costs.*

VIII. Issues Concerning Clean Product Pipelines for Pipeline Operators (Pipelines), *including capacity, product segregation, and costs.*

IX. Tanker, Barge, Rail, and Truck Transport Costs (Transportation Costs).

X. Foreign Refinery and Supply Issues (Foreign), *including likely product qualities in foreign countries in 1995 and 2000.*

Sections I through V were refinery-specific; Sections VI through IX asked for corporate-wide responses; and Section X, for the most part, asked for information about entire countries.

Potential Survey Respondents

Potential respondents to the survey were identified through lists of refiners, terminal operators, pipeline operators, and blenders provided by the Energy Information Administration. These lists were modified by the NPC to include other potential respondents, including a separate list of companies likely to have knowledge pertaining to foreign data and trends. Companies on this list without U.S. refineries received only the section of the survey dealing with foreign issues. The list of recipients of the survey sections is available as a working paper to this report.

Data Confidentiality

As noted above, individual company data from the survey were held strictly confidential by SRI. None of the individual responses have been released nor will they be released to government, study participants, or NPC staff. The only staff who had access to the data were SRI's Survey Research Program staff and two engineers who assisted survey staff in reviewing questionnaires and contacting respondents to clarify information. Each of these individuals signed confidentiality agreements with the NPC to not divulge any company-specific information that was received during the project. SRI released the aggregated data to NPC study participants only when sufficient data were available to permit aggregation in a manner that would not disclose an individual refinery's or individual company's responses. Upon completion of this study, the individual responses were destroyed.

Data Collection

In October 1991, an advance notice letter was sent to the Chief Executive Officers of potential survey respondent companies. The letter informed them of the purpose of the study, stressed the importance of participation, and requested the designation of a contact person

for the survey. A copy of this notice letter is in Appendix N.

The survey was mailed during the last week in November 1991, and responses were requested by January 31, 1992. A separate blender survey questionnaire was mailed to potential respondents identified by the EIA.

All refining companies were sent copies of Sections I through V for each of their refineries, plus corporate-wide copies of Sections VI through IX (and, in some cases, Section X). Blenders, terminal operators, and pipeline operators were sent copies of sections that applied.

Follow-up activities included letters and telephone calls made by SRI and study group participants to encourage response. An emphasis to solicit responses from the smaller refiners was made because the NPC wanted maximum response from all sectors of the industry.

Data Processing

As the questionnaires were received, SRI reviewed them for reasonableness and internally consistent responses. SRI was provided data range limits by the NPC, for guidance in screening responses. All data were entered into a computer file and then were subjected to consistency checks. Respondents were contacted to resolve difficulties as necessary. In situations in which inconsistencies, out-of-range, or otherwise inexplicable responses could not be resolved, the data were omitted.

Data Tabulations and Aggregations

Survey data from the specific sections were aggregated, as required, by Petroleum Administration for Defense District (PADD), NPC region, size/complexity, and major versus independent refiners. The questions in Sections V through VIII concerned activities in each of the 13 NPC regions. Within the limitations required to maintain confidentiality, aggregations were tabulated for each section as shown in Table 5-1. Figure 5-1 shows the United States by PADD and by NPC region.

To protect respondent confidentiality, no results were produced that contained fewer than three responses (rule of three). Cells that failed this criterion were treated as follows:

- If the aggregations were by refinery size or region, the responses often were combined with other cells (e.g., responses from two or more contiguous size-groups or contiguous regions were combined).
- If the aggregations could not be combined logically with other cells, the responses were included only in the total. When this occurred other data were suppressed also so that the data in question could not be determined by difference.
- In one instance, several pipeline companies agreed to waive the "rule of three."

Survey Response

A total of 154 refineries completed and returned Sections I (Perceptions) and II (Refinery Facilities) of the questionnaire. These refineries represented almost 95 percent of 1990 crude oil runs. Slightly smaller percentages of those surveyed (71 to 75 percent) completed and returned Sections III (Emissions), IV (Economic Impact), and V (Distribution). Response rates for Sections VI through IX were approximately 50 percent. The response rate for Section X (Foreign) was 71 percent. Table 5-2 presents the survey response rates by survey section.

SURVEY RESULTS BY SECTION

This section of the report highlights responses and significant observations by survey section. Responses concerning 1995 and 2000 were based on the respondents' anticipation of "what the world will be like in the future" as of late 1991 and early 1992. These anticipations may differ from modeling results. In addition to the aggregated response to each survey question, the number of respondents to that question is shown.

Section I: Perceptions of Regulatory Impacts on Individual Refineries

The perceptions questionnaire asked refineries to rank various regulatory requirements as to the impact on the refinery in the years 1995 and 2000. The ranking was done on

TABLE 5-1

SUMMARY OF SURVEY AGGREGATION BY SECTION

Section	Total U.S.	NPC Region (See Figure 5-1)	4 Crude Oil Distillation Capacities*	9 Crude Oil Distillation Capacities†	Location/ Complexity‡	Majors/ Indepen-dents	Foreign Region §
I. Perceptions	X		X		X	X	
II. Refinery Capabilities	X		X		X		
III. Emissions	X			X			
IV. Economic Impact	X			X			
V. Distribution	X	X					
VI. Oxygenates	X	X					
VII. Terminals		X					
VIII. Pipelines		X					
IX. Transportation Costs	X						
X. Foreign							X

* 1. 50,000 or fewer B/SD
2. 50,001-100,000
3. 100,001-150,000
4. More than 150,000

† 1. 10,000 or fewer B/SD
2. 10,001-25,000
3. 25,001-50,000
4. 50,001-75,000
5. 75,001-100,000
6. 100,001-150,000
7. 150,001-200,000
8. 200,001-300,000
9. More than 300,000

‡ 1. Simple
2. PADD I Conversion
3. PADD II Conversion
4. PADD III Conversion
5. PADD IV Conversion
6. California Conversion
7. PADD V (ex. Cal. Conv.)
8. Caribbean

§ 1. North Europe
2. Mediterranian
3. Middle East
4. Far East
5. Canada
6. Other Non-U.S. Western Hemisphere

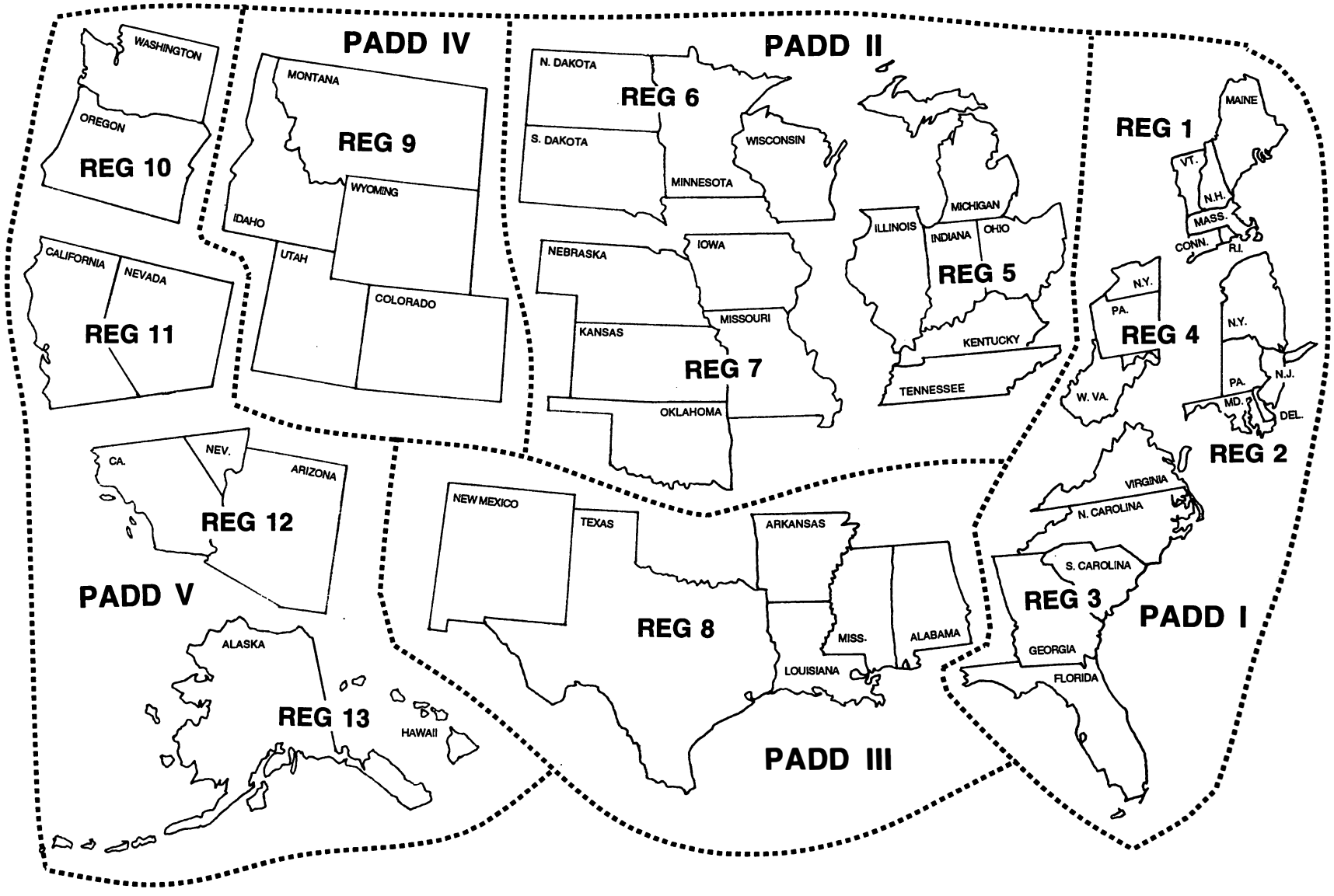


Figure 5-1. U.S. Regions–National Petroleum Council Refining Study.

TABLE 5-2

SURVEY RESPONSE BY QUESTIONNAIRE SECTION

	Survey Section	Number Sent	Not Applicable*	Potential Respondents	Number of Responses	Response Rate†
I	Perceptions	217	20	197 refineries	154	78%
II	Refinery Capabilities	217	18	199 refineries	154	77%
III	Emissions	217	18	199 refineries	151	76%
IV	Economic Impact	217	19	198 refineries	142	72%
V	Distribution	217	29	188 refineries	133	71%
VI	Oxygenates	303	73	230 companies	116	50%
VII	Terminals	335	86	249 companies	118	47%
VIII	Pipelines	135	59	76 companies	34	45%
IX	Transportation Costs	115	29	86 companies	42	49%
X	Foreign	56	11	45 companies	32	71%

* "Not Applicable" responses included respondents who reported that they did not operate during 1990 and were not anticipating operation in the future.

† "Response Rate" was calculated as the "Number of Responses" divided by the "Potential Respondents."

Notes:

1. Two refineries anticipated shutdown between 1991 and 1995, accounting for 20 "non-applicable" responses for Survey Section I as compared to 18 for Survey Section II.
2. The 199 Potential Respondents for Survey Section II include 6 refineries in U.S. territories in the Caribbean and 6 operating refineries that did not process crude oil. These 12 refineries account for the difference between 199 and the total of 187 refineries reported in the Refinery Facilities section of the NPC study.

a qualitative basis, with responses on a 4 point scale with "none" = 0, "some" = 1, "quite a bit" = 2, and "a great deal" = 3. Responses to this section were received from 154 of the 197 potential respondents.

Note that the results of this survey section are, in some cases, not completely consistent with responses to other questionnaire sections. The NPC believes that these differences are a result of (1) the non-qualitative aspects of the questions, (2) the likelihood of different individuals filling out various sections for the same refinery, and (3) a different number of respondents.

Concerning financial impacts of regulation, respondents anticipate the costs of regulations and environmental controls for refineries to have a greater financial impact than changes in product specifications for gasoline and diesel fuel in 1995 (see Table 5-3). For the period between 1996 and 2000, respondents cited costs for refinery compliance with environmental regulations as having a greater financial impact than changing product specifications. Responses showed an increase in the financial impact of changing motor gasoline specifications from 1995 to 2000 (see Table 5-3).

Concerning the impact on meeting customers' requirements for product supply, the survey results indicate that difficulties in obtaining construction and operating permits and difficulties in meeting product quality specifications are expected to have the greatest impact on meeting customers' supply requirements between now and 2000 (see Table 5-4).

For the 57 refiners that indicated that they expect to produce reformulated gasoline in 1995, the primary strategy/action anticipated to meet reformulated gasoline (RFG) specifications is to purchase oxygenates (see Table 5-5).

Section II: Refinery Facilities — Capabilities and Utilization, Feedstocks, and Product Yields

Section II of the survey reviews current (1991) and anticipated (1995) refinery unit capabilities (Part A), refinery inputs (Part B), and refinery yields by product for each U.S. refinery (Part C). Actual 1990 input and production data and anticipated 1995 data are represented. Due to differing numbers of respondents to certain questions, varying respondents to certain parts of certain questions, and data suppressed for confidentiality reasons, some inconsistent answers to similar questions resulted.

After adjusting for "non-applicable" returns, there were a total of 199 refineries in the United States and its Caribbean territories with operable capacity as of January 1, 1991. Table 5-6 presents the survey response rate among these 199 refineries by crude oil capacity. This table shows that about two-thirds of the refineries with capacity of 50 or less thousand barrels per stream day (MB/SD) and over 90 percent of larger refineries responded to the survey. This represents nearly 95 percent of the crude oil distillation capacity in the United States.

Table 5-7 summarizes survey response by refinery complexity. Complex refineries are defined as those with catalytic cracking, coking, or hydrocracking capability. Table 5-8 summarizes the same responses by PADD.

Caribbean Refining

Only limited specific information for Caribbean refineries is available from the survey due to confidentiality limitations. Four of six refineries responded to the survey, and in many instances the "rule of three" precluded survey answers from being available. Nonetheless, some important observations can be made:

- Utilization of Caribbean crude oil distillation units for respondents is expected to increase from less than 70 percent to over 80 percent (see Table 5-9).
- Caribbean refinery respondents expect to produce 174 thousand barrels per calendar day (MB/CD) of gasoline in 1995.

U.S. Refining (Excluding Caribbean)

For comparative purposes, the following data exclude Caribbean refineries. As a function of U.S. refinery capacity, responses represent about 95 percent of January 1, 1991 crude

TABLE 5-3

SURVEY RESPONDENTS' PERCEPTIONS OF THE FINANCIAL IMPACT OF VARIOUS REGULATORY REQUIREMENTS ON INDIVIDUAL REFINERIES

	1995		2000	
Regulatory Requirements	**Number of Responses**	**Mean* Response**	**Number of Responses**	**Mean* Response**
Motor Gasoline				
Reduction in RVP	148	1.8	146	1.8
Additional Oxygenates	148	1.7	146	1.6
Reduction in VOC	148	1.7	145	2.1
Air Toxic Requirements	148	1.5	146	2.0
Reduction in Benzene	148	1.5	NA	NA
Reduction in Sulfur Content	148	1.2	146	2.0
Additional State/Local Laws	148	1.2	146	1.3
Diesel Fuel				
Reduction in Sulfur Content	150	2.1	148	1.5
Reduction in Aromatics	NA	NA	148	1.7
Additional State/Local Laws	150	0.9	148	1.0
Facilities				
OSHA Requirements	150	2.3	148	2.0
Air Emissions (Pollutants)	150	2.1	149	2.1
Air Emissions (Toxics)	150	2.1	149	2.2
RCRA Requirements	149	2.1	148	2.1
Remediation (Soil/Water)	148	2.1	148	2.1
Waste Water Quality	149	1.9	149	1.9
Additional State/Local Laws	149	1.7	148	1.8

* Mean Response – Based on a 4 point scale where None = 0, Some = 1, Quite a Bit = 2, and A Great Deal = 3. Have No Idea responses were not used.

NA = Not Applicable.

TABLE 5-4

SURVEY RESPONDENTS' PERCEPTIONS OF THE SUPPLY IMPACT OF VARIOUS REGULATORY REQUIREMENTS ON INDIVIDUAL REFINERIES

	1995		2000	
Regulatory Requirements	**Number of Responses**	**Mean* Response**	**Number of Responses**	**Mean* Response**
Obtain Construction Permits	146	1.6	144	1.7
Meet Product Quality Specs	150	1.6	148	1.7
Product Quality Enforcement	150	1.4	148	1.5
Facility Emissions Regulations	150	1.4	148	1.4
Facility Emissions Enforcement	150	1.2	148	1.6
Facility Safety Regulations	150	1.2	148	1.3
Facility Safety Enforcement	150	1.2	148	1.3

* Mean Response – Based on a 4 point scale where None = 0, Some = 1, Quite a Bit = 2, and A Great Deal = 3. Have No Idea responses were not used.

oil distillation capacity and included about 90 percent of major process unit capacity as shown on Table 5-10. Table 5-11 shows a summary comparing key respondent information for 1990 with totals for U.S. refinery operations as published by the EIA.

Part A — Capabilities and Utilization

Part A of Section II reviews the unit capacities and throughputs as reported in the survey. Capacities are as of January 1, 1990, January 1, 1991, and January 1, 1996, and throughputs are for calendar years 1990 and 1995.

Atmospheric Crude Oil Distillation

Between January 1, 1991, and January 1, 1996, it is anticipated that a net eight crude oil units will be shut down. This does not necessarily mean that eight refineries will shut down. Crude oil capacity will remain essentially unchanged at about 14,800 MB/SD. Crude oil runs are anticipated to increase approximately 750 MB/CD, with an overall utilization increase from 85 percent in 1990 to 90 percent in 1995 (see Table 5-12).

Hydrotreating

By 1996 there will be a net increase of 49 hydrotreating units in the United States. Naphtha hydrotreating capacity remains essentially unchanged. Gas oil/FCC feed and residual fuel capacity will see modest increases. Distillate hydrotreating capacity will see a large increase of 32 percent or 870 MB/SD capacity (see Table 5-13). This capacity is anticipated to be the response to lower sulfur diesel requirements.

Other anticipated significant changes are:

- A 140 percent increase in PADD II distillate hydrotreater throughput and a 60 percent increase in kerosene/kerosene-type jet fuel throughput

TABLE 5-5

STRATEGIES/ACTIONS FOR PRODUCING REFORMULATED GASOLINE IN 1995* (Responses of those Refineries that Expect to Produce Reformulated Gasoline in 1995)

Strategies/Actions	Number of Responses	Mean† Response
Buy Oxygenates	57	2.4
Build New Process Facilities	57	2.0
Modify Existing Process Units	57	1.9
Buy, Sell, Exchange Finished Gasoline	57	1.8
Statistical Quality Control	57	1.8
Shift Boiling Ranges to Distillates	57	1.6
Make Oxygenates	57	1.4
Eliminate Midgrade Gasoline	57	1.4
Realign Distribution System	57	1.3
Buy, Sell, Exchange Blendstocks	57	1.3
Increased Quality Giveway	57	1.2
Increased Tankage	57	1.2
Use Credit Trading/Averaging	57	1.2
Rework Off-Spec Product	57	1.0
Adopt RFG Specs for Conventional Gasoline	57	0.9
Reduce Throughputs on Process Units	57	0.9
Produce Gasoline Subgrades	57	0.7
Blocked Production of RFG	57	0.7
Withdraw from Selected Markets	57	0.4
Shut Down Marginal Process Units	57	0.3
Produce Only One RFG Grade	57	0.2

* These refineries represent about 65 percent of the 1990 EIA crude oil inputs.

† Mean Response based on a 4 point scale where None = 0, Some = 1, Quite a Bit = 2, and A Great Deal = 3. Have No Idea responses were not used.

TABLE 5-6

RESPONSES BY CRUDE OIL DISTILLATION CAPACITY*
(Barrels per Stream Day)

Crude Oil Capacity	Potential Responses	Number of Responses	Numeric Response Rate	Percentage of 1/1/91 EIA U.S. Operable Crude Oil Distillation Capacity
50,000 or less	99	63	64%	10%
50,001 to 100,000	42	36	86%	16%
100,001 to 150,000	24	22	92%	18%
More than 150,000	34	32	94%	51%
Total	**199**	**153**	**77%**	**94%**

* Includes U.S. Territories in the Caribbean.

TABLE 5-7

RESPONSES BY REFINERY COMPLEXITY

Type	Potential Responses	Number of Responses	Numeric Response Rate	Percentage of 1/1/91 EIA U.S. Operable Crude Oil Distillation Capacity
Simple	66	35	55%	17%
Complex	133	119	89%	77%
Total	**199**	**154**	**77%**	**94%**

TABLE 5-8

RESPONSE BY PETROLEUM ADMINISTRATION FOR DEFENSE DISTRICTS

Area	Potential Responses	Number of Responses	Response Rate
PADD I	21	18	86%
PADD II	40	32	80%
PADD III	68	52	76%
PADD IV	18	15	83%
PADD V	46	33	72%
Caribbean	6	4	67%
Total	**199**	**154**	**77%**

TABLE 5-9

CARIBBEAN REFINERIES

	1990	1995	Increase/ (Decrease)
Crude Oil Distillation Capacity, MB/SD	639	639	0
Average Gross Feed Rate, MB/CD	436	525	89
Crude Oil Unit Utilization, %	68%	82%	14%

TABLE 5-10

COMPARISON OF JANUARY 1, 1991 REFINERY CAPACITY NPC SURVEY AND EIA DATA*
(Thousands of Barrels per Stream Day)

	Survey Response	EIA† Total	Percent of Respondents
Operable Crude Oil Distillation	14,820	16,557	90%
Fluid & Delayed Coking	1,512	1,629	91%
Catalytic Cracking	5,156	5,559	93%
Catalytic Hydrocracking	1,177	1,308	90%
Catalytic Reforming	3,649	3,926	93%

* Excludes Caribbean.

† From Energy Information Administration *Petroleum Supply Annual, 1990*, Volume 1, Table 38, "Capacity of Operable Petroleum Refineries by State as of January 1, 1991."

- A 44 percent increase in PADD III distillate hydrotreater throughput
- A 30 percent decrease in PADD V-CA distillate hydrotreater throughput, which appears to be offset by an equivalent increase in kerosene/kerosene jet blendstock capacity.

Aromatics Saturation

It is anticipated that between 1990 and January 1, 1996, 11 new aromatics saturation units will start up. Ten of those units appear to be light naphtha/gasoline units. It is likely that these units are in response to reformulated gasoline requirements to reduce benzene.

Coking

It is anticipated that there will be a 130 MB/SD or 10 percent increase in delayed coking capacity with a net increase of three units. Fluid coking capacity remains essentially constant.

Fluid Catalytic Cracking

Fluid catalytic cracking capacity is anticipated to remain essentially unchanged at about 5,200 MB/SD. Average utilization will increase from 84 percent in 1990 to 90 percent in 1995 (see Table 5-14). Many refineries appear to be planning an increase in C_3/C_4 olefin recovery; likely in response to RFG requirements.

TABLE 5-11

COMPARISON OF SURVEY RESPONSE TO EIA DATA FOR 1990 REFINERY TOTAL INPUT AND PRODUCTION*
(Thousands of Barrels per Calendar Day)

	Survey Responses	EIA† Total	NPC Percent of EIA
Refinery Inputs			
Crude Oil	12,480	13,409	93%
Other Inputs‡	1,280	1,180	108%
Total Inputs	**13,760**	**14,589**	94%
Refinery Production			
Total Motor Gasoline	6,483	6,959	93%
Kerosene-Type Jet	1,237	1,311	94%
Distillate Fuel Oil	2,529	2,925	86%
Residual Fuel Oil	745	950	78%
Asphalt & Road Oil	373	449	83%
Other Products‡	2,769	2,680	103%
Total Production	**14,137**	**15,272**	93%

* Excludes Caribbean.

† Energy Information Administration, *Petroleum Supply Annual 1990*. Table 16, "Refinery Input of Crude Oil and Petroleum Products." Table 17, "Refinery Net Production of Finished Petroleum Products."

‡ Other Inputs and Other Products represent the "net" value of production less inputs for numerous products.

Note: Totals may not add due to independent rounding.

TABLE 5-12

ATMOSPHERIC CRUDE OIL DISTILLATION

	1990*	1995	Increase/ (Decrease)	% Change
Operable Units	222	214	(8)	(4)
Total Capacity, MB/SD	14,820	14,756	(64)	(<1)
Average Gross Feed Rate, MB/CD	12,566	13,316	750	6
Utilization†	85%	90%	5	

* Units and capacity are as of January 1, 1991.

† Utilization is average gross feed rate divided by total capacity.

TABLE 5-13

HYDROTREATING*

	1990†	1995	Increase/ (Decrease)	% Change
Total Operable Units	374	423	49	13
Capacity, MB/SD				
Naphtha	3,811	3,847	36	1
Distillate	2,740	3,610	870	32
Gas Oil	1,745	2,022	277	16
Residua	308	334	26	8
Total	**8,604**	**9,813**	**1,209**	**14**
Average Feed Rate, MB/CD				
Naphtha	2,841	2,951	110	4
Distillate	2,003	2,806	803	40
Gas Oil	1,297	1,792	495	38
Residua	224	229	5	2
Total	**6,365**	**7,779**	**1,413**	**22**
Utilization,‡ %				
Naphtha	75%	77%	2	
Distillate	73%	78%	5	
Gas Oil/FCC Feed	74%	89%	15	
Residua	73%	69%	(4)	

* These refineries represent about 91 percent of 1990 EIA crude oil inputs.

† Units and capacity are as of January 1, 1991.

‡ Utilization is total throughput divided by total capacity.

Note: Totals may not add due to independent rounding.

TABLE 5-14

FLUID CATALYTIC CRACKING*

	1990†	1995	Increase/ (Decrease)	% Change
Operable Units	126	124	(2)	(2)
Total Capacity, MB/SD	5,156	5,221	65	1
Throughput, MB/CD	4,353	4,716	363	8
Utilization‡	84%	90%	6	

* These refineries represent about 85 percent of 1990 EIA crude oil inputs.

† Units and capacity are as of January 1, 1991.

‡ Utilization is total throughput divided by total capacity.

Overall U.S. increase in olefin recovery is anticipated to be 17 percent, spread fairly uniformly across all PADDs.

Hydrocracking

There is an anticipated net increase of five hydrocracking units and 13 percent capacity increase from 1990 to 1995 (see Table 5-15).

Catalytic Reforming

A shift from small high-pressure reforming units to higher capacity low-pressure reforming units is anticipated. Between January 1, 1991, and January 1, 1996, survey respondents report that 22 high-pressure reforming units equaling 310 MB/SD will be shut down and three low-pressure reforming units equaling 93 MB/SD and nine continuous regeneration units totaling 209 MB/SD capacity will come on-stream (see Table 5-16).

Isomerization

There is a planned increase of 24 new isomerization units, approximately half in California. Of the new units, there is a planned increase of 59 MB/SD (110 percent increase) in the isomerization of normal butane to isobutane, and a 142 MB/SD increase of pentane/hexane isomerization (a 37 percent increase). Over 90 percent of the pentane/hexane capacity increase is in once-through rather than recycle units (see Table 5-17).

Alkylation

The net capacity change is an increase of 78 MB/SD, with over 60 percent of this total slated for California. Most of the capacity increase is in sulfuric acid units with only a small increase in hydrofluoric alkylation capacity (see Table 5-18).

Refinery Produced Oxygenates

Respondents indicate that 125 MB/SD of additional methyl tertiary butyl ether (MTBE) capacity (a 345 percent increase) is planned by 1996. Fifty-six percent of this increase is planned for PADD III. At the time of the survey, there was no anticipated production of ethyl tertiary butyl ether (ETBE). There is 62 MB/SD of new tertiary amyl methyl ether (TAME) capacity planned for 1996. There was no reported TAME capacity in 1990. Sixty percent of this capacity is planned for PADD III.

Aromatics Extraction

There is an anticipated capacity increase of 12 percent, or 24 MB/SD. Eighty percent of this capacity increase is slated for PADD III.

Secondary Gasoline Fractionation

There is an anticipated increase of 1,193 MB/SD of secondary gasoline fractionation capacity, or a 50 percent increase.

TABLE 5-15

HYDROCRACKING*

	1990†	1995	Increase/ (Decrease)	% Change
Operable Units	44	49	5	11
Total Capacity, MB/SD	1,177	1,326	149	13
Throughput, MB/CD	938	1,203	265	28
Utilization‡	80%	91%	11	

* These refineries represent about 50 percent of 1990 EIA crude oil inputs.

† Units and capacity are as of January 1, 1991.

‡ Utilization is total throughput divided by total capacity.

TABLE 5-16

CATALYTIC REFORMING*

	1990†	1995	Increase/ (Decrease)	% Change
High Pressure, Semi-Regenerative				
Operating Units	104	82	(22)	(21)
Capacity, MB/SD	1,484	1,174	(310)	(21)
Throughput, MB/CD	1,063	842	(221)	(21)
Utilization‡	72%	72%	0	
Low Pressure, Semi-Regenerative				
Operating Units	68	71	3	4
Capacity, MB/SD	1,591	1,666	75	5
Throughput, MB/CD	1,242	1,357	115	9
Utilization‡	78%	82%	4	
Continuous Regeneration				
Operating Units	20	29	9	45
Capacity, MB/SD	574	783	209	36
Throughput, MB/CD	483	692	209	43
Utilization‡	84%	88%	4	

* These refineries represent about 54 percent of 1990 EIA crude oil inputs.

† Units and capacity are as of January 1, 1991.

‡ Utilization is total throughput divided by total capacity.

Note: Totals may not add due to independent rounding.

Hydrogen

Hydrogen manufacturing is anticipated to increase about 25 percent with a net addition of 20 units. Hydrogen purification capacity is anticipated to increase by about 60 percent.

Further details on unit capacities and throughputs are found in Attachment 1 at the end of this chapter.

Part B — Refinery Feedstocks

Part B of Section II provides actual 1990 and estimated 1995 data on crude oil and other refinery inputs. The summary responses shown in Table 5-19 indicate that changes in overall feedstock quality were anticipated. Average crude oil gravity was anticipated to decline by 0.7°API between 1990 and 1995. The EIA reported that average U.S. crude oil gravity declined by 0.6°API in 1990. Average crude oil percent sulfur is anticipated to increase 0.1 percent. EIA reported that average sulfur increased from 1.1 to 1.13 percent in 1990.

Further questions asked the amount of sweet crude oil, as of January 1, 1991, that could have been replaced by light high sulfur crude oil while maintaining about the same product mix. One hundred and forty two refineries with total 1990 crude oil throughput of slightly over 12 million barrels per calendar day (MMB/CD) responded that they *could* have replaced 464 MB/CD of sweet crude oil with 403 MB/CD of light high sulfur crude oil in 1990.

TABLE 5-17

ISOMERIZATION*

	1990 †	1995	Increase/ (Decrease)	% Change
Operating Units	57	81	24	42
Butane Units				
Capacity, MB/SD	51	112	61	118
Throughput, MB/CD	33	80	47	142
Utilization ‡	65%	71%	6	
Pentane/Hexane Units—Once Through				
Capacity, MB/SD	188	312	124	66
Throughput, MB/CD	126	243	117	93
Utilization ‡	67%	78%	11	
Pentane/Hexane Units—Recycle				
Capacity, MB/SD	194	212	18	9
Throughput, MB/CD	133	148	15	11
Utilization ‡	69%	70%	1	

* These refineries represent about 53 percent of 1990 EIA crude oil inputs.

† Units and capacity are as of January 1, 1991.

‡ Utilization is total throughput divided by total capacity.

Note: Totals may not add due to independent rounding.

TABLE 5-18

ALKYLATION*

	1990†	1995	Increase/ (Decrease)	% Change
Operating Units	108	109	1	1%
Capacity, MB/SD				
Hydrofluoric	539	552	13	2%
Sulfuric	498	563	65	13%
Total	1,037	1,115	78	8%
Throughput, MB/CD	771	860	89	12%
Utilization ‡	74%	77%	3	

* These refineries represent about 87 percent of 1990 EIA crude oil inputs.

† Units and capacity are as of January 1, 1991.

‡ Utilization is total throughput divided by total capacity.

TABLE 5-19

REFINERY CRUDE OIL INPUTS*
(Thousands of Barrels Per Calendar Day)

	1990	1995	Increase/ (Decrease)
Crude Oil Type			
Light, Sweet	4,440	4,105	(335)
Heavy, Sweet	542	571	29
Light, Med. Sulfur	611	594	(17)
Heavy, Med. Sulfur†	1,539	1,660	121
Light, High Sulfur	801	994	193
Heavy, High Sulfur	4,547	5,159	612
Total	**12,480**	**13,085**	**605**
Average Gravity, ° API	31.7	31.0	(0.7)
Average Sulfur, wt%	1.2	1.3	0.1
Average 1,050 ° F +, vol%	17.1	17.8	0.7

* These refineries represent about 94 percent of 1990 EIA crude oil inputs.

† Includes Alaskan North Slope crude oil.

Note: Totals may not add due to independent rounding.

Refiners were asked the extent that environmental or other constraints will restrict the ability to process high sulfur crude oil in 1995. As shown in Table 5-20, almost two-thirds of the respondents stated that product sulfur content would restrict them from running high sulfur crude oils. The anticipated effects of other restrictions are also shown.

Besides crude oil, refiners were asked about other inputs. The level of unfinished oil and other raw material from outside the refinery is shown in Table 5-21. Even though refiners are adding 125 MB/SD of MTBE capacity, additional MTBE supplies will come from sources outside of the refinery. Other changes in outside feedstocks are relatively small.

Part C — Product Rates

Part C of Section II shows actual 1990 and estimated 1995 production rates, details of motor gasoline and distillate fuel oil production, and estimates of production changes. Table 5-22 compares the estimated 1995 production with 1990 actuals. An overall U.S. Summary is found in Attachment 2 at the end of this chapter.

The following observations are made:

- Gasoline production is projected to be up by 794 MB/CD, or 12 percent. This expectation by survey respondents is inconsistent with projected constant gasoline demand in the United States.
- There will be a shift from naphtha-type jet fuel to kerosene-type jet fuel, reflecting a shift in demand by the U.S. military.
- Kerosene and distillate fuel oil production remain essentially unchanged.
- Residual fuel oil is down by 165 MB/CD, or about 22 percent. The largest decrease is in the high sulfur category.

TABLE 5-20

REFINERIES RESTRICTED FROM RUNNING HIGH SULFUR CRUDE OIL IN 1995*
(Percent Answering "Quite a Bit" plus "A Great Deal")

Required Sulfur Content of Products	64%
Stationary-Source Air Emissions Requirements	57%
Residual Fuel Oil Processing Capacity	51%
Metallurgy	45%
H_2S Recovery Capacity	42%
Sulfur Content of Refinery Fuel	38%
Effluent Water Quality Requirements	29%

* These refineries represent about 90 percent of 1990 EIA crude oil inputs.

Note: Responses were based on a 4 point scale where None = 0, Some = 1, Quite a Bit = 2, and A Great Deal = 3. Have No Idea responses were not used.

- BTX (benzene, toluene, and xylene) and petrochemical stocks are up about 164 MB/CD, or 38 percent. This increase is primarily in PADD III.

The next two questions compared the anticipated production of gasoline by type and grade in 1995 with actual production in 1990 (see Table 5-23). The following observations are drawn from these results.

- Total gasoline production is planned to increase by about 810 MB/CD, or 12 percent.
- Oxygenated gasoline will grow from 3 percent of the pool in 1990 to 6 percent in 1995.
- It is anticipated that over 35 percent of the gasoline produced in 1995 will be reformulated gasoline. This volume is higher than the anticipated demand for the nine worst ozone nonattainment metropolitan areas.
- Regular, midgrade, and premium production percentages are essentially unchanged, as shown in Table 5-24.

Respondents were asked to compare planned diesel fuel production in 1995 with 1990 actuals. Reflecting government-mandated fuel qualities, low sulfur middle distillate fuel (< .05 wt% sulfur) will grow from 4 percent of the pool to 62 percent by 1995 (see Table 5-25). This is more than projected demand in 1995.

The following observations are derived from responses shown in Table 5-26.

- Middle distillate production is essentially constant at about 2,500 MB/CD. An increase in segregated (versus "common stream") product is not anticipated by survey respondents.
- Most of the production increase will come from the > 0.05 wt% sulfur category, which is consistent with the significant increase in middle distillate hydrotreating capacity shown in Table 5-12.
- At the time of the survey, there was an anticipated production of 75 MB/CD of CARB diesel fuel. (Potential demand for CARB diesel is approximately 165 MB/CD.)

TABLE 5-21

OTHER RAW MATERIALS INPUTS*
(Thousands of Barrels per Calendar Day)

Feedstock	1990	1995	Increase/ (Decrease)
Propane	8	1	(7)
C_3/C_4 Olefins	27	30	3
Isobutane	166	140	(26)
Normal Butane	127	142	15
Natural Gasoline	235	286	51
Heavy Naphtha	162	122	(40)
MTBE	37	252	215
Ethanol	2	4	2
Methanol	5	43	38
Other Gasoline Blendstocks	163	72	(91)
Middle Distillates	44	77	33
Heavy Gas Oils	555	474	(81)
Residual Fuel Oil	234	273	39
Benzene, Toluene, Xylene	10	25	15
Alkylation Feedstocks	12	14	2
Other	77	83	6
Natural Gas (FOE)†	144	173	29
Natural Gas (FOE) for Hydrogen	30	39	9
Hydrogen (FOE)	9	16	7
Total	**2,048**	**2,266**	**219**

* These refineries represent about 92 percent of 1990 EIA crude oil inputs.

† FOE = Fuel Oil Equivalent.

Note: Totals may not add due to independent rounding.

TABLE 5-22

MAJOR PRODUCT COMPARISON*
(Thousands of Barrels per Calendar Day)

Product	1990	1995	Increase/ (Decrease)
Motor Gasoline	6,483	7,277	794
Naphtha Type Jet Fuel	125	20	(105)
Kerosene Type Jet Fuel	1,237	1,395	158
Kerosene	80	83	3
Diesel/No. 2 Fuel Oil	2,529	2,540	11
Residual Fuel Oil	745	580	(165)
Benzene, Toluene, and Xylene & Petrochemical Feeds	435	599	164
Total	**11,634**	**12,494**	**860**

* These refineries represent about 90 percent of 1990 EIA crude oil inputs.

TABLE 5-23

U.S. MOTOR GASOLINE PRODUCTION BY TYPE*
(Thousands of Barrels per Calendar Day)

Gasoline Type	1990	Percentage of Pool	1995	Percentage of Pool	Increase/ (Decrease)
Conventional					
Leaded	297	5%	50	1%	(247)
Unleaded	5,864	90%	4,018	55%	(1,846)
Oxygenated	221	3%	425	6%	204
Reformulated	—	—	2,641	36%	2,641
Subgrades	100	2%	158	2%	58
Total	**6,482**	**100%**	**7,291**	**100%**	**809**

* These refineries represent about 93 percent of 1990 EIA U.S. motor gasoline production.

Note: Totals may not equal sum of components due to independent rounding.

TABLE 5-24

U.S. GASOLINE PRODUCTION BY GRADE*
(Thousands of Barrels per Calendar Day)

Gasoline Grade	1990	Percentage of Pool	1995	Percentage of Pool	Increase/ (Decrease)
Regular Grade	4,158	64%	4,446	61%	288
Midgrade	601	9%	775	11%	174
Premium Grade	1,284	20%	1,746	24%	462
Subgrades & Other	439	7%	324	4%	(115)
Total	**6,482**	**100%**	**7,291**	**100%**	**809**

* These refineries represent about 93 percent of U.S. motor gasoline production.

TABLE 5-25

TOTAL MIDDLE DISTILLATE FUEL OIL PRODUCTION PERCENTAGE OF POOL BY SULFUR CONTENT
(Thousands of Barrels per Calendar Day)

Sulfur Content	1990	Percentage of Pool	1995	Percentage of Pool	Increase/ (Decrease)
< 0.05 wt% Sulfur	103	4%	1,555	62%	1,452
0.05 – 0.2 wt% Sulfur	952	38%	567	23%	(385)
> 0.20 wt% Sulfur	1,442	58%	375	15%	(1,067)
Total	**2,497**	**100%**	**2,497**	**100%**	**0**

* These refineries represent about 84 percent of 1990 EIA middle distillate production.

Table 5-27 shows the characteristics of 1990 motor gasoline blending components.

Table 5-28 shows the refineries' ability to maximize motor gasoline, kerosene-type jet fuel, and No. 2 distillate production, utilizing capacity available as of January 1, 1991. It also shows the potential production of other products when maximization occurs. Refineries cannot maximize production for multiple products simultaneously.

Table 5-29 shows the volumes of additional crude oil and the crude oil properties that would be run if responding refineries operated with a 5 percent increase in crude oil inputs. The table indicates that a 5 percent increase would result in a production increase of approximately 322 MB/CD of motor gasoline, middle distillate, kerosene-type jet fuel, and residual fuel oil. The relatively low increase in production appears to indicate that refineries are constrained by downstream processing capacity limitations. The table also indicates that a 5 percent decrease in crude oil inputs would not substantially alter the amount of products produced; again indicating current high utilization of downstream capacity.

TABLE 5-26

MIDDLE DISTILLATE FUEL OIL PRODUCTION*
BY FUEL TYPE . . . BY SULFUR CONTENT
(Thousands of Barrels per Calendar Day)

Fuel Type	1990	Percentage of Pool	1995	Percentage of Pool	Increase/ (Decrease)
Common No. 2 Diesel/ No. 2 Fuel Oil†					
< 0.05 wt% Sulfur	77	3%	1,343	54%	1,266
0.05 – 0.2 2 wt% Sulfur	801	32%	417	17%	(384)
> 0.20 wt% Sulfur	1,171	47%	295	12%	(876)
No. 2 Diesel Fuel					
< 0.05 wt% Sulfur	26	1%	103	4%	77
0.05 – 0.20 wt% Sulfur	64	3%	0	0%	(64)
> 0.20 wt% Sulfur	183	7%	14	1%	(169)
No. 2 Fuel Oil					
< 0.05 wt% Sulfur	0	0%	36	1%	36
0.05 – 0.20 wt% Sulfur	87	3%	150	6%	63
> 0.20 wt% Sulfur	88	4%	67	3%	(21)
CARB Diesel ‡	0	0%	75	3%	75
Total	**2,497**	**100%**	**2,497**	**100%**	**0**

* These refineries represent about 85 percent of 1990 EIA middle distillate production.

† Common means can be sold as Diesel or No. 2 Fuel Oil.

‡ Meets California Air Resources Board vehicular diesel spec.

Section III: Refinery Emission Sources and Controls

Section III reviews refinery emission sources and controls. The findings present data on refinery sulfur recovery, waste water treatment facilities, storm water surge capacity, ground water monitoring and treatment, and contaminated soil remediation. The age of refinery storage tanks, their capacity, and emission controls are discussed in this section. Responses were received from 151 of the 199 refineries for a response rate of 76 percent.

Refinery locations in attainment/nonattainment areas are shown in Table 5-30.

Reported January 1, 1991, sulfur recovery capacity is about 19,000 long tons per stream day (LT/SD). Refiners would have to add about 6,000 LT/SD by the end of 1995 to achieve total redundancy of their largest unit. Section II of the survey indicates that refiners anticipate adding only 3,000 LT/SD of capacity by January 1, 1996. In addition, approximately 4,300 LT/SD of sulfur recovery tail gas unit treating capacity would be needed to

TABLE 5-27

U.S. MOTOR GASOLINE BLENDING COMPONENTS IN 1990 ANNUAL AVERAGE CHARACTERISTICS

Blending Component	Product Rate (MB/CD)	Benzene (vol%)	Aromatics (vol%)	Olefins (vol%)	ASTM 90% Boiling Pt (° F)
Reformate*					
Full Range	1,123	3.33	62.22	0.65	335
Light	102	6.98	29.48	1.85	230
Heavy	426	1.15	84.94	0.74	351
Straight-Run Naphtha	261	1.69	7.20	0.62	208
Natural Gasoline	107	0.85	2.40	0.90	186
FCC Naphtha					
Full Range	1,182	0.99	27.88	28.42	362
Light	768	1.25	16.99	37.62	273
Heavy	533	0.53	47.17	17.49	387
Pentane/Hexane Isomerate					
Once-Through	169	0.03	0.22	0.29	145
Recycle	116	0.01	0.14	0.28	132
Coker Gasoline	49	0.96	6.36	38.95	228
Hydrocracker Gasoline	174	1.33	2.83	0.12	178
Alkylate	773	0.01	0.47	0.28	277

* Some refiners reported that they blend "full range" reformate, while others reported that they separate reformate into light and heavy fractions for gasoline blending. The total reformate blended to gasoline is the sum of the three parts presented on this table.

Notes:

1. There were a varying number of responses for the components.
2. For any one cell, represents a maximum of 95 responses and about two-thirds of the U.S. motor gasoline production.

TABLE 5-28

ONE-MONTH CAPABILITY TO PRODUCE SELECTED PRODUCTS WITH JANUARY 1, 1991 OPERABLE CAPACITY*

Production Maximums	MB/CD	MB/CD	Number of Responses
Maximum Summer Motor Gasoline Production	6,773		112
If Maximize Gasoline, Kerojet Production		1,308	
If Maximize Gasoline, Middle Distillate Production		2,392	
If Maximize Gasoline, Residual Fuel Oil Production		696	
Maximum Winter Kerosene-Type Jet Fuel Production	1,691		96
If Maximize Kerojet, Gasoline Production		5,912	
If Maximize Kerojet, Middle Distillate Production		2,364	
If Maximize Kerojet, Residual Fuel Oil Production		772	
Maximum Winter Middle Distillate Production	2,971		115
If Maximize Distillate, Gasoline Production		5,931	
If Maximize Distillate, Kerojet Production		952	
If Maximize Distillate, Residual Fuel Oil Production		694	

* These refineries represent about 89 percent of 1990 EIA U.S. crude oil inputs.

provide total redundancy for the largest tail gas unit.

Approximately 80 percent of the refineries expect to have at least secondary treatment (activated sludge); and 30 percent will have tertiary waste water treatment facilities (filtration, activated carbon) by the end of 1995.

By the end of 1995, refineries anticipate that there will be over 2,600 million gallons of storm water surge capacity. This compares with the estimated requirement of 2,900 million gallons to contain a 10-year 24-hour storm. By the end of 1995, almost half the refineries plan to have more than 75 percent of their process waste water segregated from storm water. Two-thirds of refineries expect to have ground water monitoring systems in place by the end of 1995, and half expect to have recovery and treatment systems operating.

Less than 20 percent of refinery tanks will be equipped with tank bottom leak detection and containment by the end of 1995. Approximately half of the refinery tankage (both numbers and total capacity) will be over 40 years old at the end of 1995.

Section IV: Economic Impacts of Environmental Regulations on Refineries

Section IV addresses the economic impacts of environmental regulations on refineries. The findings present data on anticipated expenditures for air, water, and solid waste emission controls and reformulated fuels. The refineries were asked for historical expenditures based on annual submittals of form MA-200 to the Department of Commerce. Also included are estimates for operating and

TABLE 5-29

U.S. REFINERY INCREMENTAL CRUDE OIL RUNS IN 1990* EFFECTS ON U.S. PRODUCTION IF INCREASE OR DECREASE CRUDE OIL INPUTS BY 5 PERCENT AT EACH REFINERY

If crude oil runs INCREASED 5%	
Additional crude oil processed, MB/CD	514
Gravity of crude oil processed, ° API	32.2
Sulfur content of crude oil processed, wt%	1.17
Increased product production	
Motor Gasoline, MB/CD	105
Kerosene-Type Jet Fuel, MB/CD	46
Middle Distillate Fuel Oil, MB/CD	122
Residual Fuel Oil, MB/CD	49
If crude oil runs DECREASED 5%	
Crude oil NOT processed, MB/CD	563
Gravity of crude oil NOT processed, ° API	31.9
Sulfur content of crude NOT processed, wt%	1.08
Decreased product production	
Motor Gasoline, MB/CD	139
Kerosene-type Jet Fuel, MB/CD	61
Middle Distillate Fuel Oil, MB/CD	127
Residual Fuel Oil, MB/CD	42

* These refineries represent about 84 percent of 1990 EIA crude oil inputs.

TABLE 5-30

PERCENTAGE OF REFINERIES IN ATTAINMENT AND NONATTAINMENT AREAS

	Percentage of Responding Refineries	
Nonattainment Parameter	**Attainment Area**	**Nonattainment Area**
Ozone	49	51
Carbon Monoxide	76	24
Particulates	81	19
Sulfur Dioxide	90	10
Nitrogen Oxides	95	5

maintenance expenditures, as well as refinery plans to meet current and anticipated environmental regulations. Responses were received from 142 refineries for a response rate of 72 percent. As noted on the following tables, substantially fewer refineries responded to individual questions.

Tables 5-31, 5-32, and 5-33 show refining capital expenditures, operating and maintenance expenses, and one-time expenses for air, water, solid waste, and reformulated fuels.

- Capital expenditures reported by survey respondents in the 1991 to 1995 period, for air, water, and solid waste emission controls (excluding reformulated fuels) averaged almost twice that reported for the 1990 level.
- The capital expenditures, as identified in the survey, for that five-year period (1991-1995), on *air* emission regulations are anticipated to be almost twice that of *water* and *solid wastes* combined.
- The capital expenditures, as identified in the survey, for reformulated fuels for the five-year period (1991-1995) are anticipated to be greater than that spent on air, water, solid waste emission controls, and process safety combined. This finding is inconsistent with responses in Section I, Perceptions.
- Operating and maintenance (O&M) expenses for air, water, and solid waste emissions controls, as shown in Table 5-32, are anticipated to rise slightly (12 percent) between 1990 and 1995.
- For 1995, *air* emission regulations are anticipated by survey respondents to consume more O&M expenses than *water* and *solid waste*, but only slightly more than the O&M expected for new *reformulated fuels* projects.
- As shown in Table 5-33, the largest one-time expense (OTE) expenditure reported for the next five years (1991-1995) will be for solid waste management, primarily remediations.

In general, as shown in Table 5-34, most permit applicants anticipated being able to obtain a construction permit in less than 12 months.

Section V: Distribution and Transport Mode of Products from Refineries

Section V asked for information on the transportation mode—pipeline, tanker, barge, rail, or truck—of various products moved between the 13 NPC demand regions in 1990 with projections for 1995. One hundred and thirty three refineries responded for a response rate of 71 percent, but very few indicated that they move products between regions. This information is intended to determine changes in distribution costs and help identify potential distribution bottlenecks.

Table 5-35 shows motor gasoline, middle distillate, and kerosene/kerosene-type jet fuel movements from refineries by mode of transportation. Pipelines are the favored transportation type for all three major products, accounting for 71 percent of finished motor gasoline movements, 66 percent of diesel/No. 2 distillate movements, and 78 percent of kerosene/kerosene-type jet fuel movements.

Survey respondents moved about 6.7 MMB/CD of finished motor gasoline as compared to almost 7 MMB/CD moved from refineries, as reported by the EIA for 1990; about 2.5 MMB/CD of diesel/distillate No. 2, as compared to 2.9 MMB/CD reported by the EIA; and about 1.3 MMB/CD of kerosene/kerosene-type jet fuel, as compared to 1.4 MMB/CD reported by the EIA.

Survey respondents indicate that in 1995 almost 5 percent of the oxygenated and reformulated gasoline supplied will be supplied to non-required areas or for non-required use (i.e., "spillover," due to distribution constraints). It should be noted that industry experts now anticipate a much lower spillover than was anticipated when the survey was completed.

TABLE 5-31

ACTUAL 1990 AND 1991-1995 ANTICIPATED ENVIRONMENTAL EXPENDITURES TOTAL CAPITAL EXPENDITURES (Millions of Dollars)

Type of Expenditure	Actual 1990	Anticipated 1991-1995	Number of Responses
Air-Related Costs			
Clean Air Act Amendments of 1990		1,135	
Benzene Waste NESHAP		1,577	
Local Requirements		1,876	
Other		969	
Total	**399**	**5,557**	119
Average Expenditures per Year		**1,111**	
Water-Related Costs			
Clean Water Act/NPDES		1,031	
Other		1,200	
Total	**376**	**2,231**	112
Average Expenditures per Year		**446**	
Solid Waste-Related Costs			
Waste Treatment		427	
RCRA Facility Closures		137	
Corrective Actions/Remediation		215	
Other		145	
Total	**88**	**924**	108
Average Expenditures per Year		**185**	
TOTAL FACILITIES ENVIRONMENTAL CAPITAL COSTS	**863**	**7,512**	
Average Expenditures per Year		**1,502**	
Reformulated Fuels-Related Costs			
Low Sulfur Diesel		3,165	
Oxygenated Gasoline		1,710	
Reformulated Gasoline		3,979	
State & Local Regulations		1,914	
Other		202	
Total		**10,970**	108
Average Expenditures per Year		**2,194**	
Process Safety-Related Costs		1,005	101
Average Expenditures per Year		**201**	

Source: NPC Survey, Section IV.

TABLE 5-32

1990 ACTUAL AND 1995 ANTICIPATED ENVIRONMENTAL EXPENDITURES OPERATING & MAINTENANCE EXPENDITURES (Millions of Dollars)

Type of Expenditure	Actual 1990	Anticipated 1995	Number of Responses
Air-Related Costs			
Clean Air Act Amendments of 1990		215	
Benzene Waste NESHAP		146	
Local Requirements		314	
Other		837	
Total	**1,112**	**1,512**	119
Water-Related Costs			
Clean Water Act/NPDES		336	
Other		353	
Total	**586**	**689**	117
Solid Waste-Related Costs			
Waste Treatment		322	
RCRA Facility Closures		22	
Corrective Actions/Remediation		100	
Other		139	
Total	**483**	**583**	117
TOTAL FACILITIES ENVIRONMENTAL O&M COSTS	**2,180**	**2,431**	
Reformulated Fuels-Related Costs			
Low Sulfur Diesel		241	
Oxygenated Gasoline		162	
Reformulated Gasoline		527	
State & Local Regulations		175	
Other		49	
Total		**1,154**	95
Process Safety-Related Costs		114	88

Source: NPC Survey, Section IV.

TABLE 5-33

ANTICIPATED ENVIRONMENTAL EXPENDITURES ONE-TIME EXPENDITURES BETWEEN 1991 AND 1995 (Millions of Dollars)

Type of Expenditure	Anticipated 1991-1995	Number of Responses
Air-Related Costs		
Clean Air Act Amendments of 1990	113	
Benzene Waste NESHAP	96	
Local Requirements	456	
Other	119	
Total	**784**	87
Water-Related Costs		
Clean Water Act/NPDES	165	
Other	270	
Total	**435**	83
Solid Waste-Related Costs		
Waste Treatment	217	
RCRA Facility Closures	230	
Corrective Actions/Remediation	800	
Other	188	
Total	**1,435**	114
TOTAL FACILITIES ENVIRONMENTAL ONE-TIME COSTS	**2,384**	
Reformulated Fuels-Related Costs		
Low Sulfur Diesel	553	
Oxygenated Gasoline	163	
Reformulated Gasoline	457	
State & Local Regulations	84	
Other	33	
Total	**1,290**	65
Process Safety-Related Costs	346	81

Source: NPC Survey, Section IV.

TABLE 5-34

AS A RESULT OF ENVIRONMENTAL REGULATIONS, THE ANTICIPATED AVERAGE TIME TO OBTAIN CONSTRUCTION PERMITS AND AVERAGE CONSTRUCTION TIME FROM PERMIT APPLICATION TO START-UP FOR NEW AND REVAMPED PROCESS UNITS ANTICIPATED TO BE IN OPERATION ON JANUARY 1, 1996 (Months – Except for Number of Responses)

	Average Permit Time	Permit Time Range	Average Project Interval	Start-Up Interval Range	Number of Responses
Crude Oil Distillation	11	*	23	*	4
Vacuum Distillation	9	*	22	*	4
Hydrotreating	8	2–21	22	11–39	70
Aromatics Saturation	11	7–15	23	16–30	6
Delayed Coking	7	*	15	*	3
Catalytic Cracking	11	6–17	23	10–38	24
Hydrocracking	28	6–13	22	14–31	10
Reforming	10	5–16	20	8–32	16
Isomerization	11	3–20	25	9–35	22
Alkylation	11	5–18	25	8–45	20
Oxygenates	9	3–20	22	9–42	39
Aromatic Extraction	9	*	15	*	4
Hydrogen Manufacture	10	4–20	25	16–34	17
Hydrogen Purification	7	*	21	*	4
Secondary Gasoline Fraction	10	3–20	23	9–40	27
Sulfur Recovery	7	3–13	21	8–36	37
Waste Water Treatment	8	2–18	19	6–45	56

* Data withheld to avoid disclosure of individual company data.

Note: Survey did *not* ask for "pre-engineering" time for projects. This time is for preliminary engineering necessary for project evaluation and for documenting and defining necessary information for permit application. This requirement is expected to add to least 6 months to larger project elapsed time from project inception to start-up.

TABLE 5-35

1990 PRODUCT MOVEMENTS FROM REFINERIES BY MODE OF TRANSPORTATION (Thousands of Barrels per Calendar Day)

	Finished Motor Gasoline	Motor Gasoline Subgrades	Diesel/ No. 2 Distillate	Kerosene/ Kero Jet	Total Movements
Pipeline	4,761	29	1,653	1,002	7,445
Tanker	274	*	115	82	*
Barge	736	26	389	116	1,266
Rail	15	0	16	17	47
Truck	903	16	348	67	1,334
Total	**6,688**	*	**2,521**	**1,284**	*

* Data suppressed.

Note: Totals are the sum of reported data.

Section VI: Corporate Supply and Distribution of Oxygenates

The purpose of Section VI is to determine the anticipated volumes, transportation modes, and interregional flows, both domestic and foreign, of oxygenates in 1995. This information was used in evaluating the logistical issues relating to the transportation of oxygenates. Section VI requested a corporate response to planned oxygenate storage and distribution in 1995; 116 responses were received for a response rate of 50 percent. Respondents indicated that they will blend approximately 360 MB/CD of ethers and 10 MB/CD of alcohols. Of these totals, about 155 MB/CD of ethers will be imported. The respondents indicated they will own approximately 22 million barrels of ether storage and 3 million barrels of alcohol storage in 1995. Leased storage capacity of ethers and alcohols is projected to be about 5 million barrels.

It should be noted that the low response rate (50 percent) could impact the validity of these answers. For example, respondents to Part C of Section II anticipated blending 252 MB/D of ethers from sources outside the United States.

Section VII: Issues Concerning Terminals for Terminal Operators

In Section VII, data were reported on 1990 and 1995 product segregations at terminals for NPC demand regions. Those operators with deep-water terminals were also asked questions concerning marine terminal tanker inputs, outputs, and capacity. All operators were requested to provide estimated environmental expenses for their terminal operations as well as some general data on number, capacity, and age of tanks. The results provided input to the distribution and transportation models. One hundred and eighteen responses were received for this section for a response rate of 47 percent.

Terminal operators expect the average number of gasoline segregations in terminals to increase from 3.3 to 3.7 with the introduction of oxygenated and reformulated gasolines between 1990 and 1995. One-half of the terminals will add another segregation. In regions that consume or produce both oxygenated gasoline and reformulated gasoline (Regions 1, 8, and 12), terminal operators expect to add one segregation per terminal (see Table 5-36).

TABLE 5-36

AVERAGE FUEL SEGREGATIONS PER TERMINAL 1990 AND 1995 — BY NPC REGION

NPC Region	Motor Gasoline		Diesel		Jet Fuel		Total	
	1990	1995	1990	1995	1990	1995	1990	1995
1	3.7	4.6	1.4	1.9	1.3	1.3	6.4	7.8
2	3.2	3.8	1.5	1.9	1.2	1.4	5.9	6.9
3	3.2	3.5	1.1	1.4	1.3	1.5	5.6	6.2
4	2.9	3.5	1.2	1.4	1.3	1.3	5.4	6.2
5	3.4	4.0	1.3	1.8	1.5	1.6	6.2	7.3
6	2.5	2.8	1.5	1.9	1.2	1.4	5.2	5.9
7	2.9	3.1	1.5	1.8	1.6	1.8	6.0	6.5
8	3.9	4.8	1.6	2.1	1.9	2.0	7.4	8.8
9	3.7	3.8	1.4	1.8	1.6	1.6	6.7	7.2
10	3.0	3.3	1.3	1.5	1.6	1.5	5.9	6.4
11	3.3	3.3	1.3	1.3	1.9	1.8	6.5	6.5
12	4.3	5.5	1.9	2.2	2.3	2.2	8.5	10.0
13	2.9	2.6	1.5	1.7	2.6	2.4	7.0	6.9
Average	**3.3**	**3.7**	**1.4**	**1.7**	**1.6**	**1.7**	**6.4**	**7.1**

Notes: In some cases this is an average for 1990 and 1995 responses. Responses vary by cell; the maximum response is 37.

Source: NPC Survey, Section VII, Aggregated Survey Results.

The average number of distillate segregations in a terminal will go up from 1.4 to 1.7 with the introduction of 0.05 percent sulfur on-highway diesel fuel oil between 1990 and 1995. The anticipated number of jet fuel segregations in 1995 changes very little from 1990.

One hundred and eighteen companies with terminals reported they had a total of 1,108 terminals, or about 9.4 terminals per company. Approximately 45 percent of these terminals have marine facilities. The reported terminals had a total of 11,365 tanks in hydrocarbon fuels service with a capacity of 485 million barrels. On average there are 10.3 tanks per terminal with a capacity of 42.6 thousand barrels. 16.4 percent of the tanks are equipped with leak containment and detection and 25.9 percent with double seals or equivalent. Sixty-six percent of the tanks with seventy-one percent of the volumetric capacity are less than 40 years old.

Section VIII: Issues Concerning Clean Products Pipelines for Pipeline Operators

This section focused on the capacities, utilization, and percentage of selected products moving from region to region. NPC-defined regions (as shown in Figure 5-1) can be aggregated into PADDs. The pipeline operators

were also asked to estimate percentage change in 1996 rates/tariffs from 1991 rates/tariffs due to increased capacity. In addition, data on the potential impact of the Clean Air Act Amendment of 1990 was requested. Of the 76 potential respondents, 34 responses were received for a response rate of 45 percent. These data were used in the distribution and transportation models to project beyond-1995 activities. Tables 5-37 and 5-38 show a comparison of the NPC survey data for pipelines with EIA data on pipeline movements.

In addition, survey respondents indicated that:

- Of those pipelines that indicated that they expect to increase capacity, 56 percent indicated that they would not increase rates/tariffs as a result.
- They expect that obtaining permits and rights of way to construct or expand their facilities will take, on average, 12 months.
- The probabilities of respondents transporting alcohol blended gasoline, neat methanol, or neat ethanol are low.

Section IX: Tanker, Barge, Rail, and Truck Transportation

Section IX was designed to determine 1990 marine, rail, and truck costs and projected increases, especially due to anticipated environmental regulations. The section specifically asked respondents to include the increased costs of compliance with the 1990 Oil Pollution Act (OPA'90) when estimating the cost of waterborne transportation. Questions regarding rail and truck transport asked for cost of transport and average route distance for both gasoline and distillate products as a category and oxygenates as a separate category. Forty-two responses were received for a response rate of 49 percent.

TABLE 5-37

COMPARISON OF NPC AND EIA 1990 PIPELINE MOVEMENTS (Thousands of Barrels per Day)

From PADD	To PADD	1990 Survey Utilization	1990 EIA† Petroleum Supply Annual
I	II	238	233
II	I	51	40
II	III	11	81
II	IV	*	54
III	I	2,162	2,045
III	II	601	535
III	V	*	53
IV	II	28	28
IV	V	*	45

* Suppressed survey data.

† Energy Information Administration, *Petroleum Supply Annual 1990,* Table 33. Includes motor gasoline, blending components, finished aviation gasoline, jet fuel, kerosene, distillate.

TABLE 5-38

COMPARISON OF NPC PIPELINE SURVEY DATA WITH EIA PIPELINE MOVEMENT DATA (Thousands of Barrels per Day)

Movement Between NPC Regions		Capacities		Survey Utilization
From	To	Average 1990	Anticipated 1995	Average 1990
2	4	359	322	238
3	2	1,278	1,278	966
3	5	299	299	238
4	2	*	*	*
5	4	126	118	51
5	6	291	291	155
5	7	123	164	84
5	8	—	—	—
7	5	840	854	386
7	6	237	237	100
7	8	45	53	11
7	9	*	*	*
8	3	2,546	2,546	2,162
8	5	—	—	—
8	7	993	996	601
8	9	*	*	*
8	12	*	*	*
9	6	45	54	28
9	7	—	—	—
9	10	*	*	*
12	11	—	—	—

* Suppressed survey data.

The respondents anticipate that environmental and process safety hazard regulations on the U.S. flag tanker fleet will increase oil product transportation costs by the equivalent of 8 points of the 1991 American Tanker Rate Schedule. The anticipated increase for the foreign flag tanker fleet is 12 points of the 1991 World Scale Rate Schedule.

In 1990 the average rail route distance for motor gasoline and distillate transport by rail car was about 400 miles. The average rail route distance for oxygenates was about 1,230 miles, reflecting markets distant from regional production centers. The average distance for motor gasoline by truck is about 70 miles and about 270 miles for oxygenates moved by truck. As anticipated by respondents, the mean increase in trucking cost between 1990 and 1995 due to environmental regulations is 23 percent.

TABLE 5-39

CHANGES IN MOTOR GASOLINE CHARACTERISTICS*

Region	Percentage of Domestic Motor Gasoline Pool that Will Be Unleaded		Percentage of Year-Round Pool of Motor Gasoline 1.0% or Below Benzene		Percentage of Year-Round Pool of Motor Gasoline 35% or Less Aromatics		Percentage of Year-Round Pool of Motor Gasoline Below 11.0 psi RVP	
	1995	2000	1995	2000	1995	2000	1995	2000
Northern Europe	78	96	1	46	6	41	29	80
Mediterranean	42	75	0	33	9	38	96	96
Middle East	52	99	0	26	0	28	74	99
Far East	81	95	4	21	8	35	77	78
Canada	100	100	50	75	25	50	67	100
Western Hemisphere (non-U.S.)	51	75	7	7	33	33	88	100

* Weighted average calculated for each region based on EIA data for 1989 motor gasoline consumption of each country in the region.

Source: NPC Survey, Section X, "Foreign Refinery and Supply Issues," pages 2, 3, 4, 5, 8, and 9.

Section X: Foreign Refinery and Supply Issues

Section X was designed to investigate current and future product quality in foreign areas to determine the similarity of U.S. and other country fuel specifications. This section presented a definition of reformulated gasoline, as well as a set of acronyms and abbreviations that might have been unfamiliar to foreign respondents. Thirty-two responses were received for a response rate of 71 percent.

Gasoline quality questions asked for a mixture of past actual data or estimates, and forecast estimates for future years. Gasoline quality areas addressed included octane and octane additives, benzene, aromatics, RVP, oxygen content, sulfur level, olefin content, and 90 percent distillation. Questions about the quality of mid-barrel and fuel oil focused on the sulfur content of these products. Diesel aromatics content was also investigated. Respondents were also asked about refinery operating mode, ability of various countries to supply U.S. specification products, and financial impact of future regulatory requirements.

Respondents indicated that there will be significant moves in the unleaded gasoline portion of the gasoline pool (see Table 5-39). Respondents saw general trends in control of gasoline parameters, particularly benzene, aromatics, and RVP. Few respondents saw implementation of minimum oxygenate content as a future issue. In most countries, the percentage of benzene in the year-round motor gasoline pool will drop to below 2 percent by 2000. Many countries in the Middle and Far East, however, will continue to have no requirements for benzene reduction. Most regions of the world show aromatics controls by 2000. Respondents anticipate that by 2000 many North European countries will lower their maximum-allowed yearly average RVP to 11 psi and under. The Mediterranean countries will start moving below 9 psi. The other countries do not anticipate much change in their 1995 levels.

Bahrain (67 percent) and Saudi Arabia (75 percent) were the only two foreign countries that a majority of respondents indicated would be capable of supplying 3 million barrels per month of RFG to the United States.

In general, the respondents believe there is a trend toward lower sulfur levels in diesel fuel (see Table 5-40). Most respondents believe that the Northern Europe and Mediterranean Regions, along with Canada, will require 0.05 wt% or below by 2000. Seventy-seven percent of respondents expressing an opinion about the Far East indicated that diesel sulfur levels would be 0.05 wt% maximum or 0.2 wt% maximum. Most respondents indicated little movement to restrict the aromatics content of diesel fuel. Thirty-two percent of respondents believe that Northern European diesel specification will include aromatics limits by 2000. Twenty-five percent of respondents believe that aromatics in diesel fuel in Canada will be limited to between 11 and 20 percent by 2000.

The respondents indicated a general trend to lower sulfur levels in residual fuel oil in Northern Europe and the Mediterranean regions.

TABLE 5-40

CHANGES IN DIESEL FUEL SULFUR CONTENT*

Region	Percentage of Sales with Sulfur less than 0.05% 1995	2000
Northern Europe	13	92
Mediterranean	6	89
Middle East	0	0
Far East	0	44
Canada	32	83
Western Hemisphere (non-U.S.)	0	0

* Weighted average calculated for each region based on EIA data for 1989 fuel oil/ distillate consumption of each country in the region.

Source: NPC Survey, Section X, "Foreign Refinery and Supply Issues," pages 2, 3, 4, 5, 8, and 9.

ATTACHMENT 1

SUMMARY OF UNIT CAPACITIES AND THROUGHPUTS
(Thousands of Barrels per Day)

	1990		1995	
	Capacity* (MB/SD)	Throughput (MB/CD)	Capacity (MB/SD)	Throughput (MB/CD)
Atmospheric Crude Oil Distillation	14,820	12,566	14,756	13,316
Vacuum Distillation	6,542	5,257	6,482	5,602
Solvent Deasphalting	301	208	319	268
Hydrotreating				
Naphtha	3,811	2,841	3,847	2,961
Distillates	2,740	2,003	3,610	2,806
Gas Oil	1,745	1,247	2,022	1,792
Residual	308	224	334	229
Aromatic Saturation				
Light Naphtha/Gasoline	11	10	44	26
Kerosene/Jet Fuel	55	38	56	41
Middle Distillates	–	–	67	41
Delayed Coking	1,329	1,120	1,434	1,305
Fluid/FlexiCoking	184	168	191	174
Visbreaking	124	73	113	74
Catalytic Cracking	5,156	4,353	5,221	4,716
Hydrocracking	1,177	938	1,326	1,203
Catalytic Reforming				
High Pressure	1,484	1,063	1,174	842
Low Pressure	1,591	1,242	1,666	1,367
Continuous	574	483	783	692
Isomerization				
Isobutane	51	33	112	80
Pentane/Hexane Once Through	188	126	312	243
Pentane/Hexane Recycle	194	133	212	48
Alkylation				
Hydrofluoric Acid	539	771	552	860
Sulfuric Acid	498		563	
Polymerization/Dimersol	90	50	91	54
Aromatics Extraction	537	411	587	488

* Capacity as of January 1, 1991.

ATTACHMENT 2

COMPARISON OF ACTUAL 1990 PRODUCTION WITH ESTIMATED 1995
(Thousands of Barrels per Calendar Day)

	1990	1995	Increase/ (Decrease)
Fuel Gas (FOE)	648	657	9
Ethane	35	30	(5)
Propane	374	405	31
Butanes	110	153	43
Oxygenates Not Blended	4	30	26
Total Motor Gasoline	6,483	7,277	794
Aviation Gasoline	22	19	(3)
Solvents	54	56	2
Naphtha-Type Jet	125	20	(105)
Kerosene-Type Jet	1,237	1,395	158
Kerosene	80	83	3
#2 Diesel/#2 Fuel Oil	2,529	2,540	11
Other Distillate	29	15	(13)
Residual Fuel Oil <.3% Sulfur	50	42	(8)
Residual Fuel Oil 3-1.0% Sulfur	144	115	(29)
Residual Fuel Oil > 1% Sulfur	551	423	(128)
Asphalt & Road Oils	373	361	(12)
Lubes/Waxes	149	158	9
Benzene	42	59	17
Toluene	25	49	24
Xylene	51	66	15
Petrochemical Naphtha (<400° F)	220	262	42
Petrochemical Feedstocks (>400° F)	97	165	68
Unfinished Oils			
Light Straight Run Gasoline	45	36	(9)
Heavy Naphtha	101	56	(45)
Gasoline Blendstocks (Ex Oxy)	104	49	(55)
Distillate Cutter Stock	59	91	32
Gas Oil/Cracker Feed	290	199	(91)
Residual	120	122	2
Marketable Coke	307	332	25
Catalytic Coke	140	160	20
Decant Oil	41	36	(5)
Other Products	167	123	(44)
Sum of Products	14,804	15,581	750
Processing Gain	394	464	70
Sum of Crude Oil & Raw Materials	14,526	15,278	664
Total Sulfur Long Tons/CD	11,289	14,360	3,071

APPENDICES

APPENDIX A

REQUEST LETTER AND DESCRIPTION OF THE NATIONAL PETROLEUM COUNCIL

The Secretary of Energy
Washington, DC 20585

June 25, 1990

Mr. Lodwrick M. Cook
Chairman
National Petroleum Council
1625 K Street, N.W.
Washington, D.C. 20006

Dear ~~Mr. Cook~~ Lod:

Through this transmittal, I am formally requesting that the National Petroleum Council (NPC) perform two studies that are currently of critical interest to the Department of Energy. These studies are described below.

Constraints to Expanding Natural Gas Production, Distribution and Use

I request that the NPC conduct a comprehensive analysis of the potential for natural gas to make a larger contribution, not only to our Nation's energy supply, but also to the President's environmental goals. The study should consider technical, economic and regulatory constraints to expanding production, distribution and the use of natural gas. In the conduct of this study, I would like you to consider carefully the location, magnitude and economics of natural gas reserves, and the projected undiscovered and unconventional resource; the size, kind and location of future markets; the outlook for natural gas imports and exports; and potential barriers that could impede the deliverability of gas to the most economic, efficient and environmentally sound end-uses.

This study comes at a critical time, given the increased interest in natural gas, for developing public and private sector confidence that natural gas can make a greater contribution to the energy security and environmental enhancement of our Nation. I anticipate that the results of your work will be able to contribute significantly to the development of the Department's policies and programs.

The U.S. Refinery Sector in the 1990's

U.S. refineries face significant changes to processing facilities in the next decade, particularly in response to new environmental legislation that will affect emissions and waste disposal from refineries and the composition of motor fuels. Substantial investments are likely to be required to comply with proposed Clean Air Act Amendments, including provisions dealing with air toxics and alternative fuels. There is concern about the U.S. engineering and construction industry's capability to design, manufacture, and install quickly the large number of new, sophisticated processing facilities that would be necessary to supply these fuels.

Product imports, which are projected to increase, may also have to be treated differently than in the past. For example, if U.S. refiners have different gasoline specifications (e.g., Reid Vapor Pressure, aromatics, olefins, oxygen content) than foreign refineries, imported products may require additional U.S. refining.

I request that the NPC assess the effects of these changing conditions on the U.S. refining industry, the ability of that industry to respond to these changes in a timely manner, regulatory and other factors that impede the construction of new capacity, and the potential economic impacts of this response on American consumers.

I look forward to receiving your results from these two studies and would like to be notified of your progress periodically.

Sincerely,

James D. Watkins
Admiral, U.S. Navy (Retired)

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 was 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 the Secretary, relating to oil and natural gas or the oil and gas industries. Matters that the Secretary of Energy would like to have considered by the Council are submitted in the form of a letter outlining the nature and scope of the study. This request is then referred to the NPC Agenda Committee, which makes a recommendation to the Council. The Council reserves the right to decide whether it will consider any matter referred to it.

Examples of recent major studies undertaken by the NPC at the request of the Secretary of Energy include:

- *U.S. Arctic Oil & Gas* (1981)
- *Environmental Conservation—The Oil & Gas Industries* (1982)
- *Third World Petroleum Development: A Statement of Principles* (1982)
- *Enhanced Oil Recovery* (1984)
- *The Strategic Petroleum Reserve* (1984)
- *U.S. Petroleum Refining* (1986)
- *Factors Affecting U.S. Oil & Gas Outlook* (1987)
- *Integrating R&D Efforts* (1988)
- *Petroleum Storage & Transportation* (1989)
- *Industry Assistance to Government* (1991)
- *Short-Term Petroleum Outlook* (1991)
- *Petroleum Refining in the 1990s—Meeting the Challenges of the Clean Air Act* (1991)
- *The Potential for Natural Gas in the United States* (1992).

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 the oil and gas industries and related 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.

NATIONAL PETROLEUM COUNCIL

MEMBERSHIP

1993

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President
Alcorn Production Company

Robert J. Allison, Jr.
Chairman and Chief Executive Officer
Anadarko Petroleum Corporation

Eugene L. Ames, Jr.
President
Venus Oil Company

Robert O. Anderson
President
Hondo Oil & Gas Company

Ernest Angelo, Jr.
Petroleum Engineer
Midland, Texas

Philip F. Anschutz
President
The Anschutz Corporation

O. Truman Arnold
Chairman of the Board, President
and Chief Executive Officer
Truman Arnold Companies

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Wainoco Oil Corporation

Ralph E. Bailey
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United Meridian Corporation

D. Euan Baird
Chairman, President and
Chief Executive Officer
Schlumberger Limited

William W. Ballard
President
Ballard and Associates, Inc.

Victor G. Beghini
President
Marathon Oil Company

David W. Biegler
Chairman, President and
Chief Executive Officer
ENSERCH Corporation

Jack S. Blanton
President and Chief Executive Officer
Eddy Refining Company

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

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President and Chief Executive Officer
Colonial Pipeline Company

Frank M. Burke, Jr.
Chairman and Chief Executive Officer
Burke, Mayborn Company, Ltd.

Michael D. Burke
President and Chief Executive Officer
Tesoro Petroleum Corporation

Bruce Calder
President
Bruce Calder, Inc.

NATIONAL PETROLEUM COUNCIL

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President and Chief Executive Officer
Sun Company, Inc.

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President
Carl Oil & Gas Co.

Philip J. Carroll
President and Chief Executive Officer
Shell Oil Company

R. D. Cash
Chairman, President and
Chief Executive Officer
Questar Corporation

Merle C. Chambers
President and Chief Executive Officer
Axem Resources Incorporated

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

Rodney F. Chase
President and Chief Executive Officer
BP America Inc.

Danny H. Conklin
Partner
Philcon Development Co.

Lodwrick M. Cook
Chairman of the Board and
Chief Executive Officer
Atlantic Richfield Company

Milton Copulos
President
National Defense Council Foundation

Edwin L. Cox
Chairman
Cox Oil & Gas, Inc.

John H. Croom
Chairman, President and
Chief Executive Officer
The Columbia Gas System, Inc.

Thomas H. Cruikshank
Chairman of the Board and
Chief Executive Officer
Halliburton Company

Keys A. Curry, Jr.
Executive Vice President and
Chief Operating Officer
Destec Energy, Inc.

George A. Davidson, Jr.
Chairman of the Board and
Chief Executive Officer
Consolidated Natural Gas Company

Alfred C. DeCrane, Jr.
Chairman of the Board and
Chief Executive Officer
Texaco Inc.

Kenneth T. Derr
Chairman of the Board and
Chief Executive Officer
Chevron Corporation

John P. DesBarres
President and Chief Executive Officer
Transco Energy Company

Cortlandt S. Dietler
Chairman and Chief Executive Officer
Associated Natural Gas Corporation

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Co-Chairman of the Board
Forest Oil Corporation

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President
Western Petroleum Company

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Erickson Petroleum Corporation

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President
Equity Oil Company

Richard D. Farman
Chairman and Chief Executive Officer
Southern California Gas Company

J. Michael Farrell
Partner
Farrell & Levin

William L. Fisher
Director
Bureau of Economic Geology
University of Texas at Austin

Charles R. Ford
State Senator
Tulsa, Oklahoma

Joe B. Foster
Chairman
Newfield Exploration Company

H. Laurance Fuller
Chairman, President and
Chief Executive Officer
Amoco Corporation

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International Business and Energy Advisor
Honolulu, Hawaii

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President
Five States Energy Company

James J. Glasser
Chairman and President
GATX Corporation

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Chairman of the Board,
Chief Executive Officer and
Chairman of the Executive Committee
Ethyl Corporation

John J. Graham
President and Chief Executive Officer
Graham Resources Inc.

David G. Griffin
Owner/President
Griffin Petroleum Company

David N. Griffiths
Senior Vice President, Administration
Citizens Gas and Coke Utility

Fred R. Grote
Chairman of the Board and
Chief Executive Officer
DeGolyer and MacNaughton

Robert D. Gunn
Chairman of the Board
Gunn Oil Company

Ron W. Haddock
President and Chief Executive Officer
FINA, Inc.

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

Ronald E. Hall
President and Chief Executive Officer
CITGO Petroleum Corporation

Frederic C. Hamilton
Chairman, President and
Chief Executive Officer
Hamilton Oil Company, Inc.

John P. Harbin
Chairman of the Board, President
and Chief Executive Officer
Lone Star Technologies, Inc.

Raymond H. Hefner, Jr.
President
Bonray Inc.

Frank O. Heintz
Chairman
Maryland Public Service Commission

Roger R. Hemminghaus
Chairman and Chief Executive Officer
Diamond Shamrock, Inc.

Dennis R. Hendrix
Chairman, President and
Chief Executive Officer
Panhandle Eastern Corporation

Leon Hess
Chairman of the Board and
Chief Executive Officer
Amerada Hess Corporation

NATIONAL PETROLEUM COUNCIL

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President/Owner
Badger Oil Corporation

H. T. Hilliard *
Director
Hallador Petroleum Company

Robert B. Holt
Independent Oil and Gas Producer
Midland, Texas

T. Milton Honea
Chairman of the Board and
Chief Executive Officer
Arkla, Inc.

Robert E. Howson
Chairman of the Board and
Chief Executive Officer
McDermott International, Inc.

Roy M. Huffington
Houston, Texas

Ray L. Hunt
Chairman of the Board
Hunt Oil Company

Joseph T. Hydok
Executive Vice President,
Gas Operations
Consolidated Edison Company
of New York, Inc.

Ray R. Irani
Chairman, President and
Chief Executive Officer
Occidental Petroleum Corporation

A. Clark Johnson
Chairman and Chief Executive Officer
Union Texas Petroleum Corporation

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Partner
Jones Company, Ltd.

Jon Rex Jones
Partner
Jones Company, Ltd.

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President
Julander Energy Company

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Chief Executive Officer
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Chairman and Chief Executive Officer
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Ronald L. Kuehn, Jr.
Chairman, President and
Chief Executive Officer
Sonat Inc.

Kenneth L. Lay
Chairman and Chief Executive Officer
Enron Corp.

William I. Lee
Chairman of the Board and
Chief Executive Officer
Triton Energy Corporation

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

Dennis W. Loughridge
Group General Manager and President
BHP Petroleum Americas

William T. McCormick, Jr.
Chairman and Chief Executive Officer
CMS Energy Corporation

Jerry R. McLeod
Executive Vice President
Pacific Gas and Electric Company

Jack W. McNutt
President and Chief Executive Officer
Murphy Oil Corporation

Frank A. McPherson
Chairman and Chief Executive Officer
Kerr-McGee Corporation

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* Deceased July 22, 1993

Cary M. Maguire
President
Maguire Oil Company

Patrick J. Maher
Chairman and Chief Executive Officer
Washington Gas Light Company

Frederick R. Mayer
President
Petroro Corporation

Judy Meidinger
Director
Koniag, Inc.

C. John Miller
Partner
Miller Energy Company

George P. Mitchell
Chairman of the Board, President
and Chief Executive Officer
Mitchell Energy and Development Corp.

James R. Moffett
Chairman of the Board and
Chief Executive Officer
Freeport-McMoRan Inc.

Donald I. Moritz
President and Chief Executive Officer
Equitable Resources, Inc.

William Moss
Chairman of the Board
William Moss Corporation

William D. Mounger
President
Delta Royalty Company, Inc.

John Thomas Munro
President
Munro Petroleum &
Terminal Corporation

John J. Murphy
Chairman of the Board and
Chief Executive Officer
Dresser Industries, Inc.

Allen E. Murray
Chairman of the Board, President
and Chief Executive Officer
Mobil Corporation

Robert L. Nance
President
Nance Petroleum Corporation

Constantine S. Nicandros
President and Chief Executive Officer
Conoco Inc.

Raymond J. O'Connor
Commissioner
New York Public Service Commission

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Chairman of the Board, President
and Chief Executive Officer
Rowan Companies, Inc.

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Chairman of the Board
Parker Drilling Company

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President and Chief Executive Officer
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Pitts Energy Group

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Chief Executive Officer
Exxon Corporation

Corbin J. Robertson, Jr.
President
Quintana Minerals Corporation

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

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President
Rylander Consulting Group

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Sanchez-O'Brien Oil and Gas Corporation

G. Henry M. Schuler
Director
Energy Program
Center for Strategic and
International Studies

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Chief Executive Officer
Phillips Petroleum Company

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President
Simmons Royalty Company

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Chairman of the Board and President
Slawson Companies

Weldon H. Smith
Chairman of the Board
Big 6 Drilling Company

William T. Smith
Immediate Past Chairman
Wolverine Exploration Company

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President
M. H. Whittier Corporation

Richard J. Stegemeier
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Chairman, President and
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The Louisiana Land and
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Managing Co-Owner
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Edward O. Vetter & Associates, Inc.

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Owner-President
Ward Petroleum Corporation

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

Larry E. Williams
President and Chief Executive Officer
National Cooperative Refinery Association

Irene S. Wischer
President and Chief Executive Officer
Panhandle Producing Company

William A. Wise
President and Chief Executive Officer
El Paso Natural Gas Company

Dalton J. Woods
President
Dalwood Corporation

James D. Woods
Chairman of the Board, President
and Chief Executive Officer
Baker Hughes Incorporated

John A. Yates
President
Yates Petroleum Corporation

Daniel H. Yergin
President
Cambridge Energy Research Associates

Henry Zarrow
President
Sooner Pipe & Supply Corporation

APPENDIX B

STUDY GROUP ROSTERS

NATIONAL PETROLEUM COUNCIL

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Chairman of the Board and
Chief Executive Officer
Chevron Corporation

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Deputy Secretary of Energy
U.S. Department of Energy

EX OFFICIO

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Chairman
National Petroleum Council
c/o Hunt Oil Company

SECRETARY

Marshall W. Nichols
Executive Director
National Petroleum Council

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President
Marathon Oil Company

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President and Chief Executive Officer
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President and Chief Executive Officer
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Chairman and Chief Executive Officer
BP America Inc.

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Chairman of the Board and
Chief Executive Officer
Atlantic Richfield Company

Alfred C. DeCrane, Jr.
Chairman of the Board and
Chief Executive Officer
Texaco Inc.

H. Laurance Fuller
Chairman, President and
Chief Executive Officer
Amoco Corporation

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

Ron W. Haddock
President and Chief Executive Officer
FINA, Inc.

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

Ronald E. Hall
President and Chief Executive Officer
CITGO Petroleum Corporation

Roger R. Hemminghaus
Chairman and Chief Executive Officer
Diamond Shamrock, Inc.

Leon Hess
Chairman of the Board and
Chief Executive Officer
Amerada Hess Corporation

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Chairman and Chief Executive Officer
Koch Industries, Inc.

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

Allen E. Murray
Chairman of the Board, President
and Chief Executive Officer
Mobil Corporation

Constantine S. Nicandros
President and Chief Executive Officer
Conoco Inc.

Lee R. Raymond
Chairman of the Board and
Chief Executive Officer
Exxon Corporation

Robert G. Reed III
Retired Chairman of the Board,
President and Chief Executive Officer
Pacific Resources, Inc.

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

Richard J. Stegemeier
Chairman of the Board and
Chief Executive Officer
Unocal Corporation

Larry E. Williams
President and Chief Executive Officer
National Cooperative Refinery Association

NATIONAL PETROLEUM COUNCIL

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Chevron Research and
Technology Company

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Office of Oil and Gas
Energy Information Administration
U.S. Department of Energy

ASSISTANT TO THE CHAIRMAN

Robert B. Warden
CRTC Fellow
Process Planning Unit
Fuels Group
Chevron Research and
Technology Company

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Acting Director
Office of Oil and Natural Gas Policy
Office of Policy, Planning and
Program Evaluation
U.S. Department of Energy

SECRETARY

John H. Guy, IV
Deputy Executive Director
National Petroleum Council

* * *

Paul C. Battersby [2]
Senior Consultant
Unocal Petroleum Products &
Chemicals Division
Unocal Corporation

John R. Coleman, Jr.
Manager, Fuels Technology
Marathon Oil Company

John S. Doust [3]
Vice President, Refining
BP America Inc.

W. R. Finger
President
ProxPro, Inc.

Robert E. Funk
General Manager
Business Planning & Economics
CITGO Petroleum Corporation

Stephen H. Grote [4]
President
Brown & Root Braun

R. C. Harrell [5]
Vice President
Refining and Supply
Shell Oil Products Company

D. R. Hayward
Vice President
Marketing & Refining Planning
Mobil Oil Corporation

Dana O. Ladd
Vice President
Petroleum Planning and Analysis
Ashland Petroleum Company

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[1] Replaced Guy F. Caruso and E. David Doane
[2] Replaced Daniel M. Waldorf
[3] Served until June 30, 1993
[4] Served until July 31, 1993
[5] Replaced Quartus P. Graves, Jr.

COORDINATING SUBCOMMITTEE

Paul W. Lashbrooke
Vice President
Refining and Research and Engineering
Conoco Inc.

T. Stan McGowin
Manager - Projects
Texaco Refining and Marketing Inc.

Michael F. Milam
Director, Operations
Diamond Shamrock, Inc.

James R. Nolan [6]
Director
Strategic Planning
Sun Company, Inc.

Kenneth G. Riley
Vice President
Business Management and
New Ventures
ARCO Products Company

S. Roy Slovenko
Slovenko and Associates

L. Douglas Smith
Manager
Refining Economics and Planning
Fina Oil and Chemical Company

Randall M. Trembly [7]
Vice President - Refining
Crown Central Petroleum Corporation

---

[6] Replaced David E. Knoll
[7] Replaced Edward L. Rosenberg

NATIONAL PETROLEUM COUNCIL

FINANCIAL ANALYSIS SUBGROUP OF THE NPC COMMITTEE ON REFINING

GROUP LEADER

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Vice President
Petroleum Planning and Analysis
Ashland Petroleum Company

Robert E. Funk
General Manager
Business Planning & Economics
CITGO Petroleum Corporation

John H. Guy, IV
Deputy Executive Director
National Petroleum Council

Donald J. Marshall
Consulting Engineer and Economist

James R. Nolan
Director
Strategic Planning
Sun Company, Inc.

Jon A. Rasmussen
Supervisory Economist
Financial Analysis Branch
Economics & Contingency Information Division
Energy Information Administration
U.S. Department of Energy

NATIONAL PETROLEUM COUNCIL

REFINERY FACILITIES TASK GROUP
OF THE
NPC COMMITTEE ON REFINING

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Vice President
Refining and Research and Engineering
Conoco Inc.

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Barry M. Yaffe
Senior Engineer/Energy Analyst
Office of Oil and Gas
Energy Information Administration
U.S. Department of Energy

ASSISTANT TO THE CHAIRMAN

Ronald G. Bruce [8]
Senior Consultant
Business Development and Optimization
Conoco Inc.

SECRETARY

Donald J. Marshall
Consulting Engineer and Economist

* * *

Harold F. Elkin
Senior Environmental Consultant
Environmental Affairs
Sun Company, Inc.

John H. Gray
Manager (Air Issues)
Environmental Engineering & Permitting
Ashland Petroleum Company

Joseph A. Marcinek
Planning Associate
Marketing & Refining Division
Mobil Oil Corporation

Thomas R. Richart
Manager
Environmental/Safety Division
Chevron U.S.A. Inc.

Kent W. Rogers
Environmental Support Manager
Products Environmental Conservation
Shell Oil Company

Ronald E. Schmitt [9]
Director
Environmental Performance Management
Amoco Corporation

SPECIAL ASSISTANT

Robert M. Nolan
Staff Coordinator
Refining Department
Exxon Company, U.S.A.

---

[8] Replaced Toby L. Casteel
[9] Replaced J. R. Spetz

NATIONAL PETROLEUM COUNCIL

SUPPLY, DEMAND, AND LOGISTICS TASK GROUP OF THE NPC COMMITTEE ON REFINING

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President
ProxPro, Inc.

GOVERNMENT COCHAIRMAN

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Director
Petroleum Supply Division
Office of Oil and Gas
Energy Information Administration
U.S. Department of Energy

ASSISTANT TO THE CHAIRMAN

Graham K. Barnes
Planning Advisor
Downstream Planning & Analysis
Exxon Company, U.S.A.

SECRETARY

Donald J. Marshall
Consulting Engineer & Economist

* * *

Howard W. Beatty [10]
Director
Supply Planning & Optimization
Amoco Oil Corporation

C. A. Fetzek [11]
Senior Analyst
Operations Planning
Marathon Oil Company

D. L. Fry [12]
Senior Process Advisor
Process Engineering Department
Caltex Services Corporation

William H. Leney
President
Brittain Associates

Roger C. McGee
Manager
International Petroleum Planning and Development
Chevron International Oil Company

Dennis W. Marple
Vice President
Supply, Trading and Transportation
La Gloria Oil and Gas Company

Richard H. Meadows
Assistant Manager
Product Supply and Distribution
Fina Oil and Chemical Company

Roy E. Pratt
Senior Group Leader
Process Research
Texaco Inc.

Mark E. Rodekohr [13]
Director, Energy Demand and Integration Division
Office of Integrating Analysis and Forecasting
Energy Information Administration
U.S. Department of Energy

---

[10] Replaced C. Chatt Smith
[11] Replaced Philip G. Arnold, Jr. and Martin Mick
[12] Replaced S. T. Gale and Derek Webster
[13] Replaced Arthur T. Andersen

SUPPLY, DEMAND, AND LOGISTICS TASK GROUP

David T. Smith [14]
Manager, Supply Coordination
Marketing and Refining Planning
Mobil Oil Corporation

William A. Taraschi [15]
Senior Policy Consultant
Public Issues
Government Affairs
Atlantic Richfield Company

Paul W. H. Taylor
Senior Staff
Research Engineer
Shell Development Company

Alfred B. Zustovich
Energy Advisor
Downstream Planning & Analysis
Exxon Company, U.S.A.

SPECIAL ASSISTANTS

Aileen A. Bohn
Operations Research Analyst
Office of Energy Emergencies
U.S. Department of Energy

Ronald W. O'Neill
Chief, Industry Analysis Branch
Petroleum Supply Division
Energy Information Administration
U.S. Department of Energy

Stefanie Palumbo
Supervisory Statistician
Petroleum Supply Division
Office of Oil and Gas
Energy Information Administration
U.S. Department of Energy

---

[14] Replaced Roger F. Aaron, Donald M. Crann, Peter N. DiGiovanni, and Gerald L. Harris
[15] Replaced Arnold B. Baker

NATIONAL PETROLEUM COUNCIL

PRODUCT QUALITY TASK GROUP
OF THE
NPC COMMITTEE ON REFINING

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T. Stan McGowin
Manager - Projects
Texaco Refining and Marketing Inc.

GOVERNMENT COCHAIRMAN

Barry D. McNutt
Policy Analyst
Office of Energy Demand Policy
U.S. Department of Energy

SECRETARY

Benjamin A. Oliver, Jr.
Committee Coordinator
National Petroleum Council

* * *

Allen M. Burns
Senior Refinery Technologist
Ethyl Petroleum Additives, Inc.

Elizabeth E. Campbell
Economist
Office of Oil and Natural Gas Policy
U.S. Department of Energy

Terrence S. Higgins
Technical Director
National Petroleum Refiners Association

Philip F. Hodges
Director, Refinery Support Services
Crown Central Petroleum Corporation

Richard P. Long, Sr.
Senior Business Analyst
Ashland Petroleum Company

David L. McColloch
Director
Domestic Operations Division
Office of Emergency Planning and Operations
U.S. Department of Energy

Alvin B. Schachtschneider [16]
Refining Specialist
International Business Development
Amoco Oil Company

Robert T. Stanfield [17]
Senior Refining Engineer
Marathon Oil Company

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APPENDIX C

WINTER 1992-93 OXYGENATE SUPPLY/DEMAND FOR THE CARBON MONOXIDE NONATTAINMENT AREAS

The Phase I report of the NPC refining study, entitled *Petroleum Refining in the 1990s—Meeting the Challenges of the Clean Air Act,* expressed the view that an oxygenate shortfall would occur during the winter 1992-93 oxygenated fuel period. While there was a wide range of view expressed, the consensus of the refining industry interviewees in early 1991 was that there would not be enough oxygenate for all carbon monoxide nonattainment areas. An oxygenate shortfall did not occur, primarily because of changes in regulations which reduced the demand for oxygenates and a higher than anticipated supply of oxygenates from storage.

REGULATED OXYGENATE DEMAND

The ranges for NPC oxygenate demand estimates for the 1992-93 winter were based on the oxygen content and oxygenated fuel period rules written at the time, the cities involved, and an assumed 10 percent spillover.

Since completion of the Phase I study, the EPA decided to delay the start of the 1992-93 oxygenated fuel program to November 1 and made it a four-month program in most carbon monoxide nonattainment areas. Unexpectedly, some nonattainment areas did not participate in the 1992-93 oxygenated fuel program. Also, California adopted a 2 percent oxygen content level, rather than the federal 2.7 percent level. All these steps significantly reduced the winter 1992-93 oxygenate demand. Spillover appears to have been substantially less than 10 percent.

DELIVERIES FROM STORAGE

The availability of oxygenate from storage was cited by the Phase I study as one of the most uncertain factors in the oxygenate supply/demand balance. Because of lower than expected demand for gasoline, particularly premium gasoline, less MTBE was used for gasoline blending to meet octane requirements in 1991 and 1992 than expected. Thus, substantially more MTBE was available and there was a large buildup of MTBE and ethanol inventories.

OXYGENATE PRODUCTION AND IMPORTS

The study's estimate of domestic MTBE production in winter 1992-93 now appears to have been high. An adequate supply of MTBE was available from inventory without

maximizing production. MTBE import data are not available. Ethanol production remained high throughout 1992.

OXYGENATE SUPPLY/DEMAND BALANCE

With the lower demand for oxygenates required by regulation, increased supply available from storage, and few compliance problems, the potential shortage did not occur.

Data on how much ethanol and MTBE were used in the oxygenated fuel program and how much in conventional gasoline blends during the 1992-93 winter season are not available. Extension of the ethanol subsidy to blends containing less than 10 percent ethanol increased the economic attractiveness of ethanol in the oxygenated fuel program. Ethanol supply and use in the oxygenated fuel program appears to have exceeded that anticipated in the Phase I study.

In summary, the reduced demands brought about by local actions and the shortened season for the oxygenated fuel program defined by the EPA have served to lower the oxygenate requirement such that industry was able to meet the demand without difficulty. The stable-to-declining spot price level for MTBE in the period preceding and during the compliance period suggests that most of the industry saw a supply/demand balance.

APPENDIX D

REVIEW OF FINDINGS FROM 1986 NPC REPORT

The 1986 National Petroleum Council report entitled U.S. Petroleum Refining was the last refining report produced by the NPC. The 1986 report reached three major findings and conclusions, which can now be examined with the vision of hindsight.

1986 Conclusion #1: Based on the 1988 data from the NPC Refinery Survey and modeling results, the U.S. refining industry is approaching maximum gasoline manufacturing capacity.

During the intervening years, gasoline production grew from 6.42 million barrels per day (B/D) in 1985 to 6.96 million B/D in 1988 and has remained almost constant since. During the same period, gasoline imports increased from 381 thousand B/D in 1985 to 405 thousand B/D in 1988, but declined to 294 thousand B/D in 1992.[1] The 1986 study estimated that at 6.8 million B/D gasoline production, downstream conversion units would be fully utilized, and hence increasing crude oil runs would provide very little additional gasoline.

Gasoline manufacturing capacity has remained adequate during the 7 years following 1985. During this same time frame, unleaded gasoline grades production increased from 4.14 million B/D in 1985 to 6.95 million in 1992 while leaded gasoline declined from 2.28 million B/D in 1985 to 0.11 million B/D in 1992[2] Thus, more than 95 percent of leaded gasoline was replaced by unleaded grades. Table D-1 shows the 1985-1992 U.S. refining industry gasoline production by leaded and unleaded volumes.

The 1986 report suggested that debottlenecking or minor additions to octane enhancement facilities could raise the annual gasoline production capability level above 6.8 million B/D. Octane changes in this period were in part accomplished through greater use of MTBE, a high-octane oxygenate.

1986 Conclusion #2: 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.

The 1986 report listed a series of premises that support Conclusion #2:

- An increase in world product demand with no change in the ratio of light to

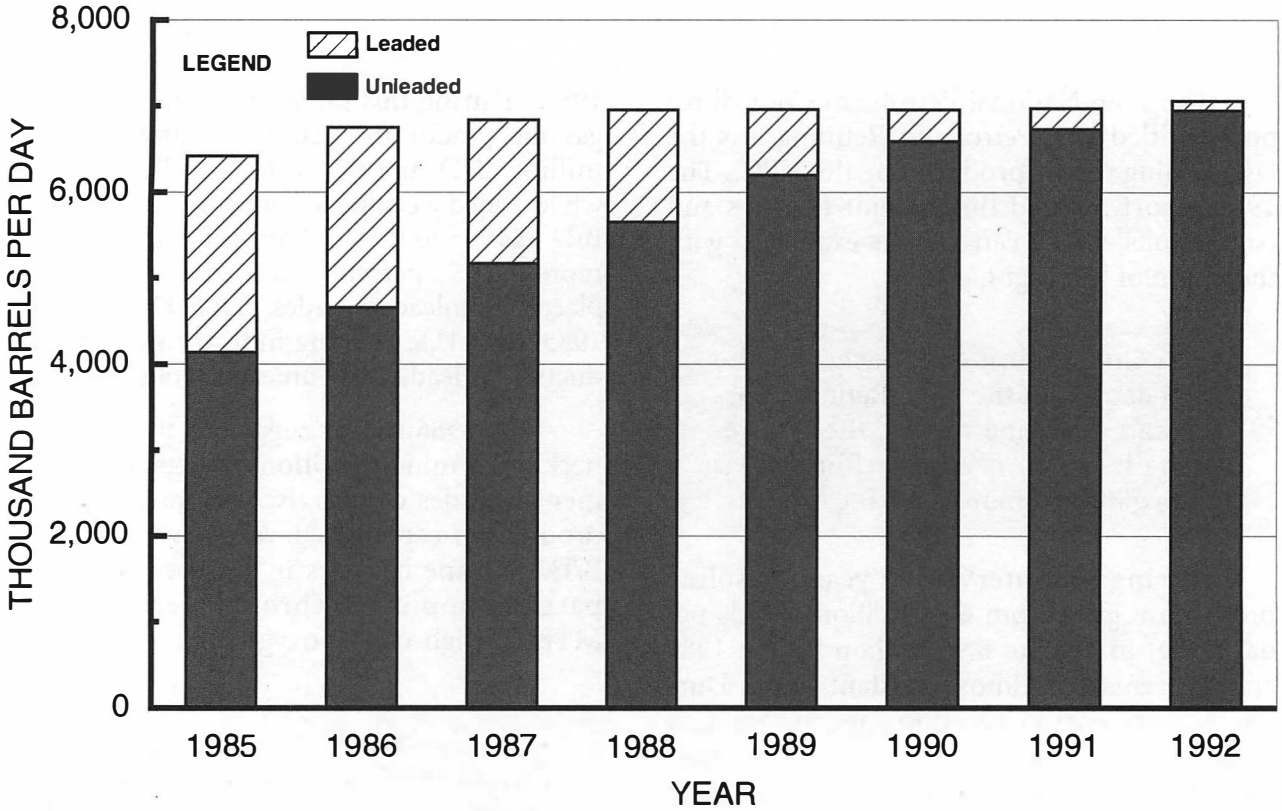
[1] *Petroleum Supply Annual 1992*, Volume 1 May 1993, Energy Information Agency, Office of Oil and Gas, U.S. Department of Energy, Washington, DC 20585, Table S4, page 17.

[2] *Petroleum Supply Annuals* 1985-1992, Table 3.

TABLE D-1

U.S. GASOLINE PRODUCTION — 1985-1992
(Thousands Barrels per Day)

Year	Unleaded	Leaded	Total
1985	4138	2281	6419
1986	4656	2096	6752
1987	5174	1668	6842
1988	5654	1302	6956
1989	6200	763	6963
1990	6590	369	6959
1991	6731	245	6976
1992	6951	112	7063



U.S. Gasoline Production.

heavy products should result in an increase in U.S. refinery throughput.

Table D-2 shows the demand for products within the United States and worldwide. World product demand for major products increased steadily from 59.7 thousand B/D in 1985 to 65.7 thousand B/D in 1989. During this same period, the U.S. refinery capacity utilization increased steadily from 77.6 to 86.3 percent. The light/heavy product ratio in the world dropped in the first year, but partially recovered in the following years.

- An increase in the worldwide ratio of light product to heavy product demand with

TABLE D-2

TOTAL APPARENT CONSUMPTION WORLDWIDE (Thousands Barrels per Day)

	1985	1986	1987	1988	1989
United States	15,726	16,281	16,665	17,283	17,325
North America	18,780	19,262	19,739	20,532	20,726
Central & South America	3,341	3,494	3,565	3,561	3,579
Western Europe	11,956	12,334	12,585	12,762	12,859
Eastern Europe and USSR	10,641	10,845	10,850	10,705	10,490
Middle East	2,682	2,724	2,798	2,969	3,126
Africa	1,862	1,819	1,836	1,905	1,991
Far East & Oceania	10,482	10,884	11,354	12,064	12,938
World Total	**59,745**	**61,363**	**62,727**	**64,499**	**65,709**

Source: Energy Information Administration/International Energy Annual 1986-1990.

UNITED STATES REFINERY UTILIZATION RATES (Percent of Calendar Day Capacity)

	1985	1986	1987	1988	1989
Crude Oil Distillation	77.6%	82.9%	83.1%	84.4%	86.3%
Cokers			92.3%	97.8%	95.5%
Catalytic Crackers			86.2%	88.4%	89.5%
Hydrocrackers			87.9%	84.8%	81.9%

Source: *Petroleum Supply Annual 1991*, Volume 1, pages 81-83. Downstream unit capacity. Utilization not available for 1985-86.

no change in total demand should result in an increase in U.S. refinery throughput and a decrease in imports.

Since the total worldwide demand did not hold constant and the light/heavy ratio declined slightly, this theory is neither confirmed nor refuted by the facts. Product imports did not show a steady trend.

- 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.

The demand and product mix changes did not occur only in the United States, but changed throughout the world as well.

1986 Conclusion #3: 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.

In the 1986 study, it was concluded that foreign and U.S. governments can affect product flows through changing operating and importing incentives. Using the study model, various

tariffs were imposed in the EEC and in the United States to determine how the product export/import flows would be affected.

- Middle East and North African refineries were run at estimated maximum throughput with the result of increased imports into Europe, the Far East, and the United States.
- European tariffs increases of $5 per barrel resulted in increased imports into the United States. A similar U.S. tariff increase would offset the European tariff.
- Imposed U.S. import tariffs on products that are not offset by foreign tariffs will cause:
  1. Reduction in product imports, with import shutdown at a tariff differential of $4 per barrel.
  2. Redistribution of U.S. imports to the rest of the world.

Major tariffs or other economic production incentives have not been imposed in the United States, the EEC, or other countries. Since the world crude oil price collapse of 1986, we have had a period of comparative price and supply stability with the exception of relatively short-term major interruptions such as the cold winter of 1990 and Iraq's invasion of Kuwait. However, major producing and consuming governments have not interfered in the petroleum product marketplace and thus the conclusion is still empirically untested.

In addition to the three major findings, the 1986 study noted several other findings and conclusions:

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

As noted in major conclusion #1 above, when conversion capacity is nearing full utilization, increasing crude runs is not likely to increase gasoline production significantly. Under these circumstances, distillation utilization is not representative of how much more capacity is available for incremental production. Since the 1986 NPC study, the Energy Information Administration within the Department of Energy has started compiling statistics of utilization rates for major conversion units (Cokers, Catalytic Crackers, and Hydrocrackers).[3] The EIA reports Fresh Feed Inputs, Average Charge Capacity, and Percent Utilization Rates for the three major conversion unit types. With the new reported utilization, the industry no longer need speculate on whether the crude oil distillation utilization is reflective of refinery unit capacity utilization.

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

Regional refineries continue to play an important and unique role in meeting the petroleum requirements of their areas. Major pipelines and marine carriers move product from the major refining centers to the markets they serve. This is particularly true of Gulf Coast refining capacity serving East Coast and South East Markets. However, Mountain and Pacific refineries continue to be the primary source for products in their regions.

Los Angeles Basin refineries are subject to unique environmental regulations.

Los Angeles refineries continue to be subject to unique environmental regulations. Since the 1986 report, California and the Southern Coast Air Quality Management District have established the toughest environmental restrictions in the country.

- NOx emissions limitations were implemented in 1988 with a maximum of 0.14 pounds/million BTUs. At the end of 1992, the limit was further reduced to 0.10 pounds/million BTUs. An additional cut to 0.03 pounds/million BTUs will take place 1995. These emission levels apply to all boilers rated at more than 40 million BTUs per hour.
- Drainage systems must be sealed and a strict inspection program has been improved.

[3] *Petroleum Supply Annual 1991*, Volume 1 Table FE4, page 83.

- Tank seals on floating roof tanks must be doubled for all products of greater than 0.5 psi vapor pressure. This includes all gasolines and military jet fuel (naphtha-jet). Kerojet and distillates do not require double sealed tankage.

In the California South Coast area, the RECLAIM program, under which emitters can buy and sell credits resulting from cutbacks which exceed standards, is being evaluated.

In addition, the California Air Resources Board will require more stringent gasoline specifications in 1996 through their Phase 2 program. Diesel specifications will also be more severe than the federal requirements.

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

The 1986 report was prophetic in arriving at this conclusion. The subsequent legislation and regulations stemming from the Clean Air Act Amendments of 1990, Oil Pollution Act of 1990, and the various state environmental legislation constitute the basis for this National Petroleum Council report on refining.

ACRONYMS AND ABBREVIATIONS

°API—degrees API gravity

% S—weight percent sulfur

(R+M)/2—(Road octane + Motor octane)/2*

API—American Petroleum Institute

ASTM—American Society for Testing and Materials

B/D—barrels per day

B/CD—barrels per calendar day,* total barrels processed or produced in a year divided by 365 days

B/SD—barrels per stream day,* total barrels processed or produced in a typical day when operating on normal feed at normal conditions

BTU—British thermal unit

CAA—The Clean Air Act of 1970

CAAA—The Clean Air Act Amendments of 1990

CARB—California Air Resources Board

CERCLA—Comprehensive Environmental Response, Compensation, and Liability Act of 1980

CG—conventional gasoline

CMSA—Consolidated Metropolitan Statistical Area

CO—carbon monoxide

CO_2—carbon dioxide

CPE—Centrally Planned Economies

cpg—cents per gallon

CWA—Clean Water Act

DCF—discounted cash flow*

DOE—Department of Energy

DOT—Department of Transportation

DWT—deadweight tons

EEC—European Economic Community

EIA—Energy Information Administration (of DOE)

EPA—Environmental Protection Agency

ETBE—ethyl tertiary butyl ether. An oxygenate produced by the combination of ethanol with isobutylene.

FC-I—Foundation Case I*

FC-II—Foundation Case II*

FC-III—Foundation Case III*

FCC—fluid catalytic cracking

FERC—Federal Energy Regulatory Commission

FOE—Fuel Oil Equivalent

FRS—Financial Reporting System*

* See Glossary for more detailed description.

GDP—Gross domestic product

H/S/E—Health, safety, and environmental cost increases in fixed facilities

I&M—Inspection and Maintenance (procedures)

IEA—International Energy Agency*

IMO—International Maritime Organization*

LP—linear programming

LPG—liquefied petroleum gas (propane, butane, or a combination of both)

LT/D—long tons per day

M—thousand

MA-200—Department of Commerce "Survey of Pollution Abatement Costs and Expenditures" questionaire for business establishments. Survey results are organized by Standard Industrical Classification groups, including Petroleum and Coal Products (SIC 29).

MACT—Maximum Achievable Control Technology: for CAAA, the basis for stationary source standards to be promulgated by EPA; to be equal to the best controlled 12 percent of similar sources

MB/CD—thousand barrels per calendar day

MB/D—thousand barrels per day

MB/SD—thousand barrels per stream day

MDWT—thousand deadweight tons

MM—million

MTBE—methyl tertiary butyl ether. An oxygenate used by refiners for gasoline blending. MTBE is produced by the combination of isobutylene and methanol.

NAAQS—National Ambient Air Quality Standards

NOTC—Northeast Ozone Transport Corridor*

NESCAUM states—Northeast States for Coordinated Air Use Management. Includes New York, New Jersey, and New England states.

NESHAP—National Emission Standards for Hazardous Air Pollutants

NGL—natural gas liquids

NOx—nitrogen oxides

NPC—National Petroleum Council

NPRA—National Petroleum Refiners Association

NPRM—Notice of Proposed Rulemaking

O&M—Operating and Maintenance expenses

OECD—Organization for Economic Cooperation and Development

OG—oxygenated gasoline

OPA'90—Oil Pollution Act of 1990

OPEC—Organization of Petroleum Exporting Countries

OPRG—oxygenated program reformulated gasoline*

OSHA—Occupational Safety And Health Administration (Act)

OTE—One-Time Expenses

PADD—Petroleum Administration for Defense District

PHA—process hazards analysis

PP&E—Property, plant, and equipment: a general accounting category for physical assets.

ppm—parts per million

PSA—*Petroleum Supply Annual* of the Energy Information Administration, U.S. Department of Energy

psi—pounds per square inch

RBOB—refinery blendstocks for oxygenate blending

RCRA—Resource Conservation and Recovery Act

RFG—reformulated gasoline*

RMT—Refining, Marketing, and Transportation sectors of the petroleum industry

ROI—return on investment*

ROR—rate of return*

RVP—Reid Vapor Pressure*

S—sulfur (wt%)

SCAQMD—South Coast Air Quality Management District, the Southern California air environmental regulatory body

SCF—standard cubic feet

SOx—sulfur oxides

SWMU—Solid Waste Management Unit

T_{90}—Temperature (°F) at which 90 percent of product is distilled away

T_{50}—Temperature (°F) at which 50 percent of product is distilled away

TAME—tertiary amyl methyl ether. An oxygenate for gasoline blending, produced by the combination of isopentene (isoamylene) and methanol.

TAP—toxic air pollutants, as described in the Clean Air Act Amendments of 1990. *See* Air Toxics.*

TBA—tertiary butyl alcohol

TSCA—Toxic Substances Control Act (1976)

U.S.—United States

USEC—U.S. East Coast

USWC—U.S. West Coast

USGC—U.S. Gulf Coast

VOC—volatile organic compounds

vol%—percent by volume

WSPA—Western States Petroleum Association

wt%—percent by weight

GLOSSARY

1986 NPC Report—The NPC report entitled *U.S. Petroleum Refining*, published October 1986 for the Secretary of Energy.

1990 Dollars—*See* Constant Dollars.

Additives—Chemicals blended in small amounts into gasoline and other petroleum products to improve performance.

Air Toxics—Under the Clean Air Act, total mass emissions of benzene, formaldehyde, acetaldehyde, butadiene, and polynuclear organic material. These are anticipated to cause serious or irreversible chronic or acute health effects in humans.

Alkylation—A refining process for chemically combining isobutane with olefin hydrocarbons (e.g., propylene, butylene) in the presence of an acid catalyst. The product alkylate, an isoparaffin, is blended to gasoline.

Antidumping—The prevention of changes of conventional or non-reformulated gasoline properties that could increase VOC, NOx, or TAP emissions.

Aromatics—Hydrocarbons characterized by unsaturated ring structures of carbon atoms. Aromatics in gasoline include benzene, toluene, and xylene.

Attainment Area—An area considered to have air quality as good as or better than the National Ambient Air Quality Standards as defined in the Clean Air Act (e.g., ozone attainment, CO attainment). An area may be an attainment area for one pollutant and a nonattainment area for others. *See also* Nonattainment Area.

Barrel—The standard unit of measurement of liquids in the petroleum industry, containing 42 U.S. standard gallons at 60 degrees Fahrenheit.

Barrels per Calendar Day (B/CD)—The maximum number of barrels of input that can be processed during a 24-hour period after making allowances for the following limitations: (1) the capabilities of other facilities within the refinery; (2) the types and grades of inputs processed; (3) the types of grades of products manufactured; (4) the environmental constraints associated with refinery operations; (5) the reduction of capacity for scheduled downtime such as routine inspection, maintenance, repairs, and turnaround; and (6) the reduction of capacity for unscheduled downtime due to causes such as mechanical problems, repairs, and slowdowns.

Barrels per Stream Day (B/SD)—The amount a unit can process running at full capacity under normal input and product conditions.

Baseline—Summer and winter gasolines as defined in the 1990 Clear Air Act Amendments or by EPA regulations, for use as a reference for required performances standards for VOC, TAP, and NOx emissions.

Batch—Homogeneous quantity of petroleum product shipped through a pipeline.

Bulk Plant—A small storage facility of less than 50,000 barrels without pipeline connections.

Bulk Terminal—A facility used primarily for the storage and/or marketing of petroleum products that has a total bulk storage capacity of 50,000 barrels or more and/or receives petroleum products by tanker, barge, or pipeline.

Butane—A four carbon hydrocarbon with no double or triple carbon to carbon bonds; straight or branch-chain structure (i.e., normal or isobutane). Butane is extracted from natural gas or refinery gas streams.

Butylene (alternatively called butene)—A four carbon, olefinic hydrocarbon. Butylene is produced in fluid catalytic cracking operations or ethylene manufacturing units.

Capital Charge—The equal annual amount of income before tax and depreciation, that amortizes a capital expenditure over its usable life taking into account tax effects and the time value of money. For this study, the capital charge of $0.172 per dollar of investment is sufficient to earn a 10 percent discounted cash flow rate of return on the capital expenditures assuming an overall 36 percent income tax rate, fifteen-year project life, double declining balance tax depreciation, and a two-year construction period.

Capital Expenditure—An expenditure for goods and/or services which, by generally accepted accounting principles and tax code requirements, is depreciated over its useful life for purposes of determining operating expense.

CARB Phase 2 Gasoline—Reformulated gasoline required in California in 1996.

Catalytic Cracking—The refining process of breaking down larger, heavier, and more complex hydrocarbon molecules into simpler and lighter molecules. Catalytic cracking is accomplished by the use of a catalytic agent and is an effective process for increasing the yield of gasoline from crude oil.

Catalytic Reforming—A refining process run at high temperature with a catalyst to convert paraffinic and naphthenic hydrocarbons into high octane stocks, primarily aromatics suitable for blending into finished gasoline.

Coking—A process by which heavier crude oil fractions can be thermally decomposed under conditions of elevated temperatures and pressure to produce a mixture of lighter oils and petroleum coke. The light oils can be processed further in other refinery units to meet product specifications. The coke can be used either as a fuel or in other applications such as manufacturing steel or aluminum.

Common Carrier—Transportation line or system carrying persons or goods for compensation, impartially for all persons or shippers.

Compatibility—*See* Product Compatibility.

Complex Emissions Model (also called "complex model")—A term for the equations describing the relation between fuel properties and regulated emissions. Starting in 1997, emission performance for gasoline will be calculated by the complex emission model specified by the EPA. The model methodology allows each refinery to vary certain individual parameters to best meet emission standards. As of June 1993, no final choice of model had been made.

CO Nonattainment—Regions of the United States that do not attain EPA air quality standards for carbon monoxide.

Constant Dollars (in this report labeled "1990 dollars")—An economic term for dollars of constant purchasing value. Determined by discounting "then current dollars" for general inflation affects. In this study, then current dollars have been multiplied by the GDP (Gross Domestic Product) deflator to convert to 1990 dollars.

Cost of Capital—For this study, the difference between the Capital Charge and book depreciation (16 year book life). For the Capital Charge of $0.172 per year, Cost of Capital is $0.1095 per year with depreciation of $0.0625 per year per dollar of capital expenditure.

Crude Oil—A mixture of hydrocarbons that exists in liquid phase in underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities.

Crude Oil Distillation—The refining process of separating crude oil components at atmospheric pressure by heating to temperatures of about 600 to 750 degrees Fahrenheit (depending on the nature of the crude oil and desired products) and subsequent condensing of the fractions by cooling.

Current Dollars—*See* Then Current Dollars.

Deadweight Tons (DWT)—The number of tons of cargo, stores, and bunkers that a vessel can carry. It is the difference between the tons of water a vessel displaces in its "light" and loaded condition. A vessel's cargo capacity is less than its total deadweight tonnage. Deadweight capacity can be expressed in long tons or metric tons.

Depreciation—The charge to operating expense for the decrease in productive life of an asset with time. For financial accounting purposes, depreciable life approximates economic life of an asset. For tax purposes, depreciation is defined by asset category.

Diesel Fuel—A distillate fuel used in diesel engines. *See* Off-Highway Diesel Fuel, On-Highway Diesel Fuel, Railroad Diesel Fuel.

Discounted Cash Flow (DCF)—The present worth of a series of cash amounts distributed over time. The discount factor in project finance applications which equates the present worth of the expenditures and cash flow is known as the project rate of return (ROR).

Distillates—Petroleum fractions nominally in the middle boiling point range (approximately 300 to 659 degrees Fahrenheit). As used here, includes diesel fuel and home heating oil.

Domestic (Capacity/Supply)—Volumes produced within the United States. *See also* Offshore (Capacity/Supply).

EPA—Environmental Protection Agency; an independent federal agency in the executive branch that coordinates governmental action in regard to the environment.

Ethane—A normally gaseous straight-chain hydrocarbon. It is a colorless paraffinic gas that boils at a temperature of minus 127.48 degrees Fahrenheit. It is extracted from natural gas and refinery gas streams.

Ethanol—Ethyl alcohol (grain alcohol) usually manufactured by fermentation of a variety of organic materials, such as grain, potatoes, sugar, timber, and wastes. In the United States, most ethanol is made from corn. Can be used as an oxygenate in motor fuel. A mixture of 10 percent ethanol and 90 percent gasoline is sometimes called gasohol.

Financial Reporting System (FRS)—As started in 1974, the Department of Energy's FRS required line of business reporting by firms which were both in the top 50 publicly owned domestic producers or owners of at least 1 percent of oil, gas, coal, or uranium; or 1 percent of refining capacity or petroleum product sales. Since 1981, companies operating approximately 70 percent of the U.S. refining distillation capacity have been included in the system.

Foreign Regional Areas—For analytical purposes, six foreign regions of product supply to the United States were defined as the six foreign regions of potential supply of product to the United States: Canada, Northwest Europe, Mediterranean, Middle East, Latin America, the Pacific Rim.

Foundation Case I (FC-I)—NPC increasing U.S. demand foundation cases for the years 1995, 2000, 2010.

Foundation Case II (FC-II)—NPC no growth U.S. demand foundation cases for the years 1995, 2000, 2010.

Foundation Case III (FC-III)—NPC declining U.S. demand foundation cases for the years 1995, 2000, 2010.

Gasoline Grade—Refers to finished gasoline octane grade, e.g., regular unleaded.

Gasoline Type—Refers to finished gasoline meeting requirements of a given area, e.g., reformulated gasoline and conventional gasoline are two types of gasoline.

Gasoline Volatility—The properties of gasoline that characterize its tendency to evaporate. Reid Vapor Pressure and ASTM distillation are two measures of gasoline volatility.

Gravity—A measure of the density, that is the weight per unit volume of petroleum liquid, usually expressed in either degrees API or related to water as a specific gravity. API gravity is a measure of density in degrees API; specific gravity is the weight per unit of a liquid as related to water.

High Sulfur Fuel Oil—Normally fuel oil of 3.5 (or higher) wt% sulfur content.

Home Heating Oil—Distillate fuel oils used for domestic heating or moderate-capacity industrial burners.

Hydrocarbons—Components containing hydrogen and carbon.

Hydrocracking—A refining process that uses hydrogen and catalysts at high pressures for converting middle boiling or heavy material to gasoline blendstocks, reformer charge stock, distillate blendstocks, and low sulfur heavy oils.

Hydrotreating—A refining process for treating petroleum fractions from atmospheric or vacuum distillation units (e.g., naphthas, middle distillates, reformer feeds, residual fuel oil, and heavy gas oil) and other petroleum (e.g., cat cracked naphtha, coker naphtha, gas oil, etc.) in the presence of catalysts and hydrogen. Hydrotreating includes desulfurization, removal of substances (e.g., nitrogen compounds) that deactivate catalysts, conversion of olefins to paraffins, and other processes to upgrade the quality of the fractions.

Incremental Cost-Effectiveness—as used by the EPA, the economic criteria for evaluating the level of regulation based on the incremental emissions reduction and cost of the reduction.

International Energy Agency (IEA)—An autonomous body within the Organization for Economic Cooperation and Development (OECD) to implement an international energy program.

International Maritime Organization (IMO)—A U.N. agency responsible for maritime safety and environmental protection of the seas, to which all major shipping nations belong.

Isobutane—The branched chain form of butane that is extracted from natural gas or refinery gas streams. It is normally used as an alkylation process feedstock in a refinery, or, more recently, as feedstock to dehydrogenation process for production of isobutylene.

Isobutylene (also called isobutene)—The branched isomer of butylene that reacts to produce MTBE.

Isomerization—A refining process that rearranges the atoms in a molecule. One use is to convert normal butane into isobutane, an alkylation process feedstock.

Jones Act—Commonly used term for the Merchant Marine Act of 1920 that provides for the protection of the U.S. merchant fleet by excluding foreign-built, owned, or operated ships from the U.S. domestic trades. The Jones Act covers all waterborne transportation between U.S. ports, including inland waterways, Great Lakes, and the oceanborne trade between the U.S. mainland and the noncontiguous areas of Alaska, Hawaii, and Puerto Rico; also designates all vessel personnel, longshoremen, and harbor workers as "seamen" and wards of the federal court.

Light Products—Here defined as the sum of gasoline, jet fuel, and distillates (diesel fuel, home heating oil, No. 1, No. 2, No. 4 fuel oils, and kerosene).

Logistics System—The combination of facilities that distribute petroleum products from refineries to customers to meet local demand. As premised in this study, the system is operated to minimize the cost of products delivered by choice of refinery source and transportation mode up to the capacity of such facilities.

Low Sulfur Fuel Oil—Normally 1.0 wt% or lower sulfur fuel oil.

Methane—The simplest, i.e., single carbon, hydrocarbon; normally the predominant molecule in natural gas.

Methanol—Methyl alcohol; made from natural gas, coal, biomass, and many other organic substances.

Midgrade—Middle octane grade of gasoline.

Minimum Operating Inventory—The lowest inventory at which "normal" supply operations are maintained. At lower levels, the system may incur abnormal costs to maintain consumer supply and there may be other problems (e.g., runouts).

Minor Products—All non-major refinery products, i.e., products other than gasoline, jet fuel, distillates, and residual fuel oil.

Motor Gasoline (Finished)—A complex mixture of relatively volatile hydrocarbons, blended to form a fuel suitable for use in spark-ignition engines.

Naphtha—A generic term applied to a petroleum fraction with an approximate boiling range between 122 and 400 degrees Fahrenheit. Used as a petrochemical feedstock or feedstock for gasoline production. Parts of naphtha can be suitable for motor gasoline blending.

Natural Gas Liquids (NGL)—High vapor pressure, hydrocarbon liquids separated from wet natural gas and moved by pipeline to a fractionation facility where the components are separated into ethanes, propanes, butanes, and natural gasoline.

Neat—The material prior to blending; e.g. neat ethanol or neat MTBE.

Net Investment in Place—An accounting term as used in the EIA Financial Reporting System covering Net Property, Plant, and Equipment plus investments and advances to unconsolidated affiliates. In practice, for domestic refining industry aggregate, Net Investment in Place is approximately equal to Net Property, Plant, and Equipment.

Net Property, Plant, and Equipment (PP&E)—The accounting category which is the difference of total expenditures for property, plant, and equipment less accumulated depreciation.

No. 2 Oil—Collective description of No. 2 Fuel Oil (home heating oil for the purposes of this glossary) and No. 2 Diesel Fuel (off-highway, on-highway, and railroad diesel fuel for the purposes of this glossary).

Nonattainment Area—Regional area that is not in compliance with criteria set forth in the Clean Air Act (e.g., ozone

nonattainment, CO nonattainment). *See also* Attainment Area.

Northeast Ozone Transport Corridor (NOTC)—Composed of the New England states, Pennsylvania, New Jersey, Delaware, Maryland, and the District of Columbia metropolitan area for purposes of establishing complementary regulation of interstate ozone air pollution under the CAAA.

NOx—Nitrogen Oxides. Chemical compounds containing nitrogen and oxygen; reacts with volatile organic compounds in the presence of heat and sunlight to form ozone. It also contributes to acid rain.

Off-Highway Diesel Fuel—Diesel fuel burned in engines or vehicles designated as "Nonroad" in the Clean Air Act, excluding locomotives (railroad diesel fuel). Off-road vehicles can be used on-highway and must use ultra-low sulfur diesel fuel.

Off-Specification Product—Finished product that is not in compliance with specifications.

Offshore (Capacity/Supply)—Volumes produced outside the United States, even by domestic companies. *See also* Domestic (Capacity/Supply). The U.S. possessions, Puerto Rico and the Virgin Islands, are considered offshore in this study.

Olefins—Hydrocarbon molecules with at least one double bond between carbon molecules.

On-Highway Diesel Fuel—Diesel fuel used by on-highway vehicles. Taxed and subject to EPA regulations re sulfur content and cetane quality.

One-Time Expenses—Non-recurring expenditures, such as those for one-time remediation, that are accounted for as an expense in the year incurred rather than capitalized.

Operable Capacity—The amount of refining capacity that, at a given date, is in operation or not in operation and not under active repair, but capable of being placed in operation within 30 days; or not in operation but under active repair that can be completed within 90 days.

Operating Capacity—The component of operable refining capacity that is in operation at a given date.

Operating Expense—In the financial chapter of this study, the sum for labor, services, utilities, and depreciation for operations. Does not include basic crude oil raw materials. Does include purchased oxygenates and incremental materials pursuant to meeting new product quality requirements.

Opt-In—The option of the ozone nonattainment areas, other than the original nine cities, to join, or "opt-in" to, the reformulated gasoline program at the request of the state and acknowledgement of the EPA.

Oxygenate—Oxygen-containing compounds, such as alcohols and ethers, approved by the EPA for use in gasoline (e.g., MTBE, ethanol).

Oxygenated Gasoline—Gasoline containing oxygenates, which meets the Clean Air Act requirements for winter gasoline in CO nonattainment areas.

Oxygenate program reformulated gasoline (OPRG)—Under CAAA, gasoline sold during winter months in 39 cities that are CO nonattainment areas which will contain 2.7 percent (by weight) of oxygen; and which, after 1995 must also meet reformulated gasoline requirements (excepting the limit of 2.0 percent oxygen).

Ozone—A compound consisting of three oxygen atoms, which is a significant constituent of smog. It is formed through chemical reactions in the atmosphere involving volatile organic compounds, nitrogen oxides, and sunlight.

Petroleum Administration for Defense District (PADD)—A geographic aggrega-

tion of the 50 states and the District of Columbia into five districts originally designed by the Petroleum Administration for Defense in 1950 for purposes of administration.

PADD I	U.S. East Coast
PADD II	U.S. Midwest
PADD III	U.S. Gulf Coast
PADD IV	U.S. Rocky Mountain states
PADD V	U.S. West Coast, Alaska, and Hawaii

Petroleum Products—A generic term used to describe products obtained from distilling and processing crude oil, unfinished oils, natural gas liquids, blendstocks, and other miscellaneous hydrocarbon compounds.

PM-10—Particulate Matter. A standard for measuring the amount of solid or liquid matter, under 10 micrometers in diameter, suspended in the atmosphere.

Pollution Abatement Gross Annual Cost—As defined by the Department of Commerce, Bureau of Census MA-200, "Survey of Pollution Abatement Costs and Expenditures," includes operation and maintenance of plant and equipment, depreciation of same, materials, fuel/power and services to abate air and water pollution and for solid waste management.

Premium—Premium octane grade gasoline.

Product Compatibility—The ability to mix separate batches of a specific, complying product type with the resulting product remaining on-specification: a quality necessary for the effective operation of the logistics system.

(R+M)/2—(Research octane + Motor octane)/2; an octane index calculated as the arithmetic average of the research and motor methods for determining motor gasoline octane.

Railroad Diesel Fuel—Diesel fuel for use in locomotives.

Rate of Return (ROR)—*See* Discounted Cash Flow.

Rationalization—The reduction of industry capacity by shutdown of individual units within a refinery or of entire refineries. The results of rationalization include increases in utilization of remaining capacity and increases in operating efficiency.

Reference Value—1989 product values based on publicly reported 1989 product prices for supply regions.

Refinery Capability (to produce light products)—In this study, based on EIA 1989 U.S. operable capacity and crude oil input plus blended inputs (MTBE). For later years, includes announced capacity additions. Represents industry capability to produce light products.

Reformate—General term referring to the high octane gasoline blendstock resulting from reforming processes. *See* Catalytic Reforming.

Reformulated Gasoline (RFG)—Gasoline with different properties than conventional gasoline that results in the emission of lower levels of air pollutants from vehicles. Meets the requirements of the Clean Air Act Amendments of 1990, including, on average, at least 2 wt% oxygen, less than 1 wt% benzene, and reductions in emissions of volatile organic compounds and toxic air pollutants.

Reforming—*See* Catalytic Reforming.

Regular—regular octane grade gasoline.

Reid Vapor Pressure (RVP)—A measure of product volatility, measured in pounds per square inch (psi). The higher the RVP, the more volatile a gasoline is and the more readily it evaporates.

Resid—The heavier hydrocarbons contained in crude oil that have higher boiling points in the distillation process.

Residual Fuel Oil—Fuel oil blended with resid. Because of its physical proper-

ties this fuel oil is burned primarily in larger boilers such as electric-utility and industrial boilers and in ships. For purposes of compliance with sulfur emission restrictions, four levels of sulfur in residual fuel oil are defined in this report: 0.3 wt% – Very Low Sulfur Fuel Oil; 1 wt% – Low; 2 wt% – Medium; and 3.5 wt% – High.

Return on Investment (ROI)—For this study, a measure of financial performance, calculated by dividing net income on an annual basis (after taxes but before interest) by average net investment in property, plant, and equipment.

Shortfall—Shortage of material relative to amount required.

Sour Crude Oil—A crude oil having a sulfur content of more than 0.5 percent (by weight).

Specification Product—Finished gasoline in compliance with all specifications (e.g., octane, RVP, distillation). *See also* Off-Specification Product.

Spillover—The supply of Clean Air Act-mandated fuels to areas not requiring such material because of limitations on the distribution (logistical) system.

Spot Market—Commodity transactions whereby participants make buy-and-sell commitments of relatively short duration, in contrast to the "contract" market in which transactions are long term.

Sulfur Content—The amount of sulfur in crude oil or petroleum product, expressed as a percentage by weight. This sulfur can be in the form of elemental sulfur, mercaptan sulfur, hydrogen sulfide, or other sulfur compounds.

Summer—Second and third calendar quarters.

Sweet Crude Oil—A crude oil having a sulfur content of less than 0.5 percent (by weight).

Tariff—(1) The document published by the common carrier pipeline owner setting rates charged and rules and regulations under which these services will be performed. Interstate common carriers must file tariffs with the Federal Energy Regulatory Commission.

(2) Import duty.

Then Current Dollars—Dollars as spent. Also known as "current dollars," "actual dollars," "nominal dollars," "dollars of the day," "as spent dollars." The dollar value used in financial accounting, including accounting for capital expenditures for assets and their depreciation.

Topping/Reforming—Literally atmospheric crude oil distillation capacity plus catalytic reforming capacity (to convert distilled naphtha to gasoline). In this volume and in common industry usage, topping/reforming capacity includes any refinery capacity remaining after coking and cracking capacity is fully utilized.

Toxics—*See* Air Toxics.

Transition Periods—Periods before and after seasonal specification changes when product specifications are potentially influenced by logistical constraints (e.g., delivery of oxygenated gasoline prior to its mandated requirement to ensure compliance with the Clean Air Act).

Ultra-Low Sulfur Diesel Fuel—Diesel fuel of maximum 0.05 wt% sulfur content required by the EPA for on-highway applications, starting October 1993.

U.S. Flag Fleet—All ships registered in the United States.

Waiver—The EPA can grant waivers from the requirements for oxygenated gasoline in a CO nonattainment area, based on inadequate domestic supply of or distribution capacity for oxygenated gasoline, or the deleterious effect of oxygenate on other certain air pollutants (NOx).

Winter—First and fourth calendar quarters.

INDEX

A

Additives, 325
Air pollutants, hazardous, MACT, 93
Air regulations, local, 80
Alcohol, 140-141
  isopropyl, 143
Alkylation, 347
Alkylation units, 251
Alternative transportation fuels. *See* Vol. II, Appendix E
Ambient Air Quality Standards, 85
American Tanker Rate Schedule (ATRS), 167
Amoco-EPA Yorktown study, 7, 67-68. *See also* Vol. III, Appendix K, Section III
Annual Energy Outlook, 1990, 25, 323
Antidumping regulations, 233, 239
Aromatics, 216, 251, 283
  extraction, 347
  reduction, 225-226
  saturation, 344
Assumptions, development of, 176-183

B

Barge transportation, 166, 366
Bechtel study, 83-100. *See also* Vol. III, Appendix K, Section II
Benzene, 216-217, 225, 233, 251, 283
Benzene waste NESHAP, 80
Bonner & Moore Associates, 126. *See also* Vol. IV, Appendix L, Section IV-1
Butane/butylene, volumetrics, 148
Butane dehydrogenation, 148

C

Calibration and validation runs, 122
California Air Resource Board
  Phase 2 gasoline, 2, 6, 20, 37, 145, 216, 218-222, 237
  diesel fuel, 300-305
  rule-making activity, 224-225
  standards outside California, 269
California regulatory costs, 2
Canada, 188
Capital expenditures, 5, 16-18, 31-37, 80, 219-220. *See also* Vol. III, Appendix J, Section III
Carbon monoxide, 105
  nonattainment areas, 215
  nonattainment gasoline, 141
Caribbean refining, 339
Cash flow, 43, 46-52
Catalytic cracking, 251, 344
Catalytic reforming, 347
Clean Air Act of 1967, 8
Clean Air Act Amendments of 1990, 1, 5, 8, 19, 20, 32, 85, 101, 140, 157, 215, 218-221
Clean product pipelines, 365-366
Clean Water Act/NPDES, 80, 94
Closed loop, 94
Coker gasoline fractionation, 251
Coking, 344
Complex emissions model, 237-281
Construction permits, 82
Consumer costs, 33-34, 56-58. *See also* Vol. III, Appendix J, Section V
Consumer product demand, 126
Cost assumptions, 151-155
2000 Cost Break Target Case, 244-251
Cost curve break point, 15
Cost estimation, methodology of, 69-70
Cost projection, 83
Cost sensitivities, 16, 67, 97
Cost-volume relationship, 106, 195-196. *See also* Vol. IV, Appendix L, Section VIII
Crude oil, 176
  atmospheric distillation, 341
  constant quality, 230
  distillation, 251
  high-sulfur vs. low-sulfur, 320
  quality, 318-323

D
Deferred taxes, 46
Demand development
carbon monoxide and ozone nonattainment areas. *See* Vol. IV, Appendix L, Sections III-4 and III-5
domestic, 111-114. *See also* Vol. IV, Appendix L, Sections III-1, III-2, III-3, and III-6
foreign, 114-120
worldwide. *See* Vol. IV, Appendix L, Sections I and III-7
Demand volumetrics, 150-151
Demands, factors affecting, 123
Diesel fuel, 123, 292-298
CARB, 300-305
facility changes, 294
low aromatics, 16, 300-303
low sulfur, 80, 222-224, 227
quality requirements, 292
ultra-low sulfur, 6-8, 218
Distillate, 131, 180, 292-305
modeling, 230
product rates, 350
survey results, 307
ultra-low sulfur, 298-300
varying demand, 314-316
Distribution logistics, 146
Dried distillers grain, 144

E
Emission controls
calibration, 133
improvements, 5
refinery, 126, 355-357
validation, 137
Emission performance standards, 216
Emissions models, 216, 229, 231-281
Emissions reduction, cost-effective solution, 244
Environmental control systems, Bechtel methodology for cost estimating, 83-84
Environmental cost information, 70-77
current, 70, 79-82
future, 70-71, 82-96
historical, 70-78
Environmental cost recovery in marketplace, 7
Environmental improvements
capital expenditures, 53
cost recovery, 7
Environmental legislation, summary of. *See* Vol. II, Appendix F
Environmental Operations Primer. *See* Vol. II, Appendix I
Environmental Protection Agency (EPA), 7, 15-16, 23-26, 215-216, 222
rule-making activity, 224-225
Environmental regulations, 10
impact on refineries, 357
stationary source facilities, 61
Ethanol, 20, 105, 123, 140-141, 143-144, 325
blending, 145-146
California, 227
corn (wet milling), 148
legislation/regulatory environment, 145-146
production costs, 152-153
regulatory concerns, 276
use in reformulated gasoline, 274-276
Ethers, 143, 162
Europe, northwest, 188
Exports, 189-191. *See also* Vol. IV, Appendix L, Section VII-11

F
Feedstocks, 348
costs, 154
Financial data, historical, 39-42
Financial Reporting System (FRS), 33, 39-59
Fluid catalytic cracking, 344
Foreign flag tankers, 169
Foreign netback adjustments, 128
Foreign products, 123
demand, 22-25
health, safety, and environmental regulation, 22
supply cost, 6, 21-25
Foreign refining industry, 22, 186-189
background study development, 174-176. *See also* Vol. IV, Appendix L, Sections VII-1 through VII-9
stationary emissions, 181. *See also* Vol. IV, Appendix L, Section VII-10
supply issues and, 369
Foundation Cases, 102, 111-120, 137-139
findings, 198-200. *See also* Vol. IV, Appendix L, Section IX
Fuel oil, 180

G
Gasohol, 123-124, 141, 151

Gasoline, 180
comparison of properties, 246
conventional, 123, 215, 216, 226, 274
costs, 4-5
ethanol blending, 145
fractionation, 249, 347
grades, 122
modification, cost-effectiveness, 216
motor, 131
oxygenated, 5, 20, 80, 123, 215
pool description, 246
product rates, 350
refining and logistics costs, 13
reformulated. *See* Reformulated gasoline (RFG)
survey results, 307
types, 122
varying demand, 314
Geographic factors, 99
Ground water protection, 95-96

H

Harbor maintenance fee, 171
Hazardous air pollutants, 93
Hazardous materials, phase-out of, 96
Hazardous waste, disposal of, 93
Health and safety, 82, 96
Historical costs, 71, 78
History of refining operations. *See* Vol. II, Appendix H
History of U.S. petroleum supply, demand, and logistics. *See* Vol. II, Appendix G
Hydrocracking, 251, 347
Hydrofluoric acid, 96
Hydrogen, 348
Hydrotreating, 341

I

Import duties and fees, 169-171
Import/export assumptions, 183
International Maritime Organization, 166
Isobutylene, MTBE and TAME from, 148
Isomerization, 347
Isopropyl alcohol, 143

K

Kerojet, 180
Kerosene, product rates, 350
Kerosene/jet fuel, 123, 131, 309
product rates, 350

L

Land ban restrictions, 95
Latin America, 189
Lead, 8
anti-knock compounds, 233
Light products, 124, 137, 307
Logistics costs, 4, 13, 15
Logistics model, 124. *See also* Vol. IV, Appendix L, Sections IV and VI-1
consumer product demand, 126
contractor, 126
development, 125
Logistics system, 13-15, 18, 127, 156, 288
environmental costs, 157
transportation cost matrix. *See* Vol. IV, Appendix L, Section VI-2

M

Maximum Achievable Control Technology (MACT), 93
Mediterranean, 188
Merchandise processing fee, 170
Merchant Marine Act of 1920, 167
Methanol, 143, 148, 162
Middle East, 188
Model
calibration, 133
contractor, 126
output, 183-189
validation, 137
Modeling
assumptions and premises, 230, 326-328
results, 309-314
specifications, 328
Motor fuel production rates, 220
MTBE (methyl tertiary butyl ether), 16, 20, 37, 144, 162, 325
capital investment costs, 154
from FCC isobutylenes, 148
performance standard and, 276
production costs, 154

N

National Emission Standards for Hazardous Air Pollution (NESHAP), 80
Nitrogen oxides (NOx), 16, 93, 218, 221, 225-227, 231, 239
Northeast Ozone Transport Corridor, 6, 20, 141
Notice of Proposed Rulemaking (NPRM), 218

O

Octane enhancement, 162
Oil Pollution Act, 1990, 166
Oil Price Handbook and Oilmanac, 128
Oil Spill Liability Fund, 171
Olefin reduction, 225, 266, 282
One-time expenses, 81
Operating and maintenance expenses, 81
Organization for Economic Cooperation and Development (OECD), 102
Oxygen content, 216, 231, 283
Oxygen-containing compounds, 142-143
Oxygenates, 6, 8, 14, 20, 37, 124, 137, 140-144, 225. *See also* Vol. IV, Appendix L, Section V
  costs for new facilities, 142
  future, 150
  geographic spillover, 21
  historical overview, 140
  imports, 145
  properties, 142
  refinery produced, 347
  spillover, 146
  supply and distribution of, 364
  supply volumetrics, 146-148
Ozone, 93
Ozone nonattainment areas, 5-6, 122, 140, 144, 217, 233

P

Pace Consultants, 181, 215. *See also* Vol. IV, Appendix L, Sections VII-2 and VII-9
Pacific Rim, 139, 189
Performance Profiles of Major Energy Producers, 41
Permits, 82, 93
Petroleum Administration for Defense Districts (PADDs), 14-15, 101, 183-186, 216
Petroleum Marketing Annuals, 128
Pipelines, 5, 8
  clean product, 365-366
  throughput data, 133
  transportation costs, 161-166
Process plants, investment, 181
Process water, 94
Products
  compatibility, 5, 18-19, 160-161, 215, 288-291
  costs, 127-128, 139, 191-195, 203
  demand, crude oil quality and, 216
  distribution and transport mode, 359
  quality, 178, 225, 227
  rates, 350
  supply, 25-29, 124-127, 200
  transportation, 359
Production capabilities and flexibility, 305-318
Profitability, 42-46

R

Rail transportation, 366
Recommendations, 6-7
Reference point calculation, 131, 139
Refineries, U.S.
  California, 323
  complexity, 316-317
  construction permits, 82
  emission sources and controls, 355-357
  health and safety, 82
  impact of environmental regulations, 357-359
  operating, maintenance, and one-time expenses, 79
  planned expenditures, 79-80
  regulatory impacts on individual, 335-339
  size, 318
  topping/reforming, 317
Refinery blendstocks for oxygenate blending (RBOBs), 288
Refinery capacity basis, 230
Refinery facilities
  capabilities and utilization, 6, 25-29, 213-214, 339-354
  changes and cost-effective solution, 246
  stationary source, 61-100
Refinery model, 216, 228-229. *See also* Vol. V, Appendix M
  assumptions and premises, 230, 326-328
  EPA complex, 237-239
  linear program, 331
  specifications, 328-331
Refinery product demand, 230, 327
Refining
  availability of resources and, 20
  capability, 5, 19-20, 215
  capacity, 177
  cost shifts for RFG, 251-254
  environmental cost recovery, 7
  investment, cost, and regional variation, 244
  logistics costs and, 4, 13
Refining industry, foreign. *See* Foreign refining industry

Refining industry, U.S.
background study development, 174-176. *See also* Vol. IV, Appendix L, Sections VII-1 and VII-2
capability utilization, 213-214
cash flow criterion and market outlook, 50
comparative profitability, 42-46
comparisons, 339
costs, 4-5, 10-15, 33-34, 37-39, 70-96
distillation capacity and number of, 8
environmental emission controls, 10
financial analysis, 31-59
financial background, 39-49. *See also* Vol. III, Appendix J, Section III
financial implications for, 58-59
financial performance, 33
historical investment, 46-49
historical performance, 39-42
modeling, background of, 174-176
modeling results for 1995, 310
modeling results for 1989, 309-310
modeling results for 2000, 310
motor fuel production rates, 220
product supply and utilization, 6, 25-29
projected interest and dividends, 50
projected investment, 49-56. *See also* Vol. III, Appendix J, Section IV
regional and size impacts on, 220
regulatory uncertainties and concerns, 221
stationary source facilities, 61-100, 181
stationary source regulatory cost, 4, 10-13
total cash flow, 52
Refining, marketing, and petroleum transportation activities (RMT), 33
Reformulated gasoline (RFG), 20, 37, 80, 102, 122, 215-216, 222-231
amount produced, 251
California, 226-227
composition, 251
cost, 217, 291
cost-effectiveness of, 7, 218, 281-288. *See also* Vol. V, Appendix M
emissions reduction performance, 19, 216
modeling, 230
performance standard, 276
performance variation, 254-269
Phase II of CAAA, 239
processing costs, 14, 16
program requirements, 231
specifications, 328
Region development, 120-122
Regional products, 131-133
Regulation, costs of, 34-39, 181
Regulatory concerns, 20, 221, 287
Regulatory requirements, 144-145
Reid Vapor Pressure (RVP), 123, 231
reduction, 16, 19, 216, 225, 282
Resources, availability of, 20
Rule-making activity, 224

S

Seasonality, 277-281, 328
Simple emissions model, 231-235
Soil, contaminated, 13, 95
Solid waste management units, 95
Spillover, 172, 328
SRI International, 333. *See also* Vol. VI, Appendix N
Stationary source emissions control costs, 14
Steel Trade Liberalization Program Implementation Act of 1990, 145-146
Storm water, 94
Strategic Petroleum Reserve (SPR), 323-325
Study design and concepts, 68-71
Subgroups of the Supply, Demand, and Logistics Task Group, 105-106
Sulfur, 233, 298
crude oil, 320
reduction, 225-226, 265, 282
Sulfur oxides (SOx), 93
Superfund tax, 170
Supply assumptions, 144-146
Supply/demand/logistics effort, 101-111
Supply/demand regions, 109
Supply volumetrics, 146-150
Survey, 333. *See also* Vol. VI, Appendix N
Bechtel utilization of, 84
data information, 334-335
description of, 334
results, 235, 335-371

T

TAME (tertiary amyl methyl ether), 20, 144, 162
from FCC isobutylenes, 148
performance standard and, 276
Tanker transportation, 166-169, 366. *See also* Vol. IV, Appendix L, Section VI-4
Taxes, deferred, 46
Technology trends, 325
Terminals, 171-172, 364

Toxic air pollutants (TAP), 218, 225, 231, 239
Transportation, 171, 359, 366
Turner, Mason & Company, 215. *See also* Vol. V, Appendix M, Section II

U

U.S. Department of Energy's Energy Information Administration (EIA), 20
U.S. Flag (Jones Act) Tankers, 157, 167-169. *See also* Vol. IV, Appendix L, Section VI-3
U.S. oil products
    cost buildup, 203-213
    supply trends, 200-203

V

Vapor recovery, 172
Volatile organic compounds (VOC), 14-16, 93, 218, 225-227, 231, 239, 276
Volumetrics
    butane/butylene, 148
    demand, 150-151
    methanol, 148
    oxygenates, 146-148
    supply, 146-150

W

Waste, solid, 13, 62, 80, 95
Waste water, 13, 94-95
Western State Petroleum Association, 237
Wet milling process, ethanol from corn, 148
World oil demands. *See* Vol. IV, Appendix L, Section I
Worldscale, 169

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