MERGERS IN THE PETROLEUM INDUSTRY

REPORT OF THE FEDERAL TRADE COMMISSION

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TABLE OF CONTENTS

APPENDIX B

BACKGROUND CORRESPONDENCE

APPENDIX C

COMMISSIONERS' SEPARATE STATEMENTS

I. INTRODUCTION AND SUMMARY

By letter dated January 15, 1982, addressed to Chairman Miller, the Chairmen and Ranking Minority Members of the Senate and House Judiciary and Commerce Committees requested that the Federal Trade Commission conduct an investigation of mergers and acquisitions involving large oil companies. The Senators and Congressmen noted a perception that merger activity by petroleum companies had increased and that several members of Congress had sponsored legislation to impose a moratorium on oil company mergers.

The letter requesting the study suggested that the inquiry focus on the following issues:

> (1) the numbers and size and a description of the terms of such mergers in each of the last ten years; (2) factors influencing such mergers, including the role of oil price decontrol, and the causes for their recent acceleration in number; (3) the impact on competition and on the availability and prices of petroleum products to consumers; (4) the effect of acquisitions in diverting investment capital for the exploration for and development of energy sources; (5) the extent of concentration in each major sector of the petroleum industry, the impact of such concentration on competition, and the impact of mergers on concentration levels; (6) the transactional costs of such mergers, including fees to lawyers, investment bankers, and accountants, and the time expended by company officials in connection with the transaction; and (7) the extent of any asserted efficiency justifications for such mergers.

In preparing this report, the Commission has relied on data from a variety of internal and external sources. One important source is the information subpoenaed in a number of past investigations and litigations concerning the oil industry. These materials were supplemented by data obtained from the Department of Energy, responses to questionnaires sent out to 21 oil companies, interviews with members of the industry, published sources of petroleum industry data, and statistical studies relating to acquisitions and competitive activities in the oil industry.

Section II of this study is a brief overview that provides background information on the petroleum industry. As discussed in that section, the industry includes the exploration for and the production of crude oil, the refining of crude oil into various products, transportation of crude oil and refined products, and the distribution and sale of refined products.

Section III of the study provides the results of two studies undertaken by the Commission in response to the first component of the Congressional inquiry. The first study examines acquisitions by large petroleum companies from 1971 through 1981. This study indicates that there has been an increase in the acquisition activity of large petroleum companies since 1978. An important part of this increase can be accounted for by three particularly large acquisitions, suggesting that an examination of the reasons underlying particular transactions may be as informative as a search for general reasons for increased merger activity in this area. Acquisitions of fossil fuel deposits also figured prominantly in this increased acquisition activity. The second study reported in Section III compares the level of acquisitions by large oil companies from 1979 to 1981 with the level of acquisitions by a sample of other large firms over the same time period. This study also shows that the large petroleum companies engaged in greater acquisition activity after 1978, particularly when compared with a sample of nonpetroleum companies. When compared with other types of companies, large petroleum companies' increased acquisition activity was markedly directed towards acquisitions of fossil fuel deposits. In terms of ownership of domestic crude oil reserves, these acquisitions had only minor effects on concentration.

Section IV of this study discusses and evaluates factors that underlie a firm's decision to make an acquisition, with special attention devoted to the potential incentives for oil industry mergers and acquisitions. This section responds to the second, fourth, sixth, and seventh Congressional inquiries. Mergers and acquisitions are presumably effected to maximize profits (in a general sense), and can accomplish this goal in a number of ways. Among the goals commonly cited are increased efficiency, increased market power, regulatory and tax considerations, the capture of "undervalued assets", subjective management objectives, and a response to special financial factors. Although some mergers may be stimulated primarily by anticompetitive motivations, such mergers have almost certainly been greatly reduced by antitrust enforcement. Nonetheless, mergers stimulated primarily by other factors may have important competition implications, justifying scrutiny by antitrust authorities.

Price regulation and allocation of petroleum during the 1970's may have affected incentives for merger and acquisition activity. The recent "windfall profits tax" also had some effects upon incentives to merge. While it reduced the profitability of some types of efficiencies captured by merger activity, the tax also increased the rewards to certain forms of enhanced recovery that might result from mergers. Other tax incentives may stimulate mergers and acquisitions, including tax loss carry-forwards and tax-free exchanges.

One prominent motivation for mergers is the acquiring firm's belief that the stock of a target company is undervalued. Acquisitions of fossil fuel reserves have figured prominantly in the increased acquisition activity of major oil companies, indicating, evidently, that large oil companies have expectations about the future trend of oil prices which differ from those of the "market" in general. Only time will tell whether these different expectations were justified.

While profits and cash flows to the oil industry have increased significantly in the 1970's, the connection between cash flows and mergers is less than clear. Oil industry investments and acquisitions both increased during the past decade. However, acquisitions were not a major factor in oil industry growth.

Section V of the study discusses transaction costs associated with oil company acquisitions, as requested by the sixth Congressional inquiry. A review of the publicly available data and the results of a Commission survey indicate that the costs of planning, structuring, and carrying out most acquisitions — exclusive of the compensation paid to obtain the acquired company — constitute from one-half to one percent of the total purchase price. These data also suggest that, for a number of mergers, the transaction costs may have exceeded the one percent level. However, the available information does not include the full public costs of reviewing and enforcing laws pertaining to mergers. For any single merger, the actual transaction costs principally depend on five major variables: (1) whether the takeover is "friendly" or "hostile"; (2) whether the government intervenes once the transaction is announced, and the form such intervention takes; (3) the size and complexity of the transaction; (4) whether firms other than the initial offeror submit bids for the target company; and (5) whether shareholders of the target firm contest the transaction.

Section VI of the study responds to the Congressional inquiries regarding concentration and competition in the petroleum industry. Competitive relationships at the various horizontal levels of the industry are examined, including the likely geographic areas within which this competition occurs. These functional levels are crude oil acquisition and production, refining, transportation and the marketing of petroleum products. The competitive effects of past acquisitions, particularly at the crude and refinery levels, are separately discussed.

In assessing the competitive effects of a particular merger, the Commission and the courts have typically examined market share statistics to determine the extent to which a merger increases market concentration. A merger between two companies may be more suspect when market concentration is high or if the merging firms have significant shares within a given market. However, share statistics alone are not sufficient to determine the competitive effects of a particular acquisition. Many other factors are relevant, including barriers to entry, the price elasticity of demand, product homogeneity, and other factors influencing the likely success of collusive behavior.

Both domestically and internationally, there are thousands of crude oil producers, and concentration in crude oil production and reserves is quite low. Nonetheless, there are two potential sources of concern about the effects of petroleum mergers on the market for crude oil. First the OPEC cartel commands about 60 percent of free world crude oil production and over 75 percent of its proven reserves. Therefore, one reason for concern about such oil mergers is that they might inhibit one of the parties' ability under certain circumstances to undercut the cartel's ability to raise or maintain price. The second source of concern about mergers involving crude oil is that such mergers could have anticompetitive effects where there is reason to believe that relatively localized crude oil markets exist in the United States. The West Coast of the United States, for example, might be an appropriate geographic market for certain types of crude oil.

Oil refineries produce a variety of products from the light products (gasoline, kerosene), through the "middle distillates" (fuel oil and jet fuel, diesel fuels), to the heavy products from the "bottom of the barrel" (bunker fuel and residual fuels for industrial purposes). Although for some purposes one might treat all refined products as a relevant product market, limitations on supply and demand substitutability mean that at some times particular refined products may constitute relevant product markets. Firm conclusions could not be drawn concerning the geographic market for gasoline and middle distillates, the two most prevalent refined products. It appears that certain refining areas, where there may be bottlenecks in the flow of products from refineries to distribution terminals, may constitute individual competitive regions, at least in the short run. However, in most regions, concentration levels are relatively low. In other regions, where concentration is higher, particular mergers may raise antitrust concerns. This is especially true if entry may be retarded because of environmental regulations and crude access problems.

Over the last 30 years, the existing firms have significantly expanded capacity. If current trends in gasoline demand continue, major increases in market capacity may be a thing of the past, so that major refiner mergers should perhaps be given greater scrutiny in the future.

As in any acquisition, combinations among petroleum pipelines may be analyzed using horizontal merger analysis: identifying relevant product and geographic markets and determining concentration levels and assessing entry conditions to determine whether the acquisition or merger may create or enhance market power. Because of the potential economies of scale of certain pipelines, the possibility of market power exists. The degree of such market power will often depend on the size of the pipeline, which may confer unique competitive advantages upon it in comparison with other, smaller pipelines or alternative modes of transportation in a given service area. The effectiveness of pipeline regulation also influences the exercise of market power, even in concentrated pipeline markets. All these factors must be weighed and considered in the evaluation of mergers or acquisitions which involve the transfer of pipeline ownership by competing oil companies.

Wholesale gasoline markets may be more localized than refining markets, because of the importance of distribution and storage facilities in or near metropolitan centers. Although the precise borders for these markets have not been determined, potential markets are often distinguished by a cluster of terminals from which products are dispensed into trucks for distribution to retail outlets for gasoline and other products. The intensity of competition in these local markets seems to depend upon a number of factors including the level of concentration and the presence of independent, non-branded gasoline marketers. Many of the largest oil companies apparently do not directly supply the independents, as a matter of corporate policy. While this policy may have limited the independents' effectiveness in many areas, in other markets products seem more generally available, particularly when second-tier refiners are able to supply independent marketers. Therefore, a merger between a large refiner and a second-tier refiner may threaten the supply to independent marketers and should receive careful examination. For example, Mobil's attempted acquisition of Marathon presented two potential competitive problems in gasoline marketing. The combination of the two firms' gasoline marketing organizations would have been quite high, exceeding 30 percent in various metropolitan areas. Moreover, Mobil's policy of refusing to supply independents conflicted with Marathon's policy of freely supplying these independents. Thus, the acquisition could have threatened the independents' supply and reduced their competitive impact on the market.

In Section VII, the Conclusion, it is noted that significant mergers can be readily discerned in Hart-Scott-Rodino filings, scrutinized for anticompetitive potential, and prevented under Section 7 of the Clayton Act and Section 13(b) of the FTC Act if they are likely to have anticompetitive effects.

In complex acquisitions, such as Mobil-Marathon and Gulf-Cities Service, post-acquisition divestiture remedies or other remedies may be especially problematic. If effective relief can not be fashioned within the Hart-Scott-Rodino time periods, the Commission may be required to seek a preliminary injunction under Section 13(b) of the FTC Act, pending the issuance and resolution of an administrative complaint. During this time, difficult remedy questions can be addressed in a deliberate manner. For this reason, the Commission determined to seek a preliminary injunction against both the Mobil-Marathon and Gulf-Cities Service acquisitions.

By and large, recent acquisitions have not had an anticompetitive effect and many have presented opportunities for enhanced efficiency in the industry. Because the Commission believes that the antitrust laws are sufficient to remedy those acquisitions likely to have anticompetitive effects, a statutory moratorium on oil company mergers is not necessary. Such a merger ban could have an adverse effect on efficiency in the petroleum industry, discouraging the industry from exploiting opportunities for developing additional supplies of petroleum, or using existing supplies in the most efficient manner.

II. OVERVIEW OF THE PETROLEUM INDUSTRY

The petroleum industry consists of the exploration for and production of crude oil and related hydrocarbons, the refining of these materials, the transportation of both crude oil and refined products, and the sale of refined products. Although many smaller firms participate in only one sector of operations, all of the largest firms in the industry (the "majors"), and almost all of the firms just below the "major" category are fully integrated and participate in all four levels of operation. The eleven largest companies all ranked within the top 20 "Fortune 500" companies for 1981.[1]

In the past, crude prices were relatively stable for long periods of time. During the decade of the 1960's, for example, crude prices declined, reaching lows of $1.20 per barrel in the Persian Gulf by the end of 1969. During this time, bargaining between international oil companies and the Organization of Petroleum Exporting Countries (OPEC) was over pennies per barrel.[2] Crude oil prices had increased somewhat (in nominal, but generally not in real terms) throughout this period, but a sharp increase in oil prices occurred as a result of OPEC action in the fall of 1973, when Saudi Arabia reduced output by 25 percent and instituted a total embargo against the United States. Just before the embargo, crude oil sold for about $3.00 per barrel; within three months, refiners purchasing on the open markets were paying up to $22 per barrel.[3] Crude oil prices subsequently declined but then resumed their upward climb. For example, between 1950 and 1970 the price of fuel oil, expressed in constant 1972 dollars, fell by 6.7 percent.[4] Since 1973, crude oil prices have risen in constant dollar terms from about

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1 Fortune 259 (May 3, 1982). In addition, E.I. Du Pont de Nemours (parent of Conoco) ranked twelfth and U.S. Steel (parent of Marathon) ranked nineteenth. See Appendix E for a listing of 21 petroleum companies and the short form references used throughout this study.

2 R. Stobaugh & D. Yergin, Energy Future 25 (1979).

3 Id. at 28.

4 Resources for the Future, Inc., Energy in America's Future 93 (S. Schurr ed. 1979).

$3.00 per barrel to over $15.00 per barrel in 1981 (in 1973 dollars).

Another sharp increase in crude prices occurred in late 1978 when the petroleum output of Iran, OPEC's second largest exporter, fell from a normal level of 5.5 million barrels a day to 500,000 barrels a day by the end of the year.[5] The effect on open or spot market prices was immediate and extreme. For example, from the third quarter of 1978 to the second quarter of 1979, the average spot market price of heavy fuel oil increased by 79 percent.[6] Product shortages ensued and long gasoline lines became commonplace. In addition, on December 13, 1979, Saudi Arabia attempted to raise its crude oil price to $24 per barrel, a 33 percent increase over the price established over the previous six months. The attempt was successful and the average price paid by United States refiners for imported crude oil continued to rise in 1980. Simultaneously, the government in Iran announced its aim of restricting future exports to the United States.[7]

These price increases have led to a dramatic decline in American consumption of foreign oil. Imports of foreign oil have declined sharply — by 29 percent (in barrels) from 1979 to 1981.[8] During the same period, imports of OPEC oil have decreased by an even greater amount — 41 percent.[9] Nonetheless, imports of foreign crude are still significant, recently amounting to about 41 percent of total consumption (imports plus domestic production).[10]

Against this background of rapid price increases, government regulation of the

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5 Brookings Inst., Energy Policy in Perspective 603 (C. Goodwin ed. 1981) [hereinafter cited as Goodwin].

6 Id. at 606.

7 Id. at 632.

8 Department of Energy, Monthly Energy Review, 14 (April 1982).

9 Id.

10 Id. at 30-31.

petroleum industry has been reduced, including the elimination of federal controls over price and allocation of product. For example, the Mandatory Oil Import Program, a program that restricted the amount of foreign oil that could be imported and allocated import "tickets" to refiners, was in place between 1959 and 1973. This program was modified in the early 1970's into pricing and output controls using licenses and fees,[11] which have been lifted on a piecemeal basis.[12] The phase out of price controls was completed by President Reagan's January 1981 order deregulating the petroleum industry.[13] In this changed regulatory climate, companies now have a greater incentive to respond to market conditions, rather than to regulatory dictates. Lastly, the advent of Alaskan North Slope (ANS) production in 1977 brought to market a new source of crude oil that quickly became a significant component of domestic crude oil production, accounting for 18 percent of total United States crude oil production by the end of 1981.[14]

A. Crude Oil Exploration and Production

The crude oil segment of the petroleum industry is comprised of two principal functions: exploration and production. Exploration begins with the search for crude oil reservoirs through geological surveys and the drilling of exploratory wells, both on land and in water. Once oil is discovered, developmental wells are drilled to determine the size and shape of the reservoir and prepare it for production. The area containing many wells producing from one or more related reservoirs is called a field. Deposits of crude oil in the ground are called reserves. Most of the nation's crude oil reserves are located

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11 See Goodwin, supra note 5, at 421-34.

12 See e.g., 10 C.F.R. § 212.57 (1980) (exemption of No. 2 heating oil from price controls in 1976); 10 C.F.R. § 212.58 (1980) (exemption of jet fuel from price controls in 1979).

13 Exec. Order No. 12,287 (Jan. 28, 1981), implemented in 46 Fed. Reg. 20,508 (1981). See 2 Fed. Energy Guide (CCH) ¶ 14,500-15,602.

14 Dep't of Energy, Petroleum Supply Monthly 51 (Apr. 1982).

in (or in coastal areas adjacent to) Texas, Louisiana, New Mexico, Oklahoma, California, and Alaska.

Production is simply the process of removing the oil from its underground reservoirs. Oil may flow naturally from the well, or it may be removed through various chemical and mechanical methods. From the wellhead, crude oil is transported to a refinery for processing, usually via pipelines.

Exploration and production takes place both onshore and offshore. Onshore lands are acquired either from private parties, through purchase or lease, or by leases from the state and federal governments. Offshore activities take place primarily on tracts leased from the federal government.

Exploration for oil is a very fragmented part of the industry. Wildcatters provide much of this activity. These independent explorers search for new oil reserves but often leave the actual production to others. Numerous parties often have a financial interest in a producing property, but the production effort is generally undertaken by a single firm acting on behalf of all lease interest holders. This lease operator produces the crude oil, disposes of it, and distributes royalties and revenues. Additionally, a group of producing tracts may be "unitized" under state laws to coordinate production and maximize the yield of the reservior.

B. Refining

The purpose of a refinery is to transform crude oil into one or more of a wide range of products, from the "top of the barrel" light products (gasoline, propane, butane, and petrochemical feedstocks such as benzene, xylene, and propylene), through the "middle distillates" (home heating oil, diesel and jet fuel, and kerosene), down to the heavier products at the "bottom of the barrel" (residual fuel oil, petroleum coke, and asphalt). While most refineries produce a variety of products, they all are limited in their ability to adjust the relative proportion of products ("product slate") manufactured in response to changes in relative prices from a given supply of crude oil.

The extent to which refiners can alter the product slate in response to relative price differences depends importantly on three factors: the types of crude oil the refiner "runs" through its plant; the sophistication of the plant's processing equipment; and the rate at which the refiner feeds crude oil into the facility. Recent market demand trends have led most refiners to adjust their facilities to increase yields of gasoline, diesel fuel, jet fuels and petroleum feed stocks. Gasoline accounts for about one-half of the refinery output in the United States and an even greater amount of the dollar sales of refined products.

While most refineries can produce high proportions of gasoline from certain higher quality crude oils, there is a fairly specific fit between each refinery design and the crude oils that can be refined most efficiently.[15] If a refinery designed to operate on light crude were to run on heavy crude instead, the proportion of heavy, low-value products in its output mix would increase substantially, and this revenue loss would generally more than offset the lower price of the heavy crude. Conversely, if a refinery designed to process an inferior type of crude were to run a better crude instead, the value of the product slate would probably rise, but again, generally not enough to compensate for the higher crude price. These factors increase the importance to refineries of having continuing access to a reliable source of similar grade crude oil.

In general, more sophisticated equipment can be added to a refinery to alter the types of products manufactured, improve the yield of preferred products or accommodate lower quality crude oils.[16] Sophisticated refining equipment is expensive,

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15 "If a refinery processes a type of crude oil for which it was not designed, the effective throughput capacity of the refinery will in many cases be reduced substantially." The Basic Factors Underlying The Present Shortage of Refining Capacity In the United States: Hearings Before the Senate Comm. on Interior and Insular Affairs, 93d Cong., 1st Sess. 49 (1973) (statement of Orin E. Atkins, Chairman, Ashland Oil Inc. and Chairman Nat'l Petroleum Council's Comm. on Factors Affecting U.S. Petroleum Refining).

16 Nat'l Petroleum Council, Refinery Flexibility 174 (1980) [hereinafter cited as Refinery Flexibility].

however; both the capital outlay and total operating expenses are substantial.[17] As a result, only the larger refineries typically employ this equipment.[18] Nonetheless, there are small refineries with sophisticated equipment giving high yields of gasoline, lubricating oils, and other "top of the line" products.[19]

Refiners with less efficient technology can survive if they enjoy other advantages such as location. Historically, refineries were located to take advantage of local crude oil availability, existing supply routes, and proximity to population centers. While the growth of pipelines has reduced the importance of these factors, location can still be quite important. Particularly in regions such as the Rocky Mountain states, where pipeline linkages are not common, a regional refiner may enjoy substantial locational advantages that offset production disadvantages arising from its small scale.[20]

Changes in market conditions can have obvious effects on the viability of particular refiners. A reduction of transportation costs can undermine locational advantages. Changes in the relative prices of different crude oils can alter the value of sophisticated refining apparatus. Changes in the regulatory environment also can affect the advantages accruing to certain refiners, and changes in market demands for various refined products can contribute to a refiner's viability.

The last three factors have contributed greatly to recent trends in the refining industry. The declining availability of low sulfur crude, for example, has induced many

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17 Marathon's project to add a processing reformer to its Robinson, Illinois refinery to improve yield of no-lead gasoline cost $100 million.

18 A recent National Petroleum Council study concluded that larger, more sophisticated refineries may enjoy a competitive advantage over smaller, less complex plants because the larger ones can produce from lower priced crude oil a greater yield of more profitable light products and a lower amount of less profitable bottom of the barrel products. <u>Refinery Flexibility</u>, <u>supra</u> note 16, at 174-91.

19 <u>Id</u>. at 22.

20 <u>Id</u>. at 22-23.

refiners to add the additional equipment necessary to process high sulphur crudes. Much of the refining capacity that has been closed in the past year was eliminated, at least in part, because it could not process such crudes.[21]

A fundamental change which primarily affects small refiners is the withdrawal of subsidies that have favored these small operations since 1959. First, the mandatory oil import program and then the small refinery bias to the crude oil entitlements program provided small refiners a disproportionately large amount of crude oil below market price. The demise of such special treatment has already had a substantial impact upon the viability of many small refiners.

Another factor affecting refiners generally is the 15 percent decrease in oil consumption since 1978. It has been reported that forecasts of stagnant demand over the 1980's, the move to world pricing for domestic crude, and the increase in the demand for light products "all combined to destroy the economic viability of the majority of refineries which are either inflexible, unsophisticated or have relatively high operating costs," and will force "many more refiners . . . to close permanently."[22]

C. Transportation

Transportation of crude oil or petroleum products may be accomplished by pipelines, tankers, barges, railroad tank cars, and tank trucks. Pipelines are the predominant form of petroleum transportation because, except for localized, low volume or irregular movements, they are generally more economical and efficient than other modes of transportation. In 1974, some 87 percent of refinery inflows of domestic crude oil were delivered by pipeline, compared to 11 percent by tanker or barge and only 2

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21 One recent study concludes that while crude oil distillation and catalytic cracking capacities appear adequate for the 1980's, capacities for downstream conversion will require substantial expansion to meet future U.S. product needs. The industry may face a shortage of necessary conversion capacity by the mid 1980's. _See_ _Refinery Flexibility_, _supra_ note 16, at 5-6.

22 Oil Daily, Mar. 22, 1982, at B 20-21.

percent by rail or truck. Approximately 50 percent of all petroleum products movements are by pipeline, including most long distance movements. The network of interstate petroleum pipeline is extensive, consisting of about 227,000 miles of line.[23]

There are three types of pipelines: gathering lines, crude trunk lines, and product lines. Gathering lines are small diameter lines in an oil field used to collect crude oil from individual lease tanks for delivery to field storage tanks. Crude trunk lines are large diameter pipelines linking interior and offshore crude oil production areas with crude oil tanker loading and unloading terminals and with petroleum refineries. They play an important role in supplying both domestic and imported crude oil to refineries, moving imported crude oil from coastal ports to inland refineries, and moving crude oil from remote production areas, such as the Alaskan North Slope, to port terminals. The largest capacity crude oil pipeline is Capline, a 40-inch line carrying crude oil from St. James, Louisiana to Patoka, Illinois, with a throughput capacity of 1209 mb/d.[24]

Product pipelines are large diameter pipelines which carry refined petroleum products from refineries to product terminals serving regional markets. A terminal is a central storage and distribution facility, usually located adjacent to a pipeline, which handles a variety of petroleum products. The terminals are ordinarily owned and operated by one or more owners of the product pipeline serving the terminal. The largest capacity petroleum pipeline is the Colonial Pipeline, extending from the Houston, Texas refinery region through the eastern states to Linden, New Jersey. Colonial Pipeline accounted for about 40 percent of all product movements by pipeline in 1978.[25]

Most larger volume pipeline systems are "joint venture pipelines" owned by several oil companies. There are two types of joint venture pipelines — "stock companies" and

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23 Dep't of Energy, Petroleum Pipeline Deregulation, A Competitive Analysis 2 (May 1982) [hereinafter cited as DOE Pipeline Deregulation].

24 Id. at 58.

25 Oil & Gas J. 69 (Aug. 13, 1979).

"undivided interest" pipelines. A joint venture stock company is a distinct corporate entity organized to construct and operate a pipeline. Participants in the venture typically hold stock in the company in proportion to their anticipated shipments through the pipeline. The pipeline company issues one common set of tariff rules applicable to all shippers. In an undivided interest pipeline, although each participating pipeline company has an ownership share proportionate to its projected shipments, no separate pipeline company is formed. Rather, one of the participating pipeline companies typically serves as operator. Each participant publishes its own tariff rules for use of its respective share of space on the line. An undivided interest pipeline thus is one pipeline physically, but for many purposes, it may be viewed as a bundle of competing pipelines. In the 1970's, the 85 joint venture pipeline systems transported one-third of all crude oil and two-thirds of all product shipped by pipeline in the U.S.

To increase the throughput capacity, a pipeline can be expanded in a number of ways. The throughput can be increased either by the addition of pumping stations or the upgrading of existing stations or by adding pipe alongside the original pipe (called "looping"), either for small portions of the line or its entire length.

D. Marketing

The marketing of petroleum products begins at the terminals connected to the product pipeline. Terminals tend to be clustered in population centers adjacent to product pipelines. At the terminal, various grades of gasoline and other refined products are stored in large tanks. The terminal includes equipment (known as a "rack") to dispense product into delivery tank trucks. In 1980, domestic gasoline sales totalled about 96.3 billion gallons, which were distributed from 1,058 terminals to about 158,540 retail stations.[26]

Major brand gasoline generally refers to the sale of gasoline bearing the brand name of one of the 15 or so largest integrated refiners (e.g., Amoco, Texaco, Sunoco). Branded majors distribute gasoline directly to branded retail outlets, branded jobbers, and to other customers. Jobbers usually own some storage capacity and delivery equipment. A jobber will supply retail service stations which it either leases to independent dealers or operates itself. The vast majority of gasoline refined by majors is ultimately retailed through branded outlets.

Smaller independent refiners sell gasoline directly to their own retail dealers, to employee operated outlets, and, at the terminal rack, to unbranded jobbers. These refiners are called independents because they are not as fully integrated as the major oil companies and because much of the gasoline they sell is unbranded. Many smaller, nonintegrated firms are engaged exclusively in the private brand marketing of gasoline. The private brand marketing strategy usually relies upon low price and high volume. These marketers rarely have permanent, exclusive supply arrangements with any particular supplying refiner. The independent refiners and the independent private brand marketers together sell about 35 percent of all gasoline sold in the United States today.

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26 Nat'l Petroleum News, NPN Factbook 11, 34-42 (Mid-June 1981). The approximate 160,000 retail station figure does not include stores, such as 7-11's, which derive more than 50 percent of their sales from non-gasoline products.

III. MERGERS AND THE PETROLEUM INDUSTRY SINCE 1971: THE EMPIRICAL DATA

This section presents the results of two studies — undertaken by the Commission in response to the first component of the Congressional inquiry — which measure the absolute size and relative magnitude of merger activity involving large petroleum firms since 1971. The first study examines acquisitions by large petroleum companies from 1971 through 1981. The second study compares the level of acquisitions by large oil companies from 1979 through 1981 with the level of acquisitions by a sample of other large firms over the same time period.

A major difficulty in measuring the acquisition activity of large petroleum companies over time is the distortions caused by inflation and the even more rapid increases in the value of oil industry assets since 1971. These distortions are partially responsible for the perception that merger activity involving petroleum companies has increased. After adjusting for the effects of inflation, the study of acquisitions by major oil companies indicates an increase in the acquisition activity of large petroleum companies in the period after 1978. Prominent in this increase in acquisition activity is a marked increase in fossil fuel reserves acquisitions. Discerning the impetus for such acquisitions is probably important in understanding the reasons for the increase in acquisition activity. In addition, three large acquisitions in the 1979-1981 period accounted for a substantial proportion of the increase in total acquisition activity, suggesting that the particular reasons underlying these transactions may also provide an important component of the explanation of the increased merger activity in the oil industry.

The results of the second study also indicate that the large petroleum companies engaged in greater acquisition activity in the 1979-1981 period compared with a control group of other large companies having no involvement in the petroleum industry. However, when compared with the acquisition activity of a second control group (composed of companies having some prior [pre-1978] involvement in the petroleum industry), the large petroleum companies do not appear to have engaged in significantly greater acquisition activity in recent years. The results of this study are also significantly influenced by the impact of a few large transactions. These studies are discussed in detail below.

A. Acquisitions Involving Large Petroleum Companies Since 1971

In requesting a review of petroleum company mergers, Congress asked the Commission to "focus on mergers and acquisitions of assets or stock in which the acquiring or acquired firm is a large domestic or international petroleum company or an affiliate." The study reported in this section was designed to provide a profile of merger activity by this set of firms from 1971 through 1981. Limited exclusively to mergers and acquisitions by large petroleum firms, the study provides information on the level of petroleum company acquisition activity in the past decade and on the changes in the frequency and size of these transactions throughout the period.

1. Methodology

Although the terms "large petroleum company" and "mergers and acquisitions" have colloquial meanings, these terms are not sufficiently precise to permit the construction of meaningful merger series. The definitions of a "large petroleum company" and "an acquisition" as well as the procedures used in the analysis are discussed below. The data sources used in this study are discussed in Appendix A.

a. Identifying "large petroleum companies"

The study categorized companies as large if they ranked among the top 100 firms of the Fortune 500 as of January 1, 1971.[1] Firms were treated as "large petroleum

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1 Fortune, "The 500 Directory," May 1971. This procedure provides a manageable universe of large firms from which to define a group of large oil companies and permits the inclusion or exclusion of firms based on a review of their operations. Selection from the list of the Fortune 500 excludes two categories of firms: those not classified as "industrial" by Fortune and privately held firms. We do not believe that the first exclusion is unreasonable. Although there are nonindustrial firms (such as Union Pacific) that have significant oil interests, their oil-related activities are not sufficiently important relative to their other activities to warrant
(continued)

companies" based on the size of their domestic crude oil production and domestic refining activities relative to total firm operations as of January 1, 1971.[2] Table III-1 presents the raw data and several ratios involving crude production, refining capacity, assets and sales for two groups: (a) the sixteen large petroleum companies in the Fortune 100, and (b) the seven Fortune 100 which possessed significant crude production or refining operations but were excluded from the group of large petroleum companies because their petroleum related activities were small relative to their other activities. The companies included in the group of large petroleum companies are listed as numbers 1-16 in Table III-1 and those which were excluded from this group are listed as numbers 17-25. While the selection of firms to be included as large petroleum companies required some subjective evaluation, the figures presented in Table III-1 indicate that the

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classification as an industrial firm. The exclusion of privately held firms is unavoidable. If a firm is privately held, not only is it very difficult to determine if the firm belongs in the top 100 of the Fortune 500, but data on its crude production, acquisitions and dispositions are generally unavailable.

2 Classifying firms with a 1971 benchmark avoids the possibility that a firm's merger activity over the period studied would influence whether or not it is included in the sample. Failure to adopt this procedure could overstate merger activity before the selection date relative to merger activity after the selection date. This is because active acquirers in the period prior to the selection date would be more likely to be included in the sample than firms which were not active acquirers or which were divesting operations in the period prior to the selection date.

Similar considerations underlie the process for classifying a firm as a "large petroleum company." The aim was to select a sample on an objective basis unrelated to the firms' merger activity in the period studied and therefore to avoid selecting only those companies that have attracted public attention through their recent acquisition activity. For example, suppose the group of firms whose merger activity is to be studied was selected by choosing only those oil companies that made major acquisitions in the period 1979 through 1981. This procedure could easily lead to a conclusion that there had recently been a dramatic increase in merger activity by large petroleum companies when in fact this was not the case. Thus, suppose that the process generating large oil company mergers is approximated by a 25 percent chance of a large acquisition by a given firm in any three-year period. The odds of a firm in the sample making a large acquisition in any preceding three-year period would then be 1 in 4. If the sample included only those firms making large acquisitions, then each included firm would have made an acquisition in the current period. The selection procedure would then be expected to find a four-fold increase in merger activity while in fact the process generating mergers was stable. While this example is extreme, any subjective selection procedure risks being influenced by a firm's merger activity subsequent to 1970.

excluded firms were generally less involved in crude production and refining than the petroleum firms included in the study group.

Table III-1. Listing of 1971 Fortune-100 Companies with Significant Oil Interests

Oil Companies	Fortune Rank	Assets as of Jan. 1, 1971 (million dollars)	1970 Sales (million dollars)	1970 U.S. net domestic crude and NGL (000 bbl/d)	Refining capacity as of Jan. 1, 1971 (000 bbl/d)	Col. (4) ÷ Col. (2)[1]	Col. (4) ÷ Col. (3)[1]	Col. (5) ÷ Col. (2)[1]	Col. (5) ÷ Col. (3)[1]
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1. Getty Oil	95	$1,946	$1,221	313.0	207.0	16.08	25.63	10.64	16.95
2. Shell Oil (U.S.)	19	4,610	3,589	599.6	1,011.5	13.01	16.71	21.94	28.18
3. Union Oil	57	2,515	1,811	311.4	444.0	12.38	17.19	17.65	24.52
4. Sun Oil	48	2,767	1,942	257.9	455.0	9.32	13.28	16.44	23.43
5. Atlantic Richfield	30	4,392	2,738	405.7	681.7	9.24	14.82	15.52	24.90
6. Cities Service	62	2,193	1,714	197.4	281.0	9.00	11.52	12.81	16.39
7. Phillips Petroleum	39	3,057	2,273	270.7	398.0	8.86	11.91	13.02	17.51
8. Standard Oil (Indiana)	16	5,397	3,733	466.6	1,040.4	8.65	12.50	19.28	27.87
9. Texaco	9	9,924	6,350	796.1	1,029.5	8.02	12.54	10.37	16.21
10. Gulf Oil	11	8,672	5,396	626.0	713.8	7.22	11.60	8.23	13.23
11. Standard Oil (California)	14	6,594	4,188	474.4	974.4	7.19	11.33	14.78	23.27
12. Continental Oil	31	3,023	2,712	204.0	299.0	6.75	7.52	9.89	11.03
13. Standard Oil (New Jersey)	2	19,242	16,554	960.8	1,087.0	4.92	5.71	5.65	6.57
14. Mobil Oil	6	7,921	7,261	385.0	794.0	4.86	5.30	10.04	10.95
15. Standard Oil (Ohio)	83	1,747	1,374	30.6	439.0	1.75	2.23	25.13	31.95
16. Ashland Oil	79	1,000	1,407	11.1	328.3	1.11	.79	32.83	23.33
17. Signal Cos.	78	$ 1,323	$ 1,412	36.5	70.0	2.76	2.59	5.29	4.95
18. Tenneco	34	4,344	2,525	74.7	84.0	1.72	2.96	1.93	3.32
19. Occidental Petroleum	40	2,563	2,240	13.2	0	.52	.59	0	0
20. Swift	23	825	3,076	n.a.	29.5	—	—	3.58	.96
21. Union Carbide	24	3,564	3,026	n.a.	0	—	—	0	0
22. Monsanto	47	2,145	1,972	16.2	0	.76	.82	0	0
23. W.R. Grace	50	1,575	1,918	n.a.	0	—	—	0	0
24. Dow Chemical	51	2,780	1,911	n.a.	17.0	—	—	.61	.89
25. Allied Chemical	91	1,582	1,248	n.a.	8.5	—	—	.54	.68

Table III-1. Listing of 1971 Fortune-100 Companies with Significant Oil Interests--continued

n.a. -- not applicable

-- not calculated

1 Since the decimal point has no particular significance in ratios of crude production or refinery capacity (measured in 000 bbl/d) to sales or assets (measured in millions of dollars), it has been moved to the right to make the data more readable.

Source: Cols (1) - (2): Fortune "The 500 Directory," May 1971.

Col. (4): FTC Economic Report on Concentration Levels and Trends in the Energy Sector of the U.S. Economy, March 1974 at 194.

American Petroleum Institute, Market Shares and Individual Company Data for U.S. Energy Markets: 1950-1979, API Discussion Paper, October 30, 1980.

Company Annual Reports and SEC forms 10-k.

Col. (5): Department of Interior, Bureau of Mines, Minerals Industry Survey, "Petroleum Refineries in the U.S. and Puerto Rico," January 1, 1971.

b. Defining an acquisition

This study employs two definitions of an acquisition. The first, and narrower, definition embraces only the acquisition of entire companies; that is, acquisitions of stock or assets which result in the disappearance of a business operating in the U.S. whose stock was not held exclusively by another corporation. This type of acquisition is referred to as a "whole company acquisition." The second definition of acquisition includes whole company acquisitions, plus all other acquisitions of stock of companies operating in the U.S. or of assets located in the U.S., with the following exceptions:

> corporate reorganizations;
>
> the acquisition of undeveloped real estate, undeveloped oil and gas leases, or of similar inputs into a production process;
>
> the acquisition of oil or coal production payments;
>
> the acquisition of an interest in a joint venture through contributions of assets rather than through cash purchase; and
>
> the closing out of a joint venture through a division of assets rather than a cash buyout.[3]

Acquisitions covered by this second definition are referred to as "total acquisitions." All total acquisitions which are not whole company acquisitions are referred to as "asset acquisitions."

Mergers which eliminate independent business entities and those which do not have been treated separately because the two types of transactions may be sufficiently different in their motivations and effects to warrant distinct consideration. If an entire company is acquired, an independent actor necessarily disappears, and the survivor is larger than either of the predecessor entities. On the other hand, if companies sell

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3 Corporate reorganizations involve changes in corporate organization and do not comprehend purchases of assets or the stock of another company. The second category would embrace a large number of transactions by companies in the ordinary course of business. Sales of production payments are not treated as acquisitions because these transactions are simply a form of debt financing. The treatment of joint ventures distinguishes between those transactions which alter a firm's operations and those which primarily change only its organization.

portions of their assets to other firms, no independent actors disappear. In addition, the larger firm involved in such a transaction is not necessarily the one to grow. Moreover, cash acquisitions and sales of assets, when viewed in conjunction with each other or together with capital expenditures, may simply be a means of shifting a firm's resources between different areas (e.g., refining and retailing) without affecting overall firm size.

The main difficulties in applying these definitions arise in the context of multiple-step transactions. Several instances of acquisitions accomplished through two or more steps were encountered. Indeed, it appears increasingly common for an acquirer to buy an interest in another firm—usually a controlling interest—in one period and acquire the remainder later for stock or debt. Such transactions were treated as whole company acquisitions if (a) the acquirer owned less than 51 percent of the stock of the acquired company on January 1, 1971, and (b) the acquirer eventually purchased 100 percent of the stock of the acquired entity. If these criteria were not met, the transaction was treated as an asset acquisition. If a transaction met these criteria and was completed within a single calendar year it was consolidated and considered as a single acquisition in the data. If a transaction meeting the criteria began and concluded in different calendar years,[4] it was treated as two transactions. That is, the compensation paid in each year was included in the data for whole company acquisitions in that year, and the assets and

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4 Mobil's acquisition of Marcor is an example.

sales of the acquired firm were entered in proportion to the ownership interest acquired in that year.[5]

A final category of transaction deserving explanation is one in which several business entities with common ownership are acquired. This study treated such transactions as one acquisition. Although some such links at the stockholder level may have been overlooked, the acquiring company's form 10-K usually indicated such relationships.

c. Oil company acquisition activity: 1971-1981

Tables III-2 and III-3 provide summary information regarding the number and size of oil company acquisitions in each year from 1971 through 1981. The data in Table III-2 refer only to whole company acquisitions. Column 1 of Table III-2 lists the total number of whole company acquisitions by year which were valued at $10 million or more, while column 2 provides the total value of these acquisitions. Columns 3 and 4 present the assets and sales, respectively, of the acquired companies.

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5 Thus, in the Mobil-Marcor example, Mobil is recorded as acquiring $832 million in 1974 and $859 million in 1976 measured in terms of purchase price. Mobil will also be recorded as acquiring 55 percent of Marcor's assets and sales in 1974 and 45 percent in 1976. The data for each year are considered whole company acquisitions.

The procedures described for multi-step acquisitions have two noteworthy limitations, one potential and one actual. The potential problem is the possibility that whole company acquisitions could be understated if the observation period ended before the second step of an acquisition is completed. By the same token, the technique could understate whole company transactions in the early 1970's if the January 1, 1971 origin falls between the first and second steps of significant acquisitions. Because both steps of a transaction occurring in the middle of the observation period are more likely to fall within the period's boundaries than are both steps of transactions occurring at the period's beginning or end, the data on whole firm acquisitions could show an artificial bulge in the mid-1970's. The actual merger data, however, did not indicate that any significant acquisitions spilled over either the start or finish of the period.

The second limitation is that the available data for some multi-step acquisitions do not show whether the two criteria described above were satisfied. In such cases, the transactions are treated as asset acquisitions, which may not be correct. Such ambiguities appear to be restricted to relatively small transactions.

Table III-3 presents figures on total acquisitions. Column 1 lists the total number of acquisitions by year which were valued at $10 million or more, while column 2 lists the total value of these acquisitions. Columns 3 and 4 reflect the fact that many of the large petroleum companies both sold and purchased assets during the period studied. Thus, column 3 of Table III-3 gives the number of divestitures by these companies which were valued at $10 million or more, while column 4 gives the total value of acquisitions

TABLE III-2

Whole Company Acquisitions by the 16 Largest Petroleum Companies[1]

Year	Number of Acquisitions	Value of Acquisitions	Assets of Acquired Companies	Sales of Acquired Companies
		(in millions of dollars)		
	(1)	(2)	(3)	(4)
1971	1	26.0	92.0	72.0
1972	1	47.0	28.0	9.0
1973	1	10.0	13.0	13.0
1974	5	956.0	1,823.8	2,295.4
1975	2	36.0	47.7	89.8
1976	3	1,164.0	2,300.6	2,629.8
1977	7	1,351.1	2,034.6	1,485.1
1978	3	48.0	42.0	85.0
1979	9	5,989.0	2,025.0	1,828.0
1980	12	1,451.0	2,303.0	2,889.0
1981	8	3,145.0	5,195.0	5,490.0

1 Whole company acquisition of at least $10M.

Table III-3

Total Acquisitions and Divestitures by the Sixteen Largest Petroleum Companies[1]

Year	Number of Acquisitions	Value of Acquisitions (millions $)	Number of Divestitures	Value of Acquisitions Net of Divestitures (millions $)
	(1)	(2)	(3)	(4)
1971	2	113.0	0	113.0
1972	4	132.0	6	-289.0
1973	3	55.0	5	-184.0
1974	13	1,358.0	1	1,333.0
1975	7	678.0	0	678.0
1976	7	1,256.0	5	859.0
1977	13	1,598.0	2	1,542.0
1978	7	399.0	4	288.0
1979	14	7,140.0	11	4,907.0
1980	23	5,528.0	4	5,052.0
1981	19	4,553.0	8	3,549.0

1 Acquisition of at least $10M.

net of divestitures.[6]

Table III-4 provides information on the value and terms of each acquisition of $100 million or more in the study period.

The data presented in Tables III-2, III-3 and III-4 support the view that merger activity involving large petroleum companies has increased, particularly during 1979-1981 when compared with earlier years. This is so whether acquisition activity is measured by the value of total acquisitions, total acquisitions net of divestitures, or whole company acquisitions. For example, total acquisitons net of divestitures averaged $4,502 million per year over the period 1979-1981 compared with an average of $542 million per year over the period 1971-1978. Comparable averages for the value of whole company acquisitions are $3,528 million (1979-1981) and $455 million (1971-1978).

An interesting change in the pattern of acquisitions by the large oil companies occurred in the post-1978 period. The total value of acquisitions net of divestitures for the period 1971-1981 was $4.34 billion, and for the period 1979-1981, this total was $13.308 billion. For the period 1971-1978, the total value of energy (oil, gas, coal, shale) related acquisitions net of divestitures was $1.273 billion, while this figure for the 1979-1981 period was $8.788 billion. Therefore, energy-related net acquisitions as a proportion of total net acquisitions were 29.3 percent for the period 1971-1978, but increased dramatically to 63.1 percent for the period 1979-1981. Comparable figures for net large (greater than $100 million) energy related acquisitions as a percentage of total large acquisitions are 14.7 percent (1971-1978) and 62.3 percent (1979-1981). Clearly, a major feature of the increased acquisition activity of the large oil companies during the period 1979-1981 was the acquisition of fossil fuel reserves. The reasons for this change are uncertain. It seems clear that the large oil companies placed a greater value on

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6 Asset and sales-based measures of acquisition activity could not be used to measure total acquisitions because the necessary information is rarely available for acquisitions of less than an entire firm.

fossil fuel reserves than did the "market" in general, and as a consequence their acquisitions were part of the mechanism by which these resources were revalued subsequent to the 1979 oil shortage. Whether in fact these acquisitions will be justified by future oil prices is presently unknown.

The data presented in Tables III-2-4 must be used cautiously. All of the measures presented are biased towards finding an increase in merger activity. The most important sources of this bias are the general inflation between 1971 and 1981 (greater than 100 percent) and the even more dramatic increase in the value of most oil industry assets over the same period. The same physical assets would have a higher market and accounting asset value, and would generate a larger dollar sales volume in 1981 than in 1971 even after discounting for inflation. The reported values of acquisitions should be interpreted keeping inflation in mind.

Table III-4. Domestic Acquisitions and Divestitures Valued at $100 Million or More

Petroleum company	Price[1]	Year	Transaction	Type of asset involved
Std. Oil (IN)	272	1981	Acquired the mining operations of Harbert Corp for $10 cash and $262 stock.	Coal
Std. Oil of Calif	130	1981	Acquired phosphate reserves from Stauffer Chemical Co. for cash.	Non-Energy
Std. Oil of Calif	200	1981	Swap of Shale reserves for coal reserves with Du Pont.	Coal
Std. Oil of Calif	-200	1981	"	Shale
Gulf	331	1981	Acquired Kemmerer Coal Co. from Kemmerer Corp.	Coal
Gulf	120	1981	Acquired 50 percent interest in coal properties of Republic Steel.	Coal
Std. Oil (OH)	-1,770	1981	Acquired Kennecott.	Non-Energy
Std. Oil (OH)	607	1981	Acquired Coal reserves from U.S. Steel.	Coal
Std. Oil (OH)	106	1981	Acquired Gibbs Oil Co. from Gibbs Industries.	Marketing
Ashland	403	1981	Acquired U.S. Filter Corp. for cash.	Non-Energy
Ashland	238	1981	Acquired Integon for $115 cash and $123 stock.	Non-Energy
Ashland	-103	1981	Sold 25 percent interest in Ashland Coal Co. to West German Company.	Coal
Sun Co.	-252	1981	Sold Sperry-Sun to NL Industries.	Non-Energy
Sun Co.	-265	1981	Sold its Corpus Christi refinery to Koch Industries for cash.	Refining
Conoco	100	1981	Acquired Manor Coal properties from U.S. Steel.	Coal
Sun Co.	-140	1980	Sold its Duncan, OK refinery to Tosco for cash.	Refining
Sun Co.	2,389	1980	Acquired most assets of Texas Pacific from Seagrams for cash.	Oil and Gas
Getty	621	1980	Acquired Reserve Oil and Gas for cash.	Oil and Gas
Getty	568	1980	Acquired ERC Corp. for cash.	Non-Energy
Exxon	300	1980	Acquired 60 percent interest in Colony Oil Shale from Arco for cash.	Shale
Arco	-300	1980	Sold 60 percent interest in Colony Oil Shale to Exxon for cash.	Shale
Arco	270	1980	Bought out Halcon International's interest in Oxirane Chemical for cash.	Non-Energy
Mobil	715	1980	Acquired Transocean Oil from Esmark for cash/stock.[2]	Oil and Gas
Std. Oil (IN)	119	1980	Acquired Emerald Mines from LTV for cash.	Coal
Sun Co.	300	1979	Acquired Elk River Resources for stock.	Coal
Getty	266	1979	Acquired producing properties from Ashland for cash	Oil and Gas
Exxon	1,236	1979	Acquired Reliance Electric for cash.	Non-Energy
Ashland	-266	1979	Sold oil and gas properties to Getty for cash.	Oil and Gas
Ashland	-331	1979	Sold oil and gas properties to Mesa and Tenneco for cash.	Oil and Gas
Ashland	-117	1979	Sold oil and gas properties to Petro-Lewis for cash.	Oil and Gas
Std. Oil (OH)	105	1979	Acquired Webb resources and Newco exploration for cash/stock.[3]	Oil and Gas
Gulf	121	1979	Acquired Amalgamated Bonanza Petroleum for $2 cash and $119 stock.	Oil and Gas
Mobil	-653	1979	Sold 17.9 percent interest in Belridge to Shell for cash.	Oil and Gas
Mobil	792	1979	Acquired general crude from International Paper for cash.	Oil and Gas
Texaco	-623	1979	Sold 17.4 percent interest in Belridge to Shell for cash.	Oil and Gas

Table III-4. Domestic Acquisitions and Divestitures Valued at $100 Million or More--continued

Petroleum company	Price[1]	Year	Transaction	Type of asset involved
Shell Oil	3,653	1979	Acquired Belridge Oil for cash.	Oil and Gas
Std. Oil (IN)	462	1979	Acquired Cyprus Mines for $117 cash and $345 stock.	Non-Energy
Sun Co.	293	1978	Acquired 34 percent of Becton-Dickinson for $260 cash and $33 notes.	Non-Energy
Gulf	455	1977	Acquired Kewanee Industries for cash.	Oil and Gas
Arco	150	1977	Acquired the polypropylene assets of Diamond Shamrock for cash.	Non-Energy
Arco	517	1977	Acquired 73 percent of the common stock of Anaconda for $97 cash and $420 stock.	Non-Energy
Union Oil	234	1977	Acquired Moly Corp. for stock.	Non-Energy
Phillips Petroleum	-230	1976	Sold West Coast refining and marketing to Tosco.	Refining and Marketing
Mobil	859	1976	Acquired 45 percent of Marcor for stock and notes.	Non-Energy
Arco	267	1976	Acquired 27 percent of Anaconda's common stock and convertible debentures for cash.	Non-Energy
Std. Oil (IN)	224	1975	Acquired producing properties from Pasco	Oil and Gas
Std. Oil of Calif.	354	1975	Acquired 20 percent of Amax for $169.5 cash and $184.5 stock.	Non-Energy
Sun Co.	114	1974	Acquired the producing properties of Forest Oil for cash.	Oil and Gas
Mobil	832	1974	Acquired 55 percent of Marcor for cash.	Non-Energy
Std. Oil (OH)	-100	1973	Sold its Houston refinery and Southeastern marketing to Petrofina for cash.	Refining and Marketing
Arco	-157	1972	Sold Rocky Mountain refining, marketing and producing properties to Pasco for cash.	Refining, Marketing, Oil and Gas
Conoco	-105	1972	Sold its plant foods business to Williams Co. for cash.	Non-Energy

1 A minus sign indicates a divestiture, price is in millions of dollars.

2 Mobil bought Esmark stock for cash from the public and gave this stock to Esmark for Transocean.

3 Sohio purchased its own stock in market for reissue to Webb-Newco owners.

Inflation also causes a distortion in the number of acquisitions in each year reported in Tables III-2, III-3, and III-4 because the tables do not report acquisitions valued at less than $10 million and $100 million, respectively. Since the same physical assets will have a higher market value over time, the same acquisition is more likely to exceed the $10 million (and $100 million) threshold, the later in the period the transaction takes place. While the actual impact of this distortion is difficult to measure, the numerical predominance of small transactions in general merger statistics (see Tables III-5 and III-6) suggests that the impact could be substantial.

The basic effect of inflation on market value, assets and sales-based measures of merger activity is more obvious. For instance, if the large oil companies acquired exactly the same physical assets in each year, a measure of merger activity based on acquisition price would show virtually continuous increases. A similar effect would also occur if sales or assets were used to measure merger activity, although the increase in accounting assets would be less extreme.[9] A meaningful measure of an increase in merger activity should reflect more than simply an increase in the price level.

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9 Book assets will not immediately rise to reflect the price changes. Over a period of years, however, old low-valued assets will be replaced by assets valued at current prices.

Table III-5. Number of Mergers and Acquisitions Completed by Asset Size of Acquired Companies, 1979

Asset Size Class of Acquired Company ($ Millions)	A. Number	Average number per million interval
Total	1,214	
$100.0 and over	75	---
$50.0 to $99.9	57	1.1
$10.0 to $49.9	213	5.3
$1.0 to $9.9	123	13.7
Under $1.0 and unknown	746	746.0
	B. Percent	**Average percent per $1 million interval**
Total	100.0	
$100.0 and over	6.2	---
$50.0 to $99.9	4.7	.1
$10.0 to $49.9	17.5	.4
$1.0 to $9.9	10.1	1.1
Under $1.0 and unknown	61.4	61.4

* Sums may not always add due to rounding.
NOTE: Partial acquisitions are not included in above table.
Source: Bureau of Economics, Federal Trade Commission.

TABLE III-6

Frequency Distribution of
Value of Mergers

Price Paid Value	Percent of Transactions		Approximate Percent of Each $1 Million Interval	
	1970	1980	1971	1980
$1 million or less	6	5	6	5
$1.1 - 2.0	8	7	9	7
$2.1 - 3.0	8	8	8	8
$3.1 - 4.0	7	7	7	7
$4.1 - 5.0	7	7	7	7
$5.1 - 10.0	19	18	3.8	3.6
$10.1 - 15.0	9	9	1.8	1.8
15.1 - 25.0	10	9	1.0	.8
$15.1 - 50.0	11	12	.49	.48
$50.1 - 99.9	7	7	.14	.14
$100 million or more	8	11	--	--

Source: W.T. Grimm & Co., 1980 Merger Summary 7.

The indices presented in Table III-7 allow a comparison of how the sixteen large petroleum companies have fared relative to inflation. The first index is simply the GNP deflator and is shown in column 1 of Table III-7. The second index, shown in column 2, is an index of oil company market value and is computed as the ratio of the total market value of the 16 oil companies in each year to their total market value on January 1, 1971. Column 3 is an index of oil company assets, calculated in the same manner as the market value index. The fourth index, listed in column 4, is the ratio of the large petroleum companies' sales in each year to their sales in 1970.[10] The fifth index is the ratio of total funds from operations in each year to total funds from operations in 1972 and is listed in column 5 of Table III-7.

To correct for the general effects of inflation, the data in Tables III-2 and III-3 has been deflated by the GNP deflator. The deflated data is presented in Tables III-8 and III-9.

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10 The sales index ends in 1980 since 1981 sales data were not available.

Table III-7. Indices of Inflation and Oil Company Performance

Year	GNP Deflator[1] (1)	Market Value Index[2] (2)	Asset Index[2] (3)	Sales Index[2] (4)	Total Funds From Operations Index[3] (5)
1971	100	1.00	1.00	1.00	N.A.
1972	1.04	1.02	1.07	1.09	1.00
1973	1.10	1.21	1.13	1.36	1.07
1974	1.20	1.28	1.27	2.39	1.40
1975	1.31	.94	1.58	2.51	1.89
1976	1.38	1.12	1.71	2.84	1.48
1977	1.46	1.47	1.93	3.19	1.81
1978	1.56	1.37	2.13	3.49	1.98
1979	1.70	1.44	2.33	4.59	2.34
1980	1.85	2.05	2.79	4.06	3.46
1981	2.02	3.26	3.28	N.A.	4.5

1 Calculated from the Implicit Price Deflator for GNP, 1982 Economic Report of the President 236 (Table B-3).

2 Calculated from Compustat II, Data Tape, Industrial files, Standard & Poor's Corp. Annual.

3 Total funds from operations is defined as the sum of income before extraordinary items, deferred taxes, and depreciation, less unremitted earnings of unconsolidated subsidiaries. Standard and Poor's Compustat Services, Inc., Compustat II, sec. 9, p. 75 (December 21, 1981) [hereinafter cited as Compustat II]. This measure does not include changes in debt position, which can also generate cash for the firm.

The potential bias created by the use of a constant $10 million reporting threshold is addressed by using the GNP deflator to adjust the threshold from year to year. Thus, a time series of the number of mergers using the GNP deflator counts the number of acquisitions of $10 million or more in 1971, of $10.4 million or more in 1972, of $11 million or more in 1973, and up to acquisitions of $20.2 million or more in 1981. The results, for the numbers of whole company acquisitions, total acquisitions, and divestitures are presented in Table III-8 and III-9. A similar procedure is used to adjust the valuation, assets and sales measures of merger activity by the large petroleum companies. The results are also shown in Tables III-8 (for whole company acquisitions) and in Table III-9 (for total acquisitions and total acquisitions net of divestitures).

Table III-8. Deflated[1] Whole Company Acquisitions by the 16 Largest Petroleum Companies, 1971-1981[2]

		------------in millions of dollars----------		
Year	Number of acquisitions	Value of acquisitions	Assets of acquired companies	Sales of acquired companies
1971	1	26.0	92.0	72.0
1972	1	45.2	26.9	8.7
1973	0	0	11.8	11.8
1974	5	796.7	1,519.8	1,912.8
1975	2	27.5	36.4	68.5
1976	3	843.5	1,659.1	1,869.4
1977	7	925.3	1,393.5	1,017.2
1978	1	13.5	19.9	28.2
1979	8	3,516.5	1,174.7	1,005.9
1980	5	731.4	1,228.6	521.1
1981	8	1,556.9	2,571.8	2,712.9

1 Deflated by GNP deflator (1971 = 100) (Economic Report of the President, 1982).

2 Whole company acquisitions of at least $10 M in constant dollars.

Table III-9. Deflated[1] Total Acquisitions and Divestitures by the Sixteen Largest Petroleum Companies, 1971-1981[2]

Year	Number of acquisitions	Value of acquisitions ($ millions)	Number of divestitures	Value of acquisition net of divestures ($ millions)
	-----------------------	in millions of dollars	-----------------------	
1971	2	113.0	0	113.0
1972	4	126.9	6	-277.9
1973	2	40.9	5	-176.4
1974	12	1,123.3	1	1,102.5
1975	6	507.6	0	507.6
1976	7	910.1	4	631.2
1977	9	1,061.0	2	1,022.6
1978	4	230.1	3	166.0
1979	13	4,193.5 (3,045.5)[3]	11	2,880.0 (1,732.0)[3]
1980	16	2,935.1 (1,643.8)[4]	3	2,683.2 (1,391.9)[4]
1981	17	2,239.1 (1,347.8)[5]	8	1,742.1 (850.8)[5]

1 Deflated by GNP deflator (1971 = 100) (Economic Report of the President, 1982).

2 Acquisitions of at least $10 M in constant dollars.

3 Excludes Shell/Belridge

4 Excludes Sun/Texas Pacific

5 Excludes Sohio/Kennecott

Several features of this data deserve comment. First, while whole company acquisition activity is higher in 1979 (as measured by the market value of the acquisitions) and in 1981 (by all the measures) than in prior years, the difference is much smaller than in the undeflated data. Second, two transactions, the acquisition of Belridge by Shell in 1979 and of Kennecott by Sohio in 1981, account for most of the apparent increase in 1979 and essentially all of the increase in 1981. For example, subtracting the deflated purchase price for Belridge of $2.15 billion from the deflated market value total for 1979 in Table III-8 yields $1.37 billion, which while higher than in any preceding year, is much more in line with several of the values reported for prior years. Similarly, subtracting the deflated data for Kennecott from the 1981 total in Table III-8 yields a new market value total for the year of $680.7 million, a new asset total of $972.3 million, and a new sales total of $1.5 billion. These totals for 1981 are lower than the levels in several prior years.[11] Third, the deflated data also shows a much less dramatic increase in the value of total acquisitions and in the value of total acquisitions net of divestitures in the 1979-1981 period. (See Table III-4). Nevertheless, the figures still indicate a substantial increase in net acquisition activity for 1979-1981 compared with earlier years: when deflated, total acquisition net of divestitures averaged $2.48 billion per year from 1979-1981 and $386.1 million per year from 1971-1978. Again, an important part of the increase is accounted for by the Shell/Belridge and Sohio/Kennecott acquisitions, and by Sun's acquisition of the assets of Texas Pacific. The numbers in parentheses in Table III-9 exclude these large transactions. The deflated total value of acquisitions net of divestitures excluding these three large acquisitions averaged $1.32 billion per year from 1979-1981 compared with $386.1 million per year from 1971-1978. Roughly 46 percent of total acquisitions net of divestitures from 1979-

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11 It should be noted that since the sales by Mobil and Texaco of their interests in Belridge to Shell are accounted for as divestitures, the net effect of the Belridge acquisition on the acquisitions net of divestitures column of Table III-9 is only $1.4 billion.

1981 is accounted for by the three large acquisitions noted above.

The impact of inflation provides the major cause of distortion in the data, but it is not the only one. Although every effort has been made to identify oil company acquisitions in the 1971-1981 period, it is virtually certain that the data is to some extent incomplete. If the omissions were unsystematic, the reliability of the results would diminish but the results would not be biased toward any particular conclusion. However, the advent of the Hart-Scott-Rodino (HSR) premerger notification reporting requirements in late 1978 provides reason to suspect that the merger data will be more complete for the period of 1979-1981 than in the earlier period, leading to a bias in the study towards finding more mergers in the recent period.[12] The transactions most likely to be missed in the pre-HSR period but identified in the later period are those involving assets valued between $15 and perhaps $50 million. Since transactions in this range appear numerous relative to transactions of larger size, the distortion in measures of merger activity based on the number of transactions could be significant.

While there is no perfect solution to this problem, the possibility that differential success in identifying acquisitions is responsible for the apparent increase in acquisition activity after 1978 can be partially tested by restricting the analysis to transactions of a size certain to be identified throughout the period studied. Since in all likelihood transactions valued at $100 million or more have all been identified, $100 million is used as an additional threshold value, adjusted for inflation in the manner previously described. Table III-10 lists the number of deflated large whole company acquisitions, large total acquisitions, and divestitures by year from 1971-1981.

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12 A transaction for which an HSR report was filed is included in the study only if other information sources confirmed that the transaction was consummated. Thus, all such transactions were listed in a publicly available source in addition to the HSR filing. Many of these transactions were confirmed, however, by referring to annual reports, 10-K's, or Moodys entries for the other party to the transaction identified by the HSR filing. In the absence of the filing, they may not have been identified.

Table III-10. Number of Deflated[1] Large Acquisitions and Divestitures Per Year (deflated valuation $100 million or more)

Year	Deflated number of whole company acquisitions	Deflated number of total acquisitions	Deflated total number of divestitures
1971	0	0	0
1972	0	0	2
1973	0	0	0
1974	1	1	0
1975	0	2	0
1976	2	2	1
1977	3	4	0
1978	0	1	0
1979	4	6	4
1980	2	6	1
1981	5	6	2

[1] Deflated by GNP deflator (1971 = 100) (Economic Report of the President, 1982).

While it is less plausible that differential success in identifying acquisitions would materially affect the market value, asset, and sales measures of merger activity, this possibility can also be partially tested using the same procedure. The results of restricting the analysis to transactions with a deflated value of $100 million or more are presented in Tables III-11 (for large whole company acquisitions) and in Table III-12 (for large total acquisitions). With these corrections, the apparent increase in acquisition activity after 1979 remains for total acquisitions and total acquisitions net of divestitures. For whole company acquisitions, an increase over earlier years is much less apparent.

Table III-11. Deflated Large[1] Whole Company Acquisition Measures (in millions $)

Year	Deflated market value of acquired companies	Deflated total assets of acquired companies	Deflated sales of acquired companies
1971	0	0	0
1972	0	0	0
1973	0	0	0
1974	693.3	1,441.5	1,898.6
1975	0	0	0
1976	815.9	1,647.5	1,840.4
1977	826.0	1,286.0	841.8
1978	0	0	0
1979	3,324.1	922.9	775.9
1980	642.7	1,075.7	1,162.2
1981	1,492.1	2,501.5	2,576.7

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1 Deflated by GNP deflator (1971 = 100) (Economic Report of the President, 1982).

Table III-12. Deflated[1] Large Total Acquisition Measures (in millions $)

Year	Deflated Market value of total acquisitions	Deflated market value of total acquisitions net of divestitures
1971	0	0
1972	0	-251.9
1973	0	0
1974	693.3	693.3
1975	441.2	441.2
1976	815.9	649.3
1977	928.8	928.8
1978	187.8	187.8
1979	3,946.5	2,844.7
1980	2,628.6	2,466.5
1981	1,792.6	1,536.6

1 Deflated by GNP deflator (1971 = 100) (Economic Report of the President, 1982.

Correcting only for general inflation still leaves a somewhat misleading picture since the price of oil, and in particular, the oil company assets, sales, and market value all increased at a much faster rate than the general index of inflation. To place oil company acquisition activity in the perspective of what has happened to the oil industry in the past ten years, the market value, assets, and sales of whole company acquisitions are expressed in Table III-13 as percentages of oil company market value, assets, and sales, respectively. In addition, the market value of whole company acquisitions is expressed as a percentage of total flow of funds of the oil companies. In Table III-14, total acquisitions and total acquisitions net of divestitures are expressed as percentages of the market value and of total funds from operations of the large petroleum companies.

One of the major activities of oil companies is acquiring oil reserves, either through exploration and development or through acquisition of reserves already held by others. Because of the increase in the price of oil and associated increased valuation of reserves, it would be expected that the value of acquisitions of oil reserves (and other fossil reserves) would have increased markedly in the last ten years and faster than the general rate of inflation.[13] The data presented in Tables III-13 and III-14 provide a partial control for this effect. For example, oil company market value, assets, sales and flow of funds all increased because of increases in the price of oil, so that expressing acquisitions as percentages of these financial indicators is a crude method of controlling for oil price effects. This method also controls for oil company size, which may be important in that larger companies might be expected to engage in a greater value of acquisition activity. Finally as the companies' total flow of funds increased, it would not be surprising if acquisitions also increased. It would be expected that the companies would use the increased funds for payouts to stockholders (dividends or stock purchase) or

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13 If the future trends in oil prices and technology result in more substitution among different types of fossil fuels, the acquisition of fossil fuel reserves other than oil will become increasingly important.

for investments (which could include exploration and development, purchase of capital or other assets, or acquisitions). Notice that net acquisitions have never been more than 20% of total funds from operations. In general, the figures in Table III-14 reflect relatively greater acquisition activity for 1979-1981 compared with the earlier period.

Table III-13. Whole Company Acquisitions: Percentage of Oil Company Financial Indicators[1]

Year	Market value of acquired companies as percentage of market values of oil companies	Market value of acquired companies as percentage of funds from operations of oil companies[2]	Assets of acquired companies as percentages of assets of oil companies	Sales of acquired companies as a percentage of sales of oil companies
1971	.04	--	.11	.11
1972	.07	.4	.03	.01
1973	0	.06	.01	.01
1974	1.18	6.20	1.67	1.49
1975	.06	.2	.04	.06
1976	1.64	7.15	1.57	1.39
1977	1.45	6.80	1.23	.71
1978	.04	.22	.02	.02
1979	6.54	23.31	1.01	.58
1980	1.04	3.82	.93	1.05
1981	1.50	6.35	1.86	--

-- Not available.

1 Market values, assets and sales of the large petroleum companies are as of January 1 of each year as reported in Compustant II, Data Tape, Industrial Files, Standard and Poor's Corp. annual. The value of acquisitions and divestitures are totals through the end of the calendar year.

2 Funds from operations are as defined in note 3, Table III-7.

Table III-14. Total Acquisitions: Percentages of Oil Company Financial Indictors[1]

Year	Market value of acquisitions as percentage of oil company market value	Value of acquisitions as percentage of oil company funds from operations	Value of acquisitions net of divestitures as percentage of oil company market value	Value of acquisitions net of divestitures as percentage of oil company funds from operations[2]
1971	.18	N.A.	.18	N.A.
1972	.20	1.20	-.45	-2.63
1973	.06	.47	-.24	-1.57
1974	1.66	8.80	1.63	8.64
1975	1.13	3.26	1.13	3.26
1976	1.77	7.71	1.21	5.28
1977	1.66	8.05	1.60	7.76
1978	.43	1.83	.32	1.32
1979	7.80	27.79	5.35 (2.77)[3]	19.10
1980	4.15	14.54	3.79 (2.04)[3]	13.29
1981	2.14	9.19	1.68 (.86)[3]	7.16

1 Market values, assets and sales of the large petroleum companies are as of January 1 of each year as reported in Compustant II, Data Tape, Industrial Files, Standard and Poors Corp. Annual. The value of acquisitions and divestiture are totals through the end of the calendar year.

2 Funds from operations are as defined in note 3, Table III-7.

3 Figures in parentheses omit the three very large transactions occurring in 1929-1981.

B. Comparison of Merger Activity Between Large Petroleum Companies and Other Large Companies

In this section, the acquisition activity of large petroleum companies is compared with the acquisition activity of other large firms over the period 1979-1981. The principal purpose of this study is to determine whether the recent acquisition activity of large petroleum companies differs substantially from the aquisition activity of other large firms.

1. Methodology

The definitions used in the previous study for classifying a given transaction as an asset acquisition or a whole company acquisition also apply in this comparison. The large petroleum companies were selected from the top 100 of the Fortune 500 (as of 1978 instead of 1970). Again, the selection was based on the involvement of these companies in the domestic oil industry as measured by their domestic crude production and refining capacity.[14]

The acquisition activity of these companies is compared with that of two other groups of firms. The first group consists of 16 Fortune-100 companies that have limited interests in the oil industry. Companies in this group are called petroleum-related companies. Their involvement in the petroleum industry is sufficiently small in relation to their other activities to preclude their classification as large petroleum companies. Table III-15 lists the sample of large petroleum companies and the group of petroleum-related companies and presents data (for 1978) on their involvement in the domestic oil industry.

The second comparison group, referred to as non-petroleum companies, is a sample of 18 firms randomly selected from the remaining companies in the Fortune 100. These firms had no crude production or refining capacity in 1978 and are listed in Table III-16.

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14 There are 18 such companies based on 1978 data.

Table III-15. Petroleum and Petroleum-Related Companies Used in the Comparison of Acquisition Activity

Oil companies	Fortune rank	Assets as of Jan. 1, 1979 (million dollars)	1978 sales (million dollars)	1978 net domestic crude and NGL (000 b/d)	Refining Capacity as of Jan. 1, 1979 (000 b/d)	Col. (4) ÷ Col. (2)[1]	Col. (4) ÷ Col. (3)[1]	Col. (5) ÷ Col. (2)[1]	Col. (5) ÷ Col. (3)[1]
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Standard Oil (Ohio)	43	$ 8326	$ 5198	528.4	452.0	6.35	10.17	5.43	8.70
Getty Oil	79	4718	3515	273.6	220.4	5.80	7.78	4.68	6.28
Shell Oil	14	10,453	11,063	497.0	1138.4	4.76	4.49	10.89	10.29
Marathon Oil	52	3758	4509	177.8	533.0	4.73	3.94	14.18	11.82
Cities Service	51	4005	4661	180.4	291.0	4.50	3.87	7.27	6.24
Atlantic Richfiled	13	12,060	12,298	526.9	847.0	4.37	4.28	7.02	6.89
Sun Co.	23	5498	7428	225.6	484.0	4.10	3.04	8.80	6.52
Phillips Petroleum	26	6935	6998	258.8	302.0	3.73	3.70	4.35	4.32
Standard Oil (Indiana)	12	14,109	14,961	525.0	1238.0	3.72	3.51	8.76	8.28
Union Oil	35	5525	5955	197.6	490.0	3.58	3.32	8.87	8.23
Amerada Hess	49	3435	4701	94.0	30.0	2.74	2.00	.87	.64
Gulf Oil	9	15,036	18,069	400.2	910.9	2.66	2.22	6.06	5.04
Texaco	5	20,249	28,607	511.0	1084.0	2.52	1.79	5.35	3.79
Continental Oil	18	7445	9455	165.0	363.0	2.22	1.75	4.88	3.84
Standard Oil (CA)	6	16,716	23,232	350.0	1463.0	2.09	1.51	8.73	6.30
Exxon	2	41,531	60,335	829.0	1574.0	2.00	1.37	3.79	2.61
Mobil	4	22,611	34,736	320.0	901.0	1.45	.92	3.99	2.59
Ashland Oil	44	2886	5167	22.1	385.3	.77	.43	13.35	7.46
Petroleum-Related									
RJ Reynolds	47	$ 4616	$ 4952	45.5	0	.99	.92	0	0
Tenneco	19	10,134	8762	89.0	115.0	.88	1.02	1.14	1.31
International Paper	62	4099	4150	24.8	0	.61	.60	0	0
Allied Chemical	84	3228	3268	19.7	0	.61	.60	0	0
WR Grace	59	3268	4310	10.97	0	.34	0.25	0	0
Esmark	38	2116	5827	*	64.1	<.25	<.25	3.03	1.10
Occidental Petroleum	33	4609	6253	*	0	<.20	<.20	0	0

Table III-15. (continued)

Oil companies	Fortune rank	Assets as of Jan. 1, 1979 (million dollars)	1978 sales (million dollars)	1978 net domestic crude and NGL (000 b/d)	Refining Capacity as of Jan. 1, 1979 (000 b/d)	Col. (4) ÷ Col. (2)[1]	Col. (4) ÷ Col. (3)[1]	Col. (5) ÷ Col. (2)[1]	Col. (5) ÷ Col. (3)[1]
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Monsanto	45	5036	5019	*	8.5	<.20	<.20	.17	.17
General Electric	8	15,036	19,653	*	0	<.10	<.10	0	0
ITT	11	14,035	15,261	*	0	<.10	<.10	0	0
Dow Chemical	27	8789	6888	*	17.0	<.10	<.10	.17	.25
Continental Group	67	2997	3944	**	0	-	-	-	-
Borden	68	2166	3803	**	0	-	-	-	-
Armco	54	3096	4357	**	0	-	-	-	-
Georgia Pacific	53	3344	4403	**	0	-	-	-	-
E.I. Du Pont	16	8070	10,584	**	0	-	-	-	-

- not calculated.

* Net crude, condensate and NGL production less than 15,700 b/d but greater than 1100 b/d rough estimates used to calculate columns (6) and (7).

** Net crude production less than 1100 b/d.

1 Since the decimal point has no particular significance in ratios of crude petroleum or refinery capacity (measured in 000 b/d) to sales or assets (measured in millions of dollars), it has been move to the right to make the data more readable.

Source: Cols (1) - (3): Fortune, "The 500 Directory" May 1979.

Col. (4): American Petroleum Institute, Market Shares and Individual Company Data for U.S. Energy Markets: 1950-1979, API Discussion Paper, October 10, 1980.

Company Annual Reports and SEC forms 10-K.

Department of Energy listing of firms with 1978 crude production of 400,000 bbl or more.

Col. (5): Department of Interior, Bureau of Mines, Minerals Industry Survey," Petroleum Refineries in the U.S. and Puerto Rico," January 1, 1979.

Table III-16. Non-Petroleum companies

Company	1978 Fortune Rank	1979 Assets	1978 Sales
		---(million dollars)---	
Republic Steel	82	$2585	$3479
Boeing	40	3573	5463
American Home Products	94	1862	3063
Dresser Industries	95	2355	3054
Aluminum Co. of America	65	4167	4052
McDonnell Douglas	63	3098	4130
Proctor & Gamble	20	4984	8100
Textron	89	1988	3231
Ralston Purina	64	1898	4058
Coca Cola	56	2583	4338
Goodyear Tire & Rubber	22	5231	7489
Raytheon	88	2061	3239
Westinghouse Electric	29	6318	6663
LTV	42	3720	5261
Bethlehem Steel	34	4933	6185
American Can	66	2478	3981
United Technologies	32	4074	6265
Rockwell International	37	3535	5833

The analysis was restricted to transactions occurring during 1979, 1980 and 1981 for which a filing was made under the Hart-Scott-Rodino Act and for which either the consideration paid exceeded $15 million or the assets acquired exceeded $15 million. Defining a specific universe of identifiable transactions reduced data distortions due to differences in the availability of information regarding the acquisition within the three groups. Because the HSR filing requirements took effect in the fall of 1978, data obtained through the HSR system was necessarily limited to recent years.

2. The Study

The measures of acquisition activity used here are the same as those used in the previous study. Table III-17 shows for each year the number of whole company acquisitions, the total number of acquisitions, and the total number of divestitures for each group of companies. Since there are only 16 companies in the oil-related group (opposed to 18 in each of the other two groups), the data for the oil-related group have been multiplied by 9/8. According to this measure, it does not appear that there has been consistently greater acquisition activity by large petroleum companies than by the other large firms during the study period. During the 1979-1981 period the large petroleum companies made 48 acquisitions compared to 21 by the nonpetroleum group and 63 by the petroleum-related group. Thus, while the large petroleum companies made a substantially larger number of acquisitions than did the nonpetroleum companies, it was the petroleum-related group which made the largest number of acquisitions.

Measures of acquisition activity based on transaction size are presented in Tables III-18 and III-19. These data also present a mixed picture of acquisition activity. While the acquisition activity of the petroleum and petroleum-related groups appears to have been much greater than that of the nonpetroleum group, the petroleum-related companies apparently were more active acquirers than the petroleum companies. For example, the market value of whole company acquisitions averaged $5.6 billion per year for the petroleum-related companies and $3.5 billion per year for the petroleum companies (over 1979-1981).[15] Similarly, total acquisitions net of divestitures by the petroleum-related companies averaged $4.9 billion per year compared with $4.8 billion by the petroleum companies. While an important part of the acquisition activity of the petroleum-related group was accounted for by DuPont's $7.8 billion acquisition of Conoco in 1981, exclusion of this transaction would still leave total acquisitions net of divestitures by the petroleum-related companies above that of the petroleum companies for that year.[16]

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15 Corresponding figures for assets are $7.2 billion and $2.4 billion and for sales, $11.3 billion and $4 billion.

16 When averaged over the 3 years, the exclusion of DuPont-Conoco results in greater acquisition activity by the petroleum group. The market value of whole company acquisitions by the petroleum-related group averages $2.9 billion compared with $3.5 billion for the petroleum group. Corresponding averages for total acquisitions net of divestitures equal $4.9 billion and $2.2 billion.

Table III-17. Number of Acquisitions by Petroleum, Petroleum-Related, and Nonpetroleum Companies 1979-1981

Acquisition type/ year	Petroleum companies	Petroleum-related companies	Non-petroleum companies
Whole Company Acquisitions			
1979	8	15	6
1980	10	10	5
1981	8	12	2
Total Acquisitions			
1979	13	18	7
1980	19	18	7
1981	16	27	7
Total Divestitures			
1979	9	10	3
1980	2	11	4
1981	9	19	6

Table III-18. Whole Company Acquisitions by Petroleum, Petroleum-Related, and Nonpetroleum Companies 1979-1981

Measure of acquisition activity/year	Petroleum companies	Petroleum-related companies[1]	Non-petroleum companies
Market Value ($ millions)			
1979	5,978	3,189	1,548
1980	1,469	1,481	937
1981	3,145	12,167	751
Assets ($ millions)			
1979	2,013	2,998	1,673
1980	2,290	3,185	427
1981	2,798	15,368	624
Sales ($ millions)			
1979	1,755	4,064	2,509
1980	5,195	1,170	709
1981	5,117	28,699	637

1 Data for this group has been multiplied by 9/8 to compensate for differing sample size.

Table III-19. Market Value of total Acquisitions by Petroleum, Petroleum-Related, and Nonpetroleum Companies 1979-1981

Measure of acquisition activity/year	Petroleum companies	Petroleum-related companies[1]	Non-petroleum companies
Total acquisitions ($ millions)			
1979	7,129	3,665	1,618
1980	5,263	2,142	986
1981	4,412	13,399	929
Total acquisitions net of Divestitures ($ millions)			
1979	6,172	2,208	1,500
1980	4,823	446	786
1981	3,348	11,943	709

1 Data for this group has been multiplied by 9/8 to compensate for differing sample size.

Interpretating these data is necessarily difficult because of the short period covered and the diversity of the firms included in the analysis. However, there is one difference among the three groups which could have an important influence on the acquisition activity reported in Tables III-18 and III-19. Firms in the petroleum group are far larger on average than the firms in the two other groups. This fact is reflected by the figures in Table III-20.

While the difference in firm size might not be expected to alter the number of acquisitions by the firms in each group, it seems likely to affect the absolute size of their acquisitions. To control for this possibility, the different measures of acquisition activity by the firms in each group are expressed as percentages of the corresponding size - measure of the firms within that group. That is, the value of total acquisitions (or the value of total acquisitions net of divestitures) for a given year is expressed as a percentage of the total market value (at the beginning of the year) of the companies within the same group.[17] Assets and sales based measures of acquisition activity are similarly restated. The results are presented in Tables III-21 and III-22.[18]

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17 Although the effect of using the same threshold value of $15 million for the firms in each group would probably be negligible, this potential influence on the results is taken into account in Tables III-21 and III-22. In each year, the threshold for acquisitions by companies in the nonpetroleum group is taken as $15 million. The threshold for the petroleum group (or petroleum-related group) is adjusted each year by multiplying $15 million by the ratio of the market value (or assets) of the petroleum group (or petroleum-related group) to the market value (or assets) of the non-petroleum group.

18 An alternative way to adjust for differences in firm-size would be to select a non-random sample of control companies from the Fortune 100 so that the firms in the control groups are comparable in size to the petroleum companies. This procedure was not adopted because of the difficulties created by the overwhelming preponderance of petroleum companies at the top of the Fortune 100 (10 of the top 20 in 1978).

Table III-20. Average Firm Size for Petroleum, Petroleum-Related, and Nonpetroleum Companies 1979-1981

	Year		
	1979	1980	1981
	(million dollars)		
Average assets			
Petroleum	$11,408	$13,673	$16,084
Petroleum-related	5,915	6,793	7,473
Non-petroleum	3,414	3,886	4,257
Average sales			
Petroleum	$19,149	$17,181	$ n.a.
Petroleum-related	8,461	9,281	n.a.
Non-petroleum	5,861	6,551	n.a.
Average market value			
Petroleum	$5,218	$7,516	$11,924
Petroleum-related	2,623	3,048	3,704
Non-petroleum	1,974	1,988	2,556

n.a.--not available.

Source: COMPUSTAT II, Data Tape, Industrial Files, Standard & Poor's Corp. Annual.

Tables III-21 and III-22 reflect the greater acquisition activity of the petroleum and petroleum-related companies compared with the nonpetroleum companies. As a group, the market value of whole company acquisitions by the nonpetroleum companies averaged .84 percent of total market value per year (1979-1981), whereas the corresponding average for the petroleum companies is 2.91 percent, and for the petroleum-related companies, 9.16 percent (4.77 percent if DuPont-Conoco is excluded). Similarly, total acquisitions and total acquisitions net of divestitures expressed as percentages of market value are substantially higher for the petroleum and petroleum-related companies compared with the nonpetroleum companies.

The figures in Tables III-22 also reveal virtually no difference in the relative importance of total acquisitions between the petroleum and petroleum-related companies in 1979 and 1980. However, in 1981, total acquisitions by the petroleum-related group increased substantially compared with the petroleum group: 20.03 percent of market value as against 2.30 percent. (Excluding DuPont-Conoco, the percentage for the petroleum-related group falls to 6.87 percent). However, the petroleum-related group had also divested relatively more than the petroleum group. On balance, total acquisitions net of divestitures averaged 3.83 percent of market value per year (1979-1981) for the petroleum group, and 7.79 percent for the petroleum-related group (3.40 percent excluding DuPont-Conoco). Although the greater divestiture activity of the petroleum-related group reduces the difference in net acquisition activity between these two groups, the petroleum-related companies nonetheless appear to have had a higher rate of acquisition activity than the petroleum companies.

It was shown earlier that a substantial portion of the increased acquisition activity of the large petroleum companies during the period 1979-1981 was made up of acquisitions of energy related assets. (Large net energy related acquisitions made up 64.8 percent of total net large acquisitions for this period). The non-petroleum group was a net divestor of energy related assets. (Large net energy related acquisitions as a percentage of total large net acquisitions were - 4 percent for this group). The data for the petroleum related group were significantly influenced by the DuPont-Conoco acquisition. Large net energy related acquisitions as a percent of total large net acquisitions were 56.7 percent for the petroleum related group. However, the exclusion of the DuPont-Conoco acquisition changes this percentage to - 10.8 percent. Thus it is clear that, except for DuPont-Conoco, the energy related emphasis of the large petroleum companies' increased acquisition activity over the period 1979-1981 was not a feature of other large companies' acquisition activity during the period. Apparently the large petroleum companies generally placed a higher value on fossil fuel reserves than did other potential acquirers or did the market in general.

To sum up, the large petroleum companies appear to have increased their acquisition activity subsequent to 1978 compared with earlier years. An important part of the increase can be accounted for by three particularly large acquisitions occurring in 1979-1981, although these acquisitions do not account for the whole of the increase. In 1979-1981, the petroleum companies as well as the petroleum-related companies engaged in relatively greater acquisition activity than did a comparison group of nonpetroleum companies. Differences in the acquisition activity of the petroleum and petroleum-related companies are less pronounced than the difference between these two groups and the nonpetroleum group.

Table III-21. Market Value, Assets and Sales of Whole Company Acquisitions as a Percentage of Market Value, Assets and Sales: Petroleum, Petroleum-Related and Nonpetroleum Companies 1979-1981

Measure of Acquisition Activity/Year	Petroleum Companies	Petroleum-related Companies	Non-petroleum companies
Market value as a percentage of market value			
1979	6.36	6.64	1.59
1980	.93	2.62	.59
1981	1.44	18.21 (5.05)[1]	.35
Assets as a percentage of assets			
1979	.92	2.73	.81
1980	.89	2.58	.15
1981	1.77	11.39 (2.16)[1]	.22
Sales as a percentage of sales			
1979	.48	2.58	.72
1980	.82	.66	.22

1 Figures in parentheses reflect percentages excluding Du Pont-Conoco.

Source: Market Value, Assets and Sales from Compustat II, Data Tape, Industrial Files, Standard and Poor's Corp. Annual.

Table III-22. Total Acquisitions and Total Acquisitions Net of Divestitures as a Percentage of Market Value: Petroleum, Petroleum-Related and Nonpetroleum Companies, 1979-1981

Measure of acquisition activity/year	Petroleum companies	Petroleum-related companies	Non-petroleum companies
Total acquisitions as a percentage of market values			
1979	7.54	7.65	1.66
1980	3.69	3.83	.59
1981	2.01	20.03 (6.87)[1]	.35
Total acquisitions net of divestitures as a percentage of market value			
1979	6.58	4.60	1.60
1980	3.36	.86	.50
1981	1.58	17.91 (4.75)[1]	.31

1 Figures in parentheses reflect percentages excluding DuPont-Conoco.

IV. INCENTIVES FOR MERGERS

A. Introduction

Although the explanations of mergers are varied, abrupt changes in market conditions in the late 1970's provide likely reasons for several recent oil-company mergers. This section discusses those changes in market conditions and also other factors that may provide incentives for mergers.

B. Motives for Mergers

Maximization of profits (in a broad, general sense) is presumably the primary force behind merger activity. A merger can increase profits in a number of ways; among those commonly cited are increased efficiency, enhanced market power, regulation, taxes, capture of "undervalued" assets, and financial considerations. Each of these factors is discussed below.

1. Economic efficiencies or synergies as a merger motive

One of the most important reasons for mergers, both for the parties involved and the economy at large, is the greater efficiency that can be derived from the potential realignment of assets toward their highest and best use. Such efficiencies lower the costs of production or distribution and increase profits. The realization of such efficiencies is of obvious social benefit. To the extent that such efficiencies exist, mergers can be an important means to advance productivity.

a. Managerial synergies

If superior managers gain control of poorly managed firms, they may transform the managerial staff and organization, revitalizing the company and enhancing its profitability. H.G. Manne has argued that the possible replacement of management by means of a takeover afforded noncontrolling stockholders with some protection against incompetent corporate managers. "The lower the stock price, relative to what it could be with more efficient management, the more attractive the takeover becomes to those who believe that they can manage the company more efficiently. . . . Only the takeover scheme provides some assurance of competitive efficiency among corporate managers."[1] Manne also contended that potential managerial efficiencies are most likely when the merging firms produce closely related goods or services.[2]

b. Productive efficiencies

Mergers may also offer potential gains in productive efficiency. These manufacturing synergies are categorized as either plant-specific or product-specific.

A plant-specific gain requires construction or expansion of a plant in order to attain scale economies not available prior to merger. Since most firms have settled locations or have attained most available economies, the merger gains from plant specific scale economies are likely to be small. However, an increase in the number of plants operated by a given firm may permit cost reduction not otherwise attained by a firm operating fewer plants.

Product-specific economies may offer more impressive gains. These efficiencies are attainable by reorganizing existing production or marketing methods without implementing major changes in plants. For example, by rearranging production assignments, the runs of a single product may be lengthened, reducing set-up costs. Product-specific economies may also include consolidation or rearrangement of sales forces, research and development, and other "support" functions necessary to the successful maintenance of product quality and distribution.

Although efficiencies can be an important motivation for mergers, their existence

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1 Manne, "Mergers and the Market for Corporate Control," J. of Pol. Econ. 110-20 (Apr. 1965).

2 This may be too strong a conclusion, if the concern solely is with management effects. Basically, the merger provides an opportunity to replace current managers, hopefully leading to a reorganization of production. It is not clear that those most capable of providing this managerial boost are horizontal competitors, in that managerial skills may not be market-specific. O. Williamson, Markets and Hierarchies: Analysis and Antitrust Implications, 132-75 (1975) discusses more generally the importance of managerial and organizational form, particularly with respect to conglomerate firms where managerial benefits may be independent of any horizontal market relationships with acquired firms.

does not appear to be universal. One recent study of horizontal mergers in Great Britain concluded that efficiency gains were minimal, as against some quite substantial anticompetitive effects.[3] The general consonance of efficiencies with mergers is well documented. For example, Scherer concluded from a review of four other studies of horizontal mergers that "[t]he general implication . . . is that production economies do arise in conjunction with many mergers, and especially horizontal mergers, but that for the most part the benefits are not large."[4]

2. Market power as an incentive to merge

Although efficiencies can be an important motivation for mergers, market power can also be an important motive. For example, the previously cited recent study of horizontal mergers in Great Britain concluded that efficiency gains were minimal, as against some quite substantial anticompetitive effects.[5] This form of profit enhancement through increased market power is most likely in a horizontal merger that significantly increases the relative size of the merged entity or strengthens the ability of firms to act collusively. The passage of the Sherman Act and the Clayton Act, as amended, has almost certainly reduced the number of mergers undertaken primarily for anticompetitive reasons.

Although few of today's mergers may be spurred primarily by clear anticompetitive intent,[6] such mergers can still produce an anticompetitive effect. For

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3 K. Cowling, P. Stoneman, J. Cubbin, J. Cable, G. Hall, S. Domberger & P. Dutton, Mergers and Economic Performance 370-71 (1980). The methodology used is case studies of major mergers in 1968-69. One major merger in the ball-bearing industry does seem to have produced significant manufacturing efficiencies. See id. at 95-104 (case study of Ransome, Hoffman and Pollard).

4 F. Scherer, Industrial Market Structure and Economic Performance 137 (1980).

5 K. Cowling, P. Stoneman J. Cubbin, J. Cable, G. Hall, S. Domberger & P. Dutton, supra, note 3, at 370-71.

6 There are exceptions. See e.g., United States v. Md. & Va. Milk Producers Assoc., 167 F. Supp. 799, 804-06 (D.D.C. 1958) (evidence indicated defendant's clear intent to eliminate by acquisition of a "disturbing influence" on price).

example, the Commission sought to enjoin Mobil's attempted acquisition of Marathon and Gulf's attempted acquisition of Cities Service, after finding reason to believe that these acquisitions would be likely to have anticompetitive effects in particular geographic and product markets, not because the basic intent of these firms was to lessen competition.[7]

C. Efficiency Considerations in Some Recent Oil Company Mergers

An important potential efficiency in a merger between crude oil producers is the application of specialized techniques to raise the productivity of crude oil reserves. Methods of raising production include the exploitation of deeper zones or reservoirs from reserves already in production. Firms with the necessary expertise can also extract higher proportions of crude oil from producing reservoirs. These enhanced recovery techniques include the use of water flooding or gas injection ("secondary recovery") or the use of heat microemulsion or miscible-fluid displacement ("tertiary recovery").

The feasibility of employing enhanced recovery techniques depends upon the price of oil. Given the recent and rapid escalation in the world price of oil, firms with the necessary technical ability are likely to find that certain recovery methods are now profitable. It would not be surprising to find the most technically proficient firms acquiring reserves from those less adept in these techniques.

Some of the recent crude oil acquisitions may be primarily for this reason. Of the three we have examined more closely — Shell's acquisition of Belridge, Mobil's aborted acquisition of Marathon, and Du Pont's acquisition of Conoco — only the Shell acquisition

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7 In point of fact, Mobil's position in the Marathon v. Mobil private action indicated its willingness to resolve horizontal overlaps by partial divestitures. Published news reports following Gulf's aborted takeover of Cities Service likewise recount anticipated discussions by Gulf with antitrust officials to resolve potential overlap problems in future acquisition attempts, prior to making a tender offer. See Marathon Oil Co. v. Mobil Corp., 530 F. Supp. 315 (N.D. Ohio 1981), aff'd 669 F.2d 378 (6th Cir. 1981) [hereinafter cited as Marathon v. Mobil]. Mobil's willingness to spin off the assets whose acquisition potentially had an anticompetitive effect while continuing its efforts to acquire Marathon's remaining assets implies that the acquisition was not primarily motivated by market power considerations. See 669 F.2d at 383. See also, Morton, Gulf Oil Comes out Smiling, N.Y. Times, Aug. 10, 1982 (Business Section), at 1.

displays clear effects along these lines.

1. Shell's acquisition of Belridge

Prior to it's acquisition by Shell in late 1979, Belridge was a relatively obscure, closely-held, California crude oil producer, whose principal owners were heirs of three of the five founding families.[8] After soliciting acquisition proposals, on September 28, 1979, the Directors of Belridge selected Shell as the successful bidder.[9] Shell's interest in Belridge was predicated on its assessment that:

> with substantial capital expenditures (estimated to approximate $1 billion over the next ten years) and Shell's expertise in production technology, the production ultimately recoverable from these properties [Belridge reserves] might substantially exceed the estimates of the reserves presently attributable to them.[10]

After the announcement of Shell's bid of $3.65 billion and the revelation that Shell's bid substantially exceeded the price offered by the next highest bidder, Shell was subjected to considerable criticism for having bid too much.[11] But two years after the consummation of the merger, it appears that even Shell underestimated the extent to which Shell's superior production technology would enhance the value of the Belridge operation. As of last November, Shell had increased Belridge's production from 40,000 barrels per day to 68,000 barrels per day, and plans called for production to exceed

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8 Wall St. J., Oct. 18, 1979, at 1. Mobil and Texaco were shareholders also, together holding approximately 35 percent of Belridge.

9 Form S-14, "Registration Statement" 12-13 (Nov. 23, 1979) (submitted by Kernridge Oil Co. & Shell Oil Co. to the Securities and Exchange Comm.) (amend. 1).

10 Id. at 16.

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> "I'm glad I didn't have John's [Bookout, Chief Executive of Shell] job of explaining that to their shareholders," George Keller, Chairman of Standard Oil of California told a gathering of New York securities analysts. "The oil's there. The question is whether they could have gotten it for $1.5 billion less."

Getschow & Thurow, "Working Marriage: Shell-Belridge Merger Thrives on Technology, Avoids Most Pitfalls," Wall St. J., Nov. 5, 1981, at 1.

100,000 barrels daily by the mid-1980's. It is generally agreed that such improvements could not have been achieved if Belridge had not combined with a major petroleum firm.

2. Mobil's proposed acquisition of Marathon

In the case of Mobil Corporation's attempted acquisition of Marathon, efficiency considerations of the type discussed here seem to have been of minimal importance. A number of other possible efficiencies can be hypothesized: lower costs of its operations resulting from greater crude holdings; improved management; cheaper manufacturing; or efficiencies expected from fitting together the companies' refining, transportation, and marketing facilities. However, examination of the available evidence, including internal documents obtained by the Commission, does not indicate that considerations such as these weighed heavily as a major objective of the acquisition.

The most commonly cited attraction of Marathon to Mobil was Marathon's crude oil reserve holdings, principally its interest in the Yates Field, the second-largest quantity of reserves in the United States. Acquisition of the Yates Field would have improved Mobil's crude position much faster than could be achieved via increased exploration.[12] But unlike the Shell/Belridge case, there was no indication that Mobil would have been able to produce oil from the Yates field more cheaply, or that Mobil could reduce its other costs of operation significantly through ownership of this source of crude oil. The view that Mobil's desire to acquire Marathon's crude resources stemmed from Mobil's belief that the assets were undervalued in the stock market is discussed below.

3. The Du Pont acquisition of Conoco

Du Pont, a large and diversified chemical manufacturing firm, merged with Conoco in the summer of 1981.[13] First Seagram's, then Du Pont, and finally Mobil, made

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12 Stuart, "What Makes Mobil Run: A Chronic Shortage of Oil Helps Keep Big Oil's Biggest Maverick Combative," Fortune 93 (Dec. 14, 1981).

13 This summarizes events reported in R. Phalon, The Takeover Barons of Wall Street, (Continued)

successive offers for parts or all of Conoco's outstanding shares, eventually forcing Du Pont to pay $98 per share in cash for 45 percent of Conoco's shares and to exchange 1.7 Du Pont shares for each remaining Conoco share — a total of $7.54 billion.

Ruback, who closely analyzed the transaction, found it difficult to explain Du Pont's interest in Conoco.[14] While Du Pont uses petroleum feedstocks in chemical production, it relied on Conoco for only a small volume (4 percent of purchases) and should have been indifferent between Conoco and other suppliers. Even if Du Pont felt that its crude supplies might be threatened, Conoco could not be a guarantor of future feedstocks because its supplies did not even satisfy its own needs.

Du Pont itself considered the acquisition to be a good business opportunity for a number of reasons. Du Pont believed that Conoco was substantially undervalued by the stock market, so that the acquisition was felt to be worthwhile investment. Another reason advanced by Du Pont for the acquisition was its value as a natural-resource diversification. Du Pont also considered Conoco's hydrocarbon position to be an effective hedge against future surges in the prices of raw materials to Conoco. Finally, Du Pont believed that its superior management could be effectively used within the acquired company.[15]

Whatever Du Pont's underlying motives may have been, the stock market did not seem to concur in its decision. Ruback concluded that Du Pont's acquisition of Conoco resulted in a 10 percent ($790 million) fall in Du Pont's equity value between June 17, 1981, when Conoco rejected the initial Seagram's offer, and August 5, 1981, when Du

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14 A full history and analysis of this particular merger is available in Ruback, "The Conoco Takover and Stockholder Returns" (forthcoming in 23 Sloan Mgmt. Rev. 13 (Winter 1982)). The Seagrams, Du Pont, and Mobil offers may have been initiated by an earlier bid for 20% of Conoco's stock by Dome Petroleum, Ltd. Dome's ability to gain well over 20% for a $15 per share premium may have indicated an undervaluation of Conoco Shares.

15 Memoranda from E. G. Jefferson to Du Pont Board of Directors and from D. K. Barnes to Du Pont Executive Committee (July 1, 1981).

Pont's success was announced.[16] Conoco's shareholders realized a 71 percent return. Seagram's suffered no net impact from its failure to acquire Conoco and in the process obtained approximately 20 percent of Du Pont's equity at a premium of only 15 percent over Du Pont's August 5 closing price.[17] Mobil, another unsuccessful bidder, experienced an estimated loss of $400 million in the value of its stock during the attempt.[18]

D. Petroleum Price and Allocation Regulations

1. Historical description.

Federal regulation of oil prices began in August 1971, when petroleum product prices were frozen along with the prices of other commodities by Phase I of the Nixon administration's wage and price controls. When controls on other commodities were substantially eliminated, oil price controls were maintained or expanded. These controls placed rigid price ceilings on crude oil and generally limited price increases to cost pass-throughs. In May 1973, after shortages began appearing,[19] the administration established a voluntary petroleum allocation program[20] which later evolved into mandatory regulations embodied in the Emergency Petroleum Allocation Act (EPAA).[21]

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16 Ruback, supra note 14.

17 This is a small premium for so large a block of stock, which made Seagram's the largest shareholder of Du Pont.

18 Ruback is somewhat at a loss to explain this. He believes it may be related to the Justice Department's announcement of antitrust concerns, signaling to investors that Mobil would have difficulty making acquisitions in the oil industry.

19 The rigid retail price ceilings originally imposed were particularly prone to cause shortages. Subsequent price regulations attempted to remedy this problem but were never completely successful. See C. Roush, Effects of Federal Price and Allocation Regulations on the Petroleum Industry 10-14 (staff report prepared for the Fed. Trade Comm.); S. Harvey & C. Roush, Petroleum Product Price Regulations: Output, Efficiency and Competitive Effects 169-80 (1981) (staff report prepared for the Fed. Trade Comm.).

20 This was accomplished under authority of the Economic Stabilization Act of 1970, Pub. L. No. 91-151, 83 Stat. 371.

21 Pub. L. No. 93-159, 87 Stat. 619.

Under the controls established by the EPAA, most crude oil from domestic properties in production in 1972 ("old oil") was subject to an absolute price ceiling equal to the crude's May 15, 1973 market price, plus $1.35 per barrel. "New oil" (from properties put into production subsequent to 1972), imported oil, and certain other specified crude oils were exempt from price control. Refiners of petroleum products were required to place their customers into "classes of purchasers," and to compute the average price charged to each class on May 15, 1973—the base-period price. Prices in excess of the base-period price were permitted only to allow the refiner to pass through increases in "allowable" cost according to specified formulas for allocating costs among products.[22] Resellers and retailers of petroleum products were subject to similar cost pass-through price regulations.

The allocation regulations for crude oil and products required suppliers at each level of the industry to offer crude oil or product to their customers as of December 1, 1973 based on the volumes sold to them on that date.[23] However, the regulations did little to prevent integrated crude oil sellers from discriminating between their own refineries and others' by using their low priced, controlled crude in their own refineries, while selling their higher priced, uncontrolled crude to meet their allocation obligations. This tended to put the integrated firms' non-integrated customers at a disadvantage in the refined products market.[24] In November 1974, the Federal Energy

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22 For example, most common costs were allocated on the basis of the relative number of barrels sold.

23 Some new entrants were assigned suppliers by the Federal Energy Administration, while others were unable to get allocations and had to rely on unallocated volumes of product. Such unallocated product was frequently but not always reliably available.

24 A refiner could increase its profits by rolling in price controlled crude with uncontrolled (e.g., foreign) crude oil to achieve a higher volume of product input at any given ceiling price. The way in which refiners' profits were linked to volume is complicated and is explained in detail in S. Harvey & C. Roush, supra note 19, at Ch. 2.

Administration responded to this problem by establishing the "crude-oil price equalization program." Under this program, an "entitlement" was needed to refine each barrel of price controlled crude oil. The entitlements were distributed among refiners, and refiners that processed more old oil than they had entitlements for had to purchase entitlements from refiners who had a surplus. The price of entitlements was set by FEA to equal the difference between the weighted average prices of controlled oil and of oil not subject to price control.[25]

These types of price and allocation regulation of petroleum were continued under the Energy Policy and Conservation Act (EPCA) of 1975,[26] but this Act also allowed the FEA to decontrol petroleum products subject to a one-house Congressional veto. Over the next five years, beginning with the heaviest products, all major petroleum products except gasoline became exempt from regulations. In August 1976, the Energy Conservation and Production Act exempted from price controls crude production from wells producing fewer than 10 barrels per day ("stripper wells").[27] On June 1, 1979, the Carter Administration initiated a gradual crude-oil decontrol program, and in January 1981, all remaining price and allocation controls were removed by an Executive Order issued by President Reagan.

2. Effects of the price and allocation regulations

The EPCA's regulatory scheme provided various advantages to firms with the ability to undertake new tertiary recovery projects. For instance, in September 1978,

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25 Had entitlements been distributed among refiners in proportion to their crude oil input, the entitlements program would have made crude oil acquisition prices approximately equal for each refiner. However, there was an explicit bias in the program toward small non-integrated refiners. Non-integrated refiners whose crude runs were less than 175,000 barrels per day received a disproportionate share of entitlements. In addition, certain small refiners—particularly those in financial difficulty — were relieved entirely of the obligation to buy entitlements.

26 Pub. L. No. 94-163, 89 Stat. 950 (1975).

27 Pub. L. No. 94-385, 90 Stat. 1132 (1976).

the Department of Energy promulgated regulations that lifted price control ceilings on incremental crude oil produced by tertiary recovery techniques.[28] One year later, in October 1979, DOE increased the rewards to tertiary production by allowing producers to recoup 75 percent of the cost of tertiary-recovery projects. Producers were compensated for the investment through a program that "released" additional oil from the grip of price controls.[29] Of course, rising crude oil prices increased the profits that could be derived from such programs and commensurately increased the incentives for reserve acquisitions.

Decontrol rendered these programs nugatory and provided an important production incentive. Because all crude oil could now be priced at the world level, all programs that could enhance recovery increased in value. Thus, domestic decontrol may have served to widen the divergence in (stock market) valuation among firms based on their ability to produce oil.

The regulatory scheme also gave oil companies an incentive to alter their structure through vertical integration. Because the price regulations were based on cost pass-throughs, and because vertically integrated firms "purchase" from themselves, such firms have an enhanced ability to manipulate the costs they report for inputs. This may frequently benefit the integrated firms because of loopholes in the regulations or because of different market conditions at different vertical levels of the industry.

Some regulatory incentives to restructure were more specific. For example, during the regulatory period prior to implementation of the entitlements program, there was a strong incentive for crude oil producers to own refinery capacity at least sufficient to process their production of old oil. As noted above, a producer could sell that portion of its crude oil which was not under price control and channel its price controlled oil to

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28 43 Fed. Reg. 33,679 (1978), 10 C.F.R. § 212.78 (1979).

29 44 Fed. Reg. 51,148 (1979), 10 C.F.R. § 212.78 (1979).

its own refinery. By doing so, a producer/refiner could gain increased market share and profits through its refining operations.[30] Even after the entitlements system was introduced, some crude oil remained more valuable than other oil, and it could be to a producer's benefit to channel that crude through its own refinery.[31]

There were also specific regulatory incentives for integration between refining and marketing.[32] First, integrated refiners generally profited more from sales they made through their own outlets than from sales made through independent outlets. This arose because retail operations did not tend to be constrained by the regulations, even when refining operations were. Based on the way increased marketing costs entered the ceiling price formulae, integrated refiner-marketers could more than recover increased marketing costs if they altered their historic pattern of gasoline distribution by circumventing nonaffiliated wholesalers and marketers and performing the downstream functions themselves.[33]

E. Federal Tax Incentives to Merge

1. The windfall profits tax incentive

Merger inducements flowing from the windfall profits tax[34] are a function of the

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30 See C. Roush, supra note 19, at 34-38, 48; S. Harvey & C. Roush, supra note 19, at 10, 11, 45, 46.

31 See Bur. of Competition, Fed. Trade Comm., Concerning the Competitive Impact of Wellhead Price Ceilings, Entitlements, The Reseller Rule, The Supplier/Purchase Rule (May 23, 1978) (comments to Economic Regulatory Admin., Dep't of Energy).

32 These effects are too complicated to be fully explained here. The effects mentioned in the text are treated at length in S. Harvey & C. Roush, supra note 19, at 22-24, 57-73, 116-31.

33 Not all regulatory incentives stimulated increased integration. For example, nonintegrated marketers were in some cases allowed to increase prices with a presumption that their costs had increased, while integrated marketers had to document the cost increases before they were allowed to raise their prices. Horizontal integration between small refiners was discouraged to a certain extent by the entitlements bias that tended to discourage the growth of small refiners either through internal expansion or acquisition.

34 Crude Oil Windfall Profit Tax of 1980, § 101(a)(1), 26 U.S.C. § 4986, as amended (Continued)

tax rate, the price of oil, and the special treatment given to certain categories of oil. The tax is essentially an excise tax levied as a percentage of selling price above a given base price. There are three important categories of oil under the tax. Although independent producers are subject to lower rates, most oil is in Tier I and is taxed at a rate of 70 percent of the sales price above a base price (which is on average \$12.81/barrel plus an adjustment for inflation since May 1979). Tier II oil is produced from stripper wells and is taxed at a 60 percent rate on all sales revenue above an inflation-adjusted base price averaging \$15.20/barrel. Tier III oil is taxed at lower rates and includes newly discovered oil, heavy crude oil (below 16° gravity), and incremental production from tertiary recovery. The oil is taxed at a 30 percent rate above an inflation-adjusted base price of about \$16.55/barrel. To encourage tertiary production, the 30 percent rate applies not only to production above the base production of a field, but to much pre-existing production from the field as well. Once the tertiary project is initiated, producers can transfer to the Tier III category about 2.5 percent of the base production from the field per month. Thus, within about 40 months most of the production from a field will qualify for the lower tax rate.[35]

While the windall profits tax creates a number of stimuli pertinent to mergers, some of them may be offsetting. To some extent the tax may attenuate the merger incentive that arises from high crude oil prices. By reducing the profits attributable to special expertise in development and production, the tax narrows the differences in reserve valuation based on differing capabilities among producing firms. Theoretically, the tax mitigates the drive of the more efficient extracting firms to acquire reserves from other companies.

(1981).

35 The windfall profit tax will be decreased for all tiers during a 33-month phaseout period beginning between December 1987 and December 1990. 26 U.S.C. § 4990. The decline rate for newly discovered Tier III oil, however, begins in 1982, at a tax rate of 27 1/2%. Id. at § 4987.

On the other hand, the segregation of crudes for tax purposes may have increased the rewards from certain mergers. The most extreme example is the tertiary recovery provision. Tertiary recovery methods are expensive and the technologies are untried, but the tax compensation for using them may be substantial. A firm that acquires reserves and obtains a significant increase in production through enhancement techniques will find that the entire reserve is subject to the lower tax rate within 40 months. Therefore, the tax increases the amount by which a firm with expertise in specialized recovery techniques will value reserves more highly than a firm without such expertise.

According to one commentator, an enhanced recovery project that increases tertiary production only 10 percent may increase the producer's net revenue by as much as 65 percent. If the prevailing crude oil price were about $35/barrel, the incremental production would be worth more than $100/barrel.[36] This powerful incentive may have been one of the motivations for Sun Company's $2.3 billion acquisition of the U.S. oil and gas properties of Texas Pacific (a subsidiary of Seagram). Texas Pacific had many old fields that had been depleted by years of production. These older properties were still valuable as candidates for tertiary production techniques.[37]

2. Taxable acquisitions and stepped-up basis

The ability to step up the basis of an acquired firm can provide a substantial incentive for merger by allowing the combined firm to redepreciate assets and reduce tax liabilities. For a merger that does not qualify as tax-free, the implications are as follows:

(1) the seller of the acquired stock has a taxable gain on the difference between his adjusted basis in the stock and the price received;

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36 Verleger, "A Windfall Tax Incentive," Wall St. J. May 23, 1980, at 20.

37 Id.

(2) the acquired assets are stepped-up from their original basis to a new basis equivalent to the price paid by the acquiring company;

(3) the acquired company is required to recapture certain previously claimed depreciation and other deductions and tax credits, and to recognize certain previously deferred items, which results in additional federal income taxes to the acquiring firm.

The implications of these provisions can be significant for merger activity. For example, assume that the shareholders of Company T value T at $8 million, that their total basis in T is $6 million, that each shareholder is subject to the maximum capital gains tax of twenty percent, and that the tax basis of T's assets is $2 million. If, without regard to stepped-up basis, Company A also values T at $8 million, a tax-free exchange of Company A's stock for Company T's stock or assets (as allowed by Internal Revenue Code Section 368) would not be particularly attractive to either party.[38] A taxable transaction for $9 million, however, would be desirable for both parties. After paying capital gains tax, T's shareholders would net $8.4 million, an amount exceeding their valuation of T. Company A would step up the basis of T's assets from $2 million to $9 million, yielding $7 million more in depreciation or depletion. If A's tax rate were forty-six percent, A would realize $3.2 million in tax savings from the stepped-up basis. These tax savings would occur over several years, making the discounted present value of the savings somewhat less than $3.2 million. Assuming the present value is only $1.6 million, the net effect of the transaction to A is that it has paid $9 million and received assets worth $8 million plus $1.6 million of tax savings, for a total of $9.6 million.[39] Thus, a merger that the two parties would have been indifferent to on a tax-free basis, becomes

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38 The ability of one company to acquire another in a tax-free transaction does not in itself create the valuation difference between buyers and sellers which is necessary to trigger a merger. The tax-free provisions do, however, eliminate a potential disincentive to merge — the need for the buyer to compensate the seller for the latter's capital gains tax incurred in a taxable transaction.

39 This example assumes no recapture taxes were payable by the acquiring company.

attractive to them solely because of a tax incentive created by the stepped-up basis of the acquired assets.[40]

P. Steiner has noted that if the depreciation deduction accruing to the buyer is more valuable than the avoidance of capital gains to the seller, there will be a net incentive to merge by means of a taxable, rather than a tax-free, transaction.[41] More precisely, the tax benefit of the extra depreciation to the buyer must be greater than both the capital gains tax to the seller and any recapture taxes which the buyer must pay.[42]

In order to minimize the effect of the recapture provision in an acquisition that allows stepped-up basis, both Mobil and U.S. Steel considered maintaining Marathon Oil as a separate subsidiary of the parent. Through a partial liquidation, some Marathon assets could then be transferred to the parent company. The partially liquidated assets

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40 For a more detailed example of how stepped-up basis can induce a merger, see Ferguson & Popkin, "Pulling Rabbits Out of Hats in the Oil Business and Elsewhere," Fin. Analysts' J. 24-27 (Mar.-Apr. 1982).

Net operating losses (NOL) which would expire unused absent a combination of the NOL company with a profitable company can also act as direct tax incentives for mergers. In five recent large oil industry mergers examined infra, however, neither the acquired nor acquiring company had NOL's at the time the merger took place.

41 P. Steiner, Mergers: Motives, Effects, Policies, 83 (1974). In an examination of five large oil industry acquisitions we found that four were taxable. The mergers examined were: Sun's purchase of some Texas Pacific assets, Du Pont's acquisiton of Conoco, Sohio's purchase of Kennecott, Mobil's proposed takeover of Marathon, and U.S. Steel's acquisition of Marathon.

42 Two aspects of the Economic Recovery Tax Act of 1981 increase the likelihood that a taxable merger will be preferable to a tax-free merger and also increase the likelihood that, due only to tax reasons, mergers will occur because a particular company is valued more by another corporation than by its own shareholders. These two provisions are the reduction in the capital gains tax (which reduces the taxes payable by a seller in a taxable merger) and the speeding up of depreciation under the ACRS system (which increases the value to the buyer of the stepped-up basis).

The dramatic rise in oil prices over the past few years has almost certainly caused a significant difference between the current market value and the historical tax basis of oil properties. This divergence increases the tax advantage from stepped-up basis in a taxable merger.

would receive a step-up in basis. At the same time, the partial liquidation would be treated as an intercorporate transaction between the parent and Marathon. Under such circumstances, the recaptured taxes could be deferred. By treating the partial liquidation as a transaction between members of a controlled group of corporations that file a consolidated tax return, Mobil or U.S. Steel could thus obtain the benefits of stepped-up basis without the drawback of paying immediate recapture taxes.

Based on the Marathon - U.S. Steel Proxy/Prospectus and on internal Mobil Corporation documents, it is possible to estimate the component of the Mobil and U.S. Steel offering prices for Marathon stock that would be recouped due solely to tax savings from the stepping-up of basis through a partial liquidation of Marathon's assets. Mobil's average offering price for the Marathon stock was $108 per share, a premium of $44 over the Marathon closing price of $63.75 per share on the day prior to the Mobil offer. Approximately $11 per share, or 25 percent of the premium offered, would have been offset from the potential tax savings to Mobil. U.S. Steel's average offering price for Marathon was $103 per share, or a premium of $39 over the pre-tender offer price. U.S. Steel's tax savings equaled about $10 per share, 26 percent of the purchase premium. The tax savings from stepped-up basis did not account for the entire premium offered by Mobil or U.S. Steel for Marathon. But because substantial premiums are required in a hostile takeover, the size of the offering price, as permitted by the potential tax savings, may have been pivotal in persuading enough Marathon shareholders to tender their stock.[43]

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43 U.S. Steel needed to attract 51% or thirty million of Marathon's shares in its tender offer. While $63.75 was the price at which Marathon stock sold just prior to the takeover attempts, the price was based on sales of only a small portion of all outstanding Marathon shares. Perhaps the marginal shareholder necessary to obtain the last percent would not have sold for anything less than the $125 cash tender price offered by U.S. Steel. If that were true, and if $125 were the highest price U.S. Steel had been willing to offer, including the gains it could obtain through the tax benefit of stepped-up basis, then without such benefit U.S. Steel's maximum offer would have been lower and the tender offer would not have been successful. The Tax Equity and Fiscal Responsibility Act of 1982 eliminates partial liquidations as a means of deferring recapture taxes on stepped-up assets. An acquiring corporation may still elect to step-up the basis of acquired assets, but will then be subject to immediate repayment of any recapture taxes.

F. Diverse Expectations and the Evaluation of Acquisition Targets

One motivation given prominence in discussions of recent oil industry acquisitions is that the target companies, particularly those holding significant fossil fuel deposits, are undervalued in the stock market. This motive has been discussed widely in the press and by Mobil Corporation representatives. For example, consultants for Mobil argued that Mobil's bid for Marathon

> . . . could correct the valuation of Marathon's assets in the market. Mobil believes that other investors have been unduly pessimistic about the value of Marathon's assets and prospects, and the acquisition would result in more accurate price signals about asset valuation. . . .
>
> We emphasize, . . . the benefits from correcting asset valuations. Arbitrageurs perform the socially valuable function of moving prices toward market-clearing levels, which then induce optimal investment and consumption decisions. A change in the relative attractiveness of equity investments in oil companies will call forth new investments in these firms. Mobil could be wrong in assessing profit opportunities, but it would not be appropriate for the Department to oppose the merger because it may disagree with Mobil's judgment that Marathon's assets are undervalued. The Department has no comparative advantage in making oil investment decisions. If Mobil is wrong, it will bear the full costs of its error. Business errors are self-penalizing; they hurt the blunderer, not the consumer.[44]

The same valuation argument has been made in the popular press[45] and by the President of Mobil Oil who is reported to have said, in discussing the Marathon purchase, "Don't tell me there's a cheaper way of buying oil reserves. There is no cheaper way."[46]

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44 F. H. Easterbrook, R. S. Stillman, and N. H. Lewis, Economic Analysis of the Proposed Acquisition of Marathon Oil Company by Mobil Corporation, p. 203 (Lexecon Inc., November 2, 1981).

45 Hamilton, "If Mobil Conquers Marathon, Oil War Will Escalate to Mid-Tier, Critics Cry," Wash. Post, Dec. 6, 1981, at F1. Even after the eventual purchase of Marathon by U.S. Steel there was substantial discussion that Marathon shares remained undervalued. See Metz, "Marathon Says Price Paid by U.S. Steel Fell Far Below Estimates of Firm's Value," Wall St. J., Feb. 3, 1982, at 2.

46 Martin, "Mobil's Bold Strategy: Continuing a Tradition," N. Y. Times, Dec. 11, 1981, at D1. Also see the testimony of W.P. Tavoulareas, President of Mobil Corporation, at 430-49, Mobil/Marathon (transcript).

There are two plausible explanations for this disparity in valuation. First, firms like Mobil may have better information than the market. Second, even though comparable information is readily available, it is evaluated differently by different parties.

1. Valuing a target firm[47]

A firm's value will depend on the expected value of the profits obtained by the firm in future years.[48] Calculation of expected profits requires numerous assumptions, including estimates of the future price and quantities for various products sold, future costs of producing, storing and marketing those products, and future non-operating revenues (such as any gains from the sale of assets). Expected profits must also be discounted to account for the lower value of future as opposed to current income. Given the uncertain nature of future events in markets for oil and oil-based products, the valuations placed on a firm by potential bidders could easily differ.[49]

2. Oil company valuations of target firms

It is not surprising that different analysts and corporations hold diverse views about the current value of oil companies, simply because they have different

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47 The current price reflects the current value of a marginal share of the firm as a going concern. This price may not fully reflect the value of the firm to superior managers or to acquiring firms who envision certain cost savings from operating the combined firm after the merger. In addition, because various current owners of the stock will value the shares more highly than the marginal owner, a premium above the market price must usually be paid to obtain more than a small portion of the outstanding shares. The premium required to obtain 51 percent of a firm's shares may be substantial, and a tender offer will reflect the acquiring firm's estimation of the premium. In any event, the issue is why one group of investors might have evaluations that differ substantially from those of the market and assuming that the market value is "correct" will simply beg the question. We proceed on the premise that the undervaluation reflects a short-run stock market disequilibrium.

48 See J. Weston & E. Brigham, Managerial Finance 283-340 (6th ed. 1978) ("Capital Budgeting Techniques").

49 The list of complications given here is not exhaustive. The point is simply that any calculation of the value of a profit stream (pre- or post-tax) is complicated, and the conclusions reached even by sophisticated and relatively well informed bidders could easily differ.

expectations concerning future oil prices. These expectations no doubt are strongly influenced by different estimates about the behavior or continued success of OPEC or concerning the political situation in major producing nations. In fact, the spectrum of opinion may have widened in the past few years.

For most of the decade of the 1970's, domestic reserves were insulated from international oil-price uncertainty by the more predictable domestic regulations on price. But the combination of decontrol and the sharp increase in oil prices in 1973-74 (through the activities of OPEC) and between January 1979 and January 1980 (resulting, in part, from the turmoil in Iran and later the Iran-Iraq conflict) could easily have led to greater disparity of opinion over the current value of domestic oil companies.[50] A recent report indicates that 10 well known energy models predict crude oil prices for 1995 as high as \$83 and as low at \$40 per barrel (in constant 1981 dollars) even when all 10 models use standardized assumptions regarding OPEC production capacity, economic growth rates and demand elasticities.[51] The greater the divergence in investors' expectations, the more likely will be exchanges of ownership. One way for exchanges in ownership to be effected is through mergers.

Oil companies which believed the stock market undervalued the assets (particularly fossil fuel deposits) held by other companies may have been active in this process, particularly if they were able to obtain relevant information more cheaply and more quickly (given that they were already in the oil business) than other market participants. However, the evidence suggests that oil companies did not have any significant informational advantages over many other potential acquiring firms. For example, an independent evaluation of Marathon conducted by a respected industry

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50 "Outlook for Stable Prices Clouded by Iranian Dispute," Oil & Gas J. 43 (Apr. 28, 1980).

51 See Energy Modeling Forum, World Oil 26-50 (Stanford University, February 1982) (report 6).

expert, John S. Herold, Inc., valued Marathon's equity in October 1980 at $12.1 billion, or about $200 per share. Since the Herold estimate was publicly available at relatively low cost, it is difficult to argue that Mobil had a substantial information advantage.

Moreover, the fact that non-oil companies were active bidders in the Conoco and Marathon takeovers suggests that information concerning the value of these targets was dispersed among both oil-producing and other firms. It could be argued that the ultimate winner in the Marathon takeover was initially unaware of Marathon's value and that Mobil's bid was an important "signal" of the true value of the target firm's assets.[52] This argument, however, does not hold in the case of Conoco, where Mobil entered the bidding later than others. While there was undoubtedly some information value to other firms in knowing that Mobil had bid for a target company, the purported undervaluation of Marathan and Conoco was common knowledge in investment circles prior to Mobil's announcement.

3. Stock market "undervaluation" as an explanation for mergers

In the Marathon acquisition "battle," despite an apparent lack of important differences in information, Mobil and others valued Marathon at two to three times its stock market price. While uncertainty may be the most likely reason for this wide gap in opinion, another possibility is that Mobil and others simply possess greater evaluative powers than the market. For instance, some observers have noted that the market implicitly values a barrel of reserves at $3 while oil companies must spend approximately $6 per barrel to find additional reserves.[53] If these calculations are correct, oil

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52 Regulations that hamper a firm's efforts to obtain the gains offered by its discovery of undervalued assets may discourage such efforts. For a discussion of the "public good" aspects of tender offers and the effects of regulations, such as the Williams Act, on private efforts that generate this information, see Jarrell & Bradley, "The Economic Effects of Federal and State Regulations of Cash Tender Offers," 23 J. L. & Econ. 371 (1980).

53 One investment analyst has estimated that the cost of finding a barrel of oil is $12 to $15 while the price per barrel implicit in Mobil's $85 per share bid for Marathon is $3 to $4. See Blustein, "Mobil's Bid for Marathon Reflects Lessons from Conoco (Continued)

companies can obtain reserves at a bargain through acquisition.

However, such an observation may be simplistic. It is important to recognize that newly discovered oil and preexisting reserves are taxed at very different rates, because of the windfall profits tax. "Old oil" is taxed at the higher Tier I rates; new discoveries, at the Tier III rates.[54] This difference in tax treatment can make a rather substantial difference in the after-tax profit to be obtained from the "old" oil owned by Marathon. Under plausible assumptions about discount rates and decline rates, it is quite likely that the after-tax profit from a barrel of crude oil purchased on the floor of the New York Stock Exchange is not very different from that obtained from a barrel of newly discovered crude.[55]

This view is further supported by the behavior of both major and smaller oil producers. If oil company managements really valued reserves at only $3 per barrel and those reserves cost $6 to find, they would cease all exploration activity. The fact that huge expenditures are continually being made to find new oil implies that these activities are not viewed as unprofitable, and that oil companies do not view oil purchased on the stock exchange as being significantly cheaper.

A second problem with the undervaluation argument is that on the basis of the Herold estimates the major oil companies that have attempted to acquire smaller oil

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Offer, Urge to Gain Reserves," Wall St. J., Nov. 4, 1981, at 29. Union Oil has noted that the market value of its stock implies a per barrel price of $3 to $4, whereas the cost of finding new reserves in 1980 was approximately $7.50 per barrel. See letter from R. P. Bermington to R. B. Rowe (May 5, 1982). Even if this analysis is correct, one would not necessarily expect the phenomenon to lead to the wholesale disappearance of small oil companies, since stock prices should rise to reflect the undervaluation and pessimistic owners would be bought out. This process of revaluation does not require takeovers by larger oil companies.

54 26 U.S.C. § 4986. These rates will converge somewhat between now and the expiration of the tax in the the 1990's. Id. § 4990.

55 Using a 15 percent discount rate, both 5 and 10 percent decline rates, and a constant crude price of $35 per barrel, one finds that the after corporate income tax difference between the present value of the windfall profits tax on Tier I oil and on Tier III oil is approximately $2.50 per barrel. This difference would increase if higher future prices were expected.

companies are generally more undervalued than the acquisition targets. Using the ratio of Herold's August 14, 1981 estimates of oil company value to market value, the unweighted average ratio for the top 9 oil companies is 2.96 (Herold value to market value), and the next 6 companies have an average ratio of 2.33, while the remaining 18 companies have an estimate-to-market ratio of 1.36. Thus, the 15 largest companies (ranked by market value) are more highly undervalued than the smaller oil companies. If this were actually the case, a major would be better off purchasing its own stock than purchasing the stock of the second-tier company.[56]

The process of valuing a firm is complex and sensitive to a large number of estimated parameters. This complexity will inherently lead to differences among potential acquirers in their valuations of various firms. Since the potential acquirer with the highest valuation of the target will tend to bid the most for it, the target firm's resources will flow to their most highly (estimated) valued use.[57] The bidding process will lead to a revaluation of assets that may give more appropriate market signals. This appears to be the case in recent oil industry mergers. A diverse set of firms have bid up the value of some oil company assets. The purchasing firms presumably are those having the most optimistic expectations about the income stream to be derived from the acquired assets. It does not appear that the buyers have information that is particularly different from the rest of the market.

G. Financial Considerations as a Motive for Acquisition Activity

As in any industry, an increase in net funds could be used for payouts to shareholders (dividends or share repurchases), debt retirement, or investment.

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56 One can be a bit skeptical of the Herold estimates because they are so sensitive to the chosen discount rate and expected future price of oil. A recent Herold reevaluation of the equity value of oil companies that used a higher discount rate and a less optimistic view of future oil prices led to substantial reductions (on the order of 20 to 30 percent) in appraised values.

57 The buyer may in fact overvalue the assets and thereby bid too much. In this event it will absorb any attendant losses.

Investment could take a variety of forms: purchase of short or long term instruments, capital expenditures, research and development, exploration, or acquisitions. Therefore, it would not be surprising if a marked increase in the net funds accruing to the oil companies was accompanied by an increase in their acquisition activity. The next section demonstrates the substantial increase in net funds accruing to oil companies during the 1970's. This increase was probably a factor in the increase in oil company acquisition activity during this period. However, as was shown in Section III, the increase in net funds is probably not a satisfactory primary explanation of the increase in acquisition activity in the period 1979-1981, because total acquisitions net of divestitures by the large petroleum companies in 1979-1981 increased relative to the firms' total funds from operations. Conversely, capital expenditures by these firms as a percentage of funds from operations averaged 78.9 percent per year from 1979-1981, compared with an average of 104.7 percent per year from 1972-1978. Comparable percentages for the petroleum-related companies are 86.9 and 82.9 percent, and for the non-petroleum companies, 84.4 and 68.7 percent. Why the relative decline occurred for the petroleum companies over 1979-1981 compared with the earlier period is not certain. However, there has been a marked decline in the demand for gasoline since 1978 which may have reduced the demand for new refining capacity (as well as new wholesaling and retailing capacity).[58]

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58 The capital expenditures data cited here are from Compustat II Data Tapes, Industrial Files, Standard & Poor Corp., Annual. These data represent the funds used for additions to a company's property, plant, and equipment, excluding funds used for acquisitions, as reported in the Statement of Changes in Financial Position. A cursory review of many oil-company 10-K annual reports indicates that not all of the oil companies have an acquisitions category on their Statements of Change in Financial Position. These companies (and Compustat) may thus list some acquisitions as capital expenditures rather than acquisitions, so that Compustat figures may overstate capital expenditures.

1. Oil company cash flows in the 1970's

The increase in oil company cash flow during the 1970's is illustrated in Table IV-1, which lists the total funds from operations[59] obtained by 16 large petroleum companies (the same companies as those used in Section III of this study). The table demonstrates a substantial rise in funds since 1971, with the largest increases occurring in 1973-74 and 1979-80. These cash accumulations reflect the dramatic advances in the price of oil during those years.

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59 Total funds from operations is defined as the sum of income before extraordinary items, deferred taxes, and depreciation, less unremitted earnings of unconsolidated subsidiaries. Standard & Poor's Compustat Services Inc., COMPUSTAT II Sec. 9, p. 75 (Dec. 21, 1981) [hereinafter cited as COMPUSTAT II]. Notice that this measure does not include changes in debt position, which can also generate cash for the firm.

TABLE IV-1

Total Funds from Operations for
16 *Fortune* 100 Oil Companies

Year	Total Funds (million $)	Percent Increase (Decrease) from Previous Year (percent)
1972	$11,000.96	n.a.
1973	11,756.00	6.86
1974	15,427.20	31.22
1975	20,784.40	34.71
1976	16,275.36	-21.68
1977	19,862.40	22.03
1978	21,796.64	9.73
1979	25,688.80	17.85
1980	38,014.72	47.98
1981	49,545.12	30.33

n.a. -- not applicable.

Source: COMPUSTAT II, Data Tape, Industrial Files; Standard & Poor's Corp. Annual

Internally generated oil company funds have increased not just in absolute size, but also in relation to the value of the firms' assets, particularly during the period 1979-1981. This increase is reflected in Table IV-2 which lists total funds from operations as a percentage of total assets.[60] These percentages are also compared with similar percentages for the group of petroleum related companies and the group of non-petroleum companies. These groups are the same as those previously discussed in Section III of this study. Funds from operations in the large petroleum companies as a percentage of assets were generally higher than the percentages for the comparison groups throughout the period and particularly for 1979-1981.

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60 Total assets represents the sum of current assets, net plant, and other non-current assets such as intangible assets, deferred items, and investments and advances.

TABLE IV-2

Total Funds from Operations
as a Percentage of Total
Assets for Three Groups of Firms
1971-1980

Year	Large Petroleum Companies	Petroleum Related Companies	Non-Petroleum Companies
	(percent)		
1972	12.10	10.59	9.77
1973	12.22	10.55	10.68
1974	13.42	12.8	11.18
1975	15.47	12.01	11.33
1976	12.59	12.07	10.31
1977	13.09	12.08	10.89
1978	13.21	12.31	10.33
1979	14.04	12.32	11.34
1980	17.27	12.52	11.67
1981	17.67	14.43	11.17

Source: COMPUSTAT II, Data Tape, Standard & Poor's Corp. Annual

2. The use of internal funds in oil industry mergers: five case studies

Although it might be expected that the increase in net cash flows accruing to the oil companies would have stimulated somewhat greater acquisition activity, ceteris paribus, acquisitions are generally much more complicated financially than simple cash transactions. This section examines five major proposed or completed acquisitions involving oil companies to reveal the manner in which the acquisitions were financed. Of the five consummated or proposed mergers involving large oil companies examined as part of this study, only Sohio's acquisition of Kennecott was financed entirely from internally available funds. Sun Company paid $2.3 billion for Texas Pacific Oil Company's United States assets. Of this amount, $.5 billion came from internal funds and $1.8 billion from the issuance of floating rate notes to Texas Pacific. Du Pont's purchase price for Conoco, Inc. was $7.8 billion. Du Pont financed that sum by taking on $3.9 billion in new debt and by issuing shares of Du Pont stock to Conoco's stockholders for the remainder. Sohio acquired Kennecott Corporation for $1.8 billion. Sohio provided these funds from its available working capital.

The price paid by U.S. Steel Corporation for Marathon Oil Company was $6.2 billion. To finance the acquisition, U.S. Steel used $.8 billion of internal funds, borrowed $3.0 billion in new bank debt, and issued $2.4 billion in notes to the shareholders of Marathon Oil. Mobil Oil Company proposed to pay $6.4 billion for Marathon Oil. Mobil planned to finance $3.9 billion of this amount primarily through new bank debt and to issue debentures to Marathon's shareholders for the remainder.

The immediate source of funds to carry out a merger can be misleading, however. For example, the Kennecott/Sohio merger proxy statement indicates that Sohio would use internal funds to acquire Kennecott. Sohio's 1981 annual report notes, however, that "the significant 1981 growth in capital expenditures, including the major acquisition of Kennecott for $1.77 billion . . . caused a decrease in the cash and short-term investments during the year and prompted the Company to supplement its cash flow from operations with short-term borrowings."

H. Conclusions

Mergers are one mechanism through which a free market economy reallocates its resources. Within a market economy, market actors generally invest resources in socially beneficial activities in response to private profit opportunities. While mergers represent fairly dramatic realignments of control over assets, there is no reason to believe that they are guided any differently than other business decisions.

A number of motivations have been identified for mergers. Some of these involve incentives specific to the oil industry, such as escalating crude oil prices and changes in regulations. Others involve incentives that apply to industry more generally, such as realizing efficiencies, attaining market power engaging in speculation, and responding to the tax treatment of mergers. It is important to recognize that each merger is an individual transaction with individual motivations and that no general theory will explain it entirely.

Whatever the motivations for mergers and acquisitions, the policy questions that pertain to them are the same, in kind, as are the questions relating to other investments. In a market economy investors are usually free to succeed or fail unless the investment decision might have pernicious economic or social effects. One such impact that may be of concern is a lessening of competition. To the extent that mergers have these effects they should be prohibited, especially where they yield no offsetting benefits to competition. However, where such anticompetitive effects are absent the appropriate policy will usually be to avoid interference with the merger process.

The one immediate consequence of an acquisition is the real cost of transacting the deal. This includes attorney's fees, fees to investment bankers, and all other related costs of completing the acquisition in addition to the actual payment for assets. In comparison to the value of the acquisition, these transactions costs are small relative to the size of the acquisition, but not insignificant, as the next section will show.

V. MERGER TRANSACTION COSTS

The preparation and execution of a merger involves a variety of costs to private parties and government law enforcement bodies that extend beyond the compensation an acquiring firm pays to obtain the target company. This section discusses these "transaction costs" and estimates their magnitude for several petroleum company mergers. A review of the publicly available data and the results of an FTC survey[1] indicate that the transaction costs typically amount to at least .5 - 1.0 percent of the purchase price. The data also suggest that, in some cases, the amount may exceed one percent.

A. The Types of Transaction Costs and the Factors Affecting Their Magnitude

Presented below are the principal categories of transaction costs and a description of their main components.[2] These costs consist of expenses incurred by private entities and public law enforcement instrumentalities. Although the classification scheme used here is somewhat arbitrary,[3] its individual elements constitute a fairly comprehensive

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1 The Commission asked a sample of nine petroleum companies to review a tentative list of transaction costs and comment upon its accuracy and completeness. The Commission also requested that the sample firms attempt to estimate these costs, based upon the firms' acquisition experiences over the past decade.

2 Academic studies which have analyzed the types and significance of merger transaction costs include J. Bradley & D. Korn, Acquisition and Corporate Development 50-53 (1981); P. Steiner, Mergers — Motives, Effects, Policies 173-77 (1975); Smiley, "Tender Offers, Transactions Costs and the Theory of the Firm," 58 Rev. Econ. & Stat. 22 (1976). Informative popular treatments dealing with one or more mergers include R. Phalon, The Takeover Barons of Wall Street (1981) (focusing upon the Sun Company's acquisition of a 34% interest in Becton, the Dickinson Company in 1978); "Deals of the Year," Fortune 36 (Jan. 25, 1982) [hereinafter cited as "Deals of the Year"]; Brill, "Conoco: Great Plays and Errors in the Bar's World Series," Am. Law. 39 (Nov. 1981). Congressional hearings and studies have also examined elements of merger transaction costs from time to time. See, e.g., Staff of the Antitrust Subcomm. of the House Comm. on the Judiciary, 92d Cong., 1st Sess., Report on Investigation of Conglomerate Corporations (Comm. Print 1971) (discussing, among other subjects, the role of financial intermediaries such as investment banks in the merger process and the compensation they receive for their services).

3 For example, our classification system treats printing as a separate cost, although printing fees could theoretically be allocated to other categories (such as legal (Continued)

roster of merger transaction costs.[4]

Legal costs. This category embraces the expense to the companies and to the government of legal counseling and formal judicial proceedings associated with a merger. For the private companies, these include:

* fees paid to outside legal counsel;

* time and resources spent by the firms' own attorneys, executives, and other employees in preparing for and participating in legal proceedings (e.g., appearing as witnesses, complying with discovery, or assembling information to be filed pursuant to requests by state and federal law enforcement agencies).

The direct public costs include:

* time and resources spent by state and federal government law enforcement bodies in reviewing and, in some instances, challenging proposed or completed mergers;

* time and resources spent by the federal and state judicial systems in adjudicating disputes arising from proposed or completed mergers.

Financial and search costs. The private parties to a merger typically encounter a variety of costs associated with identifying and financing a transaction. These include:

* fees to investment bankers and other financial consultants for finding and evaluating possible acquisition candidates and for structuring the proposed transaction;[5]

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4 The discussion in the text incorporates the comments of firms which responded to the Commission's request.

5 Although the literature on the subject is limited and less than definitive, it appears that investment bankers and other financial consultants often play a pivotal role in identifying attractive takeover candidates for potential acquirers. See R. Phalon, supra note 2, at 99-124; Bebchuk, "The Case for Facilitating Competing Tender Offers," 95 Harv. L. Rev. 1028, 1037 (1982); W. Boucher, The Process of Conglomerate Mergers 116-19 (1980) (study prepared for the Federal Trade Commission); Brill, supra note 2, at 42 (noting that before its tender offer for Conoco, Seagrams had hired financial consultants "to study the long-range potential of various . . . industries in which Seagram might invest").

* fees to brokers for contacting shareholders and soliciting the tender of securities;

* expenses associated with establishing and maintaining lines of credit.

Accounting and auditing fees. These consist mainly of fees paid to accounting firms to evaluate the financial condition of the merged entity.

Registration and listing costs. For some transactions, the purchaser issues new notes or other securities to finance the acquisition. The Securities and Exchange Commission charges a fee for registering such securities. Stock exchanges also impose fees for listing the securities. Under the SEC and stock exchange fee schedules, the size of the registration and listing fees rises as the total value of the new securities increases.

Printing costs. These include the expense of printing registration statements, court papers, proxy statements, and new securities.

Postage costs. This category covers the cost of mailing many of the materials mentioned above to shareholders and other individuals and institutions.

Solicitation costs. These consist of fees paid to proxy solicitors and for advertising to encourage shareholders to tender their shares.

Depository costs. For a tender offer, the potential purchaser establishes a depository (usually with a bank) to collect and hold the tendered shares.

Asset evaluation, appraisal, and title search fees. Potential purchasers sometimes employ the services of consulting specialists to evaluate a takeover candidate's assets or various aspects of its operations.[6] Acquisitions of real property also may involve the hiring of firms to conduct title searches.

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6 For acquisitions of firms engaged in the oil industry, a potential buyer might consult outside petroleum engineering firms for estimates of crude oil and natural gas reserves. More generally, the acquiring firm may hire special consultants to examine the target firm's computer, financial, or other support systems.

Stay bonuses. The acquiring firm sometimes pays bonuses to key employees of the acquired firm to encourage them to remain with the company.

Other personnel costs. To the extent not covered in the categories above, this classification encompasses the cost to the firm of having its personnel — particularly corporate officers — devote their attention to supporting, executing, or defeating pending merger proposals rather than carrying out their regular duties.[7]

Uncertainty costs. This category covers two types of costs arising from the uncertainty created by the announcement or pendency of a merger. These are:

* costs associated with deferring company decisions pending resolution of an existing transaction or in anticipation of an imminent proposal;[8]

* losses in employee productivity due to concern or speculation about the ultimate effects of a merger.[9]

Many of the costs outlined above are generated to some degree by all mergers and acquisitions. Their absolute size, however, varies significantly depending upon the size and complexity of the merger and the reaction to a merger proposal by the target firm

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7 To the extent that a firm and its officers regard acquisitions as being an important company priority, one might regard time used to prepare and execute mergers as being an ordinary, not an extraordinary, use of resources. For example, one firm responding to the FTC's survey noted that its "Corporate Strategic Planning group is continually engaged in the evaluation of acquisitions and divestitures as a part of its operation function, so that costs associated with the [sample] acquisition would not in any sense be regarded as added costs."

8 This description contemplates the inclusion of uncertainty effects traceable to an actual merger proposal (whether or not public) or to the strong likelihood that a concrete proposal will soon emerge. This limitation is designed to exclude the effects upon firm or management behavior that stem from a corporate officer's general awareness that every company is, to some extent, a potential takeover target. Without a temporal dimension, much — if not all — firm behavior could theoretically be described in terms of management's desire to avoid takeovers.

9 The prospect of an acquisition can sometimes be a morale stimulant to one or both of the parties to a merger and perhaps a spur to greater productivity. In discussing one of its acquisitions, a firm responding to the FTC's survey stated that the "transaction was generally viewed favorably by . . . management and we know of no loss attributable to 'apprehension about the effects' of the transaction."

and its shareholders, government law enforcement bodies, and other potential bidders for the target company. Stated more fully, the magnitude of merger transaction costs hinges principally on the following factors:

Does the target firm resist the takeover effort? Perhaps the single most important factor governing the total amount of transaction costs is whether the merger is "friendly" or "hostile." The hostile takeover typically costs considerably more to transact than a friendly merger.[10]

What action do government law enforcement bodies take? As the level of intervention increases, the transaction costs to the firm and to government bodies grows.[11]

How large and complex is the transaction? Many investment bank financial counseling agreements link the bank's compensation to the size of the transaction. Thus, larger deals produce greater counseling expenses.[12] In addition, a relatively simple, one-step acquisition will normally cost less to implement than an intricate, multi-stage deal which demands greater legal and financial resources to structure and execute.

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10 See P. Steiner, supra note 2, at 175 (summarizing the results of one study of hostile mergers occuring in the 1960's that estimated "the direct outlays in contested mergers to have been at least twice as high as the cost of a routine uncontested merger, and in major contests, the costs may double again").

11 For example, for federal antitrust agencies, enforcement options range from routine approval to the issuance of requests for additional information and, in some instances, to the commencement of formal proceedings to stop the transaction. For a review of the gradations of government intervention, short of a formal complaint, in reviewing a merger, see S. Thompson, Evaluation of Premerger Notification Program (1981) (study prepared for the Federal Trade Commission).

12 See "A Corporate Sell-Off Spree," Newsweek 62 (Mar. 29, 1982).

Are multiple bids submitted for the target company? Aggregate transaction costs and the costs to each offeror will tend to rise if more than one firm bids for the target firm.[13]

Do shareholders of the target firm contest the transaction? Particularly where the management of a target firm has placed its weight behind one of several competing tender offers, some shareholders of the target firm may sue the firm's officers if they believe these executives effectively denied shareholders the benefit of a more lucrative bid.[14] Lawsuits to settle the claims of disgruntled shareholders can extend well beyond the consummation of the transaction.

Although one could single out other general factors,[15] the five variables presented above generally determine the size of transaction costs for a particular merger. Transaction costs will likely be relatively modest for a friendly merger involving minimal government review, no rival bidders and a paucity of subsequent shareholders' challenges to the acquisition. Transaction costs will be comparatively high for a hostile takeover that involves several bidders, attracts careful government review and possibly a formal suit to block the merger, and ultimately provokes shareholders' suits attacking various features of the acquisition.

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13 Legal fees increase substantially as the participants in a multi-firm bidding contest mount wide-ranging litigation campaigns to exploit possible antitrust and securities law infirmities in their rivals' bids. See Brill, supra note 2 (describing the three-way legal struggle among Du Pont, Mobil, and Seagrams in their efforts to purchase Conoco).

14 For a listing of such suits arising from U.S. Steel's purchase of Marathon, see United States Steel Corporation, Form 10-K For the Fiscal Year Ended December 31, 1981, at 17-21.

15 One additional factor, for example, would be the extent to which companies rely, respectively, upon outside and in-house counsel to perform legal work related to the merger. There is evidence that firms with strong legal departments may be able to reduce their total legal expenses considerably by contracting for fewer services with private law firms. See Bernstein, "Profit Pressures on the Big Law Firms," Fortune 84-85 (Apr. 19, 1982) (noting that an increasing number of corporations "have grown choosey about giving business to outside counsel" and have assigned more tasks to their own attorneys).

B. Empirical Data Concerning Merger Transaction Costs

Presented below are costs by category for several individual transactions based upon information derived from the Commission's survey and contemporary accounts. The available data are fragmentary, but they reasonably suggest the order of magnitude of the transaction costs incurred in these mergers.

1. Costs by category

Legal costs

The data permit observations about the costs borne by private parties and public bodies, respectively. As mentioned above, the private costs have two components — fees paid to outside counsel and the companies' own internal legal expenses.

Fees paid to outside counsel. Many major law firms charge corporate clients an average of \$80-100 per hour per lawyer. Takeover work, especially in hostile tender offers, often commands a substantial premium above the base rates.[16] Many companies which perceive themselves to be possible takeover candidates also pay fixed retainers to law firms specializing in takeover work to have immediate access to their services should a hostile tender offer take place.[17]

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16 One major business periodical recently offered the following calculation:

> Once a takeover fight begins all [law] firms charge higher-than-usual rates. According to its formal billing policy, one firm specializing in takeovers bases its charges in part on "the responsibility assumed and the result achieved." That means "not less than 200% and sometimes more than 300% of base time charges." Rough translation: \$400 to \$600-plus per hour per lawyer.

Bernstein, supra note 15, at 84, 94.

17 Fortune recently reported that "for about \$75,000 a year clients can retain Skadden Arps. The down payment ensures the client a crack at Skadden Arps' services should it become involved in a takeover brawl. . . . More than 200 companies have anted up for 'the Joe Flom protection policy,' as one lawyer dubs it." Bernstein, supra note 15, at 94. Conoco apparently invoked just such a policy with Skadden, Arps, Slate, Meagher & Flom upon learning that Dome Petroleum had made a tender for its shares, launching the series of bids that produced the DuPont-Conoco merger. See Brill, supra note 2, at 40.

The total fee paid to outside counsel for its work on a merger case varies depending on the type of case. One recent study estimates the fee charged by outside counsel for litigating an average antitrust merger case to run from an absolute minimum of $700,000 to a moderate level of $1.4 million.[18] The Commission's survey and recent public accounts reveal a diversity of fees paid to outside legal counsel in recent cases, ranging from several hundred thousand dollars for relatively simple, uncontested transactions to a reported $13.5 million for lawyers advising the parties in the Du Pont-Conoco merger.[19]

Internal legal costs. In addition to payments to outside counsel, many companies devote substantial internal resources to legal matters. Company officials, for example, may sometimes be deposed or called as witnesses in lawsuits challenging the validity of a transaction.[20] More common tasks include the assembling of documents to

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18 Fisher & Lande, Efficiency Considerations in Merger Enforcement 74 & n.267 (draft, Apr. 1982) (forthcoming in 92 Yale L. J. (1982)). This estimate assumes an effort by the government to obtain a preliminary injunction; discovery consisting of 25 depositions and production of 10,000 documents; a trial of 6 to 10 weeks; and an appeal. Fisher and Lande caution that the average litigated merger case may well exceed $1.4 million in legal fees, as the $1.4 million amount assumes a fairly simple, expeditious proceeding.

19 At the lower end of the range, one company reported outside legal fees of about $100,000 and $256,000 for two uncontested transactions in the late 1970's. Similarly, another firm reported total legal costs of $286,500 and $298,000 for two recent unidentified transactions, the first a tender offer followed by an exchange offer and the second a straight tender offer. A third company calculated outside fees of $500,000 for its purchase of a natural resources concern.

In the middle range, two firms provided estimates of, respectively, about $1.295 million and $1.6 million in outside fees for two separate transactions, each valued at over $1 billion.

At the high end of the scale were the Mobil-U.S. Steel-Marathon and Du Pont-Conoco-Seagrams tender offer contests which apparently accounted for, respectively, a total of about $10 million and $13.5 million in outside legal fees. See Brill, supra note 2, at 40; "Takeover Battle Legal Bill: $7M," Nat'l L. J., Feb. 15, 1982, at 2; Lowenstein, "Mobil Corp Says It Isn't Seeking Major Oil Firms," Wall St. J., May 7, 1982, at 4.

20 For example, leading corporate officers of Mobil and Marathon testified during the trial of Marathon's suit to block Mobil's takeover bid. One firm's response to the
(Continued)

comply with formal discovery or government information requests.[21] Responses to the Commission's survey indicate that, for each firm, quantifiable internal legal costs may amount to 20-30 percent of fees paid to outside counsel.[22]

The data on legal costs borne by public bodies is also limited. The FTC's experience indicates that an average, fully-litigated merger case consumes approximately 14,000 professional hours, although some merger matters have taken as much as 40,000 hours.[23] Using a fully allocated cost of $40 per hour,[24] an average, fully-litigated case would cost the Commission about $560,000, exclusive of amounts paid for witnesses and certain other litigation-related costs. A contested tender offer, however, can require a larger proportionate outlay, even if the matter ends well short of a final, non-appealable decision on the merits. For example, tentative estimates indicate that the FTC billed 13,700 professional hours (or approximately $550,000) to the U.S. Steel-Mobil-Marathon takeover contest over a 2 1/2 month period.[25]

FTC survey indicated that, for a large transaction accomplished within the past 18 months, the time of its chief executive officer "expended in the acquisition effort was substantial" for the periods immediately before and during the acquisition.

21 One firm's response to the Commission's survey stated that 25 of its attorneys spent approximately three weeks "directing, collecting, and reviewing documents" which antitrust authorities requested to evaluate a proposed merger.

22 For two transactions one firm reported internal legal costs of $30,^00 (versus $100,000 for outside fees) and $50,000 (versus $256,000 for outside fees). A second company indicated that it spent about $315,000 for inside counsel on one acquisition compared to $1.295 million for outside counsel.

23 Fisher & Lande, supra note 18, at nn. 268, 270. Fisher and Lande based their estimates upon an analysis of FTC professional staff time billed to merger cases over the past decade. The calculation of 14,000 hours represents a weighted average of cases concluded by consent agreements and decisions on the merits, as well as cases litigated but closed for various reasons.

24 Id.

25 The Commission's actions consisted mainly of conducting a premerger review of the U.S. Steel and Mobil tender offers and filing a request for a preliminary injunction to halt apparently anticompetitive aspects of Mobil's bid.

Financial and Search Costs

The reported data indicate that this is the largest category of transaction costs, with investment banking fees constituting the largest single type of transaction expense.

Investment banking and financial consultant fees. Investment banks which act as counsellors to the parties in a consummated merger generally received a fee ranging from .2 percent to 1 percent of the purchase price.[26] In Shell's $3.6 billion acquisition of Belridge, for example, Belridge paid its bankers about $14.6 million.[27] For U.S. Steel's $6.7 billion takeover of Marathon, U.S. Steel and Marathon paid their investment bankers approximately $10 million and $17.4 million, respectively.[28] One public account of Du Pont's $7.2 billion takeover of Conoco stated that the transaction earned First Boston $15 million and Morgan Stanley $14 million for representing Du Pont and Conoco, respectively.[29]

Establishing and maintaining lines of credit. The sole piece of empirical data available on this point is the response of one firm which participated in the FTC survey. This firm estimated that its cost of establishing and maintaining lines of credit for use in multi-billion dollar acquisition to be about $3.22 million.

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26 See Newsweek, supra note 12, at 63; "Deals of the Year," supra note 2, at 36 (Jan. 25, 1982) The percentage tends to increase for smaller transactions and drop for larger deals. The financial intermediary for an unsuccessful bidder or an aborted merger effort normally receives a flat fee that ranges between less than $100,000 for a smaller transaction up to several hundred thousand dollars for a major deal.

27 Belridge's estimate appears in the Form S-14 filed by Kernridge Oil Company with the Securities and Exchange Commission on November 23, 1979.

28 See Nat'l L. J., supra note 19, at 7.

29 Fortune, supra note 2, at 37. Although it did not indicate the size of the two transactions, one firm reported payment of investment banking and financial counseling fees of $1.4 million and $3.7 million for two recent acquisitions. For one multi-billion dollar transaction, another company paid an estimated $4.7 million for financial counseling services; for one other takeover costing several hundred million dollars, the same company spent about $' 7 million for these services.

Accounting and Auditing Fees

The Commission's survey produced three estimates of these costs. One company reported accounting and auditing costs of $45,000 for a multi-billion dollar acquisition. Another firm reported two unnamed transactions, giving an estimate of $10,000 outside fees/$50,000 inside costs for the first and $100,000 outside fees/$90,000 inside costs for the second. The third company listed fees of $56,800 and $2,580 for two unidentified acquisitions. A fourth firm reported that total accounting fees incurred by the acquiring and acquired companies in a multi-billion dollar transaction were $600,000.

Registration and Listing Costs

The Commission's survey provided registration and listing cost estimates of $1.2 million, $1.043 million, and $819,000, respectively, for three multi-billion dollar acquisitions. The FTC also received estimates for several acquisitions under $1 billion. One concern listed fees of $4,250 and $44,000 for two unnamed transactions, and a second firm reported costs of about $77,000 for one of its acquisitions.[30]

Printing and Postage

The Commission received printing cost estimates of, respectively, $3.9 million, $536,000 and $400,000 for three multi-billion dollar transactions. It also obtained estimates of $50,000 and $134,000 in two unnamed acquisitions by one company and $765,000 and $157,000 in two unidentified acquisitions by another firm. One company indicated that its postage costs had been "insignificant." On the other hand, a second concern noted postage costs of $127,500 for one transaction.

Solicitation and Depository Costs

One firm responding to the FTC survey stated that it had incurred a total of $1,189,000 in depository costs and $124,000 in solicitation expenses for a multi-billion dollar acquisition. Another company reported solicitation fees of $21,675 for one

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30 On average, registration fees paid to the SEC appeared to account for 80% of the total amount, with stock exchange listing fees constituting the balance.

transaction and depository costs of $54,000 and $15,000 for its two sample acquisitions.

Asset Evaluation, Appraisal, and Title Search Costs

One firm noted an expenditure of $560,000 attributable to "time costs for preparation and technical evaluation" of the assets it acquired from a natural resources company. Another firm reported fees of $3.2 million for title search and deed abstraction services for one acquisition and $400,000 for a second merger.

Stay Bonuses

One firm paid an estimated $7.9 million in such bonuses to key employees of a natural resources firm it acquired.[31]

Other Personnel Costs and Uncertainty Costs

To some observers, these transaction costs are particularly important,[32] but barely amenable to either quantitative or qualitative analysis.[33] Anecdotal accounts of the Du Pont-Conoco,[34] U.S. Steel-Marathon[35] and Sun-Becton Dickinson[36] transactions,

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31 For one public account of a merger that suggests the importance of retaining key employees of the acquired firm, see Getschow, "Loss of Expert Talent Impedes Oil Finding by New Tenneco Unit," Wall St. J., Feb. 9, 1982, at 1.

32 One experienced member of the antitrust bar — a specialist in takeovers — informally indicated his belief that this category of costs was "of a magnitude greater" than the "hard cost" categories for which quantitative data are available. On the other hand, one firm's response to the FTC survey stated: "We question whether 'uncertainty costs' should be included in a listing of merger and acquisition costs since it is not certain that they exist and, if they do, it is impossible to quantify these costs."

33 Companies which responded to our request generally agreed that they were important. Only one firm felt it possible to attempt a ballpark estimate for time spent by its executives and other employees; for its two transactions it listed $100,000 and $150,000 for "Executive Time; Planning; Treasury." One other firm questioned the treatment of these expenses: "[the firm's] employees performed substantial work on [two] transactions in such areas as financial analysis and accounting, business planning and analysis, crude oil reserve management and technology, human resources, legal and operations groups. However, . . . employee costs are largely fixed and would have been incurred regardless of acquisitions"). It would nonetheless appear that the foregone output which would have been obtained if these employees had been devoted to other tasks represents a cost to the firm of merger activity.

34 See Brill, supra note 2; "Du Pont's Great Leap," Newsweek 52 (July 20, 1981).
(Continued)

for example, depict top corporate officials of all participants, bidders and targets alike, as devoting substantial if not exclusive attention to the preparation and execution of the transaction at hand.[37] Other contemporary accounts suggest that concern with developments in the takeover process can come to dominate the routine employees of the target firm.[38] The empirical data probably support a conclusion that this collection of intangible costs can be significant and is worthy of study. Nonetheless, rigorous, feasible methods for testing this proposition are decidedly elusive.

2. Two case examples

This segment attempts to assemble the individual costs listed above into a composite picture for two transactions — U.S. Steel-Marathon and Du Pont-Conoco. The publicly available data are listed, along with a brief explanation showing categories for which no estimation was obtained.

U.S. Steel-Marathon. Presented below is a summary of the publicly available transaction cost data for this contested $6.7 billion tender offer acquisition:

Item		Cost (dollars)
Legal Costs		
	Outside Counsel (all firms)	$10,000,000
	Government (FTC)	550,000
Financial Costs		
	Investment Banks	27,400,000
Total		$37,950,000

This calculation omits estimates for many categories, including certain legal costs

35 See "Mobil's Marathon Loss, Its Second in 6 Months, Is Tied to Its Blunders," Wall St. J., Jan. 8, 1982, at 1.

36 See R. Phalon, supra note 2, at 21-27, 31-32, 77-78 (analyzing role of Sun President Richard Sharbaugh in planning the Becton takeover effort).

37 See also Chakravarty, "Is the Hunter Being Stalked," Forbes 38 (Mar. 29, 1982) (discussing Gulf management's concern about a possible tender for its own shares and management's own acquisition interests).

38 See Nag & Rotbart, "U.S. Steel Bids to Rescue Marathon From Mobil in 2-Part Merger Plan," Wall St. J., Nov. 20, 1981, at 3.

(notably costs to the judicial system and to government agencies other than the FTC), some financial costs (e.g., the fee Mobil paid to its financial advisors), all accounting and auditing fees, registration and listing costs, printing, postage, publicity, solicitation fees, depository costs, and intangible costs associated with uncertainty and the diversion of employee time from routine business. It also omits costs incurred by Amerada Hess as part of its efforts to reach an agreement with Mobil to remove possible antitrust problems arising from Mobil's tender for Marathon.

Du Pont-Conoco. For this $7.2 billion transaction, only outside legal fees and financial counselling fees are publicly available:

Item	Costs (dollars)
Legal Costs (private counsel for all firms only)	$13,500,000
Financial Costs (investment banks representing Du Pont and Conoco only)	29,000,000
Total	$42,500,000

As in the previous example, the data here are largely incomplete.

A fuller analysis of transaction costs would require filling the gaps for these comparatively large transactions as well as obtaining detailed data on small and medium size acquisitions. The estimated costs for the two transactions examined above equal roughly six-tenths of a percent of the total purchase price, with slight variations. This calculation likely understates the actual transaction costs, owing to incomplete data on both hard and less tangible expenses. It is not unreasonable to estimate that the transaction costs for most acquisitions range from between at least .5 and 1 percent of the purchase price.[39] The data also suggest that, for a number of mergers, the amount may well exceed 1 percent.[40]

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39 Data submitted by one company on a major unidentified transaction indicate a transaction cost expenditure by the acquiring firm alone amounting to .4 percent of the purchase price. Another company estimated that its transaction expenses for a multi-billion dollar acquisition came to about .79 percent of the purchase price. Neither of these transaction cost estimates included resource expenditures by public bodies or the acquired firms.

40 For example, one acquiring company alone incurred transaction costs amounting to 1.67 percent of the purchase price in a small, unidentified acquisition. Similarly, another acquiring firm estimated its own transaction costs for a several hundred million dollar acquisition to be .9 percent of the purchase price. As above, these cost figures do not include estimates for several categories of transaction costs which private and public bodies likely encountered.

VI. COMPETITIVE FACTORS IN EXAMINING PETROLEUM MERGERS

Several of the questions raised in the January 15, 1982 letter to Chairman Miller relate to the state of competition in the petroleum industry. Specifically, the letter requested that the study evaluate the impact of oil industry mergers on competition (and therefore, on the availability and prices of petroleum products to consumers) and the adequacy of current law as it relates to mergers involving major oil companies. To discuss these issues, the general analysis typically applied in evaluating mergers under Section 7 of the Clayton Act is briefly described. The analysis is then applied to each of the major functional levels of the petroleum industry — crude oil exploration and production, refining, transportation, and marketing.

A. Overview of Competition Policy

1. Introduction

Petroleum industry mergers can have competitive implications at any vertical level of the industry. While each level has its own particular characteristics which may affect merger analysis (e.g., government regulation of petroleum pipelines), virtually all mergers of competing firms — within and without the petroleum industry — require an examination of certain fundamental threshold issues. The Commission and the Department of Justice have recently issued statements of merger enforcement standards and policy.[1] This brief overview is not intended to substitute for these more detailed statements.

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1 Statement of Federal Trade Commission Concerning Horizontal Mergers, June 14, 1982; U.S. Department of Justice Merger Guidelines, June 14, 1982.

2. The economic rationale for preventing certain horizontal mergers[2]

Merger analysis rests on the hypothesis of economic theory and on empricial evidence that changes in market structure resulting from a merger may cause noncompetitive pricing and output behavior. This is more likely to occur in more concentrated markets where a small number of firms compete. Where a market is highly concentrated, ceteris paribus, it is easier for each firm to monitor the behavior of others, deter price competition, and coordinate price and output decisions.

Horizontal mergers reduce the number of competitors and may increase concentration.[3] This may have adverse effects on competition. Section 7 of the Clayton Act provides a basis for preventing mergers that may have anticompetitive effects. Of course, most mergers have no significant effect on competition; many may even facilitate competition or efficiency, where resources move to their most valued use.

3. Application of Section 7 of the Clayton Act to horizontal mergers

Section 7 of the Clayton Act prohibits persons from acquiring stock or assets from any other person "where in any line of commerce in any section of the country, the effect of such acquisition may be substantially to lessen competition, or tend to create a

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2 In addition to mergers between competitors (horizontal mergers), the Clayton Act has been applied to mergers involving firms operating at two different levels of an industry (vertical mergers) and mergers between firms operating in different industries (conglomerate mergers). Because virtually all the significant petroleum firms operate at every level of the petroleum industry, mergers involving these companies will tend to be viewed as horizontal. Accordingly, this study is confined to the effects of horizontal mergers.

3 A firm could sell a portion of its business to a competitor so that the number of firms would remain the same. If a big firm sold to a small one, concentration might actually decrease under some measures.

monopoly."[5] Section 7 provides no definitive tests for determining whether a particular merger lessens competition. It leaves this analysis for the courts and for the Commission, to permit the law to develop in accordance with the evolving understanding of the competitive effects of mergers.

The Commission and the courts typically begin the analysis of a particular acquisition by determining the relevant product and geographic markets. The competitive impact of the merger is then assessed in these markets by analyzing market share statistics and other relevant information.

Relevant markets

A relevant product market should include all items that are reasonable substitutes for each other, such that an increase in price for one item would significantly increase the demand for the other. Such substitution inhibits a group of firms from raising prices on their products because the price increases would cause a substantial number of customers to purchase substitute products.

A relevant product market should also account for manufacturers' ability to shift production among various items. If manufacturers can readily supply more of one product and less of another product in reaction to price changes, then both may be included in the product market.

The major difficulty in judging demand and supply substitutability is that there is no easy way to determine how customers and suppliers might behave in response to price

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5 15 U.S.C. § 18. Section 7 does not bar all mergers, but only those which lessen competition. However, because the statute requires a prediction of future effects, no absolute showing of anticompetitive effect is required. The statute focuses on the probability, not certainty, that anticompetitive effects will result from the merger. FTC v. Proctor & Gamble Co., 386 U.S. 568, 577 (1967). But "[p]roof of a mere possibility of a prohibited restraint or tendency to monopoly will not establish the statutory requirement." United States v. du Pont & Co., 353 U.S. 586, 598 (1957).

changes.[6] Practical indicia of the degree of substitutability have instead been employed. The major indicia are: (1) industry recognition of markets; (2) peculiar characteristics and uses of products; (3) the uniqueness of production facilities; (4) distinct prices; (5) sensitivity to price changes; (6) unique customers; and (7) specialized vendors.[7] Some of these factors closely resemble the test of demand substitutability (peculiar characteristics and uses, distinct prices, sensitivity to price changes). Others resemble the supply substitutability test (uniqueness of production facilities). In drawing conclusions, it is not necessary that all seven of the factors support the market, but one or only a few factors may not be sufficient to define a market.[8]

Relevant geographic markets must also be delineated. A geographic market should be drawn to define the area within which the major supply and demand forces determine the price of the relevant product. In a properly drawn market, firms' output decisions in one geographic market would be largely unaffected by the actions of firms taken outside that market.[9]

It should be emphasized that trading areas and geographic markets need not be synonymous. Two firms with very local and noncontiguous trading areas may be in the same geographic market if broader forces are at work affecting the price of each firm's output. On the other hand, firms trading on a national scale and distributing supplies from several localized plants may well be involved in discrete geographic markets,

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6 The problem is particularly acute in merger cases, where determinations must often be made quickly.

7 E.g., United States v. Continental Can, 378 U.S. 441 (1964). This listing is not intended to be all inclusive of factors considered in defining product markets. Moreover, individual factors must be interpreted in the context of other factors. See also, FTC Statement and DOJ Guidelines, supra note 1.

8 General Foods Corp. v. FTC, 386 F.2d 936, 941 (3d Cir. 1967), cert. denied, 391 U.S. 919 (1968); Reynolds Metals Co. v. FTC, 309 F.2d 223, 227 (D.C. Cir. 1962); United States v. Black & Decker Mfg. Co., 430 F. Supp. 729 (D. Md. 1976); United States v. Consolidated Foods Corp., 455 F. Supp. 108 (E.D. Pa. 1978).

9 See FTC Statement, supra note 1, at 13.

depending upon the scope of the supply and demand forces at work.

The key question to ask when defining a geographic market is whether if prices were increased in the purported geographic market, sources of supply from outside would flow in, reducing prices back to approximately their initial levels. If outside sources of supply could not have such an effect, they should not be included in the market.

One test for the presence of distinct markets is the existence of persistent differences in prices between areas, after making adjustments for regional cost differences. A related form of inquiry evaluates the changes in prices over time, to determine whether common price movements occur in different geographic areas.[10] Common price movements would suggest that the same competitive forces are operating in the geographic areas, indicating that the market may include all such areas. An examination of common price movements, however, may also incorrectly identify as one broad market two areas which are distinct markets. For instance, petroleum product prices generally rise in a fairly uniform fashion in widely separated areas in the country, but this is not necessarily because suppliers in those areas compete with one another, but may be because all areas are subject to the same crude oil price increases.

In lieu of price information, shipment data has been used to determine geographic markets.[11] An area is often assumed to be a geographic market if it has few imports and exports. In other instances, attempts have been made to assess the substantiality of barriers that impede movement of products between areas. For example, such factors as transportation costs or distance have been studied.[12]

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10 Horowitz, "Market Definition in Antitrust Analysis: A Regression-Based Approach," 48 S. Econ. J. 1 (1981).

11 A more formalized test has been proposed by Elzinga and Hogarty. Elzinga & Hogarty, "The Problem of Geographic Market Delineation in Antimerger Suits," 18 Antitrust Bull. 45 (1973).

12 Weiss, "The Geographic Size of Markets in Manufacturing," 54 Rev. of Econ. & Statistics 245 (1972). F. Scherer, A. Beckenstein, E. Kaufer, & R. Murphy, The Economics of Multiplant Operation (1975).

The courts have relied upon all of these different types of data in defining the "area in which the seller operates, and to which the purchaser can practicably turn for supplies."[13] For example, various cases have considered transportation costs,[14] localized demand,[15] industry recognition of the areas of competition,[16] pricing data, and shipment patterns.[17]

Significance of market share and market concentration

Once the relevant markets have been defined, the Commission or a court will examine the merging firms' market shares and other indicia of market concentration.[18] Generally, the first step is to determine the effect of the acquisition on market concentration.[19] The Commission or a court will also generally consider the level of concentration in the market. A merger may deserve a higher level of scrutiny if it occurs in a highly concentrated market.[20] The significance of market concentration also may vary according to the distribution of market shares of firms in a market.[21]

The most commonly used measures of concentration are the combined market

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13 Tampa Elec. Co. v. Nashville Coal Co., 365 U.S. 320, 327 (1961).

14 FTC v. Procter & Gamble Co, 386 U.S. 568 (1967).

15 Tampa Elec. v. Nashville Coal, 365 U.S. 320 (1961).

16 United States v. Phillipsburg Nat'l Bank, 399 U.S. 350 (1970).

17 Jim Walter Corp. v. FTC, 625 F.2d 676, 682 (5th Cir. 1980); T mpa Elec. Co. v. Nashville Coal Co., 365 U.S. 320 (1961).

18 Market shares are typically the starting point in the analysis of mergers. United States v. Continental Can, 378 U.S. 441, 458 (1964). They are not, however, conclusive indicators of anticompetitive effects; other factors must be examined. United States v. General Dynamics, 415 U.S. 486, 498 (1974). Other factors are considered below.

19 United States v. Phillipsburg Nat'l Bank, 399 U.S. 350 (1970).

20 United States v. Aluminum Co. of America, 377 U.S. 271 (1964); United States v. Continental Can Co, 378 U.S. 441, (1964).

21 See Kwoka, "The Effect of Market Share Distribution on Industry Performance," 61 Rev. of Econ. & Statistics 101 (1979).

shares (i.e., concentration ratios) of the top two, four, and eight firms, and the Herfindahl index, considered by many to be a more useful measurement of concentration, because it captures some properties of the full distribution of shares rather than just the shares of the top firms.[22]

Additional relevant factors

Various aspects of firm behavior or particular product characteristics within an industry in which a merger is to be examined have been associated with the likelihood of interdependent or collusive behavior. These are discussed more fully in the recent FTC statement on Horizontal Mergers and the Department of Justice Merger Guidelines, dated June 14, 1982, supra note 1.

Barriers to Entry. The ability of new firms to enter the market acts as a constraint on the ability of existing firms to raise the price above competitive levels. If entry barriers are low it is unlikely that the exercise of market power, whether individually or collectively exercised, will go unchecked. Conversely, if a few large firms (relative to a given market) can produce more cheaply than smaller firms (because of technical aspects of production), or if only a few firms have access to important factors of production that are not alternatively available except at higher cost, then prices may be increased to some extent over the costs of existing producers without attracting entry. Similarly, government regulations may prevent or deter entry, as may large capital costs if capital markets do not function well. Mergers must be carefully evaluated when these or other conditions may restrict entry.

Price Elasticity of Demand. The price elasticity of demand for a good or service reflects the responsiveness of the quantity demanded resulting from a change in

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22 The Herfindahl index is equal to the sum of the squares of the market shares of each firm in the market. Thus, a market consisting of four firms, each with a 25 percent share, would have a Herfindahl index of $.25^2 + .25^2 + .25^2 + .25^2 = .25$ (sometimes expressed without a decimal as 2500). The measure ranges between 0 and 1 when market shares are expressed in decimals. See DOJ Guidelines, supra note 1, at 16-21.

price. In large part, the degree of elasticity will depend upon the extent to which customers can substitute other goods for the particular product when its price increases. The less elastic the demand for a product at the competitive price, the greater are the potential gains to firms from collusion, since revenue gains from an increase in price will be less offset by a reduction in the quantity demanded at the higher price.[23]

Product Homogeneity. Collusion to maintain prices above the competitive level is less likely to be successful the more heterogeneous, complex, and changing in nature are the products involved. The fact that products are differentiated adds an additional variable upon which collusive agreement must be reached.[24] Firms must agree not only on price, but also on the extent to which one product merits a premium over another. Collusive arrangements may break down not only as a result of instances of price competition, but also through nonprice competition.

Vertical Integration. Collusive arrangements are more complicated when firms sell at different levels of distribution, especially when firms differ in the degree to which they are vertically integrated.[25] Detection of price cuts may also be more difficult when firms differ in the degree to which they transfer the product internally rather than sell on the open market. Furthermore, varying degrees of integration can alter firm cost structures, giving firms different preferred prices.

Noncompetitive Conduct and Performance. Some types of conduct or industry practices may facilitate coordination betweem firms, increasing the likelihood of successful collusion.

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23 Kamerschen, "An Economic Approach to the Detection and Proof of Collusion," 17 Am. Bus. L. J. 193 (1979).

24 R. Posner, Antitrust Law 59 (1956); P. Areeda & D. Turner, IV Antitrust L w 91 (1978).

25 Posner, supra note 24, at 60; Kamerschen, supra note 23, at 200.

Maverick Firms. Individual firms which have rejected oligopolistic pricing and output policies and have been particularly vigorous competitors obviously increase the degree of competition. A merger which eliminates such a firm from the market may result in more competitive harm than is indicated by the market share statistics.[26]

History of Antitrust Violations. Some industries may have displayed a higher degree of cooperative behavior in the past than others. Past behavior reflecting as the existence of price fixing agreements or other collusive activity may indicate that a merger could be particularly injurious to competition.[27]

Anticompetitive Intent. Although a finding of anticompetitive intent is not necessary to finding that a merger will substantially lessen competition, the existence of such a motive may be indicative that anticompetitive effects are likely to occur.[28]

4. **Petroleum merger cases**

Mergers in the petroleum industry have resulted in litigation under Section 7 of the Clayton Act on several occasions. These cases illustrate how petroleum mergers have been treated in the past.

In 1968, the Department of Justice sought a preliminary injunction to prevent Atlantic Richfield's acquisition of Sinclair Oil Company, alleging that the acquisition would substantially lessen competition in gasoline marketing in four geographic markets: (1) in the Northeastern States, where the firms were active competitiors; and in the Rocky Mountain States, the Central States, and the Southeastern States, where the firms were alleged to be potential competitors.[29] The product and geographic markets

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26 United States v. Aluminum Co. of America, 377 U.S. 271, 279-80 (1964); United States v. Maryland & Va. Milk Producers Ass'n, 167 F. Supp. 799, 804-06 (D.D.C. 1958).

27 Posner, supra note 24, at 61; F. Scherer, Industrial Market Structure and Economic Performance 225-27 (1980); Kamerschen, supra note 23, at 201.

28 United States v. Aluminum Co. of America, 233 F. Supp. 718, 729 (E.D. Mo. 1964), aff'd per curiam, 382 U.S. 12 (1965).

(continued)

were uncontested. The argument instead focused on whether the merger would lessen competition. The court held that the acquisition would not lessen marketing competition in the Northeastern States because Sinclair had entered into an agreement to sell the marketing assets in these states to a new entrant, BP Exploration USA, Inc. The court also rejected the government's potential competition allegations involving the Rocky Mountain and Central States. However, the government did prevail on its claims regarding the Southeastern States. Finding a history of acquisitions by Atlantic Richfield, significant entry barriers, and little chance for future entry, the court enjoined the acquisition.[30]

A more thorough analysis was set out in United States v. Pennzoil Co.,[31] in which the court enjoined Pennzoil's acquisition of Kendall Refining Company. The court found the relevant markets to be the sale of Pennsylvania grade crude oil in the Appalachian Basin. The court noted that Pennsylvania grade crude oil yields a very high quality lubricant and that refineries using such crude primarily produce lubricants. The court was not swayed by the fact that other crude oils also yield lubricants, but rather saw the price premium commanded by Pennsylvania grade crude oil as a sign of its low demand substitutability. In defining the geographic market for Pennsylvania grade crude oil, the court examined oil shipments. Because all Pennsylvania grade crude oil was delivered to local refineries, all of which obtained all their crude locally, the Appalachian Basin was found to be the relevant geographic market. The court issued a preliminary injunction because it was convinced by the high and increasing shares of the producers in light of existing concentration and it appeared that the government would ultimately succeed at

29 297 F. Supp. 1061 (S.D.N.Y. 1969), aff'd sub nom, Bartlett v. United States, 401 U.S. 986 (1971).

30 When Sinclair and Atlantic Richfield subsequently arranged to sell Sinclair's Southeastern marketing assets to BP, the court lifted the injunction and allowed the merger. United States v. Atlantic Richfield Co., 297 F. Supp. 1075 (S.D.N.Y. 1969).

31 252 F. Supp. 962 (W.D. Pa. 1965).

trial.

In United States v. Continental Oil Co.,[32] the district court refused to enjoin Continental Oil's purchase, following its earlier lease, of the Malco refinery in New Mexico, because the combined market share of 9.6 percent was too low to indicate a likely substantial harm to competition.[33] The parties stipulated a gasoline product market, but disagreed about the geographic market. In rejecting the government's assertion that the state of New Mexico was the relevant geographic market, the court found that significant gasoline shipments to Arizona and El Paso, Texas required the inclusion of these areas. The court also considered shipments from other refineries into these areas and found that the geographic market was an area consisting of eastern Arizona, New Mexico and West-Texas. The court also mentioned that refineries in southern California and elsewhere in Texas were capable of supplying the geographic market.

The most recent private litigation involving a merger in the petroleum industry was Marathon Oil v. Mobil Corp.[34] The district court in that case issued a preliminary injunction after finding that Marathon was likely to succeed in establishing a violation. While both Marathon and Mobil agreed that gasoline was the most important product to examine, the geographic market was hotly contested. Mobil asserted that the market was nationwide, while Marathon urged a market consisting of the upper Midwest states. In finding a regional geographic market, Judge Manos noted both transportation cost and long-term price differentials among regions:

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32 1965 Trade Cas. (CCH) ¶ 71,557 (D.N.M. 1965).

33 In finding that competition had "not been affected at all" (1965 Trade Cas. at 81,544) following the initial lease, the court pointed to several factors: (1) Continental's market share dropped below the shares of the two firms combined; (2) Continental sold off the distribution assets; and (3) Continental acquired the refinery to supplement its own local refinery, which had a remaining useful life of only two years.

34 530 F. Supp. 315 (N.D. Ohio 1981), aff'd, 669 F.2d 378 (6th Cir. 1981).

> [A]s a general rule, due to increased transportation costs, retailers of motor gasoline do not acquire their refined product in geographic areas of the nation which are remote to their places of business. Similarly, at the gasoline pump, consumers do not customarily journey out of a locality to purchase motor gasoline.
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> * * *
>
> There is little doubt that price differentials do exist over time and that their magnitude is significant when compared to a petroleum company's profits. The persistence of price differentials in various areas of the nation demonstrates that motor gasoline does not move from area to area in response to price changes easily or as readily as Mobil asserts. Rather, they indicate that the relevant geographic market for motor gasoline is something less than nationwide.[35]

The court focused on the marketing of gasoline by the two companies in each of six Midwestern states and concluded that Marathon was likely to show at trial that the acquisition would lessen competition because of high concentration, high market shares, and substantial entry barriers.[36]

The Commission also filed suit in federal court to enjoin alleged anticompetitive effects from the takeover of Marathon by Mobil.[37] The Commission found reason to believe that petroleum product distribution systems and terminals were the proper focus for analysis of the competitive effects of this attempted acquisition. There was also reason to believe that terminal clusters in various subsections of the upper Midwest were relevant markets.[38]

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35 530 F. Supp. 315, 322.

36 Id. at 323-26. The fact that most petroleum merger cases have been resolved in actions for preliminary injunctions means that the scope of analysis has been limited. A court or the Commission might examine a greater number of factors in a full trial on the merits.

37 FTC v. Mobil Corp., No. C81-2473 (N.D. Ohio 1981). After Marathon prevailed in its litigation, the Commission's lawsuit became moot.

38 Other petroleum cases are less significant as market definition exercises, because the markets were not contested, but address the issues of concentration and market shares. In United States v. Phillips Petroleum Co., 367 F. Supp. 1226 (C.D. Cal. 1973), the parties conceded that the market was the sale of gasoline in California.
(continued)

More recently, the Commission determined that Gulf's attempted takeover of Cities Service would violate Section 7 of the Clayton Act in three important markets: jet fuel production and distribution; wholesale gasoline distribution; and product pipeline transportation. The Commission filed an application for a temporary restraining order and preliminary injunction on July 29, 1982, to halt the merger in the United States District Court for the District of Columbia.[39] After the Commission obtained a temporary restraining order ("TRO") but before the hearing on its request for a preliminary injunction, Gulf withdrew its tender offer.

The acquisition of Tidewater Oil Company by Phillips was enjoined because the acquisition would remove Phillips as a potential entrant into the market. Id. at 1226. Similarly in United States v. Standard Oil Co. (Indiana), 1964 Trade Cas. (CCH) ¶ 71,215 (N.D. Cal. 1964), an injunction was denied because the crude oil acquisition was too small to be significant, regardless of the geographic market.

39 FTC v. Gulf Oil Corp., Civ. No. 82-2131 (D.D.C. 1982).

B. Crude Oil

1. Overview

The free world's production of crude oil arises primarily from liftings arranged by contract between oil companies and the countries possessing oil reserves. Both domestically and internationally, there are literally thousands of crude oil producers. Concentration ratios for the oil companies' production of crude oil are low. Few firms possess market shares (domestic or international) of as much as 5 percent of total production. Despite this low concentration, there are two potential sources of concern about the competitive implications of mergers between oil-producing companies: (1) holdings of reserves are fairly concentrated on a country basis and the countries can control production levels within their borders; and (2) there may be certain local markets for crude oil in the United States that could be adversely impacted by some mergers.[1]

Perhaps the single most important factor in the world market for crude oil is the posture of the OPEC cartel, which accounted for about 60 percent of free world crude production in 1980 and about 77 percent of free world crude reserves as of January 1, 1981.[2] Because of the cartel's importance, the central issue in some crude oil mergers may be their effect on OPEC.

The member countries of OPEC differ markedly in the type, quality, and quantity of their crude-oil reserves, in costs of exploitation and exploration, and in national objectives. It is well established in the economics literature that such important asymmetries among members of a cartel are likely to make it difficult to insure members' adherence to joint agreements. This is because asymmetries lead to

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1 In addition to merger analysis, many of the issues described in this section are relevant to the analysis performed by the Commission in fulfilling its statutory role of commenting on proposed Outer Continental Shelf lease sales. See Section 205 of the Outer Continental Shelf Lands Act Amendments of 1978, 43 U.S.C. § 1337 (Supp. 1980).

2 See Tables VI B-2 and VI B-3, infra. In 1980 OPEC had 45.2 percent of world crude oil production and 66.9 percent of world reserves. Id.

differences in "preferred" prices and market shares for the individual members of the cartel. Under these circumstances, aggressive buyers may be able to exploit the incentives to charge different prices by extracting secret concessions from some members of the cartel. This behavior could undermine the ability of the cartel to raise prices. In terms of the OPEC cartel and U.S. oil-company merger policy, it is important that oil-company mergers not significantly reduce the aggressiveness with which the American oil industry negotiates and contracts with members of OPEC. American oil companies may be less inclined to bargain aggressively and seek secret concessions from OPEC members if their long run reserve positions are under the control of particular members of OPEC. But the issue is complicated, because OPEC members dissatisfied with assigned production quotas may wish to increase output, and they may be able to accomplish this through the firms with which they currently have longer term contracts. It should also be noted that the market power attributed to OPEC is a direct function of the vast reserves of crude oil OPEC's members presently possess. It may be that present and future oil finds will significantly diminish this advantage. Mexican and North Sea finds provide an example of new oil fields with as yet unknown total resource volumes.

The effects on competition of a domestic merger of producing companies also may deserve some scrutiny where there is reason to believe that there are relatively localized crude oil markets in the United States. The following analysis will attempt to describe one such market, on the basis of a past FTC investigation, as an example of how separate markets may be defined, and the conditions under which certain domestic crude oil mergers could adversely affect competition.

2. Product market

Crude oil includes a wide range of natural, liquid substances composed principally of hydrocarbons and traces of sulphur, nitrogen, and oxygen compounds.[3] With minor exceptions, the sole use of crude oil is as a raw material for the refining of various petroleum products. Conversely, under the current state of technology, crude oil is the only substance from which refined petroleum products can be manufactured.

The sharp surge in crude oil prices during the 1970's prompted a search for feasible crude oil substitutes, and some progress has been achieved to date. For example, a primary alternative under study has been the conversion of oil shale into synthetic crude oil. However, despite an enormous resource base, the existing technologies for commercial production of synthetic crude oil from oil shale are apparently not economically viable at this time. Within the past year, a number of oil shale projects have been canceled by major oil companies.[4]

Of course, the demand for crude oil ultimately stems from the demand for various refined products such as gasoline, heating oil, and fuel oil. As a result, substitution for oil production may occur further downstream, i.e., through the use of an alternative energy source to accomplish an objective previously met through the use of a product manufactured from crude oil. If such substitution were substantial in the short run, other energy sources would have to be included in the same product market with crude oil. For example, increases in refiner's raw material costs normally result in increased prices for refined products, such as gasoline and home heating oil. This in turn may lead to the use of alternative energy sources, such as solar energy, or to substitution of more energy-efficient mass transit for less energy-efficient auto travel. The reduction in demand for these refined products would produce a corresponding drop in demand for crude oil. The

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3 As used herein "crude oil" also includes natural gas liquids. Natural gas liquids are hydrocarbons that sometimes exist in the gaseous phase in natural underground reservoirs, but are liquid at atmospheric pressure after being recovered from the well. Natural gas liquids are commingled and refined with the crude stream.

4 Most recently, on May 2, 1982, Exxon Corporation announced it was withdrawing from the Colony oil shale joint venture with Tosco Corporation due to construction cost overruns. Wash. Post, May 3, 1982, at 1.

available evidence, however, indicates that consumers have relatively limited substitution possibilities for petroleum products, even in the face of increases in the price of crude oil from about $2.50 per barrel in 1973 to over $15.00 (constant dollars) and over $30.00 (nominal dollars) per barrel in 1981. In the long run, substitution will likely be more pronounced as the price of crude oil rises to the point where alternative energy sources become more profitable to exploit.

The conclusion that crude oil is a relevant product market can be confirmed by application of a somewhat different theoretical test, the "cartel standard." This test posits the existence of a market if colluding sellers can be successful in restricting output and raising price.[5] As more fully explained below, it is generally believed that OPEC functioned successfully as a cartel over the last ten years by raising the world price of crude oil above the marginal cost of production. This could not have occurred if good quality substitutes for crude oil products were abundantly available. OPEC's success demonstrates that crude oil is a relevant product market.

There is also evidence to support the view that there may be product submarkets in crude oil, since for practical reasons, crude oil streams may not all be close substitutes for each other in the short run. Different crude oil streams are distinguished on the basis of two important properties: the refining yield of the various refined products and the level of dissolved impurities. Gravity, measured in API degrees, is a proxy measurement of the refining yield of crude oil. Low gravity (e.g., 20° and below) refers to dense crude oil while the lightest types of crude oil have a gravity of 35° or more. Higher gravity crude streams generally yield higher proportions of the more valuable light products such as gasoline and jet fuel. Conversely, as gravity decreases, more low value products such as residual fuel oil are derived. Because the lighter products are more valuable, lighter crudes command a higher price in the marketplace.

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5 P. Areeda & D. Turner II Antitrust Law 347-48 (1978).

Crude oils are also distinguished by dissolved mineral content, which affects the ability to process the crude and the value of the products produced. For instance, crude oil with relatively low-sulfur content is known as "sweet" crude. High-sulfur ("sour") crude is less desirable for two reasons. First, it makes refining more difficult and costly since the sulfur inhibits processing and causes corrosion of metal in refining facilities. Second, because sulfur is an air pollutant, refined products which are high in sulfur are less valuable on the market. Desulfurization requires additional costly facilities.

Since different types of crude oil produce different arrays and proportions of petroleum products, significant price differentials exist for different types of crude oil. Therefore, a refiner may invest in expensive equipment in order to transform heavier, less expensive crude oil into more desirable products. Similarly, unless an investment is made in special processing facilities, high-sulfur crude oils would produce high-sulfur products, unsuitable for many utilities because of environmental regulations.[6] Instead, such products command a lower price, and are used, for example, as fuel for ocean going tankers.

However, the fact that such investments are necessary does not itself demonstrate the existence of separate product submarkets. The issue remains whether producers of a particular type of crude oil can alter the price differential among crude oils that would exist in a competitive market. The answer depends upon a variety of fairly complicated market relationships. An analysis of one geographic market in which crude oil substitution may be somewhat limited is presented below in a case study.

3. The international market for crude oil

a. The free world as a geographic market

A geographic market should define the entire geographic area over which the

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6 West Coast refiners responding to a National Petroleum Council survey attribute the inability to substitute sour for sweet crude to environmental regulation. See Tables 19 & 20 Nat'l Petroleum Council, Refining Flexibility, An Interim Report 52-53 (Dec. 1979).

forces of supply and demand significantly interact to determine closely interrelated prices. Because crude oil is widely bought, sold, and transported on an international basis, in most cases the relevant geographic market for crude oil is the entire free world. The U.S. continues to rely substantially on imported crude to meet refining demand, even though imports as a percentage of the oil consumed by U.S. refineries declined from 32.2 percent in 1979 to 27.6 percent in 1981, a substantial reduction.[7] Further, prices for crude oil from all parts of the world have exhibited considerable uniformity over the period 1976-1981.[8] These similarities in price movements, together with the level of imports into the U.S., indicate that for the most part there is a free-world market for crude oil, though there may be significant [product or] geographic submarkets.

b. Concentration in the international market

As is the case for other natural resources industries, concentration in crude oil markets can be measured by examining actual production figures or the amount of reserves[9] held by competing firms. Production data provide an accurate indicator of market shares and concentration in extractive industries for the short term. However, as noted by the U.S. Supreme Court,[10] the amount of production by a firm in a given year does not necessarily correlate with the ability of that firm to maintain such a share of

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7 Cent. Intelligence Agency, Economic and Energy Indicators 9 (Mar. 19, 1982).

8 Dep't of Energy, Int'l Energy Annual 47 (1981).

9 "Reserves" can be defined in a variety of ways. In general, reserves are volumes estimated to exist in known deposits, and which are believed to be recoverable in the future through the application of present or anticipated technology. As defined by the Department of Energy, "proved reserves" are those volumes of crude oil which geological and engineering data demonstrate with reasonable certainty to be recoverable in the future, under existing economic and operating conditions. This classification of reserves is used in this report. Other categories of reserves, including "probable reserves" and "speculative reserves" generally include deposits for which there is less certainty of recoverability.

10 United States v. General Dynamics, 415 U.S. 486, 501 (1974).

the market in the future, so that while reserves are somewhat more difficult to measure than production, reserves generally provide a better long term indicator of market structure. Therefore, both production and reserves data have value as measurement tools in the analysis of concentration in crude oil.

In general, if one relies strictly on concentration and market share figures (in either production or reserves), mergers between crude oil producing companies would appear unlikely to raise any competitive concerns. Table VI B-1 shows 1980 worldwide crude production for the leading U.S. producers. (Major foreign producers, such as British Petroleum, are not listed.) Based on the relatively low market shares attributable to U.S. firms, it seems clear that they play a limited role as suppliers in the international oil market. The combined share of the top 4 U.S. firms is 27.0 percent, and the top eight account for 34.5 percent. No domestic company had a share as high as 10 percent of total free world crude oil production in 1980, and only 3 firms (Exxon, Texaco, and Socal) had shares exceeding 5 percent. All but 5 firms had less than a 2 percent market share. Moreover, Table VI B-1 includes production arising from contracts with certain producing nations. While the firms have some discretion over the amount of oil they take under these contracts, the ultimate control over output rests in many instances with the producing nations' governments. Thus, Table VI B-1 may actually overstate the importance of these firms in the world crude oil market.

Table VI B-1

World Crude Oil Production[1]
by Leading Domestic Companies
1980

Company	Production (000 barrels per day)	World Market Share	Free World Market Share
		----(percent)---	
Exxon	4008	6.7%	8.9%
Texaco	3179	5.3	7.0
Socal	3009	5.1	6.7
Mobil	1991	3.3	4.4
Gulf	1169	2.0	2.6
Amoco	836	1.4	1.8
Sohio	716	1.2	1.6
Occidential	706	1.2	1.6
Arco	590	1.0	1.3
Shell	532	0.9	1.2
Conoco	458	0.8	1.0
Phillips	452	0.8	1.0
World Total	59,445	100.0	-
Free World Total	45,206	76.0	100.0
Top 4	12,187	20.5	27.0
Top 8	15,614	26.3	34.5

Source: Oil Daily, Apr. 5, 1982, at 12; Cent. Intelligence Agency, Economic & Energy Indicators 8 (Mar. 19, 1982).

1 Includes amounts purchased under long-term or special arrangements. In some countries, (e.g. Saudi Arabia), ownership of reserves by individual companies is not available. Instead, companies have long-term contracts providing access to production. In addition, the companies sometimes act as producers in such countries.

Because the actual control of reserves resides predominantly with the countries possessing reserves, it is more appropriate to examine shares of worldwide production and reserves by country. Table VI B-2 shows 1980 world crude oil production attributable to each of the major producing countries. Four countries — the U.S.S.R., Saudi Arabia, the United States, and Iraq — accounted for 55 percent of the world's 1980 supplies. Of greater significance in the long run may be the fact that the OPEC countries accounted for 45.2 percent of total world production and 59.5 percent of free world production. Table VI B-3, giving data on world crude reserves by country, suggests even greater OPEC dominance for the future. OPEC members own 66.9 percent of total (known) world oil reserves and 77.2 percent of the reserves of the free world.

Table VI B-2

World Crude Oil Production
1980

	Production (000 barrels per day)	Share of World Total (percent)	Share of Free World Total (percent)
U.S.S.R.	11,700	19.7	n.a.
Saudi Arabia[1]	9,900	16.7	21.9
United States	8,595	14.5	19.0
Iraq[1]	2,514	4.2	5.6
Venezuela[1]	2,167	3.6	4.8
China	2,114	3.6	4.7
Nigeria[1]	2,055	3.5	4.5
Mexico	1,937	3.3	4.3
Libya[1]	1,787	3.0	4.0
United Arab Emirates[1]	1,709	2.9	3.8
Iran[1]	1,662	2.8	3.7
Kuwait[1]	1,656	2.8	3.7
United Kingdom	1,622	2.7	3.6
Indonesia[1]	1,577	2.7	3.5
Canada	1,424	2.4	3.2
Algeria[1]	1,012	1.7	2.2
World Total	59,445	100.0	n.a.
Free World Total	45,206	76.0	100.0
OPEC Total	26,890	45.2	59.5
Top 4 OPEC members	16,636	28.0	36.8

Note: n.a. means not applicable

1 OPEC member.

Source: Cent. Intelligence Agency, Economic and Energy Indicators 8 (Mar. 19, 1982).

Table VI B-3

World Crude Oil Reserves
By Country
January 1, 1981

	Reserves (billion barrels)	Share of World Total	Share of Free World Total
		(percent)	
Saudi Arabia[1]	168.0	25.9	29.9
Kuwait[1]	67.9	10.5	12.1
U.S.S.R.	63.0	9.7	--
Iran[1]	57.5	8.9	10.2
Mexico	44.0	6.8	7.8
United Arab Emirates[1]	30.4	4.7	5.4
Iraq[1]	30.0	4.6	5.3
United States	26.4	4.1	4.7
Libya[1]	23.0	3.5	4.1
China	20.5	3.2	--
Venezuela[1]	18.0	2.8	3.2
Nigeria[1]	16.7	2.6	3.0
United Kingdom	14.8	2.3	2.6
Indonesia[1]	9.5	1.5	1.7
Algeria[1]	8.2	1.3	1.5
World Total	648.5	100.0	n.a.
Free World Total	562.2	86.7	100.0
OPEC Total	434.1	66.9	77.2
Top 4 OPEC members	323.8	49.9	57.6

Note: n.a. means not applicable

1 OPEC member

Source: Dep't of Energy, 1980 Int'l Energy Annual 82 (Sept. 1981).

c. Special considerations in the international market

Overview. OPEC is the most important factor in the world market today.[11] As described previously, the combination of any two U.S. oil companies' crude oil holdings is insignificant in comparison with the size of the OPEC countries' crude reserves. In this context, a merger of crude oil producers is more likely to have important economic effects through its effect on OPEC's activities than through the degree to which it increases crude oil reserve concentration. U.S. oil companies are not only producers of crude oil but are major clients of the OPEC cartel. Therefore, in their capacity as purchasers, they may be able to influence OPEC. Some kinds of acquisitions may create some antitrust concern by limiting such procompetitive influences on OPEC.

OPEC is a cartel which attempts to raise the profits of its members by coordinating oil prices and production.[12] Its success depends on the willingness of its individual members to cooperate and maximize joint profits rather than cutting price in attempts to increase market share and thereby increase individual profits. This willingness to cooperate is tempered by the incentives of individual members to deviate

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11 The members include Saudi Arabia, Iran, Iraq, Bahrain, Kuwait, Qatar, the United Arab Emirates, Libya, Algeria, Nigeria, Venezuela, Ecuador, and Indonesia.

12 OPEC was founded in September 1960 by Iraq, Kuwait, Saudi Arabia, Iran, and Venezuela to defend their common interests against the international oil companies. See Mikdashi, "Cooperation Among Oil Exporting Countries," Int'l Org. (Winter 1974). However, since 1971, OPEC's history reveals a concerted attempt to set prices and, at times, production levels. Moran, "Modeling OPEC Behavior: Economic and Political Alternatives," Int'l Org. 241-72 (Spring 1981). There is ample evidence to support the view that OPEC has been pricing monopolistically. For example, the price of Saudi Arabia's light crude, OPEC's market crude for price setting, has risen dramatically over the past eight years, even when expressed in constant dollars. Dep't of Energy, Int'l Energy Annual 47 (1981). This price increase has led prices to levels substantially above average production costs. Saudi Arabia's current production cost per barrel is less than $.50, and in no OPEC member nation does this cost represent a significant fraction of the current price. Affadavit of M.A. Adelman, FTC v. Mobil Corp., No. C81-2473 (N.D. Ohio 1981). Indeed, there is little doubt that the price of OPEC members' oil has been above the average production cost of the oil, including a 20 percent return on investment, since the early 1960's. See Adelman, infra note 20. The incremental cost per barrel in Saudi Arabia may have been as low as $.10 a barrel in 1970.

from the cartel agreement. If the other producers adhere to the cooperative agreement, a "cheater" can give small price discounts, gain market share from his rivals, and reap higher profits.[13] The incentives to "cheat" make the stability of cartel agreements difficult to maintain.

Whatever the form of the coordination underlying a cartel, its stability is enhanced if the firms generally agree on price and if market shares are stable. If firms have different costs, or their products are not identical, or their locations differ when transportation costs are important, reaching and maintaining agreement on prices can be difficult.[14]

In addition, anything that raises the uncertainties concerning proper price structure — such as the development of substitutes, increased non-OPEC reserves, and unexpected changes in demand — undermine the ability of the cartel to maintain prices.

Although Section 7 Clayton Act cases have generally been concerned with seller combinations, Clayton Act and FTC Act principles may have some application to the destabilization of OPEC pricing. If a merger removes an aggressive price-conscious oil buyer from the market, it may also remove a potential cartel destabilizing influence. In such an event, the effect of the acquisition "may be substantially to lessen competition" as contemplated in Section 7, and in Section 5 of the FTC Act.[15]

The presence of significant excess capacity increases the incentives to "cheat" on a cartel agreement.[16] OPEC currently has significant excess capacity because output is

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13 This results because the marginal revenue for the individual firm, given that the other firms do not respond, is above its marginal cost.

14 The only exception is the unlikely case where all firms' marginal cost curves happen to intersect at the point where they cross the marginal revenue curve. See F.M. Scherer, Industrial Market Structure and Economic Performance 157 (1980).

15 If the acquired aggressive price-conscious oil buyer was only one of many similar oil companies, it is unlikely that a substantial lessening of competition could be inferred.

16 See Osborne, "Cartel Problems," Am. Econ. Rev. 835 (1976), for a typical technical (Continued)

below 17.5 mb/d, while total OPEC capacity is 34 mb/d.[17] It follows that any practices the cartel can institute to stabilize market shares and output levels will reduce the chances for cheating and help sustain higher prices. The OPEC countries employ two practices which may have been adopted for various reasons but may nevertheless have these stabilizing effects: requiring long-term purchase contracts, and encouraging oil company investments in OPEC member countries.

To the extent that oil companies are "locked in" by long-term contracts, they may be restricted from "shopping around" for lower prices in periods of excess capacity. Of course, long-term contracts may benefit both buyers and sellers. They contribute to orderly market transactions by insuring that countries are not surprised by sudden drops in sales. They also give oil companies known sources of supply for lengthy periods. OPEC may have some power to enforce long-term contracts and therefore restrict the ability of contractors to "shop around" in periods of excess capacity by threatening a concerted refusal to deal in response to "irresponsible" behavior (such a threat can be found in OPEC's charter).[18] Thus, long term contracts may help to stabilize the cartel in periods of excess capacity, at least in the short run.

Oil company investments in OPEC countries are subject to threats of appropriation if the countries disapprove of the investing companies' behavior.[19] As is discussed below, Saudi Arabia may have influenced Texaco and Mobil to maintain their purchases of Nigerian crude in April by threatening their access to Saudi oil concessions or their many investment projects within Saudi Arabia, as described below. These close ties

treatment of cheating.

17 M. Adelman, The World Petroleum Market (1972). This takes potential capacity in Iran and elsewhere into account as of September 1981.

18 See R. Mancke, The Failure of U.S. Energy Policy (1974).

19 The general use of appropriable "rents" as a means of enforcing contracts is discussed in Klein, Crawford & Alchian, "Vertical Integration, Appropriable Rents, and the Competitive Contracting Process," J. of L. & Econ. 297-326 (Oct. 1978).

between companies and countries when a valuable property can be appropriated, help maintain market shares and prevent cheating.

Of course, there are many oil companies, domestic and international, that are not tied to producing countries through long-term contracts or investments. These firms are free to purchase from any source and, accordingly, their purchase decisions are influenced principally by short-run price considerations. M.A. Adelman has contended for many years[20] that OPEC's nationalization of U.S. oil company assets and the general severing of ties between countries and companies have the potential to turn at least some buyers into aggressive "comparison shoppers" on the world market. As a result of their aggressive shopping behavior, these price-conscious purchasers encourage cheating by cartel members, and therefore could play an important procompetitive role in the international oil market.

d. Influence of price-conscious company behavior on pricing policy

The following discussion, based on newspaper and trade journal accounts, is an example of how oil company purchasing decisions can influence the pricing decision of an oil producing industry. In the spring of 1981, a soft crude market began to trigger lower prices. In addition, bulging inventories caused some oil importers to terminate traditional supply relationships.[21] One such cancellation reportedly occurred in July, when British Petroleum Co. Ltd. decided to walk away from two small Libyan supply contracts. Soon thereafter, other companies with more substantial Libyan interests indicated they also would suspend liftings. Amerada Hess had already refused to make liftings in June, and stated it had no plans for purchasing crude in July. Its partner in the "Oasis" oil concession joint venture, Conoco, along with Sun, also gave notice that they intended to walk away from contracts.[22] Other companies, including the largest

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20 See M. Adelman, supra note 17, at 224; R. Mancke supra note 18, at 154-162.

21 Oil & Gas J. 3 (Apr. 20, 1981).

(Continued)

producer of Libyan crude oil (Occidental), were actively involved in lengthy negotiations to secure arrangements that would leave their oil allocation intact even if contract liftings lapsed.[23]

By August, the $41 per barrel price of Libyan crude, well over the OPEC average of $35, caused Libyan oil production to fall 700,000 barrels a day from a high of 1.7 million barrels per day in January. In the same month, at a Tripoli meeting with purchasers, the Libyan government urged the oil companies not to exercise clauses in their contracts which permitted the suspension of liftings. However, when Libya failed to grant the companies any price concessions, most of the companies remained firm in their resistence to Libya's request for increased company purchases.[24] By September, most companies had suspended their liftings entirely, and only a few were lifting minimal volumes.[25]

Widespread company resistance to paying premium crude prices eventually convinced the Libyan government to offer Occidental a large discount in return for increased purchases. In October, following this offer, Libya and Occidental signed a new production agreement which was regarded by industry sources as the "envy of the industry," ensuring Occidental a "good profit" on its Libyan operations.[26]

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22 Oil & Gas J. 58 (July 13, 1981).

23 Id.

24 Wall St. J., June 6, 1981, at 4. As a result of the Tripoli discussions, Libya did offer to liberalize credit terms for crude payments from one month to three months, which would have resulted in a savings of only about $1 per barrel. However, since Libya would not reduce its high $40 plus per barrel price, companies refused to promise to resume liftings to previous levels. Platts Oilgram News 2 (Aug. 10, 1981).

Neither Libyan efforts to pressure the oil companies to take more oil at a subsequent Tripoli meeting in mid-August nor Libyan attempts to stave off lowering its price by offering barter deals pegged to the official $40 per barrel selling price, were successful in inducing foreign companies to increase their oil production. Wall St. J., Aug. 28, 1981, at 2.

25 Platts Oilgram News 3 (Aug. 28, 1981).

(Continued)

Libya, however, refused to offer similar discounts to other companies. As a result, the other equity producers remained steadfast in their campaign to obtain better conditions in equity production and contract sales.[27] Libya's failure to increase the volume of total crude liftings was soon compounded by an additional problem in mid-November when Exxon decided to withdraw its oil and gas production operations in Libya.

Although Exxon's withdrawal may have been motivated by political considerations,[28] it provided the Oasis group with a psychological advantage. Within a week, Libya notified the companies in the Oasis group that it would cut its price to about $36 per barrel. This move was regarded as the first significant attempt by Libya to defuse its confrontation with the oil companies and was seen to be part of a broader conciliatory program to spur purchases by U.S. oil companies.[29] Yet, there is ample evidence that this effort resulted in relatively small increases in liftings, as companies continued to negotiate with the Libyan government to obtain additional price concessions.[30]

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26 Oil Daily, Dec. 14, 1981, at 21; Oct. 5, 1981, at 1. Occidental was said to make an effective profit of about $33 per barrel under its agreement with the Libyan government. Although the nature of the agreement has never fully been made public, it was said to be contingent on Occidental lifting as much as 150,000 barrels per day, at least until recently. It is not known whether Occidental was actually taking this amount. Oil Daily, Nov. 16, 1981, at 1-2; Dec. 14, 1981, at 21.

The sweetening of Occidental's purchasing arrangement in early October turned out to have been only temporary; by the end of November, the agreement was being renegotiated. Petroleum Intelligence Weekly 5 (Nov. 30, 1981). Meanwhile, Occidental continued to steadily reduce its dependence on Libyan crude, while seeking to expand its crude operations in other countries. Oil Daily, Dec. 14, 1981, at 21; Feb. 11, 1981, at 1.

27 Platts Oilgram News, 2 (Nov. 16, 1981).

28 See infra.

29 Wall St. J., Nov. 18, 1981, at 2.

30 Petroleum Economist (Dec. 1981). Confidential Form EIA-67 data indicates that acquisitions of crude oil by the Oasis partners increased modestly in the fourth quarter of 1981 over the previous quarter, yet were substantially lower than second quarter volumes.

(Continued)

By December, only small amounts of Libyan crude were being sold at the still high official selling price, as the vast majority of crude was either going to equity producers with significant tax advantages or moving under special arrangements effectively involving a lower price.[31] Throughout the first quarter of 1982, the bulk of Libyan crude was being sold at under-the-table discounts, as the price of Libyan light crude oil was becoming more competitive with the price for comparable quality oil in Nigeria, which was averaging about $36 per barrel.[32] Yet, by the time the U.S. government decided to bar crude imports from Libya in March, U.S. companies were importing almost 30,000 barrels per day less than the previous year's average.[33]

e. Oil company ties to Saudi Arabia

The Libyan example demonstrates that under certain circumstances, the behavior of purchasers of crude supplies may exert considerable influence on a producer government's output and price strategy. Some companies, however, appear more limited in their ability to act as price-conscious purchasers, because of their established ties to major Persian Gulf crude producers. Ties to Saudi Arabia appear to be of particular importance since the country is the leader of the cartel and its largest producer. Companies with substantal investments in Saudi Arabia may be hesitant to undermine Saudi intervention to maintain the cartel's stability. Noncompliance with Saudi directives could lead to a loss of investment, foreclosure of new opportunities, and restrictions on the availability of supplies.[34]

With respect to Continental's liftings, see, Oil Daily, Dec. 10, 1981, at 1.

31 Platts Oilgram News 2 (Dec. 14, 1981).

32 Bus. Wk. 2 (Mar. 22, 1982).

33 N.Y. Times, Mar. 11, 1982, at 1, indicating that several oil companies participated in the destabilization of Libyan prices.

34 First quarter 1982 profits of the four Aramco partners declined by 22 percent primarily because they were taking large volumes of relatively high-priced Saudi crude. Reflecting a situation common to all four, Texaco's chairman explained to his shareholders: "The company has continued to make these [Saudi] purchases only
(Continued)

Arabian American Oil Company (Aramco) members may provide the best example of tied companies whose foreign operations have been inhibited by their Saudi connections. For example, Mobil's relationship with Saudi Arabia began in 1948 when it joined Aramco. Mobil's ownership interest in Aramco is currently 15 percent, with Socal, Texaco, and Exxon each holding a 28-1/3 percent interest. Recently, the government of Saudi Arabia assumed control over Aramco assets. Although Socal, Exxon, Texaco, and Mobil can still lift volumes according to their Aramco equities, they now receive a service fee for oil field operations and a discovery incentive fee instead of receiving profits on equity production. According to published reports, this fee was set initially at about 21 cents per barrel.[35]

Mobil was the first company in the industry to sign contracts with Saudi Arabia for major industrialization projects. To date, these projects have included a refinery, a petrochemical plant, a pipeline, a lubricating oil refinery and blending plants, and a can manufacturing facility. While Mobil asserts that the projects have been profitable, the company acknowledges that a purpose of the projects is to enhance its access to Saudi crude oil.[36] For example, Mobil would receive an additional 1.4 billion barrels of Saudi "incentive" crude over a 15-year period from Petromin, the Saudi Arabian national oil company, for its participation in petrochemical and refining projects at Yanbu.[37] Mobil's

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after careful consideration and upon the expectation of having continued access in the years ahead to Saudi Arabia's reserves, which are the largest in the world." Petroleum Intelligence Weekly 2 (May 3, 1982).

35 Petroleum Intelligence Weekly 2 (March 29, 1976).

The history of the Aramco concession is discussed in Dep't of Energy, Energy Industry Abroad 149 (1981); Dep't of Energy, The Role of Foreign Governments in the Energy Industries 234 (1977); Dep't of Energy, An Analysis of Current Trends in United States Access to World Oil Annex 1 at 4-6 (1978); "Saudi Takeover to Give Aramco Almost All the Oil," Petroleum Intelligence Weekly 1-3 (Mar. 29, 1976); "Crown Prince Fahd Outlines Terms of ARAMCO Deal," Middle East Economic Survey 1-3 (July 26, 1976).

36 Mobil, 1980 Annual Report 11.

37 Platts Oilgram News 2 (Dec. 11, 1980); Middle East Economic Survey 9 (Dec. 15,
(Continued)

incentive crude entitlement was said to be 500 barrels per day for each $1.0 million invested.[38] Under the terms of its contracts, Mobil was entitled to begin early liftings of this incentive crude at the rate of 50,000 barrels per day in anticipation of the completion of the two projects.[39] Because of the type and magnitude of its Saudi investments, Mobil is no doubt very much conscious of its ties to Saudi Arabia.

The Nigerian example. Recent events in Nigeria provide an indication of how companies with ties to Saudi Arabia may generally be constrained from operating in any OPEC country as aggressively as other purchasers. Last spring, when certain companies attempted to cancel purchase contracts and reduce their equity liftings to pressure Nigeria to lower prices, Saudi Arabia threatened sanctions against any company purchasing oil from the Saudis who undertook such peremptory action.[40] Such threats did not go unheeded by those Aramco partners that had substantial Nigerian production.[41]

International companies appear to have begun bargaining in earnest with the Nigerian government for lower crude prices as early as May 1981.[42] In June, in the face

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1980). In March, 1980, Mobil and Petromin signed an agreement to form a joint venture company which will own a 250,000 b/d fuels export refinery at Yanbu. On April 19, 1980, the Saudi Basic Industries Corporation (SABIC) and Mobil signed a joint venture agreement to build and operate a one billion pounds a year petrochemical complex also at Yanbu. Middle East Economic Survey 3 (Apr. 28, 1980); Petroleum Intelligence Weekly 11 (March 31, 1980).

38 Petroleum Economist 37 (Jan. 1981).

39 These early liftings, which were to begin in January, 1981, are to increase annually by additional increments of 50,000 b/d during the four-year phase-in period while the projects are under construction, to a total at the time of start-up of about 225,000 b/d. Middle East Economic Survey 9 (Dec. 15, 1980); Petroleum Economist 37 (Jan. 1981).

40 Platts Oilgram News 3 (Mar. 29, 1982); Wall St. J., Mar. 29, 1982, at 2; Apr. 1, 1982, at 5.

41 Bus. Wk. 33 (Apr. 12, 1982); Newsweek 64–65 (Apr. 12, 1982).

42 In May, Gulf asked Nigeria for a price cut, and threatened to reduce the volume of oil lifted if such a reduction was not effected. Wall St. J., May 13, 1981, at 2.

of a pronounced crude surplus, oil companies began to reduce their Nigerian crude purchases because of Nigeria's high prices.[43] In July, Royal Dutch/Shell, the largest producer of Nigerian crude (lifting over half the country's total), and Gulf, the second largest producer (lifting about 18 percent of the total), notified the Nigerian government that they would purchase no contract oil beyond the third quarter if prices remained at current levels.[44] By July, Royal Dutch/Shell had cut its liftings from over 1 million barrels per day in March to a little more than Gulf's lifting level of 235,000 b/d.[45]

In a bid to retain customers, the government announced in late August a $4 discount on its official selling price of $40 a barrel.[46] Over the next three months, Nigeria unilaterally reduced its price from a high average of $40 a barrel to as low as $34.50 a barrel by granting discounts and easier payment credits.[47] Due primarily to these concessions, Nigeria's oil production gradually rose to 1.3 million barrels a day in November 1981 and then to 1.7 million barrels a day in January 1982.[48] Despite these lower prices, companies continued to complain that the profit margin of as little as 77 cents per barrel allowed by the government was too low to justify future drilling projects.[49] In a move designed to thwart renewed company threats to walk away from

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43 Wall St. J., June 11, 1981, at 30.

44 Platts Oilgram News 1 (July 15, 1981). Lifting shares taken from first quarter 1981 statistics. Id. at Table 8.

45 Platts Oilgram News 1 (May 5, 1982); Oil Daily, Oct. 8, 1981, at 14. In its joint lifting arrangement with the Nigerian National Petroleum Corporation (NNPC), the Nigerian company takes 80 percent of Shell's production and sells it to third parties. In its arrangement with Gulf, the Nigerian corporation takes 60 percent of Gulf's production. Dep't of Energy, Energy Industry Abroad 193 (1981).

46 Oil Daily, Oct. 8, 1981, at 14.

47 Wall St. J., Nov. 13, 1981, at 2. It should be noted that in mid-November Nigeria officially adjusted its oil prices to a range of $35.20 to $36.60 a barrel retroactive to November 1.

48 Wall St. J., Nov. 13, 1981, at 2; Platts Oilgram News 4 (Mar. 22, 1982).

49 Bus. Wk. 33 (Feb. 8, 1982).

contracts, Nigeria promised in early March an additional price cut of $5 to $5.50 per barrel, retroactive to March 1.[50] However, at its Vienna meeting, the OPEC ministers in a unique display of unity decided to stabilize Nigeria's price at the existing $35.50 per barrel level.[51]

When certain international oil companies subsequent to OPEC's Vienna meeting again slashed their Nigerian crude production, Saudi Arabia threatened to cut off supplies to companies that did not immediately resume their Nigerian liftings.[52] Saudi warnings went to a number of major companies most heavily involved in Nigeria, including Mobil and Texaco (partners in Aramco), plus Gulf and Royal Dutch/Shell, the two largest producers in Nigeria.[53]

Even prior to the Saudi warning, the conduct of Mobil and its Aramco partner, Texaco, may have reflected their close relationship with Saudi Arabia. Royal Dutch/Shell's share of total production in Nigeria declined between January and March of 1982 from 51.9 percent (915,636 b/d) to 37.9 percent (353,393 b/d), and Gulf's percentages dropped from 17.9 percent (315,732 b/d) to 16.3 percent (152,052 b/d), Mobil's share proportionately rose from 11.4 percent (201,773 b/d) to 16.5 percent (153,673 b/d) during this period, and Texaco's share of production increased from 2.4 percent (42,884 b/d in January) to 4.3 percent (40,216 b/d) in March 1982. When comparing the change in first quarter 1982 liftings with those reported during the same period in 1981 for these same companies, the percentage reductions were as follows: Royal Dutch/Shell, - 41.8 percent; Gulf, - 28 percent; Mobil, - 14.8 percent; and Texaco,

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50 Platts Oilgram News 1 (Mar. 11, 1982). Promised price cuts were seen as a ploy by Nigeria to maintain output in March without angering OPEC members by making a preemptive price cut.

51 Newsweek 64 (Apr. 12, 1982).

52 Id. In March, Nigerian production dropped to 933 mb/d from 1,394 mb/d in February. Platts Oilgram News 1 (May 5, 1982); 1 (Apr. 19, 1982).

53 Oil Daily, Apr. 12, 1982, at 2.

- 4.4 percent.[54] Production decreases in 1982 for the two Aramco companies were clearly less precipitous than the reductions effected by the two largest, non-Aramco Nigerian producers.

The apparently contrasting actions of companies with and without ties to OPEC may have implications not only on the price of oil on the world market, but also for enforcement of the acquisition provisions of the Clayton Act. The merging of two companies with conflicting systems could result in a single company with objectives highly compatible with those of OPEC. Because the merged company may be unlikely to reject ties that have been so profitable, aggressive price bargaining may very well be eliminated.[55]

In general, however, it is as yet uncertain whether these or other adverse competitive effects can be predicted in the context of a particular merger with sufficient confidence to warrant antitrust prosecution. There have been instances in which Saudi-tied producers may have engaged in actions detrimental to the Saudis.[56] A plausible argument also may exist that mergers between OPEC-tied companies and companies with large non-OPEC resource positions may possibly strengthen the bargaining position of OPEC-tied companies. In addition, there are enough companies without ties to OPEC that significant adverse effects arising from a merger between a tied and untied company would most likely be the result of special characteristics of the tied and untied companies.

Adelman has also noted that whereas oil consumption has decreased, exports from

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54 Computations based on statistics taken from Platts Oilgram News 1 (May 5, 1982); 1 (Apr. 19, 1982); 4 (Mar. 22, 1982).

55 *Cf.* Interamerican Ref. v. Tex. Maracaibo, Inc., 307 F. Supp. 1291 (D. Del. 1970), for an example of an OPEC member country using the threat of termination of its supply relation with a large concessionaire to order the concessionaire to stop selling its concession oil to plaintiff, a price-cutting refiner in another country.

56 Examples may include Exxon's investment in oil shale and its withdrawal from Libyan production.

other countries (such as Mexico and Great Britain), have increased substantially. Adelman views the U.S. production decline of the 1973-1981 period as largely attributable to the "folly of price control"; low "old oil" prices were deliberately restrained, blunting any incentive to develop new technology in secondary and tertiary oil recovery. That production decline, he noted, has nearly ceased since decontrol.[57] Although it may be difficult to posit that these and other production increments will amount to more than a fraction of OPEC's (presently known) vast oil reserves, they may exert a further destabilizing influence on OPEC cartel discipline.

4. The effect of mergers in domestic crude oil markets

a. Potential domestic submarkets

While it is clear that crude oil today generally trades in a free-world market, various other considerations can also affect the definition of a relevant market. Courts have posed the test: where, as a practical matter, can the purchaser turn for alternatives?[58] In view of the unique role played by oil in our economy and the associated political considerations, this standard raises the question: Do United States crude purchasers have the ability to turn to foreign crude producers at little or no cost penalty? Both history and well established national security interests strongly suggest that, as a practical matter, crude oil purchasers may not in the long term have the alternative of purchasing unlimited amounts of foreign crude oil. Accordingly, mergers which appreciably increase concentration in domestic crude oil markets may be of concern.[59]

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57 See M. Adelman, North Sea Oil & Gas in the World Market: Perspective in 1981-2100 12-13 (unpublished, unrevised paper prepared for the Center for Policy Studies, London, July 30,1981).

58 FTC v. Southland Corp., 471 F. Supp. 1, 3 (D.D.C. 1979).

59 From 1959 until 1973 a mandatory import quota limited imports of crude oil, thus effectively insulating the U.S. market. See generally D. Bohi & M. Russell, Limiting Oil Imports, An Economic History and Analysis (1978). Then, starting in October 1973, the Arab oil embargo sharply curtailed the amount of foreign crude

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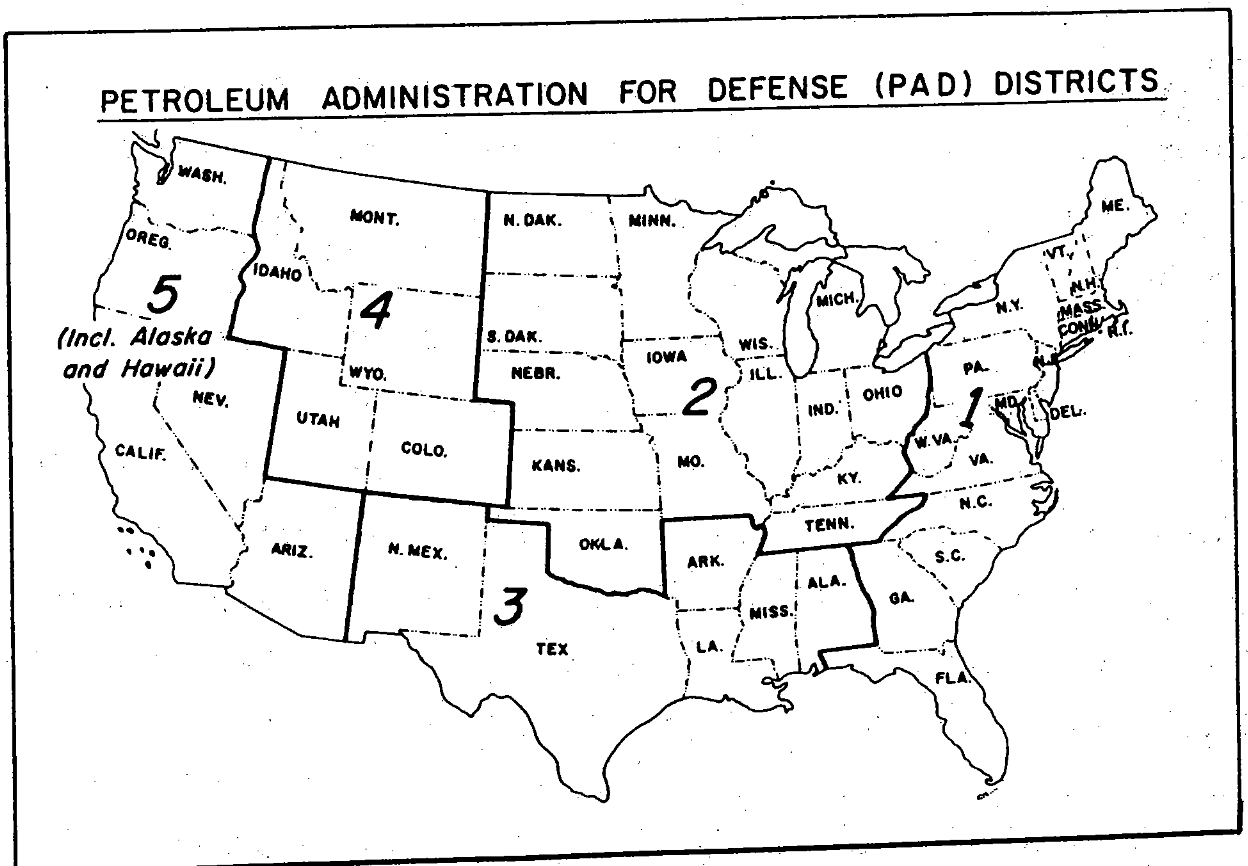
In addition, within the United States, there may be certain geographic submarkets for crude oil within which certain mergers should be analyzed. In 1950, the Petroleum Administration for Defense divided the United States into five districts for purposes of collecting and maintaining petroleum industry data. Petroleum Administration for Defense District (PADD) I comprises New England and the Eastern Seaboard; PADD II is the Midwest; PADD III is comprises the Gulf Coast states; PADD IV is made up of the Rocky Mountain states; and the West Coast states constitute PADD V. The figure below shows the boundaries of each PADD.



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oil available to U.S. refiners until the embargo was lifted in March 1974. During the embargo, imports of Arab oil averaged 2.2 million barrels per day less than projected levels. During the period of the embargo, the U.S. economy suffered a 7 percent decrease in real GNP, rather than the forecasted increase. S. Rep. No. 260, 94th Cong., 1st Sess. 9 (1975).

While PADDs do not constitute economic markets just because the government has established them for planning purposes, they are a useful beginning point for purposes of analyzing whether more localized geographic markets exist in the U.S.[60] In this connection, while other PADDS have distinguishing features that may qualify them as rough proxies for geographic submarkets, information gathered by the FTC in one investigation provides a basis for a case study, the PADD V submarket for crude oil.

PADD V low quality crude submarket case study. A PADD V low-quality crude oil "submarket" was the subject of an investigation by the FTC concerning the petroleum industry in the western portion of the U.S. That investigation, which led to the preparation of a FTC staff report and is now closed, produced evidence suggesting that Alaskan North Slope (ANS) type oil may be a relevant product submarket, and that PADD V may be a relevant geographic submarket. If either of these two conjectures is valid, mergers between companies overlapping in either of these markets could have adverse effects on competition.

The evidence suggests that problems of substitution by refineries between ANS-type crude oil and other type of crude oil may be of sufficient importance to justify defining ANS-type crude oil as a relevant submarket for antitrust purposes. In particular, refineries equipped to handle other crude oils apparently have difficulty in refining ANS-type crude oil. When ANS production expanded significantly in 1977, importation of ANS-type crude oil virtually ceased, while imports of other crude oil

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60 For example, in 1980, both the FTC and the Antitrust Division analyzed PADD V crude oil as a relevant crude oil submarket for the purposes of antitrust analysis under the Outer Continental Shelf Land Act. Letter from Carol M. Thomas, Secretary to the Fed. Trade Commission, to John H. Shenefield, Assistant Attorney General for Antitrust, Dep't of Justice, (Jan. 18, 1980); The Department of Justice reached a similar conclusion. See Dep't of Justice, Advice and Recommendations of the U.S. Department of Justice to the Secretary of the Interior Pursuant to Section 205 of the Outer Continental Shelf Lands Act of 1978 (Jan. 24, 1980).

groups declined less dramatically.[61] This evidence, if valid, suggests that at least in the short run, it may be difficult to substitute ANS-type crude oil for other crude groups, presumably because of the nature of existing refining capacity. Therefore, separate product submarkets may exist, for some period of time.[62]

ANS crude is a particularly significant factor in the PADD V section of the country, since it accounts for almost 60 percent of West Coast production.[63] PADD V imported 16.5 percent of its crude oil in 1980[64] and shipped about 21.5 percent of its 1980 crude production to other districts.[65] Based on such statistics, PADD V may not constitute a relevant geographic submarket for crude oil. However, PADD V may be a relevant geographic submarket for heavy, high-sulfur crude oil or ANS-type crude oil. The net (of transportation costs) price received for ANS oil in the Gulf Coast appeared to be significantly below the net West Coast ANS oil price. Some of the data developed in the investigation are summarized in Table VI B-4. Those data show that if estimated transportation cost differentials between the West and Gulf Coasts are taken into

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61 Dep't of Energy, Energy Data Reports (1976-1980); John G. Yeager and Asociates, Inc. and Osford Petroleum, Inc., Petroleum Import Data Book (1976-1980). The decline in heavy very high sulfur crude oil should not be deemed significant because of the very small quantities that were initially imported. Some decline in the other crude groups should be expected, in part because these other crudes may have been used in a blend that had ANS-type characteristics. ANS crude may substitute for such a blend.

62 Since the import prices of higher quality crudes continued to be set by the world market and elicited roughly historical import levels, while the price of lower quality crude was lowered enough by the pricing of ANS crude to cause dramatic reductions in the sales of comparable foreign crude, it appears that the cross-elasticity of demand for different crudes may be lower than the cross-elasticity of demand between foreign and domestic ANS-quality crude. This type of difference in cross-elasticities of demand may justify classifying products in different product markets, rather than in the same product market.

63 Dep't of Energy, Petroleum Supply Monthly 51 (Apr. 1982).

64 Dep't of Energy, Energy Data Reports, Crude Petroleum, Products, Natural Gas Liquids 9, 19 (Dec. 1980).

65 Id. at 8, 16, 28.

Table VI B-4
Comparison of Three Producers' Prices of ANS Crude Oil to the West and Gulf Coast--1978

Company Month	West Coast Price	Gulf Coast Price	Full Cost of Transportation from West Coast to Gulf Coast[1]	Difference in Price Between Destinations After Transportation Adjustment[2]
	(dollars per barrel)			
SOHIO				
January	13.33	13.41	2.06	1.98
February	13.36	13.28	2.06	2.14
March	13.12	13.05	2.06	2.13
April	12.40	13.01	1.92	1.31
May	12.64	13.05	2.16	1.75
EXXON				
March	13.16	13.00	2.35	2.51
April	12.83	13.00	2.40	2.23
May	12.65	13.00	2.54	2.19
PHILLIPS				
May	12.65	13.10	3.79	3.34
June	12.65	13.10	3.79	3.34

1 Transportation costs equal the difference between shipping crude oil by tankers to the West Coast and the Gulf Coast from Valdez, Alaska.

2 To calculate the actual difference between Gulf and West Coast prices, transportation costs of shipping from the West Coast to the Gulf Coast were subtracted from Gulf Coast prices.

Source: Dep't of Nat. Resources, State of Alaska, Petroleum Royalty Reports.

account, the net price received from ANS oil producers for oil sold in the Gulf is significantly below the net price received for ANS oil sold in the West Coast area. This evidence suggests that some ANS oil producers may be able to price discriminate between the two markets, indicating that some producers may have market power in PADD V. If such market power exists, mergers between companies operating in that submarket may raise antitrust concerns.

b. Concentration in domestic crude oil markets

In comparison with worldwide production by individual companies, domestic crude oil production was only slightly more concentrated. According to Table VI B-5, the four-firm concentration ratio in 1981 was 24.7 percent and the eight-firm ratio was 39.4 percent. Each of the top four firms had a share between 5 and 10 percent of the market. A principal difference between worldwide and domestic production rankings is in the shares of the top firms which ranked below the top 4. Domestically the firms in this group had slightly larger shares of the market. The highest ranked firm with less than 2 percent of the domestic market was Union, ranked number 13. In the free world, the 6th-ranked firm, Standard Oil of Indiana, had 1.8 percent (in 1980).

An additional difference is the identity of the leading firms in the two markets. While Exxon is the top firm both domestically and worldwide, there are substantial differences in the rankings of the remaining firms. For example, the 2d-, 3d- and 4th-ranked firms worldwide ranked 6th, 8th and 9th, respectively, on the domestic list. Conversely, the 2d-, 3d- and 4th-ranked firms domestically were respectively the 7th, 9th and 10th leading producers worldwide.

Table VI B-6 shows U.S. market shares based on reserves, which, as indicated above, is a better indicator of future market power. This table shows slightly greater concentration, with 4 and 8 firm concentrations of 37.0 percent and 55.0 percent, respectively. The leading firm, Sohio, has more than 10 percent of domestic proven reserves. (Sohio's leading share is almost entirely attributable to its interest in the field at Prudhoe Bay, Alaska.) There is little other difference in the rankings by reserves rather than production. For example, other than the reversal of the top two firms, the rankings of the first five firms on both lists are identical.

Because of the relative lack of concentration in worldwide and national markets, significant increases in market share as a result of a crude oil merger would (as previously discussed) only be of concern in particular product or geographic submarkets, assuming such submarkets can be found to exist.

Table VI B-5
United States Crude Oil [1]
Production by Leading Companies, 1981

Company	Production (000 barrels/day)	Market Share (percent)
Exxon	752.0	7.4
Sohio	717.3	7.0
Arco	539.9	5.3
Shell	514.0	5.0
Amoco	437.0	4.3
Texaco	381.0	3.7
Gulf	345.4	3.4
Socal	342.0	3.3
Mobil	316.0	3.1
Phillips	279.0	2.7
Getty	277.7	2.7
Sun	217.3	2.1
Union	168.2	1.6
Marathon	165.9	1.6
Cities Service	149.1	1.5
Conoco	139.0	1.4
Subtotal	5740.8	56.2
U.S. Total	10,222.0 [2]	100.0
Top four	2523.2	24.7
Top eight	4023.6	39.4

Source: 1981 Annual Reports and 10k's.

1. Crude oil, condensate and natural gas liquids.

2. Oil and Gas J., Jan. 25, 1982.

Table VI B-6
United States Crude Oil
Reserves[1] by Leading Companies, 1981

Company	Reserves (million barrels)	Market Share (percent)
Sohio	3419	11.5
Exxon	2822	9.5
Arco	2549	8.6
Shell	2208	7.4
Amoco	1674	5.6
Getty	1322	4.4
Socal	1237	4.2
Texaco	1120	3.8
Mobil	898	3.0
Gulf	865	2.9
Sun	716	2.4
Marathon	641	2.2
Union	533	1.8
Phillips	476	1.6
Conoco (DuPont)	387	1.3
Cities Service	325	1.1
Subtotal	21,192	71.3
U.S. Total	29,785	100.0
Top 4	10,998	37.0
Top 8	16,351	55.0

Source: 1981 Annual Reports and 10k's.

1 Includes proven developed and undeveloped reserves of crude, condensate and leasehold natural gas liquids.

c. Other factors affecting the domestic industry

Notwithstanding the relative lack of concentration in domestic crude oil production and reserves ownership, mergers should be examined to assess whether, because of particular aspects of industry structure and practice, a merger may have anticompetitive consequences in domestic markets that would not be inferred from market share and concentration statistics alone. The following is a brief discussion of factors that could affect the analysis of the competitive effects of a merger in the petroleum industry.

1. Control factors

One possible source of concern is a number of longstanding business practices which have evolved to facilitate relationships among the various participants in the industry. Some of these practices may complicate the interpretation of market conditions. The following description of these practices is not intended to suggest that any of the described practices is or should be considered illegal or anticompetitive in and of itself. Rather, the intent in describing these practices is to provide a fuller context for analyzing acquisitions by major crude oil producers.

In general, petroleum firms do not own the land on which they produce oil. Instead, the producer typically enters into an oil and gas lease, which allows the oil producer to drill wells on the land and recover the crude oil found. As payment for this concession, the producer will customarily assign the landowner a royalty share (usually 1/8) of the crude oil produced. Because the landowner is not normally a participant in the petroleum industry, this share will most often be taken in cash. Thus, in the most common arrangement of this type, for every seven barrels reported as a part of the firm's owned production, an additional barrel of royalty oil will be under the control of the firm for purposes of sale or other disposition.[66] To the extent that royalty oil is excluded from reported production, market share figures for leading firms could be understated by as much as 14 percent.[67]

A second type of arrangement which may affect the interpretation of market share calculations is known as a farm-out. Under a farm-out agreement, a major firm will permit independent producers to drill for and produce oil on a given land parcel in exchange for a portion of the oil produced.[68] Farm-outs probably do not appreciably affect industry concentration, but unfortunately the extent and effects of farm-out arrangements have never been accurately measured.

Joint venture production arrangements are extremely common in the petroleum industry. Some joint ventures between crude oil producers and natural gas companies exist because crude oil and natural gas are often found and produced together. While each participant may have an interest in the total production of the venture, their agreement may logically specify that the oil firm will take the crude production and the natural gas firm will take the natural gas.[69] If so, ownership figures would understate

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66 This is reflected in internal company documents, e.g. company document (Royalty oil included in self-sufficiency computation); company document ("While royalty oil has no profit associated with it, to a large extent it represents crude oil we control . . . .").

67 If a producer paid a 1/8 cash royalty on its entire production, the producer would usually report 7/8 of the production as its own. However, since it normally controls the disposition of the full amount, its market share should be adjusted to include the royalty oil. The full production is 8/7 of the producer's ownership share, or 114 percent.

68 In other words, the large integrated company simply hires a third party to perform the tasks associated with producing the oil in exchange for a fee based on the amount of oil produced. Again, the major commonly controls the disposition of the oil. One important caveat: the firm hired to produce the oil generally makes the production decisions, including those relating to output. So even if the integrated firm possesses some degree of market power based in part on oil obtained through farm-outs, the firm would have no power to reduce output from the farm-out. Its only recourse would be to absorb the full farm-out production and reduce its own production output.

69 These arrangements are more likely to be employed by integrated firms who have (Continued)

the quantity of oil controlled by the petroleum firm.

Fourth, the ownership of gathering lines may enhance to some degree the market power held by the larger firms.[70] In theory, because gathering lines are common carriers under the law of almost every producing state, an independent producer can ship its oil on the gathering system in the field or sell its oil to any purchaser, who may then use the gathering system. In fact, for reasons that are not entirely clear, such producers normally sell their oil to the gathering system owners. Thus, additional quantities may effectively be under the control of major firms who own the gathering facilities.[71]

2. Interdependence factors

Some internal company documents indicate that major crude producers may on occasion have adjusted output individually to prevent price reductions, even though, in a "textbook" competitive market, changes in output on the part of one firm would have no noticable effect on price. Although it may be difficult to rationalize such oil company perceptions in view of the relatively low market concentrations in domestic crude oil markets, the answer may rest in the extensive interdependence found among major crude oil producers, based upon the variety of joint arrangements through which they explore for, develop, and produce crude oil. These arrangements, consisting of crude oil joint bids for federal and state oil and gas lands, joint drilling ventures, crude exchanges, ownership of crude gathering and transportation systems, should therefore be examined in assessing the impact of particular mergers on competition.[72]

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substantially more refining capacity than crude oil production and consequently are seeking access to more crude oil. Company documents.

70 Gathering lines are small diameter pipelines used to transport crude oil from the wellhead to the major interstate transportation systems.

71 A recent Congressional committee staff study found that in 1974, in Texas, the twenty largest oil companies together gained physical control through gathering of an additional amount of crude oil equivalent to 13.1 percent of their Texas production. Subcomm. on Monopolies and Commerical Law of the House Comm. on the Judiciary, 96th Cong., 1st Sess., Interdependence in Domestic Crude Oil Joint Ventures, Farm Outs, Exchanges, and Gathering Lines 32 (Comm. Print 1979).

(Continued)

3. Oil reserve acquisitions

While the extremely high prices paid for the acquisition of oil and gas producing companies in recent years may seem to suggest that these transactions would materially alter the concentration in the ownership of U.S. reserves, these high prices are actually more reflective of the rapid escalation in the value of oil land gas reserves during the 1970's than of the magnitude of the resulting changes in reserve ownership. The actual impact of mergers and acquisitions involving crude oil reserves on the concentration of reserve ownership during the 1978-1981 period is presented below. The period studied is determined by the available data. The disclosures regarding oil and gas reserves appearing in company annual reports and/or 10-K's are the source of the data. These statements not only provide estimates of year end net reserves on a consistent basis for December 31, 1977 through December 31, 1981, but also provide a breakdown of the source of changes in reserve levels from year to year. The categories "purchases of minerals in place" and "sales of minerals in place" provide the data on which we rely. Prior to the SEC's announcement of uniform oil and gas reserve disclosure requirements on September 12, 1978, there were large differences among the companies in the manner in which reserves were reported and virtually no companies provided a breakdown of the sources of changes in reserves. This precluded our extension of the data series into earlier periods.

Table VI B-7 presents concentration data for the top four, eight, and sixteen reserve owners as of January 1, 1978 through January 1, 1982. It also shows the change in concentration attributable to the purchase and sale of oil reserves during each year for each of these groupings. It is readily apparent from this data that acquisitions of oil reserves by large oil companies had a negligible effect on concentration except in the year 1979. The company-specific data used in generating table VI B-7 is presented and explained in table VI B-8.

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[72] See id. at 6-32.

Table VI B-9 lists the major acquisitions of oil reserves by large oil companies in the 1970's, the volume of reserves acquired in each transaction, and the reserves acquired as a percent of U.S. reserves for each transaction. The U.S. Steel acquisition of Marathon and the Du Pont acquisition of Conoco are not included because U.S. Steel had no proved reserves prior to the acquisition and any proved reserves of Du Pont were insignificant.

Table VI B-7. Concentration of U.S. Reserve Ownership, 1978 to 1982

	1978	1979	1980	1981	1982
Top Four Firms					
Year start reserve ownership in millions bbl	13,190	12,275	11,684	11,346	10,998
Percent of total reserves	37.2	36.4	35.7	35.3	37.0
Net acquisitions of reserves in year in millions bbl	-16	+2	+0	+0	
Percent of total reserves	-.04	+.006	0	+0	
Top Eight Firms					
Year start reserve ownership in millions bbl	19,874	18,595	17,407	16,902	16,351
Percent of total reserves	56.0	55.1	53.2	52.7	55.0
Net acquisitions of reserves in year in millions bbl	-6	+613	+9	+0	
Percent of total reserves	-.02	+1.82	+.03	0	
Top Sixteen Firms					
Year start reserve ownership in millions bbl	25,675	24,082	22,446	21,917	20,716
Percent of total reserves	72.4	71.4	68.6	68.3	71.3
Net acquisitions of reserves in year in millions bbl	+42	+720	+153	+3	
Percent of total reserves	+.12	+2.13	+.47	+.01	

TABLE VI B-8. Net Crude, Condensate, and NGL Reserves by Company

	December 31, 1977			December 31, 1978			December 31, 1979			December 31, 1980			December 31, 1981	
	Rank	Reserves	Net Purchases in Year	Rank	Reserves	Net Purchases in Year	Rank	Reserves	Net Purchases in Year	Rank	Reserves	Net Purchases in Year	Rank	Reserves
Standard Oil (OH)	1	4,285[1]	0	1	4,106	+2	1	3,888	0	1	3,659	0	1	3,419
Exxon	2	3,751	0	2	3,435	0	2	2,997	0	2	2,854		2	2,822
Atlantic Richfield	3	2,807	-16	3	2,781	0	3	2,588	0	3	2,559	0	3	2,549
Texaco	4	2,347	0	4	1,953	0	7	1,316	0	8	1,229	0	8	1,120
Standard Oil (IN)	5	1,906[1]	0	5	1,779	0	5	1,653	+0	5	1,663	0	5	1,674
Shell Oil	6	1,779	+9	6	1,679	+599	4	2,211	+0	4	2,274	0	4	2,208
Getty Oil	7	1,592	+1	7	1,509	+12	5	1,438	+11	6	1,372	+1	6	1,322
Standard Oil (CA)	8	1,407	0	8	1,353	+0	7	1,316	-2	7	1,292	-1	7	1,237
Gulf	9	1,095	0	9	1,050	+15	9	978	+0	9	920	+0	10	865
Mobil	10	933	0	10	854	+68	10	869	+18	10	890	+0	9	898
Sun Co	11	819[1]	+6	12	733	+1	12	666	+126	11	751	+3	11	716
Marathon	12	789	+44	11	779	+23	11	727	+0	12	683	+0	12	641
Belridge	13	598[2]	N.A.	13	598[2]	N.A.								
Union Oil	14	565[2]	0	14	538[4]	+0	13	526[4]	+0	13	528[4]	+0	13	533[4]
Phillips	15	550	+1	15	522	+0	14	508		14	498		14	
Conoco	16	452	-3	16	413	+0	15	398	+0	15	403	+0	15	387
Cities Service							16	367[3]	+0	16	342[3]	+0	16	325

TABLE VI B-8. (Continued)

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1 The December 31, 1977 reserve data presented for Sun, Std. Oil Co. (OH) and Std. Oil Co. (IN) differs from that used by the API in its calculations for that year. The API data appears to be taken from these firms 1977 10K's while the data above appears in these firms 1970 10K's. The source of the difference is unknown but believed to be attributable to slight changes in the definition of proved reserves used in making the estimates. The data from the 1979 10K is presented for comparability with subsequent years.

2 Because Belridge Oil was privately held no reserve data is available for the company in these years. The figure presented is Shell's figure for the reserves acquired from Belridge in 1979. While this reserve data will therefore not correspond to the reserves of Belridge used in computing the universe in these years, the present treatment appears preferable to ignoring the existence of the company.

3 The reserve data for Cities Service Co. differs from that reported by the API for these years. Cities Service company reports proved reserves of crude and condensate in one table and reserves of natural gas liquids to be extracted from leasehold gas in another. This appears to have been overlooked by the API whose data corresponds in these years to the figure reported by Cities Service for crude and condensate services only. The data presented includes Cities figure for leasehold NGL in the U.S. and Canada. The report says this NGL is mostly in the U.S.

4 The reserve data presented for Union Oil represents crude and condensate only. No reserve data for leasehold NGL could be located in Union Oil's financial reports. If Union's reserve/production ratio for leasehold NGL were the same as its ratio for crude and condensate, its reserves would be increased by 100 for December 31, 1977, by 91 for December 31, 1978, by 119 for December 31, 1979, and 107 for December 31, 1980 by the inclusion of leasehold NGL reserves.

TABLE VI B-9. Large Oil Reserve Acquisitions

Year	Acquiring Company	Acquired Entity	Parent of Acquired Entity	Price Millions $	Reserves acquired: Million bbl	Reserves acquired: As % of U.S. reserves
1979	Shell Oil	Belridge Co.	N.A.	$3,653	598	1.77
1980	Sun Oil	Texas Pacific	Seagrams	2,389	126	.39
1979	Mobil Oil	General Crude Oil	Int'l Paper	792	68[1]	.20
1980	Mobil Oil	TransOcean Oil	Esmark	715	18[1]	.06
1980	Getty Oil	Reserve Oil and Gas	N.A.	621	11[1]	.03
1977	Gulf Oil	Kewanee Ind.	N.A.	455	58	.16
1979	Getty Oil	Some producing properties	Ashland Oil	266	13[1]	.04
1979	Gulf Oil	Amalgamated Bonanza Oil Ltd.	N.A.	121	15	.04

1 Total reserve purchases for company in year, not specifically attributed to the transaction in question in the company financial reports.

A striking feature of the data in Table VI B-9 is that despite the enormous size of these transactions in financial terms, only Shell's acquisition of Belridge had other than minor effects on concentration. This transaction is also responsible for nearly all of the reserves acquired by large oil companies in 1979 as calculated in Table VI B-7.

5. Conclusion

Although concentration in production or reserves of crude oil of oil companies is low, the existence of OPEC and the possible existence of geographic or product submarkets suggests that the antitrust authorities have a role to play in monitoring mergers and acquisitions in the crude oil market. There are two main issues to consider in any crude oil merger or acquisition: the effect of the consolidation on OPEC's ability to maintain its pricing strategy, and the more traditional concern over a merger's effect on concentration in portions of the United States or the nation as a whole.

Although Saudi Arabia is OPEC's largest producer and "manager," the Saudis do not alone bear the responsibility for limiting output to achieve the cartel's pricing goals. Like any cartel, OPEC must cope with the problem posed by each individual member's incentive to cheat by selling more than its quota at a price lower than that set by the cartel. In the case of OPEC, this problem may be attenuated because of historic ties between certain firms and particular producing nations. Firms with no such ties can be an important procompetitive influence in the market, because they can aggressively seek out the lowest cost supplies and thus encourage cheating. Therefore, a merger between tied and untied firms should be carefully examined to assess whether it would remove an important destabilizing influence from the world market.

Because there is some evidence that geographic and product submarkets may exist in regions of the country, the effect of a merger of crude oil producers on domestic crude oil markets deserves scrutiny as well. In examining the effect on competition of crude oil mergers in the United States, it is important to consider other nonstatistical facets of domestic crude oil markets so that some assessment can be made of whether the potential of injury to competition may be greater than might be inferred from examining concentration statistics.

Finally, examination of recent crude oil asset acquisition activities by oil companies reveals that there has not been any significant increase in concentration of oil reserve ownership.

C. Refining

1. Overview

Petroleum refining operations produce a variety of products, from gasoline to feedstocks for the petrochemical industry. Refining technology allows considerable latitude in the mixture of refined products that can be produced from crude oil. Although, in the short run, the nature of existing refining capacity reduces the scope for economically varying the mixture of refined products, some degree of substitution is still possible. For example, many refineries have sufficient technical flexibility to adjust their output to emphasize either distillate or gasoline by as much as 5 to 7 percent of their total capacity. This supply substitution potential presents difficulties in defining product markets for refined products, particularly in the long run, when refining capacity can be changed.

In 1979, U.S. refineries had the following average product yields of gasoline and middle distillates as a percent of crude inputs: gasoline—43.0 percent; jet fuel—6.9 percent; kerosene—1.3 percent; and distillate fuel oil—21.5 percent. These products totalled 72.7 percent of crude oil inputs.[1] It is important to recognize that these figures mask significant differences among refineries in output composition. Thus, it has historically been the case that some refineries, particularly small ones, are designed for the production of lubes, asphalt, jet fuel or other special products and make little or no gasoline. In recent years, the small refiner bias in DOE regulations led to a proliferation of plants which produced no gasoline; the subsidy depended simply on crude runs rather than gasoline output.

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1 Am. Petroleum Inst., vol. 1, no. 3, Basic Petroleum Data Book: Petroleum Industry Statistics, sec. VIII, table 4.

Differences among refineries in output mix can be seen from EIA-87 data on output for 1981. Of the 79 refineries located in the Gulf Coast [2] which operated in 1981, 37 produced no gasoline and 41 had gasoline outputs which were less than 20 percent of crude runs. [3] Similarly, only 17 of the 79 refineries made asphalt in 1981 while only 8 made lubes. [4] Of the 48 small refineries with capacities of less than 50,000 B/D, only 12 made any gasoline, none made lubes and only 8 made asphalt.

Because gasoline and middle distillates comprise the majority of uses of crude oil, and because the technology of refining suggests focusing on substitutions among these products, this section will be concerned with gasoline and middle distillates, and whether product markets exist within this category of products. This section will also examine the geographic location of refining capacity relative to the demand for refined products, in order to assess whether there are geographic submarkets for refined products. Once the market definition issues have been addressed, concentration, conditions of entry, interdependence factors, and merger activity within markets will be summarized.

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2 The Gulf Coast consists of Alabama, Mississippi, the Texas Gulf and the Louisiana Gulf as these areas are defined in the Dept. of Energy's publication "Petroleum Refineries in the United States and U.S. Territories, January 1, 1981." Two of the 81 refineries listed in this publication as being located in the above region are omitted from the discussion. One is omitted because it did not operate at any time during 1981 and the other is omitted because it is consolidated with another refinery in the EIA-87 data.

3 These figures are derived from output data from the DOE form: EIA-87, Refinery Report. A refinery was classified as producing gasoline only if the gasoline output appeared to be a result of crude processing activities rather than blending activities. In general, gasoline output was attributed to crude processing if finished gasoline output exceeded the input of gasoline blending components on an annual basis. There are a few instances in which this criterion did not appear to work well (such as if gasoline output exceeded blending component inputs only in months in which there were no runs to stills) and discretion was exercised in deciding whether or not the refinery should be classified as producing gasoline.

4 These figures are also derived from EIA-87 data. They do not include plants which produce asphalt and lubes but do not process crude oil. They also do not include the refineries which produce the feedstock for such plants.

2. Relevant product market

a. Supply substitutability

A key issue is the extent to which refiners are able to adjust their product output slates in response to changes in the relative prices of petroleum products. The exact composition of a refiner's product slate is largely a function of three factors: the types of crude oil the refiner runs through its plant;[5] the sophistication of the plant's processing equipment;[6] and the rate at which the refiner feeds crude oil into the facility.[7] Modern domestic demand trends have led most refiners to adjust their facilities to maximize yields of gasoline and other lighter products.[8]

To some degree, a refiner can alter his product slate in the short run at a given plant without additional capital investment. Such flexibility permits the refiner to adjust production to meet short run market fluctuations as well as seasonal variations in product demand. Substantial alterations in the output slate, however, may require a

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5 Crude oils vary widely according to their "gravity" and sulfur content. High gravity or "light" crudes tend to yield a greater percentage of light products per unit of processing than low gravity or "heavy" crudes.

6 To extract greater amounts of lighter products from a barrel of crude, a refiner must supplement its basic distillation units with more complex treatment facilities which transform heavier petroleum molecules into lighter products.

7 In most refineries the special processing equipment for increasing the yield of lighter products has a smaller capacity than the refiner's principal processing equipment. The special units typically exhaust their capacity before the refinery reaches its total processing capacity. Thus, at higher input rates, the refiner is unable to channel the additional barrels through its facilities for reducing residual oil output. Consequently, the marginal barrels at high capacity levels tend to yield ever greater amounts of residual products. See Affidavit of England at ¶ 11, FTC v. Mobil Corp., No. C81-2473 (N.D. Ohio 1981).

8 Each refinery has a maximum production capacity for each product given a certain crude feedstock. The typical gasoline-type refinery produces about 50-55% of crude input as gasoline, 25-30% as middle distillates and 10-15% heavy products.

change in the types of crude oil run in the refinery or the construction of new processing equipment.[9]

There are several factors other than refinery configuration that may influence the amount of substitution in output mix by a given refiner. These include the existence of contractual or other commitments to supply various products;[10] the nature and capacity of distribution channels at the refiner's disposal (e.g., pipelines, terminals, and storage facilities);[11] the availability of desired types of crude oil (for refiners seeking to adjust their product slates by altering the type of crude oils run in their refineries);[12] and the opportunity cost of shifting production from one product to another.[13] Separately or together, these factors can shrink the range of a refiner's response to relative product price increases, at least in the short run, even though output adjustments are technically feasible.

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9 A refiner's ability to adjust its crude oil inputs depends on the design of its facilities.

10 A refiner conceivably might face a situation in which it could supply more of a given product to one region by diverting supplies from other regions or expanding the output of the product at the expense of other products. In either case, existing supply agreements might be a partial or complete obstacle to such shifts.

11 A refiner in some situations may be able to raise output of a product but may lack effective distribution channels to deliver the product to the desired location. Jet fuel, for example, may be one product which refiners can produce in greater quantities but cannot readily deliver to users because access to spur lines leading to airports is severely limited.

12 A decision to increase gasoline output by running lighter crudes, for example, would rest upon the relative price of light and heavy crude supplies — a condition which would depend upon the crude oil market at any moment.

13 The "opportunity cost" to the refiner of making a unit-for-unit shift from producing one product to another consists of the revenues lost from the sale of products it foregoes. Production adjustments become attractive when the anticipated revenues exceed the opportunity cost. The appeal of such production shifts depends, therefore, upon the relative contribution each product makes to the firm's profitability.

b. Demand substitutability

The magnitude of demand substitutability varies considerably across the product slate. At one end of the spectrum, users have few effective substitutes for gasoline, diesel fuel, and jet fuel.[14] At the other extreme, residual fuel oil faces formidable competition from coal and natural gas as a boiler fuel for utilities and for large manufacturing processes.

Home heating oil presents a more difficult, intermediate case. For substantial numbers of residential and commercial users, especially those making initial new housing decisions, natural gas is a viable substitute, although converting an existing oil heating system to gas or other fuel alternatives may require a capital outlay beyond the reach of many oil users. The availability of natural gas would therefore appear to limit the pricing discretion of heating oil producers, at least to some extent.[15]

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14 Transportation is the economic sector in which the demand for petroleum products is least amenable to substitution. Between 1973 and 1980 the average cost of jet fuel increased from 12.8 cents per gallon to nearly a dollar, causing the airlines' cost of fuel to increase from about 12% of total operating expenses to about 33%. See "The Airlines Move to Control Their Fuel Supplies," Bus. Wk. 189 (Nov. 17, 1980). Nevertheless, over the same period the number of airlines passengers has increased by 50%, from 200 million passengers/year to 300 million. See Air Transport Assoc. of Am., Fuel: The Most Critical Problem Facing the U.S. Airline Industry 11 (Feb. 5, 1980) (report presented to the Civil Aeronautics Board). Airlines now account for about 85 percent of public passenger miles between U.S. communities. Id. at 12.

Substitutes for gasoline as a fuel for local transportation are only slightly stronger. The rise in gasoline prices during the 1970's provided the impetus for increased use of mass transit and carpooling and the development of such alternatives as gasohol. Notwithstanding these developments, the demand for gasoline has not appreciably declined in relation to its price. Many studies have found that a 10% increase in gasoline price produces a short-run drop in demand of between 1 and 3%. See Dep't of Energy, Price Elasticities of Demand for Motor Gasoline and Other Petroleum Products 17-22 (May 1981).

15 Other heating oil substitutes include electricity, liquid petroleum gas, wood and coal. Note, of course, that crude refining is one source of liquid petroleum gas, and some electricity is generated by plants using residual oil as a boiler fuel.

c. Probable product markets

Although for some purposes one might treat all refined products — the refiner's entire output slate — as a relevant product market,[16] finer discriminations may also be justifiable and appropriate. First, motor gasoline may warrant analysis as a distinct product market.[17] The limited ability of refiners to shift production away from other products towards gasoline and the inability of consumers to substitute for gasoline support this approach. In some situations middle distillates may also constitute a separate product market. Further delineations within the middle distillate range of the product range may also be economically warranted. For example, there may be discrete distillate markets for No. 1 fuel oil, No. 2 fuel oil, and jet fuel.[18]

3. The geographic refining market (for gasoline and middle distillates)

a. Defining the relevant market

There are no definitive data from which to conclude either that the refinery market is nation-wide, or that firms in various sections of the United States are insulated from outside competition. However, certain refining areas, where there may be

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16 Cf. United States v. Amax, Inc., 402 F. Supp. 956, 961-62 (D. Conn. 1975); American Smelting & Ref. Co. v. Pennzoil United, Inc., 295 F. Supp. 149, 154-55 (D. Del. 1969).

17 From a legal standpoint, courts which have addressed the issue almost invariably have treated gasoline as a relevant product market. See e.g., Marathon Oil Co. v. Mobil Corp., 669 F.2d 378, 380 (6th Cir. 1981); United States v. Atlantic Richfield Co., 297 F. Supp. 1060, 1066 (S.D.N.Y. 1969).

18 The issue here is a closer one because suppliers enjoy a greater ability to shift production between No. 1 and No. 2 upon observing price increases. No. 1 fuel oil is blended to produce No. 2 fuel oil, but No. 2 cannot be converted into the lighter No. 1 without the addition of expensive processing equipment. The pattern of demand for No. 1 and No. 2 also tends to be coincident during the calendar year, making production shifts from one fuel to the other less feasible. Potential problems in obtaining satisfactory distribution arrangements may limit the ability of refiners to supply as much jet fuel as their facilities conceivably could produce.

Users, on the other hand, have few substitutes for jet fuel (which consists mainly of kerosene, a component of No. 1) or diesel fuel (a component of No. 2). Consumers do, however, have some ability to substitute alternative fuels — especially natural gas — for home heating oil (a component of No. 2).

bottlenecks in the flow of products from refineries to distribution terminals, may constitute individual competitive regions, at least for the short run. While the exact configuration of these markets is difficult to determine, because of the way data is collected, the Petroleum Allocation for Defense Districts ("PADDs") are a useful starting point in the analysis of potential geographic markets.

The analysis in this section is primarily based on shipment patterns. Interregional price relationships were also analyzed, but because of data limitations, few additional insights were apparent from that approach.[19] This evaluation has also limited its focus to gasoline and middle distillates, because they account for such a large percentage of total refined product sales. Other products may compete in a broader geographic market (residual fuel oil) or a narrower geographic market (petroleum coke and asphalt).

A point of departure for the market evaluation is an analysis of shipping costs for petroleum products. Pipelines and water carriers account for most long distance large volume shipments.[20] One estimate of shipping costs between the refinery center in the Gulf Coast and a consuming center, New York Harbor, based on 1978 data is 1.90 cents/gallon by water and 1.33 cents/gallon by pipeline.[21] More recent estimates indicate that pipeline costs have gradually risen to about 2 cents/gallon during 1980 and

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19 The most significant difficulty with the price analysis was the limited amount of data available on refinery sales to distribution terminals. While daily price data are published in Platt's Oilgram and Oil Price Information Service for spot cargo markets in New York harbor, the Gulf Coast, and Oklahoma, there are many limits on the usefulness of these data. First, tests are limited to those three areas, which means that relationships such as that between the Gulf Coast and upper Midwest cannot be analyzed. Second, these price data are very erratic, possibly due to speculation in these markets and the thinness of trade, which tends to obscure any obvious relationship with equilibrium prices. Furthermore, while the prices in these regions often move in a roughly parallel fashion, it is difficult to know how much of that movement is accounted for by similar changes in crude oil prices across all regions. Finally, non-price terms on transactions may differ widely (such as payment dates and product quality), thus limiting the comparability of interregional prices.

20 See infra, Section VI.D.

21 G. Wolbert, U.S. Oil Pipelines 405 (1979).

1981 while water shipment costs have varied between about 3 and 6 cents/gallon in this period.[22]

Although it is difficult to generalize from these estimates, a two percent cost differential probably gives local refiners on the East Coast or Great Lakes area some advantage over Gulf Coast refiners. This apparent advantage may have to be discounted somewhat in the case of Great Lake refiners because crude oil must also be shipped into that area at some cost. Consequently, the Great Lakes-refiner advantage would appear to be limited to the cost difference between shipping crude oil and product.[23] Despite this apparent cost advantage of East Coast refineries, refined product demand in the mid-Atlantic and New England States greatly exceeds the output of refineries in the region at prevailing prices and has historically been met through shipments from the Gulf Coast refining area and the Virgin Islands.

Shipment pattern analysis provides additional information on the actual competition between regions. Unfortunately, available data on transportation patterns is largely confined to shipments among the five PADD regions. Because the boundaries of actual geographic markets do not always correspond with PADD boundaries, inflow and outflow statistics for PADDs may be misleading in that some inter-PADD shipments may be intra-market shipments and some intra-PADD shipments may be inter-market

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22 Colonial Pipeline Company, Performance and Trends 13 (1982).

23 *See* testimony by Dr. F.M. Scherer, trial transcript at 255-56 (Nov. 18, 1981) in *Marathon Oil Co. v. Mobil Corp.*, 669 F.2d 378, which describes the transportation cost differential between pipeline transport of crude oil and refined product from PADD III into PADD II and why this confers an advantage on Midwest refiners.

shipments if the markets are correctly delineated.[24] Finally, shipment pattern analysis must be used with care because the real issue in market definition is whether prices can be raised without triggering a substantial inflow of shipments. It is possible that an area without substantial imports would receive such imports in the event of a price increase. Conversely, it is possible that an area with substantial imports can raise prices because there are impediments to increases in imports.

b. The Gulf Coast (PADD III) as a distinct market

Because of the significance of shipments from PADD III to PADD I, PADDs I and III may have to be combined for analyzing PADD I mergers. However, since very little product is transported from PADD I to PADD III, PADD III may be the relevant market for analysis of mergers between two PADD III refiners. Some analytical approaches, like the Elzinga-Hogarty test, assume that product can flow equally well in both directions. Under these approaches, substantial PADD III shipments into PADD I would preclude treatment of PADD III as a distinct product market. But if barriers to product inflows into PADD III are present, customers within PADD III would have no alternative sources of supply, and thus a merger of two PADD III companies may be appropriately considered

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24 For example, central or eastern Tennessee (Chattanooga, Nashville and Knoxville) are served by spurs of the Colonial or Plantation pipeline systems. These are the only source of petroleum products east of Memphis (which is where Tennessee's one refinery is located). In consequence, it would appear more appropriate to place eastern and central Tennessee (and probably southern Kentucky as well) in PADD III when analyzing shipment patterns.

In addition, since both the Colonial and Plantation pipelines enter Tennessee from Georgia (which is in PADD I), this flow of products shows up as a substantial flow of product from PADD I to II, even though the product in question is coming from refineries in PADD III. Similar problems result from the use of PADD districts in several other regions.

These data also limit the ability of economists to search for the precise market delineation which minimizes shipments between regions. These data limitations further indicate the need for an eclectic approach to market definition.

Another limitation of the shipments approach used here is that the most recent year for which data are available is 1980 and some of the shipments in this and prior years may have been induced by DOE regulations no longer in effect.

in a PADD III market. The existence of impediments to product inflows to PADD III may be suggested by the small volume of foreign imports and the insignificant amount of pipeline flow into PADD III.[25] Thus, to the extent such barriers are present, a merger of two PADD III refiners should be analyzed in a PADD III market.[26]

It should also be noted that the exercise of possible market power in PADD III conferred by any such merger would be tempered by the volume of shipments out of PADD III to PADD's I and III. In order to raise prices in PADD III it would have to be possible to discriminate in prices between PADD III and those other PADDs. Therefore, merger analysis would require consideration of the presence or absence of such ability to discriminate.

c. PADD II, the Midcontinent

Shipments from other PADDs account for between 18 and 20 percent of PADD II's consumption of gasoline and between 9 and 13 percent of its consumption of distillate fuel oil. Most of these shipments are from PADD III, but significant amounts also come from PADD I.[27] On this basis Elzinga and Hogarty would find that PADD II is only a weakly defined market. However, these statistics may be biased towards showing a unified PADDs II and III market because shipments from PADD III may only make limited

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25 The only significant pipeline flowing into PADD III is from Oklahoma to Arkansas, clearly a fringe area of PADD III. The vast majority of pipelines flow out of PADD III since that area has substantial amounts of surplus production.

26 While this seems reasonable, it is possible that a slight increase in PADD III prices would induce product flow into that area. For example, brokers may be able to buy products from Caribbean refiners and resell them to distributors. However, industry participants who were interviewed noted no historical evidence of significant amounts of imports and thought this issue was too abstract to assess. Unfortunately, this may be evidence either of the lack of significant price disparities or of the fact that PADD III is a relevant market.

27 It is likely that much of the indicated movement from PADD I to PADD II is on spurs of the Colonial and Plantation pipelines. If so, the actual origin would be PADD III for most of these shipments.

penetration into PADD II.[28] If PADD boundaries were modified to reflect actual shipping patterns in a more accurate fashion, the import percentage into the modified PADD II region might be much lower. For example, since a substantial volume of petroleum products flows into Tennessee from Georgia on spur lines of the Colonial and Plantation product pipelines, the movement of eastern Tennessee from PADD II to a modified PADD III market might have this effect. Similarly, DOE data show that barge and tanker shipments of gasoline, jet fuel and middle distillates from PADD III to the PADD II states of Illinois, Indiana, Kentucky, Missouri, Ohio and Tennessee averaged 52,129 barrels per day in the period March 1981 through February 1982. Since all but 4,247 b/d of this product was actually delivered into Tennessee, Missouri and Kentucky, slight modifications of PADD boundaries in this region also might lead to significant reductions in apparent inter-PADD flows.[29]

Another possibility is the classification of the upper Midwest into a separate market. Gulf Coast shipments via pipeline appear to have some difficulty competing in

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28 See Texas Eastern Transmission Corp., Ann. Rep. to FERC (also known as the "P - form). This form shows that in 1972 significant amounts of gasoline and distillate were delivered into Indiana and Illinois. However, the 1979 and 1980 P-forms show virtually no products other than LPG being shipped past Missouri.

29 The Department of Energy publishes data on the gross inter-PADD flows only. The figures above are calculated from non-public state to state shipment data provided to the FTC by the Department of Energy. The time period was selected to minimize the distorting effects of the crude and refined product price controls which were eliminated at the beginning of February 1981.

the upper Midwest.[30] This may be the reason for the apparent lack of interest in such interregional shipments, as reflected in the trade press' failure to discuss price differences between Chicago and the Gulf Coast to the same extent that they discuss East Coast and Gulf Coast price differences. While far from conclusive, this suggests that a well established market for these movements is not present.

The fact that the upper Midwest is approximately self sufficient in refining is consistent with it being a separate market.[31] Only if prices in the upper Midwest rise above the price in the exporting regions plus transportation costs, are exports likely to materialize. While such a price increase may be economically significant, there are other factors that may limit the power of refiners to raise prices significantly in the upper midwest. First, there is an extensive pipeline system running throughout the Mid continent region, with two pipelines running directly from the Gulf Coast to the upper Midwest.[32] When excess capacity is available on these petroleum product pipelines into

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30 One major company executive expressed such an opinion in a recent telephone interview, and a major oil company document prepared in 1964 expresses a similar view:

> Products moving from Gulf Coastal refineries do not penetrate very far into the interior. The volume moving to Dallas, however, is substantial and [one major oil company] do [sic] pipeline a small quantity as far north as Oklahoma, but the economics of the latter are highly questionable. There are sporadic emergency tender movements through [company] to Indianapolis and Chicago but their normal business consists mainly of short haul gasoline and propane and butane.

31 Dep't of Energy, I Petroleum Supply Alternatives for the Northern Tier and Inland States Through the Year 2000, II (Oct. 31, 1979).

32 The Texas Eastern System originates in Houston, Texas and had a 1979 capacity of 250,000 barrels per day of No. 2 fuel oil (or 305,000 b/d of gasoline) on shipments to Seymour, Indiana. Second, the Explorer System originates in Lake Charles, Louisiana and has a capacity for shipping No. 2 fuel oil of 367,000 b/d to Wood River, Illinois. Gasoline and mixed mode capacities are higher, but not reported.

the Midwest, additional products could be shipped into the region if local prices were to increase.[33]

Another consideration is the large refinery cluster in Oklahoma and Kansas that ships gasoline and middle distillates throughout the Midwest. This raises the possibility of indirect price effects between the Gulf and Midwest. If prices rise in the upper Midwest, shipments from Oklahoma may be pulled into that area, with Gulf refiners displacing Oklahoma refiners in sales to the lower Midwest. This may constrain upper Midwest prices as effectively as direct shipments from the Gulf.

Thus, complicated shipping patterns into the Midwest raise difficult issues of how the region should be analyzed for geographic market purposes. Possible markets include: (a) an area very similar to PADD II as a whole, if shipments from Kansas and Oklahoma to the upper Midwest are substantial; (b) a six state region consisting of Indiana, Illinois, Ohio, Wisconsin, Michigan, and Kentucky; or (c) some region in between (a) and (b). Alternatively, under the view that the Midwest is connected to the PADD I and III market, the relevant market would be PADDs I, II, and III, with slight additions or subtractions.

d. PADD IV, Rocky Mountain states

Only two product pipelines go into PADD IV, one from Kansas (PADD II) and the other from Texas (PADD III). A limited number of pipelines flow out of PADD IV, going only into eastern Washington and western Nebraska and western North Dakota. Nonetheless, PADD IV does receive about 20 percent of the refined products it consumes from other PADDs, flowing primarily from Kansas to Denver, Colorado. However, the

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33 There is also substantial capacity to ship refined products up the Mississippi and Ohio Rivers into the upper Midwest except during winter months.

shipments into Denver do not appear to penetrate any further into PADD IV.[34] Because the PADD IV states except Colorado — Montana, Idaho, Wyoming, and Utah — appear to face virtually no competition from outside refiners, it may be best to include eastern Colorado, including Denver, in the same market with Kansas, and to define the remainder of PADD IV as a distinct market. However, because refining capacity in Denver is small, this minor correction could be ignored and PADD IV could be used as an approximate market.

e. PADD V, the West Coast

PADD V seems the most isolated of all of the PADDs. The only products for which inflows exceeded 10% of PADD V consumption in 1980 were naphtha type and kerosene type jet fuel.[35] Most of the jet fuel inflows were foreign imports, which suggests that foreign competition may be an important factor limiting jet fuel prices in PADD V. 1982 import data from a different source[36] (which should be comparable to the 1980 data) reveal that all distillate imports totalled only 5,093 barrels/day in the first 4 months of 1982 compared with 19,000 b/d of kerosene type jet fuel alone imported during 1980.

The 1982 import data also permit separate analysis of imports into mainland PADD V and into Hawaii. These data reveal that of the 5,093 b/d of distillate imports into PADD V in the first four months of 1982, 4,308 b/d was imported into Hawaii. Similarly, of the 22,660 b/d of gasoline imports into PADD V in this period, 9,142 b/d were imported into Hawaii.

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34 This is because the pipelines connecting Denver to locations in PADD IV outside of Colorado flow into Denver.

35 Dept. of Energy, Energy Information Administration, Energy Data Reports, "Supply, Disposition, and Stocks of All Oils by Petroleum Administration for Defense Districts and Imports into the United States, by Country, Final 1980" Dec. 4, 1981.

36 American Petroleum Institute, "Imported Crude Oil and Petroleum Products" Jan-April 1982.

Overall, the 1982 data suggest that while imports of refined product in Hawaii are significant relative to demand, imports of refined product into mainland PADD V are very small relative to demand. Most of the other refined product inflows appear to enter PADD V in eastern Washington and Arizona to meet demand in isolated areas on the border of PADD V, rather than competing substantially with PADD V refiners. These shipment patterns suggest that the five state area of Washington, Oregon, California, Nevada and Arizona may be a distinct market.

f. Summary

It was shown above that some of the PADDs may roughly delineate geographic markets in some circumstances. More precise delineation would require better data. Since refined petroleum products are fungible, the existence of separate geographic markets hinges on impediments to the transport of refined products. It is possible to move refined product from any location to any other location in the United States by combination of rail, water, pipeline, and truck transport. Although particular shipment methods may be costly, the ability to move product around will moderate disparities in prices among some markets, even in the short run.

4. Market share/concentration data

Concentration ratios by PADD and particular subregions for refinery capacity are provided in Table VI C-1 for the period 1950 to the present. As can be seen from the Table, PADDs I, II, and III are quite unconcentrated, while the West Coast, Upper Midwest, and PADD IV are moderately concentrated. The West Coast is the most concentrated.

It is also noteworthy that in most "markets" there has been a significant fall in concentration in the past 30 years. Of the relatively concentrated "markets," PADD IV and the Upper Midwest have maintained or moderately increased in concentration.

As pointed out previously, however, refineries are not homogeneous and concentration measures based on refinery capacity do not necessarily reflect the actual ability of firms to make light products.

Table VI C-1
Refining Concentration Trends

Concentration Trends--PADD V
(Arizona, California, Nevada, Oregon, Washington)

	1950	1960	1970	1980	1982
CR4	60.2	61.9	66.5	54.4	55.91
CR8	85.1	89.6	95.2	76.5	79.48

Concentration trends--PADD IV
(Colorado, Montana, Idaho, Utah, Wyoming)

	1950	1960	1970	1980	1982
CR4	47.9	47.2	53.5	48.0	53.4
CR8	73.8	74.2	81.7	75.3	80.4

Concentration trends--PADD III
(Alabama, Arkansas, Louisiana, Mississippi, New Mexico, Texas)

	1950	1960	1970	1980	1982
CR4	49.5	43.7	44.0	36.2	36.8
CR8	73.7	65.7	64.8	54.5	55.6

Concentration trends--PADDs I and III

	1950	1960	1970	1980	1982
CR4	46.5	40.9	40.9	35.0	35.1
CR8	66.1	59.0	62.3	55.0	54.7

Concentration trends--Upper Midwest
(Illinois, Indiana, Kentucky, Michigan, Ohio)

	1950	1960	1970	1980	1982
CR4	45.3	42.9	47.7	48.7	54.1
CR8	70.4	69.0	74.4	75.5	81.6

Table VI C-1--Refining Concentration Trends--continued

Concentration trends--PADD II

	1950	1960	1970	1980	1982
CR4	36.7	34.6	38.3	37.4	40.1
CR8	55.3	53.5	59.7	60.0	60.8

Concentration trends--PADDs I, II, and III

	1950	1960	1970	1980	1982
CR4	36.0	31.4	35.2	30.7	29.5
CR8	55.7	49.6	58.0	49.2	47.8

Note: Market share is based on operating crude distillation capacity.

Source: Department of the Interior, Bureau of Mines, "Petroleum Refineries including Cracking Plants in the U.S." as of January 1, 1950, 1960, 1970; Department of Energy, Form EIA-87, "Petroleum Refineries in the U.S. and U.S. Territories" as of January 1, 1980, 1982.

One way to account for this heterogeneity is to measure concentration in terms of finished gasoline output and runs to stills. These comparisons are provided in Table VI C-2 for 1981. It can be seen that concentration when measured by either gasoline output or runs to stills is somewhat higher than when measured by refinery capacity.

In examining Table VI C-1, it is evident that concentration when measured by refinery capacity increased somewhat between January 1, 1980 and January 1, 1982 in most of the areas analyzed. The apparent reason for this increase is the substantial number of refineries which ceased operation in this period.

A detailed examination of the character of the exiting refineries on the Gulf Coast during this period, however, suggests that the increase in concentration from 1980-1982 would not significantly affect competitive conditions in the supply of gasoline. The basis for this conclusion is that the exiting refineries were largely topping plants built during the period of the small refiner bias in the DOE regulations. Most of these refineries did not produce gasoline. Of the 22 refineries located in Alabama, Mississippi, coastal Texas or coastal Louisiana which shut down during 1981, only four produced gasoline in 1981. Seventeen of these refineries had been constructed since 1976.

In Table VI C-3, 4 and 8 firm concentration figures are given for 1981 and 1982 for the Gulf Coast based on total refining capacity and the capacity of only those refineries that produced gasoline. It can be seen that while concentration when measured by total refining capacity is lower than concentration when measured by the capacity of the refineries that produced gasoline, the increase in concentration for gasoline production during 1981 is substantially less than the increase when concentration is measured by total refining capacity.

Table VI C-2. Concentration Ratios for Crude Distillation Capacity, Runs to Stills, and Gasoline Output, 1981

	4 Firm Concentration (8 Firm Concentration)		
Geographic Area	Capacity	Runs to Stills[1]	Gasoline Ouput[2]
West Coast[3]	62.7 (87.6)	55.4 (79.3)	57.1 (88.8)
PADD IV	50.3 (77.1)	52.9 (81.8)	53.2 (83.4)
Upper Midwest[4]	51.3 (76.4)	50.4 (80.4)	46.7 (79.8)
PADD II	38.3 (58.3)	35.8 (57.2)	35.1 (57.9)
PADD III	34.3 (51.6)	36.1 (55.0)	34.0 (54.7)
PADD's I + II	33.6 (52.5)	36.1 (56.2)	33.2 (54.9)
PADD's I + II + III	29.9 (47.6)	29.9 (49.5)	28.3 (48.5)

Source: For crude distillation capacity, Petroleum Refineries in the U.S. and U.S. Territories, January 1, 1981, Energy Data Report, U.S. Department of Energy, Energy Information Administration, May 22, 1981; for runs to stills and gasoline output, summary data from the Refinery Report EIA-87 provided to the FTC by the U.S. Department of Energy, Energy Information Administration.

1. Crude and NGL charged to stills in year 1981.

2. Finished gasoline output in 1981. The universe includes the output of refineries and blending plants. The universe may include the output of blending plants which are only adding lead to unfinished gasoline inputs.

3. PADD V excluding Alaska and Hawaii.

4. Illinois, Indiana, Michigan, Ohio, Kentucky.

Table VI C-3

Gulf Coast Refining Concentration

	1981	1982	Change
		Concentration based on all capacity	
4 Firm	37.3%	40.3%	+3.0
8 Firm	55.9%	60.2%	+4.3
		Concentration based on the capacity of refineries which manufacture gasoline	
4 Firm	41.3	42.3	+1.0
8 Firm	61.8	63.2	+1.4

Source: Department of Energy, Engery Information Administration, "Petroleum Refineries in the U.S. and U.S. Territories", January 1, 1981 and January 1, 1982. EIA-87.

5. Entry conditions

There are a number of factors that may have either induced or deterred new refining entry. An example of the former is the small refiner bias to the oil entitlements program, which favored small scale entry. On the other hand, there may have been inhibitions to large scale entry, such as the difficulty of obtaining access to crude oil, and the need to overcome environmental objections. The pattern of entry which encouraged small refineries was effected by a fairly long-term regulatory environment that has been recently rescinded. Even before entitlements, the formula for allocating import tickets (rights to foreign crude oil) and other federal programs favored small refiners. It therefore appears that efficient (large scale) entry may have been retarded.

a. Environmental factors

Three market characteristics have been identified as the most important factors complicating entry into refining: access to crude oil supplies, environmental regulation, and economies of scale. Of these, environmental regulation seems to be the clearest example of a barrier to entry in certain regions. On the East Coast, for example, plans for at least 20 refineries have been cancelled in recent years due to local opposition, and opposition has been so vociferous that no large grass roots refinery has been constructed for 20 years.[37] Because there have been cases of new construction in other regions, however, it is difficult to generalize about the role environmental factors play.

b. Difficulty of access to crude supplies

Access to reliable crude supplies may present another entry problem. Some analysts, such as Jones, Mead, and Sorensen, have argued that an entering refiner cannot

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37 Am. Petroleum Inst., Trends in Refinery Construction in the United States 35 (Sept. 16, 1980) (discussion paper #20) [hereinafter cited as Refinery Construction Trends].

Two smaller East Coast refineries were constructed in the late 1970s, demonstrating that the opposition is not monolithic. Seaview Petroleum opened a 44,000 b/d operation in 1979, (now at 80,000 b/d) while Cibro built a 27,000 b/d refinery in 1978 (now 42,500 b/d).

look to the foreign or domestic market for reliable and cost competitive supplies of crude oil.[38] They argue that in the foreign market, the "vagaries of international politics" and "the threat of changes in U.S. policies towards imports" could limit the security of foreign crude supplied to a new domestic refiner. Alternatively, small scale entrants might suffer a competitive disadvantage in the foreign market because they are unable to purchase in the quantities demanded by producing nations.[39] A major oil company recently rejected one acquisition candidate because two-thirds of its crude oil is from offshore contract and spot purchases, which meant that as much as two-thirds of its refined gasoline production is subject to political or economic interruption.[40] Another major oil company in 1974 stated, "it is doubtful that any refiner would proceed with plans for a new refinery until fairly well assured of an adequate supply of crude."[41] In fact, outside of PADD V, where the development of Prudhoe Bay has supported new refineries, there has been very little entry over the past 30 years on any substantial scale, based on domestic crude resources. For this reason, the adoption of import quotas similar to the Mandatory Import Quotas of the 1960s might be expected to have an adverse impact on the ease of entry into the refining industry.[42]

The importance of a crude supply is demonstrated by the fact that 39 out of the top 40, and 99 out of the top 103 refiners are also integrated backward in exploration and

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38 Jones, Mead & Sorenson, "Free Entry into Crude Oil and Gas Production and Competition in the Oil Industry," Nat. Resources J. 859 (Oct. 1978) [hereinafter cited as "Jones"].

39 See Dep't of Energy, Office of Competition, Office of Oil Policy, Crude Oil Access Study 4-7 (Draft, Oct. 6, 1980).

40 Company document.

41 Company document.

42 For example, Shell purchased Belridge for $3.15 billion. Belridge's production of crude oil was reportedly about 30 percent less than that neded to support a 100,000 barrel per day refinery.

production.[43] The presence of many existing companies having refinery capacity and networks for access to crude and channels for product distribution may limit the possible gains from output restrictions by the largest producers, since many of the smaller producers may be able to expand relatively in the future. The declines in concentration previously noted in several of the most important PADDs, reinforces this possibility.

c. Economies of scale

Petroleum refineries, like other fluids processing plants, are characterized by substantial economies of scale. From an engineering standpoint, average capital and operating costs tend to fall as refinery (and process unit) size increases.[44] In practice, however, the minimum efficient scale of a refinery is usually placed at between 150,000 and 200,000 barrels per day.[45] If 150,000 barrels per day is assumed the minimum efficient scale (MES), then the construction of one efficiently sized refinery would increase capacity in the regions described by PADDs by between 1 and 25 percent. These data are presented in Table VI C-4.

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43 Am. Petroleum Inst. Comm. on Industrial Organization, Qualification of Oil Industry Vertical Integration 4 (June 1977).

44 See "Small Refiner Bias Analysis, Final Report, January 1978" prepared for US DOE, ERA, Office of Regulations, especially pp. 48-77, 118-158. See also W. L. Nelson, "Effect of Size on Refinery Operating Cost," The Oil and Gas Journal, January 15, 1973, pp. 79-80.

45 Company document. Timothy Greening estimated that MES was 175,000 b/d. Oil & Gas J., 110 (Oct. 26, 1981). An estimate of 200,000 b/d was provided by Scherer, Beckenstein, Kaufer & Murphy, The Economics of Multi-Plant Operation 80, 94 (1975).

It should be noted, however, that lower estimates have been obtained using the survivor approach. For example, Anthony Copp found MES in PADD V to be only one percent of capacity and MES in PADDs I-IV was assessed at between 0.4 and 1.0 percent of capacity. A. Copp, Regulating Competition in Oil 46 (1976).

TABLE VI C-4.

Market Region	Jan. 1, 1982 Capacity (b/d crude runs)	MES as a % of Capacity (percent)
PADD V (excluding Hawaii and Alaska)	2,628,260	5.7
PADD IV	602,505	24.9
Illinois, Indiana, Kentucky, Michigan, Ohio, and Wisconsin	2,360,100	6.4
PADD III	7,278,698	2.1
PADDs I and III	8,941,839	1.7
PADDs I, II, and III	12,694,791	1.2
PADD II	3,752,952	4.0

Source: Dep't of Energy, EIA-0111, "Petroleum Refineries in the U.S. and U.S. Territories."

However, these data should be interpreted with caution, since a 150,000 b/d figure for the MES would be larger than many surviving refineries in the various PADDs and in fact would suggest that all of the refineries in certain PADDs are sub-optimally sized. The problem stems in part from the fact that the MES estimates do not reflect transportation costs which are relatively large in petroleum refining, particularly when compared with the magnitude of the cost savings resulting from increases in capacity beyond 100,000 b/d. For this reason, the usual estimates of efficient refinery size will generally not apply to plants processing local crude production to meet local demands. There is also some data suggesting that the cost disadvantage incurred by refineries of less than 150,000 b/d are not particularly large and that the major economies are realized by plants of only 60,000 b/d capacity.[46] Nelson even suggests that average operating costs are essentially flat for plants between 100,000 and 150,000 b/d and rise for larger plants.[47]

The influence of scale economies on the rate of entry depends not only on efficient refinery size but also on the size of the market, the elasticity of market demand, and the rate of growth of demand. For these reasons, the significance of the estimated MES must be evaluated in the context of specific markets at particular times. Obviously, scale economies are less likely to affect entry in the Gulf Coast and more likely at some locations in PADD IV.

Recent estimates of the cost of constructing a minimum efficient scale refinery vary. One major oil company projected the cost of building a sophisticated Gulf Coast

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46 Nelson, op. cit., at 79; DOE Contract Study, op. cit., at 46; Scherer, et al., op. cit., at 80.

47 Nelson, id. at 79.

refinery at $2.53 billion, while another major company estimated the cost of replacing its large complex refinery at close to $2 billion.[48]

d. History of entry into the domestic refining industry

While the actual record of entry into an industry does not by itself provide conclusive evidence bearing on the ease of entry,[49] it is nevertheless useful to examine historical entry patterns.

Between 1948 and 1978, 106[50] firms entered the U.S. refining industry through the construction of new refineries. In addition, a number of firms entered new geographic areas through the construction of refineries. However, the vast majority of these new refineries were extremely small and appear to be substantially sub-optimal in size. Table VI C-5 lists all of the new refineries built between 1948 and 1979 by de novo entrants to the industry which had a January 1, 1979 capacity of at least 50,000 b/d. De novo entry since 1979 has been even more skewed toward the construction of inefficiently small plants.

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48 Company document. Interview with major oil company.

Using 1977 data, the Oil and Gas Journal estimated that a 120,000 b/d catalytic cracking refinery would cost about $150 million. Oil & Gas J. (Oct. 26, 1981).

49 A high rate of entry into an industry would indicate that prices had reached a level at which entry appeared profitable but would not indicate whether the price level was high relative to the competitive price. Similarly, little or no entry would indicate that entry did not appear profitable, but would not indicate whether this was because price was close to the competitive level or because entry was very difficult.

50 Barbara Loveless, "Entry and Exit in U.S. Petroleum Refining, 1948-1978," API, April 1981, 42.

Table VI C-5. Large-Scale Entry Into the Refining Industry, 1950-1978

Year	Entrant name	Refinery location	Crude distillation capacity in thousands of barrels per day: initial	5 years after entry	1979	1982	Type of entry
1953	Suntide Refining	Corpus Christi, Tx	25	65.0	57	57.0	inter-regional[1]
1955	Great Northern Oil Co.	Rosemount, MN	22.2	33.3	127.3	127.3	New
1958	Amerada Hess Corp.	Sewaren, NJ	45.0	65.0	shutdown	shutdown	New
1963	Std Oil of California	Pascagoula, MS	100.0	160.0	280.0	280.0	inter-regional[2]
1967	Good Hope Refining	Good Hope, LA	6.5	8.5	80.0	100.0	New
1967	Sequoia Refining	Hercules, CA	25.0	26.0	53.3	shutdown	inter-regional[3]
1969	Exxon	Benicia, CA	72.0	87.0	99.0	106.0	inter-regional
1976	Ecol	Garyville, LA	200	255	200	255.0	New[4]

Source: The large-scale entrants are identified from an API list of new refineries constructed from 1950 to 1958. See American Petroleum Institute, "Trends in Refinery Construction in the United States," Discussion Paper #20, September 16, 1980, appendix 1.

Capacity 5 years after entry is from appendix 3 in Barbara Loveless, "Entry and Exit in U.S. Petroleum Refining, 1948-1978," American Petroleum Institute, Research Study #021, April 1981.

Capacity for years after 1978 is from the Department of Energy Refinery Surveys for the listed years. See Petroleum Refineries in the U.S. and U.S. Territories January 1, 19__." Energy Data Report, U.S. Department of Energy, Energy Information Administration.

1 Suntide was partially owned in 1953 by Sunray Oil which had refineries in Oklahoma.

2 Standard Oil of California had several refineries on the East Coast at this time. This refinery therefore represents interregional entry only if the Gulf coast is a separate market from the East Coast. Standard of California also had a small asphalt plant in Alabama at this time.

3 The relationship between Sequoia Refining and Gulf Oil is not entirely clear. This entry assumes that Sequoia Refining was not initially affiliated with Gulf.

4 This refinery was acquired by Marathon Oil before it began operating.

The most important reasons why new entry into the industry has predominately been the construction of inefficiently small plants had to do with the substantial subsidies provided to small refiners by the U.S. Government from 1959-1981. A second reason is that many of the new refineries were not intended to compete with the normal fuels-type refinery but to serve local markets. Thus, many of the refineries built in the 1948-1979 period were asphalt plants and others were built to top isolated crude production for local consumption.

Additional insight into the character of entry into oil refining is provided by a detailed examination of entry into the Gulf Coast refining region. Table VI C-6 lists all the new refineries built on the Gulf Coast between 1950 and 1982, their owners, their capacity and whether or not they represented entry.

A striking feature of this table, as well as the summary figures derived from it and presented in Table VI C-7, is that while 8 firms entered between 1950 and 1959 and 8 firms entered between 1959 and 1972, 32 firms entered between 1972 and 1982. The peculiar character of the post-1972 entrants is best illustrated by the fact that of the 14 pre-1972 entrants which still operated in 1981, 8 produced gasoline (3 of the others were asphalt plants), while only 6 of 31 post-1972 entrants which still operated in 1981 produced gasoline (only 1 of the others appears to be an asphalt plant).[51] Perhaps even more striking is the fact that none of the 17 refineries entering the Gulf Coast region after 1977 manufactured any gasoline in 1981.

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51 Department of Energy, EIA-87 data for 1981.

Table VI C-6. Entry into the Gulf Coast Refining Region, 1950-1982

Year	Entrant's name	Location	Crude distillation capacity in thousands of barrels per day: Initial	5 years after entry	January 1,1982	type of entry
1951	Canal Refining Co.	Church Point, LA	1.7	1.2	8.0	New
1951	Port Fuel Co.	Brownsville, TX	4.0	shutdown	shutdown	New
1953	Warrior Asphalt Corp.	Holt, AL	1.0	1.4	5.5	New
1953	Vulcan Asphalt Refining Co.	Cordova, AL	1.6	2.0	10.5	New
1953	Corpus Christi Refining	Corpus Christi, TX	1.7	shutdown	38.0	New
1953	Suntide Refining	Corpus Christi, TX	25.0	65.0	57.0	inter-regional
1956	Texas Asphalt Refining	Pasadena, TX	5.0	shutdown	shutdown	New
1958	Texas Gas Corp.	Winnie, TX	7.5	6.5	shutdown	New
1962	Monsanto	Chocolate Bayou, TX	5.9	4.8	37.194	inter-regional
1963	Std Oil of California	Pascagoula, MS	100	160.0	280.0	inter-regional
1966	Lamar Refining Co.	Lumberton, MS	1.0	2.0	5.8	New
1976	Goldking Petroleum	Krotz Springs, LA	5.0	48.0	shutdown	New
1975	Louisiana Land	Mobile, AL	30	41.3	41.3	New
1977	Raymal Refining LTD	Ingleside, TX	2.0	11.1	shutdown	New
1977	Shepard Oil Co.	Jennings, LA	5.0	10.0	shutdown	New
1977	Tipperary Corp.	Ingleside, TX	6.0	10.4	7.320	New
1977	Calcasieu Refining	Lake Charles, LA	6.5	16.0	14.0	New
1977	Sentry Refining	Corpus Christi, TX	10.0	30.0	25.0	New
1977	MT Airy Refining	MT Airy, LA	11.6	25.0	23.0	New
1977	Mobile Bay	Chickasaw, AL	16.8	28.1	26.6	New
1977	Bruin Refining	ST. James, LA	19.3	19.3	shutdown	New

Table VI C-6. Entry into the Gulf Coast Refining Region, 1950-1982--Continued

			Crude Distillation Capacity in thousands of barrels per day			
Year	Entrant's name	Location	Initial	5 years after entry	January 1,1982	type of entry
1967	Cracker Asphalt Co.	Moundville, AL	2.0	shutdown	shutdown	inter-regional
1967	Good Hope Refining	Good Hope, LA	6.5	8.5	100.0	New
1967	Alabama Refining	Theodore, AL	10.0	11.5	25.5	New
1968	S.W. Pallet Co.	ST. James, LA	3.0	6.0	20.0	New
1969	Southern Minerals	Corpus Christi, TX	5.5	shutdown	shutdown	New
1972	South Hampton Co.	Silsbee, TX	2	18.1	18.1	New
1975	Toro	Port Allen, LA	36	36	40	New
1975	ECOL	Garyville, LA	200	255	255	New
1976	Mid-Tex Refinery	Hearne, TX	.9	10.0	shutdown	New
1977	Erickson Refining	Port Neches, TX	30.0	30.0	shutdown	New
1978	Vicksburg Refining	Vicksburg, MS	8.5	7.9	7.9	New
1978	Ergon Refining	Vicksburg, MS	10.0	20.6	20.6	New
1978	TSS Refining	Jennings, LA	10.2	11.5	shutdown	New
1978	Central Louisiana Energy Co.	Mermentau, LA	10.4	11.0	13.5	New
1978	Uni Oil	Ingleside, TX	11.3	39.4	shutdown	New
1978	Friends Wood Refining Co.	Friendswood, TX	12.5	12.5	12.5	New
1979	Aweco	Lake Charles, LA	30	28.7	shutdown	New
1979	Mallard Resources	Gueydon, LA	7.5	7.4	7.4	New
1979	Sooner Refining	Darrow, LA	5.4	5.4	8.0	New
1979	International Processors	St. Rose, LA	28.6	28.6	28.6	New

Table VI C-6. Entry into the Gulf Coast Refining Region, 1950-1982--Continued

Year	Entrant's name	Location	Crude Distillation Capacity in thousands of barrels per day: Initial	January 1,1981	January 1, 1982	type of entry
1979	Gulf Energy Refining	Brownsville, TX	9.5	10.0	shutdown	New
1979	Petraco Valley Oil & Refining	Brownsville, TX	12.3	12.3	shutdown	New
1980	Texas Standard Refining	Houston, TX	2.0	2.0	shutdown	New
1980	Val Verde International	Brownsville, TX	1.0	1.0	shutdown	New
1980	Bronco Refining	Houston, TX	2.5	2.5	shutdown	New
1980	Dow Chemical	Oyster, TX	190.0	190.0	shutdown	New
1980	Natchez Refining	Natchez, MS	7.0	7.0	shutdown	New

Source: The list of entrants from 1950-1978 is from American Petroleum Institute, "Trends in Refinery Construction in the United States," Discussion Paper #20, appendix 1, September 16, 1980. Entrants from 1979-81 are identified from the Department of Energy Refinery Surveys for those years. See "Petroleum Refineries in the U.S. and U.S. Territories Jan 1, 19__," Energy Data Report, U.S. Department of Energy, Energy Information Administration. Information regarding the gasoline output and operational status of refineries is from summary data from the EIA-87 (refinery report) provided to the FTC by the U.S. Department of Energy, Energy Information Administration.

Table VI C-7. Summary of Entry into the Gulf Coast Refining Region, 1950-1982

	Date of Entry			
	1950-58	1959-71	1972-76	1977-82
Number of entrants	8	8	6	26
Number of entrants operating in 1981	6	7	6	25
Number of entrants manufacturing gasoline in 1981	4	4	5	1
Number of entrants operating year end 1981	4	6	4	11
Number of entrants operating April 1982	4	5	5	8

Source: Same as table VI-C-6.

Overall, it can be seen that although there have been a large number of refining entrants over the last thirty years, most entry has been through the building of small refineries that may not have been capable of survival, absent a regulatory bias toward small refineries. Periodically, however, there has been entry through the construction of large scale gasoline manufacturing refineries which has materially added to refining capacity although most of this entry has been inter-regional rather than completely de novo.

e. Capacity expansions by existing refiners

Expansions by existing competitors can have procompetitive effects similar to de novo entry. There are a number of cases, for instance, of a toehold entry by acquisition in the industry followed by expansion of the acquired refinery's capacity. Table VI C-8 lists entrants by acquisition that are now ranked among the top 30 U.S. refiners, after having made significant capacity expansions. Where more than one line is presented for a company, that represents a subsequent acquisition or refinery construction. It is noteworthy that these expansions often took five years or more to be implemented.

From 1948 to 1978, U.S. operating refining capacity grew from 5,825,566 barrels per day to 16,793,724 barrels per day—an increase of almost 190 percent. The incumbent firms in 1948 have accounted for approximately 85 percent of this increase in refinery capacity. Expansion by these incumbents, expansion by entrants, and new entry have all contributed to refining industry deconcentration over the past decade.[52]

Table VI C-9 shows that national 4-, 8-, and 20-firm concentration ratios have all fallen between 1970 and 1980, and the market share of the fringe has increased considerably. The largest firms appear to have suffered the greatest decline due to the expansion of others. Similar trends are also generally present in the regional-concentration data presented in Table VI C-2, supra.

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52 This Table also shows that concentration rose only in the 1960s, when there was a crude import quota, while it fell in the 1950s and 1970s, when there was no import quota.

Table VI C-8

Entrants by Acquisition Now Among the Top 30 U.S. Refiners Which Have Made Significant Capacity Expansions 1950-1982

Year of Entry	Firm	State	Capacity When Acquired or Constructed	Capacity 5 Years Later	Capacity 1/1/82 (DOE)	DOE Rank (OGJ Rank)
			------(000 b/d crude runs)------			
1970	Champlin	OK	37.0	53.8	53.8	17th (17th)
	Acquired 1970	TX	52.5	67.7	155.0	
	Constr. 1971	CA	30.0	30.7	60.0	
1962	Coastal Corp.	TX	29 5	54.0	92.0	19th (21st)
	Acquired 1973	KA	24.7	28.0	28.0[1]	
	Acquired 1977	CA	53.3	85.0	85.0[1]	
1973	GHR Energy	LA	8.5	80.0	100.0[2]	32nd (18th)
1969	Koch	MN	77.3	109.8	127.3	22nd
	Acquired 1981	TX	57.0	57.0		
1959	Murphy Corp.	WI	14.0	20.0	39.0	27th
	Acquired 1962	LA	22.0	26.0	90.2	
1951	Texas City Ref	TX	50.0	35.0	86.5	29th
1956	Tenneco	LA	18.0	40.0	114.0	30th

1 Inactive Refinery.

2 The Oil and Gas Journal 138 (Mar. 22, 1982) lists GHR Energy with a capacity of 300,000 b/d. This reflects recent expansions.

Sources: Dep't of Energy, "Petroleum Refineries in the United States and U.S. Territories" (Jan. 1, 1982).

Oil and Gas Journal 138 (Mar. 22, 1982).

Table VI C-9

Market Shares of Various Groups of Refining Firms 1970 and 1980

	Refinery Runs	
	1970	1980
	(Percent)	
Top 4 firms	34.2%	31.4%
Firms outside top 4	65.8	68.6
5th-8th ranked firms	26.8	22.9
Top 8 firms	61.0	54.3
Firms outside top 8	39.0	45.7
9th-20th ranked firms	30.1	26.7
Top 20 firms	91.1	81.0
Firms outside top 20	8.9	19.0

	Refining Capacity	
	1970	1980
	(Percent)	
Top 4 firms	32.5%	29.0%
Firms outside top 4	67.5	71.0
5th-8th ranked firms	5.0	20.0
Top 8 firms	57.5	49.0
Firms outside top 8	42.5	51.0
9th-20th ranked firms	26.8	25.5
Top 20 firms	84.3	74.5
Firms outside top 20	15.7	25.5

Source: American Petroleum Institute, Market Shares and Individual Company Data for U.S. Energy Markets, Discussion Paper No. 014R (1980 and 1981).

It is important to recognize, however, that government subsidies which no longer exist provided a substantial impetus for the expansion of the fringe. The most important of these subsidies was provided by the sliding scale allocation of imports under the mandatory oil import program and the small refiner bias to the entitlement program.[53] The small refiner bias, for instance, provided a benefit of up to $1.85 per barrel in 1978.[54] Recent reports indicate that many of the firms that were nourished by these federal programs may not be able to survive the decontrol process; 33 refineries have recently closed down.[55] The figures on entry reflect the fact that entry will respond to profitable opportunities, and the decisions with respect to size of entry will be similarly motivated.

f. Conclusion

The long-term role of entry is exceedingly difficult to assess in examining competition in the refining industry. Additions to industry capacity in the past have arisen primarily from expansion of existing capacity, and, while there have been hundreds of cases of small refinery entry encouraged by various regulatory programs over the past 30 years, entry through the construction of large scale refineries has not frequently occurred. The central reasons for this appear to relate to environmental opposition in certain areas and difficulties in obtaining reliable crude supply. However, any such impediments to new entry have not led to an increase in concentration in refining — and indeed, a net decrease in concentration has occurred over the past years, although there

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53 For a discussion of these regulations, see: Bureau of Competition, Federal Trade Commission, The Small Refiner Bias to the Entitlements Program and the Open Market Credit (March 1977) (comments to Department of Energy, docket no. ERA-R-78-3). See also Federal Energy Administration, Impact of Mandatory Petroleum Allocation, Price and Other Regulations on the Profitability, Competitive Viability, and Ease of Entry of Independent Refiners and Small Refiners (1977).

54 See 43 Fed. Reg. 54,652, 54,654 (Nov. 22, 1978).

55 Oil & Gas J. 79-81 (March 22, 1982).

are signs that this decline has not continued subsequent to 1980. In addition, a number of programs that previously limited the availability of crude oil to new entrants were discontinued in the early 1970s.[56] The demise of these regulations may have provided an impetus for attempted large scale entries. Nevertheless, if current trends in demand continue, large scale de novo entry would seem unlikely. As the regulatory impetus for small scale entry has been removed, moreover, the competitive impact of refining mergers may have to be examined more closely.

6. Interdependence and competition in the refining industry

The level of concentration in refining markets varies from area to area, but only in a few regions does the level of concentration reach those levels where the probability of collusive behavior would increase.[57] Furthermore, the existence of significant differences between firms may militate against successful collusion. Market participants range from international oil companies to single plant entrepreneurs, use widely different technologies, depend on access to varying grades of crude oil, and vary substantially in the extent of their vertical integration. Together, low concentration in many markets, the number of firms, and the diversity of these firms in certain regional markets suggest

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56 The mandatory oil import program limited imports until 1973. Moreover, state-run prorationing programs made it difficult for newcomers to acquire adequate domestic supplies. The newcomer would have to request additional crude from a state regulatory authority through a nomination process. The authority, if it granted the request, would raise production statewide. This meant that the entrant would be forced to bundle small volumes of crude oil from various fields across the state. This must have been a substantial deterrent to most potential entrants.

57 Although pure monopoly ends and oligopoly begins when the number of sellers rises from one or two, it is difficult to specify on a priori grounds exactly where oligopoly shades into a competitive market structure. The tendency is for the probability of collusion to vary inversely with the number of independent firms. Kamershen, "An Economic Approach to the Detection and Proof of Collusion," 17 Am. Bus. L. J. 196 (1979). One authority posits that, "As a very crude general rule, if evenly matched firms supply homogeneous products in a well-defined market, they are likely to begin ignoring their influence on price when their number exceeds 10 or 12." F. Scherer, Industrial Market Structure and Economic Performance 199 (2d ed. 1980). See supra pp. 154-155, for a general discussion of collusion and the market characteristics that can support it.

that if these refining markets are like most other markets, there should be little concern for collusion.

A final question to be addressed is whether there are special features of refining markets that could facilitate collusion, even in the presence of low concentration and firm diversity. Documents gathered in the course of FTC investigations suggest that the answer to this question may not be simple.

a. Output determined in response to marginal revenue effects

In the perfectly competitive market envisioned in textbooks, firms take the industry price as fixed, producing as much as they can so long as the costs of producing each new unit remain below the price they will receive for that unit. By way of contrast, when a firm can persistently raise market price by altering its output, it has market power. Successful exploitation of this market power, of course, generally depends on the cooperation of one's competitors. Various internal documents prepared over the years by various oil companies suggest that some oil companies acted in the belief that they had such power. For example, one oil company's documents, consisting of studies in 1971, posited that by cutting back on its output the company could affect the marginal revenue and price it received. Indeed, the company carefully calculated its power to affect price in relevant markets and even calculated the amount per gallon that the market price would change due to its marginal sale of product, stating that "the Supply Department's wholesale gasoline sales have influence not only on wholesale prices but also on retail prices, and that this effect must be considered in order to maximize overall profits." The company's "basic assumptions" underlying its profit maximizing behavior were stated to be that the company's "marginal wholesale activities have a predictable effect on wholesale prices in the Gulf Coast," and that "[a] change in Gulf Coast wholesale prices will lead to a predictable change in retail market prices (DTW) in [our company's] marketing areas."

Another analytical document from this company provides a theoretical justification for its profit-maximizing behavior, assuming its goal was "one of adjusting the firm's marginal output to the point where marginal revenue equals marginal cost." After assuming that "the petroleum industry consists of relatively few firms with important market shares and a large number of smaller firms with minor market shares," the document concludes that "the initial capital requirements tend to act as a practical economic barrier to entry in a significant way."

The interpretation of these documents, however, should recognize that the demand for gasoline is very inelastic, especially in the short run. Thus, a major supplier in a market may recognize that significant changes in its output will affect market prices, at least in the short run. The ability to sustain higher prices may be very unlikely in many markets, however, because product can be moved into such markets more easily and concentration may be lower than that required to accommodate successful collusion.

Oil company documents also indicate that major refiners apparently have sometimes recognized the importance of practicing individual self restraint in refining strategy. As was observed within a major oil company:

> The major refiner does have potential crude for making more products. However, he will not use this potential because he knows market demand is constant at any given point in time. He will have decided what his market share should be and he will not attempt to increase his product sales because he believes this will cause market price deterioration.

Another example indicating the same self-restraint is provided by a different major oil company. A company document observed that in some circumstances, "we deliberately refuse to make products with spare refining capacity using purchased crude." The document goes on to explain that "[w]hen we make such a decision it is because we conclude that the extra products dumped on the market would force comparable action by competitors and lower the market value to our marginal cost ex spare refining capacity."

The expressed concern about market price deterioration is understandable because petroleum refining is an industry characterized by highly capital-intensive production processes and very inelastic demand in the short run. Scherer notes that this type of industry may be "particularly susceptible to pricing discipline breakdowns when a cyclical or secular decline in demand forces member firms to operate well below designed plant capacity."[58] There would thus be an incentive for refiners to cooperate to assure that capacity does not "exceed demand" as defined by the industry and that price instability does not develop.[59]

b. Interrelationships among major refiners

Over the years, the oil industry majors have been involved in a number of contacts arising out of processing arrangements, exchanges, and other interfirm accommodations. For example, in 1966, two major oil companies discussed a processing contract, and utilized the opportunity to explore their respective refinery supply and expansion plans, according to internal documents of one of the participants:

> With both companies considering possible refinery expansion East of the Rockies and West of Rockies at about the same time, there is scope for investigation of possibly mutually attractive reciprocal processing deals, whereby each company will build a large and efficient refinery in one area only, and process for the other company.

In the early 1970s, before the refining shortage, major refiners' internal company documents suggest their individual perception that low profit returns on refining were due to overcapacity and the presence of increasingly efficient, independent competitors. In this situation, one company document indicates that two major oil

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58 F. Scherer, <u>supra</u> note 52, at 206.

59 It is not surprising that major refiners would recognize their effect on market prices in the short run and would in principle like to cooperate to prevent "deterioration" of prices. As noted above, however, such cooperation may be more difficult in the long run, and the low concentration in many markets may impede cooperative efforts.

companies entered into a processing contract in 1971 to avoid construction of additional capacity in their respective markets, and prevent "a major expansion by competition."[60]

c. **Intergroup rivalry between majors and independents**

The refining industry is not homogeneous. There is a great deal of diversity among refiners, although within the industry some groups of refiners may share common ties. One group, already discussed, consists of major integrated refiners. Another group is composed of independent refiners (largely less integrated than the majors). There is a certain amount of rivalry between these two groups, as evidenced by a major company's statement that "[t]he chief competitor in setting refined product prices, particularly gasoline, is now viewed as the independent refiner and marketer."[61]

There is some indication that at least one major took into account the effects that its particular decision to shut down or sell a refinery would have on the ability of independents to expand in its marketing area. The possible intent may have been to prevent the price erosion in certain markets which might occur if independents were to secure greater refinery capacity.[62]

According to another company's internal documents, a major refiner reviewed its "exchange activities" in 1973 to avoid providing independent marketers with any refiner's product cost advantage. The company even considered "increasing purchases from historical suppliers of private brand marketers" to diminish their supplies. Nonetheless, some majors believed that other majors may have supplied independents at times, indicating that efforts at curtailing supply flows to independents was flawed.[63]

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60 Company document.

61 Company document.

62 Company document.

63 Company document.

The competitive picture is less than crystal clear. It appears that independents have grown and majors did not successfully thwart such growth. Nonetheless, some activities by majors may allow majors to raise prices above costs for at least limited periods of time. An ability to manage supply by coordinating refining capacity and limiting product inflow in order to achieve a degree of balance that keeps price stable is an important factor. In such an environment, mergers should be closely scrutinized to assess whether collusive behavior may be more likely.

7. **The history of major refining acquisitions for the period 1948-1980**

This section assesses the impact on competition of refining acquisitions by the 16 largest oil companies for the period from 1948 to 1980. As can be seen from the list of such mergers in Table VI C-10, most were so small that refining concentration was not noticeably affected in the relevant geographic markets. In addition, many larger acquisitions were market extensions across the Rockies, with no major impact on concentration. Only a few of the larger mergers had a noticeable impact on market concentration, and their details are discussed below. However, when these mergers are examined in the perspective of the 10 or 15 years that have passed since they were consummated, no adverse effects on economic performance are apparent.

Seven acquisitions of more than 100,000 bbl/d of capacity were made since 1948. Of these, three were clear market-extension mergers, involving either West Coast refiners entering the region east of the Rockies, or eastern refiners entering the West Coast. First, when Atlantic's two refineries in Texas and Philadelphia were combined with Richfield's California refinery to form Atlantic-Richfield, concentration was not increased in either region. This was equally true when Union Oil entered the region east of the Rockies by acquiring four refineries in Illinois, Ohio, and Texas. Phillips' acquisition of Getty's California refinery in 1966, Gulf's acquisition of Wilshire's California refinery in 1960, and Conoco's acquisition of three California refineries of

Douglas Oil, were also cases of entry into the West Coast, with no resultant increase in market concentration.

Mergers that involve a refiner established in the area east of the Rockies acquiring an additional refinery in that area are sometimes difficult to analyze because of conflicting evidence regarding whether the entire area east of the Rockies may be considered a single market, or whether two or more separate markets might exist. Such mergers could therefore be analyzed in the context of a broad market (PADDs I, II, and III); two separate markets consisting of the Gulf Coast-East Coast area (PADDs I and III), and the Midcontinent area (PADD II); or perhaps even in the context of different regions.

Sun Oil Company's acquisition of Sunray in 1968 resulted in a noticeable increase in market concentration, but the exact amount of increase depends on how geographic markets are delineated. Sun previously owned two refineries, with January 1, 1969, capacity as follows: Marcus Hook, Pennsylvania (158,000 bbl/d); and Toledo, Ohio (112,000 bbl/d). It acquired two refineries in Oklahoma and one in Texas from Sunray (see Table VI C-10).

The most significant increase in concentration appears if PADD II (the Midcontinent region) is treated as a relevant geographic market. In that region (which includes Oklahoma), Sunray had a 4.3 percent market share, while Sun had a 3.5 percent market share and the combined company was the second largest refinery in PADD II after the merger. However, given these figures, there is little evidence that economic performance was adversely affected. Market concentration was not high even after the merger, and by 1978 three firms had expanded their capacity so that Sun was ranked fifth.

If PADD II is a distinct market, PADDs I and III combined may also be a distinct market. In that area, Sunray had a 0.7 percent market share and Sun had 2.6 percent prior to the acquisition. Thus, the combined firm was not among the top eight in that market, and given the moderate degree of concentration, no competitive injury appears to have occurred.

Little or no competitive effects were likely, as well, if PADDs I, II, and III combined are viewed as the relevant market instead of the smaller areas analyzed above. Sunray had a 1.9 percent market share, while Sun had 2.9 percent prior to the merger. Four firm concentration in that market in 1970 was only 35.2 percent, and the combined firm ranked eighth. Furthermore, Sun had fallen from the top eight by 1978.

Atlantic Richfield's acquisition of Sinclair in 1969 involved the largest amount of refining capacity of all acquisitions by the top 16 oil companies. Four Sinclair refineries changed ownership. Three (located in Texas, Wyoming and Indiana) with a combined capacity of 369,200 bbl/d on January 1, 1970 went to ARCO. One (located in Pennsylvania) went to British Petroleum, having a capacity of 105,000 bbl/d. In addition, pursuant to the consent agreement that allowed this merger, ARCO sold its own Texas refinery, having a capacity of 84,000 bbl/d.

The effect of this transaction on market concentration again depends on how geographic markets are delineated. If PADDs I and III are deemed an appropriate market, ARCO increased its share of capacity from 3.9 percent to 5.7 percent, making it the sixth largest firm in that market in 1970. This increased share was produced because the Texas refinery it acquired from Sinclair (200,000 bbl/d) was substantially larger than the one it divested to BP (84,000 bbl/d). Four firm concentration in this market was 40.9 percent in 1970.

If, instead, PADDs I, II, and III are the relevant market, ARCO increased its market share from 2.6 to 5.2 percent. This increase was produced by the addition of Sinclair's former Indiana refinery as well as the exchange of Texas refineries noted above. As a result of the acquisition, ARCO became the seventh largest refiner in this market in 1970. ARCO did not maintain its position in the top eight, however, since the acquired Indiana refinery was sold in 1976. Four firm concentration in this market in 1970, moreover, was only 35.2 percent.

The sales to British Petroleum did not have an adverse impact on concentration, as BP was a new entrant into the United States. After the acquisition, BP had a 3.0 percent share of a PADD I and III market and 2.0 percent of a PADD I, II, and III market.

Very soon after BP acquired those two refineries, it acquired a controlling interest in Standard Oil of Ohio ("SOHIO"), which owned two refineries in Ohio having capacities of 117,600 and 54,000 bbl/d. If PADD II is treated as a distinct market, these Ohio refineries would not be in the same market as BP's refineries in Texas and Pennsylvania, and thus concentration would not be increased. If the larger market of PADDs I, II, and III is used to evaluate the merger, horizontal overlap is present, but the market share of the combined firm is only 3.8 percent, putting it outside the top eight refiners in that market. Also, four firm concentration was only 35.2 percent in this market in 1970. It is also noteworthy that SOHIO subsequently sold the Texas refinery in 1973 to American Petrofina.

Table VI C-10 Acquisitions of Operating Refineries by the 16 Largest Oil Companies

Year	Refinery acquired from	State	Capacity	Acquiring cc
1948	Allied Oil Corp.	OH	12,000	Ashland
1949	Aetna	KY	8,000	Ashland
1949	Valvoline	PA	4,000	Ashland
1950	Northwestern Refining Co.	IL	4,600	Ashland
1950	Frontier	NJ	15,000	Ashland
1951	National Ref.	OH	9,000	Ashland
1959	Louisville Ref.	KY	11,000	Ashland
1970	Northwestern Refining Co.	MN	47,500	Ashland
1948	Root Petroleum	AR	23,000	Standard of Ind
1948	Petroleum Corp.	CA	6,000	Standard of Ind
1949	Coastal Petroleum	AL	6,000	Standard of Cal
1959	International Ref.	MN	15,000	Conoco
1959	Malco Asp. & Ref.	MN	11,500	Conoco
1961	Douglas Oil	CA	8,250	Conoco
	Douglas Oil	CA	4,000	Conoco
	Douglas Oil	CA	9,000	Conoco
			21,750	
1965	Empire	CO	5,000	Conoco
1970	Sequoia Ref.	OK	34,000	Conoco
1960	Wilshire	CA	33,000	Gulf
1963	Pontiac Eastern	MS	18,600	Gulf
1970	Sequoia Ref.	CA	26,000	Gulf
1964	El Paso Nat. Gas	NM	12,800	Shell
		TX	22,600	
			35,400	
1954	Sunray	CA		Union
1965	Pure Oil	IL	53,000	Union
	Pure Oil	OH	24,000	
	Pure Oil	OH	30,000	
		TX	88,500	
			195,500	
1965	Richfield	CA	165,000	Atlantic Richfie

able VI C-10 Acquisitions of Operating Refineries by the 16 Largest Oil Companies Con'td.

'ear	Refining acquired from	State	Capacity	Acquiring company
.966	Getty	CA	120,000	Phillips
.968	Sunray	OK	90,000	Sun
		OK	47,000	
		TX	45,000	
			182,000	
.970	PPG Industries	TX	5,000	Sun
.969	Sinclair	TX	200,000	Atlantic Richfield
		WY	29,200	
		IN	140,000	
			369,200	
.969	Atlantic Richfield	TX	84,000	British Petroleum
.969	Sinclair	PA	105,000	
			189,000	
.969	Sohio	OH	54,000	British Petroleum
		OH	117,600	British Petroleum

ource: Company annual reports, Moody's Industrial Manual and "Entry and Exit in U.S. Petroleum Refining, 1948-1978," American Petroleum Institute Research Study 021, Appendix 3, April 1981.

8. Conclusion

The past history of major refiner mergers suggests the absence of significant effe either on concentration or on competition. At the present time, concentration levels certain regional markets may raise antitrust concerns in the context of specific mergers firms in those areas where new entry may be retarded because of environmental regulatio and crude access problems. Significant de novo entry has apparently been difficult a therefore expansion of capacity has largely occurred through previously established firms. view of the discussion above of interdependent firm behavior, a significant merger occurri in some markets would have to be examined closely to determine whether it might furth reinforce such behavior and enhance incentives to collude.

D. PIPELINES

1. Overview

Overall, pipelines compete in broad markets consisting of an array of other transportation modes. In particular locations, pipelines alone may be the only effective supplier of transportation services. In some cases pipelines are owned by individual companies and in other cases ownership consists of one of a variety of forms of joint venture. As in any market, analysis of the effect of mergers on the control of pipelines focuses initially on the structural parameters of concentration and entry conditions. Thus, concern about mergers affecting control of pipelines depends on the definition of the market, on the number of pipelines in the market, and their existing ownership structure, on the degree to which effective competition is offered by tankers, trucks, or barges, and on the effectiveness of regulation in limiting the exercise of market power. Pipelines are regulated by the federal government. If regulation is eased, antitrust scrutiny should rise commensurately.

In the following discussion, we briefly consider the above factors and their relevance to an assessment of pipeline competition. Because of difficulty in obtaining the necessary data, the discussion of markets here is more general then that of crude oil and refining, in that it contains less analysis concerning possible geographic markets. Consequently, this section presents no figures on pipeline merger activity, and its effects on market concentration.

2. Product market definition

a. Defining a product market

Determination of the relevant product market in which to examine petroleum pipeline transportation competition requires consideration of the various types of available transport services. The aim is to assess the degree of competition faced by petroleum pipelines from other modes of transportation at each stage of transportation: crude oil gathering services, bulk movement of crude oil to refineries, bulk movement of petroleum products from refineries to central distribution points, and localized distribution of petroleum products. Each stage may be examined individually to determine the extent to which competitors may be likely to exercise a constraining influence on a pipeline's tariff, and therefore delivered cost.[1]

The ability of alternative modes to perform economically each of these transportation functions may be dictated by a variety of physical characteristics of the geographic market, such as the proximity of navigable waterways, the distances over which products are shipped, the type of products shipped, and the aggregate volumes shipped. Thus, barges and tankers may offer substantial competition to pipelines in markets containing accessible waterways. Shipping distances, and the frequency and regularity of service, also are relevant to the selection of suitable modes of transport. In addition, aggregate shipping volumes affect the economics of alternative transportation modes. Dramatic scale economies provide pipelines with a substantial cost advantage over trucks, railroads and barges in the transportation of large volumes of petroleum over long distances.[2] The type of product to be shipped may be another determinative

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1 Wolbert presented an estimate of 1979 transportation costs for the various modes of transportation in cents per 100 barrel miles to be in the following ranges:

tanker	1 - 6
pipeline	2.5 - 12
barge	4 - 15
rail	11.5 - 60
truck	51.7 - 74.75

Wolbert, U.S. Oil Pipelines at app. A (1979) (statement of Ulysses J. LeGrange, Comptroller, Exxon Corp., before FERC).

2 Id. at 132. Scale economies arise because, as pipeline diameter increases, capital costs per barrel of capacity decline. In addition, pipe friction decreases as the diameter of a pipeline rises, with a resulting drop in per barrel pumping horsepower requirements. See Cookenboo, "Costs of Operating Crude Oil Pipelines," (1954) (Rice Institute Pamphlet); Pearl & Enos, "Engineering Production Functions and Technological Progress," 24 J. of Ind. Econ. (Sept. 1975); Kennedy & Stueve, "Here's Shortcut Method for Sizing Crude Oil Pipe Lines," Oil & Gas J. 183 (Sept. 21, 1953); White, "Economies of Scale Applies in Long-distance Pipeline Transport," Oil & Gas J. 149 (Jan. 27, 1969). Economies of scale will also be realized by barges and tankers.

factor in selection of a suitable mode of transport. For example, heavier petroleum products may not lend themselves to transportation through pipelines. Thus, the suitability of particular transportation modes to the product and transportation service required must be considered in assessing the scope of competition in transportation services.

b. Transport of crude oil

1. Crude oil gathering services

Gathering services are less a transportation function than a process of aggregating and drawing together the crude oil from scattered producing wells. This collection process may be performed most economically by pipeline, except in areas of low or uncertain production, where trucking or barging may be used due to their greater flexibility and lower capital investment.[3] In areas served by pipelines, wells not connected to a pipeline are likely to face a serious cost disadvantage vis-a-vis connected wells. Gathering pipelines collect the crude oil in the field and transport the crude oil to central collecting points for transportation through a crude oil trunk pipeline. The crude oil is delivered by the gathering system, either directly to a refinery or to a port of lading for transportation by barge or tanker to a refinery. Because small fields may have only one gathering line (while larger fields may have several lines), a producer is relatively limited in his ability to sell crude oil other than to owners of existing gathering lines.

2. Movement of crude oil to refineries

In the movement of crude oil to refineries, pipelines are the preeminent mode on land for long-haul transportation. Where a water route is available, water carriers may compete with pipelines for long-distance, large-volume shipments. In 1980, 75 percent of intrastate and interstate refinery receipts of crude oil was shipped via pipeline

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3 Dep't of Transp. & Dep't of Energy, National Energy Transportation Study 6 (1980) [hereinafter cited as Transportation Study].

exclusively; 21 percent traveled by tankers and barges; and 4 percent was carried via tank cars and trucks.[4] Substantial increases in intermodal movements are projected by 1985 as a result of pipeline and tanker movements of Alaskan crude oil. Additionally, some increases are projected between 1985 and 1990 for crude oil traffic by rail, inland waterways, and domestic deep draft shipping, because existing pipelines in some areas are not expected to be adequate to carry 1990 projected levels of traffic.[5]

c. **Transport of petroleum products**

1. **Movement of petroleum products from refineries to central distribution points**

Pipelines are used extensively to handle the lighter, less viscous fluids such as gasoline and distillates, whereas the heavier products, such as residual fuel oil, waxes, lubes, asphalt, and coke must be transported by other modes.[6] In 1976, trunk pipelines

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4 Dep't of Energy, Energy Data Reports, Crude Petroleum, Petroleum Products and Natural Gas Liquids: 1980 at table 13 [hereinafter cited as 1980 Energy Data Reports]. United States crude oil movements by tanker consist primarily of movements from Alaska to the West Coast and the Gulf Coast, and deliveries of imported crude oil to coastal refineries and to pipelines for connecting inland transportation.

These figures may be broken down by PADD districts: PADD I: pipelines - 35 percent, tank cars and trucks - 10 percent, and tankers and barges - 55 percent; PADD II: pipelines - 96 percent, tank cars and trucks - 2 percent, and tankers and barges 2 percent, PADD III: pipelines - 81 percent, tank cars and trucks - 4 percent, and tankers and barges 15 percent; PADD IV: pipelines - 90 percent, and tank cars and trucks - 10 percent; and PADD V: pipelines 41 percent, tank cars and trucks - 4 percent, and tankers and barges - 55 percent. With respect to refinery receipts of foreign crude: PADD I: pipelines - 4 percent, tankers and barges - 96 percent; PADD II: pipelines - 97 percent, tankers and barges - 3 percent; PADD III: pipelines - 4 percent, tankers and barges - 96 percent; PADD IV: pipelines - 100 percent; and PADD V: pipelines - 5 percent, tanker and barges - 95 percent. Id. In fact, pipelines acccounted for 96 percent of intrastate and interstate refinery receipts for PADD II and 81 percent for PADD III. Pipelines also transported 97 percent of foreign crude refinery receipts for PADD II. Id. at tables 26, 29.

5 Transportation Study, supra note 3, at 42. New pipeline construction may augment the ability of the crude oil pipeline system to transport projected crude oil movements, thus obviating the need for expanded use of alternative modes of transport.

6 Marathon Pipe Line Company, An Analysis of Certain Considerations Relating to Suggestions of Vertical Oil Pipeline Divestiture Within the Continental United (Continued)

carried over 3.8 billion barrels of petroleum products or approximately 35 percent of total domestic movements of petroleum products.[7]

Barges carry petroleum product through many river systems in the United States,[8] and together with coastal tankers serve areas not served by major pipelines. Barges are also used to carry product between major pipeline terminals and waterside wholesale terminals.[9] For example, in 1980, barge and tanker shipments accounted for approximately 40 percent of total product shipments between the Gulf Coast and the East Coast.[10] Competition from tankers and barges is confined, however, to areas accessible to navigable waterways, and the use of barges is further limited by the freezing of waterways in the northern inland portion of the United States. An analysis recently prepared for the Association of Oil Pipelines points out that of the 59 metropolitan areas with 1975 population over 500,000, 43 have major ports, 6 are within 50 miles of a major port, and 3 are on a short haul of a pipeline whose long haul is to major ports. Further, the study reported, 38 of the 54 largest refining centers, representing 87 percent of refining capacity, have water access.[11]

States 58 (1978) (submission to the Dep't of Justice) cited by Wolbert, supra note 1, at 132.

7 Gen. Accounting Office, Petroleum Pipeline Rates and Competition - Issues Long Neglected by Federal Regulators and in Need of Attention 1 (July 13, 1979) [hereinafter cited as GAO Report]; Transportation Study, supra note 3, at 93-94.

8 These include: the Mississippi River as far north as Minneapolis; the Illinois River to Chicago; the Ohio River to Pittsburgh; the Missouri River into Nebraska; the Arkansas River into Oklahoma; the Columbia and Snake Rivers into Washington, Oregon, and Idaho; the Tennessee River into Chattanooga and Knoxville; the Warrior and the Alabama Rivers throughout Alabama; and the Hudson River into upstate New York and Vermont.

9 Transportation Study, supra note 3, at 6.

10 1980 Energy Data Reports.

11 E. Mitchell, A Study of Oil Pipeline Competition 20, 80-81 (Apr. 1982) (Assoc. of Oil Pipelines). In addition, the study noted that barges and tankers account for 48 percent of all ton-miles of refined products transported within the United States, and 41 percent of all crude oil. Id. at 21 citing Assoc. of Oil Pipelines, "Shifts in Petroleum Transportation" (Sept. 1981). Additionally, shipments of foreign crude (Continued)

However, water transportation does not always compete effectively with pipelines. For example, where the cost of pipeline transportation is substantially lower than the comparable tanker rates, tanker competition could not constrain pipeline tariffs to just cover costs. The Colonial Pipeline is one case where the more efficient pipeline mode has been able to displace higher-cost water transportation. This pipeline extends from the Texas Gulf Coast to northern New Jersey. Once the pipeline was completed in 1963, waterborne movements from PADD III to PADD I fell sharply. In 1980, 76.4 percent of gasoline was transported from PADD III to PADD I by pipeline.[12] This is in part due to Colonial's lower tariffs. In 1978, for example, the average tanker rate from Houston to New York was two and one half times that of Colonial, or $1.29 per barrel as opposed to 52 cents per barrel.[13]

2. Distribution of petroleum products

Trucks are used to transport petroleum products for short haul movement of relatively small volumes. They account for virtually all final movement of gasoline and fuel oil to retail outlets. Rail transportation is utilized almost exclusively for the shipment of small volumes of specialty products which cannot economically be transported via pipeline.[14] Generally, railroads are used in shipments greater than 200 miles where pipelines cannot be justified and water transportation is not available. In 1976, rail traffic accounted for 1.83 percent of total petroleum products movement in the United States.[15]

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oil into United States ports are about two and one half times as great as reported domestic water shipments.

12 1980 Energy Data Reports, supra note 4, at tables 26, 29.

13 Colonial Pipeline Co., Performance and Trends 2 (1978).

14 Transportation Study, supra note 3, at 6.

15 Wolbert, supra note 1, at app. L. Water carriers accounted for 26% of product movements in 1976 and motor carriers accounted for 36%. Id.

d. Other factors

Although crude oil and petroleum product transportation services often constitute separate markets, they may in some situations compete in a broader combined market. Transportation modes may, in particular instances, transport both crude oil and petroleum products. In addition, consumers in a market for petroleum products may be supplied by local refineries, which rely on crude oil movements into the market, or by distant refineries which supply the market through shipments of petroleum products. In such a situation, crude oil and petroleum product pipelines would be in competition. Increases in crude pipeline tariffs could lead to reduced refinery runs and reduced crude shipments by refiners into the region and corresponding increased shipments of petroleum products into the region by distant refiners via product pipelines. However, it should be recognized that although all refined products can be produced from crude oil transported by a pipeline to a refinery, not all products can be transported by pipeline. For example, residual fuel oils, lubricating oils, coke, and asphalt are incompatible with product pipeline movement. This may limit the degree of competition between crude oil and petroleum product pipelines.

e. Conclusion

The relevant product market for the transportation of crude oil or petroleum products for purposes of merger analysis should embrace economically substitutable petroleum transportation services. The determination of what alternative transportation vehicles and modes should be included in such a transportation services market must be based upon an assessment of transportation alternatives in each case. In such an analysis, the clear cost advantages of large diameter petroleum pipelines for long-haul movements may justify their treatment as a distinct product market, notwithstanding the existence of higher cost (though feasible) transportation alternatives. Assessment of the product market in this manner would suggest which competitors may be likely to exercise a constraining influence on a pipeline's tariff and conditions of service.

3. Geographic market definition

As previously noted, petroleum pipelines provide distinct transportation services at different levels of the industry, performing crude oil gathering at the local level, moving crude oil from producing areas or coastal ports to refining centers, transporting petroleum products from refining centers to petroleum product market areas, and facilitating product distribution to local markets. The foundation underlying the definition of geographic markets for petroleum pipelines is essentially the same as that for all products: the aim is to include all locations that contain modes of transportation that are reasonably good substitutes for each other. Thus, the issue is whether pipelines (or other modes of transportation that are in the same product market) located elsewhere would be able to prevent a particular pipeline from raising its tariff, if the alternative mode of transport had excess capacity. If these other modes of transport have that ability, they should be included in the same geographic market.

Turning this standard into concrete estimates is somewhat more complicated for pipelines than it is for other product markets, since pipelines themselves involve a geographic dimension.[16] However, a geographic market can be defined by focusing on

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16 The existing literature on petroleum pipelines provides three different spatial perspectives on the relevant petroleum transportation markets. The first views the relevant transportation market as national, suggesting that all pipelines in the United States are good substitutes for each other. This view is implicit in studies that use industry wide data, such as barrel-miles of petroleum transportation, to measure concentration. The second approach views petroleum transportation markets in terms of point to point transportation or transportation corridors. Following this approach, all pipelines connecting St. Louis and Chicago, for instance, would be serving the same transportation market, but all other pipelines would be in different transportation markets. The third approach is to analyze petroleum transportation markets in terms of separate input markets and output markets. For example, one could treat all lines transporting petroleum out of St. Louis as competing in the same transportation market and all lines transporting petroleum into Chicago as competing in the same transportation market.

The first approach is not as much an attempt to define geographic markets for petroleum pipelines as an effort to measure and delineate a transportation industry which includes crude oil and product pipelines extending for hundreds of miles, and individual pipeline companies which may be comprised of distinct pipeline routes and segments scattered throughout the United States. In a 1955
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two key questions: if a given pipeline attempts to raise its price for shipping petroleum

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study of crude oil pipelines, Leslie Cookenboo provided both a good criticism of the first approach and a clear statement of the rationale of the second approach:

> It is simply not possible to make any precise, meaningful statements about nationwide shares of the market in a transportation industry. The important factor insofar as market control is concerned is what percentage of total pipeline capacity between a given producing area and a given refining center is owned by one, two, three, or more companies. It is of little concern to an independent refiner on the Gulf Coast whether pipe lines from West Texas to Chicago are owned by majors, other independents, or the government. However, the ownership of lines from West Texas to the Gulf Coast may well be of intimate concern to him. Such statements as, "The majors have 90% of pipe line capacity; therefore independent refiners can be largely controlled by the majors," really do not mean very much. What matters is the ownership of pipelines between given producing areas and given refining areas. (Emphasis in original)

L. Cookenboo, Crude Oil Pipelines and Competition in the Oil Industry 37-38 (1955).

While Cookenboo's criticism of the first approach is appropriate, his analysis fails to recognize that a refiner, for instance, may not care about where his crude supply originates, but only about its delivered cost. Thus, in Cookenboo's example of a Gulf Coast refiner, pipelines delivering crude to the Gulf Coast from North Texas, East Texas or Louisiana could provide the refiner with alternatives to the use of the pipelines originating in West Texas, as would deliveries of foreign crude oil via tanker. Similarly, a producer of crude oil or petroleum products may be less concerned with the specific destination of its output than with whether sufficient outlets exist for its product to find a market. This view assumes that markets served by petroleum pipelines are otherwise competitive, that is, that crude oil or petroleum products are freely bought and sold in those markets. Where this is not the case, firms will tend to vertically integrate, moving secured supplies of crude oil to their respective refineries and transporting petroleum products from those refineries to the petroleum product markets in which they have established distribution channels. In this view, shippers will indeed be concerned with the availability of transportation services between designated points. The availability of alternative transportation to or from a variety of points through which the firm has no interest in moving its products, and which add substantial costs, is of little interest to such a firm. Even in this situation, however, exchanges may be employed to substitute crude oil or petroleum products in desired locations for supplies available to the firm elsewhere.

The third approach to defining petroleum transportation markets attempts to incorporate these market forces, viewing all pipelines delivering petroleum to an area as competitors and all pipelines transporting petroleum out of an area as competitors. This is the approach employed by Edward J. Mitchell in his recent paper for the Association of Oil Pipelines, supra note 11, and is the approach to defining petroleum transportation markets which has been employed by the FTC and the Antitrust Division of the Department of Justice. See, e.g., FTC, Report to

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out of an area, would other pipelines, assuming they have excess capacity, pick up a substantial portion of the anticipated decline in shipments? And, if a given pipeline attempts to raise its price for shipping product into an area, will other pipelines pick up a significant portion of the decline in shipments, assuming they may have the excess capacity to do so?

These two questions must be answered separately, since market power held by pipelines could affect customers at either end of the pipeline: higher prices can be charged to shippers wishing to export or to consumers who wish to import.

Consequently, all pipelines that deliver petroleum to an area may be in one geographic market and all pipelines that transport petroleum out of an area may be in a different geographic market. This may mean that, if it is costly to convert from transporting crude oil to product, the geographic market for pipeline transportation is smaller than the geographic market for the product being shipped.[17]

The Trans-Alaska Pipeline System (TAPS) provides an extreme example of a limited geographic market for pipelines transporting crude out of an area. Crude oil produced in the Alaskan North Slope region (ANS) can command no higher price in the West Coast market than other comparable grades of crude oil sold on the West Coast. The value of ANS crude oil at the well, however, will depend on the cost of transportation to West Coast refineries. Because there is no alternative to TAPS on one

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the President on Proposed Northern Tier Oil Pipelines (1979) (analyzing crude oil supply alternatives for northern midcontinent and northern tier states and alternative outlets for Alaskan crude oil); Antitrust Div., Dep't of Justice, Report on the Competitive Implications of the Ownership and Operation by Standard Oil Company of Ohio of a Long Beach, California - Midland, Texas Crude Oil Pipeline (1978) (analyzing separately the markets for transporting crude oil out of PADD V and transporting crude oil into PADDs II and III).

17 In the first instance, prospective geographic markets for petroleum pipeline transportation may be defined by identifying the local crude oil, refining, and petroleum product markets served by the pipeline. Pipelines may either provide transportation service within a market or may link two or more such markets. Yet geographic markets for pipelines may be narrower than the geographic market for the petroleum products the pipelines deliver; for it is only the flow of petroleum through pipelines that interconnects regions into larger geographic markets.

part of the trip to these refineries, increases in the TAPS tariffs must be absorbed by ANS producers; there is no competition to which the producer can turn to prevent his net price for ANS crude from falling as the tariff increases, assuming that this oil cannot be diverted to alternative geographic areas with comparable transport costs. The only limitation on the pipeline tariff is the constraint offered by foreign crude imports. Thus, as this one example demonstrates, the relevant geographic market for gathering lines and crude oil pipelines may be confined to the area within which local producers can turn in order to transport their crude oil out of the area.

At the other end of the petroleum spectrum, in the delivery of product to wholesale product terminals, only the pipelines serving a particular refined product market would appear to be in direct competition. Customers who purchase products from such terminals can only obtain supplies from those pipelines within an economical trucking distance. Such considerations lead to a geographic market definition of the size of wholesale product markets. Thus, only pipelines that deliver into the market, which may vary between a city and a state in size, would be in competition with each other.

In between these two extremes, the main forum of pipeline competition is in the supply of crude oil to refineries and the movement of petroleum products from refineries. Whatever market power pipelines may have at this level can be limited by indirect opportunities for substitution, lying outside the geographic and product market possibilities discussed above. Although these forms of indirect competition typically limit the ability of pipelines to increase price, they do not necessarily eliminate the possibility. For example, consider two crude oil trunk pipelines that directly compete for the business of an individual refiner. The pipelines may not be able to collude to raise the tariff substantially, because a tariff increase would prevent the refiner from competing effectively with other refiners serving the same region who do not face a similar tariff increase, perhaps because they have transportation alternatives not available to the first refiner. For collusion to be entirely successful under such circumstances, many of the crude oil pipelines supplying a refining center — encompassing a group of proximately located refineries — might have to act in concert. Thus, all the pipelines supplying such a center may be in one geographic market.

On a more indirect level, each refining center may be in competition with other refining centers because they are interconnected by product pipelines. If the crude pipelines serving one center raised tariffs appreciably, the refiners in that area would generally have their net revenues reduced. This would induce a product flow into the region from the other refining centers which are connected by a product pipeline. Such competitive pressure may force a reduction not only in product prices but in the pipeline tariffs as well. This indirect pressure implies that crude oil pipelines compete to some extent with all other crude oil pipelines serving the bulk-product market. Yet, it is important to keep in mind that this competitive pressure may be somewhat attenuated, depending on the particular cost structures of the alternative refining and transportation services involed.[20]

4. Ownership structure

Acquisitions and mergers among integrated petroleum companies will invariably involve combinations or realignments in ownership of crude oil and petroleum product pipelines. In some instances, these combinations will result in mergers between competing pipelines. In other instances, the acquiring firm will succeed the acquired firm as a partial owner of a particular pipeline. In some cases the acquiror may already be a partial owner of the line, so that the acquisition increases his ownership interest. Given the diverse ownership patterns of pipelines by integrated oil companies, most mergers among major, integrated oil companies are likely to give rise to each of these

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20 The geographic market for long-haul product pipelines will follow the same basic outline as does the geographic market for crude oil trunklines. The question is whether other transportation services compete with the shipping of product into a marketing area, or out of a refining area. Again, there can be indirect limits on market power of pipelines, which will depend on the cost structures of the alternative transportation and production activities.

pipeline acquisition issues.

Most pipelines in the United States are owned by vertically integrated oil companies. As of 1974, non-integrated pipeline companies carried only 5 percent of the crude oil and 20 percent of all petroleum products transported.[21] Pipelines affiliated with major oil companies[22] accounted for 74.2 percent of total pipeline mileage and 76.5 percent of total pipeline operating revenue in 1975.[23]

Pipeline ownership embraces a variety of forms. First, integrated oil companies may establish wholly owned subsidiaries to construct and operate common carrier pipelines. These companies may also operate private pipelines as part of their crude oil production or refining units. In some instances, as in the case of Amoco's product pipeline network, such private pipeline systems may be quite extensive.

Oil companies may also combine to establish pipeline joint ventures.[24] There are

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21 Assoc. of Oil Pipelines, Reply Statement of Data, Views and Arguments Before the Interstate Commerce Commission, Ex Parte No. 308 - Valuation of Common Carrier Pipelines 5 (May 27, 1977) (statement of Raymond B. Gary).

22 As used herein in reference to pipeline ownership, the term major oil companies shall comprise the following eighteen firms: Amerada Hess Corporation; Ashland Oil, Inc.; Atlantic Richfield Company; Cities Service Company; Conoco, Inc.; Exxon Corporation; Getty Oil Company; Gulf Oil Corporation; Marathon Oil Corporation; Mobil Oil Company; Phillips Petroleum Company; Shell Oil Company; Standard Oil Company of California; Standard Oil Company (Indiana); Standard Oil Company of Ohio; Sun Oil Company; Texaco, Inc.; and Union Oil Company. Each of these companies is involved to a substantial degree in all levels of the domestic petroleum industry. This list is consistent with the major oil companies identified in the Senate Judiciary Committee's report on the Petroleum Industry Competition Act of 1976, at 16-17, S. Rep. No. 1005, 94th Cong., 2d Sess. (1976), and with the firms identified as majors by the Department of Energy in its report on petroleum pipeline capacities and utilization. Dep't of Energy, United States Petroleum Pipelines, an Empirical Analysis of Pipeline Sizing, table V (1980) [hereinafter cited as Pipeline Sizing].

23 Staff of Senate Subcomm. on Antitrust and Monopoly of the Comm. on the Judiciary, 95th Cong., 2d Sess., Oil Company Ownership of Pipelines 56 (Comm. Print 1978) [hereinafter cited as Senate Staff Report] citing Bur. of Accounts, Interstate Commerce Comm., Transport Statistics in the United States (part 6) (1975).

24 There are over 80 joint venture pipelines in the United States, including both joint stock companies and undivided interest lines.

multiple incentives for this form of ownership. A joint venture participant, for instance, would need to contribute less capital in a joint venture pipeline than in a similar sized wholly owned line. Joint ventures also make possible larger diameter construction. Companies that are not individually capable of filling a large diameter line to capacity may share in the ownership and attain the economies associated with large diameter pipeline transportation. In addition, the existence of "common carrier" requirements may be an incentive to the formation of joint ventures, because even an interstate line owned by a single company is required to carry the oil of any other company.

Pipeline joint ventures are sometimes structured as "undivided interest" systems. Each participant in such a system is itself a common carrier pipeline company. While a single operator may be designated to run the pipeline, each participating carrier publishes its own tariff governing shipments through its respective share of the line, and shippers contract with individual owners to ship through the owner's individual space on the line. Such pipeline systems typically give individual owners greater discretion in setting tariffs and policies. In addition, individual owners may effect expansions within agreed limits without the specific approval of other owners of the line.[25] For purposes of a merger analysis, the simplest way to view an undivided interest system is as a number of competing pipelines.

Pipeline joint ventures are also organized as joint stock companies and a merger involving such firms would entail a more complicated analysis of ownership prerogatives. Joint stock company pipelines are common carriers owned by their oil

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25 In recognition of the limited total expansion capability of the pipeline, the owners of such an undivided interest system ordinarily allocate expansion rights to owners of the line in proportion to their ownership shares. Procedures designed to preserve the expansion rights of nonparticipating owners may delay, but will not preclude, expansion of the line by owners willing to underwrite an expansion. In addition to financing the cost of expansion, however, proponents of expansion may be required to compensate their other partners for use of their expansion rights. Nonparticipating owners may retain the right to recapture their share of expanded line capacity should they subsequently desire to do so.

company parents, either directly or through their pipeline subsidiaries. Ownership interests are usually in proportion to their respective projected or historical shipments through the pipeline. A joint stock company pipeline publishes one set of tariffs, and operating policies are established by the board of directors of the pipeline.

The ownership structure of joint venture pipelines and the contractual provisions in agreements among the pipeline owners — governing line expansion, transfers of ownership shares, and procedures for determining operating conditions and facilities and services to be provided by the pipeline — will determine the degree of control an individual owner or a combination of owners can exercise over the pipeline. In a joint stock company, operating decisions are made by the pipeline's board of directors, elected by the pipeline shareholders. Line expansions and capital investments may require the consent of 75 percent or more of the shareholders of the line. Agreements among shareholders may thereby confer upon a single owner, or a combination of minority owners, effective veto power over line expansion.[26] This complicates the analysis of a merger involving joint stock company lines.

Pipeline acquisitions that increase the ownership share held by a joint venture participant or substitute the acquiring firm for the acquired firm as a joint venture participant may significantly alter the competitive behavior of joint venture pipelines.[27] Assessment of the probability of such changes should be made through

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26 For example, in one major joint venture products pipeline, any expansion decision involving major new financing requires an affirmative vote of directors voting 75 percent or more of the shares of the corporation. See Company document.

27 Although a merger between two joint venture partners, or between a non-owner and a joint venture member, may give the acquiring company only a partial ownership share in the joint venture, courts have long recognized that a partial acquisition may have anticompetitive effects just as serious as a full acquisition. See, e.g., F.&M. Schaefer Corp. v. C. Schmidt and Sons, Inc., 597 F.2d 814 (2d Cir. 1979) (29 percent interest); Gulf & W. Indus., Inc. v. Great A&P Tea Co., 476 F.2d 687 (2d Cir. 1973) (19 percent interest), and accordingly have treated the market share of partially-owned horizontal competitors as if the competitors were fully merged. See, e.g., Crane Co. v. Harsco Corp., 1981-1 Trade Cas. (CCH) ¶ 63,883 at 75,600 (D. Del 1981); F. & M. Schaefer Corp. v. C. Schmidt & Sons, 597 F.2d 816; see also
(Continued)

examination of the terms of the agreements among the owners of the joint venture and the past actions of the acquiring and acquired firms to influence or direct pipeline decisions.

5. Concentration

a. Various aspects of measuring pipeline concentration

In considering concentration in the context of petroleum pipelines, it is important to distinguish between concentration in the ownership of a particular pipeline on the one hand, and overall concentration on the other hand. In examining the antitrust implications of a merger, it is necessary to examine both aspects of concentration in the relevant markets and, in light of the differing implications of alternative joint venture ownership structures noted above, apply both methods of analysis concurrently to assess overall concentration in the market.

Concentration of the ownership and control of competing pipeline companies can arise because of significant capacity advantages of some pipelines in relation to others, or because of the aggregation of multiple smaller pipeline routes under the aegis of a single pipeline company. The efficiencies associated with fewer, larger diameter pipelines generally exceed those of multiple smaller pipelines. In light of the potential efficiencies associated with large diameter pipelines, the associated concentration levels alone need not raise antitrust alarm as long as effective regulatory safeguards are available to stem the exercise of market power through control of large diameter pipelines, and as long as the owners of such pipelines do not suppress competition among themselves through contractual arrangements regarding management and use of the pipelines.

P. Areeda & D. Turner, V Antitrust Law 317, 322 (1978) (recommending that any partial acquisition involving greater than a 5 percent holding be condemned whenever a controlling or full acquisition would be deemed to offend Section 7 of the Clayton Act).

Joint ventures among oil companies for the purpose of establishing new pipelines may enable participating firms to capture greater economies by building a larger diameter pipeline than any one firm, acting alone, would be in a position to build. Mergers of existing pipelines do not offer similar efficiencies, however, for the diameters of those pipelines have already been determined. Increases in market concentration through the capture of competing routes by existing pipelines may pose a substantial loss in transportation competition with little or no offsetting efficiency gain, unless the acquisition would permit better coordination of expansion and looping at larger diameter or would permit superior management efficiencies. Similarly, accumulation of ownership of pipeline companies in the hands of individual oil companies may serve effectively to eliminate competition among those pipelines in provision of transportation services. Although efficiency gains accompanying such increases in market power would appear tenuous, efficiency considerations should be weighed in determining whether to challenge a merger.

Examination of concentration in pipeline ownership may be undertaken by assigning to each respective pipeline owner a portion of the capacity or throughput of pipelines proportional to such owner's interest in the pipeline. Such calculations are useful for assessing the degree of involvement of particular oil companies in petroleum pipelines or the extent of control of petroleum pipelines by major oil companies.[28] They

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28 In its study of pipeline capacities and usage, the Department of Energy classified individual pipelines as controlled by major oil companies, controlled by nonmajor oil companies, or as independently owned. For purposes of this classification, the DOE defined major oil companies as comprising the eighteen leading petroleum firms, as identified in note 22, supra. On the basis of these classifications, DOE found that in June 1979, 80.44% of total United States pipeline throughput (measured in barrel-miles, i.e., the number of barrels shipped on a pipeline segment multiplied by the distance shipped measured in miles) were accounted for by major oil company-owned pipelines. Nonmajors' pipelines accounted for 2.48% of barrel-mile throughput, and independent pipelines accounted for 16.68% Pipeline Sizing, supra note 22, at table V. In making these calculations, DOE included among the independent pipelines the Lakehead Pipe Line, a wholly-owned subsidiary of the Interprovincial Pipe Line Company (IPL), a Canadian corporation. What appears to be effective control of IPL (32.8%) is held by Imperial Oil Company, the Canadian
(Continued)

do not take into account, however, the implications of the ownership structures and contractual constraints that may affect the degree of control an individual owner or a group of owners may exercise over the operations and competitive activity of a joint venture pipeline.

In this regard, it may be appropriate to distinguish the treatment of joint ventures in the form of undivided-interest systems from that of joint ventures in the form of joint stock companies. Joint stock companies may be regarded as distinct competitive entities in the markets in which they operate. Overlaps in ownership among such joint ventures and other pipelines in the market should be considered, however, in assessing the ability of firms in the market to exercise market power in light of existing levels of concentration. Market shares of the merging firms may be calculated by adding to their individual pipeline holdings their respective shares of joint venture pipelines. Particular attention should be given to the ability of the merging firms to direct or otherwise influence the competitive activity of the joint ventures in which they participate.

In most instances, undivided interest systems should not be treated as distinct competitive entities for purposes of calculating market concentration, but should be treated instead as separate pipeline holdings of the owners of the line in proportion to the owners' respective interests. Agreements among the owners of the line should be examined to assess the constraints they may impose on independent action by the owners of the line and the implications of those constraints for competition in the market.

b. Concentration figures for pipeline shipments

There are a number of market areas within which one can examine pipeline concentration. One possible region is the Great Lakes region [Michigan, Illinois, Indiana,

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subsidiary of Exxon Corporation. Additional ownership interests of 7% and 2% are held respectively by Gulf Canada and Shell Canada. The remainder of IPL shares are publicly held. DOE calculated Lakehead alone to account for 10.59% of total barrel-mile pipeline throughput in the United States. Pipeline Sizing, supra note 22, at table I. If this figure were ascribed to major oil companies, their share of pipeline throughputs would rise to 91.03 percent and the independent's share would drop to 6.09 percent.

Ohio, Wisconsin (eastern portion along Lake Michigan), Kentucky (northern portion from approximately Lexington northward), West Virginia (western portion from approximately Charleston northward and westward to the borders with Kentucky and Ohio), and Pennsylvania (extreme northwestern portion along Lake Erie)]. Eleven pipeline companies transport crude oil into the Great Lakes region. As Table VI D-1 below indicates, if this region can be considered as a separate market, it has a four firm concentration ratio in terms of capacity of 57.4 percent, and an eight firm concentration ratio of 89.7 percent.

The largest diameter pipeline for the movement of imported crude from the Gulf Coast to the Great Lakes region is Capline, which is owned by Ashland, Marathon, Amoco, Texaco, Shell, Southcap Pipeline,[29] and Mid-Valley Pipeline.[30] Refinery receipts in PADD II,[31] both interstate and intrastate, by tankers and barges in 1978, accounted for 1.2 percent of shipment.[32] It appears that upper Mid-Continent refineries receive 97.4 percent of domestic crude by pipeline and 96.31 percent of foreign crude by pipeline.[33] Thus, the extent of competition from water carriers appears to be negligible.

Another example of a possible geographic pipeline market consists of all pipelines delivering petroleum products into the Southeastern United States.[34] This input market is comprised of only two product pipelines, Colonial and Plantation. Colonial Pipeline

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29 A joint venture of Union and Clark. Department of Energy, U.S. Petroleum Pipeline Survey, Form EIA-184, November 1979.

30 A joint venture of Sun and Standard Oil of Ohio. Id.

31 PADD II contains all the states in the "Great Lakes" region except Pennsylvania and West Virginia.

32 Pipeline Sizing, supra note 22, at Text Table VI.

33 Id. at Text Table VII.

34 The Southeastern United States consists of Alabama, Mississippi, Florida, South Carolina, North Carolina, Georgia, Tennessee, and Virginia.

TABLE VI D-1

Capacity and Throughput Shares
Crude Oil Pipelines Into Great Lakes Region[1]

Pipeline Company	Capacity	Throughput	Share of Total Capacity	Share of Total Throughput
	—000 barrels per day—		—(percent)—	
Amoco	440.0	399.0	16.0	16.5
Mid-Valley[2]	397.0	395.0	14.5	16.3
Shell	371.4	279.4	13.5	11.5
Texas PL	367.0	295.0	13.4	12.2
Southcap[3]	272.0	249.0	9.9	10.3
Ashland	240.0	245.0	8.8	10.1
Arco[4]	210.0	203.0	7.7	8.4
Mobil	162.0	113.0	5.9	4.7
Marathon	126.0	125.0	4.6	5.2
Pure	89.0	76.0	3.2	3.1
Texaco-Cities Service[5]	68.0	42.0	2.5	1.7
TOTAL	2742.4	2421.4	100.0	100.0
4 Firm Concentration			57.4	56.5

1 Lakehead Pipeline has been excluded, since it can supply only Canadian crude. The Canadian government has sharply limited the amount of Canadian crude which is available to the U.S. so that this pipeline may have an insignificant effect on the market. Platte Pipeline has been excluded because it carries only Wyoming crude (production of which is declining) and could not serve as a carrier of incremental foreign crude.

2 Mid-Valley is owned by Sohio (50%) and Sun (50%).

3 Owners are Union (50%) and Clark (50%).

4 Owners are Arco (71.4%) and Union (28.6%).

5 Owners are Texaco (50%) and Cities Service (50%).

Source: U.S. Department of Energy, U.S. Petroleum Pipeline Sizing Survey, Form EIA-184, Nov. 1979.

alone constitutes 77.3 percent of product capacity to the Southeast.[35] These two pipelines transported 67.52 percent of petroleum products from the Gulf Coast to the East Coast in 1978.[36] Table VI D-2 contains the capacity shares for the market constituting product pipelines into the Southeast.

Table VI D-3 delineates by capacity market share, each pipeline company owner of Colonial and Plantation. The capacity for each company was allocated in proportion to the company's ownership shares in each pipeline.

6. Federal regulation of pipelines

Consideration of the effectiveness of federal regulation of pipelines is important to an assessment of petroleum mergers. If merged pipeline assets create high concentration levels, the ability of the Federal Energy Regulatory Commission (FERC) to control any resulting market power could alleviate antitrust concerns. If pipelines were not regulated, or if regulation were not an effective constraint on pipeline tariffs and conditions of use, the same merger might have more significant competitive implications.

a. Common carrier regulation

Oil pipelines were made subject to federal common carrier regulation in 1906 by the Hepburn Amendment[37] to the Interstate Commerce Act ("ICA").[38] This legislation was prompted by Congressional concern that oil pipelines (particularly those controlled by the Standard Oil Trust) were being used to deny market outlets to small producers.[39] The FERC has succeeded to the ICC's regulatory jurisdiction to enforce the ICA as it

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35 See Table VI D-2 infra.

36 Pipeline Sizing, supra note 22 at Text Table VII.

37 34 Stat. 584 (1906) (prior to 1920 amendment), 49 U.S.C. § 1(3)(a) (1976).

38 49 U.S.C. §§ 1-27 (1976).

39 GAO Report, supra note 7.

TABLE VI D-2

Capacity Shares by Pipeline
Product Pipelines in the Southeast
June 1979

Pipeline	Capacity (000 barrels/day)	Share of Total Capacity (percent)
Colonial[1]	1908.0	77.3
Plantation[2]	559.0	22.7
TOTAL	2467.0	100.0
2 Firm Concentration		100.0

1 Colonial is owned by: Amoco Pipe Line Co. (14.3%); Atlantic Richfield Co. (1.6%); BP Oil Inc. (9.0%); Cities Service Co. (14.0%); Continental Pipe Line Co. (7.5%); Mobil Pipeline Co. (11.5%); Phillips Petroleum Int'l (7.1%); Texaco, Inc. (14.3%); Gulf Oil Corp. (16.8%); and Union Oil of California (4.0%). The capacity of Colonial in the Southeastern states was calculated from Houston to Greensboro, North Carolina.

2 Plantation Pipe Line Co. is owned by: Exxon Pipeline Co. (48.8%); Refiners Oil Corp. (Standard Oil of California) (27.1%); and Shell Pipe Line Corp. (24.0%).

Source: U.S. Department of Energy, U.S. Petroleum Pipeline Sizing Survey, Form EIA-184, Nov. 1979.

TABLE VI D-3

Capacity Shares of
Product Pipelines into the Southeast
by Individual Oil Companies
June 1979

Pipeline Company	Capacity (000 barrels/day)	Share of Total Capacity (percent)
Amoco Pipe Line Co.	272.8	11
Atlantic Richfield Co.	30.5	1
BP Oil Inc.	171.7	7
Cities Service Co.	267.1	11
Continental Pipe Line Co.	143.1	6
Exxon Pipeline Co.	272.8	11
Gulf Oil Corp.	320.5	13
Mobil Pipeline Co.	219.4	9
Phillips Petroleum Int'l	135.5	5
Refiners Oil Corp.	151.5	6
Shell Pipeline Corp.	134.1	5
Texaco Inc.	272.8	11
Union Oil of California	76.3	3
4 Firm Concentration		46

Source: U.S. Department of Energy, U.S. Petroleum Pipeline Sizing Survey, Form EIA-184, Nov. 1979.

applies to oil pipelines.[40]

The ICA also provides that rates established by a pipeline can be reviewed and suspended by the regulatory agency if the charges prove to be unreasonable, unjustly discriminatory, or unduly preferential. If rates are determined to be unreasonable, the ICA provides that more reasonable rates may be prescribed by the agency.[41] The scope and effectiveness of common carrier regulation have been criticized.[42]

b. The 1941 Consent Decree

Another major "regulatory factor" affecting oil pipelines is a consent decree entered into by the Department of Justice in December 1941 with twenty oil companies and fifty-nine oil pipeline companies.[43] This decree was signed to terminate a series of cases which rose out of a major investigation of oil company practices in the 1930s in the face of the national emergency created by the war.[44]

On November 16, 1981, the Department of Justice petitioned the U.S. District Court to vacate the consent decree, arguing that it is not effective in its stated purpose of restraining rebates. The Department further argued that the consent decree has interfered with FERC's responsibility to regulate oil pipelines because pipelines had taken the position that compliance with the decree would automatically place their rates

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40 All of the powers over oil pipelines contained in the Interstate Commerce Act were transferred to the FERC on October 1, 1977 as part of the Department of Energy Organization Act, Pub. L. No. 95-91, § 402(b), 91 Stat. 584 (1977).

41 49 U.S.C. § 15(1), (7). Note that the Interstate Commerce Act was completely recodified in 1978 and the statutory references given here are to the Act prior to that recodification. The recodification was not intended to change the substantive law of these sections. See H.R. Rep. No. 1395, 95th Cong., 2nd Sess. (1978).

42 Senate Staff Report, supra note 23, at 73. See also, Statements of Department of Energy and Justice on S. 1626, before the Senate Subcommittee on Energy Regulation, May 21, 1982.

43 United States v. Atlantic Ref. Co., No. C14060 (D.D.C. 1941).

44 For a description of the events which led up to the 1941 Consent Decree, see Consent Decree Program of the Dep't of Justice: Report of Antitrust Subcomm. of the House Comm. on the Judiciary, 86th Cong., 1st Sess. (1959).

within the ICC guidelines. Thus, argued the Department, "[b]y creating a separate and different standard, the Consent Decree has led to confusion in pipeline regulation."[45]

c. **Effectiveness of regulation of pipeline rates of return and dividends**

Pipeline rate regulation has been generally confined to establishing ceilings on overall rates of return earned and dividends paid by common carrier pipelines. The individual pipeline companies have the discretion to establish, within broad bounds, the specific tariffs for individual routes and line segments, as long as each shipper on a given route is assessed the same tariff.

Various observers have found rate regulation of oil pipelines to be less than fully effective.[46] In a report issued in July 1979, the General Accounting Office observed that "Federal regulators have not controlled pipeline profits and rates. Oil pipelines' high profits over past years have continued because (1) ICC did not review and investigate the justness and reasonableness of rates charged by the pipeline companies and (2) the 1941 Consent Decree has not worked as originally intended."[47]

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45 See Statement of Points and Authorities in Support of Motion of the United States to Vacate the Final Judgment and for Other Relief, Nov. 16, 1981 at 17, United States v. Atlantic Richfield Co., No. C1-14060 (D.D.C. 1981) [hereinafter cited as Statement of Points and Authorities]. At a court hearing in January, the judge ordered the parties to attempt to negotiate a final order and the parties have been negotiating since that time. As of July 15, 1982, they had not recommended a final order to the judge.

46 See, e.g., Senate Staff Report, supra note 23, at 74-77. Without addressing the effectiveness of current rate regulation efforts, the Department of Energy's Office of Competition has recently concluded that the concept of rate deregulation for petroleum pipelines should be supported because of the existence of competition in petroleum transportation. DOE noted, however, that special cases may exist that would require the continuation or reimposition of rate regulation (e.g., TAPS). Petroleum Pipeline Deregulation: a Competition Analysis, 50-55 (1982) [hereinafter cited as 1982 DOE Report].

47 GAO Report, supra note 7, at 19. In its report, the GAO noted that the effect of the consent decree has been to cause pipelines to reduce their equity and increase their debt ratios. "This move toward debt financing greatly increases the return on equity. This change in pipeline financing made the consent decree ineffective in controlling dividends to shipper-owners and also pipeline rates." Id. at 15.

Critics of this position have argued that pipeline rates of return have been reasonable
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Although rate regulation by FERC and the 1941 Pipeline Consent Decree may in some cases, contain overall pipeline rates of return within reasonable limits, this may not eliminate a pipeline's ability to exercise market power — assuming such power exists. Because pipeline rates of return are regulated on a company-wide basis rather than segment-by-segment, owners have substantial discretion over individual segment tariffs. Thus, a pipeline company could demonstrate a rate of return for the entire company within the prescribed limits while at the same time exercising market power with respect to particular pipeline routes. Owners may also adjust tariffs to reflect the competitive alternatives available to outside shippers, establishing relatively low tariffs on routes where the line faces substantial competition, while charging relatively high tariffs on routes where the line faces less competition. Internal oil company documents suggest that such a pattern of tariffs may exist for some pipeline operators. For example, one major company observed:

> [Two of our] Divisions, which carry substantial volumes for third parties, are earning considerably more than 7% on valuation of assets, while [another] Division, which carries almost exclusively [our] volume, is operating at a loss. While this is not illegal under ICC regulations, [the company] is vulnerable to a charge that, by an opportunistic selection of tariffs, it is subsidizing its own pipeline operations at the expense of third parties.

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when compared to other industries or even to public utility rates of return. See sources cited in Wolbert, supra note 1, at 301-09; Mitchell, supra note 11, at 25-40. Moreover, critics have pointed out that, even if pipeline rates of return are above some other comparable industries, this merely reflects the extra risk taken by a pipeline owner as a result of the fact that its assets are expensive and cannot be easily moved if demand does not materialize. Id. at 38-40.

It should be recognized, however, that pipeline assets are subject to depreciation not reflected in the historical ICC valuation calculation. Because of this, for many older pipelines, rates of return calculated using more conventional accounting methods are significantly higher. Thus, one major company observed in 1968 that the pipeline consent decree does not impose a real 7% constraint on pipeline earnings, but rather that

> 7% of ICC value is roughly equivalent to a 12% return on investment, when calculated in the usual manner.

Company document.

Earlier, in assessing a proposed tariff for one of its pipelines, that same company established two guidelines: first, that the pipeline's "rates should be at the highest competitive levels on these lines where oil is moved for others"; and second, that "[n]o attempt be made to hold the pipeline to or near a 7% earnings on valuation." Documents of other companies articulate a similar policy, but it is not known whether such practices are extensive, or confined to a few instances.

d. Effectiveness of access regulation

As common carriers, pipelines are required to provide access to shippers on a non-discriminatory basis.[48] In some cases, however, it may be possible to structure and operate pipeline systems in such a way as to impede use of the pipeline by some outside shippers.[49] In addition, common carrier regulation under the Interstate Commerce Act has not been interpreted to include authority to order expansion or extension of pipelines or authority to require pipelines to provide some facilities or services to shippers, such as storage and terminal facilities.

e. Competitive effects

If rate regulation is ineffective, a pipeline company may be able to increase tariffs following a merger where substantial pipeline overlaps are involved. A similar result is possible if the owner can restrict line capacity and deny access to outsiders, thereby restricting supply to the market.[50]

7. Entry conditions

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48 49 U.S.C. § 1(4) (1976).

49 On the other hand, in some instances common carrier nondiscriminatory pricing may allow nonowners to "free ride" on a subsidized tariff that does not reflect capital costs.

50 If pipelines are deregulated, an even higher degree of antitrust scrutiny would be warranted. Legislation has been proposed that would eliminate rate regulation of petroleum pipelines. H.R. 4488 & S. 1626, the Oil Pipeline Deregulation Act, 97th Cong., 1st Sess., would remove FERC jurisdiction over pipeline rates but retain access and nondiscrimination requirements.

The number of competing crude oil and petroleum product pipelines is limited by the economies of scale of petroleum pipelines, by the advantages of existing pipelines over new entrants in establishing additional pipeline capacity, by the need for throughput commitments to secure pipeline financing, and by other regulatory factors. Licensing requirements and the need to secure necessary rights-of-way and permits also can operate to create entry problems in pipeline services.

a. Economies of scale

The overriding economic feature of petroleum pipelines is their dramatic economies of scale. Large diameter petroleum pipelines are undeniably the least costly mode of continuous long-haul transport of large volumes of crude oil and some petroleum products from a given source of supply to a given source of demand. Because any increase in the diameter of a pipeline results in a more than proportional increase in capacity, it is far more efficient to construct a single large diameter pipeline than several smaller pipelines to serve a particular market.[51]

Additional capacity may also be economically added to existing pipelines by installation of additional pumping stations or, when the line diameter no longer makes incremental pumping capacity practical, by "looping" of the line, i.e., establishing a second pipeline parallel to the first over some or all of its length. Although the cost of construction of a complete loop may approach that of establishing a new line, it is only necessary to loop those segments of an existing line where capacity is inadequate. Indeed, through a process of gradual "debottlenecking," the pipeline owner may install the parallel line on a piecemeal basis as demand arises. Existing pipelines also enjoy an established customer base and may divert shipments from their overburdened existing pipeline to a parallel new line and allocate shipments between the two lines to maximize operating efficiency.[52] Moreover, shippers on the existing line are likely to have

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51 See Cookenboo, supra note 2.

(Continued)

incurred substantial capital investments in storage, spur pipelines, and terminal facilities to secure access to that line. All of these represent advantages of an existing pipeline over potential entrants. The difficulty faced by a new pipeline in attracting shipment volumes from existing lines may be compounded by the extensive use of throughput commitments as the basis for securing pipeline financing.[53] Because throughput commitments are generally for the entire financing period (typically 20 to 30 years), shippers that have executed such agreements with existing pipelines will not be in a position to shift dedicated volumes to a new line, leaving only incremental demand to be captured by any new line.

The effect of regulation on new entry may also be significant.[54] The time needed to obtain the necessary state and federal permits entails both costs and delays. Some new entrants must make a stronger showing that proposed pipelines are necessary to obtain any required "certificates of convenience and necessity," considering that one or more lines are already in place.

Environmental regulations also restrict entry. Such regulations have generally become more stringent over time, making new pipelines more expensive to construct than those constructed earlier. Environmental regulations also appear to hinder new pipelines as compared to expansion of existing pipelines.[55] For example, the Alaska oil

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52 The Colonial Pipeline has segregated products between its two parallel main lines to increase operating efficiency by reducing the frequency of shipment batch changes required on each of the lines.

53 A throughput commitment is an undertaking by a prospective shipper on a pipeline to utilize the pipeline. These agreements generally obligate the shipper to ship a specified volume on the pipeline or to pay for the volume shortfall in the event revenues collected for shipments on the line prove insufficient to meet the line's debt service obligations. Such deficiency payments are typically credited as advance payments against the shipper's future shipments on the line.

54 The common carrier status of petroleum pipelines has been argued to constitute a barrier to entry. See Norman, "The Deepwater Port Report: A Critique" (Apr. 1980) (Am. Petroleum Inst. Critique #008). On the other hand, common carrier status may ease entry by providing rights of way that would not otherwise exist.

55 Transportation Study, supra note 3, at 96.

pipeline was blocked until Congress passed a specific facilitating law for the project. Also, environmental concerns caused protracted delays in the proposed PACTEX pipeline system, which was eventually cancelled by Standard Oil of Ohio because the project was no longer profitable.[56] The proposed Northern Tier Pipeline, which would carry crude oil from Alaska to refiners in the northern tier states and the upper Middle West, was recently denied a necessary permit by the State of Washington, based on environmental concerns.[57] Northern Tier estimated that it had already spent $50 million to secure 1400 permits in six and one-half years of trying to gain approval for the project.[58]

8. Conclusion

As in any acquisition, combinations among petroleum pipelines may be analyzed using horizontal merger analysis: identifying relevant product and geographic markets and determining concentration levels and assessing entry conditions to determine whether the acquisition or merger may create or enhance market power. Because of the potential economies of scale of certain pipelines, the possibility of market power exists. The degree of such market power will often depend on the size of the pipeline, which may confer unique competitive advantages upon it in comparison with other, smaller pipelines or alternative modes of transportation in a given service area. Effective regulation may also make the exercise of market power difficult, even in concentrated pipeline markets. All these factors must be weighed and considered in the evaluation of mergers or acquisitions which involve the transfer of pipeline ownership by competing oil companies.

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56 Id.

57 N. Y. Times, Apr. 9, 1982, at 3.

58 Id.

GASOLINE MARKETING[1]

1. Overview

Gasoline is generally transported from refineries in bulk (usually by pipeline, barge or tanker) to terminals, where it is stored and then broken up into smaller lots for delivery to retail gas stations or to sizeable customers with their own storage facilities. These purchasers either consume the gasoline themselves, or act as retailers of gasoline to final customers. Thus, there are three distinguishable transactions involving gasoline after it leaves the refinery gate: bulk cargo sales at the refining level (cargo), wholesale (terminal) transactions,[2] and retail (pump) transactions.

Naturally, the retail and wholesale markets for gasoline are closely related. Not only does the retail marketer depend on wholesalers for products, but also, particularly for the major branded dealers, there are contractual ties between these two levels of operation. The primary focus of this chapter will be on the wholesale level, although the effects of large marketing mergers on the retail market will also be addressed. Bulk sales are discussed in the refining section of this study and retail sales are examined in detail in a recent Department of Energy report.[3] The reader should be aware that the

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1 Gasoline is only one of the oil refinery products that flows through wholesale and retail marketing channels to the ultimate consumer. However, it is the most important. In 1981, U.S. gasoline sales totalled approximately 102,321,000 gallons. Lundberg Letter 3 (February 19, 1982). U.S. refinery output of gasoline exceeds the combined output of jet fuel, no. 2 fuel oil (diesel and home heating oil), other distillate fuel oils, and residual fuel oil. See Department of Energy, Petroleum Market Shares, Report on Sales of Refined Petroleum Products (January-December 1980) (12 monthly issues). Because of the importance of gasoline, this section focuses on gasoline marketing as illustrative of the marketing of refined products.

2 Wholesale transactions occur at either unbranded "rack" prices at the terminal rack or at branded "Dealer Tankwagon" (DTW) prices after delivery by branded jobbers to the retailer. Retail prices are typically referred to as "pump prices." "Jobbers" (branded or unbranded) often act as middlemen between the terminal operator and the retailer, taking delivery into their trucks at the terminal rack and pumping the gas into retailers' tanks at gasoline stations.

3 Department of Energy, The State of Competition in Gasoline Marketing, January 1981.

available data on wholesale and retail marketing is far from perfect so that it should be used with caution. However, the data is fairly representative of actual levels and trends in concentration and market shares.

2. Product markets and geographic markets for gasoline

Wholesale gasoline marketing appears to be a viable product market. There is a set of identifiable services (storage, transport and dispensing of gasoline) which is unique to this market. If wholesalers, as a group, raise the price they charge for their services, retailers will generally be unable to turn to other sources of supply, since others are not immediately positioned to provide these services.

The definition of the appropriate geographic market is more problematical. Gasoline is fungible (particularly for nonbranded retailers) and transportable by a variety of modes. Whether transport costs may isolate some regions from outside competitive pressures, or whether access to more efficient and alternative modes of transport may open a previously isolated region to major inflows of product, should be one of the first areas of inquiry in assessing the competitive effects of particular mergers. In deciding to seek a preliminary injunction to prevent Mobil's acquisition of Marathon and Gulf's proposed acquisition of Cities Service, the Commission concluded that there is reason to believe that local and regional markets do exist.

a. Terminal clusters

The roughly one thousand gasoline terminals in the United States allow marketers to break large volume shipments down into smaller volumes.[4] These terminals store the product and dispense the products into tank trucks. A typical shipment into a terminal might be 1,000,000 gallons, while the typical shipment out by truck would be about 8,000 gallons.

Because it is relatively expensive to transport petroleum products by tank truck,

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4 National Petroleum News, NPN Factbook 34-42, June 1981.

terminals are generally located immediately adjacent to the cities or towns in which their customers are concentrated. Siting terminals in this way minimizes transportation costs because the areas of high demand are served by short truck hauls while areas of low demand are served by longer truck hauls. Given that the demand for petroleum products tends to be concentrated around urban centers, terminals also tend to cluster in these areas.[5]

A wholesale seller in a given area will usually compete directly with other sellers who market within the trucking radius of his terminal, typically about 50 miles.[6] However, sellers may also compete indirectly with firms that market outside of this area

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5 As an example of the relative transport costs into and out of terminals, it costs 1.97 cents per gallon to ship gasoline or distillate from Houston, Texas, to a Fairfax, Virginia, terminal on the Colonial pipeline—a distance of 1,370 miles. (Table of Rates, Colonial Pipeline Company, March 1982.) For an additional 2.05 cents, one Virginia tank truck operator would haul product 46 to 50 miles. (Interview with tank truck operator.)

It is important to note that this dramatic increase in per-mile delivery costs starts when the product leaves the terminal, even if the product is stored a second time in a much smaller "bulk plant" prior to final delivery (again by truck) to a retail outlet. Since the crucial economic factor is trucking cost (and because much gasoline does not move through a "bulk plant" anyway), bulk plants are largely irrelevant to geographic market analysis at the wholesale level.

Trucking costs can vary by state and carrier as well as distance. For 80-mile versus 20-mile deliveries, typical rates per gallon would be 3.94 cents versus 2.08 cents in Illinois; 3.27 cents versus 1.41 cents in Ohio; 2.99 versus 1.14 in Virginia; 2.94 versus 1.44 in California; and 1.85 versus .87 cents in Texas.

In describing which terminals it could use in supplying a given retail outlet, one company stated that in addition to dependable supply and competitive price, it would seek supplies such that the "[t]erminal is close enough to our customer that freight charges are not prohibitive." (Responses of Petroleum Companies to April 2, 1982 letter from R. B. Rowe, FTC.) See App. E.

6 "Most trips are within a 50-miles radius, although some deliveries may exceed that, particularly in Western States and rural areas of the East." (Congressional Research Service, 95th Cong., 1st sess., 1 Report on National Energy Transportation 249 [Comm. Print 1977].) Seven refiners of varying size estimated their "approximate average trucking distance from terminal to outlet"; with two exceptions (one higher and one lower), the estimates range from 20 miles to 50 miles and the median is 30 miles average trucking distance. (Responses to Rowe letter.)

but are connected to the area by a chain of partially overlapping marketing areas.[7] Any assessment of a particular merger must include analysis of whether and to what extent this indirect competitive overlap may affect the ability of a seller or group of sellers to raise prices within a terminal service area.

b. Evidence of regional markets

Wholesale prices vary across the country, and at times this variation does not seem be consistent with differences in transport or marketing costs. This evidence was derived from company documents which cite transport and marketing costs and wholesale prices over cities and regions, and also from published sources of wholesale prices. Of course, such comparisons are very sensitive to the precision with which transport and marketing costs and prices are measured.

An additional type of evidence found in company documents which bears on the possible existence of local or regional markets are company studies showing that at times prices and wholesale margins appear to be positively correlated with concentration and inversely correlated with the share of independents across regions. These studies indicate that at times there may be local or regional wholesale markets and that market power may be exercised within them.

This evidence from company documents is certainly consistent with the presence of market power at various times in some localities or regions. However, the available evidence cannot be considered to be dispositive on this issue. The short run inelasticity of (retail) demand for gasoline will generally imply that a major supplier in an area will have some control of market prices in that area in the short run. For example, if a supplier can reduce the quantity sold in an area by 1 percent, given the evidence on short run elasticities, the average market price might rise by as much as 5 percent. However,

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7 As long as one supplier's area has sufficient overlap with another, price rises may be effectively constrained by the threatened loss of sales represented by the overlap region. Of course sufficient in this context refers to volume of sales rather than geographic area.

even in the short run, in those regional or local gasoline markets with relatively low concentration, reductions in output by one supplier will be at least partially offset by increases in sales by other suppliers in that market. Sustaining higher prices in the long run may be more doubtful, if outside suppliers can service most major markets.

Documents of the major oil companies clearly recognize the inelasticity of demand and their natural interdependence. Some of these documents extol the benefits of a mutual recognition of these factors. However, the evidence to be presented below on concentration, the shifting of individual companies' shares, the increasing share of independents, and price dispersion within regions, all tend to suggest that the ability to sustain any mutual recognition leading to higher prices for any significant length of time seems unlikely for many regions. Nonetheless, major mergers having significant structural effects in concentrated localities or regions should be closely examined by antitrust authorities. In fact, as indicated above, the Commission has concluded that there are local and regional markets in which Mobil's proposed acquisition of Marathon and Gulf's proposed acquisition of Cities Service were likely substantially to lessen competition.

3. Concentration in wholesale gasoline distribution

One significant piece of evidence bearing on the likelihood of exercising market power in local or regional markets is the level and trend of concentration. Data limitations, however, prevent examination of concentration within terminal clusters or within other potential local or regional markets. Concentration figures are available on a state basis from two sources and are presented below. Actual wholesale markets may be larger or smaller than states, and the state concentration data would not generally be an accurate indicator of concentration in regional and local markets. In addition, neither set of concentration figures is based strictly on sales at the terminal level. Consequently, the data below provides only a rough approximation of actual state level concentration. The most accurate data set appears to be that computed from the Dept.

of Energy's Prime Supplier Report.[8] Concentration by state from this data for 1980, the latest year available, is presented in Table VI E-1.

The four-firm concentration ratios vary considerably across states, from a low of 32.5 percent in Missouri to a high of 98.6 percent in Alaska, with an average concentration of approximately 51 percent. Four-firm concentration exceeds 40 percent in 44 states, exceeds 50 percent in 22 states, and exceeds 60 percent in 5 states. However, the state share levels do not themselves raise significant competitive concerns, although in many instances they are sufficiently high to suggest that mergers substantially affecting wholesale concentration should be carefully examined, with particular attention given to more detailed analysis of the geographic area within which competitive forces are actually at work.

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8 Form EIA-25, "Prime Supplier's Monthly Report", Department of Energy. DOE "prime suppliers" are essentially the suppliers who make the "first sale" into a state "for consumption within the state." Department of Energy, Instructions for Filing Prime Supplier's Monthly Report I (1980). While the first sale into a state is likely to occur at the terminal level, it may take place further upstream, particularly in states in which refineries are located. The most serious problem with this data is that many reporting companies do not treat exchange agreement deliveries as first sales. Since exchange volumes are sometimes 45-75 percent of sales even for large companies, this treatment of exchange volumes may considerably understate terminal level concentration.

This data probably also includes some double counting. This problem can arise if, for example, a refiner reported a certain volume in a state as a "prime supplier" but some of this volume was subsequently resold into another state, in which case the reseller would become the "prime supplier." To avoid double-counting, refineries and resellers are "encouraged to coordinate the volumes they report." Id. To the extent such problems are not avoided, reseller reporting would presumably understate supplier concentration.

Table VI E-1

Four Largest Gasoline Suppliers And Their Combined Market Share, By State, 1980 (based on first sale into the State)

STATE	Four Largest Suppliers	CR-4 (%)
Alabama	Chevron, Shell, Gulf, Texaco	37.9%
Alaska	Chevron, Tesoro, Union, Texaco	98.6
Arizona	Shell, Chevron, Union, Exxon	57.4
Arkansas	Exxon, Sun, Texaco, Tosco	44.6
California	Chevron, Shell, Arco, Union	54.7
Colorado	Amoco, Asamera, Little America, Chevron	34.1
Connecticut	Mobil, Shell, Amerada Hess, Amoco	41.0
Delaware	Arco, Getty, Exxon, Texaco	54.1
D.C.	Amoco, Exxon, Gulf, Shell	77.9
Florida	Chevron, Amoco, Shell, Gulf	36.4
Georgia	Chevron, Gulf, Amoco, Exxon	42.3
Hawaii	Chevron, Union, Shell, Texaco	85.0
Idaho	Chevron, Little America, Phillips Conoco	48.3
Illinois	Amoco, Marathon, Shell, Phillips	50.3
Indiana	Marathon, Amoco, Shell, Rock Island	47.4
Iowa	Amoco, Sun, Phillips, Farmland	41.5
Kansas	Amoco, Derby, Farmland, Vickers	33.2
Kentucky	Ashland, Chevron, Marathon, Gulf	58.5
Louisiana	Exxon, Shell, Texaco, Gulf	47.2

Table VI E-1

Four Largest Gasoline Suppliers and their Combined Market Share (Continued)

Maine	Exxon, BP, Mobil, Gulf	52.1
Maryland	Exxon, Amoco, Shell, BP	50.1
Massachusetts	Mobil, BP, Texaco, Shell	43.8
Michigan	Marathon, Total, Shell, Mobil	42.6
Minnesota	Koch, Amoco, Ashland, Mobil	59.6
Mississippi	Chevron, Shell, Gulf, Amoco	41.1
Missouri	Amoco, Phillips, Shell, Mobil	32.5
Montana	Exxon, Conoco, Cenex, Amoco	56.3
Nebraska	Amoco, Phillips, Farmland, Mobil	44.3
Nevada	Tosco, Chevron, Shell, Union	54.7
New Hampshire	BP, Mobil, Texaco, Exxon	53.3
New Jersey	Exxon, Amerada Hess, Mobil, Sun	40.2
New Mexico	Chevron, Shell, Texaco, Navajo	45.5
New York	Mobil, Exxon, Texaco, Amoco	41.0
North Carolina	Exxon, Gulf, Texaco, Amoco	45.9
North Dakota	Amoco, Cenex, Ashland, Mobil	65.5
Ohio	Boron, Marathon, Ashland, Shell	59.6
Oklahoma	Sun, Vickers, Texaco, Phillips	43.8
Oregon	Chevron, Arco, Shell, Texaco	58.6
Pennsylvania	Arco, Exxon, Mobil, BP	43.8
Rhode Island	Mobil, Arco, Shell, Sun	47.6
South Carolina	Exxon, Gulf, Shell, Amoco	45.8

Table VI E-1

Four Largest Gasoline Suppliers and their Combined Market Share (Continued)

South Dakota	Amoco, Mobil, Farmland, Cenex	52.3
Tennessee	Exxon, Amoco, Gulf, Shell	41.0
Texas	Exxon, Gulf, Texaco, Diamond Shamrock	39.8
Utah	Little America, Chevron, Amoco Western Rfg.	48.8
Vermont	Mobil, Exxon, Texaco, Gulf	51.1
Virginia	Exxon, Gulf, Texaco, Amoco	42.7
Washington	Chevron, Arco, Texaco, Shell	55.4
West Virginia	Exxon, Ashland, Gulf, Amoco	65.8
Wisconsin	Amoco, Marathon, Mobil, Ashland	38.5
Wyoming	Little America, Amoco, Conoco Husky of Del.	55.1

Source: Dep't of Energy, Form EIA - 25," Prime Supplier Report" (1980).

4. Changes in market concentration over time

The second source of concentration figures are those computed by Lundberg and (through 1978) printed in the Factbook Issue of National Petroleum News. These data are based on tax paid sales and are probably less reliable than the DOE data, but their availability for earlier years (which is not true of the DOE data) permits an examination of changes in state level concentration over time. These data, presented in Table VI E-2 for 1970 and 1978,[9] also provide some evidence on changes in concentration. These data show that during this period the four-firm concentration ratio fell in 41 states and the 10-firm ratio fell in 45 states. In six of the nine states with an increase in four-firm concentration, 10-firm concentration decreased. In a few of the most concentrated states (West Virginia, Vermont, Utah) the four-firm concentration level fell by more than 10 percentage points.

The change in aggregate concentration does not reveal changes in firm identities. Even in states where concentration levels did not appear to undergo a significant change, there were substantial changes in the identity of the market leaders. Data on the four largest firms in each state in 1970 and 1978 are presented in Table VI E-3.

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9 The Lundberg market share figures are principally derived from data published by state tax collection agencies. While the character of these data varies from state to state, in general, the data report the volume of gasoline on which each firm paid state taxes on gasoline. Because in most states gasoline can be sold or exchanged by resellers either tax paid or not, these data do not necessarily reflect concentration at any particular point in the distribution chain. The data appear to more closely reflect branded sales than terminal level sales, particularly for the larger suppliers. Unfortunately, there are indications that at least some of the changes in concentration shown by these data between 1970 and 1978 are attributable to changes in reporting rather than in market structure.

Table VI. E-2. Four and Ten Firm Concentration Ratios by State, 1970 and 1978
(Based on tax paid sales)

State	1970 4-firm	1970 10-firm	1978 4-firm	1978 10-firm	Change 4-firm	Change 10-firm
Alabama	38.67	71.96	37.58	67.25	-1.09	+4.71
Alaska	92.93	--	94.05	--	+1.12	--
Arizona	45.87	76.64	52.41	73.85	+6.54	-2.79
Arkansas	36.66	63.86	33.92	55.62	-2.74	-8.24
California	53.52	88.02	52.80	83.69	-0.72	-4.33
Colorado	40.78	73.83	30.22	56.65	-10.56	-17.18
Connecticut	44.62	82.01	43.52	77.24	-1.10	-4.67
Delaware	48.72	78.97	43.50	72.67	-5.22	-6.30
District of Columbia	71.18	90.92	69.66	96.86	-1.52	+5.94
Florida	39.71	74.20	37.10	71.12	-2.61	-3.08
Georgia	40.84	73.65	38.05	64.25	-2.79	-9.40
Hawaii	87.10	--	83.75	--	-3.35	--
Idaho	40.47	73.34	37.63	72.18	-2.84	-1.16
Illinois	43.53	69.23	40.85	64.80	-2.68	-4.43
Indiana	42.77	73.70	45.96	64.25	+3.19	-9.45
Iowa	36.58	58.41	34.87	54.00	-1.71	-4.41
Kansas	32.87	63.68	32.23	56.64	-0.64	-7.04
Kentucky	51.90	78.25	45.47	70.04	-6.43	-8.21
Louisiana	50.80	84.42	43.51	75.24	-7.29	-9.18
Maine	45.68	85.58	46.48	81.11	+0.80	-4.47
Maryland	45.25	76.71	45.85	73.98	+0.60	-2.73
Massachusetts	41.69	80.51	38.31	73.76	-3.38	-6.75
Michigan	46.09	69.04	39.12	67.98	-6.97	-1.06
Minnesota	35.71	64.28	39.94	62.38	+4.23	-1.90
Mississippi	37.26	70.07	37.51	72.47	+0.25	+2.40
Missouri	37.91	63.68	31.31	52.09	-6.60	-11.59
Montana	50.23	85.15	50.03	84.59	-0.20	-0.56
Nebraska	39.65	70.29	36.83	61.94	-2.82	-8.35
Nevada	52.14	81.92	42.91	73.24	-9.23	-8.68
New Hampshire	42.47	80.35	37.82	73.24	-4.65	-7.11
New Jersey	43.66	77.69	45.06	79.51	+1.40	+1.82
New Mexico	41.90	69.35	37.06	69.42	-4.84	+0.07
New York	49.35	79.78	41.37	73.38	-7.98	-6.40
North Carolina	40.80	72.93	43.65	69.46	+2.85	-3.47
North Dakota	63.97	82.84	55.33	70.81	-8.64	-12.03
Ohio	53.16	83.77	49.42	71.78	-3.74	-11.99

Table VI E-2. Four and Ten Firm Concentration Ratios by State 1970 and 1978--Continued

State	1970 4-firm	1970 10-firm	1978 4-firm	1978 10-firm	Change 4-firm	Change 10-firm
Oklahoma	37.30	64.52	36.51	52.88	-0.79	-11.64
Oregon	51.49	84.66	50.29	79.74	-1.20	-4.92
Pennsylvania	48.78	76.31	41.56	66.61	-7.22	-9.70
Rhode Island	44.40	84.20	42.16	83.61	-2.24	-0.59
South Carolina	48.06	77.42	43.25	67.83	-4.81	-9.59
South Dakota	46.92	70.71	41.86	56.22	-5.06	-14.49
Tennessee	42.17	76.25	41.35	76.65	-0.82	+0.4
Texas	49.14	75.14	46.17	71.45	-2.97	-3.69
Utah	52.73	85.78	41.92	65.27	-10.81	-20.51
Vermont	53.47	86.55	40.49	72.06	-12.98	-14.49
Virginia	48.16	81.40	42.85	67.72	-5.31	-13.68
Washington	54.41	88.76	45.55	80.78	-8.86	-7.98
West Virginia	52.47	80.12	42.10	59.41	-10.37	-20.71
Wisconsin	35.58	55.42	32.10	54.79	-3.48	-0.63
Wyoming	45.86	76.07	36.15	63.33	-9.71	-12.74

Source: Lundberg Survey as printed in NPN Factbook Issue, mid June 1979, pp. 118-123.

Table VI E-3. Top Four Firms by State, 1970 and 1978
(based on tax paid sales)

State	#1 Firm	#2 Firm	#3 Firm	#4 Firm
Alabama				
1970	Kyso[1]	Gulf	Shell	Texaco
1978	Socal	Gulf	Shell	Amoco
Alaska				
1970	Socal	Union	Texaco	---
1978	Socal	Tesoro	Union	Texaco
Arizona				
1970	Socal	Shell	Texaco	Exxon
1978	Socal	Shell	Exxon	Union
Arkansas				
1970	Exxon	Texaco	Gulf	Sun
1978	Exxon	Texaco	Gulf	Sun
California				
1970	Socal	Shell	Union	Arco
1978	Socal	Shell	Arco	Union
Colorado				
1970	Texaco	Conoco	Amoco	American Fina
1978	Amoco	Texaco	Conoco	Phillips
Connecticut				
1970	Mobil	Texaco	Shell	Amoco
1978	Mobil	Shell	Amoco	Texaco
Delaware				
1970	Exxon	Arco	Sun	Getty
1978	Exxon	Arco	Texaco	Getty
District of Columbia				
1970	Exxon	Amoco	Gulf	Texaco
1978	Amoco	Exxon	Gulf	Shell
Florida				
1970	Kyso	Gulf	Shell	Phillips
1978	Socal	Shell	Amoco	Gulf
Georgia				
1970	Socal	Gulf	Texaco	Amoco
1978	Gulf	Socal	Amoco	Exxon

Table VI E-3. Top Four Firms by State, 1970 and 1978--continued

State	#1 Firm	#2 Firm	#3 Firm	#4 Firm
Hawaii				
1970	Socal	Shell	Union	Phillips
1978	Socal	Shell	Union	Texaco
Idaho				
1970	Socal	Conoco	Phillips	Amoco
1978	Socal	Amoco	Conoco	Phillips
Illinois				
1970	Amoco	Shell	Arco	Texaco
1978	Amoco	Shell	Marathon	Texaco
Indiana				
1970	Amoco	Shell	Marathon	Rock Island[5]
1978	Amoco	Marathon	Shell	Phillips
Iowa				
1970	Amoco	Sun	Phillips	Gulf
1978	Amoco	Sun	Phillips	Getty
Kansas				
1970	Amoco	Phillips	Vickers	Mobil
1978	Amoco	Vickers	Phillips	Derby
Kentucky				
1970	Kysol[1]	Ashland	Gulf	Texaco
1978	Socal	Ashland	Gulf	Shell
Louisiana				
1970	Exxon	Texaco	Gulf	Conoco
1978	Exxon	Shell	Gulf	Texaco
Maine				
1970	Exxon	Mobil	Texaco	BP
1978	Exxon	Gulf	Mobil	Texaco
Maryland				
1970	Exxon	Amoco	Shell	BP
1978	Exxon	Amoco	Shell	Gulf
Massachusetts				
1970	Mobil	Texaco	BP	Shell
1978	Mobil	Texaco	Shell	Exxon

Table VI E-3. Top Four Firms by State, 1970 and 1978--continued

State	#1 Firm	#2 Firm	#3 Firm	#4 Firm
Michigan				
1970	Amoco	Shell	Mobil	Gulf
1978	Amoco	Shell	Mobil	Sun
Minnesota				
1970	Amoco	Mobil	North Western	Phillips
1978	Amoco	North Western	Mobil	Shell
Mississippi				
1970	Kyso[1]	Gulf	Texaco	Citgo
1978	Socal	Amoco	Gulf	Shell
Missouri				
1970	Amoco	Phillips	Shell	Arco
1978	Amoco	Phillips	Shell	Texaco
Montana				
1970	Conoco	Texaco	Cenex	Exxon
1978	Exxon	Conoco	Cenex	Amoco
Nebraska				
1970	Amoco	Phillips	Farmland[4]	Mobil
1978	Amoco	Farmland[4]	Phillips	Mobil
Nevada				
1970	Socal	Shell	Phillips[2]	Texaco
1978	Socal	Phillips	Shell	Union
New Hampshire				
1970	Mobil	Gulf	Texaco	Exxon
1978	Mobil	Texaco	Exxon	Shell
New Jersey				
1970	Exxon	Sun	Gulf[3]	Hess
1978	Exxon	Sun	Amoco	Shell
New Mexico				
1970	Socal	Texaco	Phillips	Shell
1978	Socal	Texaco	Shell	Plateau
New York				
1970	Mobil	Texaco	Shell	Exxon
1978	Mobil	Texaco	Exxon	Shell

Table VI E-3. Top Four Firms by State, 1970 and 1978--continued

State	#1 Firm	#2 Firm	#3 Firm	#4 Firm
North Carolina				
1970	Exxon	Gulf	Texaco	Amoco
1978	Exxon	Gulf	Texaco	Amoco
North Dakota				
1970	Amoco	Cenex	Mobil	Texaco
1978	Amoco	Cenex	Phillips	Mobil
Ohio				
1970	Sohio	Sun	Marathon	Shell
1978	Sohio	Marathon	Shell	Sun
Oklahoma				
1970	Phillips	Texaco	Conoco	Sun
1978	Gulf	Texaco	Sun	Champlin
Oregon				
1970	Arco	Socal	Shell	Texaco
1978	Socal	Arco	Shell	Texaco
Pennsylvania				
1970	Arco	Exxon	Sun	Gulf
1978	Arco	Exxon	Sun	Texaco
Rhode Island				
1970	Mobil	Texaco	Gulf	Arco
1978	Sun	Mobil	Shell	Arco
South Carolina				
1970	Exxon	Gulf	Shell	Texaco
1978	Exxon	Gulf	Shell	Amoco
South Dakota				
1970	Amoco	Mobil	Cenex	Texaco
1978	Amoco	Cenex	Mobil	Phillips
Tennessee				
1970	Exxon	Gulf	Texaco	Citgo
1978	Exxon	Amoco	Gulf	Shell
Texas				
1970	Exxon	Texaco	Gulf	Mobil
1978	Exxon	Texaco	Gulf	Shamrock

Table VI E-3. Top Four Firms by State, 1970 and 1978--continued

State	#1 Firm	#2 Firm	#3 Firm	#4 Firm
Utah				
1970	Socal	Husky	Amoco	Phillips
1978	Socal	Amoco	Little America	Husky
Vermont				
1970	Mobil	Texaco	Gulf	Exxon
1978	Mobil	Texaco	Shell	Exxon
Virginia				
1970	Exxon	Texaco	Gulf	Shell
1978	Exxon	Shell	Gulf	Texaco
Washington				
1970	Socal	Shell	Texaco	Arco
1978	Socal	Arco	Shell	Union
West Virginia				
1970	Exxon	Gulf	Ashland	Union
1978	Exxon	Ashland	Gulf	Texaco
Wisconsin				
1970	Amoco	Mobil	Texaco	Citgo
1978	Amoco	Shell	Mobil	Marathon
Wyoming				
1970	Amoco	Conoco	Texaco	Husky
1978	Amoco	Little[6] America	Texaco	Husky

Source: 1972 and 1979 NPN Factbook Issues.

1 Kyso was acquired by Socal (Chevron) in 1962. This data represents only a name change.

2 Includes Seaside.

3 Incomplete source data used in NPN calculation.

4 Farmers Union Central Exchange is also known by the name Cenex.

5 Rock Island appears to be a refiner that does not market products directly. As a result, this change may be due to shift in who pays taxes.

6 Little America's key marketing subsidiary is Sinclair.

In only two states (Arkansas and North Carolina) were the rankings identical in 1970 and 1978, and in only eight states (California, Connecticut, Idaho, Nebraska, New York, Ohio, Oregon, and Virginia) were the same four firms ranked as the top four in both 1970 and 1978. The market leader changed less frequently, changing in only six states (Colorado, Georgia, Montana, Oklahoma, Oregon, and Rhode Island) and in the District of Columbia.[10]

5. Entry conditions

a. Pipeline and terminal access

Although current conditions of excess gasoline supply may alleviate marketers' normal supply difficulties, in periods of lessened supply, marketers may encounter obstacles in arranging pipeline transportation and terminal access in a particular market. Especially for a nonintegrated marketing firm, the lack of availability of pipeline space may sometimes be a problem.[11] Although exchanges between companies of gasoline that is located at different points along a pipeline can provide an equivalent to pipeline access for individual companies, exchanges are not always possible, especially

10 This figure excludes those states where Kyso was replaced by Socal, since this change was due to the acquisition of Kyso by Socal.

11 According to company documents, product pipeline sizes, routes, rules, and tariff charges are geared to the needs or strategies of their owners, who are almost invariably large integrated firms, not relatively small scale marketing companies. One company stated its policy in relation to one pipeline oil company executive investment proposal as follows: "This would conform to the policy of having our own production, tied in by our own pipeline and supply our own refinery, thus eliminating entirely, [sic] others profitting by our operation." Similarly, another company's document stated, "we should do everything possible to avoid using these lines for other people so we have the advantage of protections, flexibility and capacity for growth." Company document.

for aggressive marketers.[12] In addition, exchanges cannot generally be used to increase aggregate supply in a given area.

To market in an area, companies must have access to terminalling (bulk storage) facilities for gasoline that is shipped in from other areas. The difficulty of obtaining access to gasoline shipped by pipelines, however, appears to encourage independent terminals to be predominantly located where they can be served by tankers and barges.[13] Thus, the need to coordinate terminalling with tanker and barge shipments may add to supply difficulties, particularly for independent marketers in regions where a pipeline is less accessible to the smaller firms. Although obstacles to construction or purchase of terminals themselves are not prohibitive, the difficulty in obtaining access to pipelines may sometimes render this potential means of entry less likely for the typical independent marketing firm.[14] Hence direct observation of entry difficulties faced by private brand marketers is complicated by the fact that entry depends on overcoming a

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12 One company's documents indicated that its practice regarding exchanges with private brand companies has been to examine each exchange "to be sure that we are not giving the independent sector any . . . supply that they could not readily obtain from others." Another company document expressed its decision not to engage in a particular exchange based in part on its possible disruptive effect. A third company's documents contained a recommendation not to exchange with an "aggressive marketer."

On the other hand, private brand marketers can often obtain supplies via exchange or otherwise from medium-size refiners. In such cases, the "exchange" form of the transaction is less significant than the fact that gasoline locally refined or brought in by large companies (with the infrastructure to actually engage in long distance transportation) is made "available" to private brand marketers.

13 Of 15 product terminals in the states of Wisconsin, Michigan, Illinois, Indiana, Ohio, and Kentucky, owned by members of the Independent Liquid Terminals Association, only five are served by pipeline, and none are served by pipeline only. 1980 ILTA Directory, passim.

14 A terminal of 200,000 barrels (8,400,000 gallons) capacity would cost roughly $2 million for construction, plus site preparation and other costs. Interview with terminal company estimator (May 27, 1982). Also, a pipeline terminal requires a "hook-up" (connecting line) from the main trunk line, which the pipeline will often install if given sufficient guarantees of capacity utilization in future years. Interview with terminal company executive (March 30, 1982).

series of hurdles without incurring excessive cost. No one step is necessarily insurmountable, yet each can be difficult or relatively costly. In general, the greatest difficulty may be faced by the private brand marketers.

b. Wholesale supplies to independent marketers

The most serious difficulty in entry or expansion faced by private brand independents may be the reluctance of the largest majors to sell wholesale gasoline to them. Gasoline marketing for the past 20 years appears to have been characterized by a struggle between the majors (and especially the largest majors) versus "the independents" (meaning the smaller refiner-marketers and private brand marketers). The results have varied by time and place, depending on many factors. The most important of these factors appears to have been the availability of "unbranded rack" supplies to the independent marketers. When and where such wholesale gasoline supplies are available to such marketers, their lower costs and aggressive price-oriented marketing tend to encourage them to sell at low prices and to gain volume at the expense of the larger majors. Numerous company documents indicate that the largest eight majors each adopted a corporate policy of not selling gasoline to independent marketers. These policies may constrain the ability of independents to maintain their position in a shortage market.

Examination of the policies (as revealed by company documents) of these large refiners governing wholesale sales to unbranded independents over the last 10 years indicates that each of them took the position that their branded gasoline marketing strategies were vulnerable to inroads by private brand independents if independents could easily obtain wholesale gasoline supplies. Further, the large refiners appear to have acted similarly in response to this perception. The following quotations from the documents of eight different majors indicate similar policies in avoiding bulk unbranded sales to private brand independent marketers during the 1965-73 period prior to the imposition of regulatory control:

Company A	[Our company] does not make a practice of selling gasoline through unbranded jobbers; i.e., distributors who sell [our] gasolines under other brand names. We assume field managers understand and adhere to this policy.
Company B	Unbranded in all areas are to be backed out as rapidly as possible.
Company C	Independents usually do not call us, probably because we are not known as a supplier for them. Our objective is to keep it that way.
Company D	No sale of gasoline to outside private brand sector.
Company E	U.S. Marketing has long pursued a policy of not selling unbranded gasoline.
Company F	Among the numerous retail methods of operating service stations that have been avoided or eliminated by [our company] the following are most commomplace. (1) Independent, unbranded marketers.
Company G	Unbranded gasoline sales have been minimized and it is the continuing policy to elimina e this type of sale entirely to resellers or to service stations wherever possible.
Company H	Any and all requests for unbranded gasoline supply to be flatly refused, with no compromise.

That the policies may in fact have been implemented is suggested by data indicating that, in the aggregate, these eight refiners sold only a very small percentage of their gasoline output to unbranded independents throughout the years. These data are set forth in Table VI E-4, which is taken from an earlier FTC survey in which independents summarized their purchases for 1967-1971:[15]

[15] Federal Trade Commission, Preliminary Staff Report on its Investigation of the Petroleum Industry 9 (1973).

Table VI E-4

Sales of Largest Eight Refiners to Independents

Year	Gasoline Purchases by Independents from Eight Largest Refiners as a Percent of Total Purchases	Gasoline Purchases by Independents from Other Majors as a Percent of Total Purchases
1967	1.5%	51.0%
1968	.5	48.2
1969	.7	43.6
1970	1.0	44.9
1971	1.6	42.7

Data for the 1970's show a similar pattern, although DOE regulations and other changes in the gasoline marketing environment complicate the interpretation of the data. As a percent of their total gasoline sales, the largest eight refiners sold only 2.5 percent of their output to independents in 1972.[16] Later, under DOE "allocation" regulations, refiners were assigned some unbranded customers for mandated sales, and the top eight's sales to unbranded independents reached 6.5 percent of these majors' total gasoline sales in 1978.[17]

Because direct supplies to unbranded independents are apparently not available in any substantial quantity from the largest eight refiners, the competitive consequences of the acquisition by a major of any other refiner which sells a large amount of gasoline to the price-oriented private branders should be examined. Supplies of unbranded rack gasoline to private brand marketers can inject an important competitive element into the markets in which such sales are made, prompting competitive pressures which may increase in proportion to the volume of unbranded sales. Their presence as substantial factors in many markets makes price coordination by majors more difficult. However, we note below that in recent years the majors have to some extent adopted marketing practices similar to those traditionally pursued by independents, and such competition by majors may have effects similar to the competition that which can be supplied by independents when they have adequate supplies.

6. Pricing within terminal clusters

The fact that terminal clusters can apparently be geographic markets does not mean that market power is being exercised within them. For example, if market power were being exercised by the majors[18] within a given terminal cluster, a significant dispersion of

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16 Title III Report, <u>supra</u> note 47, at 116.

17 <u>Id.</u>

18 Lundberg, who prepares the share data used by most analysts, between 1972 and 1977 defined a nonmajor as any retailer not identified by the brand names Exxon, Texaco, Shell, Amoco, Gulf, Mobil, Chevron, Arco, Phillips, Sun, Union, Conoco (including Douglas, Kayo, and Onco), Cities Service, Standard of Ohio (including (continued)

their prices would not be expected. While some dispersion would be consistent with a lack of competition a sufficiently large dispersion in prices would suggest a lack of "consensus" on preferred prices and market shares, which would be a serious impediment to effective exercise of market power.

The average of the weekly ranges of resellers' prices (differences between highest and lowest prices) for majors and nonmajors in Milwaukee, Chicago, and Detroit for leaded and unleaded regular gasoline are given in Table VI E-5. The reseller prices for majors were wholesale prices of branded gasoline to jobbers. The reseller prices for nonmajors included both prices of branded gasoline to jobbers and prices for unbranded rack sales. For this reason, it would be expected that the range of prices for the majors would be less than the range of prices for nonmajors. (Branded gasoline generally sells at a premium (wholesale) over unbranded gasoline in all markets, perhaps reflecting increased quality and supply assurance.) This may be the explanation for the difference in the range of prices for the two groups in Table VI E-5. Another possible explanation is the data does not include rebates, which at times have been as large as four cents per gallon. The fact that there is a not insignificant range in the prices of the majors for branded gasoline does not provide support for a theory that the majors are able to collude effectively in these areas. Differences in the prices charged by the majors suggests differences in preferred prices and market shares, which would generally be inconsistent with the presence of effective collusion, but does not preclude the possible exercise of market power.

Differences in the range of prices charged by majors across cities may be indicative of the presence of market power. As an extreme case, if the majors always charged exactly the same price at all times in a given city (producing a zero average range), this fact would

Boron), BP, and Getty (including Skelly) as majors. In 1978 Lundberg added Marathon to the list of majors. His definition of "integrated" marketers, which are referred to here as "majors," includes those firms that produce, refine, transport and market in interstate commerce with more than 20 stations. For consistency across years, and because Marathon supplies about 50 percent of its gas to independents, Lundberg's pre-1978 definition of majors is used throughout this section.

Table VI E-5. Average Weekly Range of Major and Nonmajor Reseller Prices[1]
(cents per gallon)

	Major		Nonmajor	
	Regular	Unleaded	Regular	Unleaded
Milwaukee	1.53	1.59	3.47	3.69
Chicago	1.38	1.54	3.91	3.91
Detroit	1.77	2.32	3.03	3.16

1 Average price ranges were calculated from 1981-82 (post-controls) weekly "reseller" prices reported by the Oil Prices Information Service.

give strong support for the view that market power was being exercised in that city. Qualitatively, cities with a small range of prices for the majors (relative to the range for non-majors) are better candidates for inquiry into the possible presence of market power.

Evidence suggesting that the majors must price competitively with respect to the independents comes from examining the frequency with which majors price within the price range of non-majors. Table VI E-6 gives, for each locality and each type of gasoline, the relative frequency with which majors' weekly prices were within 1, 2, 3, 4 or 5 cents of the lowest weekly price quoted by nonmajors on corresponding dates. With the exception of Chicago, roughly between 16 and 20 percent of the reseller price quoted by majors were within 2 cents of the corresponding lowest nonmajor price in either regular or unleaded gasolines.[19] For Milwaukee and Detroit, between 42 percent and 55 percent of the majors prices were within 3 cents of the corresponding nonmajor price, and between 65 percent and 81 percent were within 4 cents. Since the average range of nonmajor prices in each product was roughly between 3 and 4 cents, it appears that significant percentages of the major reseller prices were within this range. The data for Chicago are much different from the data for Milwaukee and Detroit, indicating the possibility that there is less competition in Chicago. Again, however, no account has been taken of any rebates that may have been offered by majors, which could be a significant factor in the extent of competition in these markets.

As a final piece of evidence, the data for the three cities were used to compute the frequency with which the majors priced less than the non-majors maximum price. This frequency was 58 percent (regular) and 67 percent (unleaded) for Milwaukee, 42 percent (regular) and 39 percent (unleaded) for Chicago, and 36 percent (regular) and 38 percent

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19 Interpretations of Table VI E-7 should bear in mind that branded gasoline generally sells at a premium in <u>all</u> markets (even those where there is no question of exercise of market power), perhaps because of increased assurance of quality control or stability of supply.

Table VI E-6. Frequency of Major Reseller Prices Within Selected Differentials of Lowest Nonmajor Wholesale Price[1]

		# of major prices Reported	% Major Prices Within Lowest Nonmajor Wholesale Price				
			1¢	2¢	3¢	4¢	5¢
Milwaukee	Regular	132	8	20	44	65	89
	Unleaded	132	8	21	42	67	88
Chicago	Regular	121	0	5	17	47	72
	Unleaded	121	0	3	17	47	70
Detroit	Regular	170	2	16	52	81	94
	Unleaded	170	6	18	55	79	95

1 Price frequencies and minimum nonmajor prices were calculated from weekly "reseller" prices reported by the Oil Price Information Service.

(unleaded) for Detroit. Thus, it is clear that the majors were often not the highest price sellers in these wholesale areas.

7. Retailing

a. The number of retail outlets

Table VI E-7 summarizes the total number of gasoline service stations by state in 1977. Table VI E-8 gives the total number of branded retail outlets affiliated with twenty-six major oil companies in 1977,[20] and the number of states in which they had retail outlets. On a national basis, four-firm concentration in the number of retail outlets in 1977 was 55 percent. National concentration in the number of outlets is much higher than national concentration in sales (29 percent in 1980), which presumably indicates that the major affiliated stations have a considerable lower average volume than do stations not affiliated with majors.

As shown in Table VI E-9, the national market share of independents has grown substantially since 1969. Independents now are a major presence in all regions, as indicated by the data presented in Table VI E-10.

At the same time that independents as a group have been growing, some majors have been losing shares in some areas of the country. The majors appear weakest in those areas where the independents have obtained the largest shares (the midwest and rocky mountain states). Over the last several years, some majors have pulled out of areas where their share levels were declining and have moved to consolidate their positions in areas where they had significant market shares and independents held a relatively small market share.[21] These shifts may lead to increased concentration in some areas and decreased concentration in other areas.

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20 Number of outlets data come from the census, which will not be updated until next year.

21 A rule of thumb suggested by some industry participants is that majors appear to need 7-8 percent of a market to be profitable. National Petroleum News, February 1972, p. 43.

TABLE VI E-7

Total Branded Retail Outlets by State - 1981[1]

Alabama	7,438
Alaska	352
Arizona	1,622
Arkansas	3,256
California	12,648
Colorado	2,070
Connecticut	3,778
Delaware	585
District of Columbia	276
Florida	9,005
Georgia	7,848
Hawaii	514
Idaho	922
Illinois	6,256
Indiana	4,805
Iowa	4,151
Kansas	2,692
Kentucky	4,482
Louisiana	4,714
Maine	2,050
Maryland	3,187
Massachusetts	4,788
Michigan	5,946
Minnesota	3,466
Mississippi	3,842
Missouri	4,826
Montana	1,412
Nebraska	2,277
Nevada	567
New Hampshire	1,128
New Jersey	6,563
New Mexico	1,685
New York	11,552
North Carolina	10,564
North Dakota	1,035
Ohio	6,644
Oklahoma	3,746
Oregon	2,429
Pennsylvania	11,473
Rhode Island	1,003
South Carolina	5,483
South Dakota	1,112
Tennessee	6,841
Texas	16,541
Utah	1,033
Vermont	929

Virginia	6,909
Washington	3,307
West Virginia	2,097
Wisconsin	3,415
Wyoming	582
TOTAL	215,846

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1 NPN Factbook 48-57 (1982).

TABLE VI E-8

Total Branded Retail Outlets Affiliated With 21 Major Oil Companies in 1981[1]

Major Oil Companies	Total Branded Retail Outlets	Total Number of States Where Gasoline Brand is Marketed
Amoco Oil Co. 20,061	46	
Ashland Petroleum Co.[2]	271	8
Atlantic Richfield Co.	7,122	30
Chevron U.S.A. Inc.	12,748	39
Cities Service Oil Co.	5,784	31
Conoco, Inc. 4,885	28	
Diamond Shamrock Corp.	1,579	12
Exxon Co., U.S.A. 20,585	40	
Getty Refining & Marketing Co.	4,700	28
Gulf Oil Co., U.S.	13,870	30
Kerr-McGee Refining Corp.[2]	1,431	17
Marathon Oil Co. 2,146	6	
Mobil Oil Corp. 16,564	45	
Murphy Oil Corp. 767	14	
Phillips Petroleum Co.	12,327	38
Shell Oil Co. 13,665	36	
Standard Oil Co. (Ohio)	3,965	19
Sun Company, Inc. 8,361	33	
Tenneco Oil Co. 484	17	
Texaco, Inc. 22,490	50	
Union Oil Co. of California	12,529	44

1 Source — NPN Factbook 36 (1982).

Source — NPN questionnaires. Reported data are for 1981.

2 Reported data are for 1980.

Table VI E-9. U.S. Gasoline Market Share Trends, 1969-1980: Integrated Majors and Independents

Year	Integrated "Majors"' Total Share of U.S. Gasoline[1]	Independents' Total Share of U.S. Gasoline[2]	Independents' Gain/(Loss) Over Prior Year
1969	76.65	23.35	N.A.
1970	74.42	25.58	2.23
1971	72.56	27.44	1.86
1972	70.33	29.67	2.23
1973	71.22	28.78	(0.89)
1974	70.11	29.89	1.11
1975	68.05	31.95	2.06
1976	66.98	33.02	1.07
1977	67.85	32.15	(0.87)
1978	67.46	32.54	0.39
1979	65.60	34.40	1.86
1980	65.16	34.84	0.44

N.A. = Not Available

Source: NPN Factbook issues for 1969-80. These data were compiled by Lundberg from State gasoline tax records with adjustments. See supra note .

1 To most accurately measure trends, the same firms were consistently counted as "majors" for each year, even if their NPN classification was different for some of these years. For this table, integrated "majors" consisted of Exxon, Texaco, Shell, Amoco, Gulf, Mobil, Chevron, Arco, Phillips, Sun, Union, Conoco (including Douglas, Kayo, and Onco), Cities Service, Standard of Ohio (including Boron), BP, and Getty (including Skelly).

2 "Independents," as used here, were all firms not counted as "majors" (including cooperatives, miscellaneous, and unidentified). Notably, this group includes Marathon for all years, even though Lundberg and NPN began to count it as a major only in very recent years.

TABLE VI E-10

Market Share of Independents by Region[1]

Region	1980 Independent Share (percent)
New England	18
Mid Atlantic	26
Southeast	37
Florida	29
Great Lakes	43
Plains	54
Southwest	42
West Coast	22
Rockies	55
Total United States	35

1 Derived from U.S. Department of Commerce data.

Among the shifts that have occurred are: Arco's and BP's exit from the southeast (early 1970's);[22] Amoco's pullback from the West Coast;[23] Phillips' reduction in the Northeast; Sun's recently completed exit of the Dakotas, Minnesota, Wisconsin, Michigan, Nebraska and Kansas;[24] Exxon's exit from the Chicago area; Mobil's exit from the Rocky Mountain states (early 1970's); and Cities Service exit from the Great Lakes states (1960's).

There are also a number of pullouts which appear to be going on at the present time. These withdrawals include (1) Amoco's withdrawal from Texas and cessation of jobber supply in Montana, Oklahoma, Arkansas, most of Kentucky, West Virginia, Maine, New Hampshire, Vermont, Washington, and Oregon, by October 1982;[25] (2) Texaco's withdrawal from parts or all of 19 states in the northern Rockies, Midwest, and Great Lakes area by the middle of this year; Arco's ongoing pullout of Wisconsin, Indiana, Ohio, Michigan, and Illinois (except Chicago); Phillips Petroleum's announced interest in pulling out of the Northeast and plan to pullout of the Dakotas and Wyoming; Sun's planned pullout back from sections of Arkansas, Louisiana, Mississippi, and Tennessee; and Union Oil's withdrawal from some parts of the northern Rocky Mountain states.[26]

b. Merger activity

Unlike the 1960's and early 1970's, the last few years have seen few mergers which

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22 National Petroleum News, April 1972, p. 48.

23 National Petroleum News, March 1973, p. 10-11.

24 Ibid.

25 National Petroleum News, February 1982, p. 37.

26 National Petroleum News, February 1982, p. 37. Note that many of these ongoing pullouts were announced much earlier, but were stalled by the imposition of controls. See National Petroleum News, p. 41; National Petroleum News, February 1972, pp. 43-45 and National Petroleum News, April 1972, p. 48.

have had a significant effect on the structure of gasoline retailing markets.[27] To some extent this may be due to regulations, imposed in the later 1970's and continued into 1981, that required refiners to continue supplying their former stations after they sold them. Compounding this effect was a crude oil shortage occuring twice during the period that constrained a firm's ability to expand retail gasoline sales, reducing the incentive to expand the number of retail outlets. A comparison of Tables VI E-11 and Table VI E-12 reveals a significant difference in the number of retail outlets affected by mergers reported for the two time periods, 1965-1977, and 1978-1982.[28]

Most recent mergers appear to reflect the efforts of smaller firms to grow. The mergers involving one small firm — Power Test — may be illustrative of this important class of mergers. During the 1973-1977 period, Power Test doubled its size.[29] The fact that Power Test has four terminals in the area and a sizeable warehouse office probably facilitated its expansion.

Many of the other transactions in recent years, as discussed earlier, reflect the decisions of major firms to withdraw from certain areas of the country. If this is a continuing process, it may generate further acquisitions by smaller firms. Firms that do not have the sales to cover regional overhead may also choose to sell out to firms that are better positioned to expand their operations.

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27 If Mobil had acquired Marathon, a sizeable merger would have occurred at the retail level. Mobil owned 17,425 stations in 1981, while Marathon owned 3,051. National Petroleum News, Factbook Issue, 1981, p. 50. The horizontal overlaps in marketing between Mobil and Marathon at the state level were likewise substantial.

28 Since the average state has over 3,000 gasoline stations (National Petroleum News, 1980, Factbook Issue, p. 108), the mergers reported in the two tables appear to involve the exchange of only a small portion of the marketing assets of the two companies involved, although more detailed analysis would be required to be sure that concentration in a particular area has not been increased significantly.

29 Link, "The East's New Powerhouse Marketer," National Petroleum News, January 1979, pp. 63-67.

Table VI E-11. Large Marketing Mergers and Acquisitions in the 1960's and Early 1970's[1]

Year	Acquiring Company	Selling Company	Location of Assets	Number of Outlets Acquired
1965	Atlantic	Richfield	7 Western States	4,451
1966	Phillips	Tidewater[1]	3 Western States	3,200
1965	Union	Pure	23 Southeast East, Southern, Midwestern, and North Central States	16,308
1966	Gulf	Citgo	9 North Central and Midwestern States	2,300
1969	Arco & BP	Sinclair	All but six Western States	24,600
1969	BP	SOHIO	Ohio	3,100[2]
1968	Sun	Sunray Dx	16 Midcontinent States	5,643
1972	Pasco	Arco	Rocky Mts.	
1973	Petrofina	BP		1000+
1977	Tosco	Phillips	West Coast	1430[3]

Source: Allvine and Patterson, Competition Ltd., 1973, pp. 168-69, report mergers and acquisitions for the 1960's. For the 1973 merger see National Petroleum News, June 1981, p. 41.

1 Tidewater assets belong to Getty. These are assets that Phillips sold in 1977.

2 Obtained from NPN, Factbook Issue, 1969, p. 153.

3 Obtained by adding up Phillips' Hawaii, Washington, Oregon, and California stations in 1976. NPN, Factbook Issue, 1976, p. 53.

Table VI E-12. Illustrative Mergers and Acquisitions 1978-82[1]

Year Discribed in NPN	Acquiring Company	Selling Company	Location of Assets	Number of Outlets Acquired
1978	Union	Little America[2]		6
	Sigmor	Diamond Shamrock		400
	Power Test	Tesoro[3]	NY,NJ,PA	27
	Asamera	Gasamat	12 States	90
	Derby	Apco	OK, KS	5
	Texaco	Douglas		227[4]
	Power Test	Spiegel & Sons	NY, NJ	74[5]
	Power Test	Citgo	NY	9
	Oasis Petro Energy	Research-fuel		85
1979	Checker Oil	Exxon	IL, IN, MI, WI	
	Amoco	Checker	IL, IN, MI WI[8]	
	Getty	Reserve	CA, AR, NV	391
	Sun	Mr. Zip	SC, NC, VA	70
	Pacific Resources[6]	Tosco	CA	128
	Pantry-C	Casper House	---	109
	Southland	Tosco	---	Old Phillips properties 153[7]
	NAVCO	KAYO	---	
	Amoco Managers	Amoco	TN	6
1980	Farm Fare	Mr. Zip	SC, NC	87
	Amoco	Ashland	MD	14
	Citgo	Pronto Oil	---	--
	Conna	Petco	VT, NH, NY	26
	Conna	NY Crest	NY	19
	Sun Mark	Zippy	FL, GA, AL SC	228

Table VI E-12. Illustrative Mergers and Acquisitions 1978-82[1]--continu

Year Discribed in NPN	Acquiring Company	Selling Company	Location of Assets	Number of Outlets Acquir
1981	SOHIO	Gibbs	MA, ME, NH	200
	Delta Marketing	South Central Oil	AL, AR, FL IN, OK, TN, TX	111
	Thrifty	Gulf	West Coast	235
	Pantry	Quick-Pick		118
	Citgo	Consumers Oil	MS, KS, AR, OK	8
	PMC	Consumers Oil	MS, KS, AR, OK	28
	Sun dealers	Sun	eight Midwestern States	100
	Oasis	Pasco	AR	32
	APEX	Clark	13 Midwestern States	1,400
1982	Ashland	Tressler[10]	KY, IN, OH	--
	Oasis	USA Petrol[11]		

1 The mergers described in this table were taken from a survey of the mergers reported in the National Petroleum News (NPN) over the last five years. Since this survey may have missed some mergers reported in NPN a not all mergers are reported in NPN, this sample may not be representati Furthermore, some of the announced acquisitions may not have been consummated.
2 Little America's key marketing subsidiary is Sinclair.
3 Tesoro sold under the Digas Brand.
4 Texaco only kept 37 of these, selling 90 under a voluntary divestitur agreement with the Justice Department.
5 Station operators had right of first refusal, so fewer stations may h changed hands.
6 Desert Petroleum subsidiary made acquisition.
7 All but 25 of these were divested to unknown purchasers.
8 In March 1980, this was reported as 400 stations: 186 Mowhawk and 314 rebranders.
9 Under California Law, dealers have right of first refusal, so fewer stations may have been sold. A law suit over this issue followed (NPN October 1971, pp. 68-69).
10 Tressler Oil sold under the Comet Brand.
11 This merger does not appear to have been consummated at this time.

c. Price competition

1. Evidence from economic studies and company documents

One question bearing on whether there are important regional retail gasoline markets is whether regional variations in market structure are related to variations in pricing conduct. Given the ongoing adjustment to recent deregulation, no definitive answer can be provided at the present time. The available evidence is mixed, though there is some evidence that higher levels of concentration in regional and local areas are associated with higher prices.

Some recent research contains statistical analysis of the relationship between various measures of market concentration and the majors' wholesale and retail prices or the stability of their market shares.[30] This research, which suffers to some extent from theoretical and empirical shortcomings, contains a mixed set of results.

Masson and Allvine (1976) found that the retail prices of majors' brands during the retail price war period of 1961 to March 1965 were lower at stations located near independents' stations than at other of the majors' stations. That is, the retail prices of majors' brands varied positively with retail market concentration measured by the proportion of all retail stations (not sales) that sell majors' brands. Wholesale prices charged by majors were also lower during the retail price war periods of the early and late 1960's in cities in which independents had a larger proportion of gas stations, and the dispersion in majors' wholesale prices over time was greater in these cities.

Marvel (1978) analyzed a seven-year average of the BLS monthly highest and lowest retail gasoline prices for 22 cities over the period 1964-1971. He found no significant statistical relationship between the highest retail (city) gasoline prices and

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30 Masson and Allvine, "Strategies and Structure: Major Independents, and Prices of Gasoline in Local Markets," Essays in Honor of Joe S. Bain, 1976 pp. 155-180; "Competition and Price Levels in the Retail Gasoline Market," Review of Economics and Statistics, May 1978, pp. 252-258; and Allen, Structure and Stability of Gasoline Market," Journal of Economic Issues, 1981, pp. 73-74.

the associated state-wide Herfindahl index. On the other hand, a statistically positive relationship for the sample of lowest retail (city) gasoline prices was found. Marvel argued that the results support a view that collusion is effective in concentrated markets. However, the explanation as to why low prices (typically charged by independents) would be statistically related to concentration but high prices (typically charged by the majors) would not, is not altogether clear.

Finally, Allen (1981) investigated the determinants of the stability of individual oil company market shares in each state for the period 1964-1974. He found higher concentration to be associated with less stability in market shares, suggesting that either tacit collusion decreases with concentration, or that with higher concentration there is more reliance on nonprice competition that is more difficult to match than price competition.

Company documents over the past 10 years include studies of the relationship between prices and concentration or share of independents. These studies frequently find that higher pirces are associated with higher concentration levels and a lower share for independents. Major firms' profit margins also appear to be positively correlated with increased concentration and inversely correlated with the aggregate market share of independents.

In summary, the available evidence is mixed. There is some evidence of a positive statistical relationship between prices and concentration or an inverse statistical relationship between price and the share of independents. This evidence may indicate the presence of market power in concentrated markets, but the interpretation of such evidence is fraught with difficulties.[31] In addition, concentration is apparently associated with less stability in market shares, which is difficult to reconcile with the

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31 As in any structure-performance study, the results should be interpreted cautiously. See Goldschmidt, Mann and Weston, Industrial Concentration: The New Learning (1974).

effective exercise of market power. In general, the evidence is certainly not conclusive, but is consistent with a view that major mergers involving significant overlaps in marketing should be closely scrutinized.

2. Price competition among majors

Other recent evidence suggests the presence of retail price competition among the brands of the majors. The documents of one major firm provide a comparative survey of the retail prices of its brand versus those of other majors for more than 60 cities for a 9-month period in 1981.[32] For the 56 cities consistently reported over the time period, this company's retail price was both higher and lower than the average retail price of the brands of other majors, in full service regular and unleaded gasoline sales in each of 31 cities for each product over the period studied. Thus, the company's brand was priced higher and lower than the average price of the brands of other majors, both within and across cities, showing no definite tendency to be a high "price leader" or a consistent "follower." The average absolute value of these within-city price differentials for the 9-month period for this sample of cities was approximately 4.5 cents for regular and 5.2 cents for unleaded. Thus, in general, the retail price of this company's brand for both full service regular and unleaded gasoline varied considerably relative to the average prices of the brands of other majors.[33] Such variation is suggestive of a lack of "coordination" of prices between majors, casting doubt on assertions that the majors could have been acting in concert during the period.

3. Role of independents

Independents have traditionally tended to induce price competition in markets.

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32 The documents provide no explanation of who the other "majors" may be. Thus, it is not known whether the term major refers to the large integrated refiners (as in this study), or to major marketers within a particular city.

33 The data contained several "outliers." Thus, for two cities over the 22 month period, the range of the differential was 19 cents (0 to 19 cents and -13 cents to 6 cents). It is not known whether these observations represent significant errors in reporting.

This factor is acknowleged in internal company documents. For example, one company noted: "[T]he major problem has been the private branders — they have not gone along with price restorations except temporarily." Indeed, there is some evidence that independents may have induced medium size refiners with lower market shares or less advertised brands to adopt more price competitive strategies rather than follow marketing practices of the largest majors. As one company stated: "[It] is believed that additional major brand marketers with weak retail networks will adopt more competitive price practices in relation to the nonmajor branders, or in some cases will increase wholesale sales . . . . Such moves will maintain pressure on the spread between refinery and pump prices."

The effects of competition from independents appear to vary from place to place. One major company noted that, over a given time period, private brand impact varied noticeably depending upon the local availability of unbranded rack wholesale supplies:

> [T]he Independents are a powerful marketing force in the Mid-Continent area where ample product supply is available from Gulf Coast and Mid-Continent refiners. From there the Independents' market share progressively drops to the less-than-20% levels found on the West Coast and in the North Atlantic states where product supplies for Independents are less available.

In the Northeast region of the United States, internal documents of a major oil company discussed the minimal impact of independent marketers, because of limited supplies:

> The independents have the least market share and the poorest supply system on the East Coast, particularly in the Northeast. There are very few independent refineries, and the mini-majors, who traditionally supply the independent markets, are poorly represented on the East Coast, although they do obtain products by exchanges. In the Middle West and South and on the West Coast, the independents are strong, particularly in the Mid-Continent [region] . . . . The Northeast is a hard price area; most other areas are quite soft.

Company documents also support the view that the leading majors' marketing costs have exceeded those of the typical independent marketer throughout the 1970-1980 period. Whereas majors have traditionally favored high numbers of low-volume retail outlets, independents have traditionally followed a philosophy of a limited number of high-volume outlets. Thus, where independents could be assured of sufficient supplies, they could offer lower prices and thereby pressure leading majors to lower their prices (and perhaps adjust their cost structures) to remain competitive. As one company document noted prior to the price control period in 1972:

> "These observations support the hypothesis that the competitive pressure of independents strengthens in direct proportion to their market share, forcing reductions in price differentials and price levels, i.e., the majors are forced to price more competitively as independent market share grows."

The independents' focus on price competition continued during the controls period as well, when supplies were available. One major company noted, for example, in 1976:

> Major brand marketers are responding to increased nonmajor [sic] brand activity with more competitive pricing . . . . The result of these various pricing and retailing activities is a highly sensitive market with small price differentials resulting in sizeable volume shifts.

And following decontrol in January 1981, with sufficient product available for independents, the same major company noted:

> "[R]eady availability of product to all segments of the market has caused severe downward price pressure. This has permitted independent brands to market products with extreme aggressiveness in an effort to capture available volume in a declining market."

The majors have responded to this pressure from independents in a variety of ways. They shifted to using self-serve pumps at more stations. They introduced higher-volume stations that emphasized price over service, such as Exxon's Alert, Gulf's Safire, Mobil's Sello, and other "fighting brand" stations. More recently, some have dropped credit cards or imposed differential prices for credit and cash purchases; they have sold off many lower volume (more costly) locations; marketing department personnel have been reduced; and various withdrawals from whole territories where costs were presumably high have been implemented or announced.[34] Nevertheless, the independents' market share of gasoline sales in the country as a whole increased from 23 percent to 35 percent in 1980.[35]

4. **Price leadership.**

The structural characteristics of gasoline marketing are such that one would not predict that effective price leadership would be likely. Nevertheless, there is some evidence (particularly in company documents from the pre-embargo period) that price leadership does sometimes occur. In 1970 testimony, the President of the National Congress of Petroleum Retailers generally described gasoline pricing as follows: "Most areas of the country have a price leader, usually the strongest major in the area. He posts the price at which he is selling to his dealers. Usually the other suppliers in the area follow the price."[36] This description is corroborated by the internal company documents expressing the view of one larger company's Marketing Vice President:

> Particularly in [one region of the country], where we are the [price leader], implementation of [our pricing] policy has called for frequent bootstrap efforts on our part. We define a bootstrap to mean "a unilateral price increase followed by a waiting period to see if the competition will join us." In other

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34 Without relatively objective, contemporaneous internal documents (and very detailed and thorough examination of these) it would be extremely difficult to estimate the actual present day performance of the gasoline marketing operation within an integrated company. Appropriate allocation of costs to gasoline apart from other products, valuation of investment carrying or opportunity costs, and especially assignment of a realistic transfer price for the gasoline itself can each be critical factors. For example, a five-year forecast by one company in 1977 indicated a total profit in marketing of $890 million based on its "internally used transfer price" from refining to marketing; the same document notes, however, that using the "arm's length price which existed in the market place" would convert the same projection into a $1.33 billion loss.

35 Whether the independents' share will continue to rise, hold at its present level, or start to decrease will depend on a variety of factors. One of these factors may be the ability of relatively small independent refiners to survive in the post-controls period.

36 Marketing Practices in the Gasoline Industry: Hearings before Subcomm. on Antitrust and Monopoly of the Senate Comm. on the Judiciary, 91st Cong., 2nd Sess., Part 1 p.3 (1971) (testimony of H.C. Thompson).

areas, where we have comparatively low market position, our price restorations follow the reference marketer.

Being a consistent leader of upward price moves (or "restoration" attempts) in any given market would appear to impose a certain burden. Since leadership means going up first, coming down last, and generally averaging slightly higher prices than other majors in the area, the leader would appear to experience volume or market share losses relative to other marketers. One company's documents appear to confirm this analysis: "In some markets the Company is forced to decide between price stability or competitive position. Specifically, [our company] has often had to decide how much volume it is willing to sacrifice in order to encourage overall market stability."

5. **Practices that may facilitate price stability**

One company's documents indicate that prior to 1969, major refiners evidently felt free to telephone each other and verify net prices of competitors in a specific place.[37] But in its 1969 Container decision,[38] the Supreme Court in effect outlawed such direct inquiries by firms to find out what their competitors were charging. In commenting on the effect of Container, one company noted:

> It is difficult to over-estimate the significance of this development. Previously, with price verification, the individual majors knew the price levels of the other majors and some stability and order was possible. Today, the only

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37 By ascertaining temporary or local discounts from each other's wholesale price to dealers (temporary voluntary allowances or "TVA"), companies were apparently able to compute net price of gasoline at wholesale. One company described the benefit of such market discounts to price stabilization:

> The purpose of instituting a revised schedule for dealer and distributor sharing in depressed price markets is to discourage predatory or Maverick price behavior. It is apparent that the total of the 4.5 [cents] dealer margin and 2.75 [cents] distributor [jobber] margin encourages such predatory pricing, and we have strong evidence of this in southern Missouri, northern Arkansas, Oklahoma, and to a lesser degree in Kansas. . . . The idea of the proposal is to discourage promiscuous price cutting.

38 United States v. Container Corp. of America, 393 U.S. 333 (1969).

> information available is the actual pump price at the station which is set by some relatively irresponsible dealers, and when instability sets in, a single major does not know if this is a move by the supplier or by a few dealers.

Notwithstanding the demise of direct price verification after Container it may have been possible for refiners to continue monitoring individual refiner adjustments to dealer tankwagon prices, according to one company's internal documents. "[C]hanges in retail postings at a substantial number of service stations supplied by a competitor in a given area permit the inference that the supplier has made proportionate changes in its net retailer tank wagon prices."

6. Practices that undermine price coordination

Recent changes in major brand pricing practices may tend to complicate the monitoring of other firms' price moves. According to news reports, Exxon and Gulf, for example, are experimenting in certain states with "terminal-based" pricing for branded jobbers and dealers, which essentially will create more variations in delivered prices depending on trucking distance from individual terminals.[39] Several refiners have recently been experimenting with separate wholesale charges or discounts designed to recoup credit card costs, and Arco has eliminated its credit card altogether. Arco's action in particular apparently set off a flurry of price cutting by other majors, especially on the West Coast.[40] For about 18 months various "rebate" programs injected an especially chaotic element into major brand net wholesale prices, but most of these

39 U.S. Oil Week, Sept. 28, 1981, at 1-2. The net effect on price monitoring may, however, further depend on the timeliness and reliability (i.e., extent of discounts off) of such price postings.

40 U.S. Oil Week, Apr. 12, 1982, at 3.

programs were terminated this spring.[41] Considering the current relative glut of gasoline and the unknown future status of these and other such experiments, their long term impact cannot be predicted at the present time.

d. Nonprice competition

Gasoline is a commodity with standardized, specifiable qualities such as octane rating and lead content. But the selling of this commodity, especially as done by the largest firms, evolved into an offering of additional convenience, services, credit, and at times other inducements bundled together with the basic fuel. Such nonprice features can simply be the result of responses to consumer demand. In other cases, such features can be the result of an oligopoly's inability to control nonprice competition to the same degree it controls price competition.[42] Although it is difficult to determine their reliability, internal studies by the leading oil companies during the pre-embargo period suggested that the overall cost of their gasoline marketing significantly exceeded the associated increment in the value of their major brands in the marketplace. One company's internal analysis in 1971 implicitly reflected the conviction that the major brand marketing style would not be sustainable in a market where their wholesale supplies were offered as commercial or bulk sales, rather than through small outlets:

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41 With wide variations from refiner to refiner, the typical "rebate" program gave discounts to jobbers and dealers based on their individual sales volumes as a percentage of their individual sales volume in an earlier base period. Even though the formulas for each refiner's rebate program were announced, it would have been virtually impossible for another firm to calculate precisely the actual net selling prices of a particular refiner at a particular time. Ten refiners dropped rebates as of March 1, and several others ended their rebate programs during the ensuing weeks. U.S. Oil Week, Apr. 5, 1982 at 1.

42 An oligopoly may have much more difficulty controlling nonprice features because, among other reasons, nonprice inducements themselves can be more complex than price. That is, it is difficult to tell whether a certain advertising slogan is "worth" as much as a free glass; it is easy to tell that a 49 cent price is different from a 50 cent price. Also, new nonprice tactics can be expected to require some time lag before other firms can respond, whereas price "retaliation" can be almost instantaneous.

> If several of the large majors chose to abandon their service station business in favor of commercial or bulk sales, the independents would grow rapidly to a dominant position in the industry. This is already happening to some extent and is one of the reasons for current price problems.

The independents' growth in market share, about one percent of the market per year, may be a reflection of the traditional cost disparity between the majors' marketing style and that of the independents. However, marketing changes by the majors may have greatly reduced the traditional disparity. The majors have recently sold off many lower volume (more costly) locations; they now allow self-service at their branded outlets; they seem to less often advertise claims regarding gasoline specifically; credit card policies are being revised; marketing department personnel have been reduced; and various withdrawals from whole territories where costs were presumably extra high have been implemented or announced. Thus, it appears that the majors have made some shift toward lower cost marketing.

8. Conclusion

Significant shifts and changes in wholesale and gasoline marketing appear to have occurred since the 1960s. Different regions of the United States vary in the concentrations of sellers, and the relative strength and weakness of independent marketers and majors. Past merger activity does not appear to have affected concentration. However, mergers involving gasoline marketing should continue to receive close scrutiny under the antitrust laws. As indicated above, within the last ten months, the Commission determined that Mobil Oil Corporation's acquisition of Marathon Oil Company and Gulf Oil Corporation's acquisition of Cities Service Corporation might tend substantially to lessen competition in regional and local markets.

VII. CONCLUSION

Based on the foregoing, the Commission's findings with respect to the seven specific subjects enumerated in the January 15th Congressional request may be described in the following manner.

1. **The numbers and size and the descriptions of the terms of such mergers in each of the last ten years**

As discussed in Section III, by several empirical measures oil industry acquisition activity increased in the period 1979 and 1980 compared to earlier in the decade. However, an important part of this increase can be attributed to a few large acquisitions and to acquisitions of fossil fuel deposits. Terms of particular mergers are discussed in Sections III and IV and in Section VI(A).

2. **Factors influencing such mergers, including the role of oil price decontrol and the causes for their recent acceleration in number**

As described in Section IV, mergers are undertaken for a variety of reasons and no single theory can explain all mergers. However, at least part of the recent merger pattern appears to be due to a number of factors that gained prominence beginning in 1979. The rapid escalation of crude oil prices beginning early in 1979 made feasible a wider use of techniques for enhanced oil recovery, and this development may have encouraged the most technically capable firms to acquire reserves from other firms in order to exploit advanced recovery methods. The rapid price increases probably widened differences of opinion regarding future prices, and divergent expectations may have encouraged trades of fossil fuel related oil stocks and assets between those more pessimistic about future prices and those more optimistic. These conditions were reinforced by the phasing out and eventual decontrol of crude oil.

A number of additional forces may have influenced mergers. The windfall profits tax, for instance, increased the desirability of using certain enhanced recovery techniques, and may have motivated certain firms familiar with these techniques to acquire additional reserves. More generally, corporate income tax provisions encouraged mergers by allowing firms to increase the basis of acquired assets and to redepreciate the assets for tax purposes.

3. **The impact on competition and on the availability and prices of petroleum products to consumers**

This subject is discussed in Sections III and VI of the study. Based upon the analysis in those sections, the Commission does not believe that prices or availability of supply have been adversely affected by the acquisitions that have occurred in the past few years. Although in absolute terms many acquisitions have been large, compared to the size of the industry they have been relatively small. This can be attributed in part to the nature of the acquisitions. The largest acquisitions directly affecting competitive conditions have involved mainly crude oil assets where the market, with some exceptions, is world-wide, and where market concentration is not high.

4. **The effect of acquisitions in diverting investment capital for the exploration for and development of energy sources**

As explained in Sections III and IV, the large oil companies have (by various measures) increased their acquisition activity over the period 1979-1981, when compared with earlier years. However, this does not imply that capital has been substantially diverted from the exploration and development of energy sources, especially in view of the fact that exploration and production of crude oil generally increased during the same period. Also, it is worth noting that certain oil industry mergers might create a favorable environment for additional investments in crude oil exploration and production, as reserves are turned over to the firms best able to exploit them. Increased incentives from crude oil decontrol, tax legislation, and the desire to diminish OPEC dependence appear to have also resulted in an increase in exploration and production activity.

5. **The extent of concentration in each major section of the petroleum industry, the impact of such concentration on competition, and the impact of mergers on concentration levels**

Section VI of the study sets forth concentration levels for a variety of geographic markets at each level of the petroleum industry. These data show most markets are not highly concentrated. However, as explained in Section VII.A, competition is affected not only by the level of industry concentration but also by other conditions in the industry, including difficulty of entry, elasticity of demand, product homogeneity, and noncompetitive conduct.

Increases in concentration resulting from recent large mergers have been very small for the most part, and do not appear to have endangered competition. However, despite the existence of substantial competition in most aspects of the petroleum industry, mergers of competing petroleum firms should continue to be scrutinized for anticompetitive effects in particular markets. In the market for crude oil, the two potential sources of concern would be (a) that a merger might reduce the extent to which oil companies seek to obtain lower prices from the OPEC cartel, and (b) that a merger might have adverse effects on competition in regional markets in the U.S. At the refining level, there are a variety of possible product and geographic markets in which mergers could have anticompetitive effects. With respect to the transportation of crude oil and petroleum products, the most likely area of concern would be whether a pipeline acquisition conferred market power on the acquiring firm. At the marketing level, horizontal overlaps at the wholesale level, particularly in gasoline, as well as potential effects on supplies of gasoline to independent marketers, should receive careful scrutiny.

6. The transaction costs of such mergers, including fees to lawyers, investment bankers, and accountants, and the time expended by company officials in connection with the transactions

Section VI of the study concludes that the transaction costs for most acquisitions range from one-half of one percent to one percent of the purchase price. For a number of mergers, however, the amount may exceed the one percent level. In two recent large acquisitions — Shell/Belridge and Du Pont/Conoco — the estimated transaction costs equalled roughly six-tenths of one percent of the total purchase price. There are additional costs incurred by enforcement agencies in reviewing merger activity.

7. **The extent of any asserted efficiency justification for such mergers**

As noted in Section IV of the study, the most likely efficiency effect in a merger between crude oil producers would be the application of technical know-how to realize the maximum production from crude oil reserves and from revaluations of crude reserves. The former would result in lower production costs or higher output and the latter would alter investment decisions. The Shell/Belridge transaction and a number of other acquisitions may fit the first hypothesis. Although the evidence is less clear, Mobil's attempted acquisition of Marathon or Du Pont's acquisition of Conoco may fit the second.

In addition to requesting an analysis of the foregoing subjects, the Congressional inquiry mentioned the possibility of legislation to impose a moratorium on mergers between oil companies. Based on currently available information, the Commission recommends against any legislative ban on oil company mergers. Such interference in normal market forces is unwarranted, both because there have been no significant adverse implications on the state of competition in the industry from mergers, and because mergers with significant competitive impact can be satisfactorily examined under Section 7 of the Clayton Act and the 1976 Hart-Scott-Rodino amendments to that statute.

APPENDIX A

DATA FOR THE MERGER STUDY

I. Acquisitions by Large Petroleum Companies 1971–1981

A. The Data

The data used in the study of acquisition activity by large petroleum companies was developed in three steps. First, every transaction identified in five primary data sources was listed for each company, along with any information regarding the character of the transaction and the assets, sales, and consideration involved. These primary sources are:

1. The internal FTC version of the overall merger series;
2. The 1981 Moody's Industrial Manual description of each acquiring company;
3. Moody's Industrial News Reports 1971–1981;
4. HSR filings through January 1, 1982;
5. Piccini, Raymond, and Potter, Stephen Niles, Acquisitions by Large Oil Companies 1970–1978, API, Nov. 1979.

The second step was to use six secondary data sources both to fill in gaps in the above and to identify additional transactions. These secondary sources are:

6. Mergers and Acquisitions (Periodical);
7. Announcements of Mergers and Acquisitions (monthly), the Conference Board,
8. The following studies of oil company acquisitions by the Congressional Research Service:
    a. Spriggs & Scott, Mergers and Acquisitions by Twenty Major Petroleum Companies: 1968–76 (June 24, 1976).
    b. An Update on Mergers and Acquisitions by Twenty Major Petroleum Companies (Nov. 1977).
    c. Gelb & Jickling, Mergers and Acquisitions by Twenty Major Petroleum Companies: January 1977 through March 1981, (Apr. 9, 1981);

d. Gelb, Completed and Pending Acquisitions Involving Large U.S. Oil Companies: March 1, 1981 - Aug. 5, 1981, (Aug. 7, 1981);

9. Yearbook of Merger Activity, to January 1, 1980 (Cambridge Corporation Publishers);

10. Acquisition and Consolidation Report Niederhoffer, Cross & Zeckhauser Inc. (various issues for 1979).

11. Dun and Bradstreet, Million Dollar Directory Middle Market Directory (for sales data only).

A number of lists of oil acquisitions in various Congressional hearings and other publications were also examined. These are not listed because they all appeared to be derived from FTC or Congressional Research Service data or use less complete data than that in these two sources.

The third step was to confirm that the transactions identified in steps one and two were completed and to confirm, complete, and resolve contradictions in the data on assets, sales, and purchase price by referring to 10-K's, annual reports and Moody's publications for both the acquiring and selling firm.

B. The Merger Series

Transformation of the raw data into the merger series involved four steps. First, an acquisition was included in the merger series only if reliable confirmation of its completion was available. This confirmation was usually found in the financial reports of the parties to the transaction. A few transactions were confirmed only by Moody's Industrial Manual, the Piccini and Potter study, item 9 of an HSR filing (acquisitions in the last ten years), communications with the company involved, or the trade press.[1] If completion of a transaction could not be confirmed, it was not included in the merger series. While confirmation could be found for most transactions, there were exceptions. Since some of the deleted transactions may actually have been completed, this is a

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1 While sources one through ten above were used to identify transactions, only sources two and five were regarged as providing confirmation that the transaction was completed.

potential source of error in the data. This problem arose most often in connection with transactions during 1981, because some of the data sources used to confirm transactions are not yet available for the 1981 period.

The second step was to delete all transactions for which both the purchase price and the assets involved were less than $10 million. Transactions for which neither assets nor purchase price were known were also deleted. While a major effort was made to obtain a purchase price for every identified transaction, this effort was not completely successful. While most of the transactions excluded for lack of information were probably small, some transactions of $10 million or more could have been dropped from the data for this reason.

The third step was to resolve inconsistencies in the reported data. There are a number of instances in which different sources provided conflicting information on assets, purchase price, or sales. When the differences were irreconcilable, the following hierarchy of sources was used to choose the value used in the merger series.

Purchase Price

1. Company Financial Reports
2. Moody's
3. API Study
4. HSR filings and FTC Merger Series
5. Other

Assets and Sales

1. Company Financial Reports
2. Moody's
3. HSR item no. 9
4. API Study
5. HSR filings and FTC merger series
6. Other

The purchase price was obtained from one of the first four sources in virtually every case. Data on the assets and sales of the acquired firm were frequently obtained from the other sources. Two or three purchase prices had to be estimated because they were stock acquistions for which the number of shares issued was known but no overall valuation was found. In these instances, the mean of the stock's high and low in that year was used to value the transaction. Except for these instances in which the approximate price was calculated, every purchase in the data reflects the actual valuation of the transaction.

No information regarding purchase price could be found for one transaction of more than $10 million which appeared on a list of its acquisitions provided by one of the sample firms. This transaction was arbitrarily valued at $11 million. In all other cases the data should accurately reflect the value of the transaction.

Data on assets and sales were unavailable for probably a majority of all transactions in which the purchase price exceeded $10 million. In fact, such data were unavailable for such an overwhelming preponderance of transactions in which less than an entire company was acquired that it was not possible to use assets and sales derived from the various data sources to measure merger activity. Even for "whole company acquisitions," data on assets was unavailable for 11 of 52 transactions, and data on sales was missing for 8 of 52 transactions. However, since assets acquired is the measure of acquisition activity used in most past studies, it seemed desirable that some data on assets acquired (and on sales) should be provided. The fourth step in creating the merger series was to estimate the missing data.

Since the purchase price was known for every transaction with missing sales or assets data, the missing data were estimated for each year by assuming that the ratio of the acquired firm's assets (or sales) to purchase price was the same as the ratio of assets (or sales) to market value for the sample of large petroleum companies. If data on assets (or sales) were available for a particular transaction, ratios were derived using these figures to provide a second estimate of the missing data. When two estimates could be made, their average was used in the merger series.

These estimates will tend to overstate actual sales and assets because acquisition prices reflect a premium over the company's prior trading value (if not, there would not be a merger). Thus, the ratio of purchase price to assets for the acquired firm is likely to exceed the ratio of market value to assets for the sample of oil companies. Using the acquisition price to estimate acquired company assets (or sales) as described above will therefore provide an upward bias in the estimates of assets or sales acquired. The transactions with missing data were rather small, and any overstatement should have only a minor effect on the results and no effect on the "Large Whole Company Acquisition" data series.

C. Purchase Price as a Measure of Acquisition Activity

A significant difference between this and most previous studies of merger and acquisition activity is the extensive use in the present study of purchase price as a measure of acquisition activity.

The disadvantage of measuring acquisitions by purchase price rather than by total assets is that the size of the transaction will vary with the financial structure of the acquired company (particularly its leverage) when measured by purchase price. In recent years, however, accounting assets may provide an even worse measure of firm size because of inflation. The cost basis on which many assets are carried on a firm's books may have very little relation to their current market value. This is particularly true of crude reserves and is reflected by the fact that the market value of many crude producers is far in excess of their accounting assets.

Perhaps the best way of measuring firm size would be to sum the market value of the firm's common and preferred stock and the market value of its long-term debt. However, such a measure could be constructed only for publicly held firms, and even for them its construction would require enormous effort. The reason for this study's reliance on purchase price as a measure of acquisition activity is practical rather than theoretical. It is simply that the reported data on the assets involved in acquisitions of subsidiaries and divisions of firms is so limited that reliance on reported figures for assets acquired would require eliminating perhaps one-half of all transactions from the merger series.

The principal difficulty in using purchase price measures of acquisition activity is in valuing complicated and diverse transactions. Two recent examples illustrate this point. The agreement in Sun's acquisition of Texas Pacific (TP) from Seagram provides that "Seagram will retain a 25 percent reversionary interest in TP's U.S. producing properties and a 49 percent interest in TP's non-producing properties once certain criteria have been met. The criteria include Sun's recovery of the $2.3 billion purchase price and a committed minimum of $200 million in capital expenditures on the properties plus a rate of return of 14 percent on producing properties and 18 percent on non-producing properties."[2]

In Mobil's acquisition of TransOcean, Inc., from Esmark, Mobil paid $750 million for TransOcean Inc.'s assets, but "Esmark is entitled to a 10 percent net profits royalty interest in TransOcean's exploratory oil and gas properties."[3]

In principle, these features of the transactions could be valued but in practice the necessary information is seldom, if ever, available. In addition, it does not seem reasonable to describe the assets or interests which are retained by the seller as compensation paid by the buyer. The procedure adopted in this study is to treat provisions relating to retained equity interests[4] as describing a claim on the revenue stream which is not sold, rather than as compensation. Thus, such provisions do not alter the valuation of the transaction. For lack of any reasonable alternative, mandatory investment provisions are also ignored in valuing transactions.

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2 Oil and Gas Journal, "Sun, Seagram Sign Texas-Pacific Agreement," May 5, 1980, at 138.

3 The Oil Daily, August 27, 1980, at 192.

4 This procedure was applied only to claims on the residual. Thus, production payments are treated as debt financing and not as describing a retained interest.

A similar problem which arises primarily in the acquisition of whole companies is that the acquiring firm frequently assumes the long-term debt of the acquired entity. In some sources, the value of this debt is included in the valualtion of the transaction. In this study, however, the value of debt assumed is not added to the purchase price in valuing a transaction. This decision is arbitrary, but is based on a judgment that the available data would permit the consistent and accurate application of a rule excluding the value of debt assumed from the valuation of the transaction but would not permit a consistent or accurate application of any alternative rule.

II. Comparison of Merger Activity Between Large Petroleum Companies and Other Large Companies 1979-1981

Data for the comparison of merger activity among company groups were also developed using essentially the same sources of information and procedures described above. The starting point in the study was the FTC log of Hart-Scott-Rodino filings, since the analysis was restricted to those transactions for which a filing was made under HSR. Financial reports and other data sources previously mentioned were then used to determine whether or not these transactions were consummated and the valuation, assets, and sales of the acquired entity.

The determination of whether transactions for which a filing was made in the latter portion of 1981 were completed in 1981 or in 1982 was a particular problem. The reason for this is the previously mentioned lag in the publication of the various information sources used in this study. The procedure adopted was to include in the data transactions for which a filing was made in 1981 and were known to have been consummated in either December 1981 or January 1982 as well as those for which it is unclear whether the acquisition was consummated in either December or January. The effect of this procedure on the results is not material.

APPENDIX B

United States Senate

COMMITTEE ON THE JUDICIARY
WASHINGTON, D.C. 20510

RAL COUNSEL
RECEIVED
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January 15, 1982

Federal Trade Commission
RECEIVED
JAN 15 1982
Office of Chairman

Honorable James C. Miller, III
Chairman, Federal Trade Commission
6th Street and Pennsylvania Avenue, N.W.
Washington, D.C. 20580

Dear Mr. Chairman:

We are writing to request that the Federal Trade Commission conduct a thorough investigation of the impact of mergers and acquisitions involving large oil companies. Concern about the effects of mergers involving large oil companies has been evidenced in Congress recently in many ways. Hearings on this subject, and on merger activity generally, have been conducted in both the House and Senate by the Judiciary and Commerce Committees and Subcommittees. Several members of Congress have sponsored legislation to impose a moratorium on mergers between oil companies and one such bill passed the House on December 16, 1981. Concern in this area is heightened by a perception that merger activity involving petroleum companies has increased, a trend that you noted in testimony before the House Judiciary Subcommittee on Monopolies and Commercial law.

A study of oil company mergers by the Federal Trade Commission would be of great help to Congress in the exercise of its oversight and legislative responsibilities. In conducting your study, we would request that you focus on mergers and acquisitions of assets or stock in which the acquiring or acquired firm is a large domestic or international petroleum company or an affiliate. To the extent possible, this study should evaluate: (1) the numbers and size and a description of the terms of such mergers in each of the last ten years; (2) factors influencing such mergers, including the role of oil price decontrol, and the causes for their recent acceleration in number; (3) the impact on competition and on the availability and prices of petroleum products to consumers; (4) the effect of acquisitions in diverting investment capital for the exploration for and development of energy sources; (5) the extent of concentration in each major sector of the petroleum industry, the impact of such concentration on competition, and the impact of mergers on concentration levels; (6) the transactional costs of such mergers, including fees to lawyers, investment bankers, and accountants, and the time expended by company officials in connection with the transaction; and (7) the extent of any asserted efficiency justifications for such mergers. We would also appreciate a description and an evaluation of the adequacy of current law as it relates to mergers involving major oil companies.

We would appreciate your prompt attention to this request so that the study may be completed by June 30, 1982. If this time frame or the scope of the study as outlined above will create significant difficulties for the Commission, or if the cooperation of other federal agencies is necessary for the Commission to complete the study requested in this letter, we would appreciate being informed as soon as possible.

Sincerely,

Bob Packwood

Bob Packwood
Chairman
Senate Committee on Commerce Science and Transportation

Strom Thurmond

Strom Thurmond
Chairman
Senate Committee on the Judiciary

Howard W. Cannon

Howard W. Cannon
Ranking Minority Member
Senate Committee on Commerce Science and Transportation

Joe Biden

Joseph R. Biden, Jr.
Ranking Minority Member
Senate Committee on the Judiciary

John D. Dingell
Chairman
House Commerce Committee

Peter W. Rodino, Jr.
Chairman
House Judiciary Committee

James T. Broyhill
Ranking Minority Member
House Commerce Committee

Robert McClory
Ranking Minority Member
House Judiciary Committee

FEDERAL TRADE COMMISSION
WASHINGTON, D. C. 20580

OF THE CHAIRMAN

February 10, 1982

Honorable Bob Packwood
Chairman, Committee on Commerce,
Science and Transportation
United States Senate
Washington, D.C. 20510

Dear ~~Mr. Chairman~~ Bob:

Thank you for the letter of January 15, 1982, in which you and your colleagues request the Federal Trade Commission to study the impact of oil company mergers and acquisitions. We are pleased to undertake such a study addressing the specific areas mentioned in your letter. I understand that my staff has been in touch with yours and will arrange briefings from time to time as the study progresses.

As a basis for our research, we plan to rely on the Exxon discovery materials (Exxon Corp., et al., FTC Docket No. 8934, dismissed on September 16, 1981) and other information gathered in the Commission's recent energy activities. In addition, we have requested access to the basic oil company data supplied in the Energy Information Administration's EIA-28 Report form for major oil companies. (This information is gathered pursuant to the Financial Reporting System ("FRS") program.) The EIA-28 forms contain detailed financial information on company energy and non-energy activities, energy resource development activities, refining and marketing activities, and analyses of investment patterns. Other information will be requested, as necessary, from EIA, the Department of Energy, and perhaps other agencies.

Although the Commission is sensitive to the June 30, 1982 completion date specified in your letter, there is, of course, some risk that we may not be able to complete the entire study by that date. In addition I should note that while some of the questions addressed to us by your letter will be fairly easy to answer, others will likely prove difficult to answer with any great degree of precision. In any event, we shall do our best and will, of course, keep you advised of our progress.

Honorable Bob Packwood

Finally sir, let me apologize for the delay in answering your correspondence. (Before I did I wanted to identify the parameters of the study and be reasonably satisfied that we could deliver a quality product.) If I may be of further assistance in this or any other matter, please by all means, let me know.

Sincerely yours,

James C. Miller III
Chairman

FEDERAL TRADE COMMISSION
WASHINGTON, D. C. 20580

OFFICE OF THE CHAIRMAN

September 27, 1982

The Honorable Bob Packwood */
Chairman
Committee on Commerce,
Science and Transportation
United States Senate
Washington, D.C. 20510

Dear Chairman:

On January 15, 1982, you wrote to me requesting a thorough investigation of mergers in the petroleum industry. The Commission has completed the investigation you requested, and I am pleased to transmit to you the Commission's report on the impact of mergers and acquisitions involving large oil companies.

The study covers the issues suggested in your letter of January 15, 1982, although the organization of the report has been altered somewhat for expositional purposes. The report begins with a summary and a brief description of the petroleum industry. The section that follows analyzes the empirical data on oil mergers in response to your first request that we evaluate the number and size of mergers. Responses to your second, fourth, and seventh requests are found in the next section covering merger incentives, including factors influencing such mergers, the extent of asserted efficiency justifications, and the diversion of investment capital. The sixth issue you posed in your letter is addressed in the section on transaction costs. The third issue, the impact on competition, and the fifth issue, the extent of concentration in the petroleum industry, are discussed in the section on competitive factors in examining petroleum mergers. The conclusions of the study are summarized in a final section.

Commissioners Michael Pertschuk and Patricia Bailey have submitted separate statements pertaining to the attached report. Commissioner Pertschuk dissents from endorsing the report as a Commission study. In addition, I am submitting my own personal statement endorsing the Commission's report. All three of these statements are found in Appendix C of the report.

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*/ Identical letters were sent to Senators Thurmond, Cannon, and Biden, and to Congressmen Dingell, Broyhill, McClory, and Rodino.

If you or your colleagues have any questions concerning the Commission's study, please feel free to contact me, or your staff may want to contact Ronald B. Rowe, Assistant Director for Litigation (Petroleum), Bureau of Competition [(202) 724-1441] or Philip Nelson, Assistant Director for Competition Analysis, Bureau of Economics [(202) 254-7710].

We appreciate having this opportunity to be of service.

By direction of the Commission.

James C. Miller III
Chairman

APPENDIX C

SEPARATE STATEMENT OF CHAIRMAN JAMES C. MILLER III
CONCERNING THE OIL MERGER STUDY (SEPTEMBER 27, 1982)

Today the Commission is submitting to Congress a report entitled, "Mergers in the Petroleum Industry." In my judgment, this report contains well-reasoned analysis and wholly supportable conclusions.

On the occasion of submitting this report I want to take this opportunity to extend my personal commendation to the many Commission economists, lawyers, and other personnel who completed the task in exemplary fashion, under extremely trying circumstances occasioned by our simultaneous investigation of Gulf Oil Corporation's proposed acquisition of Cities Service Company. I also want to commend the staff for the courteous and responsive manner in which comments and suggestions from the various Commissioners were incorporated into the report.

I am confident that Congress will find the Commission's report a valuable input in its continuing deliberations.

SEPARATE STATEMENT OF COMMISSIONER PERTSCHUK
CONCERNING THE OIL MERGER STUDY TO BE SUBMITTED TO CONGRESS

September 17, 1982

I do not endorse all the conclusions of the report on oil mergers submitted to Congress. While the report contains a substantial amount of useful information and analysis, the policy conclusions seem to be that large oil company mergers do not divert capital from exploration and development of new sources of oil, that they often result in efficiencies, that past acquisitions have not harmed competition, and that no special legislation is necessary to deal with them. I disagree with each of these propositions, and I do not believe the report itself supports them.

The report concludes that oil mergers have not diverted capital from exploration "in view of the fact that exploration and production of crude oil generally increased during [1979-81]." (p. 296) However, a large number of factors may have encouraged production, including price increases and use of better recovery techniques. Moreover, the fact that exploration increased does not mean it would not have increased more without the easier alternative of buying another company's crude reserves.

A good example of an oil merger in which the acquiring company chose to substitute acquiring another company's reserves instead of pursuing its own development was Mobil's attempt to acquire Marathon. As the report itself states, "... there was no indication that Mobil would have been able to produce oil from

[Marathon's] Yates field more cheaply, or that Mobil could reduce its other cost of operation significantly through ownership of this source of crude oil." (p. 72) The best evidence on this point suggests that these reserves were undervalued in the stock market, and, therefore, Mobil wanted a cheap way to get reserves, saving it the expense of developing its own. To the extent that tax considerations, deflated stock values, or attempts to achieve market power create incentives to buy reserves rather than explore for them, there will inevitably be a reallocation away from development of new sources of crude.

The report concludes that "the most likely efficiency effect in a merger between crude oil producers would be the application of technological know-how to realize the maximum production from crude oil reserves and from revaluations of crude reserves." (p. 298) This statement is essentially a theoretical one rather than an assertion that efficiencies have been obtained. Although the report speculates that some oil company mergers have actually achieved efficiencies, the evidence is quite thin -- "anecdotal" might even be too generous a description. Of the three examples reviewed -- Shell/Belridge, DuPont/Conoco, and Mobil's attempt to buy Marathon, only one -- the Shell acquisition -- suggests efficiencies were obtained in recovery techniques, as the report notes. (pp. 70-71) Even in the case of Shell's purchase of Belridge, it was not essential that <u>another large oil company</u> had to purchase Belridge for it to pursue more efficient recovery techniques, only that management had to make the necessary decisions and convince capital markets that the expenditures in improving technology were worthwhile.

Finally, the report concludes that no legislative ban on oil company mergers is necessary and, implicitly, that no other type of legislation is needed other than Section 7 of the Clayton Act and Section 5 of the FTC Act. I disagree with this conclusion for two reasons. First, there are significant limitations under Section 7 to stopping horizontal mergers, and it is even more difficult to reach socially objectionable conglomerate mergers under existing law.

It is useful to examine existing concentration figures in the petroleum industry alongside the new Justice Guidelines for merger enforcement. As shown on pages 156 and 157, the market shares for crude oil production and reserves for the largest oil companies result in a Herfindahl index which, on a national basis, is lower than the Justice Guidelines threshold for mergers it is likely to challenge. 1/ In addition, the Guidelines indicate that a merger is unlikely to be challenged if the Herfindahl is not increased by more that 100. A merger between Exxon and Arco, the first and third largest companies in crude oil production, increases the Herfindahl by only about 78 points. The market concentration for crude oil reserves is

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1/ For example, the Herfindahl index for domestic crude oil production is approximately 300, based on the figures on p. 156. The Justice Guidelines state a merger is unlikely to be challenged if the Herfindahl for the market is less than 1000. These figures are based on the assumption of a national market. There may be regional markets or submarkets for crude and refined products.

somewhat higher, but still below the Justice threshold for mergers likely to be challenged. In addition, the Justice Guidelines indicate that imports of foreign production should also be considered in calculating market shares, and this lowers the market concentration further. 2/

The result of applying Justice Guidelines thresholds to oil mergers is that, based on national markets, a combination of Exxon and Sohio's crude production, or reserves, would not be in the "likely to challenge" range, even though those are the two largest companies in the U.S. in those areas. Mergers at the refining level may also be difficult to challenge at the national level, though there are likely to be regional markets for some products. 3/

One major consequence of the application of the Justice Guidelines to oil mergers at the crude oil and refining levels is that second tier oil companies may begin to disappear, leaving the domestic industry in the hands of eight or fewer giant companies. The attempted purchase of Marathon by Mobil, for example, almost resulted in the disappearance of Marathon as a vigorous second tier company with a history of supplying independent gasoline marketers with refined product. Yet the

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2/ The report contains extensive discussions of competitive effects of mergers at the production, refining, transportation, and marketing levels. While I agree with some points in the report's discussion of the proper analysis of these competitive effects, I do not endorse all of the report's statements and I do not consider them binding on future Commission decisions.

3/ For example, the Commission challenged the Gulf's proposed purchase of Cities Service, based on an assumption of regional markets in jet fuel.

Commission's official action was not to oppose Mobil's acquisition of Marathon's refining and crude oil assets, and, in fact, the papers filed by the Commission specified Mobil could acquire these assets. (Commissioner Bailey and I dissented from that course.) Luckily, the private court suit brought by Marathon resulted in the enjoining of the acquisition and the preservation of Marathon as an independent company.

Even more difficult to challenge are conglomerate acquisitions involving oil companies. It is surely significant to note that the three largest mergers in history -- DuPont/Conoco, U.S. Steel/Marathon, and Occidental/Cities Service have all occurred in the last year and all involved oil companies. As long as there are tax incentives and low stock values for petroleum assets, there will be incentives for these large acquisitions which have nothing to do with efficiencies.

What's wrong with these mergers? First, they may divert available credit from more productive uses. The spate of giant mergers in this past year tied up billions of dollars of available credit. Second, they divert the company's own capital and management resources to new lines of production which they may have no particular skill in managing. As Robert J. Samuelson put it in a recent essay in the National Journal, "The Bendix brawl has precious little to do with innovation. The dilemma of a mature economy is that investment decisions are dominated by mature corporations that may have a conservative bias. Doing big things to keep themselves big, they may ignore the small things that start tomorrow's industries." Third, aggregate industrial concentration has long term adverse social and political consequences by focusing economic and political power in fewer and fewer hands. I have recently provided a statement to the House Judiciary Committee on these points which is attached. 4/

One approach to stopping huge oil mergers that would otherwise be difficult to challenge under the antitrust laws is a temporary or permanent ban on oil mergers above a certain size. I support a temporary moratorium as one way of dealing with the current wave of oil mergers that are clearly not based on production efficiencies. A longer term solution, which I continue to favor, is a "cap and spinoff" approach to huge acquisitions. This was the approach advocated to Congress in 1979 by the Director of the Bureau of Competition and myself. 5/ Under it, an acquisition over a certain size would be permitted so long as assets equivalent in value to the purchased assets would be divested within a particular period.

Whatever the approach taken, I do not believe we can rely upon current law alone to deal with large oil company mergers. The combination of lax enforcement in some quarters and the difficulty of dealing effectively with conglomerate acquisitions under current law will lead to a permissive government attitude toward mergers that in the long run will prove harmful to our economic and political health.

4/ See also, M. Pertschuk and K. Davidson, "What's Wrong with Conglomerate Mergers?" Fordham L.Rev., Oct. 1979.

5/ The entire Commission, with the exception of Commissioner Clanton, advocated legislation to deal with conglomerate mergers in 1979 while not endorsing a specific approach.

STATEMENT OF

MICHAEL PERTSCHUK

COMMISSIONER

FEDERAL TRADE COMMISSION

TO

SUBCOMMITTEE ON MONOPOLIES AND

COMMERCIAL LAW

OF THE

HOUSE COMMITTEE ON THE JUDICIARY

AUGUST 26, 1981

I appreciate the opportunity to provide my views concerning the current wave of large mergers which we have witnessed over the past few months. */ It is important to note that this merger wave is not just a recent phenomenon but represents the continuation of an extraordinarily high level of large-scale merger activity over the last several years. The size of these acquisitions, however, has now reached unprecedented levels. As I testified with the Chief of Justice's Antitrust Division in 1978, there were 41 mergers over $100 million in 1977, 80 in 1978, 83 in 1979 and 94 in 1980. The Commission began to keep track of $500 million in 1978 -- there were six that year and 16 in 1979. Now there have been a significant number of billion dollar-plus mergers in 1981, culminating with the DuPont-Conoco acquisition valued at well over $7 billion.

There are three possible problems with such large mergers, all based on the fact they concentrate social, economic and political power. First, they may reduce competition in one or more markets. Second, they may harm the American economy by promoting inefficiency. Third, they may harm American society and the long run health of the American political process.

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*/ This statement reflects my own views and not necessarily those of the Commission or any Commissioner.

If the merger is between competitors, it reduces the number of firms in the market and may increase the tendency for supra-competitive oligopolistic or collusive pricing. If the merger is between a supplier and a buyer, it may reduce the opportunity for other suppliers or buyers to have access to supplies or customers. If the merger is "conglomerate," that is, it does not fit in either of these first two categories then there may be a loss of competition several ways. As one example, a leading firm in one market may become entrenched in a dominant position so that it is even less likely that it can be challenged. As another example, a large firm, which may have expanded internally to enter a new market and thereby improve competition, may take a short-cut by buying a major firm already in the market.

All these concerns of loss of competition are traditional antitrust principles and each large merger which possibly raises these problems deserves careful scrutiny. I fear there is some trend, particularly in the Justice Department, to abandon all concern about conglomerate mergers, and I strongly encourage my colleagues at Justice to continue to apply these traditional principles where appropriate.

The fact is, however, that existing antitrust laws are often not sufficient tools for dealing with massive combinations of corporate entities. This is true because, in general, the courts have construed the antitrust laws to require a clear showing of harm to competition in one or more markets before a merger can be judged unlawful. Sometimes it is difficult to make such a showing because the economic issues in a major merger case are complex indeed -- so complex that expert economists and lawyers on both sides can earn a living for many years while the dispute wears on, often coming to ambiguous results in the end. Sometimes the problem is not primarily one of harm to competition in particular markets but more general harm to our economy or our society. Consequently, I strongly encourage your serious consideration of additional legislation to deal with huge mergers which present no social or economic benefits.

Large mergers can harm efficiency by leading managers to focus attention on growth by acquisition rather than growth by innovation and internal capital investment and expansion. Whenever a corporation spends hundreds of millions of dollars to buy a leading firm in another market, it is not using this available cash or credit line to buy new capital equipment, to replace outworn plant, or to engage in research and development to support the core enterprise of the company. While the cash or stock paid for the acquired company does go to stockholders, they do not necessarily turn their windfalls into productive investments. There is evidence that some firms have sacrificed profitable internal growth opportunities to finance acquisitions. **/ As an August 10, 1981, Business Week editorial, titled "Mergers

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**/ D. Mueller, "The Effects of Conglomerate Mergers," 1 Journal of Banking and Finance 315 (1977).

are not Growth," stated, "What U.S. industry needs is giant investment in new products and modern manufacturing processes. It needs to shed its preoccupation with short-term earnings and be concerned with growth that also helps the economy to grow."

Some would argue that large-scale mergers must <u>increase</u> efficiency, or otherwise, they would not occur. But how do the proponents of large-scale mergers claim that they increase efficiency? One possible way is that poor management is replaced by better management. While this may be true in the case of small acquisitions, does it make sense to say that one giant corporation is able to better manage another giant corporation in a totally separate market than managers which can be brought in from outside the struggling firm? In fact, an analysis by William Abernathy and Robert Hayes of the Harvard Business School suggests that the American business executives' preoccupation with strategy and acquisitions, rather than productivity and investment, has contributed to the deteriorating position of American business. ***/ Even some leading advocates of diversification concede that most mergers have not improved corporate profits. ****/ The fact is that the desire of managers for

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***/ "Managing Our Way to Economic Decline," <u>Harvard Business Review</u>, July-August 1980.

****/ Salter and Weinhold, <u>Diversification Through Acquisition - Strategies for Creating Economic Value</u> (New York: The Free Press, 1979).

growth in itself, efforts to exploit low stock values and other motives, not necessarily related to a more efficient allocation of resources, are often the driving force behind large mergers.

Another possible efficiency argument is economies of scale. Yet, our foreign rivals have generally not relied upon bigness to compete but upon incorporating available innovations, emphasizing productivity, and producing high quality products. For example, in the Japanese auto industry, Toyota, Nissan, Mitsubishi, Togo Kogyo, Honda, and Fugi are all formidable world competitors which compete aggressively at home. In color TV's, the Japanese have Matsushita, Sony, Toshiba, Hitachi, Sanyo, and others. Similar examples are present in other industries. A series of recently completed cross-national studies by Keith Cowling, Michael Firth and others, has shown that, on average, no economic gains have resulted from mergers even between direct competitors.

The second problem -- concentration of economic and political power in fewer and fewer hands -- is inherently more subtle and difficult to evaluate. I cannot point to a numerical index which shows that American society becomes less democratic as an increasing proportion of its assets are owned by fewer companies. This is the very type of social concern that no economist, no cost-benefit analysis, can reduce to an equation. I deeply believe, however, that economic power is political power and that a concentration of the first means a concentration of the second and that the influence of the average citizen is correspondingly diminished.

The original antitrust laws were enacted in response to radical new concentrations of economic power. During this century, the antitrust laws have aided in slowing concentration in American industry, particularly by limiting horizontal acquisitions. However, there is no doubt that mergers have continued to contribute substantially to concentration levels. One study concluded that, during the period 1960 to 1968, mergers were responsible for increasing the share of the 200 largest manufacturing firms by ten percentage points. These figures suggest that aggregate concentration would have declined without the mergers which actually took place. While the figures on concentration trends in the total economy are somewhat mixed, it is clear there has been a long-term trend toward increased concentration in manufacturing. The largest 200 manufacturing firms in the U.S. have controlled over 60% of total manufacturing assets since 1972, a considerable increase over the 46% they controlled in 1947. Massive multi-billion dollar mergers threaten to dramatically change the character as well as the degree of this long-term trend.

In 1979, the Federal Trade Commission called upon Congress to enact legislation to deal with the then-current high level of large mergers. The aggregate size of acquisitions that frightened us then is mild compared to the magnitude and level of merger activity that faces us now. As I felt in 1979, I believe we do know enough to conclude that the burden should be shifted to the proponents of large-scale mergers to demonstrate their benefits.

In my view, the conceptual approach in H.R. 4409 is sound. This bill functions principally to shift the burden of persuasion, not to prohibit huge mergers altogether. If the proponents of a large acquisition could demonstrate that the transaction would substantially enhance competition or result in substantial efficiencies, the bill's prohibition would not apply. Moreover, I believe it is essential to retain a "cap and spinoff" approach as embodied in H.R. 4409. This provision allows businesses the flexibility of having an option to divest assets equal in value to those they wish to acquire. Thus, H.R. 4409 would not prevent mergers which promised significant efficiencies, even if the proponent could not (or did not want to try to) sustain his burden of demonstrating the merger would help competition or achieve efficiencies. As I have previously testified, a demonstration of efficiencies will often lead to complex and possibly unworkable litigation. The "cap and spinoff" approach reduces this problem by preserving flexibility and allowing beneficial mergers when such a showing cannot be made.

I strongly support the efforts of the Subcommittee in dealing with this important set of issues, and I encourage your serious consideration of the concepts embodied in H.R. 4409.

SEPARATE STATEMENT OF COMMISSIONER BAILEY ON SUBMISSION TO CONGRESS OF OIL MERGER STUDY

SEPTEMBER, 1982

The Commission's study of recent merger activity in the U.S. oil industry is an honest and responsible treatment of the subject by a group of Commission attorneys and economists who are experienced in the workings of the petrcleum industry. It should not, however, be construed to be--nor does it purport to be--the definitive government study of oil mergers. The report was prepared under tight time constraints, involved no new use of compulsory process to obtain important empirical information, and deals in detail with only a few mergers occurring over a relatively short time frame. I accept this report as descriptive and analytical as to a few mergers that we have already witnessed, and overly broad generalizations drawn from these few examples can be misleading. It is enough to say that the report is likely to be useful generally, both to the Congress and to the public seeking to explore the possible motivations for and potential effects of these large mergers.

The editing of the report reflects the unavoidable compromises that proceed from the collaboration of more than a score of writers and researchers. I cannot say that I am in agreement with each editorial decision or judgment call that attributes particular likely procompetitive results from oil mergers.

There are some areas of the report that deserve particular attention in this regard. I'm not sure the conclusion that some recent mergers may have facilitated the development of crude oil reserves should be read so broadly as to be a judgment sanitizing future oil mergers where crude oil is part of the package of assets to be acquired. I am therefore also uneasy with the conclusion that oil mergers may create efficiencies as eager acquiring firms bring superior resources and technology to bear to develop newly acquired reserves. It may be that there is an opposite incentive to remove reserves from the development agenda, although the mergers studied do not support this thesis. I also believe the report contributes relatively little to a better understanding of the significance of vertical integration in this industry, where very large corporations meet repeatedly, but in different markets. It seems to me this might heighten prospects for collusion. Similarly, the relationship of these mergers to the competitive situation in the international crude oil market is imperfect in outline. A good deal of sophisticated theorizing links domestic merger activity with positioning on the part of U.S. firms to deal with OPEC cartel strategies. But little hard information is now available upon which one could render a responsible judgment. In the section on marketing there is more disagreement between the economic theorists and the practicing lawyers than appears in a quick read of the report. Finally, students of the editorial process in the evolution of this report will no doubt also note the failure to make more use of the documents we have obtained in previous investigations and cases--documents that bear vital witness on some of these issues. I understand many of these documents are subject to confidential treatment under the law and I fully agree that there cannot be a breach of trust on the Commission's part where such oil company documents are involved.

I do feel comfortable with the report's main policy conclusion, which is that drastic new legislation is not needed at this time to deal with the anticompetitive consequences of oil mergers. I believe these mergers can be tested in accord with traditional merger analysis, in terms of head to head competition in one or more segments of the industry.

What we need to deal with these mergers is a firmer resolve to apply existing legal remedies, particularly the preliminary injunction vehicle under Section 13(b) of the FTC Act. As the Commission's report observes, there are often both procompetitive and anticompetitive consequences in at least some of these oil mergers. Where anticompetitive features are present in such cases, I would not hesitate to bring an injunction proceeding to prevent the merger. The Commission and the parties to such transactions should understand both the seriousness and the urgency in finding remedies to potential competitive problems. In some instances, these issues can be resolved prior to consummation of a merger, but in other cases the transactions may have to be halted if the Commission is to uphold the public interest. The sheer size and momentum of these mergers calls for a tougher government antitrust posture, not an unseemly agency scramble to get out of the way.