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Performance Profiles of Major Energy Producers 1993

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Diskette Information

Historical Financial Reporting System (FRS) data are available on a 3.5 or 5.25 inch high-density diskette. These data cover the years 1977 through 1993, published in the Energy Information Administration's annual editions of *Performance Profiles of Major Energy Producers.* There are two different sets of data: aggregate data from the FRS survey form, and multi-year tables from Appendix B of *Performance Profiles of Major Energy Producers.*

The Financial Reporting System, 1977-1993 diskette is available from the Energy Information Administration. Please contact Gregory P. Filas. Telephone (202) 586-1347, Fax (202) 586-9753, or on INTERNET gfilas@eia.doe.gov.

Preface

The purpose of this publication is to examine developments in the operations of the major U.S. energy-producing companies on a corporate level, by major line of business, by major function within each line of business, and by geographic area.

Pursuant to Section 205(h) of the Department of Energy Organization Act, which established the Financial Reporting System (FRS), the Energy Information Administration (EIA), through its Form EIA-28, collects financial information and other measures of energy-related business efforts and results for major energy companies. Since the FRS data are collected on a uniform, segmented basis, the comparability of information across energy lines of business is unique to this reporting system. For example, petroleum activities can be compared to activities in other energy lines of business or nonenergy areas, and domestic activities can be compared to foreign activities.

This report presents data collected on Form EIA-28 for the calendar year 1993. The report also features a review of energy company strategies following the Arab Oil Embargo of 1973-1974. The FRS data, which span the 1974-1993 period, are utilized for this review. In 1993, 25 companies filed Form EIA-28. The analysis and data presented in this report represent the operations of the FRS companies in the context of their worldwide operations and in the context of the major energy markets which they serve. Both energy and nonenergy developments of these companies are analyzed. Although the focus is on developments in 1993, important trends prior to that time are also featured.

Economic performance, in financial and physical dimensions, continues to serve as a significant factor in evaluating past decisions and guiding future options in the development and supply of energy resources. The information contained in this report is intended to promote an understanding and provide a critical review of the possible motivations and apparent consequences of investment decisions by some of the largest corporations in the energy industry. The information is intended for use by the U.S. Congress, Government agencies, industry analysts, and the general public.

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Performance Profiles of Major Energy Producers 1993 is the seventeenth annual report of the Energy Information Administration's (EIA) Financial Reporting System (FRS). The report examines financial and operating developments in energy markets, with particular reference to the 25 major U.S. energy companies required to report annually on Form EIA-28 (see the box entitled, “The FRS Companies in the U.S. Economy and Energy Markets,” page 5, and page 111 for a listing of FRS companies). Financial information is reported by major lines of business, including oil and gas production, petroleum refining and marketing, other energy operations, and nonenergy businesses. Financial and operating results are presented in the context of energy market developments with a view toward identifying changing corporate strategies and measuring the performance of ongoing operations both in the United States and abroad.

This year's report analyzes financial and operating developments for 1993 (Part I: Developments in 1993) and also reviews key developments during the 20 years following the Arab Oil Embargo of 1973-1974 (Part II: Major Energy Company Strategies Since the Arab Oil Embargo).

Developments in 1993

In 1993, a year characterized by declining oil prices and global economic growth, the FRS companies' net income (excluding unusual items) increased 17 percent to $18 billion. The increase in earnings was generated by refining and marketing operations both in the United States and abroad, with a combined increase in income of $4 billion over 1992 levels. This increase more than compensated for the $2 billion reduction in earnings from oil and gas production caused by lower oil prices.

- *Refining and Marketing.* Income generated by the FRS companies' U.S. refining and marketing operations improved in 1993, after three consecutive years of poor financial results. Lower refined product prices and the continued U.S. economic expansion generated record levels of demand for gasoline and increased the demand for other high-end products. Due to successful cost cutting and consolidation of refining and marketing operations, the FRS companies were able to meet demand in 1993 with products that cost less to produce, so that income from U.S. refining and marketing increased more than fivefold from 1992 levels. The increase in income improved the return on U.S refining and marketing investment from 0 to 3 percent. Return on investment in foreign refining and marketing also increased, from 8 percent to 11 percent.

  Capital expenditures for refineries were lower in 1993 than in recent years, because projects for upgrading capacity, some of which were required to comply with Federal environmental regulations, were recently completed. Nevertheless, the FRS companies' worldwide capital expenditures of $10 billion for refining and marketing were exceeded only by expenditures in 1991 and 1992.

- *Oil and Gas Production.* Although natural gas prices in North America were nearly 20 percent higher than 1992 levels, income from the FRS companies' oil and gas production operations was down in 1993 due to the decline in world oil prices of about $2 per barrel. The FRS companies responded to lower oil prices by continuing to cut costs and consolidate their oil and gas operations, particularly in onshore areas of the United States. Expenditures for onshore exploration and development declined to $7 billion, the lowest level since 1977. In contrast, spending for offshore exploration and development projects in the United States, although low in comparison with most other years, increased 23 percent over 1992 levels, to $4 billion. Most of the increase was traceable to drilling and equipping of natural gas development wells.

Abroad, exploration and development expenditures for all foreign regions totaled $13 billion, essentially unchanged from 1992 levels. A reduction of $2 billion in exploration and development expenditures in Organization for Economic Coordination and Development (OECD) Europe resulted from a change in the United Kingdom's tax laws affecting exploration expenditures, and the completion of previous North Sea projects. In contrast, spending increased 41 percent in Canada, to $2 billion, as the result of recently introduced tax incentives for oil well drilling and improved prospects for natural gas sales.

- *Natural Gas Prospects*. Higher natural gas prices in the United States and Canada, and increased worldwide demand for natural gas in 1993 (excluding the countries of the Former Soviet Union) motivated FRS companies' efforts to develop gas reserves. The FRS companies completed more than four times as many gas wells in Canada in 1993 as in 1992, in response to higher prices and to prospects of expanded exports to the United States. In the United States, the number of gas wells completed by FRS companies doubled over 1992 levels in offshore areas and increased 5 percent in onshore areas.

  Additions to oil and gas reserves tended to reflect patterns of FRS exploration and development activity. The rate of replacement of foreign natural gas production through additions to reserves was 149 percent in 1993, while 99 percent of foreign oil production was replaced in 1993. In the United States, the FRS companies replaced 74 percent of gas production in onshore areas, but replaced 133 percent of offshore gas production. They replaced only 49 percent of onshore oil production, but 172 percent of offshore oil production in 1993.

- *Other Income, Taxes, and Cash Flow*. In addition to petroleum (including natural gas production), the FRS companies are involved in chemical and other diversified businesses, and to a lesser extent in production of coal and other energy. Income from nonenergy operations, primarily chemicals, increased 13 percent from 1992, to $4 billion. Income from coal and other energy fell nearly 50 percent in 1993, largely reflecting divestitures of U.S. coal assets by some FRS companies in recent years. Interest expenses decreased by $1 billion in 1993, due to a combination of lower interest rates and debt reduction.

  The FRS companies' effective rate of taxation on worldwide operations fell from 38 percent to 37 percent in 1993, despite the legislated increase in the U.S. corporate income tax rate from 34 percent to 35 percent. Several factors mitigated the effects of the rate increase, including the reversal of the effects of the Alternative Minimum Tax, which in 1993 reduced rather than increased the tax payments required of the FRS companies. In addition, lower income taxes were levied by foreign governments, particularly the United Kingdom.

  Cash flow from operations increased by $5 billion over 1992 levels. This increase can be traced to improved financial results in refining and marketing operations, reduced income tax payments, and lower interest expense. An additional $5 billion in cash was raised through sale of assets. Several possible uses of the funds, such as adding to capital or paying out dividends, were essentially unchanged from 1992. Instead, the FRS companies used the cash to continue to pay off long-term debt and to avoid taking on increased amounts of new debt.

Major Energy Company Strategies Since the Arab Oil Embargo

The year 1993 marks the twentieth year spanned by the collection of FRS data. The year also marks the twentieth anniversary of the Arab Oil Embargo. The embargo was a watershed event that propelled energy markets into prominence as crucial components of the global economy and areas of policy concern at all levels of government, including international alliances. The coincidence of the two anniversaries is not accidental. In the context of the oil price escalations following the embargo, many concerns of U.S. policymakers centered on the major energy companies. The EIA developed the FRS in order to address issues involving the financial performance of the major energy companies and the costs of energy resource development, supply, and distribution.

The FRS is unique among Federal data collection programs in its line-of-business format and ability to match companies' financial measures with associated physical results. The 20 years of FRS data are utilized in Part II of this report to provide a corporate financial perspective on energy market developments and related policy actions following the onset of the Arab Oil Embargo in late 1973.

The beginning of the 1974-1993 period and the present offer many contrasts. The period began during a time of record high oil prices and the preeminence of the Organization of Petroleum Exporting Countries (OPEC). In 1993, the role of OPEC in oil markets, though still important, is diminished and world oil prices (adjusted for inflation) are about half the level of 1974. The period also began with state energy resource nationalization, confiscatory taxation of oil earnings, and government intervention in energy markets. In 1993, state energy companies are moving toward forms of privatization. Foreign investment in energy is often welcome, and the tax structures of oil-producing nations are largely competitive. Belief in free markets has definitely undergone a renewal. Perhaps most surprising of all, in the beginning of the era the United States and the Soviet Union were contenders in a political and ideological cold war, while in 1993, the Soviet Union is dissolved and Communism in practice is defunct. Ironically, oil and gas prospects in the states of the Former Soviet Union have become some of the most prominent targets of investment for the FRS companies.

Throughout the two decades following the Arab Oil Embargo, the FRS companies remained major players in energy markets. Changes in U.S. capital markets and the increase and subsequent collapse in world oil prices caused the FRS companies to institute changes in corporate strategy, and in the most recent decade, to aggressively cut costs and streamline their resource development and refinery operations. This report reviews the strategies of the major energy companies in relation to energy market developments and shifts in government policies. The main findings include:

- *Corporate Strategy*. The increase in oil prices that began in late 1973 and lasted until early 1981 dampened demand for petroleum products, limiting the growth of the FRS companies' core business. Nevertheless, consistent with managerial and shareholders' preferences of the period, the FRS companies sought to reinvest the massive cash flow stemming from higher oil prices. Businesses outside petroleum appeared to offer avenues for investment and corporate growth. Diversification beyond petroleum involved a wide range of activities, from mining and agriculture to direct mail and retailing. Unfortunately, ventures into diversified businesses often provided lower rates of return than petroleum operations, which decreased overall corporate profitability.

  After reaching a peak in early 1981, oil prices generally declined. Expectations of lower oil prices reduced the prospective profitability of oil and gas production, the FRS companies' primary source of earnings. Demand by shareholders for better performance, and the threat of takeover attempts in the early 1980's spurred the FRS companies to increase investor returns. The FRS companies used cash generated by ongoing operations, transferring it directly to shareholders in the form of dividends and stock repurchases and, indirectly, by reducing corporate debt. They further redirected investment to their main lines of business: oil and gas production, refining and marketing, and chemicals, and sold off diversified businesses. The collapse in oil prices in 1986 added to the imperative for retrenchment and restructuring, further propelling sales of poorly performing assets.

- *Oil and Gas Resource Development*. Before the Arab Oil Embargo, the FRS companies dominated the world petroleum market, with ownership interests in oil and gas reserves across the globe, including huge reserves in the Middle East. The increased exercise of OPEC's market power, in addition to raising oil prices, also included nationalization of significant parts of the FRS companies' assets and imposition of confiscatory taxes. The FRS companies responded to the loss of low-cost investment targets by developing oil and gas resources in relatively expensive but politically secure regions of the world, particularly the United States. The high price of oil supported the increase in the cost of developing these resources.

The oil price decline that began in 1981 and the oil price collapse of 1986 compelled the FRS companies to reduce the cost of adding oil and gas reserves. The companies adopted several strategies to accomplish this. They became more selective in choosing drilling prospects, and abandoned high-cost exploration projects. At the same time, they concentrated on less risky development projects and adopted advanced technology to increase the productivity of drilling. Perhaps the most far-reaching strategy adopted by many of the FRS companies', however, was the shift in resource development out of the United States and into relatively low-cost foreign regions following the oil price collapse. By 1991, the FRS companies' exploration and development expenditures directed to foreign locales exceeded U.S. expenditures, as they have in all subsequent years. This shift has contributed to increased U.S. dependence on foreign sources of oil, but at the same time it has contributed to the geographic diversity of crude oil supplies.

- *Downstream Petroleum*. The FRS companies' downstream operations (refining, marketing, and transport) had to adapt to a rapidly changing environment following the Arab Oil Embargo. Key developments included generally deteriorating quality of crude oil supplies, substantial shifts in the level and composition of refined product demand, a variety of government policies directed toward petroleum refiners and marketers, and wide swings in oil prices. During the two decades following the embargo, the profitability of refining and marketing was volatile. Periods of excess capacity compelled massive shutdowns and cut-backs. For example, the FRS companies' U.S. crude oil distillation capacity peaked at 15 million barrels per day in 1980 (78 percent of total U.S. capacity), but, in 1993, capacity was 11 million barrels per day (68 percent of total U.S. capacity). Multi-national refiners in the FRS group made even more severe cutbacks in foreign capacity. Nevertheless, the FRS companies incurred substantial capital outlays for refining and marketing.

  Capital outlays were mainly directed toward upgrading refineries to produce lighter products and utilize lower quality crude oils, while meeting heightened environmental quality standards. Over the 1974-1993 period, U.S. refiners have had to face more stringent environmental standards for refinery emissions and effluents and for refinery products, particularly transport fuels. The path of FRS refiners' environmentally-related capital expenditures tended to reflect the passage of major environmental legislation. In the mid-1970's, over 30 percent of the FRS companies' capital expenditures for U.S. refineries was for pollution abatement. The comparable share fell to less than 10 percent in the mid-1980's. The most recent data indicate that in 1992, environmentally-related capital expenditures accounted for nearly 40 percent of the FRS companies' outlays for U.S. refineries.

Due to upgrading investments, the refineries retained by the FRS companies are much more sophisticated than those of 1974. Gasoline manufacturing capability, relative to the basic U.S. refinery capacity of the FRS companies, increased by a third over the 1974-1993 period, and the capability to utilize lower quality crude oils doubled. Gasoline marketing, after undergoing massive consolidation following the Arab Oil Embargo, became a target of FRS investment following the collapse of oil prices in 1986. Lower oil prices led to increased petroleum product demand, particularly for transport fuels. Over the period, gasoline has become a much more tailored product, with most gasoline now sold through high-volume, self-service outlets rather than through low-volume, high-service outlets. The combination of cutbacks and capital expenditures increased the productivity of FRS retail gasoline outlets fourfold over the period.

Part I

Developments in 1993

1. Energy Markets in 1993

Economic Growth, Lower Oil Prices, and Downstream Improvements

The 25 companies reporting to the Energy Information Administration's (EIA's) Financial Reporting System (FRS) derive the bulk of their revenues from petroleum operations, including natural gas production (see the box entitled, "The FRS Companies in the U.S. Economy and Energy Markets").[1] A majority of FRS companies are multinational, with over a third of the companies' assets allocated to foreign operations. Developments in petroleum and natural gas markets in the United States and abroad are of primary importance to the FRS companies' financial performance. The efforts by these companies to reduce the costs of ongoing operations through consolidation were also of importance in 1993.

Overall measures of global petroleum supply and demand appear to indicate that 1993 was a stable year for petroleum markets. World petroleum consumption[2] and oil production[3] were within 1 percent of the 1992 level. Despite the seeming absence of dynamism in 1993, the FRS companies' financial results reflected a rebound in downstream petroleum (refining, marketing, and transport) earnings from a very poor performance in 1992. The downstream recovery more than offset a deterioration in upstream (oil and gas exploration, development, and production) earnings. The FRS companies also improved bottom-line results through cost cutting and business consolidation in 1993.

Poorer upstream financial performance in 1993 was largely the result of lower oil prices, which were nearly $2 a barrel lower than in 1992. Most of the oil price decline occurred in the fourth quarter, as the Organization of Petroleum Exporting Countries (OPEC) increased production and were unwilling to reduce crude oil production quotas at their November meeting, leading to a downward slide in crude oil prices. An unusually high level of world crude oil inventories also put downward pressure on prices during late 1993.

On the demand side, although world petroleum consumption was down less than 1 percent in 1993 compared with 1992, consumption patterns varied widely across regions. At one extreme, the economies of Southeast Asia and the Pacific Rim (apart from Japan) grew at a 7-percent clip as measured by real Gross Domestic Product (GDP),[4] and petroleum consumption rose at an 8-percent rate. Several of the FRS companies have substantial refining and marketing operations that serve the economies of the Pacific Rim. At the other extreme, the former Soviet Union countries' collective GDP fell 13 percent, and petroleum consumption declined 19 percent. The U.S. economy was well within these extremes, with growth in GDP of 3 percent and petroleum consumption up 1 percent. Sluggish growth in Japan and OECD Europe led to reduced petroleum consumption in these regions. While global petroleum consumption was down slightly, gasoline and distillates registered 3-percent growth.[5] Massive investment in refinery upgrading in recent years enabled many of the FRS companies to benefit from the growth in demand for lighter end products in 1993.

In contrast to oil demand, natural gas demand was up substantially in most parts of the world. In the United States, 4-percent growth in natural gas consumption came largely from increased industrial demand. Abroad, apart from the former Soviet Union, natural gas consumption in 1993 was 6 percent above the 1992 level.[6] Natural gas prices were higher in the United States, reflecting the competitive nature of U.S. markets. Improvements in prices and the longer-term outlook for

[1]The companies that reported to the FRS system for the years 1974 through 1993 are listed in Appendix A, Table A1.

[2]British Petroleum Company p.l.c., *BP Statistical Review of World Energy*, June 1994, p. 4.

[3]Unless otherwise noted, annual energy industry price and quantity data are from the Energy Information Administration, *Annual Energy Review 1993*, DOE/EIA-0384(93) (Washington, DC, July 1994) and monthly data are from Energy Information Administration, *Monthly Energy Review*, September 1994, DOE/EIA-0035(94/09) (Washington, DC, September 1994).

[4]The WEFA Group, *World Economic Outlook*, July 1994, p. 5.11.

[5]*BP Statistical Review of World Energy*, June 1994, p. 8.

[6]*BP Statistical Review of World Energy*, June 1994, p. 22.

natural gas in recent years have led the FRS companies to increase their efforts to develop additional sources of gas supply, particularly in North America. Accordingly, natural gas accounts for a larger share of the FRS companies' upstream sales and production. Nevertheless, gas revenues did not increase enough to offset the effects of lower oil prices on upstream earnings.

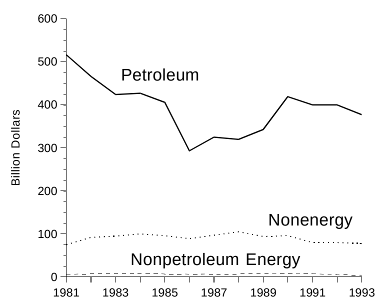
Part I of this report reviews the FRS companies' 1993 financial performance in the context of energy market developments and the companies' responses to these developments. Chapter 2 presents an overview of sources of income, cash flow, taxation, and deployment of funds including investment patterns across lines of business. Chapter 3 reviews the FRS companies' performance in petroleum and natural gas operations from geographical and functional perspectives. Chapter 4 examines developments in energy sources other than petroleum and natural gas. Appendix A describes the structure of the FRS data collection system, and Appendix B presents detailed statistical tables. A glossary provides key definitions.

The FRS Companies in the U.S. Economy and Energy Markets

Major energy-producing companies annually report to the Energy Information Administration (EIA) on Form EIA-28. These reports include data and information on financial and operating developments. For the reporting year 1993, 25 companies filed this information.[a] The FRS companies occupy a major position in the U.S.[b] economy. In 1993, their sales equaled 19 percent of the $2.4 trillion in sales of the *Fortune* 500 largest U.S. industrial corporations,[c] and their assets were equal to 17 percent of those of the *Fortune 500* companies. Of the top 25 companies (based on sales) on the *Fortune 500* list in 1993, 9 were FRS companies.

The reporting companies engage in a wide range of business activities, but their most important activities are in the energy sector. About 83 percent, or $381 billion, of allocated operating revenues were derived from energy sales. Nearly all of these sales involved petroleum (Figure 1). (For purposes of this report, petroleum is defined to include natural gas.)

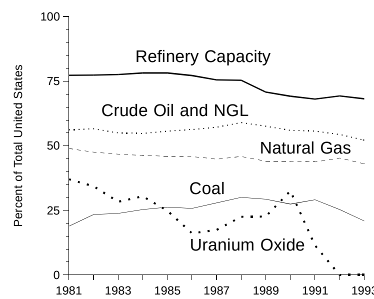
Figure 1. Operating Revenues by Line of Business for FRS Companies, 1981-1993



Source: Energy Information Administration, Form EIA-28.

In 1993, the FRS companies accounted for 54 percent of total U.S. crude oil and natural gas liquids (NGL) production, 43 percent of U.S. natural gas production, and 68 percent of U.S. refinery capacity (Figure 2). The bulk of the FRS companies' assets and new investments is devoted to sustaining various aspects of petroleum production, processing, transportation, and marketing. Nonenergy businesses accounted for about 17 percent, or $78 billion, of the FRS companies' allocated revenues in 1993.

Figure 2. Shares of U.S. Energy Production and Refinery Capacity for FRS Companies, 1981-1993



Source: See Appendix B, Table B1.

Nonpetroleum energy production is a relatively small part of the FRS companies' operations. The combined operating revenues of coal, nuclear, and nonconventional energy operations of the FRS companies totaled $4 billion in 1993, or only 1 percent of allocated revenues. Nonetheless, the FRS companies are significant participants in the coal market, producing 21 percent of U.S. coal in 1993. However, they no longer produce uranium oxide domestically.

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[a]Aggregate time series data from Form EIA-28 for 1977 through 1993 can be obtained from the EIA (see contacts, p. ii) on paper or diskette. In addition to the data provided by the detailed statistical tables in Appendix B and in the appendices of previous versions of this report, aggregate time series data from Form EIA-28 are available in a special post-embargo report covering the period 1974 through 1980. See Energy Information Administration, *Energy Company Development Patterns in the Post-embargo Era*, Vol. 1 and Vol. 2, DOE/EIA-0349 (Washington, DC, September 1982). See also a special analysis of energy developments in the 1980's published in Energy Information Administration, *Performance Profiles of Major Energy Producers 1990*, DOE/EIA-0206(90) (Washington, DC, December 1991), Part II.

[b]For purposes of this report, the term "United States" typically includes the 50 States, the District of Columbia, Puerto Rico, and the U.S. Virgin Islands.

[c]The *Fortune 500* is a list of the 500 largest U.S. industrial companies, ranked by total sales, published annually by *Fortune* magazine. To be listed, companies must obtain a majority of their sales revenues from manufacturing/mining, which includes oil production and

refining. Financial and operating statistics for the *Fortune 500* are therefore suitable for comparison with related FRS measures. Since all but one FRS company have sales revenues sufficient to qualify, the few exclusions of FRS companies from the *Fortune 500* are due principally to foreign ownership or sales in non-manufacturing sectors. All *Fortune 500* statistics used in this boxed discussion have been adjusted by the addition of those FRS companies excluded from the original *Fortune* lists. These companies are Anadarko, BP America, Enron, and Union Pacific. BP America became a 100-percent owned subsidiary of British Petroleum in 1987. Based on 1993 disclosures, BP America would rank 25th on the *Fortune 500* list.

2. 1993 Financial Highlights

Refining, Restructuring, and a Rebound in Income

The 1993 financial results of the 25 major energy companies in the Financial Reporting System (FRS) not only reflected energy market developments but also showed the effects of recent restructuring efforts directed toward reducing costs. Net income of the FRS companies registered an enormous gain, from $1.8 billion in 1992 to $15.5 billion in 1993 (Table 1). However, most of this gain in bottom-line financial results was attributable to unusual items in the prior year.[7] In particular, Financial Accounting Standard No. 106, "Employers Accounting for Postretirement Benefits Other Than Pensions" (SFAS 106), required the recognition of obligations to both current and future pensioners of U.S. corporations. Implementation required most U.S. corporations to recognize the cumulative impact of this standard for current and future obligations in a single year, 1992, reducing net income by nearly $11 billion.[8]

Excluding the effects of SFAS 106, as well as other unusual items, the FRS companies' net income was up $2.5 billion between 1992 and 1993 to $17.6 billion, a 17-percent increase. Although revenues declined, largely due to lower oil prices and lower refined product prices, operating expenses declined even more. Reduction in operating costs is a theme that appears throughout the review of 1993 results. The $1.0-billion reduction in interest expense was also a notable improvement in the FRS companies' overall corporate results. This reduction reflected the lower interest rates in recent years and the FRS companies' paring of debt levels.

Corporate profitability of the FRS companies continued to nearly match the profitability of large U.S. industrial

Table 1. Consolidated Income Statement for FRS Companies, 1992 and 1993
(Billion Dollars)

Income Statement Items	1992	1993	Percent Change 1992-1993
Operating Revenues	472.8	448.1	-5.2
Operating Expenses	-449.5	-423.0	-5.9
Operating Income	23.3	25.1	7.7
Interest Expense	-8.9	-7.9	-11.6
Other Revenue (Expense)	8.2	7.6	-7.3
Income Tax Expense	-8.6	-9.1	6.0
Discontinued Operations and Cumulative Effect of Accounting Changes	-12.2	-0.1	-98.8
Net Income	1.8	15.5	781.5
Net Income Excluding Unusual Items	15.1	17.6	17.1

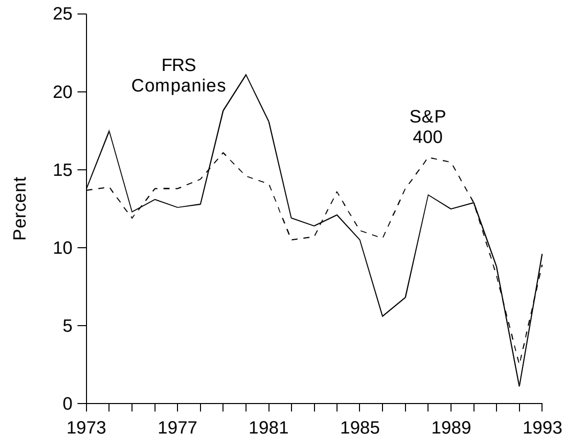
Note: Sum of components may not equal total due to independent rounding. Percent changes were calculated from unrounded data.
Source: Energy Information Administration, Form EIA-28.

[7]Unusual items are composed of gains and charges recognized in a company's income statement that are of a non-recurring nature and generally unrelated to current operations. These items include effects of accounting changes, litigation settlements, gains and losses from large divestitures of assets, provisions for the cost of restructuring, and provisions for reserves for future liabilities.
[8]Financial Accounting Standards Board, *Statement of Financial Accounting Standards,* No. 106 (Norwalk, CT, December 1990).

corporations generally in 1993. Return on equity (net income as a percent of stockholders' equity) for the FRS companies in 1993 was 10 percent, only a percentage point above the return on equity for the Standard and Poor's (S&P) 400 U.S. industrial corporations (Figure 3).[9] The corporate profitability of both groups was still relatively low in 1993 compared with other years.

The rebound in net income of the FRS companies (excluding unusual items) came almost entirely from refining and marketing operations. Net income from U.S. refining/marketing was up $2.4 billion and up $1.5 billion in foreign refining/marketing (Table 2).[10] Although worldwide consumption of petroleum was up less than 1 percent, demand for gasoline and distillates was up 3 percent.[11] In the United States, gasoline and distillate (including jet fuel) demand was also up 3 percent.[12] These products tend to yield higher refiner margins (i.e., refined product prices less crude oil input costs) than the rest of the refined product slate. As a result, even though refined product prices were lower in 1993 than in 1992, refiner margins improved.[13] Reduction in downstream operating expenses was even more important than improved margins for the FRS companies. The FRS companies' efforts to increase the efficiency of their downstream operations, in part through recent restructuring, have led to lower operating costs, particularly in the marketing and distribution stages. As discussed in Chapter 3, most of the improvement in the FRS companies' U.S. refining/marketing income in 1993 stemmed from reductions in marketing expenses. To provide an accurate perspective, it should be noted that the improvement in performance in 1993, though substantial, followed the worst year for FRS refining/marketing profitability since at least 1977. Domestic refining/marketing profitability in 1993, at 3.4 percent (Table 3), was at the fifth lowest level in the 1977-1993 period.

Figure 3. Return on Equity for FRS Companies and the S&P 400, 1973-1993



Sources: **FRS Companies:** Energy Information Administration, Form EIA-28. **S&P 400**: Standard and Poor's Compustat Services Inc.

Higher natural gas prices in 1993 could not fully offset the effects of lower oil prices in the FRS companies' upstream (oil and gas exploration, development, and production) operations. Also, evidence of upstream cost cutting was widespread, with a majority of the FRS companies reporting reductions in exploration expenses and the costs of oil and gas extraction. Worldwide net income (excluding unusual items) from oil and gas production declined $1.7 billion between 1992 and 1993 (Table 2), with the reduction about evenly split between U.S. and foreign operations. Nevertheless, oil and gas production remained the FRS companies' primary source of earnings.

[9]The S&P 400 is a well recognized database that includes 400 of the largest U.S. industrial companies. In 1993, 17 of the FRS companies were included in the S&P 400. Financial statistics for the S&P 400 were obtained by accessing Compustat, a service of Standard & Poor's, Inc.

[10]Line-of-business profit measures should be distinguished from measures that reflect company-wide results because the former reflect only allocated income, expense, and asset items. Two measures of income are presented: *operating income* and *contribution to net income*. Operating income by line of business is similar in concept to the operating income measure for total company operations. It is the net of operating revenues and operating expenses (including depreciation, depletion, and amortization) for a line of business. Contribution to net income equals operating income plus income from unconsolidated affiliates and gains on disposal of property, plant, and equipment less income taxes imputed to the line of business and excludes certain non-allocable items, primarily interest expense. Interest expense is the principal source of difference between a companywide net income figure and line-of-business contributions to net income (see Appendix A for further discussion). Line-of-business rates of return are based on historical costs and measure ex-post average profitability, not marginal or prospective rates of return.

[11]The British Petroleum Company p.l.c., *BP Statistical Review of World Energy*, June 1994, p. 10.

[12]Unless otherwise noted, energy industry price and quantity data are from Energy Information Administration, *Monthly Energy Review*, September 1994, DOE/EIA-0035(94/09) (Washington, DC, September 1994).

[13]Energy Information Administration, *Annual Energy Review 1993*, DOE/EIA-0384(93) (Washington, DC, July 1994), p. 181.

Table 2. Contributions to Net Income by Line of Business for FRS Companies, 1992-1993
(Million Dollars)

Line of Business	Net Income			Net Income Excluding Unusual Items		
	1992	1993	Percent Change 1992-1993	1992	1993	Percent Change 1992-1993
Petroleum						
U.S. Petroleum						
Production	5,588	4,839	-13.4	6,421	5,485	-14.6
Refining/Marketing	-213	1,685	--	542	2,911	437.1
Pipelines	2,080	1,566	-24.7	2,033	1,568	-22.9
Total U.S. Petroleum	7,483	8,090	8.1	9,024	9,964	10.4
Foreign Petroleum						
Production	4,657	5,160	10.8	5,002	4,254	-15.0
Refining/Marketing	2,234	3,193	42.9	1,982	3,496	76.4
International Marine	-22	21	--	-21	21	--
Total Foreign Petroleum	6,869	8,374	21.9	6,963	7,771	11.6
Total Petroleum	14,352	16,463	14.7	15,987	17,734	10.9
Coal	-486	371	--	441	195	-55.8
Nuclear and Other Energy	50	121	142.0	130	102	-21.6
Nonenergy	1,223	2,699	120.7	3,609	4,072	12.8
Total Allocated	15,139	19,654	29.8	20,167	22,103	9.6
Nontraceables and Eliminations	-13,382	-4,166	--	-5,103	-4,462	--
Consolidated Net Income[a]	1,757	15,488	781.5	15,064	17,641	17.1

[a]The total amount of unusual items was -$13,307 million and -$2,153 million in 1992 and 1993, respectively.
-- = Not meaningful.
Note: In petroleum, sum of components may not equal total due to nontraceables and eliminations.
Source: Energy Information Administration, Form EIA-28.

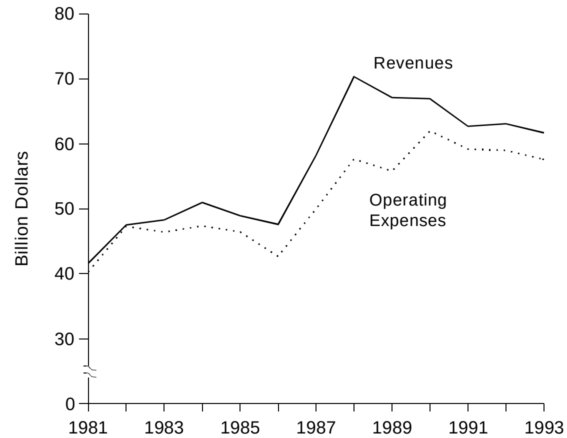
Table 3. Rates of Return by Line of Business for FRS Companies, 1986-1993
(Percent)

Line of Business	1986	1987	1988	1989	1990	1991	1992	1993
Petroleum	5.5	6.2	7.3	6.7	9.5	7.0	5.6	6.4
U.S. Petroleum	3.0	4.9	6.3	5.8	7.9	4.9	4.4	4.9
Oil and Gas Production	0.8	4.1	2.8	2.9	8.5	5.1	5.9	5.3
Refining/Marketing	4.5	2.9	14.7	11.5	5.1	2.0	-0.4	3.4
Pipelines	13.2	12.8	9.6	10.2	11.2	10.7	8.4	6.4
Foreign Petroleum	12.8	9.5	9.9	8.7	12.5	11.0	7.9	9.2
Oil and Gas Production	11.6	12.4	9.2	8.9	13.1	9.1	8.2	8.6
Refining/Marketing	16.3	4.7	11.6	8.0	11.2	14.6	7.8	10.6
International Marine	5.3	-3.6	6.8	12.4	11.7	15.6	-1.2	1.2
Coal	2.7	5.1	6.7	5.0	3.3	8.7	-9.3	7.6
Nuclear and Other Energy	-0.8	0.5	-2.5	-2.3	2.6	2.8	1.8	4.1
Nonenergy	5.1	12.2	20.3	17.3	7.8	2.9	2.1	4.7

Note: Rate of return measured as contribution to net income/net investment in place.
Source: Energy Information Administration, Form EIA-28.

In 1993, the nonenergy line of business ranked third, after refining/marketing, as a source of FRS earnings. Among the many FRS businesses outside energy, chemicals are by far the most important. Sixteen FRS companies had chemical operations with revenues that totaled $62 billion in 1993 (Figure 4).[14] Income from these operations fell sharply after peaking in 1988-1989, in part due to a reduced pace of economic activity in industrialized countries and in part due to an excess of chemical production capacity built in response to soaring profits. Chemical earnings in 1993 were nearly unchanged from 1992 (Table 4) with both revenues and operating expenses declining by $1.4 billion (Figure 4). Although the FRS companies' chemical earnings appear to have stabilized in recent years, they still amounted to only about a third of the peak levels attained in 1988-1989. Operating earnings from the balance of the FRS companies' other businesses outside energy also held steady, at slightly over $1 billion, between 1992 and 1993 (Table 4).

Figure 4. Revenues and Operating Expenses for the Chemical Segment for FRS Companies, 1981-1993



Sources: 1981-1986: Energy Information Administration, Form EIA-28. 1987 through 1993: Company annual reports to shareholders.

Restructuring among the FRS companies in 1993 continued to emphasize consolidation of ongoing businesses to attain greater operating efficiencies and lower costs. Unlike 1991 and 1992, when restructuring efforts included the exit of six FRS companies in whole or large part from the U.S. coal industry, no line of business was wholly abandoned in 1993. In the United States, the FRS companies sold more oil and gas reserves than they purchased for the fourth consecutive year, a pattern unknown before the 1990's. Abroad, the FRS companies' oil and gas acreage holdings were trimmed. Downstream, BP America and Exxon consolidated their U.S. refining operations by selling refineries in Washington and New Jersey, respectively, to Tosco Corp.[15] Gasoline marketing, though a target of investment in the late 1980's and so far in the 1990's,

Table 4. Operating Income in Chemicals and Other Nonenergy Segments for FRS Companies, 1992-1993
(Million Dollars)

Segment	1992	1993	Percent Change 1992-1993
Operating Income, Excluding Unusual Items			
Chemicals	4,024	4,089	1.6
Other Nonenergy	1,136	1,165	2.6

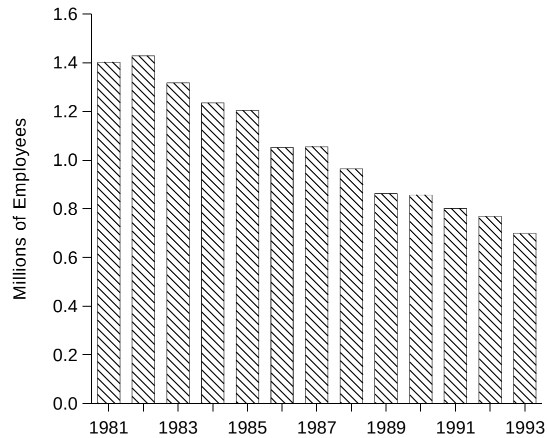
Sources: Energy Information Administration, Form EIA-28, except for chemicals segment operating income which was compiled from company annual reports to shareholders.

[14]For FRS purposes, separate reporting of income for chemical and other nonenergy segments was discontinued beginning with the 1987 reporting year. However, the disclosures of chemical segment revenues and operating income made by the FRS companies in their annual reports to shareholders closely track, in the aggregate, the comparable disclosures in the Form EIA-28 from 1981 through 1986. Thus, the public disclosures of chemical segment revenue and operating income were utilized for 1987 through 1993. Revenues and operating income for the other nonenergy segment after the 1986 reporting year were obtained by subtracting the publicly disclosed chemical segment values from the nonenergy line-of-business values reported on Form EIA-28. It should be noted that the results for chemicals are qualitatively unchanged if DuPont, the largest FRS chemical producer, is excluded.

[15]Energy Information Administration, *Petroleum Supply Annual 1993*, Volume 1, DOE/EIA-0340(93)/1 (Washington, DC, June 1994), p. 122.

continued to be subject to consolidation along geographic lines. For example, Ashland sold 51 retail gasoline outlets in Florida to Shell Oil and Chevron, while BP America and Unocal divested national truckstop networks.[16] Three FRS companies made large divestitures in the nonenergy area. BP America sold its nutrition business (e.g., Purina Mills); Chevron sold its Ortho lawn and garden division to Monsanto, and DuPont sold its acrylics business, its electronic connectors business, and Remington Arms Company.[17] Employment reductions have been a key element in restructuring by the FRS companies. In 1993, the companies employed 699,000 people, about half the number employed a decade ago (Figure 5).

Figure 5. Number of Employees of FRS Companies, 1981-1993



Source: Company annual reports to shareholders.

Cash Flow Improvement and Debt Reduction

The FRS companies' cash flow from operations[18] in 1993, at $50.2 billion (Table 5), reached the second-highest level since the oil price collapse of 1986,

Table 5. Line-of-Business Contributions to Pretax Cash Flow for FRS Companies, 1992-1993
(Billion Dollars)

Contribution to Pretax Cash Flow[a]	1992	1993	Percent Change 1992-1993
Petroleum			
Oil and Gas Production	40.3	36.2	-10.2
Refining, Marketing, and Transport	12.4	17.7	43.0
Coal and Other Energy	1.2	0.9	-19.3
Chemicals	7.8	7.9	2.2
Other Nonenergy	2.2	2.4	5.5
Nontraceable	-1.8	-2.7	--
Total Contribution to Pretax Cash Flow[a]	62.0	62.6	1.0
Current Income Taxes	-11.5	-10.1	--
Other (Net)	-5.7	-2.3	--
Cash Flow from Operations	44.8	50.2	12.1

[a]Defined as the sum of operating income, depreciation, depletion, and amortization, and dry hole expense. Excludes unusual items.

-- = Not meaningful.

Note: Sum of components may not equal total due to independent rounding. Percent changes were calculated from unrounded data.

Source: Energy Information Administration, Form EIA-28.

[16]Ashland Oil, Inc., *1993 Annual Report;* British Petroleum Company p.l.c., *BP Annual Report and Accounts 1993*; Unocal Corporation, *1993 Annual Report*.

[17]British Petroleum Company p.l.c., *BP Annual Report and Accounts 1993;* Chevron Corporation, *1993 Annual Report;* DuPont, *1993 Annual Report.*

[18]Cash is defined as currency, demand deposits, and interest-bearing assets of less than 30 days maturity. Generally, cash flow from operations is computed by adding to (subtracting from) net income those cost (revenue) items that did not actually involve an outlay (receipt) of cash. The largest of these non-cash items is the cost of depreciation, depletion, and amortization. Also, outlays (receipts) of cash that were recognized as non-cash items in previous income statements (e.g., provisions for a legal settlement taken as a charge against income in a previous year but not actually paid until the current year) are subtracted from (added to) net income in computing cash flow. Lastly, changes in working capital (excluding cash) due to operations are subtracted.

exceeded only by the cash flow generated in the context of the war-induced oil price escalation in 1990. Overall, cash flow from operations was up $5.4 billion between 1992 and 1993. Line-of-business contributions to cash flow (before taxes) followed the pattern of contributions to income in 1993. Improved cash flow from downstream petroleum, up $5 billion from 1992, more than offset the drop in upstream cash flow stemming from lower oil prices, while improved results in chemicals and other nonenergy businesses contributed modestly.

On balance, the bulk of the improvement in cash flow came from developments below the operating income line. Lower current income taxes, down $1.4 billion, reflected reduced income tax rates abroad and increased tax credits related to U.S. natural gas production from nonconventional sources (these developments are reviewed in the last section of this chapter). The $1-billion reduction in interest expense (Table 1) also enhanced cash flow. However, the financial item contributing the most to the improvement in cash flow, over $2 billion, was the accounting for deferred taxes, a somewhat technical development reviewed in the last section of this chapter.

The FRS companies' long-running efforts to contain growth in debt were notably successful in 1993. Cash raised through long-term borrowing was down 10 percent, but cash used for reduction of long-term debt remained essentially unchanged (Table 6). As a result, the FRS companies' long-term debt was at its second-lowest level in nine years. Debt reduction was widespread among the FRS group, with 18 companies reporting less long-term debt on their balance sheets at the end of 1993 than at the end of 1992. Efforts to trim debt and interest payments extended to short-term debt as well. Notes payable and trade credit were reduced to a five-year low in 1993 (Appendix B, Table B9).

The improvement in cash flow, together with additional funds yielded by asset sales pursuant to restructuring, was used to reduce debt rather than increase dividends or capital expenditures. Dividend payout was largely unchanged and capital expenditures were down 4 percent. Nevertheless, dividends were at historically high levels (discussed in Part II of this report) and capital expenditures continued to be the primary use of cash.

Table 6. Sources and Uses of Cash for FRS Companies, 1992-1993
(Billion Dollars)

Sources and Uses of Cash	1992	1993	Percent Change 1992-1993
Main Sources of Cash			
Cash Flow from Operations	44.8	50.2	12.1
Proceeds from Long-term Debt	24.7	22.2	-10.3
Proceeds from Disposals of Assets	7.3	11.8	61.8
Proceeds from Equity Security Offerings	3.4	2.1	-37.6
Main Uses of Cash			
Additions to Investment in Place	42.0	40.4	-3.8
Reductions in Long-term Debt	25.3	25.5	0.7
Dividends to Shareholders	13.5	13.6	0.3
Purchase of Treasury Stock	0.8	0.5	-37.6
Other Investment and Financing Activities, Net	0.4	-5.1	--
Net Change in Cash and Cash Equivalents	-1.0	1.2	--

-- = Not meaningful.

Note: Sources minus Uses plus Other Investment and Financing Activities (Net) may not equal Net Change in Cash and Cash Equivalents due to independent rounding. Percent changes were calculated from unrounded data.

Source: Energy Information Administration, Form EIA-28.

Natural Gas Emphasis in Capital Expenditures

Although the profitability of oil and gas production in 1993 was little changed from recent years (Table 3), worldwide capital expenditures allocated to this line of activity by the FRS companies were up $2 billion (Table 7).[19] The upswing in capital expenditures appeared to reflect higher natural gas prices in the United States and Canada in 1993, as well as longer-term prospects for natural gas as the environmentally most benign fossil fuel and as a base for chemical feedstocks. The bulk of upstream capital expenditures cannot be separated into oil versus gas, but drilling patterns suggest a heightened interest in adding to natural gas reserves and production.

In the United States, the FRS companies' gas drilling activity doubled in offshore locales (mainly the Gulf of Mexico), as measured by well completions. Onshore, FRS gas drilling reached a low point in 1987, rose in response to favorable price expectations, and then, largely due to the expected expiration of a tax credit related to drilling in nonconventional gas sources, reached a frenzied pace in 1990. The pace of FRS companies' onshore gas drilling subsequently moderated but continued on an upward path through 1993. In 1993, 16 of 22 FRS companies engaged in U.S. drilling reported an increase in onshore gas well completions. Abroad, the FRS companies' gas drilling in Canada rose nearly fivefold from 1992, to 340 completions in 1993. The surge in Canadian gas activity was driven by higher prices in 1993 and by growth in the capacity to deliver natural gas exports to the lower 48 states. Outside North America, the number of FRS companies' gas well completions was essentially unchanged between 1992 and 1993.

Oil drilling by the FRS companies, while low in historical context (e.g., their 1993 worldwide oil completions were less than a third of peak value in 1984), also registered gains in North America. In the United States, oil completions were up 16 percent due to increased developmental drilling. Exploratory oil wells were nearly unchanged between 1992 and 1993. Canadian oil drilling by the FRS companies was up 66 percent in 1993. A royalty holiday for new oil wells in the province of Alberta, the locale of the vast majority of Canadian oil production, probably contributed to this upswing in drilling. Outside North America, the FRS companies' oil well completions were nearly unchanged between 1992 and 1993.

Petroleum refining and marketing, both in the United States and abroad, became more prominent targets of investment for the FRS companies following the oil price collapse of 1986. In the late 1980's, petroleum demand, particularly demand for transport fuels, was propelled upward by lower prices and global economic growth. During this period and into the 1990's, the FRS companies further upgraded their refineries to produce lighter end products. Achievement of scheduled environmental quality improvements and investments to comply with provisions of the Clean Air Act Amendments of 1990 further added to downstream capital outlays.

The FRS companies' capital expenditures for U.S. refining peaked at $5.2 billion in 1992, and foreign expenditures peaked at $3.6 billion in 1991. Although U.S. and foreign capital expenditures for refining and marketing in 1993 were down somewhat from the prior year (Table 7), both were high in historical context. Excluding the effects of mergers and acquisitions, the FRS companies' worldwide capital expenditures for refining and marketing of $10 billion were exceeded only by their expenditures in 1991 and 1992.

The slight decline in refining and marketing capital expenditures in 1993 in part reflected downstream restructuring and the consequent reduction in investment requirements. Amoco, BP America, Coastal, and Exxon either sold or shut down U.S. refineries in 1993.[20] Completion of refinery upgrading projects in late 1992 and 1993 also contributed to reduced downstream spending. For example, in 1993, Mobil put a $150-million isomerization unit into service at its Loryton, England refinery, and completed a $150-million-plus upgrading of its Joliet, Illinois refinery to produce low-sulfur diesel and to lower emissions of sulfur dioxide.[21] Coastal, in 1992, completed a significant upgrading of the mothballed Aruba refinery acquired from Exxon in 1989. On balance, the FRS companies' capital expenditures for worldwide petroleum (including natural gas) operations totaled $32.1 billion, slightly above the 1992 level.

[19]To the extent possible, capital outlays are measured by additions to investment in place, which are defined as additions to property, plant, and equipment (PP&E) plus additions to investment and advances. In 1993, additions to PP&E accounted for 94 percent of capital outlays so measured. However, because additions to investments and advances were not collected for some FRS segments prior to 1981, capital outlays are sometimes measured by additions to PP&E. Also, in comparisons with the S&P 400, this latter measure is used since the S&P 400 database does not provide an item comparable to additions to investment and advances.

[20]Energy Information Administration, *Petroleum Supply Annual 1993*, Volume 1, DOE/EIA-0340(93) (Washington, DC, June 1994), p. 122.

[21]Mobil Corporation, *Mobil Annual Report 1993*.

Table 7. Additions to Investment in Place by Line of Business for FRS Companies, 1992-1993
(Billion Dollars)

Line of Business	1992	1993	Percent Change 1992-1993	Percent Change Excluding Mergers and Acquisitions 1992-1993
Petroleum				
U.S. Petroleum				
Production	8.8	9.5	8.1	7.7
Refining/Marketing				
Refining	5.2	4.5	-12.9	-12.9
Marketing	1.9	1.8	-7.1	-6.3
Transport	0.4	0.4	4.1	4.1
Total Refining/Marketing	7.4	6.7	-10.6	-10.4
Pipelines	1.0	1.0	-4.6	-5.5
Total U.S. Petroleum	17.3	17.1	-0.7	-1.1
Foreign Petroleum				
Production	10.2	11.4	12.4	9.4
Refining/Marketing	3.6	3.3	-8.9	-8.9
International Marine	0.2	0.2	0.4	0.4
Total Foreign Petroleum	14.0	15.0	6.7	4.5
Total Petroleum	31.3	32.1	2.6	1.4
Coal	0.9	0.2	-74.5	-59.3
Other Energy	0.2	0.4	66.8	78.2
Nonenergy				
Chemicals	6.1	4.5	-26.1	-27.3
Other Nonenergy	2.2	2.2	3.3	10.3
Total Nonenergy	8.3	6.7	-18.4	-17.4
Nontraceables	1.3	0.9	--	--
Additions to Investment in Place[a]	42.0	40.4	-3.8	--
Additions Due to Mergers and Acquisitions	1.7	1.5	-9.2	--
Total Additions Excluding Mergers and Acquisitions	40.3	38.9	-3.5	--

[a]Measured as additions to property, plant, and equipment, plus additions to investments and advances.
-- = Not meaningful.
Note: Sum of components may not equal total due to independent rounding. Percent changes were calculated from unrounded data.
Source: Energy Information Administration, Form EIA-28.

The FRS companies targeted chemical operations and coal production for the sharpest cutbacks in investment in 1993. Reduced investment in chemicals was a response to deteriorating profitability and worldwide overcapacity in some chemical product lines, particularly petroleum-based commodity chemicals. The steep decline in capital expenditures for coal in 1993 was due in roughly equal parts to the exit of some FRS companies from the industry[22] and to reduced outlays by FRS companies with ongoing asset commitments to coal production.

"Other energy," by nearly any measure, is the smallest among the FRS lines of business. Canadian tar sands, geothermal energy, cogeneration, and solar power account for the bulk of assets in this line of business. Despite the small size, capital expenditures for other energy activities registered the largest relative increase, 67 percent, of all the FRS lines of business in 1993. Nearly all of this increase was traceable to Enron's $151 million outlay for its Teesside electric power joint venture in the United Kingdom.[23] Additionally, Unocal reported increased investment in its Indonesian geothermal energy projects.[24]

The "other nonenergy" line of business was the focus of massive restructuring by the FRS companies in the mid-1980's (this development is reviewed in detail in Part II). Accordingly, capital expenditures for activities outside energy and chemicals fell drastically. For example, capital expenditures dropped from their peak value of $6.9 billion in 1981, to $2.4 billion in 1988. Since 1988, capital expenditures have remained in the range of $2.0 billion to $2.5 billion. At $2.2 billion in 1993, capital expenditures were unchanged from 1992. However, acquisitions of nonenergy businesses by DuPont and Union Pacific, in 1993, composed a significant share of other nonenergy capital expenditures (Table 8).

Table 8. Value of Mergers, Acquisitions, and Related Transactions by FRS Companies, 1993
(Million Dollars)

Line of Business and Acquiring Company	Acquisition	Reported Value of Acquisition
U.S. Oil and Gas Production		
Burlington Resources	59-percent interest in Permian Basin Royalty Trust	134
Union Pacific	36-percent interest in natural gas liquids plant (TX) from Parker & Parsley	43
Anadarko Petroleum	Deep gas properties (KS) from Mesa Limited Partnership	20
Foreign Oil and Gas Production		
Occidental Petroleum	Interest in producing properties from Republic of the Congo	150
Sun	Interests in Balmoral and Stirling fields in United Kingdom North Sea	22
Nonenergy		
DuPont	ICI Ltd.'s worldwide fibers business	380
Union Pacific	Common stock of Skyway Freight Systems	72

Sources: Company annual reports to shareholders, *Oil and Gas Investor* (September 1993 and April 1994), and various issues of *The Wall Street Journal*.

[22]In 1991 and 1992, five FRS companies either sold or announced plans to sell all or a significant portion of their U.S. coal operations. The companies included Burlington Resources, DuPont, Occidental Petroleum, Shell Oil, and Sun Company. For detailed discussion of this development see Energy Information Administration, *Performance Profiles of Major Energy Producers 1992*, DOE/EIA-0206(92) (Washington, DC, January 1994), pp. 6, 53-57.

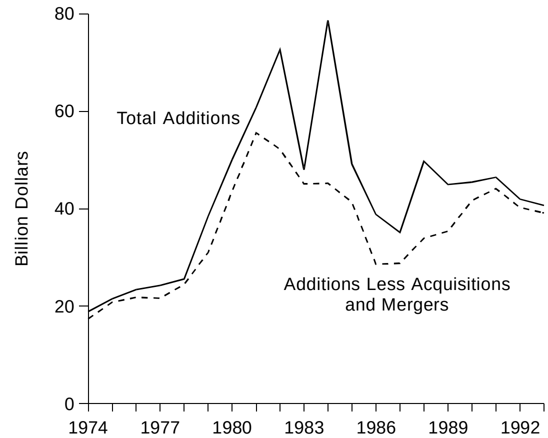
[23]Enron Corp., *1993 Annual Report to Shareholders and Customers.*

[24]Unocal Corporation, *1993 Annual Report*.

The apparent emphasis on nonenergy among the FRS companies' acquisitions was more a reflection of reduced outlays for acquisitions rather than a heightened interest in diversification. Capital expenditures for mergers and acquisitions hit a 15-year low in 1993 (Figure 6).[25] In recent years, many of the FRS companies have been more interested in selling U.S. oil and gas properties, pursuant to cost-cutting consolidations, than in purchasing them. Sales of U.S. oil and gas reserves by the FRS companies exceeded purchases for the fourth consecutive year in 1993. No multinational FRS company made notable acquisitions of U.S. oil and gas properties in 1992 or 1993.

Environmentally-related outlays have been increasingly important in the FRS companies' capital budgets. New and stricter environmental standards, particularly as they apply to petroleum refining, gasoline marketing, and chemical manufacturing, have required increased costs for compliance. Based on public disclosures made by 16 of the 25 FRS companies, capital expenditures for environmental quality and remediation totaled $4.4 billion in 1993 and accounted for 14 percent of the total capital expenditures (excluding the effects of mergers and acquisitions) for these 16 companies. The comparable shares for environmentally-related capital expenditures were 10 percent in 1991 and 8 percent in 1989.[26]

Figure 6. Additions to Investment in Place and Value of Acquisitions and Mergers for FRS Companies, 1974-1993



Sources: Energy Information Administration, Form EIA-28, and company filings of securities and Exchange Commission Form 10-K.

1993 Income Taxes: Mixed Effects

A number of fiscal and financial developments, cutting in different directions, had a variety of effects on the FRS companies' worldwide income tax obligations in 1993. On balance, FRS companies' 1993 income tax expense rose 6 percent from the prior-year level to $9.1 billion (Table 9). However, income taxes rose at a lesser pace than pretax income. Consequently, the FRS companies' worldwide effective tax rate[27] fell slightly to 37 percent (Table 10). The effective tax rate for the S&P 400 group of U.S. industrial companies also dropped slightly, by one percentage point (Figure 7).

The most dramatic development was a $1.4-billion decline in current taxes (Table 9). Current taxes constitute that portion of income tax expense deemed payable in the reporting period. Several factors played important roles in reducing current income taxes for the FRS companies in 1993. One was the reversal of the effect of the corporate Alternative Minimum Tax. The Tax Reform Act of 1986 greatly strengthened the Alternative Minimum Tax (AMT). Basically, a corporation pays the greater of (1) taxes computed from the regular corporate income tax system or (2) taxes computed from the AMT. The AMT taxes paid in excess of the regular corporate tax can be used as credits against future years' tax obligations emanating from the regular corporate income tax system. For the first six years after passage of the Tax Reform Act, the FRS companies paid $1.6 billion in added current taxes due to the workings of the AMT (Appendix B, Table B19). In 1993, this trend was reversed. A substantial number of FRS companies found that their regular corporate income tax obligations exceeded the AMT amount. These companies were able to use AMT credits carried forward from previous years to reduce their corporate income tax liabilities. In 1992, the AMT added $450 million to current taxes, but in 1993, AMT credits reduced current taxes by $158 million, a $608 million turnaround.

[25]Figure 6 and Table 7 show the value of property, plant, and equipment and investments and advances added to the companies' books as a result of acquisitions rather than the value of the transactions. The reported, or purchase, value of an acquisition shown in Table 8 can include effects on working capital, long-term liabilities, and other values that would not add to the acquiring company's investment base.

[26]Energy Information Administration, *Performance Profiles of Major Energy Producers 1989*, DOE/EIA-0206(89) (Washington, DC, January 1991), p. 10 and *Performance Profiles of Major Energy Producers 1991*, DOE/EIA-0206(91) (Washington, DC, December 1992), p. 14.

[27]Effective tax rate is calculated by dividing income tax expense by pretax income.

Table 9. Composition of Income Tax Expense for FRS Companies, 1992-1993
(Billion Dollars)

Component	1992	1993	Percent Change[a] 1992-1993
Pretax Income[b]	22.5	24.8	9.9
U.S. Federal Income Taxes			
Current	2.8	2.4	-15.0
Deferred	-2.3	-0.5	--
Total U.S. Federal	0.4	1.9	334.6
State and Local Income Taxes			
Current	0.8	0.5	-39.1
Deferred	0.0	-0.0	--
Total State and Local	0.8	0.4	-43.1
Foreign Income Taxes			
Current			
Canada	0.6	0.7	18.3
OECD Europe	2.1	1.9	-5.8
Africa	1.5	1.3	-16.8
Middle East	1.3	0.9	-30.0
Other Eastern Hemisphere	2.2	2.1	-4.8
Other Western Hemisphere	0.4	0.4	4.8
Total Current	8.0	7.3	-9.2
Deferred	-0.6	-0.5	--
Total Foreign	7.4	6.8	-8.1
Total Income Tax Expense	8.6	9.1	6.0
Total Current	11.5	10.1	-12.6
Total Deferred	-2.9	-0.9	--

[a]Based on unrounded data.
[b]Includes minority interest in income; excludes extraordinary items and cumulative effect of accounting changes.
-- = Not meaningful.
Note: Sum of components may not equal total due to independent rounding. Former Soviet Union and Eastern Europe included in OECD Europe to avoid disclosure.
Source: Energy Information Administration, Form EIA-28.

"Section 29" tax credits also helped reduce FRS companies' current Federal income taxes. These tax credits apply to the production of certain alternative (or nonconventional) fuels.[28] Based on information in company annual reports and filings of Form EIA-28, the bulk of FRS companies' reported Section 29 tax credits appear to be related to the production of gas from coal seams, particularly in New Mexico and Alabama. To a lesser extent, FRS companies also drilled gas wells in tight sands formations. The value of these tax credits to the FRS companies increased about 50 percent from 1992 to 1993.

Lower income taxes on some of the FRS companies' foreign operations (mostly oil and gas production) also lowered current taxes. The most notable area was the North Sea, where the United Kingdom's (UK) revision of the Petroleum Revenue Tax (PRT) dropped the PRT rate from 75 percent to 50 percent on producing wells, effective July 1, 1993. Additionally, new fields are only taxed at the standard UK corporate tax rate of 33 percent as of March 16, 1993.[29]

[28]"Section 29," or nonconventional, fuels generally include oil produced from shale and tar sands; gas produced from geopressurized brine, Devonian shale, coal seams, tight formations, or biomass; and liquid, gaseous, or solid synthetic fuels produced from coal.

[29]"U.K. Plans Big Changes in Taxes on Oil and Gas," *Oil & Gas Journal,* March 22, 1993, p. 31.

Table 10. Income Tax Expense, Pretax Income, and Effective Tax Rates by Line of Business for FRS Companies, 1992-1993

Sector	1992 Pretax Income	1992 Income Tax Expense	1992 Effective Tax Rate	1993 Pretax Income	1993 Income Tax Expense	1993 Effective Tax Rate
	billion dollars		percent	billion dollars		percent
Allocated U.S.						
Consolidated Petroleum	11.7	3.7	31.3	12.7	4.4	34.6
Oil and Gas Production	8.3	2.3	28.4	7.2	2.2	30.7
Refining/Marketing/Pipelines	3.4	1.3	39.0	5.5	2.2	39.7
Allocated Foreign						
Consolidated Petroleum	14.2	7.0	49.1	15.1	6.7	44.4
Oil and Gas Production	10.9	5.9	54.2	10.3	5.1	49.5
Refining/Marketing/Marine	3.2	1.0	31.6	4.8	1.6	33.6
Allocated Coal	0.4	0.1	29.5	0.2	0.1	28.1
Allocated Nuclear and Other Energy	0.2	0.1	43.6	0.2	0.1	46.5
Allocated Nonenergy	3.9	1.2	30.1	4.3	1.3	31.2
Total Allocated	30.4	12.0	39.5	32.6	12.6	38.7
Nontraceables and Eliminations	-7.9	-3.4	--	-7.8	-3.5	--
Total Consolidated	22.5	8.6	38.3	24.8	9.1	36.9

-- = Not meaningful.

Note: Sum of components may not equal total due to independent rounding. Effective tax rates are calculated from unrounded data.

Source: Energy Information Administration, Form EIA-28.

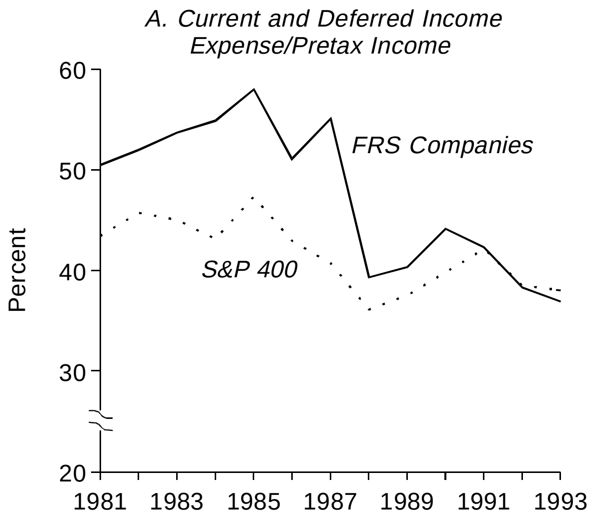
Two developments in 1993 had the effect of increasing the FRS companies' income tax expense. These well-publicized developments were the implementation of a change in Federal tax law and a change in financial reporting requirements. Under the Omnibus Budget Reconciliation Act of 1993, the highest corporate income tax rate went from 34 percent to 35 percent, as of January 1, 1993.[30] Also by 1993, all FRS companies had implemented the provisions of Statement of Financial Accounting Standard No. 109 (SFAS 109), "Accounting for Income Taxes." SFAS 109 uses the balance sheet approach, also referred to as the liability method, in determining taxes. Deferred taxes[31] increased in 1993 because SFAS 109 requires that, in the event of a change in the corporate tax rate, the deferred tax assets and liabilities must be recomputed at the new tax rate.[32] The increase in deferred tax liabilities resulting from the higher tax rate was recognized as an addition to income tax expense in the income statement for 1993. Deferred income taxes for the FRS companies increased by $2.0 billion from 1992 to 1993 (Table 9).

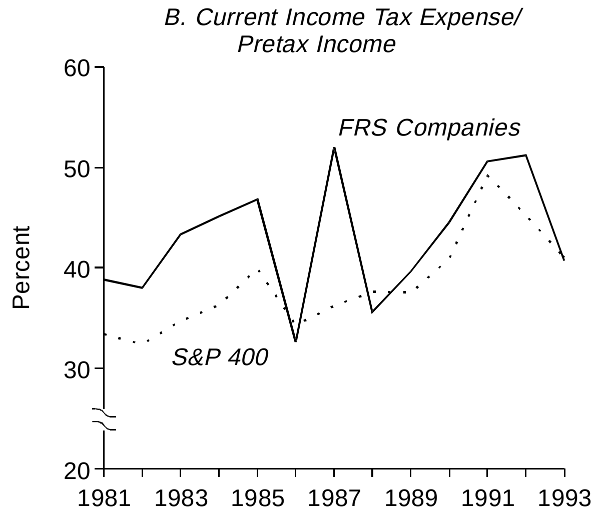
[30]Omnibus Reconciliation Act of 1993, Public Law No. 103-66, 107 Stat. 31.

[31]Deferred taxes are differences between income tax expense accrued under Generally Accepted Accounting Principles for financial reporting purposes and income taxes currently payable in the reporting period. They originate from a variety of sources and are important to the financial operations of energy companies, as well as to industry in general. Basically, deferred taxes originate because of timing differences in reporting revenue and expense for financial reporting and tax reporting. Financial reporting attempts to match items of income and expense in the periods in which they occur. Tax reporting may permit different timing for recognizing revenues and deducting expenses. For example, faster writeoffs of depreciable properties are permitted under tax laws while they may not be acceptable under financial accounting principles. Accelerated writeoffs result in lower taxable income and thus lower tax liability in the year taken. In future periods, however, taxable income and income taxes payable may be higher than pretax income for financial reporting purposes because the timing differences between tax and financial reporting are reversed.

[32]See Appendix A for a more detailed discussion of SFAS 109 and deferred taxes.

Figure 7. Worldwide Effective Income Tax Rates for FRS Companies and S&P 400, 1981-1993





Sources: **FRS Companies**: Energy Information Administration, Form EIA-28. **S&P 400**: Standard and Poor's Compustat Services, Inc.

3. Petroleum and Natural Gas

Exploration, Development, and Production

Income and Profitability

Worldwide oil and gas production is the major source of income for the FRS companies. Net income from oil and gas production (excluding unusual items) was down 14 percent in 1993. Cost cutting and favorable natural gas prices could not offset the effects of lower oil prices in 1993. In U.S. operations, revenues from natural gas sales increased over $3 billion (Table 11). However, the decline in oil prices (to an average of $13.56 per barrel) reduced FRS company revenues from U.S. oil production by $4 billion in 1993 (Tables 11 and 12). Expenses decreased, with declines in depreciation, depletion, and amortization costs, and in exploration expenses, reflecting continued consolidation of U.S. operations. Lifting costs (the out-of-pocket costs of oil and gas extraction) fell, due in part to declines in production of oil and gas. On a per-barrel basis, U.S. lifting costs continued to decline, but not as steeply as in 1992 and earlier years (Figure 8). This decline may indicate that the rising expense of producing from increasingly mature fields in the United States is offsetting cost reductions achieved by scaling back domestic operations.

In the foreign market, falling prices reduced the FRS companies' oil and gas revenues, despite increased production (Tables 11 and 12). Although the FRS companies increased foreign oil and gas production, lifting costs fell substantially, by $1.5 billion (Table 11). This steep decline was due mainly to increased efficiency and cost reductions in producing fields. Also contributing to the decline was a 29-cents-per-barrel decrease in production taxes levied by foreign jurisdictions, particularly in the United Kingdom's section of the North Sea.[33]

Income tax expense fell as the result of decreased operating income from both U.S. and foreign operations (Table 11). Although income tax expense declined in the United States, the effective tax rate (income tax expense divided by pretax income) rose from the prior year. The legislated 1-percent increase in the Federal corporate tax rate, passed on a retroactive basis for the full year in 1993, and its added effect on deferred taxes (previously discussed in Chapter 2), accounted for this increase. In foreign areas, the effective tax rate fell nearly 5 percentage points due to rate reductions by foreign governments.

Although the profitability of U.S. oil and gas production has yet to match the profitability of foreign production, the gap between the two generally narrowed following the oil price collapse of 1986 (Figure 9). The year 1993 was a modest exception to this trend due to the effects of unusual items on bottom-line net income (Table 11). Excluding unusual items, the difference between U.S. and foreign profitability continued to narrow in 1993.

Expenditures, Activity, and Results

Consolidation Continues

The decline in crude oil prices throughout 1993 put continued pressure on the FRS companies to cut costs and consolidate their U.S. oil and gas operations, especially onshore. For example, ARCO reorganized its lower-48 oil and gas operations, eliminating 1,300 jobs.[34] Oryx cut back spending for new onshore operations.[35] Coastal and FINA both restructured exploration and production operations in 1993, and Chevron "streamlined" its U.S. reserve holdings.[36] Cost cutting in 1993 included lower exploration expenses, reflecting a reduction in onshore exploratory well drilling (Table B26). The FRS companies' onshore exploration expenditures continued to decrease in 1993, reaching a new low (Figure 10). Onshore development expenditures

[33]"Tax Reforms Raise Questions for Oil Industry in the U.K.," *Oil and Gas Journal* (August 30, 1993), p. 54.
[34]ARCO, *1993 Annual Report*, p. 3.
[35]Oryx Energy Company, *Form 10-K*, 1993, p. 3.
[36]Coastal Corporation, *1993 Annual Report*, p. 19; FINA, *Annual Report 1993,* p. 3; and Chevron Corporation, *1993 Annual Report*, pp. 7, 9.

Table 11. Income Components and Financial Ratios in Oil and Gas Production for FRS Companies, 1992-1993
(Billion Dollars)

Components of Income and Financial Ratios	United States 1992	United States 1993	Foreign 1992	Foreign 1993
Oil and Gas Revenues				
Oil	29.6	25.7	NA	NA
Gas	16.9	20.2	NA	NA
Total Revenues	46.5	46.0	35.8	33.8
Expenses				
DD&A	12.3	11.5	6.4	6.3
Lifting Costs	14.6	13.7	10.8	9.3
Exploration Expenses	1.5	1.4	2.9	2.5
General and Administrative Expenses	1.8	1.6	0.9	0.9
Raw Material Purchases	7.0	7.5	NA	NA
Other Costs (Revenues)[a]	-0.1	2.4	4.5	5.7
Total Operating Expenses[a]	37.1	38.2	25.6	24.8
Operating Income[a]	9.4	7.8	10.1	9.1
Other Income (Expense)[a,b]	-0.6	-0.1	0.8	0.3
Income Tax Expense	2.3	2.2	5.9	5.1
Net Income, Excluding Unusual Items	6.4	5.5	5.0	4.3
Unusual Items	-0.8	-0.7	-0.3	0.9
Net Income	5.6	4.8	4.7	5.2
Unit Values (Dollars Per Barrel of Production COE)[c]				
Direct Lifting Costs (Excludes Taxes)	3.99	3.93	4.31	3.69
Production Taxes	0.62	0.64	1.15	0.86
Ratios (Percent)				
Rate of Return[d]	5.9	5.3	8.2	8.6
Effective Tax Rate[e]	28.4	30.7	54.2	49.5

[a]Excludes unusual items.
[b]Earnings of unconsolidated affiliates, gain (loss) on disposition of assets, excluding unusual items not already excluded from operating income.
[c]COE = Crude oil equivalent. Dry natural gas was converted at 0.178 barrels of oil per thousand cubic feet.
[d]Net income divided by net investment in place.
[e]Income tax expense divided by pretax income.
NA = Not available.
DD&A = Depreciation, depletion, and amortization costs.
Note: Sum of components may not equal total due to independent rounding.
Source: Energy Information Administration, Form EIA-28.

were up slightly, reflecting intensified exploitation of already discovered fields. Expenditures for gas drilling largely accounted for the uptick in outlays.

The U.S. offshore presented a somewhat more optimistic outlook. Exploration and development expenditures for offshore activity increased 23 percent between 1992 and 1993 (Table 13). Most categories of offshore expenditures were up, with drilling and equipping of development gas wells registering the largest gain, by far. Nevertheless, spending for offshore exploration and development by the FRS companies in 1993 was at a low level compared with most years (Figure 10). Total exploration and development

Table 12. Average Prices, Sales, and Production in Oil and Gas for FRS Companies, 1992-1993

Prices, Sales, and Production	1992	1993	Percent Change 1992-1993
Domestic Oil and Gas Production[a]			
Crude Oil and NGL (Million Barrels)	1,750.2	1,632.5	-6.7
Dry Natural Gas (Billion Cubic Feet)	7,877.7	7,651.1	-2.9
Total (Million Barrels, COE)	3,152.4	2,994.4	-5.0
Domestic Oil and Gas Sales Volumes			
Crude Oil and NGL (Million Barrels)	2,043.9	1,898.4	-7.1
Dry Natural Gas (Billion Cubic Feet)	9,712.4	9,800.9	0.9
Total (Million Barrels, COE)	3,772.7	3,642.9	-3.4
Domestic Production Segment Per Unit Sales Values			
Crude Oil and NGL (Dollars Per Barrel)	14.47	13.56	-6.4
Dry Natural Gas (Dollars Per Thousand Cubic Feet)	1.74	2.06	18.6
Composite (Dollars Per Barrel COE)	12.32	12.61	2.4
Foreign Oil and Gas Production[a]			
Crude Oil and NGL (Million Barrels)	1,292.4	1,320.9	2.2
Dry Natural Gas (Billion Cubic Feet)	3,864.7	4,099.0	6.1
Total (Million Barrels COE)	1,980.3	2,050.5	3.5
Foreign Production Segment Per Unit Sales Values			
Crude Oil and NGL (Dollars Per Barrel)	18.12	15.98	-11.8
Dry Natural Gas (Dollars Per Thousand Cubic Feet)	2.01	1.93	-4.0
Canada	1.14	1.35	18.4
OECD Europe	2.70	2.46	-8.9
Other Foreign	1.81	1.73	-4.4

[a]Production is on a net ownership basis. Sales are domestic production segment sales. See Appendix A for discussion of FRS reporting conventions.

COE = Crude oil equivalent. Dry natural gas was converted at 0.178 barrels of crude oil per thousand cubic feet.

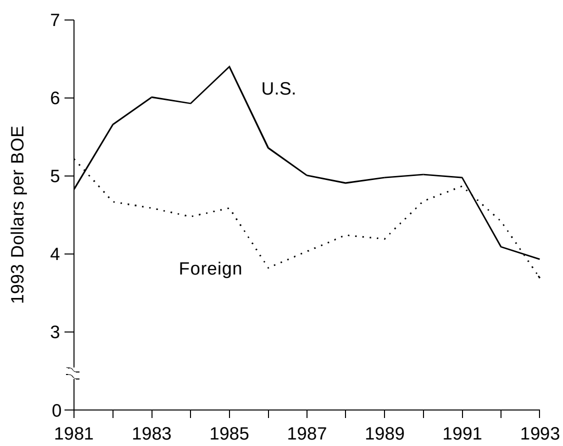
Sources: Energy Information Administration, Form EIA-28. Foreign production segment per unit sales values were compiled from information in FRS companies' filings of Securities and Exchange Commission Form 10-K, annual reports to shareholders, and supplements to annual reports.

spending changed little from 1992 in foreign regions as well (Table 13). Reductions were concentrated in OECD Europe, where spending often changes appreciably from year to year. These reductions were widespread: of the 16 firms reporting exploration and development spending in OECD Europe in 1992 and 1993, 12 reduced spending in 1993. The reductions reflect both cost-cutting efforts and efficiency improvements in North Sea projects, the completion of several large projects, and recent changes in petroleum tax laws. Because exploration expenditures are no longer tax-deductible in the United Kingdom, the FRS companies reduced their North Sea exploration efforts.[37]

In addition to cutting costs for ongoing projects in the North Sea and elsewhere, several companies reported examining their entire overseas exploration and development programs, with the intent of consolidating operations. Amoco cut back its foreign exploration program from 100 countries to 30, and Phillips sold non-strategic assets in Indonesia, the Netherlands, Egypt, and offshore Western Australia.[38] Shell restructured production operations in Syria as part of its refocused exploration program.[39] Although consolidating their operations in other parts of the world, the FRS companies are expanding operations in the Former Soviet Union (see box "Oil and Gas Operations in the Former Soviet Union").

[37]"Tax Reforms Raise Questions for Oil Industry in the U.K.," *Oil and Gas Journal* (August 30, 1993), p. 54.
[38]Amoco Corporation, *Annual Report 1993*, p. 9, and Phillips Petroleum Company, *Annual Report 1993*, p. 8.
[39]Shell Oil Company, *1993 Annual Report*, p. 2.

Figure 8. Direct Oil and Gas Lifting Costs for FRS Companies, 1981-1993

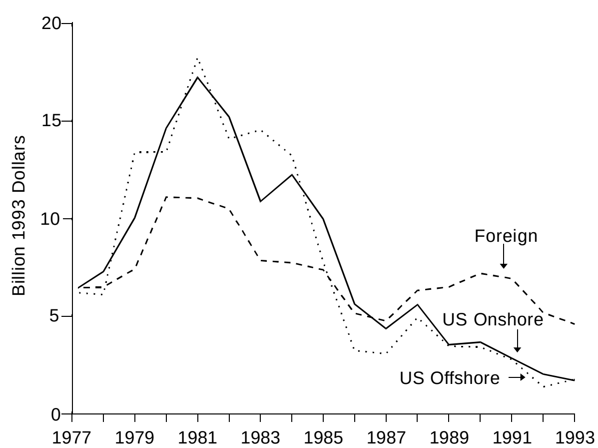


BOE = Barrels of crude oil equivalent.
Source: Energy Information Administration, Form EIA-28.

The FRS companies spent $5.8 billion on worldwide exploration in 1993, the lowest amount since 1977 (Figure 10). Many FRS companies cut costs through "prospect highgrading," where only the most promising prospects are drilled. In the process of highgrading, the companies discarded many onshore exploration prospects, as evidenced by the drop in their acreage

Figure 10. Exploration and Development Expenditures for FRS Companies, 1977-1993

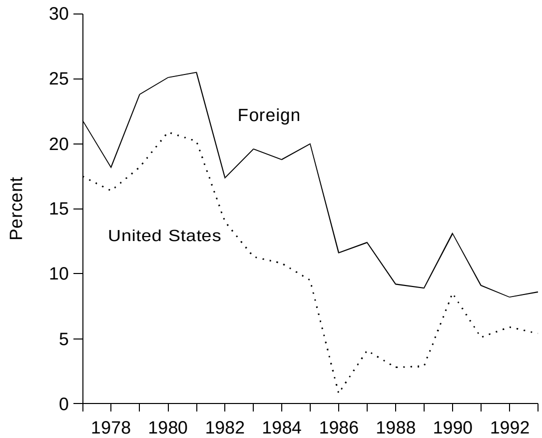
Exploration Expenditures



Note: Includes expenditures for unproved acreage.
Source: Energy Information Administration, Form EIA-28.

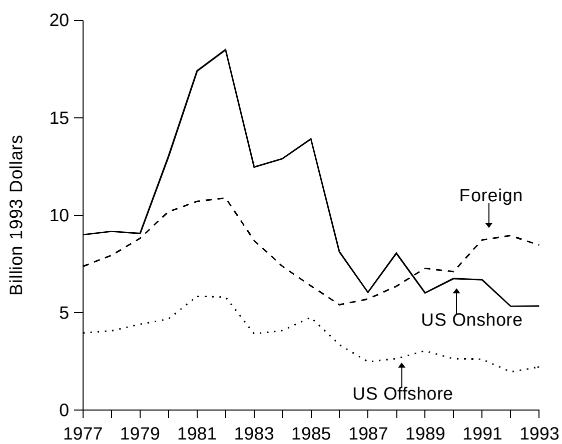
Less Exploration, More Development

Figure 9. Rates of Return in U.S. and Foreign Oil & Gas Production for FRS Companies, 1977-1993



Source: Energy Information Administration, Form EIA-28.

Development Expenditures



Note: Excludes expenditures for proved acreage.
Source: Energy Information Administration, Form EIA-28.

holdings. Undeveloped onshore net acreage held by FRS companies fell from 90 million to 42 million acres between 1987 and 1993. Offshore exploration spending in the United States in 1993 was up slightly from 1992, but still lower than at any time since 1977 (Figure 10). Offshore prospects tend to be more promising than onshore, but offshore exploration opportunities are limited because much of the Outer Continental Shelf is

Table 13. Exploration and Development Expenditures for FRS Companies by Region, 1992-1993
(Million Dollars)

Region	1992	1993	Percent Change 1992-1993
United States			
Onshore	7,296	7,214	-1.1
Offshore	3,018	3,718	23.2
Total United States	10,314	10,932	6.0
Foreign			
Canada	1,106	1,559	41.0
OECD Europe	6,796	5,482	-19.3
Former Soviet Union and Eastern Europe	--	263	--
Africa	1,393	1,472	5.7
Middle East	558	685	22.8
Other Eastern Hemisphere	2,409	2,469	2.5
Other Western Hemisphere	647	616	-4.8
Total Foreign	12,909	12,546	-2.8
Total FRS	23,223	23,478	1.1

Source: Energy Information Administration, Form EIA-28.

Oil and Gas Operations in the Former Soviet Union

The breakup of the Soviet Union unlocked the world's most promising oil and gas reserves outside of the Middle East. More than 100 consortia of American, European, Japanese, and Middle Eastern companies are beginning to bring capital and technical expertise into the region. Among the FRS companies, participation in joint ventures is widespread and geographically dispersed, from offshore Latvia in the Baltic Sea to Sakhalin Island in Eastern Siberia (Figure 11).

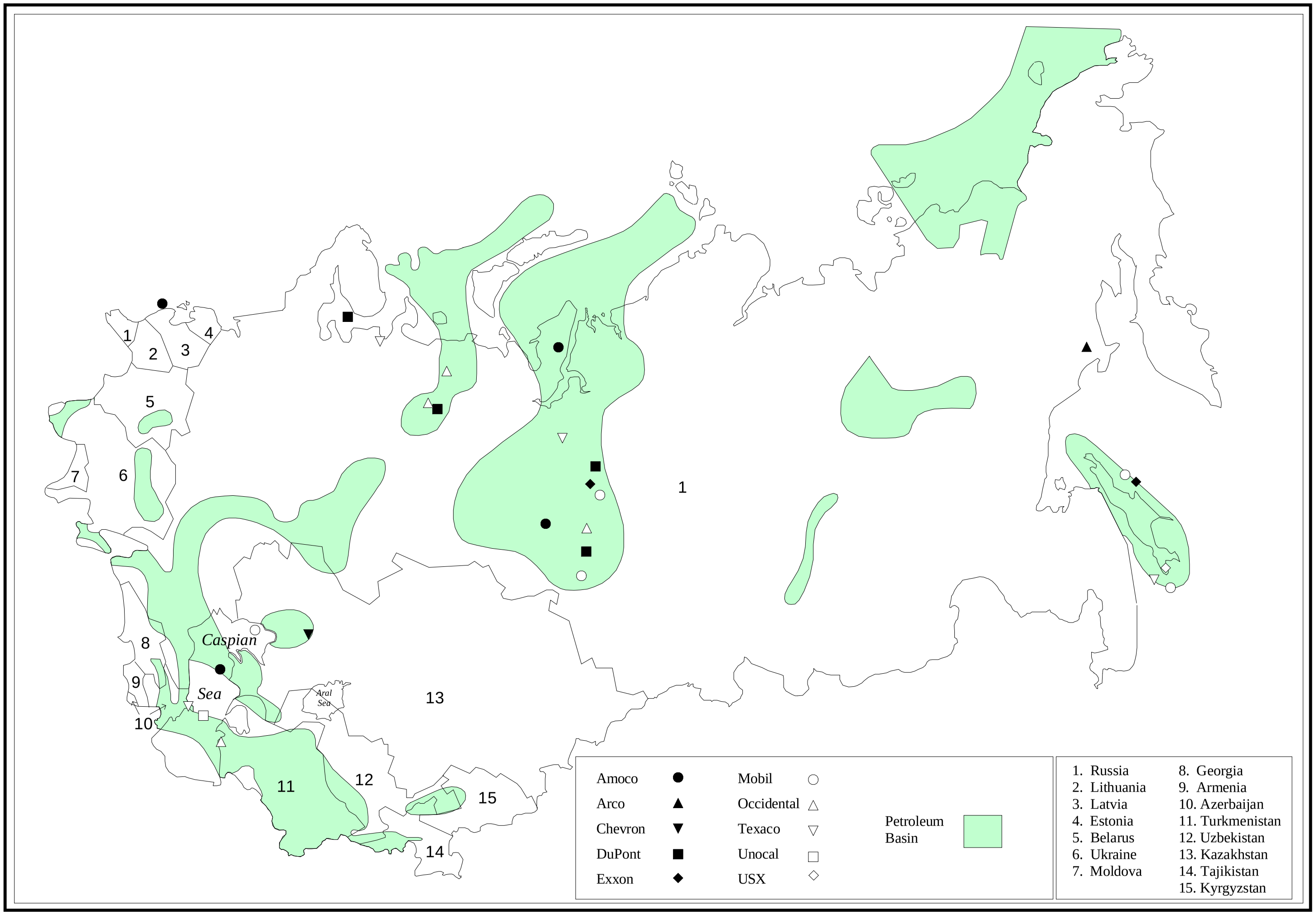
The FRS companies reported total exploration and development spending of $263 million in the Former Soviet Union in 1993, a relatively small sum in view of the number of projects and the extent of potential reserves. This partly reflects the early stages of many of the projects in which agreements have been reached, but drilling has yet to begin. It also reflects the effect of non-cash agreements, primarily Chevron's Tengiz purchase of over 1 billion barrels of reserves in Kazakhstan, where the company paid in property rather than cash.[a]

Production of oil and gas from the Former Soviet Union by the FRS companies was minor in 1993, but will increase as exploration and development gets under way. Bringing oil and gas to market from remote regions with undeveloped infrastructure promises to be challenging. Companies must build (or rebuild) pipelines and seaports, and manage export quotas and political complications regarding the use of pipelines.[b] In moving oil out of landlocked Kazakhstan, Tengizchevroil has been impeded by Russian authorities controlling the export pipeline. Other routes out of Kazakhstan, through Azerbaijan, Armenia, Iran, and Iraq, are equally precarious.

[a]Chevron Corporation, *Supplement to the Chevron Corporation 1993 Annual Report*, p. 24, and Chevron Corporation, *1993 Annual Report*, pp. 54, 58.

[b]"Russia Grappling with Economic and Political Challenges," *Oil and Gas Journal* (August 2, 1993), p. 60, and "Transport Troubles," *Petroleum Economist* (February 1994), p. 25.

Figure 11. FRS Companies Participating in Oil and Gas Projects in the Former Soviet Union



wms-0045/10-94

Note: Projects are defined as joint ventures signed or operating as of August, 1994.
Source: Energy Information Administration, "Joint Ventures in the Newly-Independent States of the Former USSR," August 1994.

restricted from exploration due to concerns about possible damage to the environment.

Rather than pursue exploration, the FRS companies have emphasized intensive development of existing fields (Figure 10). Using new technology such as three-dimensional seismology and horizontal drilling, the companies find new reservoirs to maintain production from mature fields. This short-term strategy is intended to maintain cash flow for use by other parts of the company. For example, Unocal plans to accelerate its development efforts in North America to increase cash flow to finance long-term expansion in Southeast Asia. Oryx reported investing in maintenance and development to sustain cash flow from production.[40]

In foreign regions, a similar move away from exploration and toward development was evident (Figure 10). Spending in OECD Europe (mostly for North Sea projects) dominates the FRS companies' foreign exploration and development spending. Several years ago, some FRS companies began intensive development of mature North Sea fields, often using horizontal drilling to reach reservoirs that were too small to justify an expensive drilling platform. In 1991, Unocal produced more than 70 percent of its Dutch North Sea oil with horizontal wells.[41]

North American Natural Gas Leads Upswing in Drilling

With natural gas price deregulation complete and surplus capacity in the United States reduced, average wellhead natural gas prices for 1993 were higher than at any time since 1985, providing an incentive for natural gas production.[42] The increasing use of natural gas (due to its relatively less-harmful environmental effects) is also expected to provide growth opportunities. This growth potential is viewed by several FRS companies as a key component of corporate strategy, especially to sustain operations in the United States. Burlington Resources, whose reserves are 85 percent gas, intends to stay heavily weighted to natural gas.[43] Coastal Corporation plans to concentrate on natural gas in its U.S. exploration and production program.[44] Kerr-McGee's North American operations will focus on natural gas, and FINA designated low-cost production of natural gas to be the company's primary long-term goal.[45] Amerada Hess cut back U.S. drilling to concentrate on other projects, but plans to focus on natural gas when it resumes domestic drilling.[46] Amoco, the largest producer of natural gas in the United States and Canada, looks forward to "exploiting North American natural gas."[47] In 1993, the FRS companies completed more natural gas wells in the United States than at any time in the past 10 years (with the exception of 1990).

Outside North America, demand for natural gas is also expected to increase, providing marketing and production opportunities. Demand for natural gas in Western Europe is predicted to grow more than 55 percent over the next 20 years.[48] Demand in the Asia-Pacific region is also growing rapidly, particularly for liquefied natural gas (LNG) for the Japanese market, leading those FRS companies extensively involved in Pacific Rim natural gas development to gear up to increase sales.[49] Mobil plans to provide LNG to the Pacific Rim by developing 300 trillion cubic feet of gas reserves offshore of Qatar.[50] Unocal began negotiations to acquire offshore gas fields in Myanmar, and added to its already extensive prospects in the Gulf of Thailand.[51] Chevron views its worldwide holdings of large undeveloped natural gas reserves as a key opportunity for growth.[52]

The increase in wells drilled by FRS companies in foreign locales in 1993 was concentrated in Canada (Table 14). Many companies participated in this increase, notably Exxon, with 216 new development wells in Canada (up from 50 in 1992), and Enron with 150 gas wells in Saskatchewan.[53] Non-FRS companies were also enthusiastic about Canadian prospects, and

[40]Unocal Corporation, *1993 Annual Report*, p. 7, and Oryx Energy Company, *Form 10-K*, (1993), p. 3.
[41]Unocal Corporation, *1991 Annual Report*, p. 7.
[42]Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(94/03) (Washington DC, March 1994) p. 123.
[43]Burlington Resources, Thomas O'Leary, Chairman, President and CEO, (1993) Letter to Shareholders.
[44]Coastal Corporation, *1993 Annual Report*, p. 4.
[45]Kerr-McGee Corporation, *Annual Report 1993*, p. 9, and FINA, *Annual Report 1993*, p. 3.
[46]Amerada Hess, *1993 Annual Report*, p. 9.
[47]Amoco Corporation, *Annual Report 1993*, p. 8.

[48]"Gas in Europe: Supply," *Petroleum Economist* (March 1994), p. i.
[49]"Regional Trade in Gas Grows," *Petroleum Economist* (December 1992), p. 13.
[50]Mobil Corporation, *Annual Report 1993*, p. 12.
[51]Unocal Corporation, *1993 Annual Report*, p. 8.
[52]Chevron Corporation, *1993 Annual Report*, p. 9.
[53]Exxon Corporation, *Form 10-K, 1993*, p. 5, and Enron Corporation, *1993 Annual Report to Shareholders and Customers*, p. 32.

Table 14. Well Completions by Region for FRS Companies, 1992-1993

Region	Oil Wells		Gas Wells	
	1992	1993	1992	1993
United States				
Onshore	1,776	2,074	1,709	1,791
Offshore	131	147	71	140
Total United States	1,907	2,221	1,780	1,931
Foreign				
Canada	231	383	69	340
Europe[a]	54	72	38	43
Other Eastern Hemisphere	130	133	82	79
Other[b]	200	176	8	8
Total Foreign	615	763	196	470

[a]Europe includes OECD Europe, Eastern Europe, and the Former Soviet Union.
[b]Other regions include Africa, the Middle East, and Other Western Hemisphere.
Source: Energy Information Administration, Form EIA-28.

the number of oil and gas wells drilled in Canada in 1993 doubled over 1992 levels.[54] Canada expects this drilling boom to be temporary, since it was partly generated by the province of Alberta allowing new crude oil exploration wells to produce without paying royalties for a year.[55] However, higher natural gas prices in Canada, such as those experienced by the FRS companies in 1993 (Table 12), may sustain drilling activity.

Anticipation of the significant 1993 increase (24 percent) in pipeline export capacity to the United States provided another impetus for gas well drilling in Canada.[56] Exports of natural gas from Canada to the United States began increasing several years ago when the countries simultaneously decontrolled their natural gas industries.[57] Subsequently, the Canada-United States Free Trade Agreement of 1989 formalized the trade relations that developed as a result of the deregulation. Because the recent North American Free Trade Agreement reiterates the terms of existing trade relations as they pertain to oil and gas, it probably had little direct effect on the 1993 increase in export capacity.[58]

Although low in historical context, the FRS companies' drilling in the Gulf of Mexico and other offshore areas of the United States increased in 1993 over 1992 levels (Table 14). New technology for exploring under large horizontal salt sheets in the Gulf of Mexico (the subsalt trend) paid off in 1993 when wells drilled by Amoco, Anadarko, and Phillips reached hydrocarbons.[59] Anadarko called the subsalt trend "the high-potential domestic exploration play of the 1990's," and plans to produce 45 thousand barrels per day by 1996.[60] Oryx is also exploring the subsalt trend, but considers exploration in this area to be a relatively high-risk program.[61]

Finding Costs Stable, Lifting Costs Decline

Total finding costs are defined as exploration and development expenditures, excluding expenditures on proved reserves, divided by reserve additions,

[54]Canadian Oil Markets and Emergency Planning Division, *The Canadian Oil Market Annual Review for 1993* (Ottawa, Ontario, July 1994), p. vii.
[55]Canadian Oil Markets and Emergency Planning Division, *The Canadian Oil Market Annual Review for 1993* (Ottawa, Ontario, July 1994), p. 5.

[56]Energy Information Administration, *Natural Gas 1994: Issues and Trends*, DOE/EIA-0560(94) (Washington, DC, July 1994) p. ix.

[57]Andre Plourde, "Natural Gas Trade in North America," *The Energy Journal*, 14 (1993), p. 54.
[58]"Little U.S. Benefit Seen in Nafta," *Oil and Gas Journal* (August 30, 1993), p. 42.
[59]Anadarko, *1993 Annual Report*, p. 6, "Truly, Deeply and Profitably," *Financial Times* (September 5, 1994), p. 46, and Phillips Petroleum Company, *Annual Report 1993*, p. 9.
[60]Anadarko Petroleum Corporation, *1993 Annual Report*, p. 6, and "Mahogany Group Sees Output from Subsalt Flowing 45k B/D in '96," *Platt's Oilgram News* (August 8, 1994), p. 1.
[61]Oryx Energy Company, *Annual Report 1993*, p. 10.

excluding net purchases. This ratio is often used as an indicator of the cost of adding another barrel of reserves through exploration and development activity. Since 1989, both U.S. and foreign finding costs have averaged about $5 per barrel and, in 1993, were $5.37 per barrel worldwide (Table 15). Reductions in the FRS companies' finding costs from 1992 to 1993 were minor compared to the dramatic cost reductions achieved in the late 1980's, when the rapid decline in oil prices drove the trend toward prospect highgrading and accelerated adoption of cost-saving technology (Figure 12).

In foreign regions, finding costs continued to decrease slightly in 1993, in spite of increases in OECD Europe and Canada (Table 15). Costs in OECD Europe increased partly because the United Kingdom revoked exploration tax credits in 1993.[62] The FRS companies' finding costs in Canada went up because revisions of previous estimates of reserves were revised downward. In other regions, technological and managerial improvements continued the reduction in finding costs evident since the early 1980's.

Production (or lifting) costs are the costs of extracting oil and gas, and include operating (direct lifting) costs, production taxes, and royalties. Several regions typically have high direct lifting costs per barrel, either because field sizes are small (Canada and the lower-48 onshore United States), or because production equipment is expensive to operate (the North Sea). In 1993, the FRS companies reduced direct lifting costs in almost all regions, including the United States, Canada, and OECD Europe (Table 16). These cost-cutting efforts have been effective in counteracting the expense of advanced technologies adopted to sustain production from mature and declining fields.

Overseas production taxes including royalties fell in 1993, mostly due to changes that took place in OECD Europe (Table 16). The United Kingdom reduced the Petroleum Revenue Tax on North Sea oil and gas from 75 percent to 50 percent of production in 1993.[63] In spite of the tax breaks provided by the province of Alberta and the Canadian government, the FRS companies' Canadian production taxes did not decrease, probably because the oil that is exempt from the taxes is yet to be produced. Production taxes in the United States changed little from 1992.

Differences Widen Between U.S. and Foreign Reserve Additions

Additions to crude oil reserves in 1993 reflected the FRS companies' shift in investment targets from the onshore

Table 15. Finding Costs by Region for FRS Companies, 1992-1993
(Dollars per Barrel of Oil Equivalent)

Region	1992	1993	Percent Change 1992-1993
United States			
Onshore	4.47	5.05	12.9
Offshore	6.76	5.22	-22.7
Total United States	5.05	5.11	1.0
Foreign			
Canada	9.60	10.63	10.7
OECD Europe	7.03	7.32	4.1
Africa	4.62	4.56	-1.4
Middle East	6.00	4.83	-19.6
Other Eastern Hemisphere	3.62	3.47	-4.3
Other Western Hemisphere	4.48	4.48	0
Total Foreign	5.68	5.62	-1.0
Worldwide Total	5.36	5.37	0.3

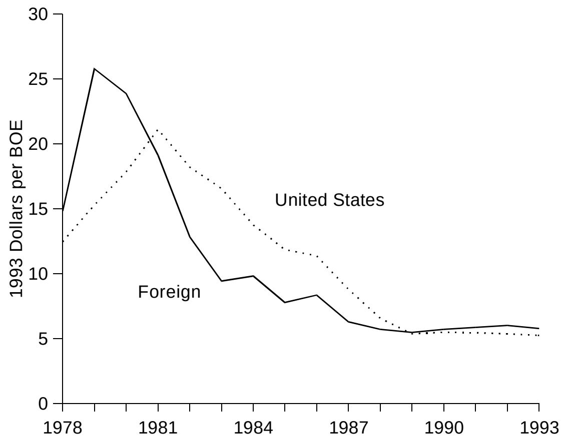
Note: The above figures are 3-year weighted averages of exploration and development expenditures, excluding expenditures for proved acreage, divided by reserve additions, excluding net purchases. Gas is converted to barrels of oil equivalent on the basis of 0.178 barrels of oil per thousand cubic feet of gas.

Source: Energy Information Administration, Form EIA-28.

[62]"Tax Reforms Raise Questions for Oil Industry in the U.K.," *Oil and Gas Journal* (August 30, 1993), p. 54.

[63]"Tax Reforms Raise Questions for Oil Industry in the U.K.," *Oil and Gas Journal* (August 30, 1993), p. 54.

Figure 12. U.S. and Foreign Finding Costs Decline



BOE = Barrels of crude oil equivalent.

Note: Finding costs are 3-year weighted averages of exploration and development expenditures, excluding expenditures for proved acreage, divided by reserve additions, excluding net purchases. Reserve additions exclude BP America's and Exxon's total 1987 downward revisions of Alaska North Slope natural gas reserves of 13.461 trillion cubic feet, and Arco's 1985 downward revisions of 8.3 trillion cubic feet. Gas is converted to barrels of oil equivalent on the basis of 0.178 barrels of oil per thousand cubic feet of gas.

Source: Energy Information Administration, Form EIA-28.

United States to offshore and overseas regions (Table 17). Onshore reserve additions continued to decline, but offshore reserve additions increased due to major discoveries of crude oil in the Gulf of Mexico by Shell, and upward revisions of previous estimates of natural gas reserves by Phillips Petroleum.[64] Although the FRS companies increased U.S. reserve additions from 1992 to 1993, they continued to produce oil and gas faster than they replaced reserves. Also, for the fourth consecutive year, the FRS companies were net sellers of U.S. oil and gas reserves (Table 17). Improved recovery remains an important source of crude oil reserve additions in the United States, but does not compensate for a lack of new producing properties. Accordingly, the production replacement ratio (reserve additions divided by production) fell from 50 percent to 46 percent for onshore oil operations. In contrast, the FRS companies doubled their production replacement ratios in offshore regions, and replaced 99 percent of the oil they produced in foreign areas. Production replacement ratios, both onshore and in foreign regions,were higher for natural gas than for oil, reflecting the companies' preparation for expected growth in the worldwide demand for natural gas. In offshore locations in the United States, the natural gas production replacement ratio increased dramatically from 58 percent to 113 percent. In foreign regions, replacement of gas continues to exceed production.

Refining and Marketing

Income and Profitability

The year 1993 saw an improvement in the earnings and profitability of the FRS companies' U.S. refining/marketing operations (Table 18 and Figure 13). This improvement followed three consecutive years of weak financial results, when U.S. downstream (refining and marketing) operations were the poorest performing of the FRS companies' domestic petroleum lines of business (Table 3). The FRS companies reported U.S. refining/marketing net income of $1.7 billion (excluding unusual items) and a return on investment of 3.4 percent for 1993. In contrast, in 1992, the FRS companies reported a $200-million dollar loss and a negative 0.4-percent rate of return. Although showing a marked improvement from 1992, the profitability of U.S. refining/marketing operations in 1993 remained low, both in historical context and compared with other FRS lines of business.

Part of the improvement in financial results can be traced to increased U.S. refined product demand. Economic activity in the United States typically has a major impact on domestic refined product demand. The U.S. economy continued to expand in 1993, growing 3 percent from 1992.[65] The strength of the current U.S. economic expansion was particularly evident in the transportation sector. Motor gasoline demand in 1993 surpassed the previous record high of 7.4 million barrels per day (b/d) realized in 1978.[66] Air travel and jet fuel sales also rose substantially from 1992.[67] Overall, U.S. gasoline, distillate, and jet fuel sales rose 2.4 percent, although total refined product demand was

[64]Shell Oil Company, *1993 Annual Report*, p. 5, and Phillips Petroleum Company, *Annual Report 1993*, p. 53.
[65]Energy Information Administration, *Annual Energy Review 1993*, DOE/EIA-0384(93) (Washington, DC, July 1994), Table D1.
[66]Energy Information Administration, *Petroleum Supply Annual 1993*, DOE/EIA-0340(93)/1, (Washington DC, June 1994), p. xiii.
[67]Energy Information Administration, *Petroleum Supply Annual 1993*, DOE/EIA-0340(93)/1, (Washington DC, June 1994), p. xiv.

Table 16. Lifting Costs by Region for FRS Companies, 1992-1993
(Dollars Per Barrel of Oil Equivalent)

Region	Direct Lifting Costs			Production Taxes			Total		
	1992	1993	Percent Change	1992	1993	Percent Change	1992	1993	Percent Change
United States									
Onshore	--	--	--	--	--	--	5.13	5.00	-2.7
Offshore	--	--	--	--	--	--	3.11	3.32	7.2
Total United States	3.99	3.93	-1.5	0.62	0.64	2.0	4.62	4.57	-1.0
Foreign									
Canada	4.06	3.51	-13.7	0.22	0.22	-2.3	4.28	3.72	-13.1
OECD Europe	6.02	5.02	-16.6	1.04	0.72	-30.4	7.06	5.74	-18.6
Africa	3.37	3.46	2.5	1.32	1.27	-3.8	4.69	4.72	0.7
Middle East	3.16	3.20	1.5	3.45	1.14	-67.1	6.61	4.34	-34.3
Other Eastern Hemisphere	2.94	2.28	-22.4	1.44	1.22	-14.8	4.37	3.50	-19.9
Other Western Hemisphere	3.42	3.08	-10.0	1.04	1.00	-3.5	4.46	4.08	-8.5
Total Foreign	4.31	3.69	-14.5	1.15	0.86	-25.4	5.46	4.55	-16.8
Worldwide Total	4.12	3.83	-6.9	0.83	0.73	-12.2	4.94	4.56	-7.8

-- = Data not available.
Note: Sum of components may not equal total due to independent rounding.
Source: Energy Information Administration, Form EIA-28.

Table 17. Oil and Gas Reserves and Production for FRS Companies, 1992-1993

Reserves and Production	U.S. Onshore		U.S. Offshore		Foreign	
	1992	1993	1992	1993	1992	1993
Oil (million barrels)						
Reserve Additions	727	606	249	528	1,230	1,313
Net Purchases	-204	-91	-52	-64	-157	995
Production	1,442	1,326	308	307	1,292	1,320
Total Oil Reserves	15,339	14,529	2,788	2,945	11,892	12,878
Oil Reserve Additions[a]/Production (percent)	50	46	81	172	95	99
Natural Gas (billion cubic feet)						
Reserve Additions	3,838	3,766	1,612	2,887	4,181	6,107
Net Purchases	-1,353	-631	-650	-597	-690	741
Production	5,094	5,089	2,784	2,562	3,865	4,099
Total Gas Reserves	60,078	58,125	19,634	19,362	53,872	56,620
Gas Reserve Additions[a]/Production (percent)	76	74	58	113	108	149

[a]Excludes net purchases and sales.
Note: Sum of components may not equal total due to independent rounding.
Source: Energy Information Administration, Form EIA-28.

Table 18. Sales, Expenses, and Income in U.S. Refining/Marketing for FRS Companies, 1992-1993

Sales, Expenses, and Income	1992	1993	Percent Change 1992-1993
	(billion dollars)		
Refined Product Sales	124.1	117.6	-5.2
Other Revenues	83.0	80.4	-3.2
Total	207.2	198.0	-4.4
Operating Income	0.1	2.6	--
Contribution to Net Income	-0.2	1.7	--
	(million barrels per day)		
Refined Product Sales	13.1	13.2	0.7
	(dollars per barrel sold)		
Average Sales Price			
Gasoline	29.61	27.27	-7.9
Distillate	24.87	23.61	-5.1
Other	19.98	19.50	-2.4
All Refined Products	25.98	24.46	-5.9
Raw Material Input and Product Purchases per Barrel	19.11	17.69	-7.4
Average Sales Price Less Cost of Raw Materials and Product Purchases (Gross Margins)	6.87	6.77	-1.5
Direct Operating Costs	6.49	6.06	-6.6
Refined Product Margin[a]	0.38	0.71	86.8

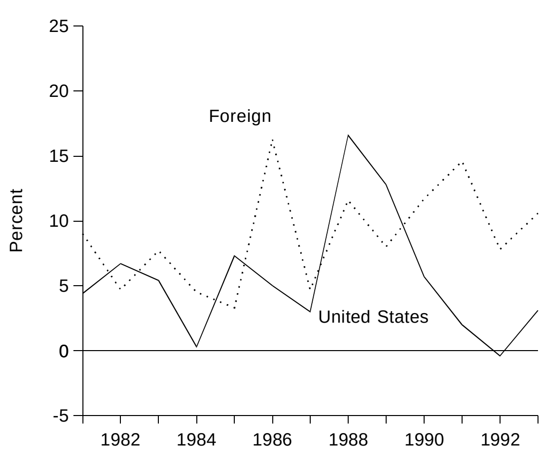
[a]See Appendix B, Table B48, for the components to calculate the refined product margin.

-- = Not meaningful.

Note: Sum of components may not equal total due to independent rounding. Percent changes were calculated from unrounded data.

Source: Energy Information Administration, Form EIA-28.

Figure 13. Refining and Marketing Return on Investment for the FRS Companies, 1981-1993



Note: Net income as a percent of net investment in place.

Source: Energy Information Administration, Form EIA-28.

up a lesser 1.2 percent.[68] Largely due to a consolidation of their U.S. downstream petroleum operations, the FRS companies' domestic refined product sales growth lagged behind that of the industry as a whole. The FRS companies reported a 0.7-percent increase in U.S. refined product sales between 1992 and 1993 (Table 18).

The bulk of the improvement in FRS refiners' U.S. financial results came from higher refined product margins in 1993.[69] This improvement in results was not attributable to a more favorable spread between refined product revenues and purchases, which changed little between 1992 and 1993, from $6.87 per barrel to $6.77 per barrel (Table 18). Rather, the source of increased income was to be found in reduced costs of operating refineries and marketing networks—down 43 cents per barrel in 1993. Largely due to recent restructurings and, in particular, marketing cost reductions, the FRS companies' refined product margins nearly doubled between 1992 and 1993.

[68]Energy Information Administration, *Monthly Energy Review July 1994*, DOE/EIA-0035(94/07) (Washington DC, July 1994), Tables 3.4-3.7.

[69]For FRS purposes, the refined product margin is defined as refined product revenues less purchase of products and raw materials, minus direct out-of-pocket costs of operating refineries and marketing networks.

Smaller FRS companies tended to be more successful in reducing marketing expense, although lower marketing expense and higher margins were realized by all FRS companies (Table 19). In their 1993 annual reports, a number of the FRS companies reported that earlier restructurings had significantly reduced downstream operating expenses in 1993, and were responsible for higher refined product margins. For example, Exxon, whose earnings from downstream operations almost tripled, noted that, among other things, the improvement was due to "major operating expense reduction programs in marketing and refining."[70] Mobil noted that "business improvement and expense reduction initiatives implemented in 1993 have significantly reduced annual expenses. Outsourcing of staff functions, such as service station real estate and engineering, and re-engineering of some administrative functions (billing and accounting, service station maintenance) have contributed significantly to overall operations efficiency and improved income."[71] Also, scaling back on advertising expenditures reduced retail gasoline marketing costs. The FRS companies' expenditures on television spot advertisements for gasoline fell an additional 5 percent in 1993, after posting declines in 1992 and 1991.[72] Employment cutbacks also reduced operating costs. Overall U.S. retail gasoline station employment (all gasoline marketers) also declined in 1993 (by 2 percent to 612 thousand employees),[73] despite a 2.6-percent rise in gasoline and diesel fuel sales.[74]

Capital Expenditures and Restructuring

The FRS companies reduced their U.S. refining capital expenditures by 13 percent in 1993 (Table 20). Part of the decline in U.S. downstream capital investment reflected a tapering off of earlier investments needed to comply with recently-introduced refined product specifications. Some of this recent investment was in preparation for October 1993, when reductions in the sulfur content of diesel fuel were to go into effect. As mandated by the Clean Air Act Amendments of 1990, the sulfur content of on-road diesel fuel was to have been reduced from a maximum of 0.25 percent per volume to 0.05 percent per volume. Due in part to heightened environmental standards, the FRS companies' U.S. refining capital expenditures more than doubled between 1990 and 1992.

The year 1993 saw a further consolidation of FRS company refining operations. There were six fewer wholly-owned FRS refineries in operation in 1993 than in the previous year. DuPont shut down its Santa Maria, California refinery[75] while Coastal suspended refining operations at its three Kansas refineries.[76] Amoco sold its Savannah, Georgia refinery to Citgo, a wholly-owned subsidiary of Petroleos de Venezuela. Still, the largest FRS company refining divestiture in 1993 involved Exxon's sale of its 260,000 b/d Bayway, New Jersey refinery to the independent refiner, Tosco in April of 1993. Six months after the Bayway purchase,

Table 19. Marketing Characteristics and Refined Product Margin for FRS Companies Ranked by Total Energy Assets, 1992-1993

Group	Average Outlet Volume (thousand gallons per month)		Refined Product Margin Per Barrel (dollars per barrel)		Marketing Expenses Per Barrel (dollars per barrel)	
	1992	1993	1992	1993	1992	1993
Top Four	81	85	0.55	0.67	2.30	2.08
Five Through Twelve	115	117	0.50	0.83	3.80	2.68
All Other	52	54	-0.01	0.58	1.70	1.66
All FRS	82	85	0.38	0.71	2.70	2.18

Source: Energy Information Administration, Form EIA-28.

[70]Exxon, *1993 Annual Report*, p. 16.
[71]*Mobil, 1993 Mobil Fact Book*, p. 52.

[72]*National Petroleum News, Market Facts*, Mid-June 1993, p. 20, and Mid-June 1994, p. 18.
[73]*National Petroleum News, Market Facts*, Mid-June 1993, p. 54, and Mid-June 1994, p. 53.
[74]Energy Information Administration, *Petroleum Supply Annual 1993*, DOE/EIA-0340(93)/1, (Washington, DC, June 1994), pp. 17 and 19.
[75]E.I. Du Pont de Nemours and Company, 1992 10-K, p. 12.
[76]The Coastal Corporation, 1993 Annual Report, p. 29.

Table 20. Refining and Marketing Financial Items and Operating Data for FRS Companies, 1992-1993

Financial Items	1992	1993	Percent Change 1992-1993
	(billion dollars)		
Contribution to Net Income (excludes unusual items)			
United States	0.5	2.9	437.1
Foreign	2.0	3.5	76.4
Total	2.5	6.4	153.8
Additions to Investment in Place			
United States			
Refining	5.2	4.5	-12.9
Marketing[a]	2.3	2.2	-5.3
Total	7.4	6.7	-10.6
Foreign Refining and Marketing	3.6	3.3	-8.9
Total	11.1	10.0	-10.0
	(thousand barrels per day)		
Refining Capacity			
United States	10,952	10,714	-2.2
Foreign	4,648	4,577	-1.5
Total	15,600	15,291	-2.0
	(percent)		
Refinery Utilization Rate			
United States	87.9	89.3	--
Foreign	80.0	82.9	--

[a]Includes refining and marketing transport.

-- = Not meaningful.

Note: Sum of components may not equal total due to independent rounding. Percent changes were calculated from unrounded data.

Source: Energy Information Administration, Form EIA-28.

Tosco bought BP America's 84,000 b/d Ferndale, Washington refinery along with its retail marketing network in Oregon and Washington.[77]

Several downstream refining transactions during 1993 involved foreign companies and state-owned petroleum companies. In addition to the Amoco/Citgo transaction mentioned above, Shell sold a 50-percent ownership interest in its Deer Park, Texas refinery to Pemex, the Mexican state oil company.[78] Foreign companies continued acquiring U.S. refining assets from non-FRS companies. In October of 1993, Castle Energy Corp., a partly-owned subsidiary of the German company, Metallgesellschaft, purchased a refinery in California from Powerine Oil.[79]

Between 1992 and 1993, overall FRS domestic refining capacity was reduced by over 200 thousand b/d (Table 20) and the FRS company share of total U.S. refining capacity fell from 69 percent to 68 percent. Buoyant product demand in the face of reduced capacity resulted in an unusually high level of capacity utilization in 1993. Capacity utilization for the domestic FRS refineries equaled 89 percent in 1993, the highest level since 1978.[80]

The FRS companies' capital expenditures for refined product marketing fell 5 percent between 1992 and 1993 (Table 20), reflecting their consolidation of retail gasoline operations in 1993. For example, the number of FRS companies' active automotive outlets fell by 2,402

[77]*The Wall Street Journal*, September 28, 1993, p. B2.
[78]Energy Information Administration, *Petroleum Supply Annual 1993*, DOE/EIA-0340(93)/1 (Washington DC, June 1994), Table 49.
[79]*The Los Angeles Times*, October 14, 1993, p. J2.
[80]Energy Information Administration, Form EIA-28.

(Table 21). In 1993, FRS retail operations sold an average of 85,000 gallons of gasoline per month, versus 82,000 in 1992. Higher average output volumes were realized by both large and small FRS companies (Table 19). In part, the gain in average outlet volume was due to an increase in overall retail sales, and in part due to FRS companies' continued push to rid themselves of lower-volume operations.

Over the past two years, FRS companies have also reduced the geographic scope of their retail gasoline marketing networks. For example, during 1992 and 1993, Sun withdrew from gasoline marketing in Oklahoma, Missouri, and Iowa.[81] This withdrawal concentrated Sun's retail network in the Northeast. In 1993, Sun maintained a retail network in 20 states compared to 27 in 1991.[82] BP America, meanwhile, sold its retail network in Florida and its aforementioned marketing interests in Washington and Oregon, reducing BP America's marketing network to Ohio and the Southeast.[83] In total, BP America reduced its geographic coverage by 8 states.[84] Unocal announced in March 1992 that it would cease operating in the Southeastern United States, leaving Unocal with marketing operations located in only 7 western states, versus 44 states in 1991.[85] In 1991, FINA's retail gasoline network was spread across 25 states; in 1992, FINA reduced its retail coverage to only 11 states, primarily located in the South.[86] Ashland operated in 11 states in 1993 compared to 18 in 1991. Since 1991, Ashland has sold its retail operations in Florida, Washington, and Wyoming to concentrate more in the upper Midwest and Ohio Valley.[87]

Table 21. Gasoline Distribution by FRS Companies, 1992-1993

Distribution Category	1992	1993	Percent Change 1992-1992
	(million barrels)		
Wholesale Volume	9,715	1,011.8	4.1
Retail Volume			
Dealer Volume	740.0	731.2	-1.2
Company-Operated Volume	349.7	341.7	-2.3
Total Retail Volume	1,089.7	1,072.9	-1.5
Direct Volume	215.9	233.4	8.1
Intersegment Volume	9.2	9.3	1.3
Total Volume	2,286.3	2,327.4	1.8
	(number of outlets)		
Dealer Outlets	36,631	34,939	-4.6
Company-Operated Outlets	9,935	9,225	-7.1
Total Retail Outlets	46,566	44,164	-5.2
	(thousand gallons per month)		
Average Monthly Outlet Volume			
Dealers	71	73	3.6
Company Operated	123	130	5.2
All Retail	82	85	3.8

Note: All percent changes were calculated from unrounded data.
Source: Energy Information Administration, Form EIA-28.

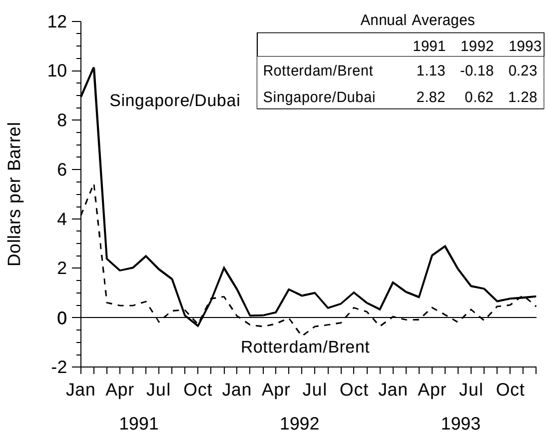
[81]Sun Company, Inc., *1992 Annual Report*, p. 15.

[82]*National Petroleum News, Markets Facts*, Mid-June 1993, p. 136, and Mid-June 1994, p. 144.
[83]The British Petroleum Company, *Annual Report on Form 20-F 1993*, p. 20.
[84]*National Petroleum News, Markets Fact*, Mid-June 1993, p. 136, and Mid-June 1994, p. 144.
[85]*National Petroleum News, Markets Fact*, Mid-June 1993, p. 136, and Mid-June 1994, p. 144.
[86]*National Petroleum News, Markets Fact*, Mid-June 1993, p. 136, and Mid-June 1994, p. 144.
[87]*National Petroleum News, Markets Fact*, Mid-June 1993, p. 136, and Mid-June 1994, p. 144.

Foreign Refining

Foreign refining/marketing operations registered a 76-percent increase in net income in 1993, to $3.5 billion, and realized the highest return on investment among the FRS companies' lines of business (Table 3). Even as lower petroleum prices drove FRS foreign refining/marketing revenues down by $18 billion, operating expenses fell by $20 billion.[88] Higher refining margins contributed to this result. Margins in both European and Asian markets in 1993 were well above prior-year levels, though short of the extraordinary margins realized in 1991 (Figure 14). Higher utilization rates also contributed to the earnings upswing. The FRS companies' overseas refinery utilization rate rose from 80 percent of capacity in 1992 to 83 percent in 1993 (Table 20), the highest rate in the 20 years spanned by the FRS data.

Figure 14. Foreign Refining Margins, 1991-1993



Note: Refining margin is defined as netback crude oil price less spot crude oil price. Netback price is calculated by multiplying the spot price of each refined product by its percentage share in the yield of a barrel of crude oil. Transport and out-of-pocket refining costs are then subtracted to arrive at netback price.

Source: *Petroleum Market Intelligence,* September 6, 1991, p. 8; April 2, 1992, p. 8; January 7, 1993, p. 8; and January 6, 1994, p. 8.

Despite the improvement in foreign refining/marketing performance, capital spending for this line of business fell 9 percent between 1992 and 1993 (Table 20). However, although FRS companies reduced their overall foreign downstream capital expenditures over the last two years, it appears that in the rapidly growing countries of Asia, refining expenditures may have increased. Chevron, DuPont, Exxon, Mobil, and Texaco accounted for most of the FRS companies' net investment in overseas refining/marketing operations.[89] These companies increased European refining throughput by 3 percent in 1993 and by only 7 percent over the last five years.[90] In contrast, the same companies increased their Asian and Pacific Rim refining throughput by 6 percent in 1993 and by 23 percent over the last five years.[91]

The FRS companies apparently are also redirecting their marketing efforts towards Asia. Evidence presented in the annual reports of a number of FRS companies with overseas downstream petroleum commitments suggests that Asian transport fuels marketing has been a growing target of investment. For example, Caltex, Chevron and Texaco's joint subsidiary, which operates primarily in Asia (but also in Africa and the Middle East), increased its capital expenditures for marketing between 1989 and 1993 from $67 million to $262 million.[92] Further, in 1990, Caltex reported that its retail distribution system included more than 16,000 retail outlets, while in 1994, Caltex reported more than 17,500 outlets.[93] In contrast, Chevron, Mobil, Texaco, and DuPont reported that the number of their European retail outlets fell from 16,441 in 1989 to 13,361 in 1993.[94] Over the same period, Mobil reported that Pacific Rim refined product sales increased 29 percent while Mobil's European product sales remained flat.[95]

[88]Energy Information Administration, Form EIA-28.
[89]Energy Information Administration, Form EIA-28.
[90]Chevron, *Supplement to the Chevron Corporation 1992 and 1993 Annual Reports*; DuPont, *Data Book 1993*; Exxon Corporation, *1992 and 1993 Financial and Operating Reviews*; Mobil, 1992 and 1993 *Mobil Fact Book, A Supplement to the Annual Report*; and Texaco, Inc., *Financial and Operating Supplement, 1992 and 1993.*

[91]Chevron, *Supplement to the Chevron Corporation 1992 and 1993 Annual Reports*; DuPont, *Data Book 1993*; Exxon Corporation, *1992 and 1993 Financial and Operating Reviews*; Mobil, 1992 and 1993 *Mobil Fact Book, A Supplement to the Annual Report*; and, Texaco, Inc., *Financial and Operating Supplement, 1992 and 1993*.

[92]Texaco, Inc., *Form 10-K, Caltex Group of Companies Combined Financial Statements and Schedules*, 1989, p. 15, and 1993, p. 18.

[93]*Caltex Reports*, 1990, p. 5, and 1994, p. 1.

[94]Chevron, *Supplement to the Chevron Corporation 1993 Annual Report*, p. 39; DuPont, *Data Book 1993,* p. 46; Mobil, *Mobil Fact Book, A Supplement to the Annual Report*, p. 66; and, Texaco, Inc., *Financial and Operating Supplement, 1993*, p. 55.

[95]*1993 Mobil Fact Book*, p. 65.

Transportation

TAPS Lowers Profits

Developments in the Trans Alaskan Pipeline System (TAPS), which transports crude oil from the North Slope of Alaska to the port of Valdez, Alaska, are central to the financial performance of the FRS companies' liquids pipelines. The three FRS companies accounting for 94 percent of TAPS ownership (ARCO, BP America, and Exxon)[96] account for a majority of the FRS companies' revenue from liquid pipelines.[97] The TAPS throughput declined 7 percent in 1993 following a 4-percent decrease in 1992. Further, tariff rates fell to $2.94 per barrel in 1993 from $3.26 per barrel in 1992.[98] Revenue for FRS liquids pipelines declined 6 percent (Table 22). Operating expenses increased 3 percent. Additions to investment in place increased 38 percent partly due to the installation of the GHX gas handling system (see the box entitled "Sustaining Prudhoe Bay in 1993"). Net income (excluding unusual items) decreased 26 percent compared to 1992 (Table 22).

Gas Pipelines' Performance Stable in 1993

Although most of the FRS companies are involved in liquids pipelines operations, two-thirds of the total pipeline assets for the FRS companies are committed to natural gas transmission. Three companies (Coastal, Enron, and Occidental) account for nearly all of the FRS companies' natural gas pipeline activity and accounted for 17 percent of U.S. natural gas transmission volumes in 1993.[99] Despite a decade of deregulatory turmoil (see the box entitled "Unbundling in Natural Gas Transmission"), financial results for natural gas pipelines were remarkably stable between 1992 and 1993. Revenues were up 3 percent (Table 22), to $6.8 billion, about the same as overall growth in U.S. natural gas consumption.[100] Operating costs increased slightly, producing a modest 4-percent rise in operating income. However, mainly due to the rise in the Federal corporate income tax rate from 34 percent in 1992 to 35 percent in 1993 and its effects on deferred taxes (see Chapter 2), net income posted a 16-percent decline.

Sustaining Prudhoe Bay in 1993

The Prudhoe Bay field is the nation's largest oil field and accounts for the majority of TAPS throughput. The Prudhoe Bay field has entered its mature phase and production levels began to decline in 1989. To mitigate this decline, the owners of the oil field initiated a gas handling expansion program to restore the reservoir pressure and enhance oil production. In 1990, the producers installed the first major gas handling system and reservoir stimulation program, GHX-1, which maintained production levels in 1990 and 1991. However, in spite of this, net production still declined by 48,000 barrels per day (b/d) in 1992 and net production in 1993 declined by 63,000 b/d. In September 1993, the first phase of a second major gas handling expansion project (GHX-2) was installed, increasing gas handling capacity to 6.7 billion cubic feet per day (bcf/d) in the fourth quarter of 1993. The second and last phase of GHX-2 will be installed in 1994 and will increase the annual gas handling capacity to 7.5 bcf/d. The total expansion, at a cost of $1.3 billion, is expected to increase field production by 100,000 b/d by 1995.

[96]Exxon Corporation, *1993 Securities and Exchange Commission Form 10-K*, p. 12.; Atlantic Richfield Corporation, *1993 Annual Report on Form 10-K*, p. 11; and British Petroleum Company, *1993 Annual Report on Form 20-F*, p. 17.

[97]The following seven FRS companies together own 100 percent of the Trans Alaska Pipeline: Amerada Hess Corporation, Atlantic Richfield Corporation (ARCO), BP America, Exxon Corporation, Mobil Corporation, Phillips Petroleum Company, and Unocal Corporation. Source: *The Christian Science Monitor*, January 5, 1994, p. 8.

[98]Atlantic Richfield Corporation, *1993 Annual Report*, p. 10.

[99]Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0130(94/03) (Washington, DC, March 1994), Table 11.

[100]Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0035(94/03) (Washington, DC, March 1994), Table 3.

Table 22. Financial Items for Transportation for FRS Companies, 1992-1993
(Million Dollars)

Financial Items	1992	1993	Percent Change 1992-1993
Natural Gas Pipelines[a]			
Revenues	6,685	6,862	2.6
Operating Expenses	5,919	6,053	2.3
Operating Income[b]	781	809	3.6
Net Income[b]	633	534	-15.6
Additions to Investment in Place[c]	592	391	-34.0
Liquids Pipelines[d]			
Revenues	5,019	4,719	-6.0
Operating Expenses	3,127	3,215	2.8
Operating Income[b]	1,896	1,509	-20.4
Net Income[b]	1,400	1,034	-26.1
Additions to Investment in Place[c]	413	568	37.5
International Marine			
Revenues	2,415	2,545	5.4
Operating Expenses	2,451	2,542	3.7
Operating Income	-36	3	--
Net Income	-21	21	--
Additions to Investment in Place[c]	223	224	0.4

[a]Data are for FRS companies with pipeline assets primarily in natural gas transmission.
[b]Excludes special charges taken by FRS companies.
[c]Measured by additions to property, plant, and equipment, plus additions to investments and advances.
[d]Data are for FRS companies with pipeline assets primarily in liquids pipelines.
-- = Not meaningful.
Source: Energy Information Administration, Form EIA-28.

Unbundling in Natural Gas Transmission

A decade-long transition towards deregulation of the U.S. interstate natural gas pipeline industry is now largely over. The year 1993 marked the first winter in which the FRS natural gas pipeline companies operated in the completely unbundled environment mandated by FERC Order 636. Prior to the Natural Gas Policy Act of 1978, FERC Order 436 and FERC Order 500 (implemented in October 1985 and 1987, respectively), natural gas pipelines acted primarily as suppliers of bundled gas services. Pipeline firms purchased gas from producers, shipped the same gas to end users, and ultimately charged end users for both the marketing and the transporting of this gas. However, in response to market and regulatory changes over the past ten years, gas pipelines have increasingly separated their transportation and marketing operations. Carriage shares (transported volumes), which were almost negligible before 1984, had exceeded sales volume by 1987. For the first half of 1993, carriage shares accounted for 86 percent of the total natural gas delivered. However, as interstate pipelines leave the merchant function mandated by FERC Order 636, natural gas sales will become insignificant. In April 1992, FERC issued Order 636, known as the "Restructuring Rule." Order 636 required pipelines to further "unbundle" their natural gas transportation services by offering transportation, sales, and storage services separately. The implementation of open access to these services has fundamentally altered the way natural gas is sold, transported, and stored in the United States. Interstate pipelines now provide a variety of gas transportation and storage services, and gas is now sold by marketers and producers.

4. Coal and Alternative Energy

Coal

Despite the lengthy coal strike (see the box entitled "Major Work Stoppage During 1993") and the reduced coal production it engendered, coal prices (adjusted for inflation) fell during 1993, for the fifteenth consecutive year.[101] Domestic coal consumption increased 4 percent between 1992 and 1993, while coal production fell 5 percent.[102] The substantial coal stocks held by coal consumers, especially electric utilities, were drawn down by 26 percent during 1993,[103] reaching their lowest level since 1974 and thereby largely offsetting the strike-induced reduction of coal output.[104]

Reduced exports also damaged the financial performance of U.S. coal operations. During 1993, U.S. coal exports fell 27 percent, to 74.5 million tons, largely due to reduced exports to Canada, France, Denmark, and the Netherlands.[105] Steam coal exports to Canada were reduced and less steam and metallurgical coal was exported to the European countries. Sluggish European economies and competition with Australia, South Africa, and Poland (the other major coal exporting countries), and competition with subsidized European coal producers, all contributed to the reduction in U.S. coal exports to Europe during 1993.[106] Lower U.S. exports were also related to the settlement of the British coal strike of 1992.

Continued pressure on coal producers from falling coal prices led to further consolidation of U.S. coal operations through mergers, exit, and diminished activity. For example, Cyprus Minerals and Amax Coal Industries merged, creating the second largest coal operation in the United States.[107] Occidental Petroleum Company, Sun, and USX's U.S. Steel affiliate all pursued or completed their exit from the domestic coal industry during 1993.[108] Some companies left the coal industry in part because they were unable to reduce their costs. For example, Sun completed the sale of its western U.S. coal operations to RTZ Kennecott Corporation during 1993. Earlier, Sun had indicated that coal production was unprofitable relative to its other operations.[109]

In 1993, the FRS reporting group reduced its presence in U.S. coal production for the fifth consecutive year. In 1989, before the exit of FRS companies began, the largest FRS coal producers were DuPont's Consolidation Coal, ARCO, Exxon, Shell Oil, and Sun; at that time, the FRS companies accounted for 29 percent of U.S. coal production. By 1993 the leading FRS coal companies were ARCO, Exxon, Kerr-McGee, RTZ Kennecott Corporation's Nerco,[110] and Chevron. The FRS share of U.S. coal production had fallen to 21 percent. Over this period, six FRS companies exited U.S. coal production—BP America, Burlington Resources, Mobil, Occidental Petroleum, Shell Oil, and Sun—and DuPont transferred its Consolidation Coal unit to Consol Energy, a 50-50 joint venture between DuPont and RWE AG of Germany, reducing the number of FRS coal producers to 11. The exit of the former FRS coal producers largely accounted for the 22-percent decline in the FRS companies' U.S. coal production in 1993 (Table 23).

[101]Energy Information Administration, *Annual Energy Review 1993*, DOE/EIA-0384(93) (Washington, DC, July 1994), p. 225.
[102]Energy Information Administration, *Annual Energy Review 1993*, DOE/EIA-0384(93) (Washington, DC, July 1994), p. 211.
[103]Energy Information Administration, *Annual Energy Review 1993*, DOE/EIA-0384(93) (Washington, DC, July 1994), pp. 211, 219.
[104]Energy Information Administration, *Quarterly Coal Report October-December 1993*, (Washington, DC, May 1994), p. 2.
[105]Energy Information Administration, *Annual Energy Review 1993*, DOE/EIA-0384(93) (Washington, DC, July 1994), p. 217.
[106]Energy Information Administration, *Annual Energy Review 1993*, DOE/EIA-0384(93) (Washington, DC, July 1994), p. 208.
[107]Cyprus Amax Minerals Company, *1993 Annual Report*, p. 9.

[108]Occidental Petroleum Company, *Annual Report 1993*, p. 2; Sun Company, *Annual Report 1993*, p. 26; and USX, *The 1993 U.S. Steel Group Annual Report*, pp. 58, 64, and 67.

[109]Energy Information Administration, *Performance Profiles of Major Energy Producers 1992*, DOE/EIA-0206(92) (Washington, DC, January 1994), p. 55.

[110]Nerco became an FRS company during the 1992 reporting year and was acquired by RTZ in 1993 (RTZ Corporation, *1993 Annual Report*, p. 16).

Major Work Stoppage During 1993

The most salient feature of the U.S. coal industry during 1993 was the prolonged United Mine Workers of America (UMWA) strike against the Bituminous Coal Operators Association (BCOA). The contract between the UMWA and the BCOA expired on February 2, 1993. Negotiations, which had begun prior to the expiration of the contract, were then temporarily ended and the UMWA selectively struck Peabody Coal operations. Within 30 days of the expiration of the contract, the strike was extended to include Consol, Zeigler Coal Holding Company, Arch Mineral, R&P, and Freeman Energy, which are other Eastern coal producers and BCOA members. Approximately 1 month into the strike, the two sides agreed to a 60-day extension (until May 3, 1993) of the expired contract.[a] However, the extension of the contract also expired without a settlement being reached. Before the strike was finally settled on December 14, 1993, it had affected coal producers in seven states and approximately 17,500 miners and their families.[b,c,d]

The principal union concerns were job security for its members and "double breasting" by the BCOA members. "Double breasting" is the term given to the creation of non-union affiliate companies by unionized companies. The union demanded that its members who had been laid off by the unionized companies be hired by the non-union affiliate companies when openings occurred. The agreement reached by the two sides requires the BCOA companies to hire three union miners for every five new employees hired at their non-union operations.[e] Additionally, miners would receive a pay increase of $1.30 per hour and the companies would be allowed more flexibility in determining work schedules.[f]

[a] *The Coal Journal*, April 1993, p. 28.
[b] Energy Information Administration, *U.S. Energy Industry Financial Developments 1993 Fourth Quarter*, DOE/EIA-0543(93/4Q) (Washington, DC, April 1994), p. 11.
[c] *The Coal Journal*, December 1993, p. 2.
[d] *The Coal Journal*, January 1994, p. 1.
[e] *The Coal Journal*, January 1994, p. 1, and Energy Information Administration, *Quarterly Coal Report October-December 1993*, DOE/EIA-0121(93/4Q) (Washington, DC, May 1994), p. 9.
[f] *The Coal Journal*, January 1994, p. 2.

Remaining FRS coal operators continue to actively seek and implement cost-reducing measures and technology.[111] For example, Coastal Corporation's coal segment had its tenth consecutive year of operating profit in 1993, indicating success in reducing its costs in the face of years of declining coal prices.[112] Exxon took steps during the year to further streamline its U.S. coal operations, realizing significant cost reductions through " ... new and ongoing programs in the highly competitive [coal industry] environment."[113] However, Exxon found that its lower operating expenses were more than offset by lower coal prices, resulting in lower earnings in 1993 than in 1992.[114]

Despite the exit by some FRS companies, other FRS companies increased their activity in the U.S. coal industry. For example, Kerr-McGee Corporation is " ... actively looking for acquisitions to further increase ... [its] reserve and operating base" in low-sulfur coal production and sales.[115] Similarly, Coastal Corporation purchased the Soldier Creek Coal Company and its 86 million tons of high-quality, low-sulfur coal reserves

[111]Kerr-McGee notes that its productivity was at an all-time high during 1993, contributing to its 5-percent increase in operating profit (Kerr-McGee, *1993 Annual Report*, p. 3).

[112]Coastal Corporation, *1993 Annual Report*, p. 23.

[113]Exxon Corporation, *1993 Annual Report*, p. 20.

[114]Exxon Corporation, *1993 Annual Report*, p. F4.

[115]Kerr-McGee Corporation, *1993 Annual Report*, pp. 3, 18.

Table 23. Coal Financial and Operating Indicators for the FRS Companies, 1992-1993
(Million Dollars)

Financial and Operating Items	1992	1993	Percent Change 1992-1993
Coal Financial Items			
Coal Revenues	3,802	3,062	-19.5
General Operating Expenses (excludes taxes and unusual items[a])	2,625	2,157	-17.5
Coal Production Taxes	211	187	-11.4
Depreciation, Depletion, and Amortization	350	342	-2.3
General and Administrative	120	89	-25.8
Operating Income (excludes unusual items[a])	496	288	-43.8
Net Income (excludes unusual items[a])	441	195	-55.8
	(million tons)		
Coal Operating Indicators			
Coal Production	252	197	-21.7
Coal Reserves	20,787	16,142	-22.3

[a]Unusual items totaled $91 million (pretax) in charges and $927 million (after tax) in charges in 1992, and $65 million (pretax) in charges and $176 million (after tax) in gains in 1993.
Sources: Energy Information Administration, Form EIA-28, and company annual reports for unusual items.

and announced its intention to expand its low-sulfur coal production.[116]

Coal market developments appeared to have an adverse effect on the FRS companies' financial results. Coal revenues fell by more than $700 million dollars and operating income (excluding unusual items) was down 44 percent from the levels of 1992 (Table 23). However, more than 80 percent of the reduction in revenues and 45 percent of the decline in income were due to the exit of former FRS coal producers.

The recent retrenchments complicate the interpretation of aggregate FRS coal data for 1992 and 1993. Table 24 presents financial and operating information for a consistent group of domestically-oriented FRS coal producers. Average coal prices received by this group fell 93 cents per ton, slightly more than the 77-cent decline in the national average price of coal. Operating costs of the group fell slightly more than did prices, reflecting the emphasis on cost cutting and better utilization of production capacity, which rose from 81 percent to 84 percent. Examples of operating cost reduction measures and technology recently implemented include: conveyor construction and upgrading, crusher upgrading (RTZ Kennecott's Nerco), shifting production to lower-cost mines from higher-cost mines (Coastal), introduction of longwall mining systems (Chevron, Exxon, and Kerr-McGee). Still other technology has been introduced to improve coal sales, such as the introduction of coal cleaning facilities (Kerr-McGee).[117] Because the consistent group achieved substantial operating cost reductions, it realized a 6-percent increase in operating income per short ton of coal produced.

Despite their modest financial improvement, the FRS companies with ongoing coal operations made sizable reductions in their capital expenditures for U.S. coal, down 34 percent. Most of the reduction in capital expenditures was made by Chevron and Kerr-McGee. Chevron's reduction followed the placement of a longwall mining system at its York Canyon, New Mexico mine and the development of the Sebree, Kentucky underground mine, both completed during 1992.[118] Kerr-McGee completed the installation of a second longwall mining system in the Galatia, Illinois mine, No. 5 unit, during 1992 and planned a temporary shutdown, beginning in 1994, of its higher sulfur Galatia No. 6 unit.[119,120]

[116]Coastal Corporation, *1993 Annual Report*, pp. 23-24.

[117]Chevron, *Supplement to the Chevron Corporation 1992 Annual Report*, p. 49; Coastal Corporation, *Annual Report 1993*, pp. 23-24; Exxon, *1993 Annual Report*, p. 20; Kerr-McGee, *Annual Report 1992*, p. 16; Kerr-McGee, *Annual Report 1993*, pp. 3 and 17; and RTZ Corporation, *1993 Annual Report*, p. 16.

[118]Chevron Corporation, *Supplement to the 1991 Annual Report*, p. 49.

[119]Higher sulfur coal can be burned only with emission allowances or after blending with low-sulfur coal.

[120]Kerr-McGee Corporation, *Annual Report 1992*, p. 18, and Kerr-McGee Corporation, *Annual Report 1993*, pp. 17-18.

Table 24. Financial and Operating Items in Coal for a Consistent Group of FRS Companies, 1992-1993

Financial and Operating Items[a]	1992	1993	Percent Change 1992-1993
	(dollars per ton)		
U.S. Operating Expenses and Revenues per Unit of Production[b]			
Revenues	18.95	18.02	-4.9
Total Operating Expenses	15.96	14.86	-6.9
Operating Income	2.99	3.16	5.7
	(million dollars)		
Additions to U.S. Property, Plant, and Equipment	193	128	-33.7
	(million tons)		
Coal Operating Indicators			
Coal Production	99	103	4.0
Coal Capacity	123	123	0.0
Coal Reserves	6,251	5,582	-10.7

[a]Data are for FRS coal producers reporting production and revenues in both 1991 and 1992.
[b]Excludes unusual items and companies with predominantly foreign coal operations.
Sources: Energy Information Administration, Form EIA-28, and company annual reports for unusual items.

Alternative Energy

In 1993, the FRS companies' alternative energy investments were largely in tar sands operations, cogeneration, and geothermal steam production. These lines of activity accounted for 84 percent of alternative energy revenues in 1993. Solar power manufacturing was of lesser importance. Sun and Exxon are largely responsible for FRS investment in oil production from Canadian tar sands. Three companies (Coastal, Texaco, and Enron) accounted for a large share of FRS company investment in cogeneration facilities while Unocal primarily accounted for the FRS companies' investment in geothermal production.

Lower prices for oil derived from tar sands reduced Sun's revenue and income in 1993.[121] Overall, total revenue for tar sands declined 12 percent compared to 1992. Exxon reported tar sands production of 44,000 barrels per day in 1993, while Sun reported production of 61,000 barrels per day in 1993. In 1992, Sun's tar sands operations were impaired by a fire.[122]

Enron, a new FRS respondent in 1992, added significantly to the FRS companies' involvement in cogeneration facilities, making cogeneration the second largest FRS investment in alternative energy in 1993. Cogeneration, which is the simultaneous production of steam and electricity from a single fuel source, is one of the largest growth markets for natural gas. In 1993, a combined cycle power plant, in which Enron holds a 50-percent ownership interest, became operational in Milford, Massachusetts. In addition to Enron's cogeneration investments in the United States, Enron has three cogeneration plants in various stages of construction in Guatemala and the Philippines.[123] In 1993, Enron's 50-percent owned combined cycle facility in Teesside, England became operational. Coastal, another major cogeneration investor, has ownership interests in four cogeneration operations in the United States and is in the early stages of developing a gas-fired cogeneration plant in Gorzow, Poland, which will have a capacity of 48 megawatts.[124] Additionally, Texaco has ownership interest in nine cogeneration facilities in the United States with a combined capacity of 1,057 megawatts.[125]

Unocal, the world's largest producer of geothermal power, has U.S. operations concentrated in California, foreign operations in the Philippines, and a development project in Indonesia. In 1993, Unocal's earnings

[121] Sun Company, *1993 Annual Report*, p. 33.
[122] Exxon Corporation, *1993 Annual Report*, p. F27, and Sun Company, *1993 Annual Report*, p. 33.
[123] Enron Corporation, *1993 Securities and Exchange Commission Form 10-K*, p. 6.
[124] The Coastal Corporation, *1992 Securities and Exchange Commission Form 10-K*, p. 22.
[125] Texaco, Inc., *1993 Financial and Operational Supplement*, p. 36.

included a $19-million gain from the sale of geothermal properties in the Imperial Valley of California; this sale, however, accounted for only 9 percent of its geothermal energy assets.[126] Excluding this gain, Unocal's geothermal earnings were down $11 million.

Commitments to solar energy by the FRS companies have been reduced in recent years. In 1990, ARCO sold off its solar power subsidiary to Siemens AG of Germany leaving only Amoco and Mobil as the remaining two FRS companies with solar power manufacturing facilities.[127] However, in November 1993, Mobil shut down its 19-year old solar energy program partly due to the expectations of poor prospects for growth in utilities' demand for solar energy facilities.[128] In August 1994, Mobil sold its solar operation to ASE Americas,[129] another German-based company, leaving Amoco, the only U.S.-based oil company invested in solar energy.

Some FRS companies have investment interests in reformulated fuels market and continued investments in coal gasification projects. For example, Kerr-McGee has operations in renewable fuels, such as ethanol, at its plant in Corpus Christi, Texas.[130] Texaco has investments in gasification in the United States and in Italy.[131]

In addition to geothermal power and solar energy, other divestments were made by the FRS companies in 1993. Suncor, Sun's Canadian subsidiary, sold 6.8 million shares of the company's synthetic crude oil operations, reducing further the company's ownership interest from 68 percent to 55 percent.[132] Mobil sold its 25-percent ownership interest in synthetic fuels operations in the New Zealand Synthetic Fuels Corporation.[133]

The combination of lower oil prices and the retrenchments in alternative energy in 1993 led to 11-percent declines in both revenues and operating expenses from 1992. The net effect was a slight decline in operating income (Table 25). However, led by Enron's $151-million investment in its Teesside facility, the FRS companies' 1993 capital expenditures were up 67 percent from the prior year. Also, Unocal reported that its capital expenditures for geothermal operations rose to $53 million in 1993 from $37 million in 1992, due in part to its geothermal developments in Indonesia, which are expected to be in operation in 1994.[134]

Table 25. Revenues, Income, and Investment in Other Energy for FRS Companies, 1992-1993
(Million Dollars)

Item	1992	1993	Percent Change 1992-1993
Revenues and Expenses			
Revenues	1,253	1,121	-10.5
Operating Expenses	1,085	969	-10.7
Operating Income[a]	168	158	-6.0
Net Income[a]	130	102	-21.5
Additions to Investment in Place[b]			
United States	77	34	-55.8
Foreign	158	358	126.6
Total	235	392	66.8

[a]Excludes unusual items.
[b]Additions to net property, plant, and equipment and advances to unconsolidated subsidiaries.
Source: Energy Information Administration, Form EIA-28.

[126]Unocal Corporation, *1993 Annual Report*, p. 23.
[127]*The Wall Street Journal*, March 27, 1991, p. A5.
[128]Mobil, *News Release*, November 4, 1993, p. 1, and *Oil and Gas Journal*, November 15, 1993, p. 31.
[129]ASE, a solar energy company newly formed from a merger of two former solar energy companies, RWE, a subsidiary of Nukem, and Deutsch, a subsidiary of Daimler Benz, intends to expand solar activities considerably over the next decade. Sources: *The Washington Post*, August 3, 1994, p. F2., and *Power Europe*, August 12, 1994, Energy Section.

[130]Kerr-McGee Corporation, *1991 Annual Report*, p. 25, and *1993 Securities and Exchange Commission Form 10-K*, p. 21.
[131]Texaco, Inc., *1993 Financial and Operational Supplement*, p. 36.
[132]Sun Company, *1993 Annual Report*, p. 20.
[133]Mobil, *News Release*, March 3, 1994, p. 1.
[134]Unocal Corporation, *1993 Annual Report*, p. 24.

Part II

Major Energy Company Strategies Since the Arab Oil Embargo

5. Overview of Markets and Policies

Petroleum has long been the lifeblood of the world's industrial economies as well as a critical factor in two world wars. Events in the past 20 years have reshaped the world's petroleum industry in ways not seen since the industry's birth in the mid-nineteenth century. Indeed, the period from 1974 to 1993 was unique.

The era commenced in late 1973 with an embargo on the export of oil to the United States, organized by members of the Organization of Petroleum Exporting Countries (OPEC). Host governments in oil-producing nations followed this concerted use of economic power with further interventions in the oil market, ranging from ever-greater capture of profits from oil extraction to outright nationalization. The world's petroleum industry found itself operating in an entirely new geopolitical landscape, dominated by a Middle Eastern oil cartel. More recently, the sudden and dramatic end of the Cold War saw new political alliances, new national and international economies, new patterns of competition, and new investment opportunities emerge in a truly global economy. The breakup of the Soviet Union, for example, offered new exploration opportunities in one of the world's first and largest petroleum producing areas. In other areas, state energy companies are increasingly turning to capital markets as a source of finance and as a route to increased economic efficiency.

The Financial Reporting System (FRS) companies, whose performance is reviewed in the remaining chapters, were major players in world energy markets over the past two decades and still are today.[135] They contributed materially to the development of oil reserve and production capabilities outside OPEC, to the emergence of natural gas as a competitor to oil in world energy markets, to the search for unconventional sources of energy, and to the reformulation of petroleum products to meet changing environmental needs. Accordingly, the remainder of this chapter reviews key features of energy markets and the policy context in which these major energy companies made business decisions.

Petroleum

The United States, the world's largest energy consumer, derives more energy from petroleum than from any other energy source. It is also one of the world's largest petroleum producers, but consumes far more than it produces. From 1974-1993, reliance on imported crude oil left the United States, and its complex industrial economy, vulnerable to oil price shocks and supply disruptions.

The Arab Oil Embargo (October 1973-March 1974) seriously disrupted petroleum supplies, caused prices to skyrocket, forced motorists into long gas lines, and encouraged energy conservation. After the Embargo, oil prices remained fairly stable until late 1978, when the Iranian Revolution reduced supplies again and caused prices to rise sharply for the second time in five years.

Adding to America's energy woes and its balance of payments problems were the price increases made by OPEC in 1979-1981. Formed in 1960, OPEC's goal was to increase member country revenues by controlling production and supply. Political rivalries among OPEC members sometimes weakened its effectiveness. Nonetheless, since the 1970's, OPEC has had a significant influence on the world's petroleum industry.

Policy responses to the energy crises of the 1970's included the nationalization of some U.S. petroleum firms' foreign operations, the attempt to capture economic rents from oil production through taxation and royalties, and the encouragement of nuclear energy and alternative energy development by subsidies, price guarantees, and research funding. Other important U.S. energy policy responses were petroleum price regulations, the 55-mph speed limit, and automobile manufacturer fuel economy regulations known as corporate average fuel efficiency (CAFE) standards.

The composition of petroleum demand changed dramatically in response to increases in oil prices, U.S. Government encouragement of fuels other than

[135]Companies in the FRS group over the 1974-1993 period are listed in Appendix A, Table A1.

petroleum, and the imposition of more stringent environmental policies. Use of residual fuel oil by manufacturing industries and electric utilities declined. Motorists used more unleaded gasoline and automotive fuels with higher-octane additives. Consumers shifted to less petroleum-intensive products and electric utilities shifted to greater use of coal and nuclear power.

Oil prices peaked in 1981. Domestic oil prices were decontrolled 8 months ahead of schedule in 1981 as market-based allocations were encouraged and the Federal Government's role in energy conservation and energy research and development was reduced. Earlier energy policy initiatives such as price controls and energy conservation tax credits (e.g., for research and development, and home insulation) were pursued less aggressively or eliminated altogether.

Ironically, exercise of market power by OPEC encouraged developments that actually eroded its subsequent influence over the course of world oil prices. Skyrocketing oil prices induced cutbacks in petroleum consumption, in large part accomplished through investments for conservation and reduced purchases of energy-intensive goods and services. In the United States, petroleum consumption per dollar of real Gross Domestic Product fell by 22 percent in the five years following the onset of the second oil price escalation,[136] equivalent to a reduction in oil use of over 2 billion barrels, annually.

Similar indications of energy conservation were evident across other industrialized nations. Higher oil prices made the search for oil economic in areas such as the North Sea and Latin American locales where the cost of finding oil otherwise would have been considered too high. Oil production outside OPEC nations increased as OPEC output diminished sharply. Also, in the context of escalating prices following the Iranian Revolution, petroleum inventories reached unprecedented levels, motivated both by concerns about refined product supply and by expectations of speculative gain. By mid-1981, high levels of inventories were putting strong downward pressures on oil prices. Perhaps the development with the most enduring imprint on oil markets was the increase in the volumes of oil traded in spot markets, which, in turn, made monitoring and enforcement of OPEC pricing arrangements more difficult.

Beginning in mid-1981, oil prices began to trend downward. With ever greater use of spot market sales of crude, OPEC solidarity dwindled. In fact, by 1985, only Saudi Arabia adhered to OPEC agreements, maintaining contract prices for the Arabian American Oil Company (Aramco[137]) which were higher than those of other OPEC members. This practice put Saudi Arabia at a distinct disadvantage. Saudi Arabia completely abandoned its role as swing producer in late 1985 when they moved from contract prices in favor of netback pricing arrangements. Netback pricing protected the refiners (buyers) from subsequent product price cuts by tying the price of crude oil to the sales price of refined products, less refining and transportation costs.[138]

The abandonment of contract prices and adoption of netback pricing led to a surge in demand for Saudi oil production and a rapidly developing glut in the oil market. Oil prices plunged in the first half of 1986. For example, the price of crude imported into the United States fell from $27 per barrel in November, 1985 to $11 per barrel in July, 1986. Accordingly, demand for petroleum products began to increase. In 1986, U.S. petroleum consumption was 3.5 percent above 1985 levels; other developed industrial countries registered a 2.4-percent increase. In late 1986, in response to the price crash, OPEC took the step of supporting a target price through outright production quotas. As a result, crude oil prices stabilized at about $18 per barrel in 1987.

Since 1987, oil prices (adjusted for inflation) have fluctuated at around half the level of 1979-1985 prices. The most notable deviation in the course of oil prices

[136]Unless otherwise noted, all price and quantity information in this chapter was taken from Energy Information Administration, *Annual Energy Review 1993*, DOE/EIA-0384(93) (Washington, DC, July 1994), and *Monthly Energy Review* September 1994, DOE/EIA-0035(94/09) (Washington, DC, September 1994).

[137]Aramco's history goes back to the early 1930's when the Saudi Arabian Government signed a basic oil concession agreement with Standard Oil of California (Socal). This concession was later assigned by Socal to a subsidiary, California Standard Oil Company (Casoc). In 1936, The Texas Company (Texaco) became a half owner of Casoc. In 1944, Casoc changed its name to Aramco. The original concession agreement was revised and renegotiated several times. By 1948, two other major U.S. oil companies, Exxon and Mobil, acquired an interest in Aramco. In 1973, The Saudi Arabian Government acquired a 25-percent interest in Aramco. This grew to 60 percent in 1974, and to 100 percent in 1980, when the Government paid for substantially all of Aramco's assets. In late 1988, the Saudi Arabian Oil Company (Saudi Aramco) was established to run Aramco for the Government.

[138]As swing producer, the Saudis had carried the full burden of any OPEC accommodation toward changes in world oil demand by adjusting Saudi production. In part, due to frustration resulting from overproduction by other OPEC members, the Saudis abandoned their role as swing producer and adopted netback pricing. While the details of netback pricing differ for each transaction, the essential ingredient was the assurance to the buying refinery of a profit margin when the crude was refined.

during this period occurred following Iraq's invasion of Kuwait in August, 1990. It is significant to note, however, that even Iraq's invasion of Kuwait and the ensuing Gulf War did not cause an “energy crisis.”

The cutoff in oil supplies that resulted from Iraq's invasion of Kuwait caused a more brief disturbance in the world oil market than previous supply disruptions, partly as a result of the workings of the spot and future markets for crude oil. The futures market for crude oil (begun in 1983) provides openly-reported prices, and prices on soon-to-be executed futures contracts are closely related to less-visible spot prices. The timely price information conveyed by the futures market helped prices to efficiently and expeditiously balance oil supply and production. In addition, replacement production, which came mainly from Saudi Arabia, and withdrawals from the U.S. Strategic Petroleum Reserve had a calming effect on world oil markets.

The oil price collapse of 1986 and the generally lower level of oil prices thereafter brought yet a further reversal of earlier energy policies both in the United States and abroad. For example, taxation on oil production was reduced, investments by U.S. energy companies abroad received greater acceptance by foreign oil-producing countries, and some OPEC members expanded their interests downstream into developed petroleum markets.

Other Energy

At first, the oil price shock of the Arab Oil Embargo spurred the energy conservation movement and gave new impetus to the development of coal, nuclear energy, synthetic fuels (e.g., shale oil and tar sands), and renewable sources of energy (e.g., solar, wind, tidal, and geothermal), and to the search for new petroleum reserves both at home (mainly in Alaska and on the Outer Continental Shelf) and overseas. From the late 1970's through the early 1990's, FRS company involvement in nuclear and alternative energy was influenced by two major factors: sharply rising and then declining oil prices; and U.S. domestic policy developments, particularly with respect to nuclear plant safety and other environmental concerns.

Throughout the post-World War II era, sometimes referred to as the dawn of the Atomic Age, nuclear energy had held out the promise of a clean, abundant, reliable, and inexpensive source of energy, particularly for the generation of electricity, but also for the propulsion of oceangoing vessels, both military (e.g., nuclear-powered submarines) and civilian (the first nuclear-powered freighter). The oil price shock of 1974 spurred even greater interest in nuclear energy.

The 1974-1986 period saw FRS company activity in nuclear energy at first grow and then diminish. The decline in oil prices was certainly one important factor in this turnaround. Uranium prices declined more sharply than oil prices due to excessive nuclear fuel inventories during much of the 1980's. However, declining prices do not tell the whole story. The Three-Mile Island nuclear plant accident in 1979 in Pennsylvania and the Chernobyl explosion and fire in 1986 in Ukraine, combined with growing concern about the safe disposal of nuclear plant waste, brought a virtual halt to the growth in the United States of the nuclear energy industry. This, in turn, reduced the demand for uranium. By 1989, all FRS companies except Chevron had left the uranium production industry; shortly thereafter, Chevron announced plans to sell off a sizeable share of its uranium operations.

Nothing illustrates the volatility of the FRS companies' investment targets during the past two decades better than the waxing and waning of their activities and investments in alternative energy in the late 1970's and 1980's. Alternative energy includes renewable energy (e.g., solar, wind, tidal, and geothermal energy), cogeneration, and the production of refinable hydrocarbons from tar sands, oil shale, and coal. At first, FRS companies viewed many alternative energy technologies as promising. For example, Exxon and Suncor (Sun Oil's Canadian subsidiary) had synfuel (tar sands) operations. Unocal and Coastal had geothermal operations. In 1982, a dozen FRS companies invested more than $1 billion in oil shale development.

The Federal Government was also enthusiastic about alternative energy. In fact, the 1977 National Energy Plan made Federal dollars and tax credits available for alternative energy investment. At that time, FRS companies already had an investment base of almost $2 billion in alternative energy.

In 1980, President Carter launched the Federal Government's own alternative energy initiative, the U.S. Synfuels Corporation, to foster a new industry that would tap unconventional energy resources like coal gasification, tar sands, oil shale, and heavy crude to meet future U.S. oil and natural gas needs. As a sign of its commitment to this mission, Congress empowered this new energy investment bank to spend up to $88 billion. While the price tag was high, public sentiment in the wake of the Arab Oil Embargo suggested that U.S. independence from foreign oil supplies might justify the expected outlays. By 1982, the FRS companies' investment base in alternative energy peaked at just over $5 billion.

The U.S. Synfuels Corporation initially was expected to approve up to $20 billion in financial backing of loans and product prices to reach its first milestone: the production of 500,000 barrels per day of crude oil equivalent by 1987. However, as with nuclear energy, declining oil prices from 1981-1986 made investing in alternative energy very unattractive. As of July 1985, the Synfuels Corporation had committed only $1.2 billion for three projects that would yield less than 2 percent of the 1987 production target. A combination of several factors, including charges of mismanagement, waning support from Congress, and declining oil prices brought the Synfuels Corporation to an end in May, 1986. After 1982, the FRS companies' investment base in alternative energy declined nearly every year; by 1992, FRS alternative energy investments had dropped below $3 billion.

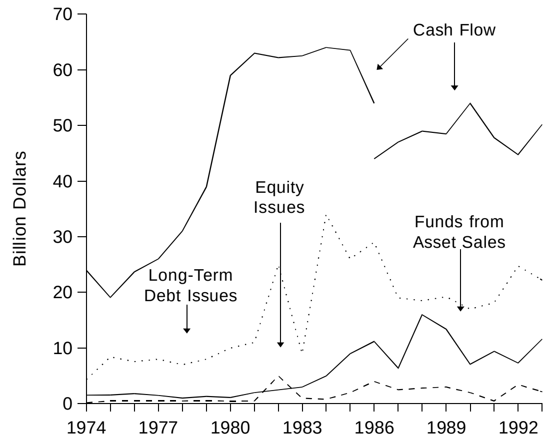
Despite continuing low oil prices, some revival of interest in alternative energy has occurred recently. The heightened interest is a response to ongoing concerns regarding the adverse environmental effects of fossil fuel consumption. Not everyone, however, has seen things the same way. For example, in 1990, ARCO sold off its solar business. Then, in April 1992, the U.S. Department of Energy awarded $22 million in solar energy research funds to seven firms, including two FRS companies. There were similarly mixed developments with respect to other forms of renewable energy. For example, in 1992, Unocal announced the planned sale of some geothermal plants and properties; these sales, however, represented only 9 percent of their geothermal assets.

As the twentieth century draws to a close, U.S. energy independence remains an elusive goal. Complicating the outlook for the world's energy industry still further are the growing concerns about gaseous emissions released by petroleum consumption. It is within this ever-changing and complicated context that the FRS companies continue their pursuit to fulfill the world's still increasing demand for petroleum.

6. Targets of Investment

The onset of sharply higher oil prices following the Arab Oil Embargo greatly increased the cash flow from the FRS companies' operations (Figure 15). Increased cash flow furnished the wherewithal for reinvestment and expansion of productive activities. However, political and market developments sharply altered the FRS companies' customary outlets for investment. Abroad, nationalizations by some producing nations reduced the role of multinational petroleum companies from equity oil producers to service companies or, in some countries, consigned them to financial exile. In the United States, price controls on crude oil, which were of uncertain duration until the phased deregulation of crude oil prices began in 1978, were a partial deterrent to investment in oil and gas exploration. Downstream (petroleum refining, marketing, and transport), expectations of growth in demand were diminished by the prospects of continued rises in petroleum prices. This was a turnabout from the postwar experience when petroleum demand, worldwide, grew threefold as did the channels for distributing the ever-growing volume of petroleum products.[139]

Figure 15. Components of Sources of Funds for FRS Companies, 1974-1993



Note: Cash flow is measured as funds from operations in 1974-1985 and as cash flow from operations from 1986 on. Funds from operations is based on working capital (i.e., current assets minus current liabilities) and cash flow from operations is based on cash and cash equivalents. Financial Accounting Standard 95 required the change in concept.

Source: Energy Information Administration, Form EIA-28.

Sharply increased inflows of cash, combined with the impairment of investment opportunities in petroleum operations, presented the FRS companies with unusual challenges following the oil price escalation of 1973-1974. In the mid-1970's, corporate growth continued to be among the uppermost values of investors and top executives. For investors, tax laws favored capital gains, which encouraged reinvestment and discouraged the payout of cash flow in the form of dividends. For managers, growth in the scale and range of businesses provided the route to higher plateaus in corporate hierarchies. The rapid economic growth in industrialized nations following World War II facilitated the reinvestment of cash flow for expansion of productive assets. For example, demand for petroleum products in the United States in the 10 years preceding the Arab Oil Embargo grew by over 60 percent,[140] outpacing the growth of the economy generally.[141] Outside the United States, petroleum consumption rose about 125 percent over the same period.[142] With a tripling of real oil prices, how might the major petroleum companies achieve corporate growth in the context of the reduced growth (caused by the Embargo) in their core business of supplying petroleum products? This was a key challenge for the FRS companies' deployment of capital.

[139]Neil H. Jacoby, *Multinational Oil* (Macmillan Publishing Co.: New York, 1974), p. 55.
[140]Energy Information Administration, *Annual Energy Review 1993* DOE/EIA-0384(93) (Washington, DC, July 1994), Table 11.10.
[141]Over the 1963-73 period, real Gross Domestic Product (GDP) grew by 47 percent. *Economic Report of the President 1994*, Table B-2.
[142]Energy Information Administration, *Annual Energy Review 1993*, DOE/EIA-0384(93)(Washington, DC, July 1994), Table 11.10.

Growth and Diversification

During the 1974-1981 period of rising oil prices and increasing FRS cash flow, businesses outside energy and chemical manufacture became targets of investment for many FRS companies. The increased attractiveness of diversification in part reflected the diminished outlook for petroleum demand, but the FRS companies' scope of expertise in their core petroleum and chemical operations appeared to promise sources of synergistic profits in a number of businesses. Integrated petroleum and chemical manufacture involve a variety of functions including extraction, bulk movement and storage of commodities, marine transport, refining, product distribution, and marketing to final consumers (including advertising, consumer credit, and direct mail). Notable diversification moves included primary metals and nonfuel minerals mining, engineering and construction, real estate development, timber, agriculture, trucking, convenience stores, insurance, computer services, and direct mail retailing. Other pursuits appeared to be of a more conglomerate nature such as department stores, automobile parts, shipbuilding, meat packing, and office and other electrical equipment.

Diversified enterprises, as represented by the other nonenergy line of business, were second only to oil and gas production in growth of capital expenditures over the 1974-1981 period. Growth was modest at first with capital expenditures rising from $0.9 billion in 1974 to $1.9 billion in 1978 (Table 26).[143] Mergers and acquisitions, which offered footholds and immediate expertise in new lines of activity, accounted for the bulk of other nonenergy capital expenditures in 1974-1978.[144] As the FRS companies' cash flow doubled between 1978 and 1981, capital spending for diversified businesses tripled to $6.3 billion and accounted for 11 percent of total capital expenditures, both of which were historical highs. The FRS companies continued to enter into mining and primary metals, insurance, and conglomerate endeavors through mergers and acquisitions.[145]

The surge in capital expenditures for diversification was led by companies that were among the least diversified at the beginning of the period. In 1974, the FRS companies clearly fell into four categories with respect to the share of net investment allocated to the other nonenergy line of business: the railroads in the group (Burlington Northern and Union Pacific), companies that were heavily diversified (“early diversifiers”) with a share of net investment allocated to the other nonenergy line of business ranging from 14 percent to 36 percent (5 companies) in 1974, 15 companies for whom the comparable share was 5 percent or less (“late diversifiers”) in 1974, and the remaining four companies who had a zero share over the entire 1974-1981 span. In 1974, the late diversifiers accounted for only 17 percent of the FRS companies' total capital expenditures for the other nonenergy line of business (Table 27). Their share increased to 60 percent in 1978, and, in 1981, the year of peak capital expenditures, the late diversifiers' $4.8 billion of expenditures for businesses outside energy and chemicals was over 75 percent of the FRS total. Over the entire 1974-1981 period, the late diversifiers accounted for nearly 90 percent of the growth in the FRS companies' capital expenditures for diversification efforts.

[143]To the extent possible, capital outlays are measured by additions to investment in place, which are defined as additions to property, plant, and equipment (PP&E) plus additions to investment and advances to unconsolidated affiliates. In 1993, additions to PP&E accounted for 94 percent of capital outlays so measured. However, because additions to investments and advances were not collected for some FRS segments prior to 1981, capital outlays are sometimes measured by additions to PP&E.

[144]Mobil's acquisition of Marcor, which included Montgomery Ward and American Can Company, for $1.7 billion, was the largest acquisition of nonenergy assets in this period. Large acquisitions were also the source of forays into mining and primary metals production, including ARCO's acquisition of Anaconda Company (reported value of $688 million), Chevron's purchase of a 20-percent interest in Amax ($350 million), and Unocal's acquisition of Moly Corp ($234 million).

[145]Acquisitions in mining and primary metals included BP America's (formerly Standard Oil of Ohio) acquisition of Kennecott Corporation for $1.8 billion and Amoco's acquisition of Cyprus Mines for $460 million. Acquisitions of insurance companies included Tenneco's acquisition of Southwestern Life ($653 million) following their $170 million purchase of Philadelphia Life Insurance in 1978, Getty's acquisition of ERC Corporation ($570 million), and Ashland Oil's acquisition of Integon Corporation ($238 million). The largest conglomerate acquisitions were Exxon-Reliance Electric ($1.2 billion) and Occidental Petroleum-Iowa Beef Corporation ($746 million).

Table 26. Additions to Property, Plant, and Equipment for FRS Companies, 1974-1981
(Billion Dollars)

Line of Business	1974	1975	1976	1977	1978	1979	1980	1981
Oil and Gas Production								
United States	7.9	6.6	8.1	8.5	9.3	18.2	21.6	26.8
Foreign	2.0	2.6	2.9	4.2	4.8	6.1	8.1	8.1
Refining and Marketing								
U.S. Refining	1.6	1.9	1.8	1.0	1.4	2.2	2.5	4.0
U.S. Marketing[a]	0.8	0.9	1.0	1.2	1.3	1.3	1.7	2.0
Foreign Refining	0.8	0.9	0.5	0.5	0.7	0.7	1.0	[b]2.4
Foreign Marketing	0.6	0.5	0.4	0.5	0.8	0.7	1.1	
Transport								
Pipelines	0.7	2.8	2.8	1.4	0.6	0.6	1.0	0.8
International Marine	1.2	1.1	0.7	0.7	0.2	0.5	0.5	0.3
Coal	0.2	0.5	0.5	0.8	0.7	0.8	1.2	2.8
Nuclear	0.1	0.1	0.1	0.3	0.4	0.5	0.3	0.3
Other Energy	0.4	0.3	0.5	0.3	0.5	0.4	0.8	0.9
Nonenergy								
Chemicals	1.0	1.7	2.3	2.7	2.3	2.3	3.0	3.5
Other Nonenergy	0.9	1.0	1.0	1.6	1.9	3.0	3.9	6.3
Nontraceable	0.1	0.2	0.3	0.2	0.3	0.4	0.8	1.0
Consolidated	18.3	21.1	23.1	24.1	25.2	37.5	47.5	58.8

[a]Includes unregulated refining/marketing transport.
[b]Foreign refining and marketing not separately available after 1980.
Note: Components may not sum to total due to independent rounding.
Source: Energy Information Administration, Form EIA-28.

Table 27. Additions to PP&E and Net PP&E in Other Nonenergy, Selected Years, 1974-1981
(Billion Dollars)

	1974	1978	1981
Additions to PP&E			
Railroads	0.3	0.5	0.4
Early Diversifiers	0.4	0.4	1.0
Late Diversifiers	0.2	1.0	4.8
Total	0.9	1.9	6.3
Net PP&E			
Other Nonenergy			
Railroads	4.6	5.4	6.8
Other FRS	2.2	6.5	15.5
Other Lines of Business	77.8	124.4	199.3

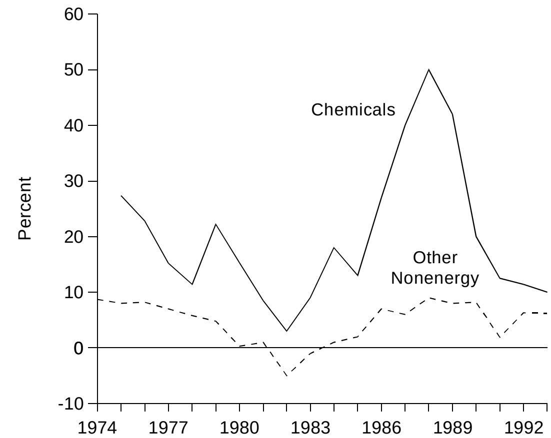
Notes: Early Diversifiers are companies that had 15 percent or more of their total net PP&E in the Other Nonenergy line of business in 1974. Late Diversifiers are companies that had 5 percent or less of their total net PP&E in the Other Nonenergy line of business in 1974. Railroads include Burlington Northern and Union Pacific. Components may not sum to total due to independent rounding.

Sources: Energy Information Administration, Form EIA-28 except for railroad data, which were taken from company annual reports.

Diversification efforts were undertaken in the context of sharply rising cash flow with the expectations of growth and profitability. Investment targets were chosen in part for their expected growth in future demand and in part for the opportunities to transfer expertise developed in petroleum and chemical operations. Overall, diversified businesses did provide a channel for corporate asset growth. Excluding railroad assets, net PP&E in the other nonenergy line of business increased by over 600 percent between 1974 and 1981 while, in total, the FRS companies' other lines of business registered net asset growth of 153 percent. However, the profitability of the other nonenergy line of business proved to be disappointing. The rate of return in this line of business fell continuously over the 1974-1982 period (Figure 16). Both early diversifiers and late diversifying companies exhibited a falling rate of return, with late diversifiers suffering negative returns more often than not (Figure 17).

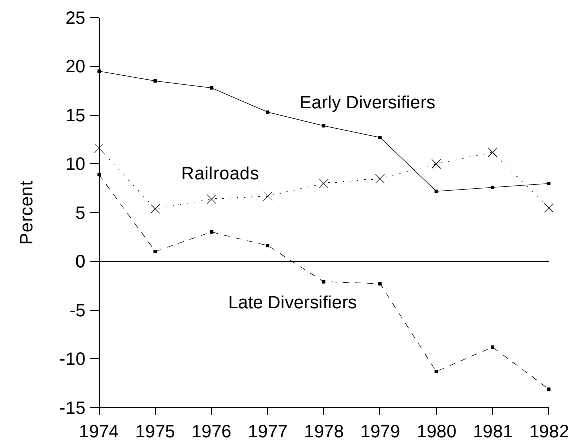
A number of factors contributed to the generally poor performance of the FRS companies' diversification

Figure 16. Operating Rates of Return in Nonenergy for FRS Companies, 1974-1993



Note: 1974 chemicals data not available.
Source: Energy Information Administration, Form EIA-28.

Figure 17. Operating Rate of Return in Other Nonenergy for FRS Groups, 1974-1982



Note: Operating rate of return = Operating Income/Net PP&E. Early Diversifiers are companies that had 15 percent or more of their total net PP&E in the Other Nonenergy line of business in 1974. Late Diversifiers are companies that had 5 percent or less of their total net PP&E in the Other Nonenergy line of business in 1974. Railroads include Burlington Northern and Union Pacific.

Sources: Energy Information Administration, Form EIA-28, except for railroad data, which were taken from company annual reports.

efforts. Economic recessions in 1974-1975, 1980, and 1981-1983 undoubtedly had negative effects on profitability, but these effects were transitory and cannot account for the continuous decline in the rate of return on diversified assets. A more likely explanation is that projections of future profit flows were not realized because of overoptimistic expectations and/or subsequent market developments that ran counter to projections. Managerial expertise may not have been as fungible as had been premised. The sheer size of the larger FRS companies inhibited the flexibility of response to competitive pressures in nonenergy markets. Whatever the causes, businesses outside energy and chemicals became prime targets of retrenchment and restructuring throughout most of the 1980's (reviewed in detail in the next section).

Most of the FRS companies had significant asset commitments in chemical operations in 1974, reflecting the close and often integrated relationships between the manufacture of many chemical products and the refining of hydrocarbons into petroleum products.

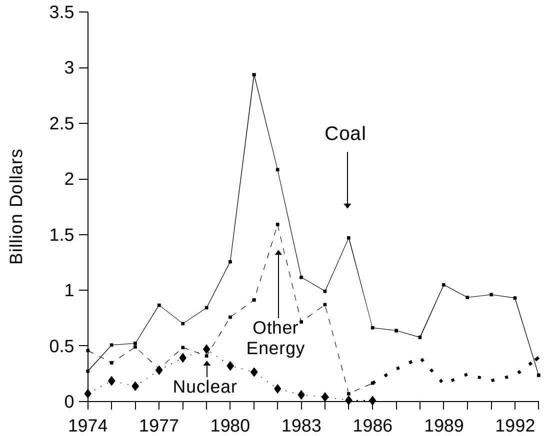
Following the economic recession of 1974-1975, demand for chemicals grew. The FRS companies' capital expenditures for chemical operations rose from $1.0 billion in 1974 to $2.7 billion in 1977 (Table 26), reaching 11 percent of total FRS capital expenditures, a share not surpassed until the late 1980's. However, the escalation of oil prices following the Iranian revolution in late 1978 raised chemical feedstock costs. The consequent rise in chemical product prices had an adverse effect on demand, which, together with earlier capacity expansions, put a squeeze on profit margins. Rates of return in chemicals (Figure 16) fell below that of the FRS companies' overall return. In response, the FRS companies trimmed back their capital expenditures for chemicals in 1978 and 1979, to about 6 percent of total capital expenditures. The profitability of the FRS chemical operations continued to decline, reaching an all-time low during the economic recession in 1981-1983, the most severe U.S. economic downturn since the Great Depression. Until chemical demand and chemical profitability surged in the second half of the 1980's, the FRS companies' capital expenditures for chemical operations remained at about 6 percent of overall capital expenditures.

Energy sources outside petroleum also became attractive investment targets for most of the FRS companies, particularly in the context of the 1979-1981 oil price escalation. Sharply rising oil prices tended to lift all energy prices, as substitution of other fuels for petroleum tended to increase the demand for them and the expected stream of future profits from investment in their development and production. Coal production and nuclear fuel production became clear areas of future growth, as the bulk of planned electrical generation capacity was directed toward use of these fuels. Less-developed energy sources, such as synthetic fuels, were attractive because the FRS companies' expertise in petroleum technologies might be employed to develop nascent technologies for economic production of unconventional fuels. For example, technological mastery of petroleum extraction and refining should be applicable to refining hydrocarbons extracted from coal or oil shale. Similarly, in the 1970's, most of the FRS companies had long-standing research and development capabilities that could be expanded to encompass invention and innovation in the area of emerging energy sources. Also, investment in the development of nonpetroleum energy sources could be a hedge for the major petroleum companies against the possibility of a greater erosion of petroleum demand should oil prices follow an even steeper trajectory than envisioned during the oil price escalations of 1974-1981, as well as a hedge against possible oil embargoes.

Among the fuel sources outside petroleum, coal production was the primary investment target during the 1974-1981 period (Figure 18). Coal had a ready and growing market, particularly in electricity generation, both in the United States and abroad. Further growth in coal demand was a likely prospect, given the expectations at the time concerning the future upward course of oil prices. Surface production of coal in Western areas, with its large investment requirements to attain economies of scale, proved especially attractive to some cash-rich FRS companies. On the East Coast, metallurgical-grade coal producers were finding growth in industrial markets abroad. The FRS companies' capital expenditures for coal operations rose from $0.2 billion in 1974 to a peak of $2.8 billion in 1981. Over the same period, their U.S. production of coal (bituminous coal and lignite) rose from 87 million tons (14 percent of total U.S. production) to 155 million tons (19 percent of total U.S. production).

Most of the growth in FRS coal production came from newly entering companies. In 1974, six FRS companies reported production of coal in the United States. Then, beginning mainly in 1977, eight additional companies joined the ranks of FRS coal producers. These entrants accounted for 79 percent of the increase in total FRS coal production during the 1977-1981 span (Table 28). Mergers and acquisitions played a minor role in the FRS companies' growing presence in the U.S. coal industry; the value of coal-related acquisitions in the 1974-1981 period was 29 percent of FRS capital expenditures for coal. Another point of interest is that

Figure 18. Additions to Investment in Place in Coal, Nuclear, and Other Energy, 1974-1993



Note: Nuclear and Other Energy not separately available after 1986. Effects of intra-FRS mergers are excluded in 1982 and 1984.

Sources: Energy Information Administration, Form EIA-28.

Table 28. U.S. Coal Production for FRS Companies, Selected Years, 1974-1981
(Million Tons)

	1974	**1977**	**1981**
Established FRS Coal Producers	87.4	82.2	95.5
Entrant FRS Coal Producers . . .	0.0	6.9	59.3
Total FRS	87.4	89.1	154.8
FRS Companies' Share of U.S. Coal Production (percent) . . .	14.5	12.9	18.9

Note: Established FRS coal producers had production in 1974 and entrant FRS coal producers began production in 1977 or later. Coal production includes bituminous coal and lignite.

Sources: **FRS Companies:** Energy Information Administration, Form EIA-28. **U.S. Coal Production**: Energy Information Administration, *Coal Production 1992*, DOE/EIA-0118(92) (Washington, DC, October 1993).

a number of FRS companies acquired coal reserves during the period but never produced any coal. By 1980, 37 percent of the FRS companies' U.S. coal reserves (and 50 percent of their Western coal reserves) were owned by nonproducers.

Alternative energy has encompassed a range of energy sources of varying commercial viability. The rise in oil prices, which began in late 1973, elevated the profit potential of theretofore excessively costly energy sources. Also, production subsidies for some forms of energy and the anticipation of subsidies for others attracted the interest of some major petroleum companies. The upswing in capital expenditures for alternative energy was somewhat belated, not beginning until 1980 (Figure 18). Over the previous five years, capital expenditures for alternative energy averaged about $400 million annually, with over 75 percent of the expenditures directed to Canadian tar sands development and production (Table 29). The emphasis on tar sands reflected this line of activity's financial viability which was made possible by the combination of high oil prices and Canadian government subsidies. Over this period, tar sands accounted for 92 percent of FRS companies' revenues from alternative energy sources.

From 1979 to 1982, the FRS companies' capital expenditures for alternative energy quadrupled, with oil shale development accounting for 90 percent of this growth. Since the late 19th century it has been known that refinable hydrocarbons could be extracted from oil-bearing shale rock. Also, it was known that the oil shale resources of the United States are vast. The challenge was to develop processes to profitably transform oil from shale into refinery inputs consistent with environmental quality standards. Expectations of continually rising real oil prices appeared to offer the prospect of profitable development of oil shale processes. The FRS companies' capital expenditures for oil shale development jumped from $23 million in 1979 to over $300 million in 1980 and 1981 and totaled $1.0 billion in 1982. In 1982, 11 FRS companies reported capital expenditures for oil shale projects.[146] However, technological disappointments and downward revisions of oil price expectations led to termination of most oil shale projects. After 1982, capital expenditures rapidly plummeted to nil and the only oil shale project to survive was Unocal's Parachute Creek operation. This project was shut down in 1990 due to increased costs relative to Federal price guarantees.

[146]Prominent among the projects were Exxon's Colony Oil Shale Project (acquired from ARCO), Chevron and DuPont's joint venture for developing an innovative retorting process, and Unocal's Parachute Creek project which would produce 10 thousand barrels per day of oil for a Federally guaranteed price of $42.50/barrel (as of July 1983) plus inflation indexing.

Table 29. Additions to Property, Plant, and Equipment in Other Energy for FRS Companies, 1974-1986
(Million Dollars)

	Annual Average 1974-1979	1980	1981	1982	1983	1984	1985	1986
Synthetic Fuels								
Tar Sands	312	333	195	150	148	124	125	83
Oil Shale	61	313	325	1,014	204	44	28	16
Coal Gasification/Liquefaction	1	13	21	3	8	([a])	([a])	0
Renewables								
Geothermal	31	57	122	148	171	621	116	103
Other	4	33	55	172	125	35	26	22
Total Other Energy	409	749	718	1,487	656	824	295	224

[a]Included in oil shale to prevent disclosure.
Source: Energy Information Administration, Form EIA-28.

Capital expenditures for geothermal energy also rose sharply in the early 1980's. In 1982, four FRS companies (Occidental Petroleum, Phillips Petroleum, Shell Oil, and Unocal) reported actual or expected near-term attainment of commercial application of geothermal energy to generation of electricity, mainly in California. However, only Unocal remained in geothermal energy production by the end of the decade.

Like coal production, the growth prospects for nuclear fuel appeared rosy in light of projections of electrical generation capacity in the 1970's. Although a few FRS companies were involved in nuclear fuel processing, most of the FRS companies' interest in nuclear fuel was in uranium production. In 1974, only two FRS companies reported uranium production. By 1977, the FRS companies accounted for 48 percent of total U.S. uranium production. In 1980, the year of peak output of uranium, 11 of the FRS companies reported production. Capital expenditures for nuclear activities showed a sharp increase as well, peaking in the 1978-1980 period (Figure 18). However, the nuclear industry became plagued with economic difficulties. As noted in the 1982 edition of this report,[147]

> The problems of the nuclear industry in the United States in the 1980's, which include high levels of inventories, lower than anticipated growth in electricity demand, cost-increasing

delays in nuclear plant construction, cancellations of nuclear plant construction, and foreign competition in nuclear fuel inputs, have led U.S. industry, and the FRS companies in particular, to a pattern of consolidation and retrenchment in nuclear operations.

Over the next three years, capital expenditures for nuclear activities plunged to near zero. All FRS uranium producers eventually withdrew from the industry, the last being Chevron in 1991.

The primary focus of the FRS companies' massive upswing in capital expenditures during 1974-1981 was oil and gas production. Sharply rising oil prices correspondingly increased the expected profitability of investments to discover and develop additional oil and gas reserves, as well as increasing the cash flow from ongoing oil and gas production operations. Over the period, the FRS companies' worldwide oil and gas exploration and development (E&D) expenditures[148] grew nearly fourfold, reaching $45.4 billion in 1981 (Table 30). However, investment targets changed over the period.

After a sharp rise following the Arab Oil Embargo of 1973, world oil prices (adjusted for inflation) were actually somewhat lower for the year 1978 than 1974, as

[147]Energy Information Administration, *Performance Profiles of Major Energy Producers 1982*, DOE/EIA-0206(82)(Washington, DC, July 1984), p. 109.
[148]E&D expenditures include exploration expenses as well as capital expenditures associated with the discovery, development, and production of oil and gas reserves.

Table 30. Oil and Gas Exploration and Development Expenditures by Region for FRS Companies, Selected Years, 1974-1993
(Billion Dollars)

	1974	1978	1981	1985	1986	1989	1993
United States							
Onshore	4.1	7.5	19.9	20.0	12.5	9.0	7.2
Offshore	4.6	4.3	13.0	8.5	4.9	6.0	3.8
Total United States	8.7	11.8	33.0	28.5	17.4	15.0	10.9
Foreign							
Canada	0.8	1.6	1.8	1.9	1.1	6.3	1.6
OECD Europe	1.1	2.6	5.0	3.7	3.2	3.5	5.5
FSU & Eastern Europe	0.0	0.0	0.0	0.0	0.0	0.0	0.3
Africa	0.6	0.8	2.1	1.6	1.1	1.0	1.5
Middle East	0.2	0.3	0.3	0.9	0.3	0.4	0.7
Other Eastern Hemisphere	1.4	0.4	1.9	1.3	1.2	2.3	2.5
Other Western Hemisphere	(a)	0.6	1.3	0.7	0.6	0.6	0.6
Total Foreign	3.8	6.4	12.4	10.1	7.5	14.1	12.5
Worldwide	12.5	18.2	45.4	38.6	24.9	29.1	23.5

[a]Combined with Other Eastern Hemisphere for 1974.
FSU = Former Soviet Union.
Note: Sum of components may not equal total due to independent rounding. Regional data for 1974 contain estimates of dry hole expense—see Energy Information Administration, *Energy Company Development Patterns in the Post-embargo Era*, Volume 1, DOE/EIA-0349/1 (Washington, DC, October 1982), Appendix G.
Source: Energy Information Administration, Form EIA-28.

were U.S. oil prices at the wellhead.[149] Nevertheless, the earlier surge in oil prices was sufficient to attract added investment. In the United States, E&D expenditures of the FRS companies rose from $8.7 billion in 1974 to $11.8 billion in 1978 (Table 30). All of the increase in the FRS companies' U.S. spending during this period was directed toward onshore targets, both in Alaska and the lower 48 states. The lack of spending growth for offshore locales was in part a reflection of the U.S. Department of Interior's Outer Continental Shelf (OCS) leasing policies at the time. The Department of Interior auctions the right to explore OCS tracts (i.e., leases). The bidder offering the highest bonus (above a minimum acceptable level) is awarded the lease. Prior to 1983, the Department of Interior selected the tracts to be auctioned from nominations made by companies active in the OCS. A then-record offering (5 million acres) of OCS leases was made in 1974, resulting in successful bonus bids of $5.0 billion.[150] In the following years, OCS bonuses were considerably lower and did not surpass the 1974 level until 1979.

The Department of Interior's OCS policy had a dual effect on offshore expenditures. First, expenditures for

OCS acreage (lease) acquisition were lower. Lease acquisition expenditures have typically been a large share of offshore expenditures. For example, over the 1977-1981 period (1977 is the earliest year for which data of requisite detail are available), acquisitions of offshore acreage by FRS companies, mainly through the payment of OCS lease bonuses, comprised 41 percent of offshore exploration and development expenditures. The comparable share for onshore expenditures was 9 percent. Second, with less offshore acreage to explore and develop, drilling and other related upstream activities (exploration, development, and production of oil and gas) were reduced.

Abroad, the FRS companies' targets of upstream investment clearly shifted to politically secure Canadian and European locales and away from oil-producing areas of potential and actual political turmoil. The FRS companies' exploration and development expenditures for Canada and Europe more than doubled between 1974 and 1978 while total expenditures for the remaining areas changed little. The main area of growth was the North Sea. Higher expected oil prices and the vast potential oil and gas reserves of this region were

[149]Energy Information Administration, *Annual Energy Review 1993*, DOE/EIA-0384(93)(Washington, DC, July 1994), Tables 5.17 and 5.20.
[150]U.S. Department of the Interior, Minerals Management Service, *Federal Offshore Statistics*, OCS Report MMS91-0068 (Herndon, VA, February 1991), Table 3.

sufficient to overcome the potentially high-cost technological challenges of exploring and producing in a very rugged offshore environment. As a share of worldwide FRS company E&D expenditures, the growth areas of U.S. onshore, Canada, and Europe rose from less than half in 1974 to nearly two-thirds in 1978.

In late 1978, the ruling regime in Iran was overthrown, and, within a year, Iran and Iraq were at war. Reduced oil production and rapid accumulation of petroleum inventories put severe pressures on oil prices. Between late 1978 and early 1981, world oil prices rose on the order of $25 a barrel. From 1978 to 1981, the FRS companies' cash flow almost doubled and their worldwide spending for exploration and development more than doubled, totaling $45.4 billion in 1981. All regions except the Middle East registered sizable increases. The surge in onshore expenditures was led by increased drilling activity, with a tripling in the FRS companies' onshore drilling expenditures and a 52-percent increase in their onshore well completions. Offshore, their increased spending was mainly for unproved acreage, expenditures that increased almost 400 percent, reflecting both the increased offerings of Federal OCS acreage and the higher bid prices induced by sharply higher oil prices.

Abroad, two-thirds of the increase in E&D expenditures was traceable to increased drilling. Regions registering the steepest growth in drilling were the Other Eastern Hemisphere (well completions up 39 percent between 1978 and 1981) and the Other Western Hemisphere (up 172 percent). Increased expenditures for Africa largely reflected exploratory efforts. Europe registered the largest absolute increase in expenditures, the bulk of which was for developmental efforts in order to bring production from North Sea fields on line. Development of North Sea production capability was reflected in the number of oil producers as well as the level of production: in 1974, FRS companies produced a total of 76 thousand barrels per day (mbd) of oil in Europe, with only four companies reporting more than 1 mbd of production; in 1981, 14 FRS companies reported European production in excess of 1 mbd, totalling 759 mbd.

Comparison of FRS company E&D expenditures for Canada in 1978 with 1981 expenditures indicates little growth. However, this comparison masks some important developments. Canada continued to be a target of FRS companies' investment through 1980. In 1980, the FRS companies' E&D expenditures for Canada, at $3.1 billion, were about double the 1978 level. Canadian energy policy changed dramatically with the passage of the National Energy Policy of 1981 (NEP).[151] The NEP directly encouraged greater Canadian ownership of energy resources in Canada through a system of subsidies and taxes. One of the effects of NEP was discouragement of energy investment in Canada by non-Canadian companies. The FRS companies cut back their Canadian E&D spending by 40 percent to $1.8 billion in 1981. Apart from the effects of intragroup mergers of FRS companies, Canadian E&D expenditures remained below $2 billion until 1988, when Canadian oil and gas development again became an attractive target, in part because the most onerous provisions of the NEP were moderated.[152]

Over the 1974-1981 period, the FRS companies' downstream capital expenditures increased from a worldwide total of $5.6 billion to $9.5 billion (Table 26). Domestic refining operations accounted for the major share of this increase, which occurred between 1978 and 1981, and continued into 1982 when the FRS companies' capital expenditures for U.S. refineries reached $4.8 billion (excluding the effects of intra-FRS mergers[153]). This upswing in spending was largely directed toward upgrading of refineries to produce unleaded gasoline requiring high-octane blending components and to utilize heavier, more sulfurous crude oil inputs. The FRS companies began to reduce their simple distillation capacity in 1981 in response to reduced demand for petroleum products and to an overall excess of refining capacity. Abroad, the FRS companies reduced their crude distillation capacity by 1.3 million barrels per day between 1974 and 1981 and continued this retrenchment into the mid-1980's. Nevertheless, their capital expenditures for foreign refining and marketing operations generally rose over the period, reaching a peak of $2.4 billion in 1981, indicating that retained facilities were objects of upgrading.

[151]For a detailed discussion of this development, see Energy Information Administration, *Performance Profiles of Major Energy Producers 1981*, DOE/EIA-0206(81) (Washington, DC, June 1983), pp. 55-58.

[152]Energy Information Administration, *Performance Profiles of Major Energy Producers 1986*, DOE/EIA-0206 (Washington, DC, January 1988), p. 77.

[153]In late 1981, DuPont acquired Conoco (an FRS respondent) which, for FRS purposes, was treated as occurring on January 1, 1982. In 1982, USX (formerly U.S. Steel) acquired Marathon Oil (an FRS respondent), and two FRS respondents, Occidental Petroleum and Cities Service, merged. Intra-FRS mergers in 1984 included Chevron-Gulf, Mobil-Superior Oil, and Texaco-Getty Oil. The value of these mergers totaled $47.0 billion.

Transport operations were occasional investment targets in the 1974-1981 period (Table 26). The heightened level of capital expenditures for liquids pipelines in 1975-1977 was largely due to the building of the Trans Alaskan Pipeline System from the Alaskan North Slope to the port of Valdez, a $9.2-billion project.[154] International marine operations (mainly oil tankers) were the primary target of the FRS companies' foreign downstream investments in 1974 and 1975. Capital expenditures for tankers exceeded $1 billion in 1974 and 1975. This emphasis on tankers was part of the surge in tanker capacity accompanying the growth in world oil trade. However, as petroleum demand fell in the context of the 1979-1981 oil price escalation and thereafter, international movements of oil, particularly from the Persian Gulf, were reduced, resulting in excess world tanker capacity. Capital expenditures for tankers dropped steeply and were less than $100 million annually during most of the 1980's.

The distribution of the FRS companies' productive assets across lines of activity shifted substantially as a result of their investment behavior. In their core area of petroleum (including natural gas production), the emphasis moved from downstream to upstream. The share of total net PP&E allocated to oil and gas production increased from 39 percent in 1974 to 50 percent in 1981, with most of the gain in U.S. operations, while the downstream share declined from 42 percent to 26 percent (Table 31). Diversified nonenergy businesses (apart from railroads) were 7 percent of the FRS companies' net asset base in 1981, more than double the 1974 share, reflecting the use of diversification as a channel for investment and growth. Chemical manufacture and energy production outside petroleum also registered higher shares of the FRS companies' productive assets.

When oil prices peaked in 1981, the FRS companies were much more oriented to oil and gas production and more diversified beyond petroleum than they were in 1974 at the onset of the crude oil price escalations.

Consolidation and Restructuring

Crude oil prices peaked in early 1981. Although the price of oil in fact began to decline later in 1981, many oil market participants and observers at that time regarded this downward movement as transitory and expected oil prices to resume an upward course. However, a number of fundamental developments that

Table 31. Distribution of Net Property, Plant, and Equipment Across Lines of Business for FRS Companies, 1974 and 1981
(Percent)

	1974	1981
Oil and Gas Production		
United States	29.6	37.0
Foreign	9.5	13.5
Total Production	39.2	50.4
Downstream Petroleum		
Refining/Marketing	32.3	18.7
Transport	9.9	7.0
Total Downstream	42.2	25.7
Coal	1.4	3.0
Nuclear	0.3	0.6
Alternative Energy	0.8	1.3
Nonenergy		
Chemicals	5.7	7.5
Other Nonenergy		
Railroads	5.2	3.0
Other	2.5	6.9
Nontraceable	3.0	1.4
Consolidated	100.0	100.0

Note: Components may not sum to total due to independent rounding.

Sources: Energy Information Administration, Form EIA-28, except for railroad data which were taken from company annual reports.

tended to offset the pricing power of OPEC were driving oil prices down. These included:

- Energy conservation and reduced demand for energy-intensive goods.
- Increased oil-producing capacity in nations outside OPEC.
- Lessened use of petroleum and natural gas for electrical generation in favor of coal and nuclear fuels.
- Utilization of spot markets for oil, rather than contract pricing, which rapidly eroded oil price solidarity among OPEC members.

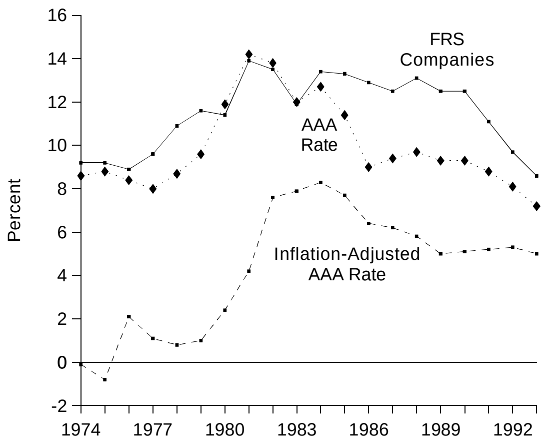
[154] *New York Times* (June 2, 1977), p. D1.

Fundamental changes in capital markets, which were to have profound effects on the FRS companies' deployment of assets, were also occurring. Unlike the 1970's and earlier post-World War II decades, shareholders were demanding greater cash payouts by corporations in the form of dividends and common stock repurchases and were placing less importance on reinvestment of cash flows. Probably the main development that drove shareholders to agitate for greater cash payout was the sharp upswing in real rates of return generally available to investors. For example, Figure 19 shows a surrogate for the real rate of return—the average yield on corporate bonds rated AAA by Moody's Investors Services minus the annual percent change in the Gross Domestic Product (GDP) implicit price deflator. By this measure, the real rate of return on low-risk corporate debt rose steeply, from about 1 percent in the late 1970's to over 8 percent by the mid-1980's. Accordingly, investors increasingly preferred receiving the cash generated by corporate operations directly, unless the corporation through its reinvestment program could convincingly match the step-ups in market returns. Also, the deterrence to dividend payout posed by the U.S. tax laws was moderated. In part, substantial changes in tax laws in the early 1980's, particularly lower marginal tax rates, reduced the taxation of dividends. Greater prominence of institutional investors and foreign investors, both of whom were little affected by U.S. tax laws and their enforcement, tended to increase the overall preference for dividends and other corporate cash payouts.

With a greater preference for direct disbursement of corporate cash flows and heightened standards of profit performance on the part of investors, many of the major energy companies became objects of shareholder discontent. Investors had a number of reasons to be dissatisfied. First, oil prices began to decline in 1981. The prospect of a long-term decline in oil prices, which had been in the realm of the unthinkable for many investors only months before, dampened the expected profit outlook for companies heavily involved in oil and gas production. Corporate involvement in downstream petroleum offered little solace to investors, since refinery capacity was in great excess and abandonment of service stations appeared to be a daily occurrence.

Second, the FRS companies' investments outside their core petroleum and chemical businesses yielded disappointing results. The profitability of these ventures tended to be not only low compared with their core

Figure 19. Average Interest Rate on FRS Companies' Long-term Debt, Moody's AAA Corporate Bond Rate, and Inflation-Adjusted AAA Rate, 1974-1993



Note: Average interest rate on FRS companies' long-term debt = annual interest expense/average of beginning-of-period long-term debt and end-of-period long-term debt. Inflation-adjusted AAA rate = Moody's AAA corporate bond rate minus annual percent change in GDP implicit price deflator.

Sources: **FRS Companies**: Energy Information Administration, Form EIA-28. **AAA Rate and GDP Deflator**: *Economic Report of the President February 1994.*

businesses but also generally declining. Third, the major energy companies tended to be somewhat stingy in their dividend policies compared with other large industrial corporations. Over the 1977-1982 period (data limitations prevent an earlier starting date), the FRS companies paid out an average of 18 percent of their internally-generated cash flow to their shareholders, but the Standard and Poor's (S&P) 400 U.S. industrial corporations[155] (excluding FRS companies) paid out 24 percent of cash flow as dividends.

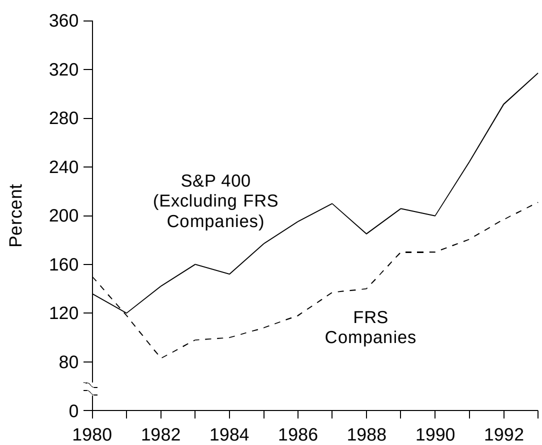
The reaction of the capital markets to these developments was to devalue the profit prospects of the major energy companies. One indicator of investors' outlook for a corporation, or a group of corporations, is the market-to-book ratio, measured as the market value of common shares divided by stockholders' equity as carried at historical values on the corporate balance sheet. The more optimistic investors are concerning the expected future profitability of a corporation, the higher

[155]The S&P 400 is a well recognized database that includes 400 of the largest U.S. industrial companies. In 1993, 15 of the FRS companies were included in the S&P 400. Financial statistics for the S&P 400 were obtained by accessing Compustat, a service of Standard & Poor's, Inc.

this ratio is, since investors will bid up the price of the corporation's shares. Conversely, downward revisions in the profit outlook for a company tend to produce a decline in the market-to-book ratio. In 1980 and 1981, the market-to-book ratio was close in value for the FRS companies and other large industrial companies (as represented by the S&P 400, excluding the FRS companies) (Figure 20). However, as investors ratcheted down their oil price expectations beginning in late 1981, market values of most of the FRS companies plummeted below book values, and by 1983 the market-to-book ratio for the FRS companies was only about half the value of the S&P group.

Deteriorating stock prices led to shareholder dissatisfaction, and shareholder dissatisfaction led to a climate favorable to takeover proposals by corporate raiders. In principle, with the market value of common shares below the net realizable value of corporate assets, a corporate raider could gain ownership through stock purchases and resell the assets for a profit. The credibility of corporate raiders and their takeover threats was strengthened by investor acceptance of low-grade bonds, generally termed junk bonds. Also, falling market values provided those major oil companies that had relatively high costs of finding reserves with the opportunity of adding oil and gas reserves at a favorable cost.[156]

Figure 20. Ratio of Market Value to Book Value, 1980-1993



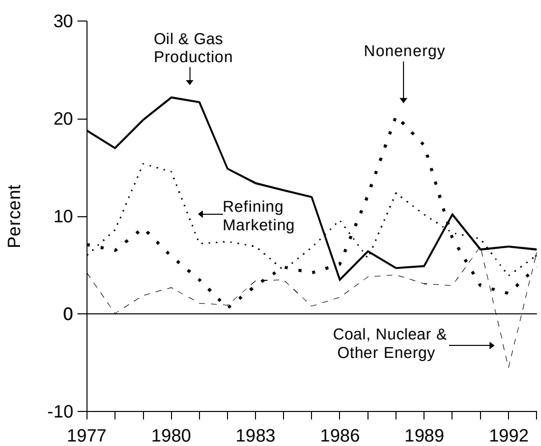
Note: Market value is calculated as the number of common shares outstanding times the average of the year-end, high, and low common stock prices. Book value is total stockholders' equity at the end of the year.

Source: Standard & Poor's Compustat Services, Inc.

During the 1981-1984 period, six FRS companies succumbed to takeovers, in transactions totaling $47.0 billion in value (Table 32). Four of these takeovers were by FRS companies (Chevron's acquisition of Gulf Oil, Mobil – Superior Oil, Occidental Petroleum – Cities Service, and Texaco – Getty Oil) and the other two takeovers brought DuPont (through their acquisition of Conoco) and USX, formerly U.S. Steel, (through their acquisition of Marathon Oil) into the ranks of major energy companies.[157] Also, attempted takeovers of Phillips Petroleum and Unocal in 1985 were thwarted mainly through massive disbursements of cash to shareholders.

The challenge for the FRS companies was to develop strategies that would increase shareholder value and overall corporate profitability in the context of shareholder discontent and investor demands for greater payouts. The challenge was made more difficult by a declining rate of return in oil and gas production, their most profitable line of activity through the first half of the 1980's (Figure 21). The response of the FRS companies largely involved restructuring and redirection of investment strategies.

Figure 21. Rates of Return by Line of Business for FRS Companies, 1977-1993



Note: Net income contribution divided by net investment in place.
Source: Energy Information Administration, Form EIA-28.

[156]See Energy Information Administration, *Financial Aspects of the Consolidation of the U.S. Oil and Gas Industry in the 1980's*, DOE/EIA-0524 (Washington, DC, May 1989) for a detailed analysis of the economic motivations for oil company mergers during this period.
[157]For a detailed review of these mergers, see Energy Information Administration, *Performance Profiles of Major Energy Producers 1990*, DOE/EIA-0206(90)(Washington, DC, December 1991), pp. 40-42.

Table 32. Mergers and Acquisitions with a Value in Excess of $500 Million for FRS Companies, 1974-1993
(Million Dollars)

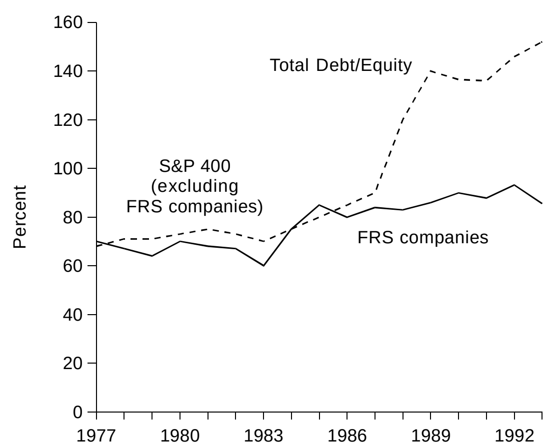
Acquiring Company	Acquisition	Value of Transaction	Year of Transaction
Acquisitions of FRS Companies			
Chevron	Gulf Oil Corp.	13,300	1984
Texaco	Getty Oil Corp.	10,200	1984
DuPont	Conoco	7,800	1981
USX (formerly U.S. Steel)	Marathon Oil Co.	5,950	1982
Mobil	Superior Oil Corp.	5,720	1984
Occidental Petroleum	Cities Service Co.	3,984	1982
Integrated Petroleum Companies			
Amoco	Dome Petroleum Ltd.	4,200	1988
Exxon	Texaco Canada	4,150	1989
Oil and Gas Production			
Shell Oil	Belridge Oil Co.	3,650	1979
USX	Texas Oil and Gas Co.	3,000	1986
Chevron	Tenneco (Gulf of Mexico offshore properties)	2,512	1988
Sun	Texas Pacific (oil and gas properties)	2,300	1980
Phillips Petroleum	Aminoil	1,600	1984
Phillips Petroleum	General American Oil Co.	1,229	1983
Oryx Energy	British Petroleum (oil and gas interests, mostly in the U.K. North Sea)	1,119	1990
Sun and Phillips Petroleum	Shell Oil (U.S. oil and gas properties)	975	1985
Amoco	Tenneco (Rocky Mountain properties)	900	1988
Amerada Hess	TXP (U.S. oil and gas properties)	866	1989
Mobil	General Crude Oil Co.	792	1979
ARCO	Britoil (24 percent interest)	758	1987
Burlington Northern	Southland Royalty	730	1985
Mobil	Trans Ocean Oil	715	1980
ARCO	Tricentrol plc.	710	1988
Exxon	Delhi Petroleum Ltd.	690	1987
ARCO	Tenneco (California properties)	654	1988
Exxon	Celeron Oil and Gas Co.	650	1987
Getty Oil	Reserve Oil & Gas	620	1980
American Petrofina	Tenneco (Gulf and southwestern States onshore properties)	602	1988
Mobil	Anschutz Corp. (U.S. oil properties)	500	1982
ARCO	Oryx Energy (California properties)	500	1991
Refining and Marketing			
BP America (formerly Standard Oil Co. (Ohio))	Chevron (Gulf's refining and marketing assets in the southeastern U.S.)	613	1985
Sun	Atlantic Petroleum Corp.	594	1988
Mobil	Tenneco (refinery in Chalmette, LA)	590	1988
Pipelines			
Occidental Petroleum	MidCon Corp.	2,608	1986
Coastal	American Natural Resources	2,452	1985
Burlington Northern	The El Paso Company	1,300	1983
Coal			
BP America	U.S. Steel (coal properties)	600	1981
Nonenergy			
Occidental Petroleum	Cain Chemical, Inc.	2,245	1988
BP America	Kennecott Corp.	1,770	1981
Mobil	Marcor, Inc.	1,701	1974, 1976
Exxon	Reliance Electric	1,236	1979
Union Pacific	Overnite Transportation	1,200	1986
Union Pacific	Missouri Pacific Corp. and Western Pacific Railroad Co.	1,000	1982
Occidental Petroleum	Diamond Shamrock Chemical Co.	860	1986
DuPont	American Critical Care, Ford Motor Co. (automotive paint operations), and Shell Oil Agrichemicals Company	834	1986
Occidental Petroleum	Iowa Beef Corporation	746	1981
ARCO	Anaconda Co.	688	1977
Tenneco	Southwestern Life	653	1980

Restructuring generally refers to corporate retrenchment in some lines of activities and consolidation of retained assets in others in order to improve corporate profitability and returns to stockholders. Mergers and acquisitions effectively consolidated energy assets, particularly oil and gas reserves, into the custody of surviving corporations. Another form of consolidation involved reducing the scale of ongoing operations. Elimination of higher-cost operations can raise the overall return on retained assets. Domestic oil and gas production, particularly onshore, is a good example. When oil prices were rising steeply, the FRS companies' net lease ownership of undeveloped U.S. onshore acreage rose from 127 million acres in 1977 to a peak value of 192 million acres in 1981. Thereafter, the FRS companies' holdings steadily declined to 42 million acres in 1993. Similarly, the number of onshore producing wells of the FRS companies, on a net ownership basis, rose from 196 thousand in 1977 to a peak value of 232 thousand in 1985 but then steadily declined to 153 thousand in 1993. One of the important effects of this consolidation was a decline in the FRS companies' cost of extracting oil and gas in the United States, from over $6 per barrel, excluding taxes, in 1985 (in 1993 dollars) to less than $4 per barrel in 1993.

Retrenchment was largely driven by two motives. One purpose was to sell, or otherwise dispose of, businesses which were of low profitability or were not integral to long-term investment strategies. Due to poor performance, diversified businesses outside petroleum and chemicals were good candidates for divestiture (Figure 16). Although the other nonenergy line of business accounted for 10 percent of the FRS companies' net assets in 1981, this line of business accounted for one-third of the value of asset disposals thereafter.[158] Overall, the FRS companies' retrenchment in diversified businesses benefitted bottom-line results. The rate of return on other nonenergy assets steadily rose from a negative level in 1982 to a positive 10 percent in 1988 and has remained positive since then, despite a recession-induced dip in 1991 (Figure 16). This improvement in financial performance reflects the higher profitability, on average, of businesses that were retained.

Another aim of retrenchment and associated sales of assets was to raise cash to reduce debt. Asset sales noticeably increased in 1983 and 1984 and reached a peak in 1988 when Tenneco sold their petroleum assets for $7.6 billion (Figure 15). The takeovers and takeover defenses of the early 1980's involved massive amounts of debt. Companies involved in takeovers and takeover defenses accounted for 73 percent of the FRS companies' build-up of long-term debt between 1981 and the peak year for FRS debt, 1987.[159] Although the sharp increase in the FRS companies' overall ratio of total debt to equity evident by 1985 (Figure 22) was largely traceable to those companies involved in takeovers and takeover defenses, two-thirds of the other FRS companies were increasing their debt load as well. As a source of financing, long-term debt jumped from less than 15 percent to nearly 25 percent of total funds in the 1981-1985 period (Table 33). In large part because of the accumulation of debt, reduction of debt claimed a growing share of the FRS companies' capital resources (Table 34). In recent years, the FRS companies have contained their growth in debt (Figure 22) and asset sales have receded in importance as a source of funds.

Figure 22. Total Debt/Equity Ratio, 1977-1993



Note: Total Debt/Equity = Total debt (including accounts payable) as a percent of stockholders' equity.

Sources: **FRS Companies**: Energy Information Administration, Form EIA-28. **S&P 400**: Standard and Poor's Compustat Services, Inc.

[158]Energy Information Administration, *Performance Profiles of Major Energy Producers 1990*, DOE/EIA-0206(90)(Washington, DC, December 1991), pp. 42-43.

[159]In 1984, Chevron, Mobil, and Texaco raised $26 billion through long-term debt issues, largely for acquisitions. In connection with takeover defenses and restructuring in 1985, ARCO, Phillips Petroleum, and Unocal issued $13 billion in long-term debt.

Table 33. Distribution of Main Sources of Funds for FRS Companies, 1974-1993
(Percent)

Main Sources	1974-1978	1979-1980	1981-1985	1986-1990	1991-1993
Cash Flow from Operations	74.8	81.0	67.1	58.0	58.0
Long-Term Debt	18.8	14.5	23.5	25.3	28.1
Equity Offerings	1.8	1.3	2.8	3.8	2.5
Asset Sales	4.6	3.2	6.6	12.9	11.5
Total	100.0	100.0	100.0	100.0	100.0

Note: Components may not sum to total due to independent rounding.
Source: Energy Information Administration, Form EIA-28.

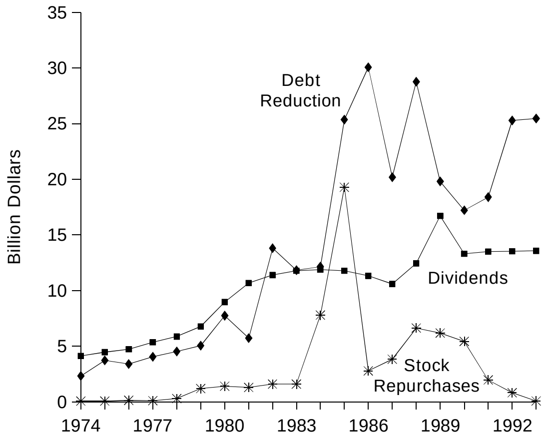
Table 34. Distribution of Main Uses of Funds for FRS Companies, 1974-1993
(Percent)

Main Uses	1974-1978	1979-1980	1981-1985	1986-1990	1991-1993
Capital Expenditures	72.4	74.0	66.2	51.1	53.6
Reduction in Long-Term Debt	11.5	10.6	14.7	27.6	28.5
Cash Dividends	15.6	13.2	12.3	15.3	16.7
Stock Repurchases	0.4	2.2	6.8	5.9	1.2
Total	100.0	100.0	100.0	100.0	100.0

Note: Components may not sum to total due to independent rounding.
Source: Energy Information Administration, Form EIA-28.

Another key element of the FRS companies' response to capital market developments was an increase in cash payouts to shareholders through dividends and repurchases of company common shares.[160] Dividends paid by the FRS companies have generally increased over time, both in amount (Figure 23) and as a share of cash flow (18 percent in 1974-1980, 22 percent in 1981-1990, and 29 percent thus far in the 1990's). The FRS companies' disbursements to shareholders in the form of stock repurchases rose to unprecedented levels in 1984 and again in 1985 during the most heated period of takeover threats and activity. Although outlays for stock repurchases never again approached the $19 billion in repurchases in 1985, repurchase of common stock became much more prevalent among the FRS companies in the 1980's. In 1980, fewer than half of the companies repurchased their stock, but by 1990 all but three of the FRS companies reported expenditures for repurchases of their common stock. In recent years, stock repurchases have declined, in part because share values increased with the bullish outlook of the capital markets and in part because interest rates declined, leading to less clamor for cash payouts.

Figure 23. Dividends, Stock Repurchases, and Reduction in Long-term Debt for FRS Companies, 1974-1993



Source: Energy Information Administration, Form EIA-28.

[160]Dividend policy tends not to be subject to large year-to-year changes. Rather, dividends tend to be viewed as being a fixed commitment to shareholders. Stock repurchases, by contrast, tend to be discrete rather than regular occurrences and offer flexibility to a corporation with respect to the timing and amount of payout to shareholders. Stock repurchases usually have an immediate and positive effect on share prices. Stock repurchases reduce the number of outstanding shares, thereby tending to raise the price of the remaining shares. Investors will bid up the price of the shares subsequent to the announcement of a stock repurchase in anticipation of price rises and receipt of a cash payout.

The FRS companies did not make many changes in the direction of their investment strategies until oil prices collapsed in 1986. Indeed, the composition of capital expenditures in the 1981-1985 period was strikingly similar to that of 1979-1980, when oil prices were escalating rapidly (Table 35). Somewhat more than 60 percent of capital expenditures was directed to oil and gas production in both periods, downstream petroleum declined to 16 percent or so of capital expenditures, about 8 percent went for diversified businesses followed closely by chemical operations, and less than 5 percent of capital expenditures was allocated to energy development outside petroleum.

Of course, mergers and acquisitions played a much larger role, since the first half or so of the 1980's was the period of consolidation of upstream assets (Figure 6 in Part I, Chapter 2). The apparent stability in the FRS companies' investment patterns in 1979-1980 and 1981-1985 largely reflected the relative profitability of their lines of business, which changed little until the oil price collapse (Figure 21). Oil and gas production continued to be, by far, the most profitable line of activity through 1985. Downstream profitability, though hurt by continued excess capacity and a glut of gasoline supplies in 1984, remained a distant but clear second to upstream rates of return, followed by chemical operations.

Table 35. Distribution of Capital Expenditures by Lines of Business for FRS Companies, 1974-1993
(Percent)

	1974-1978	1979-1980	1981-1985	1986-1990	1991-1993
Oil and Gas Production					
United States	36.3	46.8	46.3	30.9	23.5
Foreign	14.8	16.7	15.2	21.3	25.2
Total Oil and Gas Production	51.1	63.5	61.5	52.2	48.8
Downstream Petroleum					
Refining/Marketing					
U.S. Refining	7.0	5.6	6.1	6.0	11.1
U.S. Marketing[a]	4.7	3.5	3.5	6.8	5.8
Foreign Refining/Marketing	5.7	4.2	3.7	6.6	8.3
Total Refining/Marketing	17.4	13.3	13.3	19.4	25.2
Transport					
Pipelines	7.4	1.8	2.9	4.1	2.5
International Marine	3.5	1.2	0.3	0.3	0.6
Total Downstream	28.3	16.3	16.5	23.8	28.3
Coal	2.4	2.3	3.0	1.8	1.6
Nuclear and Other Energy	2.6	2.0	1.5	0.6	0.6
Nonenergy					
Chemicals	9.0	6.3	7.0	13.7	13.0
Other	5.7	8.1	8.1	6.3	5.0
Nontraceable	0.8	1.4	2.4	1.4	2.7
Consolidated	100.0	100.0	100.0	100.0	100.0

[a]Includes unregulated petroleum transport.

Note: Components may not sum to total due to independent rounding. For 1974-1980, capital expenditures are measured by additions to PP&E, and for 1981-1993, capital expenditures are measured by additions to investment in place (PP&E plus investments and advances).

Source: Energy Information Administration, Form EIA-28.

Oil prices moved from a general decline to a total collapse beginning in late 1985. For example, the average price of crude oil imported into the United States dropped from $27 per barrel in the fall of 1985 to $11 per barrel in July of 1986. Although oil prices increased somewhat since then, they have generally remained at a low level apart from a war-induced, transitory upswing in late 1990.

The lower level of oil prices since 1986 led to substantial realignments of the FRS companies' investment targets. Exploration and development expenditures fell by a third in 1986 from their 1985 level (Table 30) and generally remained far below the levels of the prior 7 years. By 1993, the FRS companies' worldwide E&D expenditures of $23 billion were at about half the peak values of 1981 and 1982. Nearly all of the cutbacks in E&D were in the United States. Apart from 1988, the FRS companies' expenditures for domestic E&D steadily fell from $28 billion prior to the oil price collapse, to a range of $14 to $15 billion, and were cut back further to $10 billion in 1992, their lowest level since 1977. By contrast, foreign E&D expenditures, which were trimmed by 25 percent in the context of the 1986 oil price collapse, nearly doubled between 1986 and 1989, and have remained in the $13 to $14 billion range into the 1990's. A variety of factors contributed to the shift in emphasis to locales outside North America. These factors, which are discussed in the next chapter, include the interactions of costs, geology, development of markets, regulations, and tax policies.

Lower oil prices, at least for the first few years after their collapse, increased the profitability of downstream petroleum and chemical operations (Figures 16 and 21). Lower oil prices led to lower petroleum product prices which, in turn, increased the demand for petroleum products. Economic growth both stimulated petroleum demand and was aided by lower oil prices, with annual real GDP growth in the United States averaging over 3 percent during 1986 through 1989. In the context of increased gasoline demand, particularly for higher-octane grades, gasoline marketing became a renewed target of investment among FRS refiners as did gasoline manufacturing capability. Refinery utilization also improved over the 1986-1989 period in part because petroleum demand increased and also because the retrenchment in U.S. refinery operations was largely at an end by the beginning of 1986. Over 3 million barrels per day of crude oil distillation capacity were removed from service between January 1, 1981 and January 1, 1986. Lower oil prices and economic growth had similar beneficial effects on chemical operations: feedstock prices fell, demand improved, and profit margins widened. The FRS companies shifted the focus of their capital spending to downstream petroleum and chemical operations in the latter half of the 1980's. The share of total FRS companies' capital expenditures allocated to chemical manufacture, petroleum refining, marketing, and transport rose from 24 percent in 1981-1985 to 38 percent in 1986-1990 (Table 35).

The emphasis on downstream petroleum and chemical operations in the capital budgets of the FRS companies continued into the early 1990's. Outlays for these lines of activity amounted to 41 percent of total capital expenditures through 1993. However, the factors contributing to this continued emphasis were somewhat different than in the late 1980's. Capital expenditures for worldwide refining operations rose to 20 percent of total outlays. In part, the growth in spending was for the continued upgrading of retained facilities to increase yields of lighter products.

Environmentally-related objectives also became more prominent in recent years. In the United States, heightened environmental standards plus scheduled compliance with earlier environmental quality requirements led to increased downstream outlays. Most recently, the Clean Air Act Amendments of 1990 mandated that: (1) reformulated gasoline be sold in areas with the severest air pollution levels (beginning January, 1995), (2) minimum oxygen content for gasoline supplied during the winter months in 39 areas of the country (beginning November, 1992), and (3) the sulfur content in diesel fuel be reduced (beginning October, 1993). The FRS companies' estimated capital expenditures for environmentally-related purposes in U.S. refining rose from $0.3 billion in 1989 to $1.9 billion in 1992.[161] Abroad, the European Community nations are reducing the lead content of gasoline, which has required additional investment for the FRS companies' foreign refineries.

Although the FRS companies' capital expenditures for their chemical operations fell from $8 billion in 1990 to $5 billion in 1993, spending for these operations remained at a high level in historical context and constituted 13 percent of total capital expenditures. A decline in chemical profitability from the record levels of 1988 and 1989 (Figure 16) reduced the attractiveness of this line of activity. A surge in additions to worldwide chemical capacity and weakened economic

[161]Environmentally-related expenditures are discussed in detail in Chapter 8.

growth beginning in late 1990, first in the United States and then in other industrial nations, dampened prices, particularly among commodity chemicals. Price-cost margins were also eroded by the higher oil and feedstock prices during the several months of conflict following Iraq's invasion of Kuwait in August, 1990. Financial results for the FRS companies in 1992 and 1993 suggest that chemical profitability may have leveled off.

Diversified businesses were second only to U.S. oil and gas production as a target of investment cutbacks in the late 1980's and early 1990's. Capital expenditures for businesses outside energy and chemicals steadily fell from their peak of $7 billion in 1981 and remained at a level slightly above $2 billion in the 1990's. Low profitability and incompatibility with longer term investment objectives led to massive divestitures of enterprises in the other nonenergy line of business during the 1980's. In addition, the FRS companies' apparent asset commitment to this line of business was further reduced in 1987, when Burlington Northern spun off its energy operations to shareholders (creating Burlington Resources) thereby removing its railroad operations from the scope of FRS reporting, and in 1988, when highly diversified Tenneco left the ranks of FRS respondents through the sale of their petroleum assets.

Despite a gradual but steady erosion of coal prices, both before and after the oil price collapse of 1986, the FRS companies generally maintained their interest in coal operations during the remainder of the 1980's. Their coal production grew at a somewhat faster pace than the rest of industry. Their capital expenditures for coal, though averaging only about half the level of earlier years ($0.8 billion annual average in 1986-1990 versus $1.6 billion in 1981-1985), were mainly directed at cutting costs and raising mine productivity rather than significant expansions of capacity. However, the profitability of coal operations was always well below the average for the other lines of business and showed no trend either upward or downward during the decade of the 1980's. Some FRS companies appeared to remain in coal production mainly for lack of a satisfactory purchase offer for their coal assets. Then, during the 1990's, seven FRS companies sold their coal assets.[162] Most of the divested coal reserves, apart from those of Burlington Resources, were located in the higher cost Eastern region of the United States, close to export points. This favorable locational feature may have enhanced their value as future sources of supply to European markets, as subsidies to local coal production are being scaled back in some European countries.[163] These divestitures of coal assets represent a sizable withdrawal of commitment by the FRS companies to U.S. coal production. In 1989, for example, these seven companies accounted for 51 percent of FRS coal production (and 15 percent of total U.S. coal production).

Unlike coal production, in which the FRS companies sustained a continuing and noticeable presence in the 1980's, nuclear and nonconventional energy were targets of divestiture. By 1986, many of the FRS companies had largely withdrawn from uranium production, due to a number of setbacks to the industry, and to nonconventional energy development, due to downward revisions of oil price expectations. The oil price collapse in 1986 and subsequent lower level of energy prices served only to accelerate the ongoing retrenchment. By the early 1990's, the last FRS uranium producer ceased operations. Ongoing operations in nonconventional energy are mainly in Canadian tar sands production and geothermal power generation with smaller asset commitments in cogeneration and solar power manufacturing. Capital expenditures for nuclear and other energy fell from over $1 billion in 1981 and 1982 to about $200 million in recent years.

The distribution of the FRS companies' productive assets across lines of business in 1993 reflected both restructurings and shifts in investment targets effected since the decline in oil prices began in 1981 (Table 36). Changes in the pattern of asset deployment largely occurred after 1985 because investment strategies changed little in the first half of the 1980's and implementation of restructuring plans can take years until completion. Petroleum refining and marketing showed the largest growth in asset share from 1985, followed by chemical manufacturing and foreign oil

[162]Divestitures of coal businesses by FRS companies, in 1990-1993, included the following: • BP America completed the sale of their coal subsidiaries to Zeigler Coal in 1990. • In 1991, Mobil exited the coal industry through the sale of their Wyoming coal mine. • On December 31, 1991, DuPont transferred its Consolidation Coal Company unit to Consol Energy, a 50-50 joint venture between DuPont and RWE AG of Germany. • Shell Oil sold their U.S. coal operations to Zeigler Coal in 1992. • Burlington Resources sold most of their coal properties to a limited partnership in 1992, retaining only a production royalty. • Occidental Petroleum and Sun Company treated their coal subsidiaries as discontinued operations in 1992, and sold them in 1993.

[163]Energy Information Administration, *Performance Profiles of Major Energy Producers 1992*, DOE/EIA-0206 (Washington, DC, January 1994), P.53.

Table 36. Distribution of Net Investment in Place by Lines of Business for FRS Companies, 1981, 1985, and 1993
(Percent)

	1981	1985	1993
Oil and Gas Production			
United States	34.6	40.2	27.5
Foreign	13.1	12.7	18.0
Total Production	47.7	52.9	45.6
Downstream Petroleum			
Refining/Marketing	19.5	16.4	24.1
Transport	6.7	5.6	7.9
Total Downstream	26.2	22.0	32.0
Coal	3.0	2.9	1.5
Nuclear and Alternative Energy	1.9	1.2	0.9
Nonenergy			
Chemicals	7.6	6.9	11.4
Other Nonenergy			
Railroads	3.0	4.1	2.9
Other	8.5	7.8	3.0
Nontraceable	2.2	2.4	2.6
Consolidated	100.0	100.0	100.0

Note: Components may not sum to total due to independent rounding.
Sources: Energy Information Administration, Form EIA-28, except for railroad data which were taken from company annual reports.

and gas production. As measured by share of net investment in place, U.S. oil and gas production was de-emphasized the most in the FRS companies' deployment of assets, followed by diversified businesses outside energy and chemicals. Also, the combined asset share of coal, nuclear, and nonconventional energy fell from 4.9 percent in 1981 to 2.4 percent in 1993.

The FRS Companies' Standing in U.S. Industry

In the 20 years following the Arab Oil Embargo, the FRS companies have had to adjust to major oil price upheavals and collapses. Government policy changes, both in the United States and abroad, also posed substantial challenges to major energy companies' decisionmaking. Some government policies were reactions to energy market developments while other policy changes derived from issues larger than energy alone. Being competitors in the capital markets, the FRS companies have had to contend with the turmoil created by changes in investor attitudes and preferences. To gauge how the FRS companies fared relative to overall U.S. industry, three key areas of performance are reviewed in the remainder of this chapter: profitability, growth, and investor perceptions.

An often-used measure of profit performance is return on equity, calculated as net income from the consolidated statement of income divided by stockholders' equity (i.e., the book value of assets minus liabilities), which provides a picture of past profitability based on historical prices and costs rather than a picture of prospective profitability based on expectations. Generally, the profitability of the FRS companies differed markedly from other large U.S. industrial corporations, as represented by the Standard and Poor's (S&P) 400, only in the contexts of two oil price escalations (1974, 1979-1981) and the oil price collapse of 1986 and its aftermath (Figure 3 in Part I, Chapter 2). Although the invasion of Kuwait by Iraq brought on an oil price escalation in the latter part of 1990, the positive effects of higher oil prices on upstream income were largely offset by adverse effects on downstream and chemical earnings. In the 1990's, the profitability of the FRS companies and the S&P 400 has been similar, so far.

In contrast, patterns of corporate growth for the FRS companies differed from that of other large U.S. industrial companies. In 1981, 13 of the top 20 companies (ranked by total assets) on the *Fortune* list of the 500 largest U.S. industrial corporations were FRS companies, up from 9 FRS companies in 1974 (Table 37). In the context of escalating oil prices and rising cash flow, the FRS companies' investment outlays surged, resulting in an annual growth in total assets of 13 percent between 1974 and 1981 (Table 38). Total assets of the *Fortune* 500 (excluding the FRS companies) grew at a lesser 10-percent rate between 1974 and 1981. Since 1981, there has been a turnabout in trends between the two groups of companies. Although U.S. industry has restructured and trimmed capital spending in recent years, the FRS companies generally started their restructuring efforts earlier and more severely cut back capital expenditures. Total assets of the FRS group grew at an annual rate of 2 percent between 1981 and 1993, far below their growth in 1974-1981, and well below the 8-percent growth registered by the balance of the *Fortune* 500. By 1993, the number of FRS companies among the top 20 U.S. industrial corporations dwindled from 13 to 8: Gulf Oil was taken over by Chevron in 1984, Tenneco left the FRS group after selling its petroleum assets in 1988, and three other FRS companies fell below the top 20 threshold.

Investors had a mixed view of the strategy and performance of the FRS companies after oil prices peaked in 1981. As previously noted, one measure of investor expectations of future returns to stock ownership in a company is the market-to-book ratio. Relative to the S&P 400, the FRS companies' market-to-book ratio plunged from parity to about half the value in the early 1980's (Figure 20). This downward valuation of the FRS companies' prospects reflected the combination of lowered oil price expectations and disappointing performance in lines of business other than oil and gas production.

Although the FRS companies' market-to-book ratio began to rise in 1983, they did not benefit from the bull market in common stocks to the extent that other companies did. The gap between the two groups' market-to-book ratio generally widened through 1986. Thereafter, the gap became narrower, indicating a favorable change in outlook for the FRS companies relative to other large industrial companies.

What caused this apparent change in outlook? No single explanation could be wholly satisfying, but a number of factors undoubtedly contributed. First, the restructuring efforts of most of the FRS companies were well under way by 1987, and the rise in the market-to-book ratio reflected investors' approval of these efforts. The sharp rise in the FRS companies' return on equity in the late 1980's (Figure 3 in Part I, Chapter 2) tended to substantiate this view. Second, the oil price collapse of 1986 reduced the value of oil and gas reserves, so that when oil prices rose from the $9-$11 range at the wellhead in the latter half of 1986 to the $16-$17 range a year later, so too did the valuation of surviving oil and gas operations. Coincident with the rebound in oil prices in the Autumn of 1987 was first a fall and then a crash in stock prices generally. However, because of favorable oil price movements, market values of the FRS companies' shares were not as adversely affected by the stock price crash of 1987. Third, investors probably took an approving view of the FRS companies' management of their debt following earlier takeovers and takeover defenses. After 1985, the growth in the FRS companies' debt about matched the growth in their equity while other industrial companies showed a marked rise in the role of debt in their balance sheets (Figure 22).

Although the capital markets' overall valuation of the FRS companies clearly improved in the latter part of the 1980's and the early 1990's, there is an indication that investors currently perceive greater risks attending the FRS companies' prospects. Until about 1985, the FRS companies' debt tended to be of the lowest risk among corporate borrowers. That is, as shown in Figure 19, the average interest rate on FRS companies' long-term debt[164] and Moody's AAA yield on corporate bonds differed little from 1974 through 1984. The Moody's AAA rating is given to corporate debt issues that have the lowest risk of default. However, by 1986, the FRS companies' average interest rate was 4 percentage points above the AAA yield, nearly 40 percent higher. One possibility is that the $9 price for oil in mid-1986 increased investors' perceptions of the volatility of future returns from investments in oil and gas. Since 1986, the interest rate differential has narrowed to less than 2 percentage points.

[164]Interest and financial charges divided by the average of prior end-of-year long-term debt and current end-of-year long-term debt.

Table 37. Top 20 Companies in the *Fortune* 500 Largest U.S. Industrial Corporations, 1974, 1981, and 1993
(Ranking Based on Total Assets)

	1974	1981	1993
Exxon	**1**	**1**	**4**
General Motors	2	2	3
Mobil	**5**	**3**	**8**
International Business Machines	6	4	5
Texaco	**3**	**5**	**15**
E I du Pont de Nemours	17	**[a]6**	**10**
Chevron	**8**	**7**	**11**
Ford Motor	4	8	2
Amoco	**11**	**9**	**13**
General Electric	10	10	1
Gulf Oil	**7**	**11**	**([b])**
Shell Oil	**16**	**12**	**14**
Atlantic Richfield	**15**	**13**	**18**
Tenneco	**14**	**14**	[c]32
BP America	**48**	**15**	**([d])**
International Telephone and Telegraph	9	16	([e])
USX	12	17	**[f]26**
Dow Chemical	19	18	16
Sun	**27**	**19**	**84**
Phillips Petroleum	**28**	**20**	**46**
Chrysler	13	38	7
Western Electric	18	25	([g])
Union Carbide	20	21	107
Phillip Morris	47	24	6
Xerox	26	30	9
RJR Nabisco	34	27	12
Proctor & Gamble	35	35	17
Hanson Industries NA	([g])	([g])	19
Pepsico	108	69	20

[a]DuPont became an FRS company when they acquired Conoco in 1981.
[b]Acquired by Chevron in 1984.
[c]Tenneco sold their petroleum assets in 1988.
[d]BP America became a 100-percent owned subsidiary of British Petroleum in 1987. Based on 1993 disclosures, BP America would rank 25th in terms of sales revenues.
[e]Name changed to ITT Corp. and primary line of business was fire, marine, and casualty insurance in 1993.
[f]USX (formerly, U.S. Steel) became an FRS company when they acquired Marathon Oil in 1982.
[g]Not in existence in year shown.
Note: FRS companies are shown in bold.
Source: *Fortune* (May, 1975; May 3, 1982; April 18, 1994).

Table 38. Total Assets of the FRS Companies and *Fortune* 500, 1974, 1981, and 1993
(Billion Dollars)

	1974	**1981**	**1993**	**Annual Growth Rate** 1974-1981	**Annual Growth Rate** 1981-1993
				(percent)	
FRS Companies	159.6	372.5	451.3	12.9	1.6
Fortune 500, excluding FRS Companies	476.9	911.4	2,274.7	9.7	7.9

Sources: **FRS Companies:** Energy Information Administration, Form EIA-28. ***Fortune* 500:** *Fortune* (May, 1975; May 3, 1982; April 18, 1994).

7. Oil and Gas Resource Development

Changes in the Global Oil and Gas Investment Climate

The rapid increase in oil prices in the late 1970's initiated changes in the oil and gas investment climate, changes that were subsequently reversed following the oil price collapse of 1986. In the 1970's and early 1980's, expectations of continued high oil prices encouraged oil-producing countries to establish state-owned oil companies. The later decline in oil prices prompted oil-producing countries to privatize state oil companies. Similarly, high oil prices had supported high taxes on oil and gas production, and the subsequent decline in oil prices compelled governments to reduce taxes and encourage oil and gas investment.

From Nationalization to Privatization

In the worldwide oil market of the 1990's, the FRS companies are smaller players facing bigger competitors, the state-owned oil companies. Most state-owned oil companies were created shortly before the oil price acceleration of the 1970's, when governments of oil-exporting countries nationalized the assets of private oil companies. Enmity toward multinational oil companies had nurtured such ambitions for years, but in general, nationalization remained more a threat than a reality until the potential of increased market power over oil prices added economic incentives to political aspirations.

Nationalization began in 1971 when Libya nationalized all of British Petroleum's holdings and 51 percent of Occidental Petroleum's operations.[165] The Shah of Iran gained control of the Iranian National Oil Company, and Iraq nationalized the Iraq Petroleum Company; both of these companies had previously been owned by investment consortia.[166] Kuwait acted next in 1975, and Venezuela nationalized the assets of Exxon and Shell in 1976.[167] Also in 1976, the Aramco partners (Exxon, Chevron, Mobil, and Texaco) reached an agreement to sell their holdings to Saudi Arabia, although no money changed hands until 1980. By nationalizing the assets of the major oil companies, the producing countries created the state-owned companies that currently dominate world oil production (Table 39).

The trend toward nationalization reversed when oil prices began falling in 1981. Lower prices exposed many inefficient and poorly managed operations, and many governments (outside of the Middle East) became disenchanted with the oil and gas production business and began encouraging privatization.[168] In 1985, Brazil offered 7 percent of Petrobras to the private market and the British government sold Britoil.[169] In 1986, France sold 44 percent of Elf Aquitaine, Britain sold British Gas, and Sweden sold Swedegas.[170] After the oil price collapse, the British government sold its shares of British Petroleum (BP), and Austria, New Zealand, Chile, France, Spain, and West Germany all sold their state-owned oil and gas companies.[171] The Peruvian private investment commission recently directed Petroperu to streamline operations and make itself more attractive to potential buyers.[172] Argentina's Yacimientos Petroliferos Fiscales (YPF) took similar downsizing action in preparation for its foray into the

[165]Daniel Yergin, *The Prize* (New York: Simon and Schuster, 1991), pp. 584-585.

[166]The Iranian National Oil Company, formerly the Anglo-Persian Oil Company, was majority owned by the British government. The Iraq Petroleum Company, formerly the Turkish Petroleum Company, was owned by the Turkish National Bank, Royal Dutch/Shell, Deutsche Bank, and Armenian-born financier, Calouste Gulbenkian. Source: Daniel Yergin, *The Prize* (New York: Simon and Schuster, 1991), pp. 185, 451.

[167]Daniel Yergin, *The Prize* (New York: Simon and Schuster,1991), pp. 647, 652.

[168]The Middle East is the exception to the privatization trend, because costs there are so low that the state-owned companies show satisfactory financial performance in spite of low oil prices.

[169]Cambridge Energy Research Associates, "Oil and Politics: The Shape of Things to Come," Private Report (Cambridge MA, January 1989), pp. 4-5.

[170]Cambridge Energy Research Associates, "Oil and Politics: The Shape of Things to Come," Private Report (Cambridge MA, January 1989), pp. 4-5.

[171]Cambridge Energy Research Associates, "Oil and Politics: The Shape of Things to Come," Private Report (Cambridge MA, January 1989), pp. 4-5.

[172]"Petroperu Sets Out Its Stall," *Petroleum Economist* (June 1993), pp. 25-27.

Table 39. Worldwide Crude Oil Production of 20 Leading Companies, 1972 and 1992
(Thousand Barrels per Day)

1972			1992		
Company	Production	Percent of Worldwide Total	Company	Production	Percent of Worldwide Total
Exxon Corp.	4,968	10.8	Saudi Arabian Oil Co.	8,165	12.5
British Petroleum	4,664	10.1	National Iranian Oil Co.	3,432	5.3
Royal Dutch/Shell	4,169	9.0	Petroleos Mexicanos	3,123	4.8
Texaco Inc.	3,777	8.2	China National Petroleum	2,835	4.3
Chevron Corp.	3,232	7.0	Petrolos de Venezuela	2,484	3.8
Gulf Oil	3,214	7.0	Royal Dutch/Shell	2,143	3.3
Mobil Corp.	2,316	5.0	Exxon Corp.	1,705	2.6
Communist Bloc[a]	1,301	2.8	British Petroleum	1,293	2.0
CFP (Total - France)	977	2.1	Sonatrach (Algeria)	1,281	2.0
Sonatrach (Algeria)	925	2.0	Lukoil (Russia)	1,138	1.7
Amoco Corp.	815	1.8	Abu Dhabi National Oil Co.	1,108	1.7
ARCO	652	1.4	Nigerian National Petroleum	1,097	1.7
DuPont (Conoco)	594	1.3	Libya National Oil Co.	1,068	1.6
USX Corp. (Marathon)	453	1.0	Chevron Corp.	944	1.4
Petroleos Mexicanos	440	1.0	Kuwait Petroleum Corp.	920	1.4
Occidental Petroleum	443	0.9	Mobil Corp.	816	1.3
Getty Oil	443	0.9	ARCO	738	1.1
Sun Co.	369	0.8	Texaco Inc.	736	1.1
Unocal Corp.	365	0.8	Pertamina (Indonesia)	715	1.1
Phillips Petroleum Co.	337	0.7	Amoco Corp.	711	1.1
Top 20 Total	34,434	74.6	**Top 20 Total**	36,452	55.8
Worldwide Total[a]	46,170	100.0	**Worldwide Total**	65,373	100.0

[a]For 1972, only non-Communist world oil production and Communist bloc (including China) exports to the non-communist world are included, while 1992 includes total world production. Sum of components may not equal totals due to independent rounding. Shares were calculated based on unrounded data.

Sources: **Company data 1972**: Jacoby, Neil H., *Multinational Oil* (New York, 1974, pp. 192-193) and company annual reports. **Company data 1992**: Petroleum & Energy Intelligence Weekly, Inc., *PIW — Special Supplement Issue* (New York, December 13, 1993). **China production data**: *Oil and Gas Journal*, "State Companies Dominate OGJ100 List of Non-U.S. Oil Producers" (September 20, 1993), p. 79. **Worldwide total 1972**: Based on data which appeared in Energy Information Administration, *International Petroleum Statistics Report* (Washington DC, August 1994), Tables 4.1 and 4.3, pp. 38-40, 42. **Worldwide total 1992**: Based on data which appeared in Energy Information Administration, *International Energy Annual*, DOE/EIA-0219(92) (Washington, DC, January 1994), Tables 1 and 2, pp. 6, 8.

private sector in 1993.[173] Other countries, while not relinquishing ownership of their state-owned companies, have begun efforts to make these companies more efficient and accountable. Nigeria, a member of the Organization of Petroleum Exporting Countries (OPEC), realigned its national petroleum company in 1988, to bring it into line with private sector standards.[174] In 1992, the Mexican government divided Pemex into four operating units, ordering each to turn a profit. Mexico is also reported to be considering requiring better financial and operating disclosure from Pemex.[175]

[173]"YPF Sell-off Back on Track," *Petroleum Economist* (November 1992), p. 12.

[174]Cambridge Energy Research Associates, "Oil and Politics: The Shape of Things to Come," Private Report (Cambridge MA, January 1989), pp. 4-5.

[175]"Leaked Government Documents Point to Deeper Mexican Privatization," *Oil and Gas Journal* (August 16, 1993), p. 26.

In Russia, where the push toward privatization is not limited to oil companies, the oil production associations, formerly reporting to the Ministry of Fuel and Energy, are currently being transformed into joint (public and private) stock companies.[176] Several vertically integrated regional companies, including Lukoil, Surgutneftegaz, and Yukos in western Siberia, have combined production associations with refineries. However, the privatization process has been complicated by lack of clear lines of authority and ownership, and the accompanying financial and political risk has kept investors cautious. For most of the post-embargo period, oil production from the Former Soviet Union exceeded that of Saudi Arabia, but through lack of investment, production dropped steadily since 1988 and fell below that of Saudi Arabia in 1993.[177]

In addition to relieving the government of fiscal and managerial responsibility for oil production, privatization can benefit a company's operations by providing access to sources of investment funds in addition to the state treasury. State oil companies have often found themselves forced to forego potentially profitable exploration and development projects, because they had to compete with politically popular social programs for limited state funds. In 1993, Pemex's exploration budget was used for Mexico's social spending program.[178] Brazil considered cutting Petrobras' budget in half in 1994 as part of an effort to reduce spending and control inflation.[179] In 1993, the cash-starved Russian energy network shut in more wells than it completed.[180]

Another incentive for privatizing state oil companies is to gain access to efficient, cost-saving technology used in private sector operations. Desire for access to the technical and managerial expertise of a number of FRS companies has led to joint exploration and development projects in the Former Soviet Union and other regions. Chevron's joint venture with Kazakhstan promoted development of the Tengiz field, where sour crude oil under high pressure caused blowouts and gushers with old Soviet equipment.[181] DuPont's Conoco reported that training Russian crews in western drilling technology reduced drilling time from 144 days to 60 days.[182] BP and its partners (including Unocal) plan to use North Sea development methods for Azerbaijan's section of the Caspian Sea.[183] Enron and British Gas bought into YPF's natural gas distribution network and, with the help of the first stage of price decontrol, increased Argentina's proved reserves of natural gas 17 percent in a single year.[184] Petrobras, employing Brazilian and foreign engineers, uses the world's most advanced offshore techniques to keep the cost of Brazilian oil competitive.[185] Smaller drilling and tool companies, looking to replace sluggish demand in the United States, have found markets for their equipment and expertise in Russia, Kazakhstan, and Brazil.[186]

From Confiscatory to Competitive Taxation

Generally, oil-producing nations have moved from confiscatory to competitive taxation of oil and gas operations. When oil prices were high, taxes were viewed by governments as a vehicle for confiscating part of the enormous gains in the oil companies' corporate earnings. As tax authorities collected large sums throughout the early 1980's, they also increased tax rates. In the United States, Congress imposed the Windfall Profits Tax in 1980. Largely due to the Windfall Profits Tax, 25 percent of the FRS companies' U.S. revenues from the sale of oil and gas were collected as petroleum taxes in 1981 (Figure 24). Prior to the Windfall Profits Tax, the comparable tax share was 6 percent.

[176]"Siberia's Oil Generals Look for Freedom and Finance," *Petroleum Economist* (February 1993), p. 5, and "Marketing in Mother Russia," *National Petroleum News* (November 1992), p. 39.

[177]"Russian Crude Output Seen Lower, Exports at Risk," The Reuter Business Report (November 8, 1993) and British Petroleum Company, p.l.c., *BP Statistical Review of World Energy* (London, England, June 1994), p. 5.

[178]"Reform and Privatisations Transform Investment Scene," *Petroleum Economist* (June 1993), p. 18.

[179]"Brazil's Development Plan Centers on Deepwater Oil," *Oil and Gas Journal* (January 3, 1994), pp. 18-20.

[180]"Russian Financial Crunch Triggers Cycle of Unpaid Debt, Production Cuts," *The Oil Daily* (February 14, 1994), p. 1.

[181]"In Russia,Turning Oil into Money is Actually Hard," *The New York Times* (March 20, 1994), p. E5, and Energy Information Administration, "Energy Analysis Brief: The Former Soviet Republics," (September 1991).

[182]"U.S. Oil Firm's Venture in Russian Arctic Passes First Test," *The Washington Post* (September 1, 1994), p. A23.

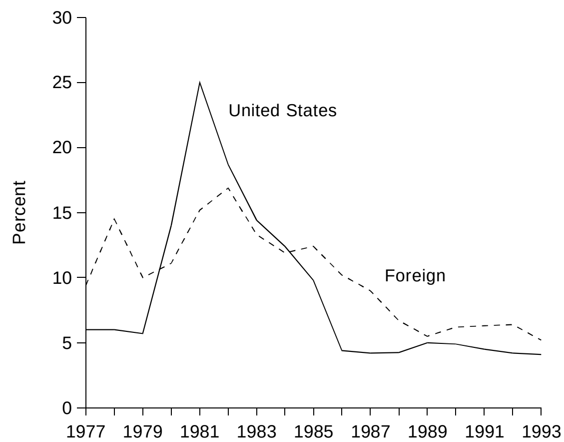
[183]"North Sea Style Development Eyed for Pair of Oil Fields off Azerbaijan," *The Oil and Gas Journal* (February 28, 1994), p. 20.

[184]British Gas, *Annual Review and Summary Financial Statement*, 1992, p. 5, and "Natural Gas: Prices Become the Paramount Factor," *Petroleum Economist* (August 1993), p. 11.

[185]"International Report," *Offshore/Oilman* (May 1993), p. 30, and "Ultra Deepwater Development Projects Under Study by Petrobras," *Offshore International* (October 1993), p. 39.

[186]"Several Russian JV's Advancing," *Oil and Gas Journal* (August 30, 1993), p. 31, and "Striking Oil But Straining Families," *New York Times* (July 7, 1994), p. D1.

Figure 24. Production Taxes as a Percent of Raw Material Revenues for FRS Companies, 1977-1993



Source: Energy Information Administration, Form EIA-28.

The new taxes imposed in response to the oil price increase were often hybrids of income, excise, and production taxes. The U.S. Windfall Profits Tax was a variable-rate excise tax on domestic crude oil that went into effect when oil prices exceeded a base price. Canada levied a tax on production and royalty income, and the United Kingdom's 75-percent tax on petroleum revenue was calculated by deducting a field's development and operating costs from its production revenue.[187]

Traditional production taxes also increased in the early 1980's. Often set up as production-sharing agreements, production taxes typically allow the company to keep a share (usually 40 percent) of a predetermined “cost recovery” level of production, valued at market price. Production above the “cost recovery” level is divided between the host government and the company (usually 80 percent for the government, 20 percent for the company). Regions of the world with low production costs (due to the favorable geological and geophysical characteristics of their producing fields) usually have high levels of production taxes, and vice versa, which tends to equalize the cost of production across the various parts of the world.[188] In the early 1980's, production taxes and royalties accounted for the bulk of the FRS companies' lifting costs in both high-cost and low-cost areas (Figure 25).[189]

In addition to production taxes, oil and gas producers pay corporate income taxes. Unlike production taxes, however, income tax rates remained relatively unchanged during the period of increasing oil prices (Figure 26). The effective rate of taxation paid by the FRS companies' foreign production segment averaged nearly 70 percent in the early 1980's; the rate paid in the United States was close to the legislated 46-percent corporate tax rate.

In the wake of the oil price collapse of 1986, governments of oil-producing countries reversed earlier policies and offered tax relief intended to attract exploration and development projects. In the United States, Congress scrapped the Windfall Profits Tax and, with the Tax Reform Act of 1986, reduced the corporate income tax rate to 34 percent. The FRS companies also benefitted from tax credits for production of natural gas from coal seams and other non-conventional energy sources in the United States. The effective tax rate on FRS petroleum production in the United States fell to 31 percent by 1993 (Figure 26).

After the oil price collapse, even countries with low production costs found they had to offer tax breaks to stay competitive, and tax differentials between countries began to narrow (Figure 25). Indonesia reduced income taxes from 56 to 48 percent, and Nigeria adjusted income taxes and royalty rates to assure companies a $2-per-barrel accounting profit. Venezuela began considering rate reductions from 60 to 30 percent on taxes applying to joint ventures with foreign petroleum companies.[190] The effective income tax rate on FRS companies' foreign operations fell from about 70 percent in 1985 to 50 percent by 1993 (Figure 26).

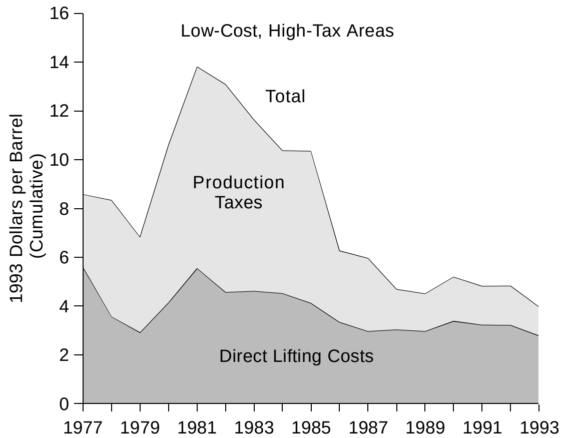
[187]The Barrows Company, Inc., *World Petroleum Arrangements* (New York, 1989), p. 1036.

[188]Production costs include direct lifting costs, the out-of-pocket costs incurred to operate and maintain wells, related equipment, and facilities. These direct lifting costs include such costs as labor, fluid injection and improved recovery projects, and operation of gas processing plants. Production costs also include severance taxes and royalties, usually levied on a per-barrel basis.

[189]The FRS operations in high-cost areas are those in which direct lifting costs are above average for the FRS companies' worldwide operations as a whole. These areas are onshore and offshore United States, Canada, and OECD Europe. Low-cost areas are the Middle East, Africa, the Other Western Hemisphere, and Other Eastern Hemisphere.

[190]"International Petroleum Operators Have Good Reason to Consider Venezuela," *The Oil Daily* (September 17, 1991), p. 2.

Figure 25. Production Costs for FRS Companies, 1977-1993



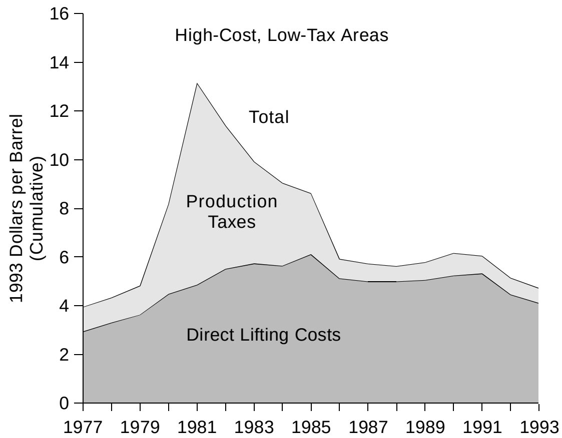
Note: Production costs are the out-of-pocket costs of extracting oil and gas. High-cost areas are those in which direct lifting costs are above-average for the FRS companies' worldwide operations as a whole. These areas are onshore and offshore United States, Canada, and OECD Europe. Low-cost areas are the Middle East, Africa, the Other Western Hemisphere, and Other Eastern Hemisphere.

Source: Energy Information Administration, Form EIA-28.

Production taxes also became more favorable, via new legislation in the United Kingdom and Canada (among other countries).[191] By 1993, the FRS companies' total lifting costs, including production taxes, were about $5 per barrel in both low-cost and high-cost parts of the world, compared with $13 and $15, respectively, when oil prices were at their peak (Figure 25). Nearly all of the decline in lifting costs is traceable to reduced production taxes. As a share of oil and gas production revenues, production taxes fell from 25 percent to 4 percent in the United States, and from 15 percent to 6 percent abroad over the same period (Figure 24).

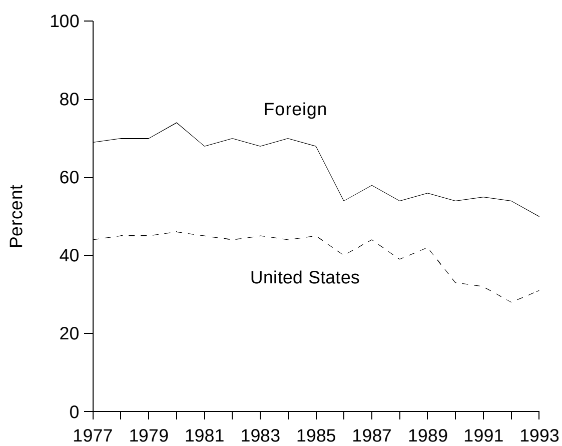
Expanded Opportunities for Natural Gas Investment

While low oil prices in the late 1980's and early 1990's discouraged oil exploration and development, prospects improved for natural gas operations. In the United States, the Natural Gas Wellhead Decontrol Act of 1989 lifted price controls completely as of January 1993, as



Source: Energy Information Administration, Form EIA-28.

Figure 26. Average Effective Income Tax Rates in Oil and Gas Production for FRS Companies, 1977-1993



Source: Energy Information Administration, Form EIA-28.

the final step of a process begun with the Natural Gas Policy Act of 1978. Natural gas emits lower levels of combustion emissions than oil or coal, and this feature is expected to lead to expanded production and marketing opportunities in the United States.

[191]Energy Information Administration, *Performance Profiles of Major Energy Producers*, DOE/EIA-0206(90) (Washington, DC, December 1991), p. 100.

Like the United States, Britain is deregulating its natural gas industry. British Gas is currently gearing up for increases in demand, by vertically integrating into North Sea gas production operations. However, it is unlikely that growing western European demand can be met with indigenous production alone.[192] Gas from Algeria will be piped across the Straits of Gibraltar, to Spain and Portugal, and eventually to France and Germany.[193] Gazprom, the huge Russian/Ukrainian/Belorusian company, plans to pipe natural gas from Siberia through Belarus and Poland to Germany.[194]

Although western European demand is expected to rise in the future, the majority of the increase in both natural gas demand and production has been in Eastern Europe and the Former Soviet Union (FSU). From 1974 to 1992, gas production in this region more than doubled, and at 29 trillion cubic feet per year, is the greatest of any region of the world.[195] Gazprom produces more natural gas than the other largest gas-producing companies combined (Table 40). Its exports to non-FSU countries amount to about 3.4 trillion cubic feet per year, more than the entire production of the next largest company.[196]

Excluding Gazprom, the world natural gas market is less concentrated than the crude oil market. The top 19 gas-producing companies after Gazprom account for about 26 percent of the market (Table 40). There are fewer state-owned companies among the largest in gas production than in oil production. Exporting dry natural gas requires highly developed infrastructure, including processing plants and transportation networks. Overseas transport depends on expensive refrigerated tankers to transport liquefied natural gas. Because natural gas is typically expensive to export, gas-producing companies generally serve smaller domestic markets, and do not provide the foreign exchange earnings that made oil companies attractive as state-owned enterprises.

Table 40. Worldwide Natural Gas Production of 20 Leading Companies, 1992
(Billion Cubic Feet)

Companies	Production	Percent of Worldwide Total
Gazprom (Russia)	21,275	28.4
Royal Dutch/Shell	2,333	3.1
Exxon Corp.	2,062	2.7
Sonatrach (Algeria)	1,869	2.5
Mobil Corp.	1,676	2.2
Amoco Corp.	1,444	1.9
Saudi Arabian Oil Co.	1,199	1.6
Chevron Corp.	1,018	1.4
Petroleos Mexicanos	915	1.2
Petroleos de Venezuela	902	1.2
National Iranian Oil Co.	877	1.2
Pertamina (Indonesia)	799	1.1
Texaco	735	1.0
AGIP (Italy)	619	0.8
Unocal Corp.	580	0.8
Oil & Natural Gas Commission (India)	580	0.8
Abu Dhabi National Oil Co.	567	0.8
China National Petroleum Co.	547	0.7
ARCO	528	0.7
Phillips Petroleum Co.	516	0.7
Top 20 Total	41,041	54.7
Worldwide Total	75,000	100.0

Note: Sum of components may not equal total due to independent rounding. Shares were calculated based on unrounded data.

Sources: **Company data**: Petroleum & Energy Intelligence Weekly, Inc., *PIW — Special Supplement Issue* (December 13, 1993). **Gazprom production data**: "Russia's Huge Gazprom Struggles to Adjust to New Realities," *Oil and Gas Journal* (October 18, 1993), p. 39. **China National Petroleum Co. production data**: "State Companies Dominate OGJ100 List of Non-U.S. Oil Producers," *Oil and Gas Journal* (September 20, 1993), p. 79. **Worldwide total**: Energy Information Administration, *International Energy Annual,* DOE/EIA-0219(92) (Washington, DC, January 1994), Table 3, p. 10.

Despite transportation costs, demand for natural gas in Japan and the Far East is growing rapidly. From 1981 to 1993, the FRS companies' production in the Other Eastern Hemisphere region grew an average of 11 percent annually, reaching a level of over one trillion cubic feet per year in 1993.[197] Enron, an FRS company, aggressively pursues utility, pipeline, and exploration projects in Asia, where environmental concerns are catching up with economic growth.[198]

[192]"Gas in Europe: Supply," *Petroleum Economist* (March 1994), p. i.
[193]"Gas in Europe: Pipeline Construction," *Petroleum Economist* (March 1994), p. iv.
[194]"Gas in Europe: Pipeline Construction," *Petroleum Economist* (March 1994), p. vii.
[195]Energy Information Administration, *International Energy Annual*, DOE/EIA-0219(92) (Washington, DC, January 1994), pp. 10, 26.
[196]"Russia's Huge Gazprom Struggles to Adjust to New Realities," *Oil and Gas Journal* (October 18, 1993), p. 43.
[197]The FRS geographic regions are defined in the Glossary (under "Foreign Operations").
[198]British Gas, *Annual Review and Summary Financial Statement 1992*, p. 4, and Enron Corp., *1993 Annual Report to Shareholders and Customers*, p. 33.

Mexico's environmental concerns have also mounted, leading to an increase in demand for U.S. natural gas. Although Mexico had itself been a net natural gas exporter until 1984, environmentally motivated conversions from fuel oil to natural gas increased demand during a time when, due to a lack of capital, Mexico could not develop its own reserves. Exports to Mexico from the United States have increased from about 2 billion cubic feet (bcf) per year in the mid 1980's to 95 bcf in 1992.[199] Although Mexico's imports from the United States fell in 1993, a provision of the North American Free Trade Agreement (NAFTA) may help long-term prospects: specifically, Mexico agreed to phase out its 10-percent natural gas import tariff over the next 10 years.[200]

Resource Development: Strategies and Results

After a sharp and prolonged upswing during the period of oil price escalations, the FRS companies succeeded in dramatically reducing the cost of finding oil and gas, particularly in the United States. Domestic finding costs rose from $12.45 (in 1993 dollars) per barrel in 1978 to $21.11 per barrel in 1981, but then fell to about $5 per barrel by 1989 (Figure 12 in Part I, Chapter 3).[201] Foreign finding costs, generally lower than U.S. costs, exhibited a similar pattern. For the FRS companies, finding costs of about $5 per barrel both in the United States and foreign areas have prevailed for the past 5 years. This stability largely reflected the reduced volatility of oil prices during the 1990's, with the exception of the short-lived oil price spike following Iraq's invasion of Kuwait.

The dramatic decrease in finding costs reflects shifts in exploration and development strategies by FRS companies that tended to increase the productivity of drilling and other exploration and development activity. Additionally, the reduction in finding costs was strongly influenced by adjustment in markets for exploration and development inputs.

Shifts in Resource Development Strategies

Cutback in U.S. Activity

High oil prices and concern about dependence on imports encouraged development of expensive domestic reserves, particularly during the 1979-1981 oil price escalation and into the early 1980's. Reduced access to foreign reserves due to nationalizations also contributed to the focus on U.S. resources. Reserves from high-cost U.S. fields compensated for lack of access to low-cost foreign reserves when oil prices were high, but damaged profitability when oil prices fell. As a result, not only did the rate of return on domestic production for FRS companies decline from almost 20 percent in 1980 to less than 1 percent in 1986, the difference between foreign and domestic profitability increased from 4 to 11 percentage points (Figure 9 in Part I, Chapter 3).

To cope with lower oil prices after the oil price collapse of 1986, the FRS companies shifted new oil and gas investment from the United States, where average discovery sizes tend to be small and production rates per well are low, and into regions with large fields and high rates of production (Figure 27). Larger discoveries tend to have lower exploration costs per barrel, reducing overall exploration and development costs per barrel of added reserves.[202] High rates of production further reduce production costs per barrel. Tax reductions offered by foreign governments after 1986 also provided incentives to invest in foreign oil and gas reserves (Figures 25 and 26).

Prospect Highgrading

Expectations of high oil prices in the early 1980's encouraged the FRS companies to pursue exploration projects in difficult and expensive areas. Heightened oil price expectations also raised the expected profitability of small-pool, high-cost prospects. The fall and subsequent crash in oil prices compelled the FRS companies to become more selective in drilling. Prospect highgrading, whereby only the most promising prospects are drilled and low-performing properties are sold, became the predominant strategy.

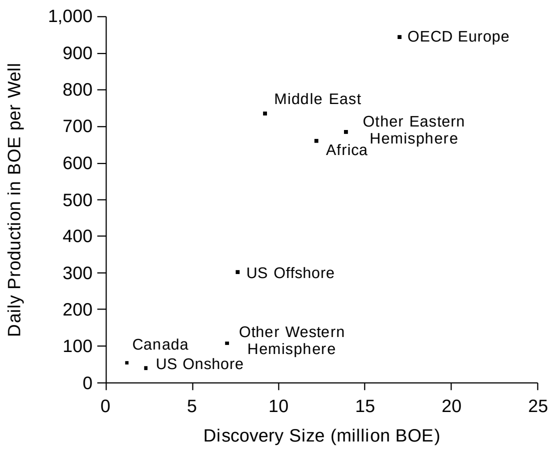
[199] "NAFTA: Possible Indications for Mexico's Oil and Gas Industry," *Energy Detente* (December 20, 1993), pp. 7-8.

[200] "NAFTA: Possible Indications for Mexico's Oil and Gas Industry," *Energy Detente* (December 20, 1993), pp. 7-8, and "Reform and Privatisation Transform Investment Scene," *Petroleum Economist* (June 1993), p. 18.

[201]Finding costs are defined as the cost of exploration and development, excluding expenditures on proved reserves, divided by reserve additions of oil and gas, excluding net reserve purchases. Natural gas is converted to oil on the basis of 0.178 barrels of oil per thousand cubic feet of natural gas. Finding costs are calculated as 3-year weighted averages, to smooth out volatility in discoveries and reduce the lag between drilling and the associated reserve additions. Calculations of finding costs, and all calculations that contain reserve additions from revisions to previous estimates, exclude BP America's and Exxon's total 1987 downward revisions of Alaska North Slope natural gas reserves of 13.461 trillion cubic feet and ARCO's 1985 downward revisions of 8.3 trillion cubic feet.

[202]Energy Information Administration, *Performance Profiles of Major Energy Producers*, DOE/EIA-0206(92) (Washington, DC, January 1994), p. 35.

Figure 27. Large Discoveries Produce More Oil and Gas Per Well
(FRS Companies, 1991-1993)



BOE = Barrels of crude oil equivalent.

Note: Gas is converted to barrels of oil equivalent on the basis of 0.178 barrels of oil per thousand cubic feet. Discovery size is calculated as a 3-year weighted average of reserve additions from extensions and discoveries divided by exploration wells drilled.

Source: Energy Information Administration, Form EIA-28.

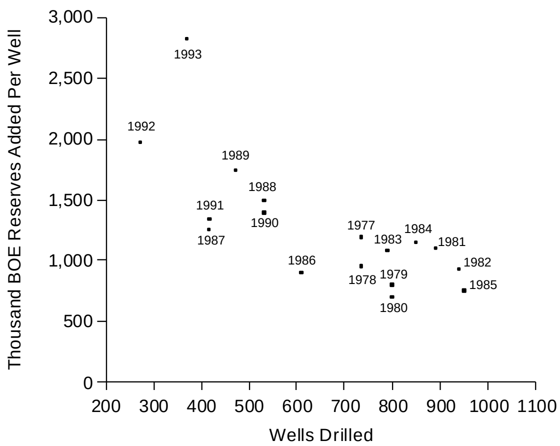
Prospect highgrading is evident in the inverse relationship between the number of wells drilled and the finding rate, especially for offshore drilling (Figure 28).

Emphasis on Development

Exploration projects carry more geological risk than development projects, because of the greater probability of drilling a dry hole. Exploration also carries more financial risk, because reserves delineated by exploration efforts may take years to bring to market. High oil prices at the end of the 1970's shortened the time to "pay back" the initial exploration and development investment, thus reducing risk and increasing the attractiveness of exploration projects. In the United States, the FRS companies' exploration expenditures, as a percent of exploration and development spending, peaked in 1981, the same year as oil prices (Figure 29).

As oil prices declined after 1981, the FRS companies cut back on exploration, and concentrated on development. Development projects (such as production and service wells) became relatively more attractive, because they pay off sooner than exploration projects. They also carry less geological risk: more than 90 percent of the

Figure 28. Offshore Finding Rates and Drilling Levels for FRS Companies, 1977-1993

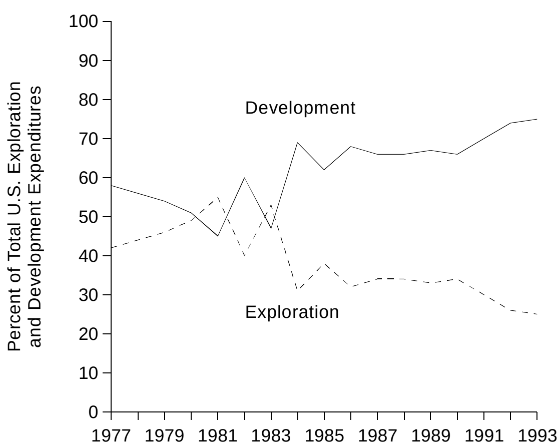


BOE = Barrels of crude oil equivalent.

Note: The above figures exclude purchases. Gas is converted to barrels of oil equivalent on the basis of 0.178 barrels of oil per thousand cubic feet.

Source: Energy Information Administration, Form EIA-28.

Figure 29. FRS Companies Spend Relatively Less on U.S. Exploration When Oil Prices Are Low



Source: Energy Information Administration, Form EIA-28.

FRS companies' development wells reach oil or gas, compared with 30 to 60 percent of exploration wells. The share of U.S. expenditures for development and proved reserves increased to 75 percent in 1993, from a low of 47 percent in 1981 (Figure 29). In foreign areas, the FRS companies' development efforts increased to 69 percent, from a low of 53 percent.

Technological Improvements

Adopting new technology for exploration and development was another strategy the FRS companies used to keep costs in line with falling oil prices. Adaptation of advanced computing equipment and software reduced a wide variety of costs and was used for applications as diverse as simulating the behavior of fluids in reservoirs and positioning floating structures over offshore wells.[203]

Advanced computers and associated improvements in software also made possible three-dimensional seismic studies. Seismic surveys measure the properties of seismic waves reflected off layers of the subsurface to determine geological structures and rock properties.[204] New three-dimensional images have higher resolution than the previously available two-dimensional images, and are particularly helpful in field development. For example, after three-dimensional data delineated new reservoirs that had been hidden by complex faulting,[205] Chevron increased production from its mature Bay Marchand field in the Gulf of Mexico from 18 thousand barrels per day to 40 thousand barrels per day. In Indonesia, Unocal's three-dimensional survey helped position development wells that increased production from 9,000 to 25,000 barrels per day.[206] Three-dimensional surveys are also becoming more common in exploration efforts. In the North Sea, where the cost of drilling a single well is very high, most exploratory seismic surveys are three-dimensional.[207]

The availability of detailed seismic surveys has fostered the use of another new technology—horizontal drilling.[208] Many reservoirs are wider than they are deep, so horizontal wells that follow the reservoir have more well bore exposed to hydrocarbons. In addition, some geological formations, such as the Austin Chalk found in Texas, trap hydrocarbons in vertical fissures that are easy to miss when drilling vertically. Drilling horizontally permits more than one fissure to be drained with a single well. The combination of using detailed three-dimensional seismic images to locate trapped oil and gas accurately, and horizontal drilling to drain these trapped areas efficiently, means fewer wells are needed to develop a field.

Like three-dimensional seismology, horizontal drilling can revitalize old fields. Use of this technique increased production from Oryx Energy's Austin Chalk wells one-hundredfold, from 160 barrels per day to 16,000 barrels per day.[209] In 1989, British Petroleum estimated that horizontal drilling would boost North Sea production by 30 percent.[210] In the North Sea, horizontal wells are doubly-effective: they increase the flow from fields otherwise too slow to be economical, and they reach reservoirs too small to justify the building of a new platform. The Danes found horizontal wells useful for a third reason—in their section of the North Sea, chalk formations trap oil vertically.[211]

Improvement in Finding Rates

The new technology and drilling strategies adopted helped increase the productivity of the FRS companies' resource development efforts, particularly following the oil price collapse in 1986. Productivity is reflected in the finding rate, measured as the 3-year weighted average of crude oil and natural gas additions to reserves per well completed. The finding rate nearly doubled for FRS operations as a whole, increasing the most in high-cost areas. In the United States, the onshore finding rate increased from 147,000 to 324,000 barrels per well, and in OECD Europe, from under 2 million to more than 5 million barrels per well (Figure 30).

[203]Diana L. Moss, "Measuring Technological Change in the Petroleum Industry: A New Approach to Assessing its Effect on Exploration and Development," National Economic Research Associates, Working Paper No. 20 (Washington DC, October 1993), pp. 12, 14.

[204]Energy Information Administration, "Three-Dimensional Seismology–A New Perspective," *Petroleum Supply Monthly*, DOE/EIA-0109(92-12) (Washington DC, December 1992), p. xiii.

[205]"Studies Underscore Value of 3-D," *AAPG Explorer* (November 1991), pp. 17,23.

[206]Unocal Corp., *1991 Annual Report*, p. 9.

[207]Energy Information Administration, "Three-Dimensional Seismology- A New Perspective," *Petroleum Supply Monthly*, DOE/EIA-0109 (92-12), (Washington DC, December 1992), p. xiii.

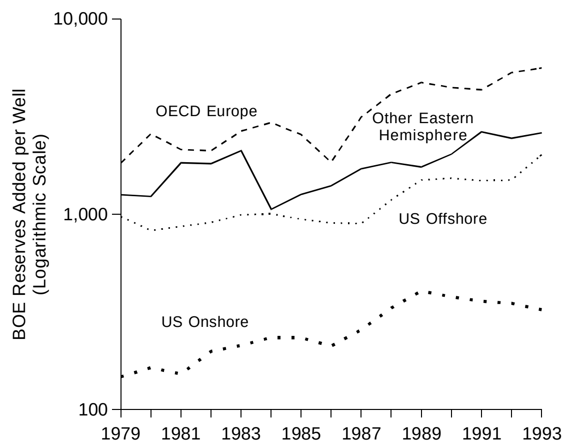
[208]"High Technology Helps the Oil Out," Reuters (November 12, 1992).

[209]"Oryx Energy Reveals Horizontal Drilling Results in Austin Chalk, Estimates Reserves at 450 Thousand Barrels per Well," PR Newswire (July 10, 1990).

[210]"OPEC Market Share Expected to Increase in Next Decade," *The Reuter Business Report* (June 27, 1989).

[211]"Denmark-Qatar," *Platt's Oilgram News* (June 29, 1992), p. 6.

Figure 30. FRS Companies' Finding Rates Increase in Major Producing Regions



BOE = Barrels of crude oil equivalent.
Note: The finding rate is calculated as a 3-year weighted average of reserves added per exploration and development well. Gas is converted to barrels of oil equivalent on the basis of 0.178 barrels of oil per thousand cubic feet.
Source: Energy Information Administration, Form EIA-28.

Adjustment in Markets for Drilling, Labor, and Acreage

The strategies adopted by the FRS companies to increase the productivity of their resource development operations were not alone responsible for the reduced cost of adding a barrel of reserves. Markets for inputs such as drilling rigs, oil and gas field labor, and undeveloped acreage also underwent dramatic changes over the two decades of oil price volatility that began with the Arab Oil Embargo.

During the boom of the early 1980's, demand for drilling rigs and crews in the United States increased faster than new ones could be made available. To keep up with demand, older, less efficient rigs were brought out of retirement, and less experienced crews were hired. The time and cost of drilling thus increased. Costs per foot (adjusted for inflation), which depend on drilling time and rig costs, increased from $85 onshore in 1977 to $138 by 1982, and offshore costs also nearly doubled.[212] The FRS companies tend to drill wells that are deeper and therefore more expensive than the industry as a whole, and drilling costs for the FRS companies increased from $138 per foot in 1977 to $274 per foot in 1982 for onshore wells, and from $552 to $789 per foot for offshore wells.

Demand for drilling was so brisk that only 2 percent of rigs in the United States stood idle in 1981.[213] However, after oil prices peaked in 1981, drilling activity slowed down, and in 1986, the oil market collapse put 74 percent of rigs out of work. Rigs were resold for a small fraction of their original value, reducing capital recovery costs; those that could not be sold were scrapped. Old rigs were scrapped first, and only the most efficient rigs remained in use. With the gain in drilling time from using only the most efficient rigs, and the lower cost of rigs in general, costs (adjusted for inflation) fell to about half the levels seen during the height of the drilling boom.

The boom and bust in oil prices produced similarly wide swings in employment and wages. The number of employees in oil and gas field services more than doubled from 1977 to 1982, from 197,000 to over 406,000, but by 1987 employment was down to 167,000 people.[214] More jobs were lost in the bust than were created in the boom. Wages in oil and gas field service companies fell steadily from 1982 through 1990.[215]

The FRS companies also benefited from reduced acreage costs as oil prices fell. During the 1980's the Federal Government changed leasing regulations for the Outer Continental Shelf, where the FRS companies spend most of their acreage acquisition dollars. Until 1982, firms could select small areas to bid on, and the most promising acreage commanded lease bonuses of up to $6,000 per acre (in 1993 dollars).[216] In 1982, the U.S. Department of the Interior switched to area-wide leasing, requiring firms to bid on larger parcels that included less desirable acreage. Firms paid under $200 per acre each year after 1986.

New technology also became less expensive. Horizontal wells drilled onshore in the United States initially cost up to three times more than conventional wells, but

[212]American Petroleum Institute, *Basic Petroleum Data Book* (Washington DC, May 1994), Tables 9a and 10a.
[213]American Petroleum Institute, *Basic Petroleum Data Book* (Washington DC, May 1994), Table 16.

[214]Oil and gas field services include Standard Industrial Classifications 1381 (Drilling Oil and Gas Wells), 1382 (Oil and Gas Field Exploration Services), and 1389 (Oil and Gas Field Services Not Elsewhere Classified). Source: Department of Commerce, Bureau of the Census, *Census of Mineral Industries: Oil and Gas Field Services*, MIC77-1-13C (Washington DC, April 1990), p. 13C-5.

[215]Wages are measured as hourly earnings in Standard Industrial Classification 138, Oil and Gas Field Services. Source: Department of Commerce, Bureau of Labor Statistics.

[216]Department of the Interior, Minerals Management Service, *Federal Offshore Statistics* (MMS 91-0068) (Washington DC, 1991), Table 3.

costs have fallen rapidly, to an average of only 17 percent more than vertical wells.[217] Costs have also fallen for horizontal wells drilled offshore.[218]

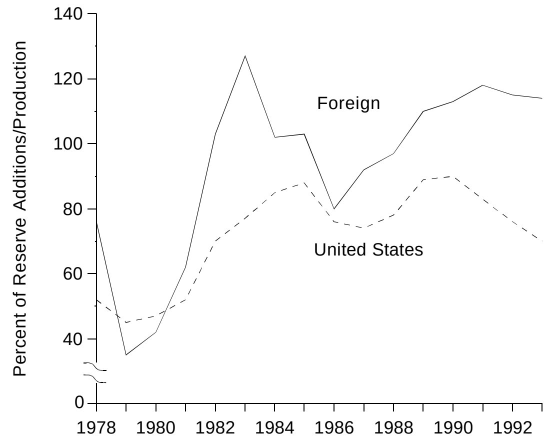
Domestic and Foreign Reserve Additions

Before the oil price collapse, expectations of indefinitely rising oil prices spurred drilling. In both the United States and overseas, the production replacement ratio grew dramatically after the price escalations of late 1978 through early 1980 (Figure 31). In the United States, the rate of increase was limited by the maturity of U.S. fields, but in regions such as the Far East and Africa, the FRS companies added new reserves more easily.

The strategies adopted by the FRS companies to survive the period of low oil prices (i.e., prospect highgrading, less exploration, and the shift to foreign locales) resulted in replacement of less oil and gas in the United States each year than was produced, and the production replacement ratio steadily declined after 1989 (Figure 31). However, in foreign areas, the FRS companies continued to replace more oil and gas than they produced. In particular, in anticipation of growing demand for natural gas in the Asia / Pacific region, the FRS companies have added about twice as much natural gas as they have produced in the Other Eastern Hemisphere each year since 1990.

Obliged by lower oil prices to cut costs and drill more selectively, the FRS companies found fewer profitable prospects in the United States. By the end of 1993, U.S. reserves of the FRS companies were 31 billion barrels, 24 percent lower than in 1981 (Table 41). Overseas, investment increased after 1986, and additions to oil and gas reserves generally outpaced production. Foreign reserves held by the FRS companies increased at an average rate of 3 percent per year after 1986, to 23 billion barrels in 1993.

Figure 31. FRS Companies Replace More Production Overseas than in the United States



Note: The ratio of reserve additions to production is calculated as a 3-year weighted average of oil and gas reserve additions (excluding reserve purchases) divided by oil and gas production. Gas is converted to barrels of oil equivalent based on 0.178 barrels of oil per thousand cubic feet.

Source: Energy Information Administration, Form EIA-28.

Table 41. Composition of Oil and Gas Reserve Changes for FRS Companies in the United States and Foreign Regions, 1981-1993

(Million BOE)

	United States		Foreign	
	1981-1986	1987-1993	1981-1986	1987-1993
Beginning Reserves	41,110	37,504	20,944	19,406
Additions	15,323	16,821	11,086	15,455
Net Purchases	1,977	-538	-2,832	1,549
Production	20,907	22,520	9,795	15,178
End-of-Period Reserves	37,504	31,267	19,406	22,957
Production Replacement Ratio (percent)	73	75	113	115

BOE = Barrels of crude oil equivalent.

Notes: Gas is converted to barrels of oil equivalent on the basis of 0.178 barrels of oil per thousand cubic feet. Sum of components may not equal totals, due to independent rounding.

Source: Energy Information Administration, Form EIA-28.

[217]Energy Information Administration, *Drilling Sideways-- A Review of Horizontal Well Technology and its Domestic Application*, DOE/EIA-TR-0565 (Washington, DC, April 1993), p. vii.

[218]"Conoco's Horizontal Drilling Boosts Flow Rates in North Sea," *Oil and Gas Journal* (March 12, 1990), p. 28.

8. Downstream Petroleum

U.S. Refining

For the U.S. refining industry, the year 1974 marked the end of a post-war boom. The stable crude oil input prices and steadily growing refined product demand that characterized the U.S. refining industry during the late 1940's, and through the 1950's and 1960's, were greatly altered beginning with the Arab Oil Embargo in late 1973. In contrast to the years preceding the Arab Oil Embargo, the experience of the last 20 years has included volatile crude oil prices, wide swings in product demand, changing crude oil input and product specifications, and greater Government intervention. Over the last two decades, the market structure, investment behavior, rate of technological advancement, and the financial performance of petroleum refining in the United States have undergone considerable change.

Although the substantial price hikes attending the Arab Oil Embargo and its aftermath did have the effect of reducing U.S. petroleum consumption, the effect was short-lived. In the United States, petroleum consumption initially fell in 1974 and, as economic recession took hold, declined again in 1975. From 1976 to 1978, however, the volume of refined products supplied to U.S. consumers increased 16 percent,[219] reflecting a resumption of economic growth and generally flat or declining petroleum product prices. For example, residential heating oil prices in 1978 (adjusted for inflation) were a mere 1 percent above the 1974 level and the real price of leaded gasoline fell 12 percent during the same period.[220] Similar patterns were evident abroad. Outside the United States, petroleum consumption in non-Communist nations rose 13 percent between 1975 and 1978.[221]

The bulk of increased U.S. petroleum consumption during this period was supplied largely from refineries other than those of the majors. Although the FRS companies supplied nearly 90 percent of U.S. refinery output in 1975, they accounted for only a third of the growth in U.S. refinery output between 1975 and 1978, while the output of non-FRS refineries nearly doubled (Table 42). Even in the context of the oil price escalations following the Iranian revolution in late 1978, and subsequent decline in U.S. refined product consumption, the output of non-FRS refiners changed little as the FRS companies bore almost the entire reduction in petroleum demand.

The disproportionate growth of non-FRS refiners was an effect of Federal petroleum price regulations, particularly the “small-refiner bias” built into these regulations. In November 1974, the crude oil entitlements program was established to eliminate disparities in crude oil acquisition costs between refiners who had favorable access to price-controlled crude oil and those who did not. The U.S. Congress further required larger refiners (those with more than 175 thousand barrels per day (mbd) of crude oil throughput) to, in effect, make payments to small refiners that more than equalized crude oil acquisition costs. The objective of this requirement was to maintain the viability of small, independent refiners.

By 1980, the entitlements program had lowered the actual cost of crude oil to non-FRS refiners relative to FRS companies by more than $3 per barrel.[222] Accordingly, many small refiners expanded while other enterprises built refineries in order to take advantage of the entitlements program. Non-FRS crude oil distillation capacity grew by over 60 percent from before the Arab Oil Embargo until 1978. So powerful was the attraction of the small-refiner bias that even with U.S. petroleum demand declining by 1.8 million barrels per day (mmbd) between 1978 and 1980, the capacity of non-FRS refiners was nearly 1 mmbd greater in 1980 than in 1978.[223] Petroleum price regulations and the small-refiner bias were terminated in January, 1981, eight months ahead of their scheduled expiration, with the result that non-FRS refinery capacity declined by 26 percent between 1980 and 1981.

[219]Energy Information Administration, *Annual Energy Outlook, 1992*, DOE/EIA-0384(92) (Washington, DC, June 1993), Table 5.11.

[220]Energy Information Administration, *Annual Energy Outlook, 1992*, DOE/EIA-0384(92) (Washington, DC, June 1993), Table 5.22.

[221]Energy Information Administration, *Annual Energy Outlook, 1992*, DOE/EIA-0384(92) (Washington, DC, June 1993), Table 11.10.

[222]Energy Information Administration, *Energy Company Development Patterns in the Postembargo Era*, (DOE/EIA-0349/1) (Washington, DC, October 1982), Table 32.

[223]Energy Information Administration, *Annual Energy Outlook, 1992*, DOE/EIA-0384(92) (Washington, DC, June 1993), Tables 5.1 and 5.9, and EIA Form-28.

Table 42. Refining Statistics for FRS Companies and U.S. Industry, Selected Years, 1975-1981
(Million Barrels/Day)

	1975	1978	1980	1981
Refined Product Supplied	16.3	18.8	17.1	16.1
Refinery Output				
FRS Companies	12.8	13.6	12.2	11.3
Non-FRS Companies	1.6	3.2	3.1	2.7
U.S. Total	14.4	16.8	15.4	14.0
End-of-Year Refinery Capacity				
FRS Companies	13.4	14.8	15.1	14.6
Non-FRS Companies	2.4	3.4	4.3	3.2
U.S. Total	15.7	18.2	19.4	17.6
Number of Refineries				
FRS Companies	125	121	120	114
Non-FRS Companies	165	195	210	210
U.S. Total	290	316	330	324

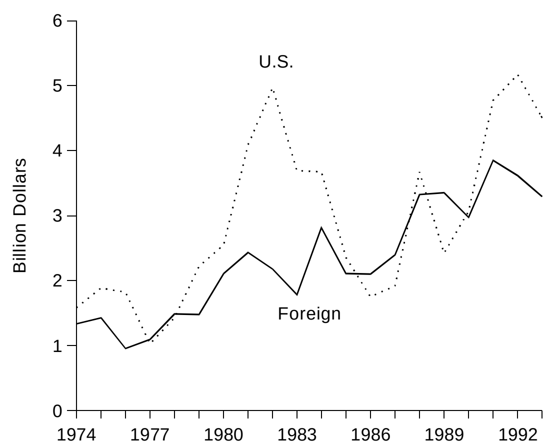
Note: Sum of components may not equal total due to independent rounding. United States includes Puerto Rico and the Virgin Islands.
Source: Energy Information Administration, *Energy Company Development Patterns in the Postembargo Era*, DOE/EIA-0349) (Washington, DC, October 1982), Table 30.

With the oil price escalations from late 1978 through early 1981, U.S. petroleum demand fell by 15 percent. Refinery output in the United States, after reaching an all-time peak of 16.8 mmbd in 1978 fell to 14.0 mmbd in 1981, with the bulk of the reduction in output traceable to the FRS refiners.[224] Nevertheless, FRS capital expenditures for U.S. refining rose sharply between 1977 and 1982 (Figure 32). Over the same period, the net value of assets per unit of FRS crude oil distillation capacity increased from $759 per daily barrel of capacity to $1,436 (Figure 33).

Clearly, the FRS companies were making investments in U.S. refining but not for expansion of basic capacity. Shifts in the composition of crude oil supplies, the composition of petroleum product demand, and environmental legislation largely underlay the surge in the FRS companies' investment during the 1977 to 1982 period—despite the general erosion in overall refined product demand and the workings of the small-refiner bias.

By 1985, the volume of products supplied by U.S. refineries was lower than in 1981.[225] However, the

Figure 32. U.S. and Foreign Refining Capital Expenditures for FRS Companies, 1974-1993

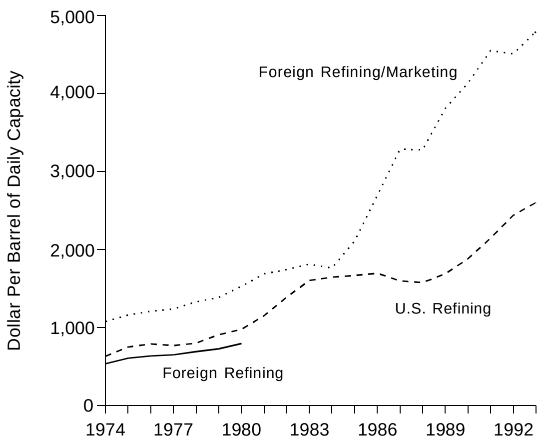


Note: Excludes effects of intra-FRS mergers in 1982 and 1984. Due to data limitations, foreign expenditures include expenditures for marketing facilities.
Source: Energy Information Administration, Form EIA-28.

[224]Energy Information Administration, *Annual Energy Outlook, 1992*, DOE/EIA-0384(92) (Washington, DC, June 1993), Table 5.11, and Form EIA-28.

[225]Energy Information Administration, *Annual Energy Outlook, 1992*, DOE/EIA-0384(92) (Washington, DC, June 1993), Table 5.11.

Figure 33. Net PP&E per Unit of Refinery Capacity for FRS Companies, 1974-1993



Note: Foreign refining data are not separately available from marketing data after 1980.
Source: Energy Information Administration, Form EIA-28.

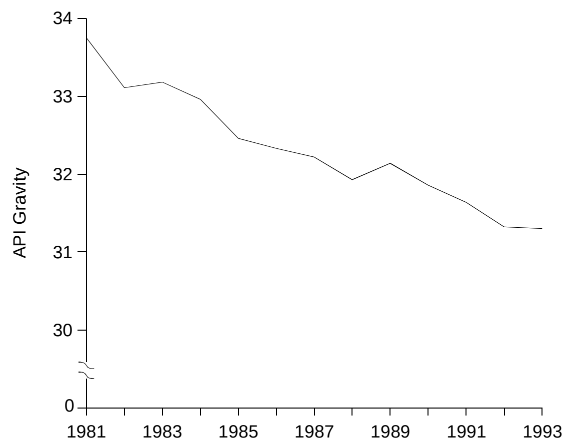
crude oil price collapse in 1986 precipitated another distinct era in the FRS companies' refining operations. In late 1985, Saudi Arabia relinquished its role as the Organization of Petroleum Exporting Countries' (OPEC) swing producer, increased its level of crude oil exports and introduced netback pricing.[226] These actions did much to restore U.S. refined product demand, margins, and downstream profitability. Between 1985 and 1989, refined products supplied by U.S. refineries grew 13 percent.[227]

In 1990, Iraq's invasion of Kuwait sent crude oil prices above $30 per barrel, the highest level since 1982.[228] High crude oil prices helped to push the U.S. economy into recession in 1990-1991, and resulted in two consecutive years of declining domestic petroleum demand.

Over the course of the last two decades, the refining industry has confronted heavier, more sulfurous crude oil supplies. Lighter (high gravity) and sweeter (low sulfur content) crude oils are easier and less costly to process than are heavy or sour crude oils. API gravity is a frequently used measure of a particular crude oil's gravity and provides one indication of the deterioration of refinery crude oil feedstocks over time. For instance, the average API gravity of crude oil inputs to U.S. refineries, which averaged 33.75 in 1981, had fallen to 31.30 in 1993 (Figure 34). At the same time, the availability of sweeter crude oil declined. In 1981, the average sulfur content of crude oil to U.S. refineries was 0.88 per barrel, while in 1993 sulfur content averaged 1.15 percent (Figure 35).

While the quality of refinery crude oil feedstocks diminished over the last two decades, refined product

Figure 34. Gravity of Crude-Oil Inputs to U.S. Refineries, 1981-1993



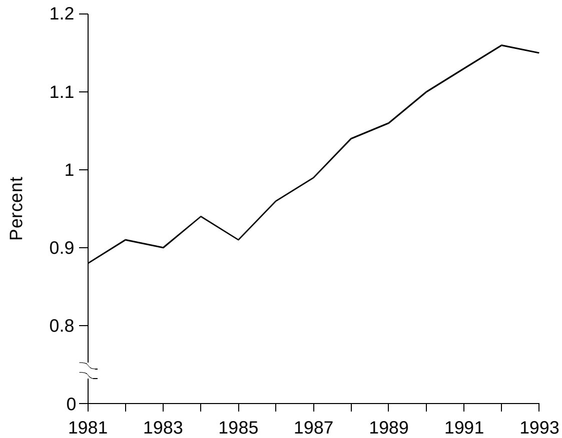
Source: Energy Information Administration, *Petroleum Supply Annual*, Volume 1, DOE/EIA-0340 (various issues) (Washington, DC), Table 16.

[226]As swing producer, the Saudis had carried the full burden of any OPEC accommodation towards changes in world oil demand by adjusting Saudi production. In part, due to frustration resulting from overproduction by other OPEC members, the Saudis abandoned their role as swing producer and adopted netback pricing. While the details of netback pricing differ for each transaction, the essential ingredient was the assurance to the buying refinery of a profit margin when the crude was refined.

[227]Energy Information Administration, *Annual Energy Outlook, 1992*, DOE/EIA-0384(92) (Washington, DC, June 1993), Table 5.11.

[228]Energy Information Administration, *Monthly Energy Review, January 1991*, DOE/EIA-0035(91/01) (Washington, DC, January 1991), Table 9.1, and *The Historical Monthly Energy Review*, 1973-1988 DOE/EIA-0035(73-88) (Washington, DC, September 1991), Table 9.1.

Figure 35. Average Sulfur Content of Crude Oil Inputs to U.S. Refineries, 1981-1993



Source: Energy Information Administration, *Petroleum Supply Annual*, Volume 1, DOE/EIA-0340 (various issues) (Washington, DC), Table 16.

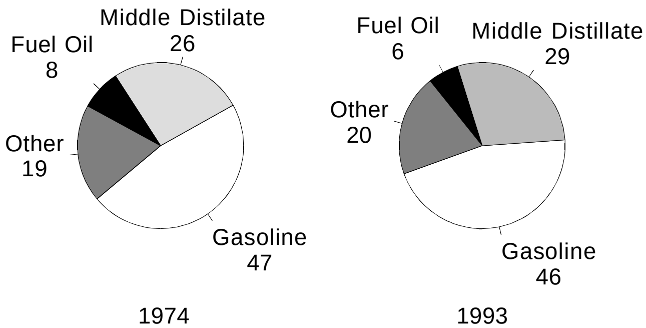
output shifted toward lighter end products due to the changing composition of product demand (Figure 36) and environmental mandates. Two indicators of refinery sophistication are the ratio of gasoline-related capacity to distillation capacity and the ratio of heavy/sour crude oil capacity to distillation capacity. In 1974, the FRS companies' ratio of gasoline-related capacity to distillation capacity was 56 percent (Table 43). By 1993, this ratio for the FRS companies had risen to 80 percent. The ability to process heavy fuels also improved over the past two decades as the FRS company ratio of heavy crude oil capacity to distillation capacity rose from 22 percent in 1974 to 47 percent in 1993.

Government Interventions and Regulatory Issues

The 1970's saw a significant increase in Federal Government intervention into the petroleum industry. The interventions deepened during the 1980's and 1990's. As noted earlier, preserving small refiners was one motivation for intervention. Others were concerns related to environmental protection, energy security, energy conservation, and consumer protection.

The reduction of lead additives in gasoline resulting from the Clean Air Act of 1970 (CAA) was one of the earliest major Federal Government environmental

Figure 36. Percent Composition of U.S. Refined Product Demand, 1974 and 1993



Note: Sums may not equal 100 percent due to independent rounding.
Source: Energy Information Administration, *Annual Petroleum Review, 1993*, DOE/EIA-0384(93) (Washington, DC, July 1994), Table 5.8.

Table 43. U.S. Refinery Configurations for FRS Companies, Selected Years, 1974-1993

Downstream Capacity as a Percent of Crude Distillation Capacity	1974	1981	1993
Catalytic Cracking	27.7	30.4	36.5
Catalytic Reforming	17.6	22.4	25.8
Hydro Cracking	5.6	5.7	9.6
Alkylation	4.8	5.3	7.7
Total Gasoline (Sum of Above)	55.7	63.7	79.7
Total Heavy Fuels	21.9	29.7	47.3

Source: *Oil and Gas Journal*, December 30, 1974, and December 20, 1993.

initiatives to face U.S. refiners during the 1970's. The CAA presented refiners with the challenge of maintaining octane levels, while reducing lead content of motor gasoline. The CAA also mandated the gradual reduction of sulfur and other pollutants in gasoline. Subsequent environmental initiatives required refiners to reduce levels of volatile organic compounds in motor gasolines (when Reid Vapor Pressure regulations were implemented in 1989), to reduce the carbon monoxide and sulfur content of motor fuels, and to add oxygenates to winter motor gasoline.

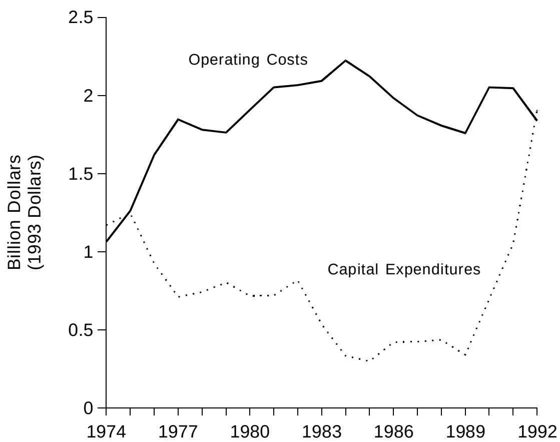
Over the past 20 years, not all Federal Government interventions in energy markets have been aimed strictly at protecting the environment, nor have they all been concerned primarily with energy. For example, the Emergency Petroleum Allocation Act of 1973 (EPAA) was enacted with the intent of assisting small refiners by providing them with cheaper sources of crude oil than that available to large refineries. In contrast, the desire to conserve domestic petroleum resources was, in part, responsible for the introduction of the Corporate Average Fuel Economy (CAFE) Standards in 1975. Domestic petroleum resource conservation was also the motivation for restrictions placed on the construction of oil- and natural gas-powered electric powerplants, the primary purpose of the Powerplant and Industrial Fuel Act (PIFUA). Government initiatives unrelated to energy have also had a substantial impact on energy markets. For example, although the primary purpose behind the deregulation of the airline industry in 1978 was not to change the nature of U.S. petroleum product demand, the resulting increase in air traffic mileage produced a substantial increase in jet fuel demand.

Environmental Expenditures

Environmental costs are an increasingly large component of FRS refining capital expenditures. In recent years, these expenditures have grown considerably and, due to the Clean Air Act Amendments of 1990, are expected to grow considerably in the years ahead.

A substantial portion of the costs to refiners associated with environmental legislation stems from reducing pollution resulting from the refining process itself. The level of FRS company stationary pollution abatement-related capital expenditures has been strongly influenced by major pieces of environmental legislation. In 1975, FRS company pollution abatement capital spending (adjusting for inflation) reached a level unmatched until 1992 (Figure 37).[229] Clearly, a large portion of the unusually high level of spending during the mid-1970's was traceable to the original 1970 Clean Air Act. Similarly, the recent sharp increase in environmental expenditures was in large measure due to the Clean Air Amendments of 1990. In 1975, the FRS companies spent an estimated $1.2 billion (in 1993 dollars), largely to reduce pollution from the refinery process itself. By 1985, these costs to FRS companies had fallen to an estimated $298 million (in 1993 dollars). Beginning in 1990, the costs associated with reducing

Figure 37. U.S. Refining/Marketing Pollution Abatement Costs for FRS Companies, 1974-1992



Source: U.S. Department of Commerce, Bureau of the Census, Current Industrial Reports, *Pollution Abatement Costs and Expenditures, 1992* (Washington, DC, March 1994), p. 12.

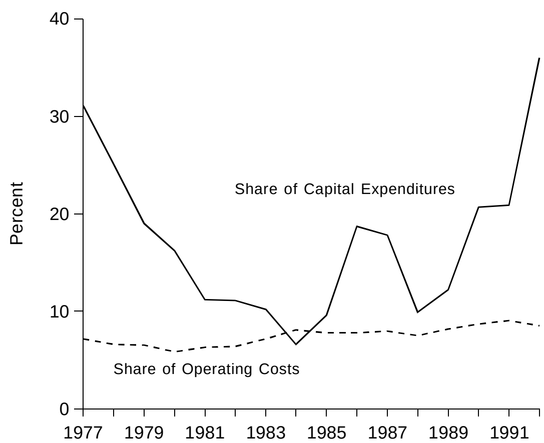
stationary pollution skyrocketed. The FRS companies expended $1 billion in 1991 and $1.9 billion in 1992. A rapidly increasing share of overall refining industry capital expenditures has been devoted to pollution abatement expenditures (Figure 38). As recently as 1989, FRS companies devoted roughly 12 percent of their domestic downstream capital budget to stationary source pollution control. By 1990, this share had risen to 21 percent and by 1992, pollution abatement expenditures comprised more than a third of FRS company capital expenditures for refining. Pollution abatement expenditures directed towards reducing air pollution accounted for two-thirds of all stationary refinery pollution capital spending in 1992, roughly equal to the share spent on refinery air pollution abatement in 1974.[230]

Operating costs (adjusted for inflation) for pollution abatement expenditures peaked in 1984, after rising sharply during the late 1970's and into the early 1980's. In the years since, operating expenses related to pollution abatement have generally been on a downward trend. However, when taken as a share of operating costs—less the costs of raw material purchases—these expenditures have grown somewhat. In 1977, the FRS companies devoted 7 cents of each

[229]U.S. Department of Commerce, Bureau of the Census, Current Industrial Reports, *Pollution Abatement Costs and Expenditures, 1992,* (Washington, DC, March 1994), p. 12.

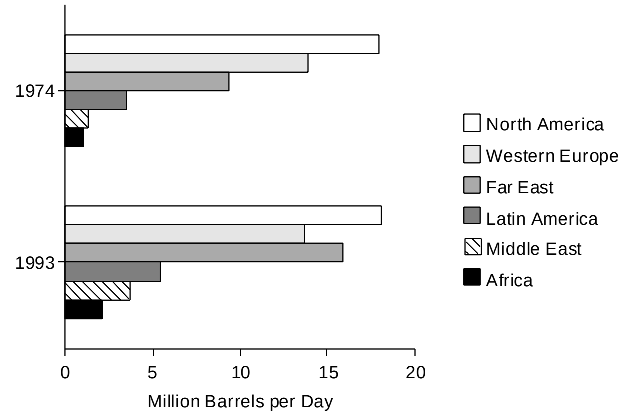
[230]U.S. Department of Commerce, Bureau of the Census, Current Industrial Reports, *Pollution Abatement Costs and Expenditures, 1992* (Washington, DC, March 1994), p. 12.

Figure 38. U.S. Refining Pollution Abatement Costs as a Share of Costs and Expenditures for the FRS Companies, 1977-1992



Source: U.S. Department of Commerce, Bureau of the Census, Current Industrial Reports, *Pollution Abatement Costs and Expenditures, 1992* (Washington, DC, March 1994), p. 12.

Figure 39. World Petroleum Consumption, by Region, 1974 and 1993



Source: British Petroleum Company, p.l.c., *BP Statistical Review of World Energy* (London, June 1994).

dollar spent on operating costs towards pollution abatement. By 1992, the FRS companies were spending nearly 9 cents of each operating cost dollar on pollution abatement.

Foreign Refining

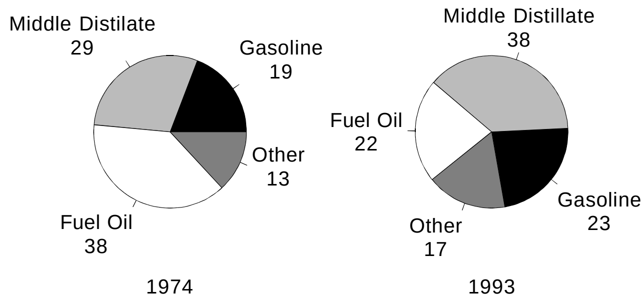
Overseas, the supply and demand for petroleum products was also strongly influenced by the Arab Oil Embargo, the Iran/Iraq War, and the 1986 crude oil price collapse. Foreign refining has also undergone a considerable restructuring and upgrading as a result of pronounced improvements in the product slate, increasing environmental strictures, and shifts in regional refined product demand. Over the last 20 years, overall foreign refined product demand growth has outstripped the growth in U.S. and European refined product consumption. Comparison of the years 1974 to 1993 shows that refined product demand was largely unchanged in North America and in Europe, but in other regions, refined product demand grew by roughly 25 percent. Of all regions, the Far East showed the largest increase in product consumption (Figure 39).

By 1993, foreign refineries had grown much more complex relative to where they were 20 years ago. This was particularly true in the Far East and Western Europe, where catalytic cracking capacity more than doubled between 1974 and 1993.[231] The product slates of foreign refineries were increasingly directed toward producing higher end products, particularly distillates (Figure 40). Although gasoline's share of total foreign product output rose only slightly (from 19 percent in 1974 to 23 percent in 1993), middle distillate's share rose to 38 percent (from 29 percent in 1974). Residual fuel oil's share of the foreign product slate fell to 22 percent (from 38 percent in 1974).

For FRS companies, foreign refining/marketing operations have generally seen a higher rate of return than investment in U.S. downstream operations. Between 1977 and 1993, the gap between returns on foreign versus domestic refining/marketing operations has averaged more than 4 percentage points for the FRS companies (Figure 41). The higher returns on foreign investments, in part, reflect the major consolidation of FRS foreign downstream operations. In 1974, FRS companies operated 75 wholly owned refineries and 25 partly owned refineries overseas.[232] By 1993, the number of foreign FRS refineries had fallen to 26 and 14, respectively.[233] In 1974, FRS companies' foreign downstream operations produced 8.7 million barrels per

[231]*Oil and Gas Journal*, December 30, 1974, p. 109, and December 20, 1993, p. 37.
[232]Energy Information Administration, EIA Form-28.
[233]Energy Information Administration, EIA Form-28.

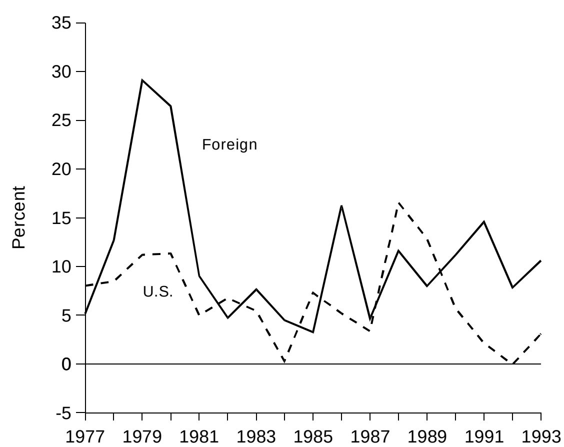
Figure 40. Percent Composition of Foreign Refined Product Consumption, 1974 and 1993



Note: Sums may not equal 100 percent due to independent rounding.

Source: British Petroleum Company, p.l.c., *BP Statistical Review of World Energy* (London, June 1994).

Figure 41. Return on Investment in U.S. and Foreign Refining/Marketing for FRS Companies, 1977-1993



Source: Energy Information Administration, Form EIA-28.

day in refined product output, 27 percent of the foreign total. By 1993, FRS companies' foreign operations were averaging 4.1 million barrels per day in product output, 9 percent of the foreign total.[234]

Interestingly, despite the reduced levels of overseas downstream refinery output, FRS company investment in foreign refining/marketing activities has risen sharply over the past 20 years (Figure 32). In the face of falling refined product output, the rise in investment has led to sharply increased capital intensity (Figure 33). In part, the foreign expenditures have been driven by the same developments affecting spending in the United States. Producing higher end products in a more environmentally benign manner accounts for some of the spending rise and is evident in the growing levels of foreign refinery complexity and increasing levels of higher end product outputs. A growing reliance on lower quality crude oil inputs has also produced a need for more capital investment in refinery conversion capacity.

U.S. Gasoline Marketing

Prior to the Arab Oil Embargo, gasoline marketing[235] was among the major petroleum companies' most rapidly growing lines of business. A sharp rise in the number of motor vehicles on the highway helped fuel this growth. During the nearly three decades between the end of World War II and the embargo, motor vehicle registrations nearly tripled. Both the construction of the interstate highway system and falling gasoline prices (adjusted for inflation) did much to spur the rapidly growing fleet of U.S. motor vehicles. Growing automobile usage, in turn, caused a boom in gasoline demand. Between 1949 and 1973, U.S. gasoline sales rose from 2.5 million barrels per day to 6.7 million barrels per day. This postwar boom was accompanied by a major change in the structure and nature of gasoline marketing.[236] To a large measure, the small “mom and pop” gasoline station gave way to larger regional and national marketing networks of the major petroleum companies. Advertising played a key role in the gasoline marketing expansion of the majors. The institution of the television set as a standard feature of the American household provided advertisers with a powerful new communications medium, allowing the majors to reach nationwide audiences.

[234]Energy Information Administration, EIA Form-28, and British Petroleum Company, p.l.c., *Statistical Review of World Energy*.

[235]See the box entitled "Gasoline Marketing in the United States" for definitions of outlet types and an overview of petroleum marketing, and the box entitled "Overseas Developments and U.S. Product Markets" for brief explanations of gasoline wholesale prices.

[236]Energy Information Administration, *Annual Energy Review 1993*, DOE/EIA-0384(93) (Washington, DC, July 1994), p. 155.

Gasoline Marketing in the United States

Generally speaking, there are two types of activities in domestic gasoline marketing: wholesaling (usually conducted by firms known as jobbers) and retailing (usually conducted by firms known as dealers). There are three types of petroleum retailers: refiner-operated retailers, jobber-operated retailers, and independent dealer-operated retailers.

Gasoline retailing is categorized by three types of ownership and operation (i.e., direct, lessee, and open dealers) and three types of suppliers (i.e., refiner, branded jobber, and private brand jobber).

Refiner-owned and operated stations are called company operations. Wholesaler-owned and operated stations are called jobber operations. In addition, refiners award franchises to firms and individuals, including jobbers, that will operate the outlet as a residual claimant with a supply contract that may be serviced by a refiner or a jobber. Some franchisees lease the property and equipment of the outlet from a refiner, jobber, or a third party. Such franchisees are usually called lessees, while the term franchisee is used more narrowly, referring to operators with only a supply contract. Lessee and franchisee operations are collectively known as dealer operations.

In addition to the types of gasoline retailers described above, retailers can be categorized by the type and scope of services they offer the public.

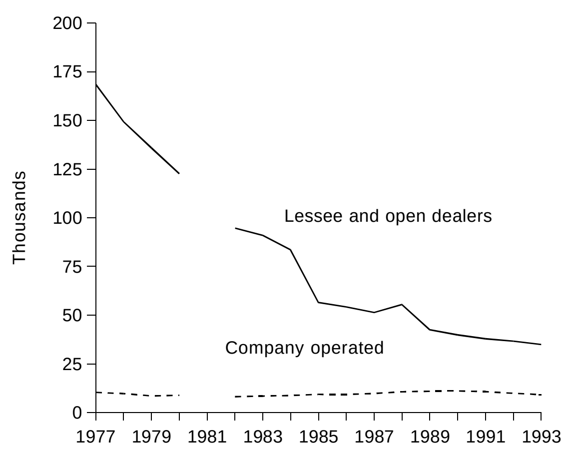
- *Traditional service stations* are outlets that offer repair services performed by an onsite mechanic and full-service gasoline in addition to, or instead of, self-serve gasoline. Traditional service stations are more likely lessee- or dealer-operated than directly operated by refiners or jobbers.
- *Self-serve stations* are outlets with comparatively high pumping capacities and some aspects of a traditional service station. However, pumping gasoline is the primary concern of a self-serve operation. Refiners and jobbers are more likely to directly operate self-service stations than traditional service stations.
- *Convenience stores* are outlets that sell gasoline and an extensive offering of food and other convenience items. The distinction between convenience stores (C-stores) and self-serve stations is based on the amount of floorspace devoted to the display of convenience items for sale. If an outlet has more than 1,200 square feet devoted to the display of convenience items, then it is deemed to be a convenience store that sells gasoline rather than a self-serve station that sells food. C-stores may be particularly attractive to dealers compared to self-serve operations because of the relatively higher profit margins earned from sales of non-gasoline items compared to gasoline. Some C-store chains have even vertically integrated “backward” into refining.

The gasoline marketing sector today is very different than it was in 1973. In fact, the very look of the average retail gasoline outlet has changed dramatically. Because of the greatly reduced number of service stations in operation, the average station today is a much higher volume outlet than 20 years ago. The last 20 years have also seen the installation of self-serve gasoline pumps as well as the increasing importance of credit and debit card sales. Meanwhile, the proliferation of the convenience store—and its growing mergence with the business of marketing gasoline—was another important change in the nature of gasoline marketing.

The oil price escalations during 1974-1981 brought a wave of restructuring in gasoline marketing, which continued until the mid-1980's. Another wave of restructuring was clearly evident by 1993. Indicative of the dramatic change in gasoline marketing has been the substantial reduction in the number of branded outlets in operation. In 1977, the earliest year for which data are available, there were about 179,000 branded (company- and dealer-operated stores) FRS outlets. However, by 1993, there were only 44,000 branded outlets (Figure 42).

The runup in gasoline prices, following the oil price escalations of 1973 to 1974 and 1979 to 1980, reduced

Figure 42. Number of Retail Outlets for FRS Companies, 1977-1993

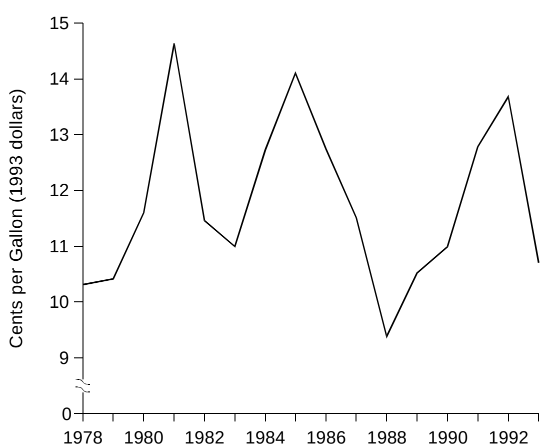


Note: 1981 data unavailable.
Source: Energy Information Administration, Form EIA-28.

gasoline consumption and provided an impetus for industry restructuring. Motorists reduced their driving, and fewer miles were driven per vehicle. At the same time, consumers were moving toward more fuel-efficient autos, and the national average for miles per gallon rose. Walking, biking, carpooling, and the use of public transportation lessened the congestion on roads and highways, raising fuel economy for those who continued to drive and allowing them to move with fewer interruptions. The reduction in gasoline demand over the 1973 to 1980 period, resulted in an excess of gasoline retail outlets, which, in turn, resulted in higher marketing costs per gallon of gasoline sold (Figure 43). Reduced gasoline demand provided the industry with a strong incentive to lower unit marketing costs through restructuring.

The effects of the Arab Oil Embargo spurred the Federal Government to take a number of actions directly affecting the U.S. gasoline market. One of the most important was mandated fuel economy standards (CAFE), which tended to reduce gasoline consumption. The Federal Government's imposition of a 55-mile-per-hour speed limit also worked to reduce gasoline consumption. These developments put upward pressure on marketing costs, providing strong incentives to reduce them through restructuring.

Figure 43. Marketing Expenses per Gallon for FRS Companies, 1978-1993

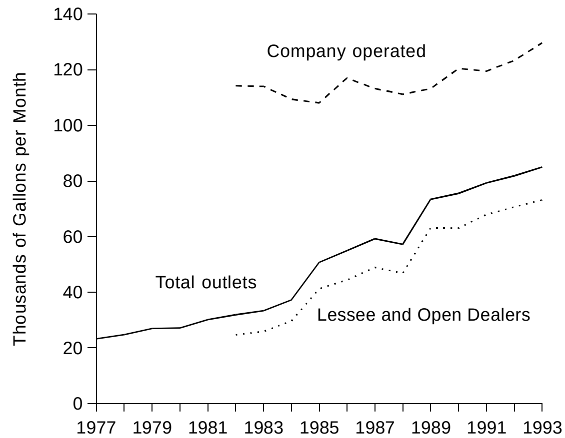


Source: Energy Information Administration, Form EIA-28.

Restructuring of gasoline marketing by FRS companies involved three major adjustments. First, the FRS companies consolidated the geographic scope of their gasoline retailing operations. The FRS companies no longer attempted to have gasoline retailing operations in all States, reducing their presence in many parts of the country.[237] This consolidation continues, as evidenced by Unocal's recent announcement that it will no longer market petroleum products in the Southeastern United States, Ashland's sale of 51 Florida retail outlets, BP America's withdrawal from the California market, and Sun's withdrawal from Iowa, Missouri, and Oklahoma.[238] Unocal had previously announced its plan to sell 140 truck stops in the Southeast and Northeast and concentrate on its California operations.[239]

The second adjustment involved the way in which the FRS companies operated their remaining gasoline outlets. The trend among the FRS refiner / marketers has been to focus on high-volume self-service and convenience store operations rather than traditional full-service stations. This adjustment, together with the elimination of lower volume outlets, greatly raised outlet productivity: average volume of the FRS companies' branded outlets quadrupled over the two decades following the Arab Oil Embargo (Figure 44). Third, as far-flung marketing networks were being reduced in size and scope, major refiners were increasing their use of wholesalers, mainly jobbers.

Figure 44. Average Outlet Volume for FRS Companies, 1977-1993



Note: Prior to 1982, only total outlet data was available.
Source: Energy Information Administration, Form EIA-28.

Between 1977 and 1986, sales to jobbers increased from 40 percent to 50 percent of FRS companies' total gasoline volume (Table 44). However, with the lower gasoline prices and higher sales volumes after 1986, the FRS refiners again emphasized retail channels for gasoline marketing, particularly company-operated outlets.

Table 44. Shares of FRS U.S. Refining/Marketing Dispositions of Refined Motor Gasoline by Channel of Distribution, 1977-1993
(Percent)

Year	Wholesale/reseller Sales	Company-operated Stores	Lessee and Open Dealer Sales	Other (Industrial, Commercial, etc.,) Sales
1977	40.5	51.1[a]	[a]	8.4
1986	50.2	13.4	29.4	7.0
1993	43.6	14.7	31.5	10.1

[a]Not separately available before 1982.
Source: Energy Information Administration, Form EIA-28.

[237]For example, a comparison of the *National Petroleum News*, Mid-June, 1992, pp. 35, 38, and 41, with *National Petroleum News*, Mid-June, 1993, pp. 35, 38, and 41 indicates that only 3 of the 19 companies listed increased the number of States in which they operate, while 10 reduced the number of states in which they operate. The story is slightly different, however, when the number of branded outlets for the two years is examined because 13 of the 19 companies reduced their number of branded stations while 6 increased the number of their branded outlets.

[238]Energy Information Administration, *Performance Profiles of Major Energy Producers 1992*, DOE/EIA-0206(92) (Washington, DC, January 1994), pp. 44-45.
[239]Energy Information Administration, *Performance Profiles of Major Energy Producers 1991*, DOE/EIA-0206(91) (Washington, DC, December 1992), p. 41.

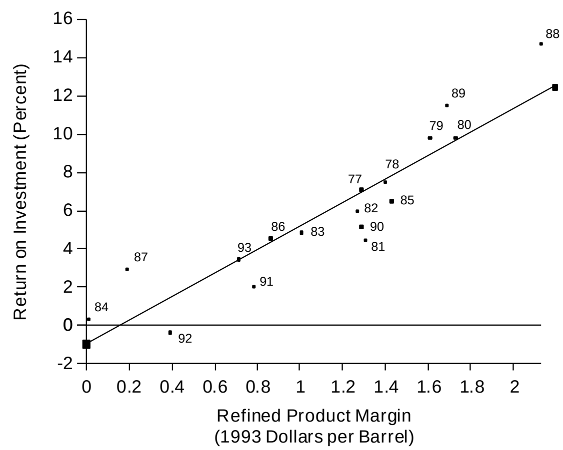
The FRS companies active in gasoline retailing sought to lower costs in every possible way, including labor costs. Tax provisions, such as accelerated depreciation and the investment tax credit (which was repealed in the Tax Reform Act, 1986), provided incentives to substitute depreciable expenses for those not depreciable (e.g., purchasing additional pumps and converting a conventional service station to a self-serve operation). In effect, capital was substituted for labor, leading to reduced employment in gasoline retailing as attendants and mechanics were replaced by fewer numbers of cashiers, and pumping capacity was expanded.

Despite substantial efforts at cost reduction, marketing costs have shown a varied pattern over the post-embargo period. The increase in marketing costs between 1979 and 1981, (Figure 43) was widespread, with 17 of 23 companies reporting increases; while the rise between 1983 and 1985 was largely accounted for by companies acquiring large blocks of downstream assets during the mega-merger period of the early 1980's. Costs subsequently declined as these assets were either integrated into ongoing operations, sold, or otherwise disposed of. However, unit marketing costs increased more than 50 percent between 1988 and 1992, with 16 of 18 FRS refiners reporting higher marketing costs. This increase in recent years has partially resulted from compliance with increasingly stringent environmental quality requirements. Whatever the sources of the increased marketing costs, their rise played a key role in the deterioration in U.S. downstream profitability in recent years, as discussed in the next section.

Profitability, Margins, and Costs

The profitability of the FRS companies' U.S. refining/marketing operations has shown great volatility over the past two decades. Foreign as well as domestic events have had a considerable impact on the FRS companies' U.S. refining operations (see the box entitled "Overseas Developments and U.S. Product Markets"). As measured by return on investment,[240] U.S. refining/marketing profitability reached 10 percent in the context of the oil price escalations following the Iranian revolution, plunged to near zero in 1984, rebounded to 15 percent in 1988, and fell below zero in 1992 (Figure 41). There is a very strong relationship between profitability and the FRS company refined product margin.[241] The FRS data demonstrate the strength of this relationship even through the vicissitudes of downstream petroleum's financial performance (Figure 45).[242]

Figure 45. U.S. Refining/Marketing Return on Investment and Refined Product Margins for FRS Companies, 1977-1993



Source: Energy Information Administration, Form EIA-28.

[240]Rate of return was measured as contribution to net income/net investment in place.
[241]The refined product margin consists of refined product revenues less raw material and product purchases and other refining and marketing expenses divided by refined product sales volume.

[242]To demonstrate the relationship between refining returns and net refining margins, a regression was run using FRS refining return on investment (ROI) ratios against the FRS refined product margin (constant dollars) for the years 1977 to 1993.

The regression results were:

ROI = -1.3 + 6.5 (FRS Margin)
R^2 = .84.
The regression produced a t-statistic of 8.42 for the independent variable, indicating that the probability of the above association between ROI and margins occurring by chance is nearly nil.

Overseas Developments and U.S. Product Markets

During the late 1970's and early 1980's, the majors' domestic refining operations were also adversely affected by events overseas. The top four FRS companies ranked according to assets (Exxon, Texaco, Chevron, and Mobil) were Aramco partners. After the price escalation of 1979, Aramco purchases of crude were especially favorable for buyers as contract price adjustments tended to lag spot price levels during a period when spot prices were rising sharply. The FRS database shows that the Aramco partners did enjoy approximately a $1-per-barrel price advantage on the costs of their U.S. crude oil inputs during the years 1979-1981 when compared to the non-Aramco FRS companies. However, the Aramco advantage did not translate into higher Aramco profitability relative to the non-Aramco FRS companies. The return on investment for the domestic refining/marketing operations of the non-Aramco FRS companies was nearly 4 percentage points higher than for the Aramco partners. The FRS data indicate that although the Aramco partners benefited from lower raw material input costs, all other operating expenses for the Aramco partners tended to be substantially higher than for the non-Aramco group of companies. This was particularly true of the Aramco group's higher marketing expenditures per unit of sales. Further, the Aramco group was less successful in passing on the rising costs of crude to their retail customers as demonstrated by the fact that their average sales prices for refined products tended to trail the non-Aramco group of companies.

Starting in 1981, crude oil prices began to fall. Over the years 1982 through 1985, Aramco companies had been characterized as being disadvantaged relative to their non-Aramco partners. During the era of "disadvantage," interestingly, Aramco companies still paid less for their crude oil inputs, although the Aramco purchase price advantage had narrowed to roughly 20 cents per barrel. Over this period, the Aramco partners still retained a higher cost structure—less crude oil purchase costs—and continued to realize lower returns on U.S. downstream operations than the non-Aramco FRS companies.

During the mid-1980's, events in Europe also had a substantial impact on U.S. petroleum product markets. One byproduct of the British coal strike of 1984-1985 was a surge in the demand for alternative electricity generating fuels--primarily residual fuel oil. However, increased production of residual fuel oil also meant increased production of gasoline and a European gasoline glut. The excess supply of gasoline in Europe wound its way to the United States. Between 1983 and 1985, U.S. imports of gasoline rose by more than 50 percent, resulting in a domestic glut of gasoline, a sharp decline in the domestic price differential between gasoline and other refined products, and reduced refined product margins.

The broadest definition of refined product margin is the spread between refined product sales price and the purchase price of raw material inputs and refined products, termed the gross margin. However, included in the gross margin are the costs of energy to run refineries, maintenance of marketing networks, and other refinery operating expenses. The gross margin less these costs represents the net margin—which is the major determinant of bottom line results. The value of these and other components of the refined product margin (in 1993 dollars) for the peak and trough years of U.S. refining/marketing profitability are presented in Table 45.

Improved profitability in 1979 (and 1980) largely came from refined product price increases which outpaced the sharp rises in crude oil prices[243] and added nearly a dollar a barrel to the gross margin in 1979 (Table 45). Also of importance was the FRS companies' reduction in operating expenses, but this gain in efficiency was nullified by higher marketing expenses and higher energy costs.

All factors worked to reduce refining profitability in the early 1980's, resulting in a near-zero return on investment in 1984 (Figure 41). Marketing and energy expenses together increased by more than a dollar a barrel, and the FRS companies' refined product sales volumes fell by 2.8 million barrels per day, a 19-percent decline, from the 1979 levels (Table 45).

The rate of return on the FRS companies' U.S. refining/marketing operations reached a low point in 1984, but then improved to an all-time high in 1988. Perhaps the most remarkable feature of the surge in refining/marketing profitability between 1984 and 1988 was that the spread between refined product prices and raw material purchases played almost no role in this improvement in financial performance. Instead, greater profitability during this period stemmed from cost reductions and increased demand.

While FRS company refined product sales volume fell 19 percent between 1979 and 1984, between 1984 and 1988, it rose 17 percent.[244] Marketing costs were reduced as the FRS companies further consolidated their marketing operations along regional lines of competitive advantage and marketing operations that were gained in earlier mega-mergers were integrated into the surviving corporations. Energy costs were halved between 1984 and 1988, falling by $1.37 per barrel (in 1993 dollars), in large part reflecting the 55-percent fall in (real) crude oil prices over the 1984-1988 period. Lower crude oil prices, which in turn led to lower product prices, were also the main sources of the 17-percent gain in FRS petroleum product sales. Refinery operating expenses changed little.

Table 45. FRS U.S. Refined Product Margins and Costs per Barrel Sold, Selected Years, 1977-1993
(1993 Dollars per Barrel)

	1977	1979	1984	1988	1992	1993
Gross Margin[a]	7.63	8.00	8.07	8.16	7.05	6.75
less						
Marketing Costs	1.92	1.91	2.53	1.87	2.77	2.18
Energy Costs	1.74	1.99	2.68	1.27	1.15	1.17
Other Operating Expense	2.68	2.50	2.85	2.89	2.74	2.71
equals						
FRS Refined Product Margin[b]	1.29	1.61	0.01	2.13	0.39	0.71
Refined Product Sales Volume (mbd)	14,622	14,868	12,088	14,115	13,090	13,178

[a]Refined product revenues less raw material and product purchases divided by refined product sales volume.
[b]Calculated from unrounded data.
Source: Energy Information Administration, Form EIA-28.

[243]This is corroborated by the "Composite Refiners Margin," which rose from 11.5 cents per gallon in 1978 to 19.4 cents per gallon in 1979. Energy Information Administration, *Annual Energy Outlook, 1992*, DOE/EIA-0384(92) (Washington, DC, June 1993), Table 5.21.

[244]Energy Information Administration, Form EIA-28.

The steep decline in refining/marketing profitability since the late 1980's (and persisting through 1992) can be traced to weak product demand and an upswing in marketing costs. The recession of 1990-1991 had an adverse effect on petroleum product demand. For the FRS companies, refined product sales volumes were off 7 percent between 1988 and 1992 (Table 45). Softened demand also put a squeeze on gross refining margins, which were down by over $1 a barrel over the same time period. Marketing cost increases were widespread among FRS companies: 16 of 18 refiners reported increases in unit marketing costs. The reasons for these increases are not altogether clear, but increased advertising outlays[245] and the costs of complying with leaking underground storage tank requirements were contributing factors. Slightly lower energy costs and refinery operating expenses were minor offsets.

The volatility of U.S. refining/marketing profitability over the past two decades is thus seen to be due to a combination of wide swings in crude oil input costs and in marketing costs which, despite the massive restructuring of marketing networks by FRS companies, have shown a varying pattern over time with no tendency toward long-term decline. Even so, efforts to lower refinery energy expense and other expenses of operating refineries have clearly been successful.

Liquids Pipelines

The FRS companies, as a group, account for the bulk of investment in U.S. liquids pipelines (oil and petroleum products). The FRS companies have accounted for over 70 percent of U.S. interstate liquids pipelines' ownership over the past two decades, as measured by share of barrel miles[246] (Table 46). The FRS companies accounted for 71 percent of the U.S. total in 1991 (the last year of available data). Liquids pipelines have traditionally dominated the FRS companies' rate-regulated pipeline activities, with 19 companies reporting assets in liquids pipelines in 1993 but only a few of them significantly involved in natural gas pipelines. The investment base in this segment, as measured by the rate of return, has been the most profitable of the transportation segments for FRS companies (Figure 46).

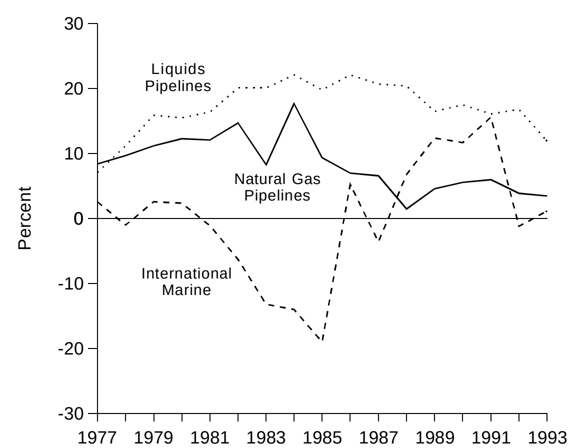
Table 46. FRS Company Shares of U.S. Interstate Oil Pipeline Barrel Miles, Selected Years, 1975-1991
(Percent)

Companies	1975	1980	1991
BP America	4.3	9.8	12.6
Amoco	10.0	7.9	6.5
Exxon	7.0	8.2	6.4
Texaco	7.6	7.4	6.2
Unocal	3.3	2.8	5.9
ARCO	4.4	6.6	5.3
Cities Service	4.2	3.8	([a])
Mobil	6.5	5.9	5.0
Shell	6.3	4.7	4.8
Chevron	9.8	8.5	3.9
Phillips	3.8	3.4	3.4
USX	3.1	2.5	3.0
Ashland	2.3	2.7	2.9
DuPont	3.2	2.6	2.8
Sun	2.9	2.3	2.2
FRS Share of U.S. Total	78.6	79.1	70.7

[a]Cities Service was acquired by Occidental Petroleum, another FRS company, in 1982.

Source: American Petroleum Institute, *Market Shares and Individual Company Data for U.S. Energy Markets: 1950-1991*, Washington, DC, October 1992, pp. 92, 97, 98.

Figure 46. Return on Investment in Transport for FRS Companies, 1977-1993



Note: Rate of return measured as contribution to net income/net investment in place.

Source: Energy Information Administration, Form EIA-28.

[245] Energy Information Administration, *Performance Profiles of Major Energy Producers, 1992,* DOE/EIA-0206(92) (Washington, DC, January 1994), p. 35.

[246] American Petroleum Institute, *Market Shares and Individual Company Data for U.S. Energy Markets: 1950-1991*, Discussion Paper #014R, Washington, DC, October 1992, pp. 92, 97, 98.

Developments in the Trans Alaskan Pipeline (TAPS) are central to the financial performance of FRS companies' liquids pipelines. In 1978, the first full year of TAPS operations, the three FRS companies accounting for 92 percent of TAPS ownership (ARCO, BP America, and Exxon)[247] accounted for nearly two-thirds of the FRS companies' revenue from liquids pipelines in that year. In 1993, these three owners accounted for a majority of the FRS companies' liquids pipelines revenue.

The TAPS was completed in 1977 and transports crude oil and natural gas liquids from the Alaskan North Slope (ANS) to the port of Valdez, Alaska. The Prudhoe Bay field was brought into production in 1977. Other producing areas in the ANS are Kuparuk River, Milne Point, Endicott, Point McIntyre, and Lisburne fields.[248] Oil production from the ANS accounts for 97 percent of Alaska's total crude oil production.[249] In 1987, Prudhoe Bay became the most productive oil field in U.S. history when it produced its 5 billionth barrel of oil.[250] However, after peaking at 2.0 million barrels per day in 1988, crude oil production at Prudhoe Bay began to decline. Prudhoe Bay is a significant source of U.S. crude oil production as it accounts for nearly 1 of every 7 billion barrels of oil produced per day.[251] Hence, the 5-percent decline in total U.S. crude oil production in 1993[252] can be attributed to the reduction in output at Prudhoe Bay.

Prudhoe Bay plays a pivotal role in sustaining the economic viability of TAPS. Additionally, TAPS owners are confronted with the problem that since 1989 both production and revenues from TAPS have declined while operating costs have risen. Unless there are new developments, TAPS throughput is projected to decrease to less than 300,000 barrels per day in the year 2009, which is the point where it is estimated to no longer be economical to ship through TAPS.[253]

The role of TAPS is very significant to Alaska. The discovery, development, and production of enormous reserves of oil in arctic Alaska in 1977, changed the economy of the State forever. Alaska's revenue base is 85-percent derived from oil royalties and taxes on oil. Between 1975 and 1982, Alaska's revenues rose from $696 million to $5.9 billion.[254] In 1992, Alaska's revenue from oil and gas production was $6.3 billion. However, with the gradual decline in Prudhoe Bay oil production, Alaska's revenue base is expected to fall in the future. Alaskan lawmakers are contemplating issues of re-imposing the state income tax that was abolished in 1980 to maintain Alaska's revenue base.[255]

The FRS companies have implemented measures to sustain Prudhoe Bay against declining production and simultaneously reduce operating costs. In 1990, after 13 years of operation, the owners of TAPS made substantial repairs on the pipeline.[256] Also, the first phase of a gas handling system and reservoir stimulation program (GHX-1) was installed, which maintained production levels in 1990 and 1991. However, in spite of the GHX-1 installation, net production declined by 8,000 barrels a day in 1992, close to the underlying natural decline rate. In 1993 and 1994, a second phase of gas handling expansion, GHX-2, will be installed at a cost of $1.3 billion, and will increase the amount of gas that can be injected into the reservoir. Field production is expected to increase by 100,000 barrels per day by 1995 as a result of the GHX-2 program.[257]

[247]The following FRS companies together own 100 percent of the Trans Alaska Pipeline: Amerada Hess Corporation, Atlantic Richfield Corporation, BP Corporation, Exxon Corporation, Mobil Corporation, Phillips Petroleum Company, and Unocal Corporation. Source:*Energy Alert*, April 3, 1992.

[248]*Oil and Gas Journal*, “Alaska Seeks Way To Boost Industry Activity in State,” August 3, 1992, p. 45.

[249]Energy Information Administration, *Petroleum Supply Annual 1992, Volume 1*, DOE/EIA-0340(92)/1 (Washington, DC, May 1993), Table 14.

[250]Associated Press “Prudhoe Bay Oil Field in Alaska Becomes Most Productive in U.S. History,” March 23, 1987.

[251]Atlantic Richfield Corporation, *1992 Annual Report*, p. 7, and Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(93/09) (Washington, DC, September 1993), p. 48.

[252]Energy Information Administration, *Monthly Energy Review September 1994*, DOE/EIA-0035(94/09) (Washington, DC, September 1994), p. 60.

[253]U.S. Department of Energy, in cooperation with the State of Alaska, *Alaska Oil and Gas, Energy Wealth or Vanishing Opportunity?* DOE/ID/01570, (Washington, DC, January 1991), pp. 1-3 and 1-4.

[254]U.S. Department of Commerce, Bureau of the Census, *State Government Finances: 1975, 1982, and 1992*, Series GF75-No. 3, Series GF82-No.3, and GF/92-No. 3, (Washington, DC).

[255]*Chicago Tribune*, January 6, 1994, p. 13, and Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(93/09) (Washington, DC, September 1993), p. 48.
[256]Atlantic Richfield Corporation, *1990 Annual Report*, p. 16.
[257]British Petroleum Company, *1992 Annual Report on Form 20-F*, p. 14; Exxon Corporation, *1992 Securities and Exchange Commission 10-K*, p.8; Atlantic Richfield Corporation, *1992 Securities and Exchange Commission Form 10-K*, pp. 3-4.

9. Coal, Nuclear, and Alternative Energy

The U.S. Coal Industry

In the first few years following the Arab Oil Embargo, coal production became an attractive outlet for investment by the FRS companies, offering promises of growth, prices that had outpaced oil prices, and a growing market for exports. At rates of production prevailing in the 1970's, U.S. coal reserves could be conveniently measured in centuries, rather than years as was the case for U.S. oil and gas. Further, investment in the coal industry provided a channel for major petroleum companies to transfer their expertise in vertically integrated energy operations and to extend their research and development efforts to finding innovative methods of transforming coal (e.g., through coal gasification) into refined products. However, the outlook for coal in the 1970's was tempered somewhat by mine safety legislation, which reduced coal miner productivity and increased operating costs, and by the possibilities offered by nuclear power. Nevertheless, profit prospects in U.S. coal production were sufficient to attract investment and entry of new enterprises among petroleum companies, electric utilities, and diversified companies.

Growth in the 1970's

Until the economic recession of 1981-1982, U.S. demand for domestic coal grew substantially. Between 1970 and 1981, domestic coal consumption increased 40 percent, to 733 million short tons (Table 47), largely due to increasing consumption of coal by electric utilities. Between 1970 and 1981, electric utilities' annual consumption of coal increased 86 percent, to 597 million short tons,[258] reflecting the growth in electricity demand and the substitution of coal for petroleum and natural gas in electricity generation.

The Arab Oil Embargo motivated a shift to heavier use of coal by utilities. Subsequent crude oil price shocks precipitated by the Iranian revolution, which began in September 1978, provided still more incentive for increased coal use by electric utilities. By 1981, 53 percent of electricity was generated from coal, a gain of seven percentage points since 1970. The availability of substantial and secure domestic coal supplies also provided a strong incentive for using coal.

In the late 1970's, passage of the Powerplant and Industrial Fuel Use Act of 1978 and the Three Mile Island accident in 1979, further improved the prospects for coal. The Powerplant and Industrial Fuel Use Act restricted the construction of petroleum and gas-powered boilers and led to additional substitution of coal for petroleum and natural gas by electric utilities. The Three Mile Island accident substantially damaged the future attractiveness of nuclear fuel for electricity generation, thereby spurring the construction of coal-powered electricity generation plants.

Coal exports, which followed an erratic path, more than doubled between 1973 and 1981. The source of most of the growth in exports during this period was a substantial increase in European purchases, particularly by France and Italy.[259] U.S. coal exports increased during this period because the demand for petroleum substitutes increased following the Arab Oil Embargo; oil-fired boilers were converted to coal following the price spikes from the Iranian revolution; European demand for electricity generally rose; and (between 1979 and 1981) major coal strikes occurred in Australia, Great Britain, and Poland.[260]

Between 1974 and 1978, increases in coal prices outpaced crude oil price rises. The early 1970's price increases combined with growth in demand for U.S. coal, both at home and abroad, to encourage a variety of companies to enter the coal industry. The new producers included independent operators, FRS companies, and electric utilities.

Electric utilities entered to acquire a comparatively cheaper boiler fuel, while several FRS companies entered and expanded their presence in the U.S. coal market (often by acquiring existing coal companies) to diversify their energy investments. In 1974, the first

[258]Energy Information Administration, *Annual Energy Review 1992*, DOE/EIA-0384(92) (Washington, DC, June 1993), p. 199.

[259]Energy Information Administration, *Annual Energy Review 1992*, DOE/EIA-0384(92) (Washington, DC, June 1993), p. 201.

[260]Energy Information Administration, *The U.S. Coal Industry, 1970-1990: Two Decades of Change*, DOE/EIA-0559 (Washington, DC, November 1992), p. 53.

Table 47. Consumption and Production of U.S. Coal, Selected Years, 1970-1993

	1970	1974	1981	1993
Consumption (millions of short tons)				
Total	523.2	558.4	732.6	926.4
Exports	71.7	60.7	112.5	74.5
Consumption by Sector (percent of total)				
Residential and Commercial	3.1	2.0	1.0	0.7
Industrial	35.7	27.8	17.5	11.6
Electric Utilities	61.2	70.2	81.5	87.7
Total	100.0	100.0	100.0	100.0
Electric Power Utility Generation Fuel (percent of total)				
Coal	46.0	44.3	52.4	56.9
Natural Gas	24.3	17.1	15.1	9.0
Petroleum	12.0	16.1	9.0	3.5
Nuclear	1.4	6.1	11.9	21.2
Hydro and other[a]	16.3	16.3	11.7	9.7
Total	100.0	100.0	100.0	100.0
Production				
Number of Mines	6,571	5,247	4,141	2,475
Output per Mine (thousands of tons)	93.2	115	198.9	329.0
Productivity (tons per miner per day)				
Underground mining	1.7	1.4	1.3	3.0
Surface mining	4.5	4.7	3.5	6.7

[a]Other includes geothermal, wood, waste, wind, photovoltaic, and solar thermal energy (Energy Information Administration, *Annual Energy Review 1992,* DOE/EIA-0384(92), p.217).

Note: Sum of components may not equal total due to independent rounding.

Sources: Energy Information Administration, *Bituminous Coal and Lignite Distribution,* DOE/EIA-0125/4Q78 (Washington, DC, April 1979), pp. 78-79; Energy Information Administration, *Coal Distribution January-December 1981,* DOE/EIA-0125(81/4Q) (Washington, DC, April 1982), pp. 21, 26; Energy Information Administration, *Quarterly Coal Report October-December 1993,* DOE/EIA-0125(93/4Q) (Washington, DC, May 1994), pp. 75-76; Energy Information Administration, *Annual Energy Review 1993,* DOE/EIA-0384(93) (Washington, DC, July 1994), p. 215; Energy Information Administration, *Annual Energy Review 1993,* DOE/EIA-0384(93) (Washington, DC, July 1994), p. 221; U.S. Department of the Interior, Bureau of Mines, *Minerals Yearbook 1974* (Washington, DC, 1975), Table 10, p. 358.

year of FRS data, six FRS companies produced 15 percent of domestic bituminous coal and lignite. By 1981, 14 FRS companies were coal producers, with a 19-percent share of domestic production (Table 48).

Consolidation and Divestitures

The high rates of growth and investment in the U.S. coal industry of the 1970's could not persist indefinitely. Even before oil prices peaked in early 1981, there were some disturbing developments in the U.S. coal industry. Legislation that addressed miner safety and environmental considerations during the 1970's reduced mining productivity (See the box entitled “Legislative and Regulatory Actions Related to the Domestic Coal

Industry, 1969-1990" and Table 47). Throughout the 1980's, the return on investment for coal remained substantially below that of other lines of business for the FRS companies. Although the difference in returns on investment tended to narrow, this was more due to declining returns from investment in other lines of business than to a sustained improvement in coal profitability (Figure 47).

The unusual negative rate of return for FRS coal operations in 1992 was due to large charges against coal net income in advance of the exit of some FRS companies from the coal industry.[261] The difference between book value and expected market value of the assets of discontinued operations were charged against

[261]Energy Information Administration, *Performance Profiles of Major Energy Producers 1992,* DOE/EIA-0206(92) (Washington, DC, January 1994), pp. 53-55.

Legislative and Regulatory Actions Related to the Domestic Coal Industry, 1969-1990

Coal Mine Health and Safety Act of 1969

Favored surface mining by increasing the amount of labor necessary to legally operate an underground mine.

Clean Air Act (CAA) of 1970

Favored low-sulfur coal, most of which is found in central Appalachian and Western coal fields.

Federal Coal Leasing Amendments Act of 1976

Promoted the development of leased reserves associated with federally administered lands, most of which are in the western coal region.

Clean Water Act of 1977 (and amendments)

Raised the cost of mining because of requirements that mine operators control acid mine drainage.

Clean Air Act Amendments of 1977

Restricted the ability of plants to burn non-low-sulfur coal without installing flue gas desulfurization equipment (i.e., scrubbers). Essentially precluded the construction of any coke plants by imposing extremely expensive environmental requirements.

Surface Mining and Reclamation Act of 1977 (and state laws)

Increased surface mining costs, reducing the cost advantages of surface mining compared with underground mining.

Powerplant and Industrial Fuel Use Act of 1978

Prohibited the use of oil and gas for some boilers for the purpose of increasing reliance on domestically produced coal as steam fuel.

Public Utility Regulatory Policies Act of 1978

Required electrical utilities to purchase electricity from cogenerators.

EPA revises CAA New Source Performance Standards in 1979

Allowed electric utilities to install flue gas scrubbers instead of using low-sulfur coal.

Clean Air Act Amendments of 1990

Allowed utilities to burn “near compliance” coal (i.e., coal with 1.2 to 2.0 pounds of sulfur dioxide per million Btu) and purchase emissions allowances to cover the excess emissions. Near compliance coal is more widely available than compliance coal (i.e., coal with no more than 1.2 pounds of sulfur dioxide per million Btu), implying lower anticipated price increases resulting from the legislation.

Source: Energy Information Administration, *The U.S. Coal Industry, 1970-1990: Two Decades of Change*, DOE/EIA-0559(92) (Washington, DC, November 1992), pp. 7, 14, 50-51, and 104, and Energy Information Administration, *The Changing Structure of the U.S. Coal Industry: An Update*, DOE/EIA-0513(93) (Washington, DC, July 1993), p. 28.

Table 48. FRS Companies' Share of U.S. Coal Production, Selected Years, 1974-1993

Year	Number of FRS Producers	FRS Companies' Percentage Share of Domestic Production
1974	6	14.5
1981	14	18.9
1988	15	[a]30.0
1993	11	20.9

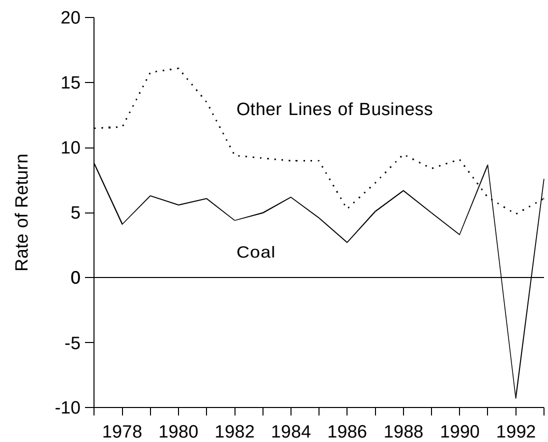
[a]Peak share of U.S. coal production by FRS companies.
Note: Includes bituminous and sub-bituminous coal and lignite.
Sources: Energy Information Administration, *Annual Energy Review 1993,* DOE/EIA-0384(93) (Washington, DC July 1994), p. 213, and Energy Information Administration, Form EIA-28.

net income and were treated as unusual items. Occidental's $600 million after-tax writedowns of its coal assets accounted for most of the drop in the rate of return for coal operations in 1992.[262] Excluding writedowns of discontinued coal operations and other unusual items, results in net income of $441 million for FRS coal operations in 1992.[263]

Contributing to the poor return from coal investments throughout the 1980's was a steady decline in the minemouth price of coal (adjusted for inflation) (Figure 48). Conservation, growth in nuclear generating capacity, and a reduction in the growth of electricity demand curtailed the growth in demand for coal relative to production capacity, lowering coal prices. Conservation partially offset growth in energy demand, leading to lower growth in the demand for coal and other fuels. In spite of the Three Mile Island accident, many nuclear power plants, which were both planned and at least partially constructed much earlier, came on line during the late 1970's and early 1980's, resulting in an 8 percent annual increase in nuclear power generation between 1981 and 1992. Meanwhile, electricity consumption increased by only 2 percent annually over the same period, half the annual growth during the 1970's.[264]

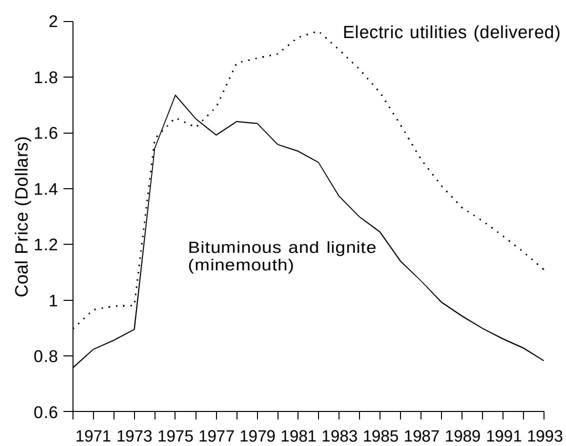
Since 1981, oil prices (adjusted for inflation) have generally fallen, which has reduced the demand for coal, an alternate fuel. Further, mining productivity (which had fallen in both underground and surface mining between 1970 and 1978) began to increase through investment in longwall mining and continuous

Figure 47. FRS Companies' Rates of Return from Coal and Other Lines of Business, 1977-1993



Source: Energy Information Administration, Form EIA-28.

Figure 48. Average Coal Prices per Million Btu by Category, 1970-1993



Source: Energy Information Administration, *Annual Energy Review 1993*, DOE/EIA-0384(93) (Washington, DC, July 1994).

[262]Occidental Petroleum Corporation, *1991 Annual Report Supplement*, pp. 39-40.
[263]Energy Information Administration, *Performance Profiles of Major Energy Producers 1992*, DOE/EIA-0206(92) (Washington, DC, January 1994), Tables 2 and 3.
[264]Energy Information Administration, *Annual Energy Review 1992*, DOE/EIA-0384(92) (Washington, DC, June 1993), p. 217.

mining techniques, leading to an increase in supply capability.[265]

The combination of a strongly competitive market structure, productivity-enhancing investments, and technological progress tended to put downward pressure on U.S. coal prices. Beginning in the 1980's, coal mine efficiency increased. Productivity nearly doubled between 1981 and 1993 (Table 47). Competitive pressures tended to transform productivity-enhancing investments into lower coal prices. Falling prices, in turn, encouraged consolidation of the coal industry. Marginal coal producers exited while FRS and other surviving coal producers shut down marginal coal production facilities. While the number of mines fell by 27 percent, output per mine rose by more than 60 percent after 1981 and coal sales continued increasing (Table 47).

The restructuring of the domestic coal industry was facilitated by the entry of foreign affiliates through the acquisition of coal-producing assets. Between 1980 and 1981, foreign affiliates' share of domestic coal production increased from 4 percent to 13 percent.[266] Subsequently, the foreign-affiliated production share increased to 26 percent by 1992.[267] Some of the foreign entry into U.S. coal production occurred in the Eastern production region because of its proximity to Atlantic coast ports.[268] Eastern coal is competitive with European coal, given sufficiently low transportation costs.

Another reason for foreign entry is the growing productivity of U.S. coal mining operations. Additionally, U.S. coal operations are expected to become even more profitable than European coal operations after the planned reforms of economic unification of the European Community are initiated because these include reduction of coal production subsidies.[269]

The FRS companies, however, did not sell significant coal assets until the 1990's. Ashland Coal Company bought BP America's Mingo Logan Coal Company in 1990. Rheinbraun AG, a German company, bought a 50-percent share of Consolidation Coal Company (renamed Consol), a subsidiary of the FRS company DuPont, in 1991. Zeigler Coal Holding Company of Illinois bought the U.S. coal assets of Shell Oil Company, with Shell Oil gaining a 25-percent equity share of Zeigler in 1992. Sun sold its coal operations in the western United States to RTZ Kennecott Corporation in 1993. Occidental began to exit from the industry by discontinuing coal operations in 1992, selling its coal subsidiary, Island Creek Coal Corporation, to Consol in 1993.[270]

Alternative and Nuclear Energy

To reduce the reliance on uncertain foreign supply sources in the context of oil price escalations, the Federal Government initiated various efforts to encourage energy conservation and develop alternative fuels. The 1977 National Energy Plan and the Energy Security Act of 1980 were enacted to make Federal dollars and subsidies available for alternative energy industry investments. In 1977, FRS companies' investment base in alternative energy was $1.9 billion.[271] By 1982, assets rose to a peak level of $5.3 billion. Thereafter, as oil prices declined and then collapsed, net assets declined virtually every year. By 1993, the FRS companies' asset base in alternative energy had diminished to $2.9 billion.

The FRS companies ventured into the alternative energy industry partly on the premise that oil prices would remain high or rise even further. However, the continued increase in oil prices did not last, making investment in many alternative energy pursuits no longer economic. The elimination of most subsidies and the oil price crash in 1986 further reduced the incentives for alternative energy development.

The 1974-1989 period saw FRS company activity in nuclear energy flourish and then diminish. Most FRS

[265]Energy Information Administration, *Coal Data: A Reference*, DOE/EIA-0064(90) (Washington, DC, November 1991), pp. 7-11. However, it was not until 1985 and 1986, respectively, that miner productivity in underground and surface mining surpassed the 1970 levels. See Energy Information Administration, *Annual Energy Review 1992*, DOE/EIA-0384(92) (Washington, DC, June 1993), p. 205.

[266]Energy Information Administration, *Profiles of Foreign Direct Investment in U.S. Energy 1983*, DOE/EIA-0466(83) (Washington, DC, February 1985), p. 18.

[267]Energy Information Administration, *Profiles of Foreign Direct Investment in U.S. Energy 1992*, DOE/EIA-0466(92) (Washington, DC, May 1994), p. 25.

[268]See Glossary for definitions of coal regions.

[269]Energy Information Administration, *Profiles of Foreign Direct Investment in U.S. Energy 1992*, DOE/EIA-0466(92) (Washington, DC, May 1994), p. 8.

[270]Energy Information Administration, *Performance Profiles of Major Energy Producers 1992*, DOE/EIA-0206(92) (Washington, DC, January 1994), pp. 54-55.

[271]The alternative energy segment of FRS companies includes nuclear energy, the production of oil from tar sands, coal gasification/liquefaction, solar energy, oil shale conversion, geothermal energy, and cogeneration.

activity in nuclear energy involved uranium production. The FRS companies' involvement in uranium production has contracted sharply since the late 1970's. In 1977, FRS uranium production accounted for over 50 percent of total U.S. production. However, in 1986 (the last year in which FRS data on uranium production were col-lected), FRS uranium production accounted for only 12 percent of total U.S. production. By 1989, all FRS companies except Chevron had exited the uranium production industry. Two years later, Chevron sold its Panna Maria mine in Texas and its Mount Taylor mine in New Mexico, ending the FRS companies' involvement in uranium mining operations.[272] Contributing to the near demise of the U.S. uranium industry was the entry of relatively cheap foreign uranium imports into the U.S. markets. For example, purchased U.S. imports of uranium declined 10 percent in 1978, while domestic production increased 24 percent, compared with the previous year. However, in 1992, purchased U.S. imports of uranium grew 43 percent, while domestic production fell 29 percent, compared with 1991.[273] Also, the decline in the completion of nuclear power plants resulted in a reduction in the demand for uranium. Uranium prices fell nearly continuously from $42.20 per pound in 1977 to $7.95 per pound in 1992.[274]

Synthetic crude oil was an important focus of the Federal Government's alternative energy policies.[275] The National Energy Plan envisioned producing 2.5 million barrels of synthetic crude oil per day by 1990.[276] The Energy Security Act established an independent Federal agency, the United States Synfuels Corporation, which set a synfuels production target of 500,000 barrels a day of synthetic liquids by 1987 and 2 million barrels a day by 1992. To show its commitment to this mission, Congress authorized the corporation to spend up to $88 billion.[277] However, since 1982, the synthetic fuels industry has virtually collapsed in response to depressed oil prices and the elimination of actual and prospective subsidies of the Synfuels Corporation.[278] In 1980 ARCO sold its 60-percent ownership interest in the Colony Oil Shale Project in Grand Valley, Colorado to Exxon.[279] Two years later, Exxon shut down this project.[280] In 1981, Chevron traded its 30-percent ownership interest in oil shale operations at Clear Creek, north of Grand Junction, Colorado for some coal properties owned by Conoco.[281] In 1990, Occidental abandoned its oil shale research program.[282] Unocal suspended oil shale operations at its Parachute Creek, Colorado mining operation in 1991 to study possible alternatives for the project's future. In January 1992, the FRS companies completely abandoned oil shale operations when Unocal shut down this eight-year project.[283]

Although solar power fared poorly in the 1980's, the future of this industry in the 1990's appears strongly dependent on subsidies from the Federal Government. In the 1980's, both Exxon and Shell entered the solar power industry and later exited. In 1990, ARCO sold off its solar power subsidiary to Siemens,[284] leaving Amoco and Mobil as the two remaining FRS companies with solar power manufacturing facilities. Due to the concern over the longevity of the solar power industry in the United States, the Department of Energy announced in 1992 that it would award $22 million over the next three years to seven solar energy producers. Of the money awarded, Solarex, Amoco's solar power subsidiary, will receive $5 million, and Mobil Solar will receive $4.1 million.[285] However, by 1993, Mobil announced the sale of its solar manufacturing subsidiary.[286]

In the 1990's, FRS companies maintain a significant involvement in geothermal energy and tar sands operations, in addition to a fairly new investment—cogeneration. Unocal is the world's largest producer of

[272]Proprietary to the United Press International 1991, June 4, 1991, Financial Section.
[273]Energy Information Administration, *Uranium Industry Annual 1993*, DOE/EIA-0478(93) (Washington, DC, September 1994), p. 34.
[274]Energy Information Administration, *Domestic Uranium Mining and Milling Industry 1992, Viability Assessment*, DOE/EIA-0477(92) (Washington, DC, December 1993), p. 12.
[275]Energy Information Administration, *U.S. Shale Oil Forecasts Technical Report (1985-1995)*, DOE/EIA-0183/20, (Washington, DC, March 1980), p. iii., and *U.S. Tar Sand Oil Forecasts Technical Report (1985-1995)*, DOE/EIA-0183/150, (Washington, DC, November 1979), p. iv.
[276]*Energy Policy*, October 1987, p. 434.
[277]*Energy Security Act of 1980*, Report of the 96th Congress No. 96-1104, p. 6., and *Oil and Gas Journal*, June 30, 1980, p. 80.
[278]*Science News*, Volume 129 (January 11, 1986), p. 22.
[279]*The New York Times*, August 4, 1980, p. 1.

[280]*The New York Times*, May 9, 1982, p. 1.
[281]*Proprietary to the United Press International 1981*, March 16, 1981, Financial Section.
[282]Occidental Petroleum, *1990 Annual Report*, p. 2.
[283]Unocal Corporation, *1991 Securities and Exchange Commission Form 10-K*, p. 11., and *The Boston Globe*, April 3, 1991, p. 17.
[284]*The Wall Street Journal*, March 27, 1991, p. A5.
[285]*Inside Energy/with Federal Lands*, April 27, 1992.
[286]Mobil, *News Release*, November 4, 1993.

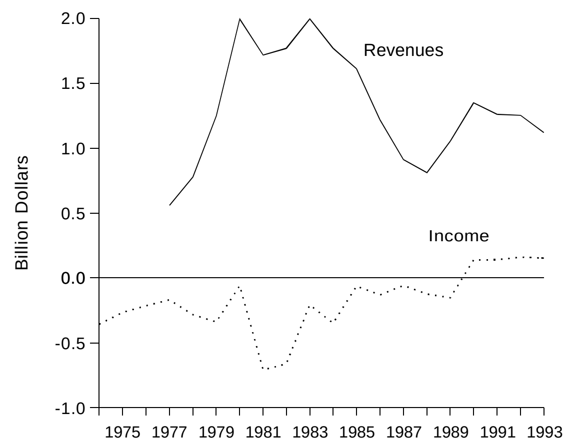
geothermal power and has been in geothermal operations for more than 20 years. In 1990, Unocal operations provided the world with one-third of all geothermal electrical generating capacity.[287] Unocal's U.S. operations are concentrated in California with overseas operations in the Philippines (and a development project in Indonesia). In 1992, Unocal announced the sale of its geothermal energy assets in the Imperial Valley of California (three geothermal power plants with a combined capacity of 80 megawatts of geothermal capacity); this sale, however, accounted for only 9 percent of Unocal's geothermal operations. Unocal also announced its intention to sell its interest in the Glass Mountain / Medicine Lake prospect in Northern California.[288] Overall, Unocal's capital expenditures for geothermal operations rose to $37 million in 1992 from $24 million in 1991, in part, due to its overseas expansion in Indonesia.[289]

Production of oil from tar sands is another area where FRS companies, mainly Exxon and Sun, maintain a significant investment. In 1992, Canadian tar sands was the largest alternative energy investment among the FRS companies. Exxon reported a record level of tar sands production of 45 thousand barrels per day in 1992, while Sun reported 59 thousand barrels per day.[290] In 1992, Suncor, Sun's Canadian subsidiary, sold 4 million shares in the company's synthetic crude oil operations, reducing the company's ownership share from 75 percent to 68 percent. Sun reported that it intends to further reduce its ownership interest in Suncor to 55 percent.[291]

Cogeneration is a relatively new alternative energy investment target in the 1990's. Two companies, Coastal and Enron, a recent addition to the FRS group in 1992, own a large share of FRS company investment in cogeneration facilities. Cogeneration, which is the simultaneous production of steam and electricity from a single fuel source, is one of the largest growth markets for natural gas. In 1992, Enron acquired a 50-percent interest in a cogeneration facility in Richmond, Virginia. In addition to its domestic cogeneration investments, Enron has 4 cogeneration plants in various stages of construction in Guatemala, the Philippines, and the United Kingdom.[292] Coastal, another major cogeneration investor, is developing a gas-fired cogeneration plant in Gorzow, Poland, which will have a capacity of 48 megawatts.[293]

Those FRS companies that continued with alternative energy operations showed considerable improvement in revenues and income in the 1990's. Revenues for alternative energy in 1992 were better than 50 percent above their low point in 1988, and operating income has been positive since 1990, after registering operating losses in every previous year since 1974 (Figure 49).

Figure 49. Revenues and Operating Income in Nuclear and Other Energy for FRS Companies, 1974-1993



Note: Revenues not reported before 1977.
Source: Energy Information Administration, Form EIA-28.

[287]Unocal Corporation, *1990 Annual Report*, p. 16.
[288]Unocal Corporation, *1992 Annual Report*, p. 12.
[289]Unocal Corporation, *1992 Securities and Exchange Commission Form 10-K*, p. 51.
[290]Sun Company, *1992 Annual Report*, pp. 18, 54, and Exxon Corporation, *1992 Supplement to Annual Report*, p. 20.
[291]Sun Company, *1992 Annual Report*, p. 17.
[292]Enron Corporation, *1992 Annual Report*, p. 60.
[293]The Coastal Corporation, *1992 Securities and Exchange Commission Form 10-K*, p. 22.

Appendix A

Structure of the Financial Reporting System - Form EIA-28

Reporting Format

The FRS data system is designed to permit review of the functional performance of major energy-producing companies in total, as well as by specific functions and geographic areas of operation. The financial reporting schedules obtain data on revenues, cost, and profits, thereby indicating financial flows and performance characteristics. In addition, Form EIA-28 is used to collect balance sheet data (e.g., accumulated property, plant, and equipment, etc.), along with data on new investment in these accounts. To complement the financial data, statistical schedules are included to trace physical activity patterns and to evaluate several physical/financial relationships.

In greater detail, the structure of the reporting package is as follows:

1. Financial Reporting

   a. The starting point is the three basic financial statements required by the Securities and Exchange Commission (SEC) Form 10-K:

      i. Consolidating Statement of Income (Schedule 5110)
      ii. Selected Consolidating Financial Data (Balance Sheets) (Schedule 5120)
      iii. Consolidated Statement of Cash Flows (Schedule 5131)

   b. Corporate-wide financial information is first disaggregated by functional lines (segments) on Schedule 5110 and 5120 as follows:

      i. Petroleum
      ii. Coal
      iii. Other Energy (includes Nuclear)
      iv. Nonenergy (includes Chemicals)

c. Nonenergy data is collected to describe corporate resource investment strategies and to allow aggregation of the FRS detailed schedules into the consolidated company amounts.

2. Operating and Statistical Information

   a. For each type of energy activity, complementary operating information is obtained through the following schedules:

      i. Petroleum (5211-5246)
      ii. Coal (5341)

   b. The schedules are designed to correspond to the financial information so that level of effort in the financial sense can be compared to physical results.

3. Complementary Schedules

   a. Examine corporate research and development funding priorities (Schedule 5111)

   b. Reveal impact of tax policy on financial results of reporting companies (Schedule 5112)

   c. Monitor raw material acquisition and refined product disposition strategies of FRS companies (5211-5212)

   d. Trace changes in reserves for petroleum (including natural gas) (5246) and coal (5341).

Petroleum Segment Overview

The petroleum line of business is further disaggregated into segments.[294] These segments are presented as though each were a separate entity, with certain

[294]The other lines of business (Coal, Other Energy, and Nonenergy) were also disaggregated into segments, but only through 1986.

limitations, entering into transactions with other segments and third parties.

The following lists each segment within the petroleum line of business along with a brief description of that segment's principal revenue-generating product or service. (Further detail on the FRS petroleum segments may be found in the section on *FRS Petroleum Supply and Trading Function* and *FRS Income Taxes*.)

1. *U.S. Production* - produces and sells U.S. crude oil, natural gas, and natural gas liquids. For FRS purposes, sales of U.S. crude oil only can be made to the U.S. refining/marketing segment. Natural gas and natural gas liquids can be purchased from or sold directly to U.S./foreign third parties, unconsolidated affiliates, and other U.S./foreign segments.

2. *U.S. Refining/Marketing* - purchases raw materials from the U.S. production segment, the foreign refining/marketing segment and third parties for refining or sale to third parties. The segment also purchases directly from the foreign production segment for those companies that do not have foreign refining/marketing and import all foreign production and purchases.

3. *U.S. Pipelines* - transports crude oil, natural gas, and natural gas liquids through Federal or State regulated pipeline operations.

4. *Foreign Production* - produces and sells foreign crude oil, natural gas, and natural gas liquids. Oil sales are made to the foreign refining/marketing segment unless the company does not have foreign refinery operations and imports all foreign oil production and purchases. Companies that meet these criteria may sell directly to the U.S. refining/marketing segment.

5. *Foreign Refining/Marketing* - purchases raw materials from foreign production segments and U.S. refining/marketing segments, refines and sells to third parties and refining/marketing segments.

6. *International Marine* - provides marine transportation of foreign and U.S. source crude oil.

Selection of FRS Reporting Companies

Twenty-seven companies were initially notified of a requirement to file Form EIA-28. This group was initially chosen from the top 50 publicly owned U.S. crude oil producers, in 1976, who had at least 1 percent of either the production or the reserves of oil, gas, coal, or uranium in the United States or 1 percent of refining capacity or petroleum product sales in the United States. General Electric (GE) was originally included in the group, because of its interest in Pathfinder Mines Corporation (Pathfinder), which was a uranium-producing company. However, GE did not file Form EIA-28 because Pathfinders's financial statements were not consolidated into the financial statements of GE as a FRS reporting company. Pathfinder was not included in the FRS database.

Mergers, acquisitions and spinoffs together with the selection criteria applied to 1991 data resulted in the list of companies shown in the tabulation on the following page.

Data Quality Assurance Program

The data quality assurance program encompasses EIA's efforts to ensure the quality and integrity of FRS data. These efforts are evidenced by the design of the form and by the procedures applied to verify the data, i.e., the machine programmed checks and desk audit.

Forms Design

The Securities and Exchange Commission (SEC) Form 10-K contains financial statements audited by independent certified public accountants. These financial statements, and the entire text of the annual report and Form 10-K, are reviewed by the SEC staff in order to provide the investing public with assurances that data filed on Form 10-K are accurate and are in accordance with generally accepted accounting principles and SEC Regulations.

In order to take advantage of the SEC review and the audit by certified public accountants, the FRS Form EIA-28 is designed in a multitier structure. This structure presents both the Form 10-K figures and statistics and the more detailed data required by the FRS system. The top FRS tier corresponds to Form 10-K; the second tier is the first tier disaggregated into the different sources of energy (e.g., petroleum, coal, etc.); and the third tier is the second tier disaggregated into the specific functional line-of-business segments within petroleum. (See the Petroleum Segment Overview section at the beginning of this appendix, which describes the FRS segments in detail.) The fourth tier provides further detail within the individual segments,

Table A1. Companies Reporting to the Financial Reporting System, 1977-1993

Company	1977-81	1982	1983-84	1985-86	1987	1988	1989-90	1991	1992-93
Amerada Hess Corporation	X	X	X	X	X	X	X	X	X
American Petrofina Inc.[a]	X	X	X	X	X	X	X		
Amoco Corporation[b]	X	X	X	X	X	X	X	X	X
Anadarko Petroleum, Inc.									X
Ashland Oil, Inc.	X	X	X	X	X	X	X	X	X
Atlantic Richfield Co. (ARCO)	X	X	X	X	X	X	X	X	X
BP America, Inc.[c]					X	X	X	X	X
Burlington Northern Inc.[d]	X	X	X	X	X				
Burlington Resources Inc.[d]						X	X	X	X
Chevron Corporation[e f]	X	X	X	X	X	X	X	X	X
Cities Service[g]	X	X							
Coastal Corporation	X	X	X	X	X	X	X	X	X
Conoco[h]	X								
E.I. du Pont de Nemours and Co.[h]		X	X	X	X	X	X	X	X
Enron Corporation									X
Exxon Corporation	X	X	X	X	X	X	X	X	X
Fina, Inc.[a]								X	X
Getty Oil[i]	X	X	X						
Gulf Oil[f]	X	X	X						
Kerr-McGee Corporation	X	X	X	X	X	X	X	X	X
Marathon[j]	X								
Mobil Corporation[k]	X	X	X	X	X	X	X	X	X
Nerco, Inc.[l]									X
Occidental Petroleum Corporation[g]	X	X	X	X	X	X	X	X	X
Oryx Energy Company[m]						X	X	X	X
Phillips Petroleum Company	X	X	X	X	X	X	X	X	X
Shell Oil Company	X	X	X	X	X	X	X	X	X
Standard Oil Co. (Ohio) (SOHIO)[c]	X	X	X	X					
Sun Company, Inc.[m]	X	X	X	X	X	X	X	X	X
Superior Oil[k]	X	X	X						
Tenneco Inc.[n]	X	X	X	X	X	X			
Texaco Inc.[i]	X	X	X	X	X	X	X	X	X
Total Petroleum (North America) Ltd.[o]							X	X	
Union Pacific Corporation	X	X	X	X	X	X	X	X	X
Unocal Corporation	X	X	X	X	X	X	X	X	X
USX Corporation[j]		X	X	X	X	X	X	X	X

[a]American Petrofina, Inc. changed its name to Fina, Inc. effective April 17, 1991.
[b]Formerly Standard Oil Company (Indiana).
[c]In 1987, BP America acquired all shares in Standard Oil Company (Ohio) that it did not already control.
[d]Burlington Resources was added to the FRS system and Burlington Northern was dropped for 1988. Data for Burlington Resources covers the full year 1988 even though that company was not created until May of that year.
[e]Formerly Standard Oil Company of California.
[f]Chevron acquired Gulf Oil in 1984 but separate data for Gulf continued to be available for the full 1984 year.
[g]Occidental acquired Cities Service in 1982. Separate financial reports were available for 1982, so each company continued to be treated separately until 1983.
[h]DuPont acquired Conoco in 1981. Separate data for Conoco were available for 1981, DuPont was included in the FRS system in 1982.
[i]Texaco acquired Getty in 1984, however, Getty was treated as a separate FRS company for that year.
[j]U.S. Steel (now USX) acquired Marathon in 1982.
[k]Mobil acquired Superior in 1984 but both companies were treated separately for that year.
[l]RTZ America acquired the common stock of Nerco, Inc. on Feb. 17, 1994. In Sept., 1993, Nerco, Inc. sold Nerco Oil & Gas, Inc., its subsidiary. Nerco's 1993 submission includes operations of Nerco Oil & Gas, Inc. through Sept. 28, 1993.
[m]Sun Company spun off Sun Exploration and Development Company (later renamed Oryx Energy Company) during 1988. Both companies were included in the FRS system for 1988 therefore some degree of duplication exists for that year.

for example, the details of petroleum raw materials purchased and sold. Therefore, the lower tiers can be aggregated to each successively higher tier until the consolidated Form 10-K figures are reached. In this way, the more detailed FRS data is tied to the aggregated figures already reported publicly to the SEC and to individual company shareholders.

Review Procedures

Detailed machine editing and desk review procedures have been established for the incoming FRS data. The result of each review is the issuance of a letter to the reporting company containing questions regarding data elements. The reporting companies respond to each question, either by explaining the item or by amending any incorrect schedule. Amended schedules are reprocessed like the original with the full range of desk and machine checks. The result of this process is an internally consistent database which has been reconciled to the SEC Form 10-K, and from which the output reports can be compiled.

The FRS review procedures include:

- Machine programmed checks for mathematical accuracy (e.g., addition and subtraction)
- Machine programmed checks to insure that corresponding schedules are correctly cross-referenced
- Desk reviews comparing reported FRS data to information from each company's Form 10-K and annual report
- Desk reviews comparing reported data (e.g., average cost per foot drilled) for an individual FRS company to the average for all FRS reporting companies and to prior year information
- Desk reviews comparing reported data to other related data series to ascertain any unusual variance
- Statistical disclosure avoidance procedures.

Machine Programmed Checks

There are 793 machine programmed checks for mathematical accuracy which ensure that each horizontal and vertical total equals the sum of the amounts within each line or column. There are also 49 machine programmed cross reference checks which ascertain that the amounts within a certain section of a schedule equal the amounts of the same description within a different schedule. The cross-reference checks are performed to ensure accuracy and consistency between different schedules. For example, the amount reported on Schedule 5210 for the U.S. production segment charges for depreciation, depletion and amortization is cross-referenced to ensure the same amount is reported on Schedule 5120. Since the number and type of errors noted during these checks is an indicator of respondent understanding of the form, existing and potential problems are identified. The FRS review staff can then focus most of their attention on specific companies and areas where data accuracy may be more of a problem.

Desk Review Procedures

This is the detailed comparison of the data submitted to the FRS system to information contained in the Form 10-K report and the annual report to shareholders as well as other publicly available information.

As stated previously, the Form 10-K report and the annual report contain financial information that has been audited by independent certified public accountants. This financial information along with textual and statistical information has also been reviewed by the SEC staff, which includes not only accountants, lawyers, and financial analysts, but also petroleum and mineral resource engineers. Hence, the data contained in these documents is considered a valuable reference in connection with the quality of FRS data.

The data contained in each respondent's submission is compared to the Form 10-K and the annual report material using a detailed review program. Each review program step is performed by trained auditors supervised by CPA's with experience in auditing medium to large public companies.

These comparisons involve checking elements in both the financial and physical information areas (e.g., production, reserves, refinery statistics, etc.). Direct comparisons are made of specific data elements of the FRS form with corresponding items on Form 10-K or in the annual report. Indirect comparisons deal with information that is mentioned in Form 10-K and the annual report but which is not quantified sufficiently for direct matching with FRS data. For example, if a respondent's annual report discussed an investment in coal, appropriate entries would be expected on the FRS schedule for coal.

The FRS desk review procedures also include two other types of comparisons. The first type of comparison is made against prior year FRS data of the reporting company as well as current average data for all FRS reporting companies. These procedures assure consistency and reasonableness across reporting years.

The second type of desk review involves comparison to other related data series. Information contained in the FRS system is compared to data available from other DOE systems and published data, such as state mining surveys.

The FRS desk review procedures described above often lead to the formulation of a set of questions which are issued to the reporting companies each year. Response to these questions generates substantial interchange between the energy company staffs and the FRS staff. From this interchange the company personnel acquire a better understanding of the unique aspects of the FRS system. The FRS staff learns more about each reporting company, the industry and how each company's accounting and reporting practices might affect the published FRS aggregate data.

Statistical Disclosure Avoidance Procedures

Procedures to prevent the disclosure of "individually identifiable energy information" have been applied to each table in this report. These tables provide summary, rather than company, level information. In most cases, the level of summarization is for all FRS companies. In certain cases, subcategories have been established that break the reports into size or other descriptive classes. Each table has been screened to ensure that no statistical disclosure will occur.

A large number of summary computer reports, generated from a single selected database, provide the basis for these tables. In conjunction with the summary reports, a parallel set of cell count reports were produced that tabulate for each report cell the number of nonzero values that were aggregated to produce the summary value. The cell count reports were then reviewed to identify whether potential disclosure problems would result from having an insufficient number of reporters or from having values that primarily represent dominant companies in a particular energy sector or activity.

If potential disclosure problems were identified, the tables were restructured to combine values or groups of individual cells in the tables so that the resulting tables were essentially disclosure free.

Financial Analysis Guide

Indicators of Financial Performance

To depict the activities of the FRS companies classified by the various energy industries, several indicators have been selected to show the amounts and geographic distribution of production, profits, cash generated, accumulated investment, and annual new investment. These indicators are compared across segments, across functions within segments, and geographically. They are the same, or similar, to indicators which have been in regular use by financial analysts and economists for many years. However, to avoid potential misunderstandings, a discussion follows of the measures used, their significance, and their limitations.

All of these measures are based upon the existing framework of financial reporting now used by industry, which relies on Generally Accepted Accounting Principles (GAAP). GAAP is the set of accounting principles by which industry reflects the financial results of operations, cash flows and financial position of individual business enterprises. The two primary problems one must contend with in using present GAAP-based data is that not all companies use the same GAAP accounting methods (e.g., full cost versus successful efforts in petroleum) and GAAP is based upon historical cost accounting principles (inflationary distortions and market values are not reflected). Both of these can cause a degree of noncomparability of reported data, across companies in the case of accounting methods, and through time in the case of historical cost accounting. In spite of these problems, the data are still regarded as meaningful, especially for trend analysis. (For a further discussion of these two problems see the Accounting Practices section of this appendix.)

The financial measure of the production and distribution of raw materials and refined products is operating revenues, or sales. Under GAAP this measure is based on arms-length transactions with third parties. However, in the FRS system the concept of sales has been extended to include sales from one segment to another. In such an approach, one segment's sales become another segment's costs, which must be eliminated in consolidation. The establishment of the FRS segments, the definition of sales (trading function), and the nontraceable and eliminations categories are discussed more fully in the Accounting Practices section of this appendix.

Profits are the measure of financial return for company activities. In the FRS system, profits are expressed in terms of net income, operating income, and contribution to net income. The first term applies only to the consolidated company profits, and represents income after the provision for income tax expense. Operating income applies both to the segments and to the consolidated company and is the net of operating revenues and operating expenses. Excluded from this figure are such items as income taxes, and interest income and expense which are not allocated to the segments because they are “corporate level” items for FRS system purposes. (This is explained more fully in the Accounting Practices section of this appendix.) Contribution to net income is meant to be the equivalent of net income for individual segments. The term net income is not used for individual segments since several corporate level items are not allocated to the segment level.

“Cash flow from operations” is presented for the consolidated company and generally follows the indirect or reconciliation method of reporting cash flow from operations allowed by Statement of Financial Accounting Standards No. 95. The indirect method adjusts net income to remove the effects of changes in receivables, payables, and inventory during the year. The indirect method adjusts for the effects of depreciation, depletion, and amortization, gains or losses on disposition of property, plant, and equipment, and other items. “Cash flow from operations” represents the cash effects of producing and delivering the company's products and services. This presentation is useful in analyzing the ability to generate future positive cash flow, adequacy of cash flow in relation to current obligations, and the relationship of net income to cash flow.

Accumulated investment is expressed by (1) total assets, (2) net property, plant, and equipment (PP&E), (3) investments and advances to unconsolidated affiliates, and (4) net investment in place.

Total assets is used in the context of the consolidated company figures, and is the total of the left-hand, or asset side, of the balance sheet.

Net PP&E is frequently used as a measure of resources committed by an enterprise to an industry or segment. In the energy industry, net PP&E accounts for the bulk of the consolidated assets.

Investments and advances to unconsolidated affiliates is of interest because many energy companies extend the range of their activities through subsidiaries of which they own less than 50 percent.

Finally, net investment in place is the total of: (1) net PP&E and (2) investments and advances to unconsolidated affiliates.

Annual new investment is the measure of newly committed resources during any given year. In the FRS system, this is expressed in terms of: (1) additions to PP&E; (2) current capitalized exploration and development (E&D) expenditures; (3) current expenditures on E&D; (4) additions to investment in unconsolidated affiliates; and (5) additions to net investment in place. The key words are: current, which means simply a current commitment of resources; and capitalized, which refers to expenditures which are classified as an addition to the PP&E account in the balance sheet rather than as an expense of the current year in the income statement. Being capitalized indicates that the expenditure benefits future years and will be amortized to expense in the years benefitted. Being expensed means the benefit is to the current year and, therefore, the item should be shown as an expense of generating that year's revenues. The capitalization concept is at the heart of the difference between the successful efforts versus full cost accounting methods (discussed in the Accounting Practices section of this appendix.). Therefore, in the FRS system, total expenditures that are both expensed and capitalized are used as a measure of activity in order to standardize the measurement of resources invested.

Foreign Reserve Interests

This category includes all three types of foreign reserves collected on the FRS form: (1) net ownership interest reserve; (2) proportionate interest in investee reserves and (3) foreign access reserves. These three foreign categories are added together for purposes of comparison with U.S. net working interest reserves because of the different nature of company interests in foreign production as compared to U.S. production.

Foreign petroleum reserve statistics are not strictly comparable to U.S. petroleum reserves because of the more complex and varying arrangements whereby U.S. companies obtain foreign crude oil. In addition, such arrangements have been known to be changed suddenly by those governments, thereby imposing a degree of uncertainty about what a reporting company can describe as their equity reserves. Foreign reserve statistics may be used as an indicator of the rate and magnitude of industry activity, but the fact that their character is distinct from U.S. reserves must be recognized.

Accounting Practices

Relation of FRS to Generally Accepted Accounting Principles

In completing the FRS form, with one exception noted below, companies use the same generally accepted accounting principles that they use in their financial statements filed with the SEC and in their annual reports to shareholders. Therefore, the amount and timing of income recognized and the capitalization policies will be the same, and net income in the FRS system will agree in total with that reported in each company's financial statements.

However, in the FRS system the presentation of the details of financial and statistical data will usually differ somewhat from that presented by most individual companies because current reporting standards do not require standardized business segments with standardized financial statement line items. In the FRS system, such standardization is necessary because of the need to aggregate a large number of companies (see Sec. 205(h), P.L. 95-91).

FRS Petroleum Supply and Trading Function

In establishing the FRS functional lines of business for reporting the activities of vertically integrated enterprises, it was necessary to define a set of trading rules. The rules define the activities which each segment can engage in. Otherwise, the segment data would be inconsistent between companies.

FRS defines the following segments within petroleum. (These segments are the main components of the 5200 series schedules.)

- U.S. Production
- U.S. Refining / Marketing
- U.S. Pipelines
- Foreign Production
- Foreign Refining / Marketing
- International Marine (Transportation)

A few of the more noteworthy rules, intended to make the trading activities of each FRS reporting company comparable to those of the other companies, are as follows:

1. Transfers (sales) between segments of the same company are recorded at arm's-length market prices. Where there are no comparable arm's-length transactions, field posted prices may be used. If third party realizations for specific raw material streams are below posted prices, the same lower prices should be used to value internal transfers of those raw materials.

2. All crude oil produced is recorded as a sale by the respective foreign or U.S. production segments to the corresponding foreign or U.S. refining/ marketing segments. The production segments are not permitted to sell crude oil directly to third parties but instead must transfer it to the company's refining / marketing segments which sells to the third parties. Companies that do not have foreign refining and import all foreign purchase may deviate from this practice and sell directly to U.S. refining / marketing.

3. Crude oil purchased from third parties is reflected as a purchase by the appropriate refining/ marketing segment: foreign refining / marketing for foreign source crude oil and U.S. refining/ marketing for U.S. source crude oil. Foreign source crude oil destined for a U.S. refining segment is then recorded as a sale by the foreign refining/ marketing segment to the U.S. refining / marketing segment.

4. Although production segments are neither sellers nor purchasers of crude oil from third parties, by

FRS system convention, natural gas may be both purchased and sold by production segments.

5. All transportation costs are incurred by the purchasing segment. Therefore, when U.S. refining/marketing segments purchase crude oil from foreign refining/marketing segments, the U.S. refining/marketing segment incurs the transportation cost.

6. With regard to sales to third parties, an export sale is a sale shipped free on board (f.o.b.) destination to a foreign location. In contrast, if a sale is made f.o.b. to a U.S. location, it is considered a U.S. sale even though the goods may ultimately be shipped overseas by a third party who purchased the goods.

7. A U.S. purchase is a purchase made from U.S. sources, even though in the case of goods purchased from third parties the materials purchased may be of foreign origin. In the FRS system the point of purchase and not the country of production is the determining factor.

Nontraceables and Eliminations

One of the objectives of the FRS system is to allow economic and financial analysis of the energy industry to be performed by function. These functions, referred to in the FRS system as segments, are presented as separate entities with their own income statements. They reflect sales and purchases not only to and from unaffiliated parties, but also to and from other segments. Because the segments are not separate entities, but are part of an integrated firm, two special classifications are defined which allow reconciliation of consolidated company figures with those of the segments.

The first is the nontraceable classification, which covers those items included in the consolidated financial statements but not allocated to the segments. The second is the eliminations classification, which prevents double counting of intersegment transactions when the segments are consolidated into total company figures.

The nontraceable classification captures assets, liabilities, revenues, and expense items, which cannot be attributed to the activities of a segment. In the FRS data, this classification reflects general overhead for the consolidated firm and financial activities which represent corporate level activities.

While the financial transactions may play a key role in the firm's ability to do business, such transactions are not allocated to activities in an individual segment. The cash, corporate investments, interest income, and interest expense are examples of this. The accompanying example illustrates a nontraceable item, interest expense of $20, and the $10 corresponding tax effect (see "FRS Segment Tax Allocation Rules" in this appendix for further explanation).

The need for the eliminations classification arises when the product of one segment is sold to a second segment, which in turn sells the product again. In the accompanying example, $80 of crude oil is sold by the U.S. production segment to the refining / marketing segment. The refining / marketing segment records $80 of purchases of crude oil and, after processing, reflects sales of $160 of refined product. If the segment figures were simply added to arrive at the consolidated total, the consolidated sales figure of $240 ($80 + $160) would be too high because of double counting. Thus, the eliminations classification subtracts $80 of sales and $80 of costs, leaving consolidated sales of $160, the appropriate measure of the firm's consolidated transactions.

The nontraceables and eliminations classifications are treated as if they are segments for purposes of aggregating segment data to the consolidated level.

Table A2. Example of Nontraceables and Eliminations

Financial Items	Consolidated	Elimination	Nontraceable	Refining/ Marketing	Production
Revenues	160	(80)	-	160	80
Less Expenses:					
General and Administrative	10	-	2	5	3
Other Operations	10	-	-	5	5
Crude	-	(80)	-	80	-
Operating Income	140	-	(2)	70	72
Less Interest Expense	20	-	20	-	-
Less Income Taxes	60	-	(11)	35	36
Net Income	60	-	(11)	35	36

Note: Numbers in parentheses are negative.
Source: Energy Information Administration, Form EIA-28.

FRS Income Taxes

FRS Segment Tax Allocation Rules. In the FRS system, the tax allocated to each segment reflects a pro-rata share of consolidated income taxes. Where the consolidated company reports income and pays a tax, but an individual segment incurs a loss, the segment with a loss reflects a tax benefit. This treatment is an FRS rule whose purpose is to reflect, at the segment level, the effect of the segment's operations on the consolidated income taxes. The tax benefit reflected at the segment level is limited to the extent it offsets taxes in other segments on a consolidated basis.

In comparing an FRS company's segment to a specialized (nonintegrated) company in the same line of business, one must consider the effect of the above described rule. The current tax effect may be different, since a specialized company cannot report tax benefits for operating losses incurred in that year. It must carry the loss forward, or backward, against profits of other years, while a segment of an otherwise profitable consolidated firm can show a tax benefit by FRS conventions since a segment's loss can offset profits in other segments on a consolidated basis.

FRS Reporting Companies, Segments, and Tax Paying Entities. FRS reporting companies and their segments differ from the entities which actually pay income taxes. The FRS system reports energy activities on a consolidated company basis, disaggregated into various energy lines of business. Accordingly, income tax expense, current and deferred, is reflected on a line-of-business basis. However, under the tax laws, taxes are not necessarily based upon FRS reporting company consolidated earnings of the FRS line-of-business segments.

The tax-paying entities of an FRS reporting company are its subsidiaries. Some are incorporated in the United States and some in foreign countries, and each may operate in the United States, foreign countries, or both. Income tax expense in the FRS system consists of both U.S. and foreign income taxes incurred by these subsidiaries. Taxes reflected by the consolidated company and each individual segment are allocated from taxes paid and deferred by the actual tax-paying entities.

Under U.S. tax law, U.S. income taxes are not required to be paid by foreign corporations on their foreign operations. Only income of foreign corporations earned in the United States or paid into the United States as dividends to a U.S. parent corporation (owner) are taxed by the United States. Foreign and U.S. earnings of U.S. corporations, including divisions and branch operations, are taxed by the United States. All income subject to U.S. tax, whether the entity is a foreign or U.S. corporation, is given the benefit of the foreign income tax credit (up to the statutory rate) to avoid double taxation. Each U.S. incorporated subsidiary of a U.S. corporation elects either to be included in a consolidated U.S. tax return or to file a separate return, depending on which election is most likely to minimize the aggregate U.S. and foreign taxes. In the FRS system corporate organization and relationships are not purely a function of line-of-business financial reporting. This fact requires that allocations be made of taxes incurred so that they can be classified according to the FRS segment format. These allocations are required when a subsidiary is involved in both U.S. and foreign operations and/or in more than one line of energy business. For example, the FRS system has separate segments for the foreign and U.S. petroleum production business, and for the foreign and U.S. refining/marketing business. Therefore, if an FRS reporting company has a foreign subsidiary involved in both petroleum production and refining/marketing of petroleum, a disaggregation of that subsidiary's activities, including income taxes, must be performed.

The disaggregation is further complicated by the existence of nontraceable items such as interest expense, interest income, minority interest and foreign currency gains and losses. The nontraceable column must be treated as a separate segment in making the tax allocation. Therefore, the nontraceable columns should generate U.S. and foreign income tax benefits.

Deferred Taxes

The Financial Accounting Standards Board (FASB) began working on a project to reexamine the generally accepted accounting procedure for income taxes in September 1982. Accounting Principles Board Opinion 11 ("APB 11"), issued in 1967, faced criticism and concerns about the inconsistencies in its amendments and interpretations. In addition, problems created by new tax depreciation methods and changes in accounting for income taxes in other countries were making APB 11 outdated. In 1988, the FASB issued Statement of Financial Accounting Standards No. 96 "Accounting for Income Taxes" ("SFAS 96") to address the increased complexity and significance of deferred taxes in the balance sheet. However, because of its complex scheduling process and conservative tax asset provisions, SFAS 96 soon became a source of controversy among businesses, CPA firms, professional organizations, and industry trade groups. In response to the criticism, the FASB deferred the required implementation date of SFAS 96 three times (SFAS 100, 103, and 108), and began developing a new standard which would not only address criticism of APB Opinion 11, but also the controversy surrounding SFAS 96. The new standard, SFAS 109, "Accounting for Income Taxes," became effective for periods beginning after December 15, 1992.

The objective of accounting for income taxes is the recognition and presentation in the financial statements of:

- Taxes currently payable or refundable
- Deferred tax assets and liabilities for the future tax consequences of events that have been recognized in the financial statements or tax returns.

Deferred taxes reflect the future tax consequences of events already recognized in either the financial statements or tax returns. SFAS 109 uses the balance sheet approach, also referred to as the liability method, to determine deferred taxes. This method, first introduced in SFAS 96, differs from APB 11, which used the income statement approach. SFAS 109 also requires a deferred tax asset to be recognized for deductible temporary differences and operating loss and tax credit carryforwards using the applicable tax rate.

The income statement approach recognizes deferred taxes on the temporary timing differences between the pretax accounting income and taxable income each year. Temporary timing differences are those differences between accounting and taxable income which will ultimately reverse. For example, intangible drilling costs for a successful well are expensed when paid for tax purposes, but capitalized and depreciated for accounting purposes. If we assume intangible drilling costs of $100,000 on one well was the only timing difference, and this cost was depreciated $20,000 per year for accounting purposes, there would be an $80,000 temporary timing difference in year one, as taxable income would be less than accounting income. This timing difference would reverse $20,000 each year as the intangible drilling cost is depreciated for accounting purposes with no deduction for tax purposes. At the end of the fifth year, the timing difference would be completely reversed.

The liability approach recognizes deferred taxes on the temporary differences between the financial and tax bases of assets and liabilities. Both the deferred tax liability and the deferred tax asset must be measured using the applicable tax rate. The applicable tax rate is the enacted tax rate to be applied to the last dollar of taxable income for the year when the liability is expected to be settled or the assets recovered. A single flat tax rate may be used for companies for which graduated rates are not a significant factor. A deferred tax asset is recognized for existing alternative minimum tax credit carryforwards for tax purposes. When computing deferred tax assets and/or liabilities, if there is a change in the tax rate or tax law, the deferred tax assets and/or liabilities should be adjusted in the period that includes the enactment date. To the extent deferred tax balances are adjusted for the effects of such changes, income tax expense or benefit from continuing operations is charged or credited. Using the example from the preceding paragraph, the financial statement basis of the intangible drilling cost in year one would be $80,000 ($100,000 less $20,000 depreciation), while there would be no basis for tax purposes as the costs were totally deducted. Deferred taxes would be provided for the $80,000 difference using enacted tax rates. Deferred taxes would be adjusted each year until the difference between the financial accounting and tax bases was fully eliminated at the end of year five.

Once deferred tax assets and liabilities relating to the future tax consequences of temporary differences and carryforwards have been measured, the deferred tax provision or benefit is based on the net change in a deferred tax balance during the year. The income tax expense or benefit for the period is derived from the total tax currently payable or refundable and the deferred tax expense or benefit.

As stated earlier, SFAS 109 became effective for fiscal years beginning after December 15, 1992. There were two transition options available when adopting SFAS 109: prospective or retroactive application. A company could elect to restate the financial statements for any number of consecutive prior years (retroactive application) or report a cumulative effect adjustment below "income from continuing operations" (prospective application).

For 1993, all twenty-five FRS companies have reported taxes in accordance with SFAS 109. For 1992, seventeen FRS reporting companies had adopted the provisions of SFAS 109, which resulted in a net $163 million benefit to their 1992 reported earnings. The remaining eight FRS reporting companies adopted SFAS 109 in the first quarter of 1993, and they have reported a $671 million benefit to 1993 reported earnings. Of the eight companies which had not adopted SFAS 109 in 1992, five reported under APB 11 and three reported in accordance with SFAS 96.

Corporate Acquisitions

Under FRS reporting rules, no acquisitions are accounted for under the pooling of interest method. This is because, under the pooling method, the financial statements do not reflect such transactions as new investment, since the historical financial statements are restated. One of the objectives of the FRS is to track new investment activities.

For FRS reporting purposes, acquisitions accounted for as pooling for annual report purposes must be reflected in the FRS filing under a modified purchase method. All purchase accounting rules are followed, except that the assets of the acquired company are not revalued, but are recorded at their book values as stated on the acquired company's books.

Full Cost and Successful Efforts Accounting Methods

FRS reporting companies are permitted to choose between two accounting methods, "full cost" and "successful efforts," to account for their exploration and production activities. Twenty-three of the twenty-five FRS companies use the successful efforts method. The main difference between the two methods is the treatment of dry exploratory well cost.

Under full cost, the cost of a dry exploratory well is capitalized and then amortized to the income statement over the production life of successful wells. Thus, the costs of both dry and successful wells are capitalized and reflected in the balance sheet as part of producing properties.

Under successful efforts, the cost of a dry exploratory well is written off to expense in the year drilling is determined to be unsuccessful. There is no capitalized cost of such dry exploratory wells carried on the balance sheet.

In comparison to the successful efforts method, the full cost method will: (1) show less volatility of earnings, since the cost of unsuccessful wells is amortized over many years; (2) show a higher balance in accumulated

Table A3. A Comparison between Full Cost and Successful Efforts Accounting Methods

Years	Full Cost	Successful Efforts
1973		
Net Income (dollars)	1,292,400	1,243,300
Net PP&E (dollars)	8,476,700	7,511,300
Net Income/PP&E (percent)	15.25	16.70
1974		
Net Income (dollars)	1,586,400	1,544,700
Net PP&E (dollars)	9,593,300	8,563,500
Net Income/PP&E (percent)	16.54	17.98

Source: Texaco, Inc., 1974 and 1977 Annual Report and Statistical Supplements.

property, plant, and equipment (PP&E), since the account contains the costs of all wells drilled, including dry exploratory wells; (3) usually show higher earnings during years of intense exploratory activity when a number of dry wells are encountered; and (4) show the same cumulative earnings over a long period of years, since eventually all costs will be amortized to the income statement. These effects are minimized if the firm is large, since the exploratory activities of a large firm are usually smaller relative to total production operations than they are in a small production firm.

Usually, the precise effect of using one method over the other cannot be determined. However, one large firm switched from full cost to successful efforts in 1975 and restated 1973 and 1974 data to the successful efforts method. Thus, we have available the impact of this conversion on their comparative net income, net PP&E, and return on net PP&E for 1973 and 1974 (see *text table).*

Since twenty-three of the FRS companies presently use successful efforts accounting, comparability problems are inconsequential.

Inventory Accounting — LIFO Versus FIFO

The Last In-First Out (LIFO) and the First In-First Out (FIFO) inventory methods are most often used in the preparation of the financial statements of industrial enterprises.

Under FIFO, the balance sheet valuation of inventory is based upon the most recent prices paid for the physical units on hand at year's end, and the income statement reflects the cost of units sold at the oldest unit cost. In periods of rapidly rising prices, the income statement reflects higher profits than would be reflected if the units sold were priced at current replacement cost or under the LIFO method.

Under LIFO, the balance sheet valuation of inventory is based on the prices paid for the first units of each major type of inventory ever purchased. For example, crude oil could be carried at $10 per barrel, which of course vastly understates the value of the inventory in terms of its replacement cost. The income statement reflects the cost of units sold at the most recent prices paid for the number of units sold. Thus, cost of goods sold reflects nearly a replacement cost amount, and profits are lower than under the FIFO method.

Since either method is permitted under the Federal tax laws, most companies use LIFO for operations subject to U.S. taxation because earnings and hence taxes are lower under this method. By 1979, most FRS reporting companies were primarily using the LIFO inventory method. Most analysts probably would agree that LIFO is the preferable method, since the income statement is more realistic than with FIFO. However, its disadvantage is that the balance sheet's inventory figure is understated, and hence the stockholders' equity amount is correspondingly understated.

In 1992 and 1993, five FRS companies reported liquidation profits or losses, compared with four in 1991. The 1993 aggregate liquidation profits increased the reporting companies' operating income by $96 million, which represented 0.4 percent of their aggregate operating income. This compares to a $7 million increase in 1992 and a $10 million increase in 1991, which represented -0.1 and 0.5 percent, respectively, of aggregate operating income for those years.

Foreign Currency Translations

In December 1981, the Financial Accounting Standards Board (FASB) issued Statement No. 52, "Foreign Currency Translations," which superseded FASB-8, "Accounting for the Translation of Foreign Currency Transactions and Foreign Currency Financial Statements." FASB-52 covers the translation of the foreign currency financial statements for the purposes of the consolidation, combination, or reporting by the equity method, and the translation of foreign currency transactions. The new statement required that assets, liabilities, and operations of an entity be stated in the currency of the primary economic environment in which the entity operates (termed, the "functional currency"). If a foreign entity has not kept its financial records in the functional currency, remeasurement is required prior to translation. Any gain or loss on remeasurement is recognized in current net income. The assets and liabilities of the foreign entity are translated from its functional currency to the reporting currency at the current rate of exchange.

Under FASB-52, gain or loss on the translation of foreign currency financial statements is shown as a separate component of stockholders' equity, whereas, under FASB-8, all non-monetary balance sheet items were translated at the historical rate of exchange. Thus, the change to FASB-52, which uses the current rate of exchange, had the most significant impact on inventories and fixed assets. With respect to the income statement, FASB-52 requires that only gains or losses from foreign currency transactions be included.

As the text table on the following page indicates, foreign currency translation losses decreased stockholders' equity by 0.4 percent, while foreign currency transaction gains increased pretax income by 0.7 percent in 1993.

FRS Database History

The Form EIA-28, Financial Reporting System (FRS), database has existed in three formats during its 20-year history. (In addition, there have been minor, periodic adjustments since 1987. The most noteworthy was the change from a Statement of Sources and Uses of Funds to a Statement of Cash Flows, effective in the 1986 reporting year. The first version of the Form EIA-28 and its database covered years 1974-1980. The second version covered years 1981-1986. The third covered years 1987- 1992. The fourth version begins with the 1993 reporting year and is approved through the 1995 reporting year. The current version was changed by adding the Former Soviet Union and Eastern Europe as a new geographical reporting areas.

The first full reporting year for the first version of the form was 1977. It consisted of 47 separate schedules containing 8,775 data elements, and was 136 pages long.[295] This version of the database contained a significant amount of detail at the consolidated level, at each line of business, and in the breadth of operating statistics. However, not all of the collected data were loaded into the database. About 1,000 elements were not unique to individual companies—such as joint venture information—and were maintained only in their hard copy format.

[295]In order to extend the range of data back through 1974, an abbreviated version of the form was collected for the years 1974 through 1976. Almost 2,900 data elements (one-third of the total) were collected for each of these years, and consisted primarily of summary data from 26 of the 47 schedules.

Table A4. The Impact of FASB-52, Foreign Currency Translations, on Stockholders' Equity and Pretax Income, 1982-1993

Year	Translation Gain/Losses	Stockholders' Equity	Percent of Stockholders' Equity	Transaction Gains/Losses	Pretax Income	Percent of Pretax Income
	(million dollars)			(million dollars)		
1982	-1,764	183,933	-1.0	-111	45,157	-0.2
1983	-1,253	192,509	-0.7	35	47,420	0.1
1984	-1,683	176,461	-1.0	-44	47,609	-0.1
1985	399	165,457	0.6	176	43,573	0.4
1986	1,786	164,601	1.1	543	20,564	2.6
1987	3,425	165,458	2.1	176	25,006	0.7
1988	-495	164,832	-0.3	89	34,285	0.3
1989	-465	160,638	-0.3	142	32,281	0.4
1990	1,918	167,060	1.1	135	37,489	0.4
1991	101	167,574	0.1	-25	25,120	-0.1
1992	-3,341	157,295	-2.1	375	22,452	1.7
1993	-637	161,769	-0.4	170	24,765	0.7

Source: Energy Information Administration, Form EIA-28.

In 1982 (for the 1981 reporting year) the form was shortened by 72 percent, to 2,468 elements. The format was still the same, with data collected at the consolidated level, four energy lines of business (petroleum, coal, nuclear, and other energy), and nonenergy. The 1981-1986 form consisted of 19 schedules, and was 35 pages long. Although data were still collected by each line-of-business, most of the decline was at the line-of-business level, where more than 81 percent of the form was eliminated, compared with a 58-percent decline at the consolidated level.

In 1988 (for the 1987 reporting year) the form was shortened by another 33 percent, to 1,650 elements. The consolidated level was shortened by 32 percent, primarily by combining other energy with nuclear energy. Petroleum data declined by 10 percent, coal by 74 percent, and separate income statement schedules for the remaining lines of business (coal, nuclear and other energy, and nonenergy) were eliminated altogether (although income statements for each of these lines of business were incorporated into Schedule 5110, Consolidating Statement of Income). The form currently has 14 schedules, and is 27 pages long.

Appendix B

Detailed Statistical Tables

Table B1. Selected U.S. Operating Statistics for FRS Companies and U.S. Industry, 1992 and 1993

Operating Statistics	FRS Companies			U.S. Industry [1]			FRS as a Percent of U.S. Industry	
	1992	1993	Percent Change	1992	1993	Percent Change	1992	1993
Petroleum								
Net Production								
Crude Oil and Natural Gas Liquids (million barrels)	1,750.2	1,632.5	-6.7	3,219.0	3,127.0	-2.9	54.4	52.2
Natural Gas (billion cubic feet)	7,877.7	7,651.1	-2.9	17,423.0	17,789.0	2.1	45.2	43.0
Net Imports								
Crude Oil and Natural Gas Liquids (million barrels)	868.8	757.5	-12.8	2,383.0	2,640.9	10.8	36.5	28.7
Refinery Capacity (thousand barrels per day)	10,952.0	10,714.0	-2.2	15,804.4	15,718.0	-0.5	69.3	68.2
Refinery Output[2] (thousand barrels per day)	10,994.0	10,822.0	-1.6	15,932.0	16,341.2	2.6	69.0	66.2
Bituminous Coal and Lignite Production (million tons)	251.9	197.3	-21.7	997.5	945.4	-5.2	25.3	20.9

1 U.S. area defined to include the 50 States, District of Columbia, U.S. Virgin Islands, and Puerto Rico.
2 For FRS companies, includes refinery output at own refineries for own account and at others' refineries for own account.

Note: The data for total U.S. production of crude oil and natural gas liquids and natural gas (dry) utilized in this report are taken from Energy Information Administration, Form EIA-23, see *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1993 Annual Report* (October 1994). This source is utilized in order to preserve consistency between production reported in the context of oil and gas reserves and reserve additions and production reported elsewhere in this report. However, the official Energy Information Administration U.S. totals for crude oil and natural gas plant production are 3,225.1 million barrels in 1993 and 3,292.5 million barrels in 1992 (see Energy Information Administration, *Petroleum Supply Annual 1993,* Volume 1 (June 1994), p. 2). For dry natural gas production, the official Energy Information Administration U.S. totals are 18,353 billion cubic feet in 1993 and 17,840 billion cubic feet in 1992 (see Energy Information Administration, *Natural Gas Monthly, September 1994,* p. 3).

Sources: Industry data - Petroleum net production: Energy Information Administration, Form EIA-23, see *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1993 Annual Report* (October 1994). Net imports: data compiled for the International Energy Agency by the Petroleum Supply Division, Office of Oil and Gas, Energy Information Administration. Refinery capacity and refinery output: Energy Information Administration, Forms EIA-820 and EIA-810, see *Petroleum Supply Annual*, 1992 and 1993. Coal production: Energy Information Administration, Form EIA-7A, see *Coal Industry Annual 1993,* (November 1994).

Table B2. Selected U.S. Operating Statistics for FRS Companies and U.S. Industry, 1987-1993

Operating Statistics	1987	1988	1989	1990	1991	1992	1993
Petroleum							
Net Production							
Crude Oil and Natural Gas Liquids (million barrels)							
FRS companies	2,069.5	2,102.1	1,911.1	1,814.0	1,818.1	1,750.2	1,632.5
U.S. Industry[1]	3,620.0	3,565.0	3,317.0	3,237.0	3,266.0	3,219.0	3,127.0
FRS as a percent of U.S. Industry	57.2	59.0	57.6	56.0	55.7	54.4	52.2
Natural Gas (billion cubic feet)							
FRS companies	7,214.1	7,627.3	7,480.7	7,578.2	7,509.5	7,877.7	7,651.1
U.S. Industry[1]	16,114.0	16,670.0	16,983.0	17,233.0	17,202.0	17,423.0	17,789.0
FRS as a percent of U.S. Industry	44.8	45.8	44.0	44.0	43.7	45.2	43.0
Net Imports							
Crude Oil and Natural Gas Liquids (million barrels)							
FRS companies	898.9	906.4	834.3	975.2	917.9	868.8	757.5
U.S. Industry[1]	1,877.7	2,003.0	2,289.3	2,324.7	2,243.7	2,383.0	2,640.9
FRS as a percent of U.S. Industry	47.9	45.3	36.4	41.9	40.9	36.5	28.7
Refinery Capacity (thousand barrels per day)							
FRS companies	12,462.0	12,281.0	11,489.0	11,372.0	11,203.0	10,952.0	10,714.0
U.S. Industry[1]	16,581.0	16,285.0	16,238.0	16,430.4	16,452.6	15,804.4	15,718.0
FRS as a percent of U.S. Industry	75.2	75.4	70.8	69.2	68.1	69.3	68.2
Refinery Output[2] (thousand barrels per day)							
FRS companies	11,712.0	12,033.0	11,413.0	11,312.0	11,122.0	10,994.0	10,822.0
U.S. Industry[1]	15,085.0	15,426.0	15,654.6	15,911.2	15,872.2	15,932.0	16,341.2
FRS as a percent of U.S. Industry	77.6	78.0	72.9	71.1	70.1	69.0	66.2
Bituminous Coal and Lignite Production (million tons)							
FRS companies	255.3	285.3	286.9	282.0	289.6	251.9	197.3
U.S. Industry[1]	915.2	950.3	980.7	1,029.1	996.0	997.5	945.4
FRS as a percent of U.S. Industry	27.9	30.0	29.3	27.4	29.1	25.3	20.9

[1] U.S. area defined to include the 50 States, District of Columbia, U.S. Virgin Islands, and Puerto Rico.
[2] For FRS companies, includes refinery output at own refineries for own account and at others' refineries for own account.

Note: The data for total U.S. production of crude oil and natural gas liquids and natural gas (dry) utilized in this report are taken from Energy Information Administration, Form EIA-23, see *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1993 Annual Report* (October 1994). This source is utilized in order to preserve consistency between production reported in the context of oil and gas reserves and reserve additions and production reported elsewhere in this report. However, the official Energy Information Administration U.S. totals for crude oil and natural gas plant production are 3,225.1 million barrels in 1993 and 3,292.5 million barrels in 1992 (see Energy Information Administration, *Petroleum Supply Annual 1993,* Volume 1 (June 1994), p. 2). For dry natural gas production, the official Energy Information Administration U.S. totals are 18,353 billion cubic feet in 1993 and 17,840 billion cubic feet in 1992 (see Energy Information Administration, *Natural Gas Monthly, September 1994,* p. 3).

Sources: Industry data - Petroleum net production: Energy Information Administration, Form EIA-23, see *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1993 Annual Report* (October 1994). Net imports: data compiled for the International Energy Agency by the Petroleum Supply Division, Office of Oil and Gas, Energy Information Administration. Refinery capacity and refinery output: Energy Information Administration, Forms EIA-820 and EIA-810, see *Petroleum Supply Annual*, 1992 and 1993. Coal production: Energy Information Administration, Form EIA-7A, see *Coal Industry Annual 1993,* (November 1994).

Table B3. A Comparison of Selected Financial Items for FRS Companies and the S&P 400, 1993 and Percent Change from 1992

Selected Financial Items	FRS Companies		S&P 400	
	1993 (billion dollars)	Percent Change from 1992	1993 (billion dollars)	Percent Change from 1992
Income Statement				
Operating Revenues	448.1	-5.2	2,706.3	-0.2
Operating Expenses	-423.0	-5.9	-2,471.0	-1.1
Operating Income	25.1	7.7	235.4	9.3
Other Income[1]	-0.5	-96.4	-102.1	-26.9
Income Taxes	-9.1	6.0	-60.5	10.7
Net Income	15.5	781.5	72.8	246.0
Cash Flows from Operations[2]				
Net Income	15.5	781.5	72.8	246.0
Other Items, Net[3]	34.7	-19.3	192.8	-15.9
Net Cash Flow from Operations	50.2	12.1	265.6	6.2
Cash Flows from Investing Activities[2]				
Additions to PP&E	-38.1	-6.0	-169.1	-0.1
Other Investment Activities, Net[4]	7.2	71.3	-40.7	43.8
Net Cash Flow from Investing Activities	-30.9	-14.9	-209.8	6.2
Cash Flows from Financing Activities[2]				
Proceeds from Long-Term Debt	19.0	-23.3	184.8	-24.2
Proceeds from Equity Security Offerings	2.1	-37.6	25.4	-3.8
Dividends to Shareholders	-13.6	0.3	-60.4	1.6
Reductions in Long-Term Debt	-20.9	-17.4	-177.8	-22.1
Stock Repurchases	-0.5	-37.6	-25.7	13.5
Other Financing Activities, Net	-4.1	([5])	7.1	([5])
Net Cash Flow from Financing Activities	-17.9	96.3	-46.5	3.8
Effect of Exchange Rate Changes on Cash	-0.2	-44.8	-2.1	-22.6
Increase (Decrease) in Cash and Cash Equivalents	1.2	([5])	7.2	([5])

[1] 'Other Income' includes other revenue and expense, discontinued operations, extraordinary items, and accounting changes.
[2] Items that add to cash are positive, and items that use cash are shown as negative values.
[3] 'Other Items, Net' includes: DD&A, deferred taxes, dry hole expense, minority interest, recognized undistributed earnings/(losses) of unconsolidated affiliates, (gain)/loss on disposition of PP&E, changes in operating assets and liabilities, and other noncash items, excluding net change in short-term debt; other cash items, net.
[4] 'Other Investment Activities, Net' includes additions to investments and advances and proceeds from disposals of PP&E.
[5] Not meaningful.
Sources: Standard & Poor's (S&P) 400 data - Compustat, Inc. FRS companies' data - Energy Information Administration, Form EIA-28.

Table B4. Consolidating Statement of Income for FRS Companies, 1993

(Million Dollars)

Income Statement Items	Consolidated	Eliminations & Non-Traceable	Petroleum	Coal	Nuclear & Other Energy	Non-Energy
Operating Revenues	448,094	-10,983	377,235	3,063	1,121	77,658
Operating Expenses						
General Operating Expenses	381,926	-9,855	321,899	2,418	706	66,758
DD&A	30,355	579	24,211	342	151	5,072
General & Administrative	10,719	1,847	6,573	89	112	2,098
Total Operating Expenses	423,000	-7,429	352,683	2,849	969	73,928
Operating Income	25,094	-3,554	24,552	214	152	3,730
Other Revenue & (Expense)						
Earnings of Unconsolidated Affiliates	2,925	55	2,412	W	W	457
Other Dividend & Interest Income	1,411	1,411	–	–	–	–
Gain/Loss on Disposition of PP&E	1,061	8	852	W	W	114
Interest Expenses & Financial Charges	-7,904	-7,904	–	–	–	–
Minority Interest in Income	-397	-397	–	–	–	–
Foreign Currency Translation Effects	170	170	–	–	–	–
Other Revenue & (Expense)	2,417	2,417	–	–	–	–
Total Other Revenue & (Expense)	-317	-4,240	3,264	14	74	571
Pretax Income	24,777	-7,794	27,816	228	226	4,301
Income Tax Expense	9,144	-3,476	11,111	64	105	1,340
Discontinued Operations	34	W	0	W	0	W
Extraordinary Items and Cumulative Effect of Accounting Changes	-179	W	-242	W	0	W
Net Income	15,488	-4,166	16,463	371	121	2,699

– = Not available.
W = Data withheld to avoid disclosure.
Source: Energy Information Administration, Form EIA-28.

Table B5. Consolidating Statement of Income for FRS Companies, U.S. and Foreign Petroleum Segments, 1993

(Million Dollars)

Income Statement Items	U.S. Petroleum				Foreign Petroleum			
	Consoli-dated	Production	Refining/ Marketing	Pipelines	Consoli-dated	Production	Refining/ Marketing	Int'l Marine
Operating Revenues								
Raw Material Sales	84,837	45,972	68,859	2,220	53,765	33,873	42,271	0
Refined Products Sales	118,227	W	117,647	W	115,284	W	115,376	W
Transportation Revenues	7,197	277	3,268	8,522	1,488	152	W	2,460
Management And Processing Fees	1,180	W	914	W	1,098	W	W	W
Other	8,092	853	7,346	209	3,119	627	2,544	W
Total Operating Revenues	219,533	47,489	198,034	11,581	174,754	35,089	161,236	2,545
Operating Expenses								
General Operating Expenses	187,607	27,786	189,686	7,698	151,341	19,000	154,006	2,371
DD&A	16,280	11,549	3,659	1,072	7,931	6,299	1,514	W
General & Administrative	4,229	1,627	2,112	498	2,346	896	1,477	W
Total Operating Expenses	208,116	40,962	195,457	9,268	161,618	26,195	156,997	2,542
Operating Income	11,417	6,527	2,577	2,313	13,136	8,894	4,239	3
Other Revenue & (Expense)								
Earnings of Unconsolidated Affiliates	650	111	209	330	1,762	1,143	616	W
Gain(Loss) On Disposition of PP&E	630	514	82	34	222	234	-20	W
Total Other Revenue & (Expense)	1,280	625	291	364	1,984	1,377	596	11
Pretax Income	12,697	7,152	2,868	2,677	15,120	10,271	4,835	14
Income Tax Expense	4,399	2,199	1,099	1,101	6,712	5,084	1,635	-7
Discontinued Operations	W	W	W	W	W	W	W	W
Extraordinary Items and Cumulative Effect of Accounting Changes	W	W	W	W	W	W	W	W
Contribution To Net Income	8,090	4,839	1,685	1,566	8,374	5,160	3,193	21

W = Data withheld to avoid disclosure.
Source: Energy Information Administration, Form EIA-28.

Table B6. Profit Rates for Lines of Business and Petroleum Segments for FRS Companies, 1987-1993

(Percent)

Line of Business	1987	1988	1989	1990	1991	1992	1993
Consolidated	3.6	7.2	6.4	6.8	4.5	0.5	4.7
Petroleum	6.2	7.3	6.7	9.5	7.0	5.6	6.4
U.S. Petroleum	4.9	6.3	5.8	7.9	4.9	4.4	4.9
Oil and Gas Production	4.1	2.8	2.9	8.5	5.1	5.9	5.3
Refining/Marketing	2.9	14.7	11.5	5.1	2.0	-0.4	3.4
Pipelines	12.8	9.6	10.2	11.2	10.7	8.4	6.4
Foreign Petroleum	9.5	9.9	8.7	12.5	11.0	7.9	9.2
Oil and Gas Production	12.4	9.2	8.9	13.1	9.1	8.2	8.6
Refining/Marketing	4.7	11.6	8.0	11.2	14.6	7.8	10.6
International Marine	-3.6	6.8	12.4	11.7	15.6	-1.2	1.2
Coal	5.1	6.7	5.0	3.3	8.7	-9.3	7.6
Nuclear and Other Energy	0.5	-2.5	-2.3	2.6	2.8	1.8	4.1
Nonenergy	12.2	20.3	17.3	7.8	2.9	2.1	4.7

Note: Profit rate measured as contribution to net income/net investment in place.
Source: Energy Information Administration, Form EIA-28.

Table B7. Profit Rates for Petroleum Segments for FRS Companies Ranked by Total Energy Assets, 1991-1993

(Percent)

Petroleum Segments	Top Four			Five Through Twelve			All Other		
	1991	1992	1993	1991	1992	1993	1991	1992	1993
Petroleum	8.9	8.1	8.1	5.9	4.1	4.9	4.0	2.5	5.1
U.S. Petroleum	3.5	5.4	4.5	6.2	4.6	5.2	4.0	2.5	4.7
Oil and Gas Production	3.3	6.8	5.5	6.6	5.5	4.4	5.1	5.0	6.9
Refining/Marketing	1.8	1.3	1.5	3.4	0.6	7.4	-0.7	-4.9	-0.2
Pipelines	16.8	16.2	13.1	9.9	6.6	4.8	9.2	9.9	8.3
Foreign Petroleum	14.1	10.7	11.2	4.7	1.8	3.9	4.1	2.4	6.6
Oil and Gas Production	13.9	13.4	12.4	2.5	0.9	2.6	4.4	3.3	6.8
Refining/Marketing	14.3	8.0	10.5	28.4	13.7	15.6	2.1	-5.8	4.6
International Marine	13.8	1.1	-0.1	33.5	-27.7	18.3	-5.9	16.7	19.4

Note: Profit rate measured as contribution to net income/net investment in place.
Source: Energy Information Administration, Form EIA-28.

Table B8. A Comparison of Balance Sheet Items for FRS Companies and the S&P 400, 1993 and Percent Change from 1992

Balance Sheet Items	FRS Companies		S&P 400	
	1993 (billion dollars)	Percent Change from 1992	1993 (billion dollars)	Percent Change from 1992
Assets				
Current Assets	93.5	-4.5	695.7	1.4
Noncurrent Assets				
Property, Plant, and Equipment				
Gross	607.9	1.3	1,850.5	2.0
Accumulated DD&A	-300.0	3.4	-857.7	3.4
Net	307.9	-0.6	992.8	0.8
Investments and Advances	23.6	8.0	67.1	8.2
Other Noncurrent Assets	26.3	8.7	1,237.8	11.2
Subtotal Noncurrent Assets	357.8	0.6	2,297.8	6.4
Total Assets	451.3	-0.5	2,993.6	5.2
Liabilities and Stockholders' Equity				
Liabilities				
Current Liabilities	96.1	-5.7	697.8	7.1
Long-Term Debt	89.4	-4.4	575.9	-0.3
Other Long-Term Items	99.1	3.1	873.5	13.7
Minority Interest	5.0	4.1	28.5	19.2
Subtotal Liabilities and Other Items	289.6	-2.3	2,175.9	7.7
Stockholders' Equity				
Retained Earnings	142.0	2.0	644.3	-3.9
Other Equity	19.8	9.0	173.3	12.2
Subtotal Stockholders' Equity	161.8	2.8	817.6	-0.9
Total Liabilities and Stockholders' Equity	451.3	-0.5	2,993.6	5.2

Sources: Standard & Poor's (S&P) 400 data - Compustat, Inc. FRS companies' data - Energy Information Administration, Form EIA-28.

Table B9. Consolidated Balance Sheet for FRS Companies, 1987-1993

(Billion Dollars)

Balance Sheet Items	1987	1988	1989	1990	1991	1992	1993
Assets							
Current Assets							
Cash & Marketable Securities	25.7	16.8	16.4	14.9	12.4	12.1	14.1
Trade Accounts and Notes Receivable	40.2	43.7	45.4	56.6	47.2	44.6	41.7
Inventories							
Raw Materials & Products	29.1	26.9	26.2	28.0	27.0	26.2	23.7
Materials & Supplies	5.6	5.3	5.3	5.3	5.2	4.6	4.3
Other Current Assets	8.8	12.2	9.2	10.5	9.2	10.4	9.6
Total Current Assets	109.4	105.0	102.4	115.4	101.0	97.9	93.5
Non-current Assets							
Property, Plant & Equipment							
Gross	525.5	526.7	536.0	565.0	581.4	599.9	607.9
Accumulated DD&A	227.9	233.0	242.8	262.5	275.9	290.2	300.0
Net	297.6	293.6	293.2	302.5	305.5	309.7	307.9
Investments & Advances to							
Unconsolidated Affiliates	18.8	16.0	16.7	17.2	20.1	21.9	23.6
Other Non-current Assets	17.9	23.2	22.2	22.2	20.6	24.2	26.3
Total Non-current Assets	334.2	332.8	332.1	341.8	346.2	355.7	357.8
Total Assets	443.6	437.8	434.5	457.2	447.1	453.6	451.3
Liabilities & Stockholder's Equity							
Liabilities							
Current Liabilities							
Trade Accounts & Notes Payable	48.3	45.9	51.9	64.6	56.5	53.1	49.1
Other Current Liabilities	49.6	48.5	47.1	50.2	47.6	48.7	47.0
Long Term Debt	95.3	93.2	90.7	88.5	90.9	93.5	89.4
Deferred Income Tax Credits	51.1	50.4	49.8	50.3	47.0	44.7	45.5
Other Deferred Credits	10.8	11.8	10.9	12.3	12.2	16.5	15.9
Other Long Term Items	19.7	19.4	19.3	19.8	21.1	34.9	37.7
Minority Interest in Consolidated Affiliates	3.4	3.6	4.2	4.4	4.2	4.8	5.0
Total Liabilities	278.2	272.9	273.9	290.1	279.6	296.3	289.6
Stockholders' Equity							
Retained Earnings	143.2	143.8	140.9	148.7	148.9	139.2	142.0
Other Equity	22.2	21.0	19.7	18.4	18.6	18.1	19.8
Total Stockholders' Equity	165.5	164.8	160.6	167.1	167.6	157.3	161.8
Total Liabilities & Stockholders' Equity	443.6	437.8	434.5	457.2	447.1	453.6	451.3
Memo:							
Foreign Currency Translation Adjustment Cumulative at Year End	-4.0	-4.7	-4.3	-3.3	-3.2	-6.6	-7.3
Foreign Currency Translation Adjustment for the Current Year	3.4	-0.5	-0.5	1.9	0.1	-3.3	-0.6

Source: Energy Information Administration, Form EIA-28.

Table B10. Distribution of Net Investment in Place for FRS Companies, United States and Foreign, 1993

Fixed Investment	Consolidated Company	United States	Foreign	Nontraceable[1]
Net Investment in Place				
(billion dollars)				
Net Property, Plant, and Equipment	307.9	206.2	93.8	7.9
Investments and Advances to Unconsolidated Affiliates	23.6	7.5	15.4	0.7
Total Net Investment in Place	331.5	213.7	109.2	8.6
Net Investment in Place				
(percent distribution)				
Net Property, Plant, and Equipment	100.0	67.0	30.5	2.6
Investments and Advances to Unconsolidated Affiliates	100.0	31.9	65.2	2.9
Total Net Investment in Place	100.0	64.5	32.9	2.6
Additions to Investment in Place				
(billion dollars)				
Property, Plant, and Equipment	38.1	21.8	15.3	1.0
Investments and Advances to Unconsolidated Affiliates	2.3	0.4	2.0	0.0
Total Additions to Investment in Place	40.4	22.2	17.2	0.9
Additions to Investment in Place				
(percent distribution)				
Property, Plant, and Equipment	100.0	57.4	40.1	2.5
Investments and Advances to Unconsolidated Affiliates	100.0	17.3	84.2	-1.5
Total Additions to Investment in Place	100.0	55.1	42.7	2.3

[1] Includes items in consolidated balance sheet that cannot be allocated to segments (nontraceables). In this table, this column is derived as a residual.

Source: Energy Information Administration, Form EIA-28.

Table B11. Net Property, Plant and Equipment (PP&E), Additions to PP&E, Investments and Advances, and Depreciation, Depletion and Amortization (DD&A), by Lines of Business for FRS Companies, 1993

(Million Dollars)

Line of Business	Year End Balance		Activity During Year		
	Net PP&E	Investments and Advances	Additions to PP&E	Additions to Investments and Advances	DD&A
Nonenergy					
Foreign Chemicals	8,416	2,361	1,082	117	949
U.S. Chemicals	25,660	1,362	3,307	0	2,934
Foreign Other Nonenergy	3,776	59	626	0	185
U.S. Other Nonenergy	15,047	1,330	1,551	66	1,004
Total Nonenergy	52,899	5,112	6,566	183	5,072
Nuclear and Other Energy					
Foreign	1,277	W	185	W	82
United States	1,392	W	17	W	69
Total Nuclear and Other Energy	2,669	285	202	190	151
Coal					
Foreign	W	W	W	W	W
United States	W	W	W	W	W
Total Coal	3,931	981	249	-12	342
Petroleum					
United States					
Production	90,778	614	9,499	18	11,549
Refining/Marketing					
Refining	28,206	1,131	4,308	198	2,130
Marketing	15,733	369	1,736	37	1,206
Refining/Marketing Transport					
Pipelines	1,645	111	150	27	117
Marine	1,787	W	79	W	152
Other	774	W	117	W	54
Total U.S. Refining/Marketing	48,145	1,663	6,390	266	3,659
Rate Regulated Pipelines					
Refined Products	1,538	325	88	-28	75
Natural Gas	15,235	707	330	64	584
Crude Oil and Liquids	6,101	494	491	14	413
Total Rate Regulated Pipelines	22,874	1,526	909	50	1,072
Total U.S. Petroleum	161,797	3,803	16,798	334	16,280
Foreign					
Production	55,149	4,514	10,036	1,394	6,299
Refining/Marketing	21,837	8,225	3,034	W	1,514
International Marine	1,717	8	223	W	118
Total Foreign Petroleum	78,703	12,747	13,293	1,657	7,931
Total Petroleum	240,500	16,550	30,091	1,991	24,211
Nontraceable	7,915	683	953	-34	579
Consolidated	307,914	23,611	38,061	2,318	30,355

W = Data withheld to avoid disclosure.
Source: Energy Information Administration, Form EIA-28.

Table B12. Income and Investment Patterns in Worldwide Petroleum for FRS Companies Ranked by Total Energy Assets, 1993 and Percent Change from 1992

Income and Investment	Worldwide	United States	Foreign
	(million dollars)		
1993			
Contribution to Net Income			
Top Four	9,362.0	2,425.0	6,937.0
Five Through Twelve	4,785.0	4,006.0	780.0
All Other	2,316.0	1,659.0	657.0
Net Investment in Place[1]			
Top Four	115,217.0	53,439.0	61,778.0
Five Through Twelve	96,720.0	76,967.0	19,753.0
All Other	45,113.0	35,194.0	9,919.0
Additions to Investment in Place			
Top Four	13,904.0	5,175.0	8,729.0
Five Through Twelve	11,668.0	7,115.0	4,553.0
All Other	6,510.0	4,842.0	1,668.0
	(percent)		
Distribution, 1993			
Contribution to Net Income			
Top Four	100.0	25.9	74.1
Five Through Twelve	100.0	83.7	16.3
All Other	100.0	71.6	28.4
Net Investment in Place[1]			
Top Four	100.0	46.4	53.6
Five Through Twelve	100.0	79.6	20.4
All Other	100.0	78.0	22.0
Additions to Investment in Place			
Top Four	100.0	37.2	62.8
Five Through Twelve	100.0	61.0	39.0
All Other	100.0	74.4	25.6
Change from 1992			
Contribution to Net Income			
Top Four	0.7	-19.2	10.3
Five Through Twelve	21.5	11.5	125.4
All Other	107.0	86.8	184.4
Net Investment in Place[1]			
Top Four	0.9	-3.3	4.8
Five Through Twelve	-0.2	-1.6	5.6
All Other	0.7	0.3	2.0
Additions to Investment in Place			
Top Four	-0.9	-7.4	3.5
Five Through Twelve	9.6	2.3	23.4
All Other	-1.2	2.9	-11.4

[1] Measured as net property, plant, and equipment plus investments and advances.

Note: Sum of components may not equal total due to independent rounding, eliminations, and nontraceables.

Source: Energy Information Administration, Form EIA-28.

Table B13. Income and Investment Patterns by Petroleum Segments for FRS Companies Ranked by Total Energy Assets, 1993 and Percent Change from 1992

Income and Investment	United States				Foreign			
	Consolidated	Production	Refining/ Marketing	Pipelines	Consolidated	Production	Refining/ Marketing	International Marine
	(million dollars)							
1993								
Contribution to Net Income								
Top Four	2,425.0	1,785.0	287.0	353.0	6,937.0	4,103.0	2,836.0	-2.0
Five Through Twelve	4,006.0	1,796.0	1,419.0	791.0	780.0	453.0	310.0	17.0
All Other	1,659.0	1,258.0	-21.0	422.0	657.0	604.0	47.0	6.0
Net Investment in Place[1]								
Top Four	53,439.0	32,208.0	18,536.0	2,695.0	61,778.0	33,127.0	27,050.0	1,601.0
Five Through Twelve	76,967.0	41,067.0	19,256.0	16,644.0	19,753.0	17,677.0	1,983.0	93.0
All Other	35,194.0	18,117.0	12,016.0	5,061.0	9,919.0	8,859.0	1,029.0	31.0
Additions to PP&E[2]								
Top Four	5,127.0	2,819.0	2,176.0	132.0	7,609.0	4,740.0	2,704.0	165.0
Five Through Twelve	6,902.0	3,775.0	2,525.0	602.0	4,030.0	3,705.0	275.0	50.0
All Other	4,769.0	2,905.0	1,689.0	175.0	1,654.0	1,591.0	55.0	8.0
	(percent)							
Distribution, 1993								
Contribution to Net Income								
Top Four	100.0	73.6	11.8	14.6	100.0	59.1	40.9	0.0
Five Through Twelve	100.0	44.8	35.4	19.7	100.0	58.1	39.7	2.2
All Other	100.0	75.8	-1.3	25.4	100.0	91.9	7.2	0.9
Net Investment in Place[1]								
Top Four	100.0	60.3	34.7	5.0	100.0	53.6	43.8	2.6
Five Through Twelve	100.0	53.4	25.0	21.6	100.0	89.5	10.0	0.5
All Other	100.0	51.5	34.1	14.4	100.0	89.3	10.4	0.3
Additions to PP&E[2]								
Top Four	100.0	55.0	42.4	2.6	100.0	62.3	35.5	2.2
Five Through Twelve	100.0	54.7	36.6	8.7	100.0	91.9	6.8	1.2
All Other	100.0	60.9	35.4	3.7	100.0	96.2	3.3	0.5
Change from 1992								
Contribution to Net Income								
Top Four	-19.2	-22.8	22.6	-22.8	10.3	-2.8	38.1	([3])
Five Through Twelve	11.5	-23.9	1,144.7	-29.2	125.4	202.0	29.2	([3])
All Other	86.8	37.2	-96.3	-16.4	184.4	111.2	([3])	50.0
Net Investment in Place[1]								
Top Four	-3.3	-5.0	-0.1	-4.2	4.8	5.0	5.1	-3.5
Five Through Twelve	-1.6	-3.9	2.9	-1.0	5.6	5.3	13.0	-41.5
All Other	0.3	-2.1	4.6	-0.8	2.0	2.1	0.5	29.2
Additions to PP&E[2]								
Top Four	-7.7	0.1	-15.4	-20.5	-8.1	-4.6	-13.0	-17.5
Five Through Twelve	-0.3	10.7	-17.2	29.2	12.7	15.1	-18.9	163.2
All Other	2.8	13.1	-4.4	-43.0	-11.0	-10.6	-24.7	33.3

[1] Measured as net property, plant, and equipment plus investments and advances.
[2] Property, plant, and equipment.
[3] Not meaningful.

Note: Sum of components may not equal total due to independent rounding, eliminations, and nontraceables.

Source: Energy Information Administration, Form EIA-28.

Table B14. Size Distribution of Income and Investment Within Worldwide Petroleum for FRS Companies Ranked by Total Energy Assets, 1991-1993

(Percent)

Patterns Across Size Groups	Worldwide			United States			Foreign		
	1991	1992	1993	1991	1992	1993	1991	1992	1993
Contribution to Net Income									
All FRS	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Top Four	59.1	64.8	56.9	25.3	40.1	30.0	86.6	91.6	82.8
Five Through Twelve	32.3	27.4	29.1	59.9	48.0	49.5	10.0	5.0	9.3
All Other	8.6	7.8	14.1	14.9	11.9	20.5	3.4	3.4	7.8
Net Investment in Place[1]									
All FRS	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Top Four	46.7	44.6	44.8	35.4	32.8	32.3	67.4	67.5	67.6
Five Through Twelve	38.4	37.9	37.6	46.6	46.4	46.5	23.3	21.4	21.6
All Other	14.9	17.5	17.6	18.0	20.8	21.3	9.2	11.1	10.8
Additions to Investment in Place									
All FRS	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Top Four	42.7	44.9	43.3	32.4	32.4	30.2	53.8	60.2	58.4
Five Through Twelve	37.8	34.1	36.4	44.1	40.3	41.5	30.3	26.3	30.5
All Other	19.4	21.1	20.3	23.5	27.3	28.3	13.4	13.4	11.2

[1] Measured as net property, plant, and equipment plus investments and advances.
Source: Energy Information Administration, Form EIA-28.

Table B15. Consolidated Statement of Cash Flows for FRS Companies, 1987-1993

(Million Dollars)

Cash Flows[1]	1987	1988	1989	1990	1991	1992	1993
Cash Flows From Operations							
Net Income	11,257	22,339	19,784	21,608	14,679	1,757	15,488
Minority Interest in Income	573	585	424	408	235	344	397
Noncash Items							
DD&A	30,673	31,052	29,598	30,739	30,017	31,033	30,355
Dry Hole Expense, This Year	1,780	2,764	2,258	2,796	2,841	1,986	1,673
Deferred Income Taxes	768	1,279	189	-39	-2,062	-3,929	-990
Recognized Undistributed (Earnings)/Losses of Unconsolidated Affiliates	-280	-338	-794	-777	-829	-350	-137
(Gain)/Loss on Disposition of PP&E	-1,561	-2,064	-3,335	-795	-1,808	-1,294	-941
Changes in Operating Assets and Liabilities and Other Noncash Items	1,847	-4,741	809	2,883	2,744	15,442	2,791
Other Cash Items, Net	2,085	-2,449	-649	-1,930	2,002	-231	1,560
Net Cash Flow From Operations	47,142	48,427	48,284	54,893	47,819	44,758	50,196
Cash Flows From Investing Activities							
Additions to PP&E:							
Due to Mergers and Acquisitions	-5,830	-15,144	-8,676	-3,467	-1,075	-874	-306
Other	-28,950	-34,653	-34,847	-41,122	-43,812	-39,604	-37,755
Total Additions to PP&E	-34,780	-49,797	-43,523	-44,589	-44,887	-40,478	-38,061
Additions to Investments and Advances	-31	121	-1,468	-886	-1,520	-1,483	-2,318
Proceeds From Disposals of PP&E	6,367	15,960	13,404	7,143	9,359	7,268	11,757
Other Investment Activities, Net	-5,347	4,623	-2,209	327	-103	-1,584	-2,242
Cash Flow From Investing Activities	-33,791	-29,093	-33,796	-38,005	-37,151	-36,277	-30,864
Cash Flows From Financing Activities							
Proceeds From Long-Term Debt	19,748	19,313	20,668	15,759	22,120	24,745	18,982
Proceeds From Equity Security Offerings	2,312	2,709	4,248	1,501	491	3,438	2,146
Reductions in Long-Term Debt	-20,209	-28,775	-19,820	-17,223	-18,411	-25,284	-20,886
Purchase of Treasury Stock	-3,839	-6,637	-6,190	-5,435	-1,973	-824	-514
Dividends to Shareholders	-10,593	-12,443	-16,699	-13,300	-13,497	-13,521	-13,563
Other Financing Activities, Including Net Change in Short-Term Debt	-2,478	413	2,111	243	-978	2,308	-4,102
Cash Flow From Financing Activities	-15,059	-25,420	-15,682	-18,455	-12,248	-9,138	-17,937
Effect of Exchange Rate on Cash	457	-247	-286	74	-138	-359	-198
Net Increase/(Decrease) in Cash and Cash Equivalents	-1,251	-6,333	-1,480	-1,493	-1,718	-1,016	1,197

[1] Items that add to cash are positive, and items that use cash are shown as negative values.
Source: Energy Information Administration, Form EIA-28.

Table B16. A Comparison of Key Financial Indicators, Selected Performance Measures, and Patterns of Finance for FRS Companies and for the S&P 400, 1991-1993

(Percent)

Financial Indicators	FRS Companies			S&P 400		
	1991	1992	1993	1991	1992	1993
Profitability Measures						
Net Income to Total Assets	3.3	0.4	3.4	2.6	0.7	2.4
Net Income to Stockholders' Equity	8.8	1.1	9.6	8.2	2.5	8.9
Net Income Plus Interest to Total Invested Capital	9.5	4.3	9.3	10.7	6.7	10.0
Cash Flow from Operations and Uses of Cash						
Net Cash Flow from Operations to Total Assets	10.7	9.9	11.1	8.6	8.8	8.9
Additions to PP&E to Net Cash Flow from Operations	93.9	90.4	75.8	73.8	67.6	63.7
Dividends to Net Cash Flow from Operations	28.2	30.2	27.0	23.8	23.8	22.8
Liquidity and Leverage Measures						
Long-Term Debt to Stockholders' Equity	54.3	59.4	55.2	66.9	70.0	70.4
Long-Term Debt to Total Assets	20.3	20.6	19.8	21.1	20.3	19.2
Current Assets to Current Liabilities	97.0	96.1	97.3	108.6	105.3	99.7

Sources: Standard & Poor's (S&P) 400 data - Compustat, Inc. FRS companies' data - Energy Information Administration, Form EIA-28.

Table B17. Worldwide Income Taxes for FRS Companies, 1992 and 1993

Taxes by Geographic Sector	Billion Dollars		Percent Change from 1992	Income Taxes as a Percent of Pretax Income	
	1992	1993		1992	1993
Pretax Income[1]	22.5	24.8	9.9	100.0	100.0
Income Taxes					
U.S. Federal	0.4	1.9	334.6	1.9	7.6
U.S. State and Local	0.8	0.4	-43.1	3.5	1.8
Foreign	7.4	6.8	-8.1	32.9	27.5
Total Income Taxes	8.6	9.1	6.0	38.3	36.9
Current Income Taxes					
U.S. Federal	2.8	2.4	-15.0	12.3	9.5
U.S. State and Local	0.8	0.5	-39.1	3.4	1.9
Foreign					
Canada	0.6	0.7	18.3	2.5	2.7
Europe and Former Soviet Union[2]	2.1	1.9	-5.8	9.2	7.9
Africa	1.5	1.3	-16.8	6.7	5.1
Middle East	1.3	0.9	-30.0	5.7	3.6
Other Eastern Hemisphere	2.2	2.1	-4.8	9.7	8.4
Other Western Hemisphere	0.4	0.4	4.8	1.9	1.8
Subtotal	8.0	7.3	-9.2	35.5	29.3
Total Current Income Taxes	11.5	10.1	-12.6	51.2	40.7
Deferred Income Taxes					
U.S. Federal	-2.3	-0.5	-80.1	-10.3	-1.9
U.S. State and Local	0.0	0.0	-195.0	0.1	-0.1
Foreign	-0.6	-0.5	-23.2	-2.6	-1.8
Total Deferred Income Taxes	-2.9	-0.9	-67.7	-12.9	-3.8

[1] Excludes discontinued operations, extraordinary items, and cumulative effect of accounting changes.
[2] For 1993, OECD Europe combined with the former Soviet Union and Eastern Europe to avoid disclosure. Prior to 1993, only OECD Europe is included in this region.
Source: Energy Information Administration, Form EIA-28.

Table B18. U.S. Federal Income Taxes for FRS Companies, 1992 and 1993

U.S. Tax Determination	Billion Dollars		Percent Change from 1992	Percent of Net Income Before Taxes	
	1992	1993		1992	1993
Pretax Income[1] (worldwide)	22.5	24.8	9.9	100.0	100.0
Adjustments to Income					
Income Not Subject to U.S. Taxes	-2.8	-3.2	17.4	-12.2	-13.0
Deductions for Income Taxes Paid in Other Jurisdictions	-1.9	-1.1	-38.6	-8.3	-4.6
Taxable Income	17.9	20.4	13.8	79.5	82.3
Expected Tax Computed at U.S. Statutory Rate	6.1	7.1	17.4	27.0	28.8
Cause of Increase or Decrease in Taxes					
Statutory Depletion	-0.1	0.0	([2])	-0.3	-0.2
Foreign Tax Credits	-4.6	-4.8	3.4	-20.4	-19.2
Alternative Minimum Tax	-0.1	0.0	([2])	-0.4	0.0
Investment Tax Credits	-0.1	-0.1	30.1	-0.4	-0.4
Other	-0.8	-0.4	-57.4	-3.7	-1.4
U.S. Federal Income Tax Expense on U.S. Taxable Income	0.4	1.9	344.3	1.9	7.6
Current	2.8	2.4	-15.0	12.3	9.5
Deferred	-2.3	-0.5	-80.1	-10.3	-1.9

[1] Excludes discontinued operations, extraordinary items, and cumulative effect of accounting changes.
[2] Not meaningful.
Source: Energy Information Administration, Form EIA-28.

Table B19. Analysis of Income Taxes for FRS Companies, 1987-1993

(Million Dollars)

Income Taxes	1987	1988	1989	1990	1991	1992	1993
Income Taxes (as per Financial Statements)							
Current Paid or Accrued							
U.S. Federal, before Investment Tax Credit & Alternative Minimum Tax	4,099	4,283	4,071	5,008	3,543	2,355	2,584
U.S. Federal Investment Tax Credit	-365	-449	-48	-75	-52	-41	-76
Effect of Alternative Minimum Tax	40	174	24	534	412	450	-158
U.S. State & Local Income Taxes	694	901	1,068	901	695	759	462
Foreign Income Taxes							
Canada	890	501	700	901	119	558	660
Europe and Former Soviet Union[1]	3,083	2,840	2,261	2,864	2,710	2,066	1,947
Africa	1,479	1,176	1,620	2,110	1,563	1,509	1,256
Middle East	1,099	670	997	1,310	1,088	1,275	893
Other Eastern Hemisphere	1,287	1,421	1,483	2,261	2,248	2,180	2,075
Other Western Hemisphere	703	700	620	862	380	420	440
Total Foreign	8,541	7,308	7,681	10,308	8,108	8,008	7,271
Total Current	13,009	12,217	12,796	16,676	12,706	11,531	10,083
Deferred							
U.S. Federal, before Investment Tax Credit	474	1,260	45	420	-1,846	-1,723	-549
U.S. Federal Investment Tax Credit	188	405	23	55	2	-43	-32
Effect of Alternative Minimum Tax	-31	-173	-13	-474	-558	-564	117
U.S. State & Local Income Taxes	23	-54	-30	24	-69	20	-19
Foreign	114	-159	192	-178	385	-594	-456
Total Deferred	768	1,279	217	-153	-2,086	-2,904	-939
Total Income Tax Expense	13,777	13,496	13,013	16,523	10,620	8,627	9,144
Reconciliation of Accrued U.S. Federal Income Tax Expense To Statutory Rate							
Consolidated Pretax Income/(Loss)	25,006	34,285	32,281	37,489	25,120	22,542	24,777
Less: Foreign Source Income not Subject to U.S. Tax	3,670	3,830	4,036	3,836	3,671	2,753	3,233
Equals: Income Subject to U.S. Tax	21,336	30,455	28,245	33,653	21,449	19,789	21,544
Less: U.S. State & Local Income Taxes	717	841	1,023	634	757	748	509
Less: Applicable Foreign Income Taxes Deducted	475	578	663	1,174	907	1,121	638
Equals: Pretax Income Subject to U.S. Tax	20,144	29,036	26,559	31,845	19,785	17,920	20,397
Tax Provision Based on Previous Line	8,145	9,873	9,030	10,821	6,717	6,082	7,138
Increase/(Decrease) in Taxes Due To							
Foreign Tax Credits Recognized	-5,454	-4,763	-5,014	-6,031	-5,263	-4,596	-4,754
U.S. Federal Investment Tax Credit Recognized	-177	-145	-26	-42	-67	-83	-108
Statutory Depletion	-115	-111	-114	-116	-86	-66	-39
Effect of Alternative Minimum Tax	10	1	10	34	-3	-87	-1
Other	1,997	642	216	802	87	-826	-352
Actual U.S. Federal Tax Provision (Refund)	4,406	5,497	4,102	5,468	1,385	424	1,884

[1] For 1993, OECD Europe combined with the former Soviet Union and Eastern Europe to avoid disclosure. Prior to 1993, only OECD Europe is included in this region.

Source: Energy Information Administration, Form EIA-28.

Table B20. U.S. Taxes Other Than Income Taxes for FRS Companies, 1993 and Percent Change from 1992

U.S. Taxes Other than Income Taxes	Total United States		Petroleum		Coal		Other[1]	
	1993 (million dollars)	Percent Change from 1992	1993 (million dollars)	Percent Change from 1992	1993 (million dollars)	Percent Change from 1992	1993 (million dollars)	Percent Change from 1992
Production Taxes								
Windfall Profit Tax	14.0	([2])	14.0	([2])	0.0	--	0.0	--
Severance Taxes	1,853.0	-9.5	1,753.0	-9.5	97.0	W	3.0	W
Other Direct Production Taxes	231.0	0.9	139.0	14.9	90.0	W	2.0	W
Total Production Taxes	2,098.0	-4.0	1,906.0	-3.1	187.0	-11.4	5.0	-28.6
Superfund	320.0	4.9	280.0	2.6	0.0	--	40.0	25.0
Import Duties	127.0	28.3	–	–	–	–	–	–
Sales, Use, and Property	3,104.0	2.3	–	–	–	–	–	–
Payroll	2,134.0	-4.0	–	–	–	–	–	–
Other Taxes	638.0	-51.2	–	–	–	–	–	–
Total Taxes Paid (Other Than Income Taxes)	8,421.0	-8.0	–	–	–	–	–	–
Excise Taxes Collected	25,317.0	6.5	–	–	–	–	–	–

[1] Nuclear, Other Energy, and Nonenergy.
[2] Not meaningful.
– = Not available.
W = Data withheld to avoid disclosure.
-- = Not applicable.
Source: Energy Information Administration, Form EIA-28.

Table B21. Petroleum Exploration and Development Expenditures for FRS Companies, United States and Foreign, 1993 and Percent Change from 1992

Exploration and Development Expenditures	Worldwide Expenditures	U.S. Expenditures			Foreign Expenditures		
	FRS Companies (million dollars) 1993	FRS Companies (million dollars) 1993	Percent Change from 1992	U.S. FRS as a Percent of Total FRS 1993	FRS Companies (million dollars) 1993	Percent Change from 1992	FRS Foreign as a Percent of Total FRS 1993
Exploration							
Acquisition of Unproved Acreage	646.0	355.0	38.1	55.0	291.0	66.3	45.0
Geological and Geophysical	1,222.0	409.0	-13.9	33.5	813.0	-27.9	66.5
Drilling and Equipping[1]	2,934.0	1,370.0	15.6	46.7	1,564.0	-3.3	53.3
Other	1,663.0	652.0	-14.0	39.2	1,011.0	-10.0	60.8
Total Exploration	6,465.0	2,786.0	4.1	43.1	3,679.0	-9.0	56.9
Development							
Acquisition of Proved Acreage	1,006.0	599.0	10.7	59.5	407.0	184.6	40.5
Lease Equipment	4,116.0	1,640.0	13.1	39.8	2,476.0	3.9	60.2
Drilling and Equipping[1]	8,130.0	4,012.0	15.1	49.3	4,118.0	7.2	50.7
Other[2]	3,761.0	1,895.0	-12.3	50.4	1,866.0	-25.3	49.6
Total Development	17,013.0	8,146.0	6.6	47.9	8,867.0	0.0	52.1
Total Exploration and Development	23,478.0	10,932.0	6.0	46.6	12,546.0	-2.8	53.4

[1] Expenditure incurred in a given year not cumulative (includes work in progress adjustment).
[2] Includes support equipment.
Source: Energy Information Administration, Form EIA-28.

Table B22. U.S. and Foreign Exploration and Development Expenditures and Production (Lifting) Costs for FRS Companies, 1993

(Million Dollars)

Expenditures	Worldwide	United States			Foreign
		Total	Onshore	Offshore	
Exploration and Development Expenditures					
Exploration Expenditures					
Unproved Acreage	646	355	218	137	291
Drilling and Equipping					
Dry Holes (Cumulative)	–	757	316	441	–
Oil Wells (Cumulative)	–	232	104	128	–
Gas Wells (Cumulative)	–	299	150	149	–
Work-in-progress Adjustment	–	82	-23	105	–
Total Drilling and Equipping	2,934	1,370	547	823	1,564
Geological and Geophysical	1,222	409	206	203	813
Other, Including Direct Overhead	1,663	652	400	252	1,011
Total Exploration Expenditures	6,465	2,786	1,371	1,415	3,679
Development Expenditures					
Proved Acreage					
(Including Mergers and Acquisitions)	1,006	599	462	137	407
Drilling and Equipping					
Dry Holes (Cumulative)	–	156	106	50	–
Oil Wells (Cumulative)	–	1,583	1,181	402	–
Gas Wells (Cumulative)	–	1,512	1,039	473	–
Work-in-progress Adjustment	–	761	380	381	–
Total Drilling and Equipping	8,130	4,012	2,706	1,306	4,118
Lease Equipment	4,116	1,640	1,109	531	2,476
Other Development					
Support Equipment	511	217	206	11	294
Other, Including Direct Overhead	3,250	1,678	1,360	318	1,572
Total Development Expenditures	17,013	8,146	5,843	2,303	8,867
Total Exploration and Development Expenditures	23,478	10,932	7,214	3,718	12,546
Production (Lifting) Costs					
Windfall Profit Tax	14	14	–	–	0
Other Severance and Production Taxes	2,861	1,892	–	–	969
Other Production Expenses	20,128	11,777	–	–	8,351
Total Production (Lifting) Costs	23,003	13,683	11,148	2,535	9,320
Total Expenditures and Costs Incurred	46,481	24,615	18,362	6,253	21,866

– = Not available.
Source: Energy Information Administration, Form EIA-28.

Table B23. Total Exploratory and Development Wells Drilled in the United States for FRS Companies and U.S. Industry, 1992 and 1993

Wells Drilled	U.S. Industry		FRS		All Other	
	1992	1993	1992	1993	1992	1993
Exploratory						
Dry	2,553	2,406	344	300	2,209	2,106
Successful	803	793	283	299	520	494
Oil	444	400	132	130	312	270
Gas	359	393	151	169	208	224
Subtotal	3,356	3,200	627	599	2,729	2,600
Percent Successful	23.9	24.8	45.1	49.9	19.1	19.0
Development						
Dry	3,908	4,311	212	249	3,696	4,062
Successful	15,865	15,920	3,403	3,852	12,462	12,068
Oil	8,294	7,742	1,775	2,091	6,519	5,651
Gas	7,571	8,178	1,628	1,761	5,943	6,417
Subtotal	19,773	20,231	3,615	4,101	16,158	16,130
Percent Successful	80.2	78.7	94.1	93.9	77.1	74.8
Total Wells Drilled	23,129	23,431	4,242	4,700	18,887	18,731

Note: Sum of components may not equal total due to independent rounding.

Sources: Industry data - Special compilation provided by the Office of Oil and Gas, Energy Information Administration. Totals are based on data which appeared in the Energy Information Administration's *Monthly Energy Review, September 1994,* p. 83. FRS companies data - Energy Information Administration, Form EIA-28.

Table B24. Completed Well Costs, Oil, Gas, and Dry, for FRS Companies and U.S. Industry, 1992 and 1993

Drilling and Equipping Measures	FRS Companies			U.S. Industry			FRS as a Percent of U.S. Industry	
	1992	1993	Percent Change	1992	1993	Percent Change	1992	1993
Exploration								
Oil Wells								
Drilling and Equipping Costs[1]	316.0	232.0	-26.6	–	–	–	–	–
Wells Completed	132.3	129.8	-1.9	444.0	400.0	-9.9	29.8	32.5
Cost per Well (thousand dollars)	2,389	1,787	-25.2	–	–	–	(2)	(2)
Average Depth (thousand feet)	9.4	9.8	5.1	6.4	6.3	-1.6	(2)	(2)
Cost per Foot (dollars)	255.04	181.53	-28.8	–	–	–	(2)	(2)
Gas Wells								
Drilling and Equipping Costs[1]	286.0	299.0	4.5	–	–	–	–	–
Wells Completed	151.3	169.2	11.8	359.0	393.0	9.5	42.1	43.1
Cost per Well (thousand dollars)	1,890	1,767	-6.5	–	–	–	(2)	(2)
Average Depth (thousand feet)	9.0	9.2	2.9	6.0	5.9	-1.7	(2)	(2)
Cost per Foot (dollars)	210.91	191.67	-9.1	–	–	–	(2)	(2)
Dry Holes								
Drilling and Equipping Costs[1]	729.0	757.0	3.8	–	–	–	–	–
Wells Completed	343.5	299.5	-12.8	2,553.0	2,406.0	-5.8	13.5	12.4
Cost per Well (thousand dollars)	2,122	2,528	19.1	–	–	–	(2)	(2)
Average Depth (thousand feet)	9.8	10.2	3.6	5.4	5.7	5.6	(2)	(2)
Cost per Foot (dollars)	215.81	248.12	15.0	–	–	–	(2)	(2)
Development								
Oil Wells								
Drilling and Equipping Costs[1]	1,432.0	1,583.0	10.5	–	–	–	–	–
Wells Completed	1,775.0	2,091.2	17.8	8,294.0	7,742.0	-6.7	21.4	27.0
Cost per Well (thousand dollars)	807	757	-6.2	–	–	–	(2)	(2)
Average Depth (thousand feet)	5.7	6.1	6.9	5.1	5.5	7.8	(2)	(2)
Cost per Foot (dollars)	142.30	124.90	-12.2	–	–	–	(2)	(2)
Gas Wells								
Drilling and Equipping Costs[1]	1,025.0	1,512.0	47.5	–	–	–	–	–
Wells Completed	1,628.2	1,761.3	8.2	7,571.0	8,178.0	8.0	21.5	21.5
Cost per Well (thousand dollars)	630	858	36.4	–	–	–	(2)	(2)
Average Depth (thousand feet)	6.8	7.1	4.8	5.7	6.2	8.8	(2)	(2)
Cost per Foot (dollars)	92.72	120.64	30.1	–	–	–	(2)	(2)
Dry Holes								
Drilling and Equipping Costs[1]	130.0	156.0	20.0	–	–	–	–	–
Wells Completed	212.2	248.9	17.3	3,908.0	4,311.0	10.3	5.4	5.8
Cost per Well (thousand dollars)	613	627	2.3	–	–	–	(2)	(2)
Average Depth (thousand feet)	6.8	6.4	-6.2	4.9	4.9	0.0	(2)	(2)
Cost per Foot (dollars)	90.15	98.30	9.0	–	–	–	(2)	(2)

[1] Million Dollars.
[2] Not meaningful.
– = Not available.

Sources: Industry data - Special compilation provided by the Office of Oil and Gas, Energy Information Administration. Totals are based on data which appeared in the Energy Information Administration's *Monthly Energy Review, September 1994,* p. 83. FRS companies data - Energy Information Administration, Form EIA-28.

Table B25. Completed Well Costs, Oil, Gas, and Dry, Onshore and Offshore, for FRS Companies, 1992 and 1993

Drilling and Equipping Measures	Total United States			U.S. Onshore			U.S. Offshore		
	1992	1993	Percent Change	1992	1993	Percent Change	1992	1993	Percent Change
Exploration									
Oil Wells									
Drilling and Equipping Costs[1]	316.0	232.0	-26.6	136.0	104.0	-23.5	180.0	128.0	-28.9
Wells Completed	132.3	129.8	-1.9	111.8	107.9	-3.5	20.5	21.9	6.8
Cost per Well (thousand dollars)	2,389	1,787	-25.2	1,216	964	-20.8	8,780	5,845	-33.4
Average Depth (thousand feet)	9.4	9.8	5.1	8.6	9.0	4.7	13.4	13.9	3.5
Cost per Foot (dollars)	255.04	181.53	-28.8	141.08	106.78	-24.3	654.55	421.05	-35.7
Gas Wells									
Drilling and Equipping Costs[1]	286.0	299.0	4.5	151.0	150.0	-0.7	135.0	149.0	10.4
Wells Completed	151.3	169.2	11.8	126.7	127.2	0.4	24.6	42.0	70.7
Cost per Well (thousand dollars)	1,890	1,767	-6.5	1,192	1,179	-1.1	5,488	3,548	-35.4
Average Depth (thousand feet)	9.0	9.2	2.9	8.2	8.4	3.2	13.0	11.6	-11.0
Cost per Foot (dollars)	210.91	191.67	-9.1	145.89	139.93	-4.1	420.56	305.33	-27.4
Dry Holes									
Drilling and Equipping Costs[1]	729.0	757.0	3.8	407.0	316.0	-22.4	322.0	441.0	37.0
Wells Completed	343.5	299.5	-12.8	294.0	230.6	-21.6	49.5	68.9	39.2
Cost per Well (thousand dollars)	2,122	2,528	19.1	1,384	1,370	-1.0	6,505	6,401	-1.6
Average Depth (thousand feet)	9.8	10.2	3.6	8.9	10.2	13.8	15.3	10.3	-32.4
Cost per Foot (dollars)	215.81	248.12	15.0	155.17	134.99	-13.0	426.49	621.13	45.6
Development									
Oil Wells									
Drilling and Equipping Costs[1]	1,432.0	1,583.0	10.5	1,087.0	1,181.0	8.6	345.0	402.0	16.5
Wells Completed	1,775.0	2,091.2	17.8	1,664.1	1,965.8	18.1	110.9	125.4	13.1
Cost per Well (thousand dollars)	807	757	-6.2	653	601	-8.0	3,111	3,206	3.0
Average Depth (thousand feet)	5.7	6.1	6.9	5.5	5.8	5.1	7.9	10.1	28.7
Cost per Foot (dollars)	142.30	124.90	-12.2	118.26	103.53	-12.5	396.10	317.28	-19.9
Gas Wells									
Drilling and Equipping Costs[1]	1,025.0	1,512.0	47.5	822.0	1,039.0	26.4	203.0	473.0	133.0
Wells Completed	1,628.2	1,761.3	8.2	1,582.3	1,663.8	5.2	45.9	97.5	112.4
Cost per Well (thousand dollars)	630	858	36.4	519	624	20.2	4,423	4,851	9.7
Average Depth (thousand feet)	6.8	7.1	4.8	6.7	6.9	3.8	10.2	10.0	-1.5
Cost per Foot (dollars)	92.72	120.64	30.1	77.63	89.89	15.8	435.62	485.13	11.4
Dry Holes									
Drilling and Equipping Costs[1]	130.0	156.0	20.0	92.0	106.0	15.2	38.0	50.0	31.6
Wells Completed	212.2	248.9	17.3	193.0	235.8	22.2	19.2	13.1	-31.8
Cost per Well (thousand dollars)	613	627	2.3	477	450	-5.7	1,979	3,817	92.8
Average Depth (thousand feet)	6.8	6.4	-6.2	6.6	6.1	-7.9	9.0	12.1	34.6
Cost per Foot (dollars)	90.15	98.30	9.0	72.44	74.18	2.4	220.93	316.46	43.2

[1] Million Dollars.
Source: Energy Information Administration, Form EIA-28.

Table B26. U.S. Net Wells Completed, and Net In-Progress Wells for FRS Companies, 1987-1993

Wells	1987	1988	1989	1990	1991	1992	1993
Number of Net Wells Completed During Year							
Onshore							
Net Exploratory Wells							
Dry Holes	498	574	395	411	297	294	231
Oil Wells	253	164	105	132	155	112	108
Gas Wells	127	202	270	490	283	127	127
Total Exploratory Wells	877	940	769	1,033	735	533	466
Net Development Wells							
Dry Holes	330	388	299	260	326	193	236
Oil Wells	4,096	3,742	2,604	3,337	2,738	1,664	1,966
Gas Wells	615	1,022	1,161	1,681	1,354	1,582	1,664
Total Development Wells	5,040	5,153	4,064	5,277	4,418	3,439	3,865
Offshore							
Net Exploratory Wells							
Dry Holes	109	164	100	114	92	50	69
Oil Wells	23	34	27	31	41	21	22
Gas Wells	40	66	61	76	55	25	42
Total Exploratory Wells	172	264	189	222	189	95	133
Net Development Wells							
Dry Holes	29	33	31	32	20	19	13
Oil Wells	163	161	161	143	128	111	125
Gas Wells	60	83	92	146	81	46	98
Total Development Wells	252	277	285	321	228	176	236
Total United States							
Net Exploratory Wells							
Dry Holes	606	738	495	525	390	344	300
Oil Wells	276	198	132	163	196	132	130
Gas Wells	166	268	331	566	338	151	169
Total Exploratory Wells	1,049	1,204	958	1,254	924	627	599
Net Development Wells							
Dry Holes	359	422	330	293	345	212	249
Oil Wells	4,259	3,903	2,765	3,479	2,866	1,775	2,091
Gas Wells	675	1,105	1,253	1,826	1,435	1,628	1,761
Total Development Wells	5,293	5,430	4,349	5,598	4,646	3,615	4,101
Number of Net In-Progress Wells At Year End							
Onshore							
Exploratory Wells	220	152	301	275	125	97	106
Development Wells	798	694	813	1,100	650	795	709
Total In-Progress Wells	1,019	846	1,113	1,375	775	892	815
Offshore							
Exploratory Wells	136	73	62	72	49	39	35
Development Wells	113	128	109	64	36	57	68
Total In-Progress Wells	249	201	171	137	85	96	103
Total United States							
Exploratory Wells	356	224	363	347	174	136	141
Development Wells	911	822	922	1,164	686	852	777
Total In-Progress Wells	1,267	1,047	1,285	1,512	860	988	918

Source: Energy Information Administration, Form EIA-28.

Table B27. Exploration and Development Net Drilling Footage for FRS Companies, 1987-1993

(Thousand Feet)

Exploration, Development, and Production Statistics	1987	1988	1989	1990	1991	1992	1993
Onshore							
Exploratory Well Footage							
Dry Hole Footage	4,388	5,014	3,143	3,660	2,611	2,623	2,341
Oil Well Footage	1,988	1,367	888	1,069	1,208	964	974
Gas Well Footage	981	1,438	1,520	2,126	1,711	1,035	1,072
Total Exploratory Footage	7,357	7,819	5,551	6,855	5,530	4,622	4,387
Development Well Footage							
Dry Hole Footage	2,251	2,426	1,858	1,758	1,130	1,270	1,429
Oil Well Footage	17,036	15,909	11,289	14,442	12,928	9,192	11,407
Gas Well Footage	4,878	6,654	7,079	10,593	7,388	10,589	11,558
Total Development Footage	24,165	24,989	20,226	26,793	21,446	21,051	24,394
Offshore							
Exploratory Well Footage							
Dry Hole Footage	1,303	1,847	1,086	1,268	1,087	755	710
Oil Well Footage	252	342	285	400	487	275	304
Gas Well Footage	511	771	694	809	647	321	488
Total Exploratory Footage	2,066	2,960	2,065	2,477	2,221	1,351	1,502
Development Well Footage							
Dry Hole Footage	291	295	260	201	202	172	158
Oil Well Footage	1,690	1,551	1,521	1,247	1,086	871	1,267
Gas Well Footage	683	892	983	1,074	711	466	975
Total Development Footage	2,664	2,738	2,764	2,522	1,999	1,509	2,400

Source: Energy Information Administration, Form EIA-28.

Table B28. U.S. Net Producing Wells and U.S. Acreage for FRS Companies, 1987-1993

Wells and Acreage	1987	1988	1989	1990	1991	1992	1993
Number of Net Producing Wells							
Onshore							
Oil Wells	174,568	167,018	143,852	133,889	123,426	112,782	106,760
Gas Wells	43,711	42,918	43,088	43,124	43,591	46,308	46,535
Total Producing Wells	218,279	209,936	186,940	177,013	167,017	159,089	153,295
Offshore							
Oil Wells	6,573	6,377	5,849	5,795	5,337	5,021	4,274
Gas Wells	3,571	3,026	3,205	3,150	2,887	2,709	2,643
Total Producing Wells	10,144	9,402	9,054	8,944	8,224	7,730	6,917
Total United States							
Oil Wells	181,141	173,395	149,701	139,684	128,763	117,803	111,034
Gas Wells	47,283	45,944	46,293	46,274	46,478	49,016	49,178
Total Producing Wells	228,424	219,339	195,994	185,958	175,241	166,819	160,212
	(thousand acres)						
Net Acreage							
Onshore							
Developed	31,208	33,068	32,864	31,345	31,043	29,590	28,856
Undeveloped	89,731	80,033	67,898	59,085	53,923	44,433	42,196
Offshore							
Developed	6,296	5,188	5,423	6,089	5,237	5,202	4,799
Undeveloped	16,055	19,619	22,010	23,095	22,993	20,837	16,175
Gross Acreage							
Onshore							
Developed	66,280	64,801	63,804	62,908	61,178	53,389	50,640
Undeveloped	135,463	117,028	104,114	92,037	84,382	68,413	65,051
Offshore							
Developed	10,552	11,134	10,532	10,829	10,673	10,602	9,753
Undeveloped	25,697	35,438	33,343	35,584	35,126	26,692	20,233

Source: Energy Information Administration, Form EIA-28.

Table B29. U.S. Net Petroleum Acreage for FRS Companies, Ranked by Total Energy Assets, 1993 and Percent Change from 1992

Petroleum Acreage	Undeveloped Acreage		Developed Acreage		Total Acreage	
	Thousand Acres	Percent Change from 1992	Thousand Acres	Percent Change from 1992	Thousand Acres	Percent Change from 1992
Onshore						
Top Four	11,664	6.7	10,300	0.7	21,964	3.8
Five Through Twelve	14,504	-11.5	8,872	-3.5	23,376	-8.6
All Other	16,028	-6.4	9,684	-4.8	25,712	-5.8
All FRS	42,196	-5.0	28,856	-2.5	71,052	-4.0
Offshore						
Top Four	3,978	-39.6	2,286	-4.6	6,264	-30.3
Five Through Twelve	8,680	-13.6	1,382	-9.3	10,062	-13.0
All Other	3,517	-16.4	1,131	-11.7	4,648	-15.3
All FRS	16,175	-22.4	4,799	-7.7	20,974	-19.5
Total						
Top Four	15,642	-10.7	12,586	-0.3	28,228	-6.4
Percent Onshore	74.6	--	81.8	--	77.8	--
Five Through Twelve	23,184	-12.3	10,254	-4.3	33,438	-10.0
Percent Onshore	62.6	--	86.5	--	69.9	--
All Other	19,545	-8.3	10,815	-5.6	30,360	-7.4
Percent Onshore	82.0	--	89.5	--	84.7	--
All FRS	58,371	-10.6	33,655	-3.3	92,026	-8.0
Percent Onshore	72.3	--	85.7	--	77.2	--

-- = Not applicable.
Source: Energy Information Administration, Form EIA-28.

Table B30. U.S. Net Ownership Interest Petroleum Reserves and Production for FRS Companies and U.S. Industry, 1993

Reserves and Production	Crude Oil and Natural Gas Liquids (billion barrels)		Natural Gas (trillion cubic feet)	
	FRS Companies	U.S. Industry	FRS Companies	U.S. Industry
Onshore				
Beginning Reserves	15.3	27.6	60.1	136.1
Ending Reserves	14.5	26.4	58.1	134.0
Percent Change	-5.3	-4.3	-3.3	-1.5
Production	1.3	2.7	5.1	12.9
Percent Change from 1992	-8.1	-3.8	-0.1	2.1
Offshore				
Beginning Reserves	2.8	3.6	19.6	29.0
Ending Reserves	2.9	3.8	19.4	28.5
Percent Change	5.6	5.0	-1.4	-1.7
Production	0.3	0.5	2.6	4.9
Percent Change from 1992	-0.5	2.9	-7.9	2.0
Total				
Beginning Reserves	18.1	31.2	79.7	165.0
Ending Reserves	17.5	30.2	77.5	162.4
Percent Change	-3.6	-3.3	-2.8	-1.6
Production	1.6	3.1	7.7	17.8
Percent Change from 1992	-6.7	-2.9	-2.9	2.1

Note: 'Net Ownership Interest' is defined as Net working interest plus own royalty interest.

Sources: Industry data - Energy Information Administration Form EIA-23, see *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves Annual Report*, 1992 and 1993 (October 1993 and October 1994). FRS companies data - Energy Information Administration, Form EIA-28.

Table B31. Proved Petroleum Reserves for FRS Companies, United States and Foreign, 1993

Reserves Statistics	Worldwide Total	United States			Foreign		
		Total	Onshore	Offshore	Total	Canada	Other
	(million barrels)						
Crude Oil and Natural Gas Liquids							
Net Ownership Interest Reserves:							
Beginning of Period	30,019	18,127	15,339	2,788	11,892	2,139	9,753
Revisions of Previous Estimates	678	224	101	123	454	-7	461
Improved Recovery	566	338	325	13	228	39	189
Purchases of Minerals-in-Place	1,399	151	135	16	1,248	38	1,210
Extensions & Discoveries	1,203	573	180	392	630	48	582
Production	-2,953	-1,632	-1,326	-307	-1,321	-168	-1,153
Sales of Minerals-in-Place	-559	-306	-226	-80	-253	-72	-181
End of period	30,352	17,474	14,529	2,945	12,878	2,017	10,861
Proportionate Interest in Investee Reserves and Foreign Access Reserves	1,596	--	--	--	1,596	W	W
	(billion cubic feet)						
Natural Gas							
Net Ownership Interest Reserves:							
Beginning of Period	133,583	79,712	60,078	19,634	53,872	10,946	42,925
Revisions of Previous Estimates	3,669	1,901	1,065	836	1,768	14	1,754
Improved Recovery	284	161	160	1	123	53	69
Purchases of Minerals-in-Place	2,549	756	624	132	1,793	184	1,609
Extensions & Discoveries	8,808	4,592	2,541	2,051	4,216	525	3,691
Production	-11,750	-7,651	-5,089	-2,562	-4,099	-993	-3,106
Sales of Minerals-in-Place	-3,036	-1,984	-1,255	-729	-1,051	-819	-233
End of Period	134,107	77,487	58,125	19,362	56,620	9,911	46,710

-- = Not applicable.
W = Data withheld to avoid disclosure.
Source: Energy Information Administration, Form EIA-28.

Table B32. U.S. Reserve Additions, Exploration and Development Expenditures, and Expenditures per Barrel of Reserve Additions for FRS Companies Ranked by Total Energy Assets and for U.S. Industry, 1991-1993

Reserve Additions, Expenditures, and Wells	1991			1992			1993		
	Onshore	Offshore	Total	Onshore	Offshore	Total	Onshore	Offshore	Total
	(million barrels)								
Reserve Additions[1]									
Top Four	712.2	337.3	1,049.5	567.5	212.4	779.8	427.8	295.2	723.0
Five Through Twelve	615.9	129.3	745.2	483.8	186.3	670.1	535.2	508.0	1,043.2
All Other	344.6	88.3	432.8	355.3	135.7	491.1	310.9	236.5	547.4
All FRS	1,672.6	554.9	2,227.5	1,406.6	534.3	1,941.0	1,273.9	1,039.7	2,313.6
U.S. Industry	3,607.2	620.2	4,227.4	4,195.4	810.5	5,005.9	3,389.1	1,424.5	4,813.6
	(million dollars)								
Exploration and Development Expenditures									
Top Four	3,032.0	1,654.0	4,686.0	2,311.0	1,014.0	3,325.0	2,173.0	1,031.0	3,204.0
Five Through Twelve	3,824.0	2,246.0	6,070.0	2,814.0	1,330.0	4,144.0	2,848.0	1,504.0	4,352.0
All Other	1,631.0	681.0	2,312.0	1,658.0	646.0	2,304.0	1,731.0	1,046.0	2,777.0
All FRS	8,487.0	4,581.0	13,068.0	6,783.0	2,990.0	9,773.0	6,752.0	3,581.0	10,333.0
U.S. Industry	–	–	0.0	–	–	0.0	–	–	–
	(number of wells)								
Wells Completed									
Top Four	1,651.2	121.0	1,772.2	945.0	66.0	1,011.0	1,214.4	139.7	1,354.1
Five Through Twelve	2,368.7	208.6	2,577.3	1,717.5	136.6	1,854.1	1,778.2	124.6	1,902.8
All Other	1,133.6	85.6	1,219.2	1,309.4	68.0	1,377.4	1,338.5	104.5	1,443.0
All FRS	5,153.5	416.2	5,569.7	3,971.9	270.6	4,242.5	4,331.1	368.8	4,699.9
U.S. Industry	28,680.0	538.0	29,217.0	22,635.0	492.0	23,129.0	22,726.0	705.0	23,431.0
	(dollars per barrel)								
Exploration and Development Expenditures per Barrel of Reserve Additions									
Top Four	4.26	4.90	4.46	4.07	4.77	4.26	5.08	3.49	4.43
Five Through Twelve	6.21	17.37	8.15	5.82	7.14	6.18	5.32	2.96	4.17
All Other	4.73	7.71	5.34	4.67	4.76	4.69	5.57	4.42	5.07
All FRS	5.07	8.26	5.87	4.82	5.60	5.04	5.30	3.44	4.47
U.S. Industry	–	–	0.00	–	–	0.00	–	–	–
	(thousand barrels)								
Reserve Additions per Well Completed									
Top Four	431.3	2,787.7	592.2	600.5	3,217.7	771.3	352.3	2,113.2	533.9
Five Through Twelve	260.0	619.8	289.1	281.7	1,363.5	361.4	301.0	4,076.9	548.2
All Other	304.0	1,031.2	355.0	271.4	1,996.0	356.5	232.3	2,263.3	379.4
All FRS	324.6	1,333.2	399.9	354.1	1,974.7	457.5	294.1	2,819.2	492.3
U.S. Industry	125.8	1,152.8	144.7	185.4	1,647.4	216.4	149.1	2,020.6	205.4

[1] Excludes net purchases of minerals in place, includes crude oil and natural gas liquids (measured in millions of barrels) and natural gas (measured in millions of barrels of crude equivalent). The conversion factor for natural gas is 0.178 barrels of crude / 1000 cubic feet. Reserve additions include the net of corrections and adjustments.

– = Not available.

Sources: Reserve additions - Energy Information Administration Form EIA-23, see *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, 1991, 1992, and 1993 Annual Reports. Wells completed - special compilation provided by the Office of Oil and Gas, Energy Information Administration. Totals are based on data which appeared in the Energy Information's *Monthly Energy Review, September 1994,* p. 83. FRS companies data - Energy Information Administration, Form EIA-28.

Table B33. Foreign Petroleum Exploration, Development, Reserves, and Production Statistics by Geographic Area for FRS Companies and Foreign Industry, 1993 and Percent Change from 1992

Foreign Petroleum Activities	Total Foreign	Canada	Europe and Former Soviet Union[1]	Africa	Middle East	Other Eastern Hemisphere	Other Western Hemisphere
Crude Oil and NGL Production[2] (million barrels)							
FRS Companies	1,337.1	168.2	458.9	234.3	105.5	284.4	85.9
Percent Change	2.2	-4.9	4.8	3.1	-6.5	9.3	-8.6
Foreign Industry[3]	19,821.2	796.9	4,896.0	2,558.1	7,135.8	1,468.4	2,966.0
Percent Change	0.9	6.1	-4.2	-1.5	5.0	-1.4	2.5
Wells Completed							
FRS Companies	1,499.9	841.3	152.1	76.9	57.7	264.9	107.0
Percent Change	36.9	113.4	7.1	-23.9	-33.9	-1.9	5.9
Foreign Industry	14,907.0	9,390.0	1,311.0	552.0	271.0	1,408.0	1,975.0
Percent Change	-29.1	111.5	-89.3	1.7	-5.9	-6.8	0.4
Success Rate[4]							
FRS Companies	82.3	85.8	75.7	67.2	65.2	80.1	88.7
Foreign Industry	81.1	80.6	77.0	81.7	86.0	74.9	89.4
Exploration and Development Expenditures (million dollars)							
FRS Companies	12,546.0	1,559.0	5,745.0	1,472.0	685.0	2,469.0	616.0
Percent Change	-2.8	41.0	-15.5	5.7	22.8	2.5	-4.8
Crude Oil and NGL Reserve Interests[5] (million barrels)							
FRS Companies	14,473.8	2,021.2	5,532.3	2,099.6	1,706.0	2,380.1	734.6
Percent Change	8.2	-5.5	29.2	5.8	-8.0	0.0	0.6

[1] For 1993, OECD Europe combined with the former Soviet Union and Eastern Europe to avoid disclosure. Prior to 1993, only OECD Europe is included in this region.

[2] Crude oil plus natural gas liquids. Includes ownership interest production and foreign access production.

[3] Foreign Industry levels defined as total activity outside of the United States except the People's Republic of China.

[4] Success Rate defined as the total number of successful well completions during the period divided by the total number of wells drilled.

[5] Includes net ownership interest reserves (89.0 percent) and 'Other Access' reserves (11.0 percent). Other access reserves include proportional interest in investee reserves and foreign access reserves.

Note: Sum of components may not equal total due to independent rounding.

Sources: FRS Companies - Energy Information Administration, Form EIA-28. Industry data - *World Oil*, August 1994, and Energy Information Administration, *International Energy Annual*, 1993.

Table B34. Foreign Exploration and Development Expenditures by Region for FRS Companies, 1987-1993

(Million Dollars)

Foreign Expenditures by Region	1987	1988	1989	1990	1991	1992	1993
Exploration Expenditures							
Canada	562	1,124	1,141	753	661	336	403
OECD Europe	1,095	1,465	1,132	2,233	2,192	1,544	1,313
Former Soviet Union and E. Europe	0	0	0	0	0	0	163
Africa	418	494	585	618	680	738	599
Middle East	124	223	197	302	258	273	225
Other Eastern Hemisphere	604	604	1,186	1,017	1,028	869	736
Other Western Hemisphere	266	316	304	327	435	283	240
Total Foreign Exploration Expenditures	3,069	4,226	4,545	5,250	5,254	4,043	3,679
Development Expenditures							
Canada	1,309	4,277	5,125	1,065	1,070	770	1,156
OECD Europe	1,889	2,854	2,407	4,383	4,643	5,252	4,169
Former Soviet Union and E. Europe	0	0	0	0	0	0	100
Africa	337	346	439	807	845	655	873
Middle East	261	153	209	296	233	285	460
Other Eastern Hemisphere	2,162	765	1,098	1,416	1,359	1,540	1,733
Other Western Hemisphere	194	419	305	343	300	364	376
Total Foreign Development Expenditures	6,152	8,814	9,583	8,310	8,450	8,866	8,867
Total Exploration and Development Expenditures							
Canada	1,871	5,401	6,266	1,818	1,731	1,106	1,559
OECD Europe	2,984	4,319	3,539	6,616	6,835	6,796	5,482
Former Soviet Union and E. Europe	0	0	0	0	0	0	263
Africa	755	840	1,024	1,425	1,525	1,393	1,472
Middle East	385	376	406	598	491	558	685
Other Eastern Hemisphere	2,766	1,369	2,284	2,433	2,387	2,409	2,469
Other Western Hemisphere	385	376	406	598	491	558	685
Total Foreign Exploration and Development Expenditures	9,221	13,040	14,128	13,560	13,704	12,909	12,546

Source: Energy Information Administration, Form EIA-28.

Table B35. Distribution of Foreign Exploration and Development Expenditures for FRS Companies Ranked by Total Energy Assets, 1993 and Percent Change from 1992

Exploration and Development Expenditures	Total Foreign	Canada	Europe and Former Soviet Union[1]	Africa and Mideast	Other Eastern Hemisphere	Other Western Hemisphere
	(million dollars)					
1993						
All FRS	12,546.0	1,559.0	5,745.0	2,157.0	2,469.0	616.0
Top Four	6,060.0	924.0	2,806.0	833.0	1,415.0	82.0
Five Through Twelve	4,528.0	406.0	1,733.0	1,161.0	738.0	490.0
All Other	1,958.0	229.0	1,206.0	163.0	316.0	44.0
	(percent)					
Distribution 1993						
All FRS	100.0	12.4	45.8	17.2	19.7	4.9
Top Four	100.0	15.2	46.3	13.7	23.3	1.4
Five Through Twelve	100.0	9.0	38.3	25.6	16.3	10.8
All Other	100.0	11.7	61.6	8.3	16.1	2.2
Change from 1992						
All FRS	-2.8	41.0	-15.5	10.6	2.5	-4.8
Top Four	-8.2	45.7	-21.8	4.6	2.8	-60.4
Five Through Twelve	12.4	73.5	-4.2	22.6	9.3	34.2
All Other	-14.0	-3.8	-13.7	-21.6	-11.7	-41.3

[1] For 1993, OECD Europe combined with the former Soviet Union and Eastern Europe to avoid disclosure. Prior to 1993, only OECD Europe is included in this region.

Source: Energy Information Administration, Form EIA-28.

Table B36. Number of Net Wells Completed, Net In-Progress Wells, and Net Producing Wells in Foreign Areas for FRS Companies, 1987-1993

Number of Wells	1987	1988	1989	1990	1991	1992	1993
Canada							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	154.9	155.3	113.9	104.9	101.3	65.1	71.7
Oil Wells	114.4	84.1	56.3	61.7	38.2	19.7	47.9
Gas Wells	35.3	54.5	38.3	48.3	54.0	29.6	46.8
Total Exploratory Wells	304.6	293.9	208.5	214.9	193.5	114.4	166.4
Development Wells							
Dry Holes	32.2	58.2	34.7	47.2	32.3	29.3	47.4
Oil Wells	660.2	690.8	168.3	225.7	169.6	211.1	334.6
Gas Wells	49.2	66.6	39.8	97.1	97.0	39.4	292.9
Total Development Wells	741.6	815.6	242.8	370.0	298.9	279.8	674.9
Net In-Progress Wells at Year End	178.1	163.5	126.3	63.9	29.3	31.7	65.3
Net Producing Wells							
Oil Wells	13,187.5	16,087.6	15,880.1	15,044.9	13,996.6	12,597.5	11,704.3
Gas Wells	3,783.3	7,795.9	7,162.6	6,635.8	6,094.0	5,927.2	5,740.2
Total Producing Wells	16,970.8	23,883.5	23,042.7	21,680.7	20,090.6	18,524.7	17,444.5
Europe and Former Soviet Union[1]							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	56.1	68.5	75.1	74.9	77.6	47.4	33.4
Oil Wells	14.6	15.8	13.7	16.1	8.2	16.2	11.8
Gas Wells	19.0	20.1	14.9	15.9	15.0	11.8	14.6
Total Exploratory Wells	89.7	104.4	103.7	106.9	100.8	75.4	59.8
Development Wells							
Dry Holes	3.0	8.6	4.9	3.7	5.4	2.6	3.6
Oil Wells	46.9	54.1	52.3	54.4	52.0	38.2	59.9
Gas Wells	7.8	25.4	27.1	22.5	26.5	25.8	28.8
Total Development Wells	57.7	88.1	84.3	80.6	83.9	66.6	92.3
Net In-Progress Wells at Year End	68.9	83.5	65.6	78.4	77.0	70.5	76.3
Net Producing Wells							
Oil Wells	1,750.7	1,532.9	1,436.8	1,475.8	1,462.0	1,459.3	1,479.3
Gas Wells	455.8	586.1	621.7	643.6	645.4	647.5	687.0
Total Producing Wells	2,206.5	2,119.0	2,058.5	2,119.4	2,107.4	2,106.8	2,166.3
Africa and Middle East							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	44.9	55.3	37.8	51.4	54.5	65.3	37.9
Oil Wells	W	W	14.5	W	W	W	W
Gas Wells	W	W	1.7	W	W	W	W
Total Exploratory Wells	57.1	74.3	54.0	67.5	73.9	84.8	52.8
Development Wells							
Dry Holes	5.0	W	W	6.6	W	W	W
Oil Wells	52.2	79.0	85.6	77.5	82.7	91.1	72.2
Gas Wells	0.0	W	W	2.0	W	W	W
Total Development Wells	57.2	95.0	93.1	86.1	94.1	103.5	81.8
Net In-Progress Wells at Year End	52.8	47.0	48.0	29.0	44.0	34.4	21.3
Net Producing Wells							
Oil Wells	889.5	1,332.1	1,349.2	1,240.7	1,294.2	1,374.1	1,322.9
Gas Wells	38.0	19.9	20.4	20.0	20.6	26.8	25.8
Total Producing Wells	927.5	1,352.0	1,369.6	1,260.7	1,314.8	1,400.9	1,348.7

See footnotes at end of table.

Table B36. Number of Net Wells Completed, Net In-Progress Wells, and Net Producing Wells in Foreign Areas for FRS Companies, 1987-1993 (Continued)

Number of Wells	1987	1988	1989	1990	1991	1992	1993
Other Eastern Hemisphere							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	35.5	70.4	61.1	57.4	60.5	47.6	43.9
Oil Wells	13.3	16.9	19.9	18.0	21.1	22.9	8.3
Gas Wells	12.8	22.1	15.2	11.0	11.4	10.0	16.4
Total Exploratory Wells	61.6	109.4	96.2	86.4	93.0	80.5	68.6
Development Wells							
Dry Holes	1.0	2.9	5.5	4.5	14.5	11.0	8.7
Oil Wells	76.6	105.9	130.1	124.6	106.4	106.7	124.9
Gas Wells	22.0	29.8	41.3	47.2	48.6	71.9	62.7
Total Development Wells	99.6	138.6	176.9	176.3	169.5	189.6	196.3
Net In-Progress Wells at Year End	51.3	58.9	65.4	85.5	89.4	71.5	83.8
Net Producing Wells							
Oil Wells	1,202.6	1,312.2	1,468.3	1,632.9	1,532.1	1,650.2	1,666.0
Gas Wells	244.1	271.9	279.8	324.8	321.1	373.2	393.9
Total Producing Wells	1,446.7	1,584.1	1,748.1	1,957.7	1,853.2	2,023.4	2,059.9
Other Western Hemisphere							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	16.1	16.7	22.6	19.7	15.1	6.9	8.1
Oil Wells	W	W	W	W	W	W	W
Gas Wells	W	W	W	W	W	W	W
Total Exploratory Wells	25.7	24.5	30.2	22.7	25.6	12.0	19.8
Development Wells							
Dry Holes	W	W	5.0	W	W	W	W
Oil Wells	117.7	140.6	119.5	87.4	87.4	87.0	78.8
Gas Wells	W	W	0.0	W	W	W	W
Total Development Wells	121.7	141.4	124.5	89.9	93.4	89.0	87.2
Net In-Progress Wells at Year End	17.0	35.0	10.3	15.1	9.6	7.4	15.6
Net Producing Wells							
Oil Wells	3,413.8	3,277.0	3,276.8	3,102.0	3,145.5	2,938.3	3,032.6
Gas Wells	109.4	92.3	88.4	48.4	44.5	42.0	65.4
Total Producing Wells	3,523.2	3,369.3	3,365.2	3,150.4	3,190.0	2,980.3	3,098.0
Total Foreign							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	307.5	366.2	310.5	308.3	309.0	232.3	195.0
Oil Wells	159.9	139.7	107.9	112.7	95.5	81.0	93.0
Gas Wells	71.3	100.6	74.2	77.4	82.3	53.8	79.4
Total Exploratory Wells	538.7	606.5	492.6	498.4	486.8	367.1	367.4
Development Wells							
Dry Holes	42.2	84.1	57.2	64.5	61.3	52.2	71.1
Oil Wells	953.6	1,070.4	555.8	569.6	498.1	534.1	670.4
Gas Wells	82.0	124.2	108.6	168.8	180.4	142.2	391.0
Total Development Wells	1,077.8	1,278.7	721.6	802.9	739.8	728.5	1,132.5
Net In-Progress Wells at Year End	368.1	387.9	315.6	271.9	249.3	215.5	262.3
Net Producing Wells							
Oil Wells	20,444.1	23,541.8	23,411.2	22,496.3	21,430.4	20,019.4	19,205.1
Gas Wells	4,630.6	8,766.1	8,172.9	7,672.6	7,125.6	7,016.7	6,912.3
Total Producing Wells	25,074.7	32,307.9	31,584.1	30,168.9	28,556.0	27,036.1	26,117.4

[1] For 1993, OECD Europe combined with the former Soviet Union and Eastern Europe to avoid disclosure. Prior to 1993, only OECD Europe is included in this region.

W = Data withheld to avoid disclosure.

Source: Energy Information Administration, Form EIA-28.

Table B37. Foreign Proved Oil and Gas Reserves for FRS Companies, 1993

Reserves Statistics	Foreign					
	Total Foreign	Canada	Europe and Former Soviet Union[1]	Africa and Mideast	Other Eastern Hemisphere	Other Western Hemisphere
	(million barrels)					
Crude Oil and Natural Gas Liquids						
Net Ownership Interest Reserves:						
Beginning of Period	11,892	2,139	4,302	2,815	1,915	721
Revisions of Previous Estimates & Improved Recovery	682	33	262	181	130	76
Net Purchases of Minerals-in-Place	995	-34	1,124	-108	12	2
Extensions & Discoveries	630	48	202	236	129	15
Production	-1,321	-168	-459	-323	-284	-86
End of Period	12,878	2,017	5,431	2,801	1,901	728
	(billion cubic feet)					
Natural Gas						
Net Ownership Interest Reserves:						
Beginning of Period	53,872	10,946	20,343	418	19,898	2,266
Revisions of Previous Estimates & Improved Recovery	1,891	67	1,079	142	632	-30
Net Purchases of Minerals-in-Place	741	-635	1,473	-60	-36	-1
Extensions & Discoveries	4,216	525	1,428	82	1,793	387
Production	-4,099	-993	-1,545	-66	-1,296	-200
End of Period	56,620	9,911	22,779	517	20,991	2,423

[1] For 1993, OECD Europe combined with the former Soviet Union and Eastern Europe to avoid disclosure. Prior to 1993, only OECD Europe is included in this region.

W = Data withheld to avoid disclosure.

Source: Energy Information Administration, Form EIA-28.

Table B38. Foreign Production (Lifting) Costs for FRS Companies, 1987-1993

(Million Dollars)

Production Costs by Region	1987	1988	1989	1990	1991	1992	1993
Canada							
Royalty Expenses	W	W	19	W	W	W	19
Taxes other than Income Taxes	W	W	94	W	W	W	56
Other Costs	976	1,323	1,528	1,736	1,797	1,388	1,210
Total Production Costs	1,091	1,437	1,641	1,814	1,893	1,464	1,285
OECD Europe							
Royalty Expenses	420	300	224	544	495	465	305
Taxes other than Income Taxes	166	153	100	270	229	257	214
Other Costs	2,991	3,147	3,073	3,692	4,353	4,199	3,617
Total Production Costs	3,577	3,600	3,397	4,506	5,077	4,921	4,136
Former Soviet Union and E. Europe							
Royalty Expenses	--	--	--	--	--	--	0
Taxes other than Income Taxes	--	--	--	--	--	--	0
Other Costs	--	--	--	--	--	--	54
Total Production Costs	--	--	--	--	--	--	54
Africa							
Royalty Expenses	438	170	210	317	295	282	W
Taxes other than Income Taxes	15	31	14	9	14	21	W
Other Costs	495	575	480	625	680	776	821
Total Production Costs	948	776	704	951	989	1,079	1,122
Middle East							
Royalty Expenses	146	103	W	W	W	62	W
Taxes other than Income Taxes	154	72	W	W	W	292	W
Other Costs	286	273	295	305	217	324	313
Total Production Costs	586	448	454	468	316	678	424
Other Eastern Hemisphere							
Royalty Expenses and Taxes other than Income Taxes	914	608	566	687	730	685	630
Other Costs	286	273	295	305	217	324	313
Total Production Costs	586	448	454	468	316	678	424
Other Western Hemisphere							
Royalty Expenses and Taxes other than Income Taxes	302	196	210	312	230	137	122
Other Costs	755	920	972	1,318	1,420	1,400	1,173
Total Production Costs	1,669	1,528	1,538	2,005	2,150	2,085	1,803
Total Foreign							
Royalty Expenses	1,217	697	618	1,107	968	991	789
Taxes other than Income Taxes	1,453	1,050	978	1,273	1,220	1,286	969
Other Costs	5,915	6,625	6,830	8,206	8,948	8,537	7,562
Total Production Costs	8,585	8,372	8,426	10,586	11,136	10,814	9,320

W = Data withheld to avoid disclosure.
-- = Not applicable.
Source: Energy Information Administration, Form EIA-28.

Table B39. U.S. Refining/Marketing Dispositions of Refined Products by Channel of Distribution for FRS Companies, 1987-1993

U.S. Dispositions	1987	1988	1989	1990	1991	1992	1993
	Values (million dollars)						
Motor Gasoline							
Intersegment Sales	189	194	244	247	568	231	196
U.S. Third-Party Sales							
Wholesale-Resellers	26,394	25,313	26,451	33,255	28,854	26,641	24,954
Company Operated Automotive Outlets	9,101	9,733	11,308	14,238	13,059	12,049	11,018
Company Lessee and Open Automotive Outlets	19,445	20,284	23,050	25,373	22,459	23,061	21,917
Other (Industrial, Commercial and Other Retail)	5,107	5,045	4,566	4,576	4,043	5,713	5,391
Total Third-Party Sales	60,047	60,375	65,375	77,442	68,415	67,464	63,280
Total Motor Gasoline Sales	60,236	60,569	65,619	77,689	68,983	67,695	63,476
Distillate Fuels							
Intersegment Sales	214	311	398	473	483	550	440
Third-Party Sales	29,523	28,218	32,277	40,222	35,052	33,370	32,624
Total Distillate Fuels Sales	29,737	28,529	32,675	40,695	35,535	33,920	33,064
Other Refined Products							
Intersegment Sales	4,283	4,404	4,511	5,093	4,435	4,671	4,213
Third-Party Sales	20,481	17,388	19,124	20,945	19,032	17,854	16,894
Total Other Refined Products Sales	24,764	21,792	23,635	26,038	23,467	22,525	21,107
Total U.S. Refined Products							
Intersegment Sales	4,686	4,909	5,153	5,813	5,486	5,452	4,849
Third-Party Sales	110,051	105,981	116,776	138,609	122,499	118,688	112,798
Total U.S. Refined Products Sales	114,737	110,890	121,929	144,422	127,985	124,140	117,647
	Volumes (million barrels)						
Motor Gasoline							
Intersegment Sales	8	9	12	8	18	9	9
U.S. Third-Party Sales							
Wholesale-Resellers	1,109	1,107	1,007	1,072	996	972	1,012
Company Operated Automotive Outlets	318	340	356	384	367	350	342
Company Lessee and Open Automotive Outlets	718	742	768	719	734	740	731
Other (Industrial, Commercial and Other Retail)	245	262	184	163	151	216	233
Total Third-Party Sales	2,390	2,451	2,314	2,338	2,248	2,277	2,318
Total Motor Gasoline Sales	2,399	2,460	2,325	2,346	2,267	2,286	2,327
Distillate Fuels							
Intersegment Sales	10	16	16	16	19	24	20
Third-Party Sales	1,345	1,395	1,345	1,356	1,328	1,340	1,380
Total Distillate Fuels Sales	1,355	1,411	1,361	1,372	1,347	1,364	1,400
Other Refined Products							
Intersegment Sales	251	272	232	230	212	232	240
Third-Party Sales	1,044	1,010	1,004	879	925	896	843
Total Other Refined Products Sales	1,295	1,281	1,236	1,108	1,137	1,128	1,082
Total U.S. Refined Products							
Intersegment Sales	270	296	260	253	249	264	269
Third-Party Sales	4,779	4,855	4,663	4,573	4,502	4,513	4,541
Total U.S. Refined Products Sales	5,049	5,152	4,923	4,826	4,751	4,778	4,810

See footnote at end of table.

Table B39. U.S. Refining/Marketing Dispositions of Refined Products by Channel of Distribution for FRS Companies, 1987-1993 (Continued)

U.S. Dispositions	1987	1988	1989	1990	1991	1992	1993
	Number of Automotive Outlets						
Number of Active Automobile Outlets at Year End							
Company Operated	9,837	10,712	10,995	11,177	10,745	9,935	9,225
Lessee Dealers	23,103	22,569	21,114	20,376	19,891	19,334	18,614
Open Dealers	28,279	32,919	21,475	19,532	17,969	17,297	16,325
Total Outlets	61,219	66,200	53,584	51,085	48,605	46,566	44,164

Source: Energy Information Administration, Form EIA-28.

Table B40. Sales of U.S. Refined Products, by Volume and Price, for FRS Companies Ranked by Total Energy Assets, 1992 and 1993

(Million Barrels and Dollars per Barrel)

Product Distribution Channel	All FRS		Top Four		Five Through Twelve		All Other	
	Volume	Price	Volume	Price	Volume	Price	Volume	Price
Gasoline								
Intra-Company Sales								
1993	9.3	21.02	8.9	20.84	0.1	34.09	0.3	22.44
1992	9.2	25.10	7.7	25.28	0.1	25.32	1.4	24.11
Percent Change	1.3	-16.3	15.7	-17.6	11.4	34.7	-77.9	-7.0
Wholesale/Resellers								
1993	1,011.8	24.66	384.9	24.56	401.5	24.87	225.3	24.47
1992	971.5	27.42	366.2	26.69	368.2	28.83	237.2	26.36
Percent Change	4.1	-10.1	5.1	-8.0	9.0	-13.7	-5.0	-7.2
Dealer-Operated Outlets								
1993	731.2	29.97	277.0	30.84	309.3	30.19	144.9	27.86
1992	740.0	31.16	275.5	32.34	316.0	30.68	148.6	29.99
Percent Change	-1.2	-3.8	0.6	-4.7	-2.1	-1.6	-2.5	-7.1
Company-Operated Outlets								
1993	341.7	32.25	94.9	34.47	163.6	31.22	83.2	31.72
1992	349.7	34.45	97.8	34.87	167.0	34.59	84.9	33.71
Percent Change	-2.3	-6.4	-2.9	-1.1	-2.0	-9.8	-2.0	-5.9
Other[1]								
1993	233.4	23.10	35.2	24.97	91.4	22.77	106.7	22.76
1992	215.9	26.47	21.3	29.14	92.8	26.63	101.8	25.76
Percent Change	8.1	-12.7	65.7	-14.3	-1.5	-14.5	4.9	-11.6
Total Gasoline								
1993	2,327.4	27.27	801.0	27.88	965.9	27.45	560.5	26.10
1992	2,286.3	29.61	768.4	29.81	944.0	30.25	573.9	28.28
Percent Change	1.8	-7.9	4.2	-6.5	2.3	-9.3	-2.3	-7.7
Distillate								
1993	1,400.3	23.61	498.8	23.60	526.2	23.86	375.2	23.29
1992	1,363.7	24.87	499.1	24.66	487.6	25.16	377.0	24.79
Percent Change	2.7	-5.1	-0.1	-4.3	7.9	-5.2	-0.5	-6.0
All Other Products								
1993	1,082.4	19.50	359.2	20.96	367.4	18.50	355.7	19.05
1992	1,127.6	19.98	379.6	22.14	371.0	19.04	377.0	18.72
Percent Change	-4.0	-2.4	-5.4	-5.3	-1.0	-2.8	-5.7	1.8
Total Refined Products								
1993	4,810.0	24.46	1,659.1	25.10	1,859.6	24.67	1,291.4	23.34
1992	4,777.6	25.98	1,647.1	26.48	1,802.6	26.57	1,327.9	24.57
Percent Change	0.7	-5.9	0.7	-5.2	3.2	-7.2	-2.8	-5.0

[1] Includes direct sales to industrial and commercial customers and sales to unconsolidated affiliates.
Note: Sum of components may not equal total due to independent rounding.
Source: Energy Information Administration, Form EIA-28.

Table B41. U.S. Petroleum Refining/Marketing, General Operating Expenses for FRS Companies, 1987-1993

(Billion Dollars)

General Operating Expenses	1987	1988	1989	1990	1991	1992	1993
Raw Material Supply							
Raw Material Purchases	111.4	102.4	121.8	151.8	135.9	134.9	125.5
Other Raw Material Supply Expense	6.5	6.3	5.6	4.1	4.8	4.3	5.1
Total Raw Material Supply Expense	118.0	108.8	127.3	155.8	140.7	139.2	130.6
Less: Cost of Raw Materials Input To Refining	71.9	61.0	71.3	83.4	72.5	69.1	61.0
Net Raw Material Supply	46.1	47.8	56.0	72.4	68.2	70.1	69.6
Refining							
Raw Materials Input to Refining	71.9	61.0	71.3	83.4	72.5	69.1	61.0
Less: Raw Material Used as Refinery Fuel	3.9	3.7	3.9	3.9	3.6	3.4	3.6
Refinery Process Energy Expense	5.4	5.5	5.2	5.5	5.5	5.4	5.6
Other Refining Operating Expenses	8.2	8.9	8.6	9.8	9.9	9.9	9.8
Refined Product Purchases	21.9	20.5	24.4	31.4	27.0	27.7	26.9
Other Refined Product Supply Expenses	3.7	4.3	3.3	4.6	4.1	3.7	4.2
Total Refining	107.2	96.3	108.9	130.8	115.5	112.4	103.9
Marketing							
Cost of Other Products Sold	2.0	2.9	4.0	4.8	5.8	4.6	4.7
Other Marketing Expenses	9.3	8.1	8.9	9.8	11.4	12.9	10.5
Subtotal	11.3	11.0	12.9	14.6	17.2	17.5	15.2
Expense of Transport Services for Others	0.4	0.5	1.1	0.6	0.5	1.1	1.0
Total Marketing	11.7	11.5	14.0	15.3	17.7	18.6	16.1
Total U.S. Refining/Marketing Segment General Operating Expenses	165.0	155.6	178.9	218.5	201.4	201.1	189.7

Source: Energy Information Administration, Form EIA-28.

Table B42. U.S. Petroleum Segments Purchases and Sales of Raw Materials and Refined Products for FRS Companies, 1987-1993

Purchases and Sales	1987	1988	1989	1990	1991	1992	1993
	Values (million dollars)						
Purchases							
U.S. Refining/Marketing Segment							
Raw Materials							
Crude Oil and NGL	105,881	97,203	116,552	144,973	129,380	124,868	111,654
Natural Gas	2,993	2,878	3,237	3,935	4,367	7,504	10,678
Other Raw Materials	2,532	2,354	1,973	2,848	2,195	2,496	3,196
Total Raw Materials	111,406	102,435	121,762	151,756	135,942	134,868	125,528
Refined Products							
Motor Gasoline	9,987	10,332	11,095	13,927	12,106	12,403	11,831
Distillate Fuels	4,393	3,642	5,274	7,006	5,738	6,008	6,629
Other Refined Products	7,516	6,489	8,016	10,497	9,136	9,261	8,467
Total Refined Products	21,896	20,463	24,385	31,430	26,980	27,672	26,927
U.S. Production Segment							
Crude Oil and NGL	1,700	1,745	2,138	2,702	4,186	2,816	2,458
Natural Gas	2,034	2,702	2,845	3,167	3,223	4,192	5,042
Total Raw Materials	3,734	4,447	4,983	5,869	7,409	7,008	7,500
Sales							
U.S. Refining/Marketing Segment							
Raw Materials							
Crude Oil and NGL	43,983	46,072	55,078	69,037	64,948	63,564	56,612
Natural Gas	2,548	2,188	2,262	3,226	3,873	7,406	10,527
Other Raw Materials	1,490	1,509	1,084	1,271	929	1,175	1,720
Total Raw Materials	48,021	49,769	58,424	73,534	69,750	72,145	68,859
Refined Products							
Motor Gasoline	60,236	60,569	65,619	77,689	68,983	67,695	63,476
Distillate Fuels	29,737	28,529	32,675	40,695	35,535	33,920	33,064
Other Refined Products	24,764	21,792	23,635	26,038	23,467	22,525	21,107
Total Refined Products	114,737	110,890	121,929	144,422	127,985	124,140	117,647
U.S. Production Segment							
Crude Oil and NGL	32,430	27,640	30,936	38,088	32,372	29,585	25,734
Natural Gas	12,789	15,241	14,965	15,999	14,071	16,905	20,238
Total Raw Materials	45,219	42,881	45,901	54,087	46,443	46,490	45,972

See footnote at end of table.

Table B42. U.S. Petroleum Segments Purchases and Sales of Raw Materials and Refined Products for FRS Companies, 1987-1993 (Continued)

Purchases and Sales	1987	1988	1989	1990	1991	1992	1993
	Volumes						
Purchases							
U.S. Refining/Marketing Segment							
Raw Materials							
Crude Oil and NGL (million barrels)	6,462	7,065	7,031	6,991	6,985	7,176	7,032
Natural Gas (billion cubic feet)	1,911	1,726	1,960	2,276	2,884	4,593	6,022
Refined Products (million barrels)							
Motor Gasoline	446	479	447	454	427	467	487
Distillate Fuels	216	195	236	242	226	253	288
Other Refined Products	371	383	442	399	407	410	378
Total Refined Products	1,032	1,058	1,125	1,094	1,059	1,129	1,153
U.S. Production Segment							
Crude Oil and NGL (million barrels)	152	166	184	177	222	206	178
Natural Gas (billion cubic feet)	1,401	1,761	1,802	1,875	2,067	2,408	2,569
Sales							
U.S. Refining/Marketing Segment							
Raw Materials							
Crude Oil and NGL (million barrels)	2,577	3,122	3,226	3,286	3,359	3,572	3,436
Natural Gas (billion cubic feet)	1,489	1,310	1,350	1,851	2,457	4,198	5,416
Refined Products (million barrels)							
Motor Gasoline	2,399	2,460	2,325	2,346	2,267	2,286	2,327
Distillate Fuels	1,355	1,411	1,361	1,372	1,347	1,364	1,400
Other Refined Products	1,295	1,281	1,236	1,108	1,137	1,128	1,082
Total Refined Products	5,049	5,152	4,923	4,826	4,751	4,778	4,810
U.S. Production Segment							
Crude Oil and NGL (million barrels)	2,294	2,347	2,180	2,088	2,078	2,044	1,898
Natural Gas (billion cubic feet)	7,811	8,718	8,622	8,979	8,761	9,712	9,801

Source: Energy Information Administration, Form EIA-28.

Table B43. U.S. and Foreign Refining/Marketing Segment, Sources and Dispositions of Crude Oil and Natural Gas Liquids for FRS Companies, 1987-1993

(Million Barrels)

Sources and Dispositions	1987	1988	1989	1990	1991	1992	1993
U.S. Refining/Marketing							
Sources							
Acquisitions from U.S. Production Segment	2,029	2,091	1,943	1,788	1,753	1,745	1,743
Purchases from Other U.S. Segments	270	424	337	308	309	567	552
Purchases from Third Parties and Unconsolidated Affiliates	3,264	3,643	3,917	3,920	4,005	3,995	3,979
Net Transfers from Foreign Refining/Marketing Segment	899	906	834	975	918	869	757
Total Sources	6,462	7,065	7,031	6,991	6,985	7,176	7,032
Dispositions							
Net Change in Inventories	-15	-22	15	28	-32	-8	31
Input to Refineries	3,900	3,965	3,790	3,678	3,658	3,611	3,565
Sales to:							
Unaffiliated Third Parties	2,528	2,734	2,849	2,957	3,040	3,171	3,261
Other Segments Excluding Foreign Refining/Marketing	50	388	377	329	320	401	175
Total Dispositions	6,462	7,065	7,031	6,991	6,985	7,176	7,032
Foreign Refining/Marketing							
Sources							
Acquisitions from Foreign Production Segment	1,261	1,253	1,196	1,246	1,241	1,150	1,163
Purchases							
Other Foreign Segments	68	49	22	28	61	77	85
Unconsolidated Affiliates	271	428	260	246	311	79	2
Unaffiliated Third Parties							
Foreign Access	155	129	156	178	131	111	114
Foreign Governments (Open Market)	370	374	495	690	580	774	725
Other Unaffiliated Third Parties	1,645	1,696	1,900	1,903	1,972	1,885	2,653
Net Transfers to U.S. Refining/Marketing Segment	-899	-906	-834	-975	-918	-869	-757
Total Sources	2,870	3,023	3,194	3,315	3,379	3,207	3,986
Dispositions							
Net Change in Inventories	3	1	-13	12	-4	-8	-1
Input to Refineries	1,326	1,401	1,346	1,361	1,508	1,367	1,530
Sales	1,541	1,620	1,861	1,942	1,874	1,849	2,456
Total Dispositions	2,870	3,023	3,194	3,315	3,379	3,207	3,986

Source: Energy Information Administration, Form EIA-28.

Table B44. U.S. and Foreign Oil Raw Materials Balance for FRS Companies Ranked by Total Energy Assets, 1991-1993

(Million Barrels)

Geographical Sector	Raw Material Acquisitions: Direct Oil Access[1]	Net Oil Purchases[2]	Net Oil Imports	Oil Stock Changes[3]	Total Refinery Input
United States					
All FRS					
1993	2,297.7	541.2	757.5	-31.0	3,565.4
1992	2,108.3	626.5	868.8	7.7	3,611.4
1991	1,891.2	816.7	917.9	32.4	3,658.3
Top Four					
1993	633.4	257.5	392.9	-29.8	1,253.9
1992	675.3	273.0	316.3	5.5	1,270.2
1991	695.8	226.2	317.1	9.4	1,248.5
Five Through Twelve					
1993	1,308.5	-63.1	168.8	1.8	1,416.0
1992	1,087.9	154.1	186.6	-7.7	1,420.9
1991	884.4	405.6	301.1	36.1	1,627.1
All Other					
1993	355.8	346.8	195.8	-3.0	895.4
1992	345.2	199.4	365.8	9.9	920.3
1991	311.1	185.0	299.7	-13.0	782.7
Foreign					
All FRS					
1993	1,077.9	1,209.5	-757.5	0.6	1,530.5
1992	1,225.9	1,001.7	-868.8	8.3	1,367.2
1991	1,560.2	862.2	-917.9	3.9	1,508.3
Top Four					
1993	524.5	1,242.4	-392.9	2.3	1,376.3
1992	654.7	886.1	-316.3	-2.1	1,222.3
1991	962.5	707.9	-317.1	-2.1	1,351.2
All Other[4]					
1993	553.4	-32.9	-364.6	-1.7	154.2
1992	571.3	115.6	-552.5	10.4	144.8
1991	597.6	154.2	-600.8	6.0	157.1

[1] Ownership interest production plus purchases from other company segments and from unconsolidated affiliates of crude oil and natural gas liquids (domestic and foreign areas) plus foreign access oil (foreign area only). Foreign access represents acquisitions from foreign entities, for which reporting firms act as producers under long-term contract.
[2] Purchases of crude and natural gas liquids (except imports) on the open market or from unaffiliated third parties less oil sales to unaffiliated third parties.
[3] Positive number indicates stock withdrawal (addition to supply).
[4] The 'Five Through Twelve' and 'All Other' groups combined into foreign 'All Other' to prevent disclosure.
Source: Energy Information Administration, Form EIA-28.

Table B45. U.S. Refinery Output and Refinery Capacity Statistics for FRS Companies, Ranked by Total Energy Assets, and for U.S. Industry, 1992 and 1993

(Thousand Barrels per Day)

Refined Product Statistics[1]	FRS Companies				U.S. Industry	FRS Percent of Industry
	All FRS	Top Four	Five Through Twelve	All Other		
1993						
Refinery Output Volume[2]	10,822	3,985	4,341	2,496	16,341	66.2
Percent Gasoline	45.8	44.2	48.8	43.0	45.7	66.4
Percent Distillate	26.9	26.0	27.6	27.3	28.3	63.1
Percent Other	27.3	29.8	23.6	29.7	26.0	69.4
Refinery Capacity						
Year's Change (Net)	-238	-83	-110	-45	-86	276.7
At Year End	10,714	3,681	4,045	2,988	15,718	68.2
Utilization Rate[3]	89.3	89.6	95.4	80.7	88.9	([4])
1992						
Refinery Output Volume[2]	10,994	4,057	4,337	2,600	15,932	69.0
Percent Gasoline	45.2	44.4	47.5	42.7	45.2	69.0
Percent Distillate	26.7	25.7	27.1	27.5	27.6	66.8
Percent Other	28.2	29.9	25.5	29.9	27.3	71.3
Refinery Capacity						
Year's Change (Net)	-251	-96	-506	351	-648	38.7
At Year End	10,952	3,764	4,155	3,033	15,804	69.3
Utilization Rate[3]	87.9	88.5	88.9	85.4	85.6	([4])

[1] U.S. FRS and U.S. industry data include operations in Puerto Rico and the U.S. Virgin Islands.
[2] For FRS companies, includes refinery output at own refineries for own account and at others' refineries for own account.
[3] Defined as average daily crude runs at own refineries, for own account and for account of others, divided by average daily crude distillation capacity.
[4] Not meaningful.

Note: Sum of components may not equal total due to independent rounding.

Sources: Industry data - Refinery output and refinery capacity: Energy Information Administration, Forms EIA-820 and EIA-810, see *Petroleum Supply Annual*, 1992 and 1993. FRS companies data - Energy Information Administration, Form EIA-28.

Table B46. Foreign Refinery Output and Refinery Capacity Statistics for FRS Companies, Ranked by Total Energy Assets, and for Foreign Industry, 1992 and 1993

(Thousand Barrels per Day)

Refined Product Statistics[1]	FRS Companies			Foreign Industry	FRS Percent of Industry
	All FRS	Top Four	All Other[2]		
1993					
Refinery Output Volume[3]	4,205	3,705	500	–	(4)
Percent Gasoline	28.5	28.2	30.8	–	(4)
Percent Distillate	42.1	41.8	44.4	–	(4)
Percent Other	29.4	30.0	24.8	–	(4)
Refinery Capacity					
Year's Change (net)	-71	-96	25	-117	60.7
At Year End	4,577	4,159	418	55,113	8.3
Utilization Rate[5]	82.9	80.0	112.9	–	(4)
1992					
Refinery Output Volume[3]	4,465	3,994	471	47,105	9.5
Percent Gasoline	29.0	28.8	31.0	20.4	13.5
Percent Distillate	42.8	42.4	46.7	36.8	11.0
Percent Other	28.1	28.8	22.3	42.7	6.2
Refinery Capacity					
Year's Change (net)	26	26	0	-1,673	-1.6
At Year End	4,648	4,255	393	55,230	8.4
Utilization Rate[5]	80.0	77.0	111.5	–	(4)

[1] Foreign FRS and foreign industry data exclude operations in Puerto Rico and the U.S. Virgin Islands, as well as China.
[2] 'Five through Twelve' and 'All Other' groups combined to avoid disclosure.
[3] For FRS companies, includes refinery output at own refineries for own account and at others' refineries for own account.
[4] Not meaningful.
[5] Defined as average daily crude runs at own refineries, for own account and for account of others, divided by average daily crude distillation capacity.
– = Not available.
Note: Sum of components may not equal total due to independent rounding.
Sources: Industry data - Energy Information Administration, *International Energy Annual*, 1992 and 1993. FRS companies data - Energy Information Administration, Form EIA-28.

Table B47. U.S. and Foreign Petroleum Refining Statistics for FRS Companies, 1987-1993

Refining Statistics	1987	1988	1989	1990	1991	1992	1993
	(thousand barrels per calendar day)						
U.S. Refining							
Runs to Stills							
At Own Refineries	10,536	10,646	10,147	9,922	9,847	9,736	9,676
By Refineries of Others	50	11	4	4	5	5	5
Total Runs to Stills	10,586	10,657	10,151	9,926	9,852	9,741	9,681
Refinery Output at Own Refineries and Refineries of Others							
Leaded Motor Gasoline	1,252	936	523	256	378	251	56
Unleaded Motor Gasoline	4,024	4,424	4,579	4,754	4,677	4,717	4,897
Total Motor Gasoline	5,276	5,360	5,102	5,010	5,055	4,968	4,953
Distillate Fuels	3,175	3,020	2,827	2,866	2,954	2,931	2,916
Other Refined Products	3,261	3,653	3,484	3,436	3,113	3,095	2,953
Total Refinery Output	11,712	12,033	11,413	11,312	11,122	10,994	10,822
Refinery Capacity at End of Year	12,462	12,281	11,489	11,372	11,203	10,952	10,714
	(number of refineries)						
Number of Wholly Owned Refineries	91	91	89	89	88	82	76
	(thousand barrels per calendar day)						
Foreign Refining							
Runs to Stills							
At Own Refineries	3,346	3,565	3,492	3,575	3,667	3,706	3,823
By Refineries of Others	709	836	685	717	632	749	312
Total Runs to Stills	4,055	4,401	4,177	4,292	4,299	4,455	4,135
Refinery Output at Own Refineries							
Motor Gasoline	1,011	1,078	1,044	1,084	1,097	1,098	1,114
Distillate Fuels	1,404	1,496	1,459	1,431	1,534	1,553	1,634
Other Refined Products	1,224	1,262	1,196	1,075	1,009	1,064	1,148
Total Refinery Output at Own Refineries	3,639	3,836	3,699	3,590	3,640	3,715	3,896
Refinery Output at Refineries of Others							
Motor Gasoline	229	270	218	208	188	199	85
Distillate Fuels	276	335	305	315	303	359	136
Other Refined Products	204	250	206	199	199	192	88
Total Refinery Output at Refineries of Others	709	855	729	722	690	750	309
Total Refinery Output	4,348	4,691	4,428	4,312	4,330	4,465	4,205
Refinery Capacity at End of Year	4,525	4,508	4,414	4,504	4,622	4,648	4,577
	(number of refineries)						
Number of Wholly Owned Refineries	32	31	28	25	27	27	26
Number of Partially Owned Refineries	16	16	18	17	15	14	14

Source: Energy Information Administration, Form EIA-28.

Table B48. U.S. Refining/Marketing Revenues and Costs for FRS Companies, 1991-1993

Revenues and Costs	Million Dollars			Percent of Product Revenues		
	1991	1992	1993	1991	1992	1993
Refined Product Revenues	127,985.0	124,140.0	117,647.0	100.0	100.0	100.0
Refined Product Costs						
Raw Materials Processed[1]	67,364.0	63,629.0	58,161.0	52.6	51.3	49.4
Refinery Energy Expense	5,544.0	5,363.0	5,636.0	4.3	4.3	4.8
Other Refinery Expense	9,053.0	9,040.0	8,889.0	7.1	7.3	7.6
Product Purchases	26,980.0	27,672.0	26,927.0	21.1	22.3	22.9
Other Product Supply Expense	4,097.0	3,739.0	4,153.0	3.2	3.0	3.5
Marketing Expense[2]	11,440.0	12,895.0	10,463.0	8.9	10.4	8.9
Total Refined Product Costs	124,478.0	122,338.0	114,229.0	97.3	98.5	97.1
Refined Product Margin	3,507.0	1,802.0	3,418.0	2.7	1.5	2.9
Dollars per Barrel Margin[3]	0.74	0.38	0.71	--	--	--
Other Refining/Marketing Revenues[4]	9,861.0	10,007.0	10,614.0	--	--	--
Other Refining/Marketing Expenses						
DD&A	3,270.0	3,532.0	3,659.0	--	--	--
Other[5]	8,736.0	8,151.0	7,796.0	--	--	--
Total Other Expenses	12,006.0	11,683.0	11,455.0	--	--	--
Refining/Marketing Operating Income	1,362.0	126.0	2,577.0	--	--	--
Miscellaneous Revenue & Expense[6]	150.0	-115.0	207.0	--	--	--
Less Income Taxes	609.0	217.0	1,099.0	--	--	--
Refining/Marketing Net Income	903.0	-213.0	1,685.0	--	--	--

[1] Represents reported cost of raw materials processed at refineries, less any profit from raw material trades or exchanges by refining/marketing.
[2] Excludes cost of marketing tires, batteries, and accessories (TBA).
[3] Dollars per barrel of refined product sold.
[4] Includes revenues from transportation services supplied (non-federally regulated), TBA sales and miscellaneous.
[5] Includes general and administrative expenses, research and development costs, costs of transportation services supplied to others not included in raw material costs, and expenses for TBA.
[6] Includes other revenue and expense items, extraordinary items, and cumulative effect of accounting changes.
-- = Not applicable.
Source: Energy Information Administration, Form EIA-28.

Table B49. Sources of U.S. Bituminous Coal and Lignite Production, by Region and Mining Method, for FRS Companies and U.S. Industry, 1993 and Percent Change From 1992

Production	Total	Region			Mining Method	
		East	Midwest	West	Underground	Surface
	(million tons)					
1993						
FRS Companies	197.3	40.7	13.5	143.0	52.8	144.5
U.S. Industry	945.4	409.6	106.5	429.3	351.1	594.4
	(percent)					
Distribution by Region, 1993						
FRS Companies	100.0	20.7	6.9	72.5	--	--
U.S. Industry	100.0	43.3	11.3	45.4	--	--
Distribution by Mining Method, 1993						
FRS Companies	100.0	--	--	--	26.8	73.2
U.S. Industry	100.0	--	--	--	37.1	62.9
FRS Companies as a Percent of U.S. Industry	20.9	9.9	12.7	33.3	15.0	24.3
Change from 1992						
FRS Companies	-21.7	-46.0	-40.5	-6.9	-37.0	-14.0
U.S. Industry Total	-5.2	-10.3	-19.3	5.0	-13.8	0.7

-- = Not applicable.

Sources: Industry data - Energy Information Administration Form EIA-7A, see *Coal Industry Annual 1993,* (November 1994). FRS companies data - Energy Information Administration, Form EIA-28.

Table B50. U.S. Coal Reserves Balance for FRS Companies, 1987-1993

(Million Tons)

Reserves Balance	1987	1988	1989	1990	1991	1992	1993
Changes to U.S. Coal Reserves							
Beginning of Period	49,629	54,595	51,710	49,200	44,949	39,026	18,593
Changes due to:							
Leases/Purchases of Minerals-in-Place	304	521	417	654	-107	571	145
Corporate Mergers and Acquisitions	764	W	W	W	W	W	0
Other Reserve Changes	6,505	W	W	W	W	W	-325
Production	-255	-285	-287	-282	-290	-252	-197
Dispositions of Minerals-in-Place	-2,352	-653	-793	-4,002	-7,824	-18,576	-2,074
End of Period Reserves	54,595	53,067	49,200	44,948	38,219	20,787	16,142
Weighted Average Annual Production Capacity	303	313	322	320	327	291	236

W = Data withheld to avoid disclosure.
Source: Energy Information Administration, Form EIA-28.

Table B51. U.S. Coal Reserves (End of Year) and Production Statistics for FRS Companies, 1987-1993

(Million Tons)

Reserves and Production Statistics	U.S. Total	Region			Mining Method	
		East	Midwest	West	Underground	Surface
1987						
U.S. Coal Reserves	54,595.2	13,069.2	7,371.2	34,154.8	16,549.5	38,045.7
U.S. Coal Production	255.3	98.3	41.7	115.3	114.5	140.8
1988						
U.S. Coal Reserves	53,067.2	12,656.0	7,256.2	33,154.9	16,287.1	36,780.1
U.S. Coal Production	285.3	108.5	38.8	138.0	124.8	160.5
1989						
U.S. Coal Reserves	49,200.2	11,462.1	7,324.2	30,413.9	15,783.7	33,416.4
U.S. Coal Production	286.9	114.0	37.7	135.1	123.9	163.0
1990						
U.S. Coal Reserves	44,948.5	8,864.7	6,812.0	29,271.9	14,865.6	30,082.9
U.S. Coal Production	282.0	118.8	25.5	137.8	119.4	162.7
1991						
U.S. Coal Reserves	38,218.9	4,802.1	5,653.1	27,763.7	10,136.4	28,082.5
U.S. Coal Production	289.6	114.1	26.2	149.4	122.8	166.8
1992						
U.S. Coal Reserves	20,787.2	4,190.0	4,733.3	11,863.9	8,127.0	12,660.3
U.S. Coal Production	251.9	75.4	22.8	153.7	83.8	168.1
1993						
U.S. Coal Reserves	16,142.0	2,946.0	3,673.4	9,522.6	6,068.1	10,074.0
U.S. Coal Production	197.3	40.7	13.5	143.0	52.8	144.5

Source: Energy Information Administration, Form EIA-28.

Table B52. Research and Development Expenditures for FRS Companies, 1987-1993

(Million Dollars)

Research and Development Expenditures	1987	1988	1989	1990	1991	1992	1993
Sources of R&D Funds							
Federal Government	17	14	11	11	14	22	16
Internal Company	3,451	3,667	3,664	3,843	3,832	3,590	3,293
Other Sources	20	18	28	49	56	60	26
Total Sources	3,488	3,699	3,703	3,903	3,902	3,672	3,335
Breakdown of R&D Expenditures							
Oil & Gas Recovery	666	726	694	727	794	768	656
Other Petroleum	463	496	575	615	678	652	569
Coal Gasification/Liquefaction	47	34	W	38	39	W	W
Other Coal	17	18	W	15	17	W	W
Nuclear and Other Energy	91	85	93	116	95	80	121
Nonenergy	2,166	2,307	2,148	2,274	2,159	2,041	1,902
Unassigned	38	33	142	118	120	117	77
Total Expenditures	3,488	3,699	3,703	3,903	3,902	3,672	3,335

W = Data withheld to avoid disclosure.
Source: Energy Information Administration, Form EIA-28.

Glossary

Acquisition Costs: Direct costs and indirect costs incurred to acquire legal rights to wasting natural resources. Direct costs include costs incurred to obtain options to lease or purchase mineral rights and costs incurred for the actual leasing (e.g., lease bonuses) or purchasing of the rights. Indirect costs include such costs as: brokers' commissions and expenses; abstract and recording fees; filing and patenting fees; and costs of legal examination of title and documents.

Acreage: An area, measured in acres, that is subject to ownership or control by those holding total or fractional shares of working interests. Acreage is considered developed when development has been completed. (See definition for Working Interest.) A distinction may be made between "gross" acreage and "net" acreage:

- **Gross.** All acreage covered by any working interest, regardless of the percentage of ownership in the interest.
- **Net.** Gross acreage adjusted to reflect the percentage of ownership in the working interest in the acreage.

Affiliate: An "affiliate" of, or a person "affiliated" with, a specific person is a person that directly, or indirectly through one or more intermediaries, controls, or is controlled by, or is under common control with, the person specified. The term "affiliate" includes any subsidiary or parent of the person specified.

Amortization: The depreciation, depletion, or charge-off to expense of intangible and tangible assets over a period of time. In the extractive industries, the term is most frequently applied to mean either (1) the periodic charge-off to expense of the costs associated with nonproducing mineral properties incurred prior to the time when they are developed and entered into production or (2) the systematic charge-off to expense of those costs of productive mineral properties (including tangible and intangible costs of prospecting, acquisition, exploration, and development) that had been initially capitalized (or deferred) prior to the time the properties entered into production, and thereafter are charged off as minerals are produced.

Branded Product: A refined petroleum product sold by a refiner with the understanding that the purchaser has the right to resell the product under a trademark, trade name, service mark, or other identifying symbol or names owned by such refiner.

Christmas Tree: The valves and fittings installed at the top of a gas or oil well to control and direct the flow of well fluids.

Coal Gasification: The process of converting coal into gas. The basic process involves crushing coal to a powder, which is then heated in the presence of steam and oxygen to produce a gas. The gas is then refined to reduce sulfur and other impurities. The gas can be used as a fuel or processed further and concentrated into chemical or liquid fuel.

Coal Liquefaction: A chemical process that converts coal into clean-burning liquid hydrocarbons, such as synthetic crude oil and methanol.

Coal Regions: The following regional definitions are used to report domestic coal reserves, production, and other operating statistics.

- **Eastern Region.** Consists of the Northern Appalachian Coal Basin. The following States comprise the Eastern Region: Alabama, Georgia, Ohio, Maryland, Mississippi, Pennsylvania, Virginia, Tennessee, North Carolina, West Virginia, and Eastern Kentucky.
- **Midwest Region.** Consists of the Illinois and Michigan Coal Basins. The following States comprise the Midwest Region: Illinois, Indiana, Michigan, and Western Kentucky.
- **Western Region.** Consists of the Northern Rocky, Southern Rocky, Western Interior, and West Coast Coal Basins. The following States comprise the Central Western Region: Alaska, Arizona, Arkansas, California, Colorado, Idaho, Iowa, Kansas, Louisiana, Missouri, Montana, New Mexico, North Dakota, Oklahoma, Oregon, Texas, South Dakota, Utah, Washington, and Wyoming.

Company Automotive (Retail) Outlet: Any retail outlet selling motor fuel under a reporting company brand name. (See definition for Branded Product.)

- **Company Operated.** A company retail outlet which is operated by salaried or commission personnel paid by the reporting company.
- **Lessee.** An independent marketer who leases the station and land and has use of tanks, pumps, signs, etc. A lessee dealer typically has a supply agreement with a refiner or a distributor and purchases products at dealer tank wagon prices. The term "lessee dealer" is limited to those dealers who are supplied directly by a refiner or any affiliate or subsidiary company of a refiner. "Direct supply" includes use of commission agent or common carrier delivery.
- **Open.** An independent marketer who owns or leases (from a third party who is not a refiner) the station or land of a retail outlet and has use of tanks, pumps, signs, etc. An open dealer typically has a supply agreement with a refiner or a distributor and purchases products at or below dealer tank wagon prices.

Contribution to Net Income: The FRS segment equivalent of net income. However, many consolidated items of revenue and expense are not allocated to the segments, and therefore they are not equivalent in a strict sense. The largest item not allocated to the segments is interest expense since this is regarded as a corporate-level item for FRS purposes.

Crude Oil: A mixture of hydrocarbons that exists in liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities. For FRS reporting, volumes reported as crude include:

- Liquids technically defined as crude oil.
- Small amounts of hydrocarbons that exist in the gaseous phase in natural underground reservoirs but are liquid at atmospheric pressure after being recovered from oil well (casinghead) gas in lease separators and are commingled with the crude stream without being separately measured.
- Small amounts of nonhydrocarbons produced with the oil.

Statistical data pertaining to crude oil production and reserves are reported as liquid equivalents at the surface (excluding base sediment and water) measured in terms of stock tank barrels of 42 U.S. gallons at atmospheric pressure, corrected to 60 degrees Fahrenheit.

Where a State regulatory agency specifies a definition of crude oil which differs from that set forth above for statistical purposes, the State definition should be followed.

DD&A: Abbreviation for depreciation, depletion and amortization.

Deferred Taxes: Taxes accrued and reflected as an expense in a company's income statement, but not payable to the taxing authority in that time period. These taxes are accrued to compensate for an understatement of income tax expense which would occur if only the tax currently due to the taxing authority were reflected as the total income tax expense.

Depletion: A term for either (1) a periodic assignment to expense of recorded amounts or (2) an allowable income tax deduction that is related to the exhaustion of mineral reserves. Depletion is included as one of the elements of amortization. When used in that manner, depletion refers only to book depletion (see definition for Amortization).

- **Book.** The portion of the carrying value (other than the portion associated with tangible assets) prorated in each accounting period, for financial reporting purposes, to the extracted portion of an economic interest in a wasting natural resource.
- **Tax-cost.** A deduction (allowance) under U.S. Federal Income taxation normally calculated under a formula whereby the adjusted basis of the mineral property is multiplied by a fraction, the numerator of which is the number of units of minerals sold during the tax year and the denominator of which is the estimated number of units of unextracted minerals remaining at the end of the tax year plus the number of units of minerals sold during the tax year.
- **Tax-percentage (or Statutory).** A deduction (allowance) allowed to certain mineral producers under U.S. Federal income taxation calculated on the basis of a specified percentage of gross revenue from the sale of minerals from each mineral property not to exceed the lesser of 50 percent of the taxable income from the property computed without allowance for depletion. (There are also other limits on percentage depletion on oil and gas production.) The taxpayer is entitled to a deduction representing the amount of tax-cost depletion or percentage (statutory) depletion, whichever is higher.
- **Excess Statutory Depletion.** The excess of estimated statutory depletion allowable as an income tax deduction over the amount of cost depletion otherwise allowable as a tax deduction, determined on a total enterprise basis.

Depreciation: See definition for Amortization.

Development: The preparation of a specific mineral deposit for commercial production; this preparation includes construction of access to the deposit and of facilities to extract the minerals. The development process is sometimes further distinguished between a preproduction stage and a current stage, with the distinction being made on the basis of whether the development work is performed before or after production from the mineral deposit has commenced on a commercial scale.

Development Costs: Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering, and storing the oil and gas. More specifically, development costs, and also depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

- Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves;
- Drill and equip development wells, development-type stratigraphic test wells, and service wells including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly;
- Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and utility waste disposal systems; and
- Provide improved recovery systems.

Distillate: A general classification for one of the petroleum fractions produced in conventional distillation operations. Included are kerosene and products known as heating oils and diesel fuels, specifically: No. 1, No. 2, and No. 4 Fuel Oils and No.1, No. 2, and No. 4 Diesel Fuels.

Domestic Operations: Domestic operations are those operations located in the United States.

- The United States is defined as the 50 States, including their offshore territorial waters, the District of Columbia, U.S. commonwealth territories, and protectorates.

Drilling: The act of boring a hole (1) to determine whether minerals are present in commercially recoverable quantities and (2) to accomplish production of the minerals (including drilling to inject fluids).

- **Exploratory.** Drilling to locate probable mineral deposits or to establish the nature of geological structures; such wells may not be capable of production if minerals are discovered.

- **Developmental.** Drilling to delineate the boundaries of a known mineral deposit to enhance the productive capacity of the producing mineral property.

- **Directional.** Drilling that is deliberately made to depart significantly from the vertical.

Drilling and Equipping of Wells: The drilling and equipping of wells through completion of the “christmas tree.”

Dry-Hole Charge: The charge-off to expense of a previously capitalized cost upon the conclusion of an unsuccessful drilling effort.

Equity in Earnings of Unconsolidated Affiliates: A company's proportional share (based on ownership) of the net earnings or losses of an unconsolidated affiliate.

Exploration: The identification of areas that may warrant examination and to examine specific areas that are considered to have prospects of containing oil and gas reserves, including drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property.

Exploration Costs: Costs, including depreciation and applicable operating costs, of support equipment and facilities and other costs directly identifiable with exploration activities, such as:

- Costs of topographical, geological, and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these costs are sometimes referred to as geological and geophysical or “G&G” costs.

- Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on the properties, legal costs for title defense, and the maintenance of land and lease records.

- Dry hole contributions and bottom hole contributions. Costs of drilling and equipping exploratory wells.

- Costs of drilling exploratory-type stratigraphic test wells.

Extraordinary Item: Income and expense items associated with events and transactions that possess a high degree of abnormality and are of a type that would not reasonably be expected to recur in the foreseeable future.

Field: An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both.

Footage Drilled: Total footage for wells in various categories, as reported for any specified period, includes (1) the deepest total depth (length of well bores) of all wells drilled from the surface, (2) the total of all bypassed footage drilled in connection with reported wells, and (3) all new footage drilled for directional "sidetrack" wells. Footage reported for directional "sidetrack" wells does not include footage in the common bore which is reported as footage for the original well. In the case of old wells drilled deeper, the reported footage is that which was drilled below the total depth of the old well.

- **Deepest Total Depth.** The deepest total depth of a given well is the distance from a surface reference point (usually the Kelly bushing) to the point of deepest penetration measured along the well bore. If a well is drilled from a platform or barge over water, the depth of the water is included in the total length of the well bore.

- **Sidetrack Drilling.** This is a remedial operation that results in the creation of a new section of well bore for the purpose of (1) detouring around junk, (2) redrilling lost hole, or (3) straightening key seats and crooked holes. Directional "sidetrack" wells do not include footage in the common bore which is reported as footage for the original well.

Foreign Access: Refers to proved reserves of crude (including lease condensate) and natural gas liquids applicable to long-term supply agreements with foreign governments or authorities in which the company acts as producer.

Foreign Operations: These are operations that are located outside the United States. Determination of whether an enterprise's mobile assets, such as offshore drilling rigs or ocean-going vessels, constitute foreign operations should depend on whether such assets are normally identified with operations located outside the United States.

Foreign operations are segregated into the following areas for FRS reporting purposes:

- **OECD Europe.** Includes Austria, Belgium, Denmark, Finland, France, the Federal Republic of Germany, Greece, Iceland, Ireland, Italy, Luxembourg, the Netherlands, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, and the United Kingdom.

- **Former Soviet Union (FSU) and East Europe.** The Baltic States of Estonia, Latvia, and Lithuania, as well as Armenia, Azerbaijan, Belarus, Georgia, Kazakhstan, Kyrgystan, Moldova, Russia, Tajikstan, Turkmenistan, Ukraine, Uzbekistan, Albania, Bulgaria, Czech Republic, Hungary, Poland, Romania, Slovakia, and Yugoslavia.

- **Middle East.** Includes Saudi Arabia, the United Arab Emirates, Iraq, Iran, Kuwait, the Iraq-Saudi Arabia Neutral Zone, Qatar, Dubai, Bahrain, Oman, Yemen, Syria, Jordan, and Israel.

- **Canada.**

- **Africa** (the African continent).

- **Other Eastern Hemisphere.** Areas eastward of the Greenwich prime meridian to 180 degrees longitude and not included in other specified domestic or foreign classifications.

- **Other Western Hemisphere.** Areas westward of the Greenwich prime meridian to 180 degrees longitude not included in other domestic or foreign classifications.

Funds From Operations: Calculated by adding noncash charges back to net income or contribution to net income. Deferred taxes and depreciation, depletion, and amortization (DD&A) are the largest noncash charges.

Funds, Total Sources of: The total source of funds including net income plus noncash charges such as DD&A and deferred taxes, issuances of stocks and bonds, and proceeds from the sale or property, plant, and equipment. The concept is similar to cash flow generated, but does not attempt to account for changes in working capital items. Thus, for example, an inventory buildup or drawdown would not be accounted for under the "funds" concept since both cash and inventory are items of working capital.

Geological and Geophysical (G&G) Costs: Costs incurred in making geological and geophysical studies, including, but not limited to, costs incurred for salaries, equipment, obtaining rights of access, and supplies for scouts, geologists, and geophysical crews.

Hydrocarbon: An organic chemical compound of hydrogen and carbon in either the gaseous, liquid, or solid phase. The molecular structure of hydrocarbon compounds varies from the simplest (e.g., methane, a constituent of natural gas) to the very heavy and very complex.

Improved Recovery: The operation whereby crude oil or natural gas is recovered using any method other than those that rely primarily on the use of natural reservoir pressure, gas lift or the use of a pump.

Intangible Drilling and Development Costs (IDC): Costs incurred in preparing well locations, drilling and deepening wells, and preparing wells for initial production up through the point of installing control valves. None of these functions, because of their nature, have salvage value. Such costs would include labor, transportation, consumable supplies, drilling tool rentals, site clearance, and similar costs.

Investment and Advances to Unconsolidated Affiliates: The balance sheet account representing the cost of investments and advances to unconsolidated affiliates. Generally, affiliates which are less than 50 percent owned by a company may not be consolidated into the company's financial statements.

Lease Bonus: An amount paid by a lessee to a lessor as consideration for granting a lease, usually as a lump sum; this payment is in addition to any rental or royalty payments.

Lease Equipment: All equipment located on the lease except the well and the complete christmas tree installation.

Lifting Costs: The costs associated with the extraction of a mineral reserve from a producing property. (See definition for Production Cost.)

Mineral: Any of the various naturally occurring substances (such as coal, crude oil, metals, natural gas, salt, sand, stone, sulfur, and water) usually obtained from the earth. The term is used to include all wasting, i.e., nonregenerative, inorganic substances that are extracted from the earth.

Mineral Interests in Properties (hereinafter referred to as Properties): These include fee ownership or a lease, concession, or other contractual interest representing the right to extract minerals subject to such terms as may be imposed by the conveyance of those interests. Properties also include royalty interests, production payments payable in oil or gas, and other nonoperating interests in properties operated by others. Properties include those agreements with foreign governments or authorities under which an enterprise participates in the operation of the related properties or otherwise serves as "producer" of the underlying reserves, but properties do not include other supply agreements or contracts that represent the right to purchase (as opposed to extract) oil and gas.

Mineral Lease: An agreement wherein a mineral interest owner (lessor) conveys to another party (lessee) the rights to explore for, develop, and produce specified minerals. The lessee acquires a working interest and the lessor retains a nonoperating interest in the property, referred to as the royalty interest, each in proportions agreed upon.

Mineral Rights: The ownership of the minerals beneath the earth's surface with the right to remove them. Mineral rights may be conveyed separately from surface rights.

Mining: Any activity directed to the extraction of ore and associated rock. Included are open pit work, quarrying, augering, alluvial dredging, and combined operations, including surface and underground operations.

Minority Interest in Income: The proportional share of the minority ownership's interest (less than 50 percent) in the earnings or losses of the consolidated subsidiary.

Subsidiaries are generally fully consolidated when a share of ownership between 51 percent and 100 percent is held by the parent. In consolidation, 100 percent of revenues, expenses, assets, etc. are included in the financial statements even though, for example, the subsidiary is only 80 percent owned by the parent company. In such cases, the consolidated balance sheet must have a caption on the right-hand side titled something like "minority interests in consolidated affiliates," and the income statement must have a similar line to reduce net income to the pro rata (80 percent in this example) share of the consolidated subsidiary's net income.

Motor Gasoline (Finished): A complex mixture of relatively volatile hydrocarbons, with or without small quantities of additives, that has been blended to form a fuel suitable for use in spark-ignition engines. Motor gasoline, as given in ASTM Specification D439 or Federal Specification VV-G-l690B, includes a range in distillation temperatures from 122 to 158 degrees Fahrenheit at the 10-percent recovery point and from 365 to 374 degrees Fahrenheit at the 90-percent recovery point. Motor gasoline includes reformulated motor gasoline, oxygenated motor gasoline, and other finished motor gasoline. Blendstock is excluded until blending has been completed.

- **Reformulated Motor Gasoline.** Gasoline reformulated for use in motor vehicles, the composition and properties of which meet the requirements of the reformulated gasoline regulations promulgated by the U.S. Environmental Protection Agency under Section 211K of the Clean Air Act.

- **Oxygenated Gasoline.** Gasoline formulated for use in motor vehicles that has an oxygen content of 1.8 percent or higher, by weight. Includes gasohol.

- **Other Finished Gasoline.** Motor Gasoline not included in the oxygenated or reformulated gasoline categories.

Motor Gasoline, Finished Gasohol: A blend of finished motor gasoline (leaded or unleaded) and alcohol (generally ethanol but sometimes methanol), limited to 10 percent by volume of alcohol.

Motor Gasoline, Finished Leaded: Contains more than 0.05 gram of lead per gallon or more than 0.005 gram of phosphorus per gallon. Premium and regular grades are included, depending on the octane rating. Includes leaded gasohol. Blendstock is excluded until blending has been completed. Alcohol that is to be used in the blending of gasoline is excluded.

Motor Gasoline, Finished Unleaded: Contains not more than 0.05 gram of lead per gallon and not more than 0.005 gram of phosphorus per gallons. Premium and regular grades are included, depending on the octane rating. Includes unleaded gasohol. Blendstock is excluded until blending has been completed. Alcohol that is to be used in the blending of gasohol is also excluded.

MTBE (Methyl tertiary butyl ether) (CH3)3C)CH: An ether intended for motor gasoline blending. (See definition for Oxygenates.)

Natural Gas: A mixture of hydrocarbon compounds and small quantities of various nonhydrocarbons existing in the gaseous phase or in solution with crude oil in natural underground reservoirs at reservoir conditions. The principal hydrocarbons usually contained in the mixture are methane, ethane, propane, butanes, and pentanes. Typical nonhydrocarbon bases which may be present in reservoir natural gas are carbon dioxide, helium, hydrogen sulfide, and nitrogen. Under reservoir conditions, natural gas and the liquefiable portions thereof occur either in a single gaseous phase in the reservoir or in solution with crude oil and are not distinguishable at that time as separate substances.

Natural gas, based on the type of occurrence in the reservoir, is classified by two categories, as follows:

- **Non-Associated Gas** is natural gas that is not in contact with significant quantities of crude oil in the reservoir.

- **Associated/Dissolved Gas** is the combined volume of natural gas which occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved).

Associated gas is free natural gas, commonly known as gas cap gas, which overlies and is in contact with crude oil in the reservoir. Dissolved gas is natural gas that is in solution with crude oil in the reservoir at reservoir conditions.

Statistical data pertaining to natural gas production and reserves are reported in units of 1,000,000 cubic feet (i.e., MMCF) at 14.73 pounds per square inch absolute and 60 degrees Fahrenheit for FRS purposes.

Natural Gas Liquids (NGL): Natural gas liquids are those portions of reservoir gas which are liquefied at the surface in lease separators, field facilities, or gas processing plants. Natural gas liquids include but are not limited to: ethane, propane, butanes, pentanes, natural gasoline and condensate.

Net Investment in Place: The sum of net property, plant, and equipment (PP&E) plus investment and advances to unconsolidated affiliates.

Nonbranded Product: Any refined petroleum product that is not a branded product.

Nuclear Fuel Operations: All nuclear fuel operations, excluding reactor and reactor component manufacturing or containment construction. Includes exploration and development; mining; milling; conversion; enrichment; fabrication; reprocessing; and spent fuel storage.

Offshore: That geographic area that lies seaward of the coastline. In general, the coastline is the line of ordinary low water along with that portion of the coast that is in direct contact with the open sea or the line marking the seaward limit of inland water.

If a State agency uses a different basis for classifying onshore and offshore areas, the State classification should be used. (Cook Inlet in Alaska is classified as offshore.)

Oil Shale: A sedimentary rock containing kerogen, a solid organic material.

Operating Expenses: Segment expenses related both to revenue from sales to unaffiliated customers and revenue from intersegment sales or transfers, excluding loss on disposition of property, plant, and equipment; interest expenses and financial charges; foreign currency translation effects; minority interest; and income taxes.

Operating Income: Operating revenues less operating expenses. Excludes items of other revenue and expense such as equity in earnings of unconsolidated affiliates, dividends, interest income and expense, income taxes, extraordinary items, and cumulative effect of accounting changes.

Operating Revenues: Segment revenues both from sales to unaffiliated customers (i.e., revenue from customers outside the enterprise as reported in the company's consolidated income statement) and from intersegment sales or transfers, if any, of product and services similar to those sold to unaffiliated customers, excluding equity in earnings of unconsolidated affiliates; dividend and interest income; gain on disposition of property, plant, and equipment; and foreign currency translation effects.

Other Energy: Energy operations not included in Petroleum or Coal. Other Energy includes nuclear, oil shale, tar sands, coal liquefaction and gasification, geothermal, solar, and other forms of nonconventional energy.

Oxygenates: Any substance which when added to gasoline, increases the amount of oxygen in that gasoline blend. Through a series of waivers and interpretive rules, the Environment Protection Agency (EPA) has determined the allowable limits for oxygenates in unleaded gasoline. The “Substantially Similar” Interpretive Rules (56 FR (February 11, 1991)) allows blends of aliphatic alcohols other than methanol and aliphatic ethers, provided the oxygen content does not exceed 2.7 percent by weight. The “Substantially Similar” Interpretive Rules also provide for blends of methanol up to 0.3 percent by volume exclusive of other oxygenates, and butanol or alcohols of a higher molecular weight up to 2.75 percent by weight. Individual waiver pertaining to the use of oxygenates in unleaded gasoline have been issued by the EPA. They include:

- **Fuel Ethanol.** Blends of up to 10 percent by volume anhydrous ethanol (200 proof) (commonly referred to as the “gasohol waiver”).

- **Methanol.** Blends of methanol and gasoline-grade tertiary butyl alcohol (GTBA) such that the total oxygen content does not exceed 3.5 percent by weight and the ratio of methanol to GTBA is less than or equal to 1. It is also specified that this blended fuel must meet ASTM volatility specifications (commonly referred to as the “ARCO” waiver).

  Blends of up to 5.0 percent by volume methanol with a minimum of 3.5 percent by volume cosolvent alcohols having a carbon number of 4 or less (i.e., ethanol, propanol, butanol, and / or GTBA). The total oxygen must not exceed 3.7 percent by weight, and the blend must meet ASTM volatility specifications as well as phase separation and purity specifications (commonly referred to as the “DuPont” waiver).

- **MTBE (Methyl tertiary butyl ether).** Blends up to 15.0 percent by volume MTBE which must meet the ASTM D4814 specifications. Blenders must take precautions that the blends are not used as base gasolines for other oxygenated blends (commonly referred to as the "Sun" waiver).

PP&E, Additions to: The current year's expenditures on property, plant, and equipment (PP&E). The amount is predicated upon each reporting company's accounting practice. That is, accounting practices with regard to capitalization of certain items may differ across companies, and therefore this figure in FRS will be a function of each reporting company's policy.

PP&E, Net: The original cost of property, plant, and equipment (PP&E), less accumulated depreciation.

Petroleum: Hydrocarbon mixtures broadly defined to include crude oil, lease condensate, natural gas, products of natural gas processing plants (plant products), refined products, and semifinished products and blending materials.

Pipelines, Rate Regulated: FRS establishes three pipeline segments; crude/liquid (raw materials); natural gas; and refined products. The pipelines included in these segments are all federally or state rate-regulated pipeline operations, which are included in the reporting company's consolidated financial statements. However, at the reporting company's option intrastate pipeline operations may be included in the U.S. Refining/Marketing Segment **if:** they would comprise less than 5 percent of U.S. Refining/Marketing Segment net PP&E, revenues and earnings in the aggregate; and if the inclusion of such pipelines in the consolidated financial statements adds less than $100 million to the net PP&E reported for the U.S. Refining/Market Segment.

Primary Recovery: The crude oil or natural gas recovered by any method that may be employed to produce them where the fluid enters the well bore by the action of natural reservoir pressure (energy or gravity).

Primary Transportation: Conveyance of large shipments of petroleum raw materials and refined products usually by pipeline, barge, or ocean-going vessel. All crude oil transportation is primary, including the small amounts moved by truck. All refined product transportation by pipeline, barge, or ocean-going vessel is primary transportation.

Producing Property: A term often used in reference to a property, well, or mine that produces wasting natural resources. The term means a property that produces in paying quantities (that is, one for which proceeds from production exceed operating expenses).

Production, Natural Gas Liquids: Production of natural gas liquids is classified as follows:

- **Contract Production.** Natural gas liquids accruing to a company because of its ownership of liquids extraction facilities that it uses to extract liquids from gas belonging to others, thereby earning a portion of the resultant liquids.

- **Leasehold Production.** Natural gas liquids produced, extracted, and credited to a company's interest.

- **Contract Reserves.** Natural gas liquid reserves corresponding to the contract production defined above.

- **Leasehold Reserves.** Natural gas liquid reserves corresponding to the leasehold production defined above.

Production, Oil and Gas: The lifting of the oil and gas to the surface and gathering, treating, field processing (as in the case of processing gas to extract liquid hydrocarbons), and field storage. The production function shall normally be regarded as terminating at the outlet valve on the lease or field production storage tank; if unusual physical or operational circumstances exist, it may be more appropriate to regard the production function as terminating at the first point at which oil, gas, or gas liquids are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal.

- **Gross Company-Operated Production.** Total production from all company operated properties including all working and nonworking interests.

- **Net Working Interest Production.** Total production accruing to the reporting company's working interests less royalty oil and volumes due others.

Production Costs: Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. The following are examples of production costs (sometimes called lifting costs):

- Costs of labor to operate the wells and related equipment and facilities.

- Repair and maintenance costs.

- The costs of materials, supplies and fuel consumed and services utilized in operating the wells and related equipment and facilities.

- The costs of property taxes and insurance applicable to proved properties and wells and related equipment and facilities.

- The costs of severance taxes.

Depreciation, depletion, and amortization (DD&A) of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

Production costs include the following subcategories of costs:

- Well operations and maintenance

- Well workovers

- Operating fluid injection and improved recovery programs

- Operating gas processing plants

- *Ad valorem* taxes

- Production or severance taxes

- Other, including overhead

Research and Development: Basic and applied research in the sciences and engineering and the design and development of prototypes and processes, excluding quality control, routine product testing, market research, sales promotion, sales service, research in the social sciences or psychology, and other non-technological activities or technical services.

Reserves, Change in: For FRS reporting, the following definitions should be used for changes in reserves.

- **Revisions of Previous Estimates.** Changes in previous estimates of proved reserves, either upward or downward, resulting from new information normally obtained from development drilling and production history or resulting from a change in economic factors. Revisions do not include changes in reserve estimates resulting from increases in proved acreage or from improved recovery techniques.

- **Improved Recovery.** Changes in reserve estimates resulting from application of improved recovery techniques shall be separately shown, if significant. If not significant, such changes shall be included in revisions of previous estimates.

- **Purchases or Sales of Minerals-in-Place.** Increase or decrease in the estimated quantity of reserves resulting from the purchase or sale of mineral rights in land with known proved reserves.

- **Extensions, Discoveries, and Other Additions.** Additions to an enterprise's proved reserves that result from (1) extension of the proved acreage of previously discovered (old) reservoirs through additional drilling in periods subsequent to discovery and (2) discovery of new fields with proved reserves or of new reservoirs of proved reserves in old fields.

Reserves (Coal): Coal reserve estimates comprising the demonstrated coal reserve base include only proved (measured) and probable (indicated).

- **Proved (Measured) Reserves.** Reserves or resources for which tonnage is computed from dimensions revealed in outcrops, trenches, workings, and drill holes and for which the grade is computed from the results of detailed sampling. The sites for inspection, sampling, and measurement are spaced so closely and the geologic character is so well defined that size, shape, and mineral content are well established. The computed tonnage and grade are judged to be accurate within limits which are stated, and no such limit is judged to be different from the computed tonnage or grade by more than 20 percent.

- **Probable (Indicated) Reserves.** Reserves or resources for which tonnage and grade are computed partly from specific measurements, samples, or production data and partly from projection for a reasonable distance on geologic evidence. The sites available are too widely or otherwise inappropriately spaced to permit the mineral bodies to be outlined completely or the grade established throughout.

Reserves, Net: Includes all proved reserves associated with the company's net working interests. (See definition for Working Interest.)

Reserves, Proved (Oil and Gas): The estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Reserves that can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

Estimates of proved reserves do not include the following: (1) oil that may become available from known reservoirs but is classified separately as "indicated additional reserves;" (2) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (3) crude oil, natural gas, and natural gas liquids that may occur in undrilled prospects; and (4) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

It is not necessary that production, gathering, or transportation facilities be installed or operative for a reservoir to be considered proved.

For natural gas an appropriate reduction in the reservoir gas volume is made to cover the removal of the liquefiable portions of the gas and the exclusion of nonhydrocarbon gases where they occur in sufficient quantity to render the gas unmarketable. If the liquefiable portions of the gas are not separately estimated, they need not be separately stated for FRS reporting purposes.

Reservoir: A porous and permeable underground formation containing an individual and separate accumulation of producible hydrocarbons (oil and / or gas) that is confined by impermeable rock or water barriers and is characterized by a single natural pressure system.

Residual Fuel: The heavier oils that remain after the distillate fuel oils and lighter hydrocarbons are distilled away in refinery operations and that conform to ASTM Specifications D396 and 975. Included are No. 5, a residual fuel oil of medium viscosity; Navy Special, for use in steam-powered vessels in government service and in shore power plants; No. 6, which includes Bunker C fuel oil, and is used for commercial and industrial heating, electricity generation and to power ships.

Royalty: A contractual arrangement providing a mineral interest that gives the owner a right to a fractional share of production or proceeds therefrom, that does not contain rights and obligations of operating a mineral property, and that is normally free and clear of exploration, developmental, and operating costs, except production taxes.

Short Ton: A unit of weight that equals 2,000 pounds.

Support Equipment and Facilities: These include, but are not limited to, seismic equipment, drilling equipment, construction and grading equipment, vehicles, repair shops, warehouses, supply points, camps, and division, district, or field offices.

Tangible Development Costs: Cost incurred during the development stage for access, mineral-handling, and support facilities having a physical nature. In mining, such costs would include tracks, lighting equipment, ventilation equipment, other equipment installed in the mine to facilitate the extraction of minerals, and supporting facilities for housing and care of work forces. In the oil and gas industry, tangible development costs would include well equipment (such as casing, tubing, pumping equipment, and well heads), as well as field storage tanks and gathering systems.

Tar Sands: Naturally occurring bitumen-impregnated sands that yield mixtures of liquid hydrocarbon and that require further processing other than mechanical blending before becoming finished petroleum products.

Timing Differences: Differences between the periods in which transactions affect taxable income and the periods in which they enter into the determination of pretax accounting income. Timing differences originate in one period and reverse or "turn around" in one or more subsequent periods. Some timing differences reduce income taxes that would otherwise be payable currently; others increase income taxes that would otherwise be payable currently.

Transfer Price: The monetary value assigned to products, services, or rights conveyed or exchanged between related parties, including those occurring between units of a consolidated entity.

Uncompleted Wells, Equipment, and Facilities Costs: The costs incurred to (1) drill and equip wells that are not yet completed, and (2) acquire or construct equipment and facilities that are not yet completed and installed.

Undeveloped Property: Refers to a mineral property on which development wells or mines have not been drilled or completed to a point that would permit the production of commercial quantities of mineral reserves.

Uranium Oxide: The final precipitate formed in the uranium milling process. U_3O_8, a common form of triuranium oxide, is the powder obtained by evaporating an ammonial solution of the oxide.

Well: A hole drilled in the earth for the purpose of (1) finding or producing crude oil or natural gas; or (2) providing services related to the production of crude oil or natural gas.

Wells are classified as (1) oil wells; (2) gas wells; (3) dry holes; (4) stratigraphic test wells; or (5) service wells. The latter two types of wells are not counted for FRS reporting.

Oil wells, gas wells, and dry holes are classified as exploratory wells or development wells. Exploratory wells are subclassified as (1) new-pool wildcats; (2) deeper-pool tests; (3) shallow-pool test; and (4) outpost (extension) tests. Well classifications reflect the status of wells after drilling has been completed.

- **Completion.** The term refers to the installation of permanent equipment for the production of oil or gas.

- **Development Well.** A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

- **Dry Hole.** An exploratory or development well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

- **Exploratory Well.** A well that is not a development well, a service well, nor a stratigraphic test as those items are defined elsewhere.

- **Oil Well.** A well completed for the production of crude oil from at least one oil zone or reservoir.

Wellhead Price: The value at the mouth of the well. In general, the wellhead price is considered to be the sales price obtainable from a third party in an arm's length transaction. Posted prices, requested prices, or prices as defined by lease agreements, contracts or tax regulations should be used where applicable.

Working Interest: An interest in a mineral property that entitles the owner of that interest to all of a share of mineral production from the property, usually subject to a royalty.

A working interest permits the owner to explore, develop and operate the property. The working interest owner bears the costs of exploration, development, and operation of the property, and in return is entitled to a share of the mineral production from the property, or to a share of the proceeds therefrom. It may be assigned to another party in whole or in part, or it may be divided into other special property interests.

- **Gross Working Interest.** The reporting company's working interest plus the proportionate share of any basic royalty interest or overriding royalty interest related to the working interest.

- **Net Working Interest.** The reporting company's working interest not including any basic royalty or overriding royalty interests.