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Performance Profiles of Major Energy Producers 1999

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Data File Information

Historical Financial Reporting System (FRS) data are available from the Energy Information Administration's File Transfer Protocol (FTP) site and are also available on a 3.5-inch high-density diskette. These data cover the years 1977 through 1999, 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 1977-1999 data files can be downloaded from the Energy Information Administration's FTP site (ftp://ftp.eia.doe.gov/pub/energy.overview/frs/) or by accessing the Energy Information Administration's Worldwide Web site (http://www.eia.doe.gov/emeu/finance/page2.html). For further assistance, please contact the National Energy Information Center at (202) 586-8800, FAX (202) 586-0727, TTY (202) 586-1181, or on INTERNET infoctr@eia.doe.gov.

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Preface

Performance Profiles of Major Energy Producers presents a comprehensive annual financial review and analysis of the domestic and worldwide activities and operations of the major U.S.-based energy-producing companies. (For a list of the companies covered in this report, the Financial Reporting System (FRS) companies, see Chapter 1, the box entitled "The FRS Companies in 1999.") Emerging issues in financial performance are also analyzed. The report primarily examines these companies' (the majors') operations on a consolidated corporate level, by individual lines-of-business, by major functions within each line-of-business, and by various geographic regions. A companion analysis of foreign investment[i] (trends and transactions) in U.S. energy resources, assets, and companies used to be included as a separate chapter in the report. However, beginning this year, the Foreign Direct Investment report was published separately on the Internet (see http://www.eia.doe.gov/emeu/finance/fdi/index.html). (Note that the coverage of foreign direct investment developments discussed in the report lags the discussion of the FRS companies by one year. This is due to the later release date of much of the foreign direct investment data.)

Performance Profiles annually looks at aggregate changes in the U.S. energy industry resulting from major energy company current operations, and from strategic corporate decisions relating to profits, investments, and new business initiatives. Significant organizational decisions of the majors (such as those involving corporate mergers or joint ventures) are highlighted, and new strategic directions (such as concentration on core businesses or competencies, movements into new lines of business, or changes in global investment patterns) are discussed. Changes in the majors' investment and resource development patterns, which may result in new or increased opportunities for independent oil and gas producers and fast-growing petroleum refiners in the United States, are also explored.

This edition of *Performance Profiles* reviews financial and operating data for the calendar year 1999. Although the focus is on 1999 activities and results, important trends prior to that time and emerging issues relevant to U.S. energy company operations are also discussed.

The analysis in this report is based on detailed financial and operating data and information submitted each year to the EIA on Form EIA-28, the Financial Reporting System. The analysis and FRS data are also supplemented by additional information from company annual reports and press releases, disclosures to the U.S. Securities and Exchange Commission, news reports and articles, and various complementary energy industry data sets.

Since the Form EIA-28 data are collected by the EIA on a uniform, segmented basis, the comparability of information across energy lines of business is unique to the FRS reporting system. For example, petroleum activities of the major U.S. energy companies (and financial returns attributable to these activities) can be compared to activities in other lines of energy business (such as coal, and/or alternative energy) or nonenergy areas (such as chemicals). Similarly, financial returns and operating results from domestic activities can be compared to results from foreign activities and operations.

The information in *Performance Profiles* responds to the requirements of the Financial Reporting System, set forth in P.L. 95-91, the Department of Energy Organization Act of 1977 (see http://www.eia.doe.gov/emeu/finance/page1a.html). Both this report, and similar energy financial analyses provided by the EIA (see http://www.eia.doe.gov/emeu/finance/pubs.html), are intended for use by the U.S. Congress, government agencies, industry analysts, and the general public.

Additional information about the Form EIA-28 can also be found at http://www.eia.doe.gov/emeu/finance/page1a.html. Also see Appendix A of this report for information concerning the format of Form EIA-28, important financial reporting concepts and accounting principles, and other information about the Financial Reporting System. For a glossary of terms and definitions used in this report, see http://www.eia.doe.gov/emeu/perfpro/glossary.html.

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[i]The purpose of the foreign direct investment report is to provide an assessment of the degree of foreign ownership of energy assets in the United States. Section 657, Subpart 8 of the U.S. Department of Energy Organization Act (Public Law 95-91) requires an annual report to Congress which presents: "…a summary of activities in the United States by companies which are foreign owned or controlled and which own or control United States energy sources and supplies…."

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Executive Summary

Global energy market developments in 1999 and recent years led to volatility in oil prices and wide swings in energy companies' financial performance. Key developments in 1999 included:

- A large overhang of petroleum inventories at the beginning of the year

- A drop in world oil production of about one million barrels per day

- A 2-percent increase in world petroleum demand led in large part by the economic recovery of Asia-Pacific nations that were afflicted by financial crises in 1997 and 1998

- A rise in crude oil prices during 1999 from $10 per barrel in January, a 25-year low, to over $24 per barrel by December, the highest level of oil prices since the Gulf War

- Winter weather in 1999 that was colder in much of the industrialized world than in the previous year.

To see how these and other developments have affected energy industry financial and operating performance, strategies, and industry structure, the Energy Information Administration (EIA) maintains the Financial Reporting System (FRS), which is used to perform these analyses.

Through Form EIA-28, major U.S. energy companies annually report to the FRS (see the box entitled "The FRS Companies in 1999" in Chapter 1 of this report). Financial and operating information is reported by major lines of business, including oil and gas production ("upstream"), petroleum refining and marketing ("downstream"), other energy operations, and nonenergy business.

Wide Swings in Profits Reflect Petroleum Market Volatility

Net income of the FRS companies totaled $22.9 billion in 1999, an increase of 83 percent from 1998 net income. However, excluding the effects of unusual items (such as litigation settlements), which were prevalent in 1998 but not in 1999, net income was up a lesser 21 percent. Cash flow generated from operations, which is largely unaffected by unusual items, rose 14 percent. The financial results in 1999 were well above those of 1998, but only average compared to the rest of the 1990's. Reflecting the volatility of petroleum markets, overall corporate profitability swung from a 15-year high in 1996 to 1997 to its third lowest level in 1998, rising in 1999 to a level somewhat below the companies' long-run average. Profitability of the FRS companies remained well below that of other large U.S. corporations overall.

The upswing in oil prices during the year and the sizable overhang of petroleum inventories that began the year largely drove financial results in 1999. Oil and gas production operations benefited from oil prices that rose from $10 per barrel at the beginning of 1999 to nearly $25 by the end of the year. Excluding unusual items, income contributed by the FRS companies' worldwide oil and gas operations totaled $16.5 billion in 1999, more than double the level of the year before.

The surge in earnings from oil and gas production was partly offset by results from petroleum refining and marketing operations. Net income from worldwide refining/marketing operations, excluding unusual items, fell by $4.3 billion, to $6.3 billion. This decline was a break in the upward trend in the FRS companies' downstream earnings that began in 1996.

The economic climate in 1999 favored a continued upswing in downstream earnings: strong economic growth in the United States, a return to positive growth in the Asia-Pacific region, and winter weather that was colder than the previous year in much of the industrialized world. However, 1999 began with relatively large levels of global petroleum inventories. Petroleum stock build-ups began in 1997 and continued through 1998, spurred by the Asian financial crisis and two consecutive mild winters. Throughout 1999, refiners drew down excess inventories, but the continual drawdown tended to restrain the effects of rising crude oil prices on refined product prices. As a result, the margin between refined product prices and crude oil input costs narrowed. The FRS refiners reported tighter margins in nearly all areas of the world. Although the companies were able to make some cuts in operating costs, the reductions were not sufficient to offset the margin squeeze.

Capital Expenditures Slashed in 1999

Market developments appeared to favor an increase in investment in oil and gas exploration and development in 1999. Oil prices in 1999 were up nearly 50 percent, on an annual basis, over 1998 prices. Cash flow realized from oil and gas production was also up 50 percent. Countries in Africa and South America continued to open deepwater oil and gas prospects to FRS companies. The overall costs of finding oil and gas reserves, on an annual basis, declined for the first time since 1994.

Despite these favorable developments, the FRS companies chopped their worldwide expenditures for oil and gas exploration and development by $19 billion, a 38-percent reduction, between 1998 and 1999. Fewer mergers and acquisitions accounted for about half of the spending cutbacks. In 1998, five upstream acquisitions each exceeded $1 billion in capital outlays while in 1999 only one transaction exceeded $1 billion. Even excluding the effects of mergers and acquisitions, only South America registered a clear increase in spending. The biggest cuts were for U.S. onshore activities and European prospects (mostly in the North Sea), with both regions experiencing spending cuts of over 50 percent.

Why did the FRS companies' upstream spending in 1999 run so strongly counter to the customary relationships between investment and expected profitability? The cutback in oil and gas exploration and development was part of a larger reduction in outlays, which saw the FRS companies slash their total capital expenditures by 23 percent between 1998 and 1999.

The FRS companies' reduction in capital outlays in 1999 was the major part of their effort to repair the damage to their balance sheets incurred in 1998. In 1998, their capital expenditures exceeded their cash flow by an unprecedented $27 billion, or by 56 percent. To close this $27-billion gap in 1998, the FRS companies increased their debt, resorted to issuing more stock, sold a record amount of assets, reduced cash payouts to shareholders, and drew down their cash balances by $4 billion. The adverse effects of these actions included more debt and higher interest expenses. Issuance of more stock tended to dilute the value of existing common shares, which, together with reduced dividends and share repurchases, tended to increase shareholder discontent.

To repair the damage done in 1998, the FRS companies increased their cash outlays for debt reduction in 1999 while cutting dividends and share repurchases as well as slashing capital expenditures.

Not all lines of business were targeted for investment cutbacks. The other energy line of business (i.e., energy operations other than oil, gas, and coal) registered a 42-percent increase in capital expenditures (after adjusting for an accounting change). In 1999, this line of business was dominated by enterprises engaged in various aspects of electric power production and supply in the United States and abroad. Although the other energy line of business accounted for only slightly over 2 percent of the FRS companies' asset base in 1999, and only a minority of companies are involved, it has been the fastest growing target of investment in the 1990's. The value of the FRS companies' productive assets in other energy grew at a 13-percent annual rate in the 1990's while all other businesses grew at a combined 3-percent annual rate.

Surprisingly, other nonenergy was the line of business that registered the largest increase in capital expenditures in 1999. Other nonenergy consists of the FRS companies' diversified enterprises outside the energy field. From the early 1980's until about 1997, nonenergy businesses outside of chemicals were generally targets of retrenchment, as the FRS companies restructured themselves to focus on core competencies in petroleum and natural gas and away from areas peripheral to energy. However, in 1999, capital expenditures for the other nonenergy line of business increased by $4.0 billion, a 152-percent increase, over prior-year expenditures. The bulk of this increase was for communications businesses, particularly fiber optic networks. Not only was communications an atypical business for the FRS respondent group but the two companies largely responsible for investment in communications, Enron and Williams Companies, reflect the emergence of the energy service company as the fastest growing segment of the major U.S. energy companies included in the FRS.

Growth of Energy Services Companies and Mega Mergers Alter the Cast of FRS Companies

The collection of U.S.-based major energy companies that enable EIA's Financial Reporting System to maintain coverage in oil and gas production and petroleum refining and marketing has changed considerably in recent years. The conventional picture of a major energy company portrayed in the popular media is of a large, vertically integrated petroleum company that combines the functions of oil and gas exploration and production with petroleum transport, refining, and marketing.

When the FRS began in the late 1970's, 24 of the 26 companies selected were vertically integrated, with vertically integrated companies accounting for 97 percent of the FRS companies' total assets. During the 1980's, three mega mergers (Chevron-Gulf Oil, Occidental Petroleum-Cities Service, and Texaco-Getty Oil) and two divestitures of downstream operations (Occidental Petroleum and Union Pacific) reduced the number of vertically integrated majors, but the traditional major still accounted for nearly all (90 percent) of the FRS companies' total assets at the end of the decade. More recently, mega mergers between BP and Amoco at the end of 1998 and Exxon and Mobil in late 1999 reduced their numbers by two. At the time this report is being written, BP Amoco's acquisition of ARCO, and the newest FRS company El Paso Energy's acquisition of Coastal will reduce the number of vertically integrated majors to 10. Based on 1999 data, the vertically integrated companies account for 70 percent of the FRS companies' total assets. Over the entire 1974 to 1999 span of FRS data collection, no major energy company has become vertically integrated.

As the number and role of vertically integrated majors have declined in recent years, other corporate structures have grown to prominence. The six large, specialized oil and gas producers in the FRS respondent group are composed of five formerly vertically integrated FRS companies plus Anadarko Petroleum. Ten non-integrated refiners became FRS respondents due to their rapidly growing shares of U.S. downstream activity in recent years. These specialized refiners accounted for 38 percent of U.S. refining capacity in 1999, up from only 7 percent in 1990. Two-thirds of this growth came through acquisitions of capacity from vertically integrated and formerly vertically integrated FRS companies.

The most rapidly growing companies in the FRS group have been the three energy services companies--Enron, El Paso Energy, and Williams Companies. Services provided typically include natural gas transmission and distribution; electricity generation and distribution; trading, wholesaling, and marketing of natural gas and electricity; and associated customer services such as risk management. Although the energy services companies are involved in natural gas production or petroleum refining, these businesses are usually minor in comparison with gas and power services.

Over the 1995 to 1999 period, the energy services companies nearly tripled in size (as measured by total assets), in significant part through mergers and acquisitions. Among the vertically integrated companies, the mega merger survivors, BP Amoco and ExxonMobil, grew a collective 65 percent over the 1995 to 1999 period. In contrast, the other integrated majors collectively grew only 9 percent over the same period.

Corporate growth is only one indicator of strategic success. More critical to the prospects for future success are the assessments of the capital markets. Using common stock price appreciation as a measure of investor perceptions indicates that the capital markets have given favorable nods to the energy service companies and mega merger survivors. Over the 1995 to 1999 period, the weighted average share price of the energy services companies grew at an annual 23-percent clip. The share prices of BP Amoco and ExxonMobil grew at a 20-percent rate over the period. Interestingly, other vertically integrated companies' overall share price kept pace with BP and Exxon through 1997, but was flat between 1997 and 1999. Thus, based on corporate growth and share price appreciation as indicators of strategic success, the energy service companies' presence among the ranks of U.S.-based major energy companies is likely to increase and vertically integrated majors should grow larger but fewer in number.

1. Markets And Companies in 1999

Developments in Global Oil and Gas Markets

The major U.S. energy companies[1] derive the bulk of their revenues and income from petroleum operations, including natural gas production. A majority of these companies are multinational, with 38 percent of the majors' net investment located abroad. Worldwide petroleum and natural gas market developments are of primary importance to the companies' financial performance. (For a list of these companies, the Financial Reporting System (FRS) companies, see the box entitled "The FRS Companies in 1999.")

The FRS Companies in 1999

(* Denotes new survey entrant in 1999)

Amerada Hess Corporation	Kerr-McGee Corporation
Anadarko Petroleum Corporation	Lyondell-CITGO Refining, L.P.
Atlantic Richfield Company (ARCO)	Motiva Enterprises, L.L.C.
BP America, Inc.	Occidental Petroleum Corporation
BP Amoco, Inc.	Phillips Petroleum Company
Burlington Resources, Inc.	Shell Oil Company
Chevron Corporation	Sunoco, Inc.
CITGO Petroleum Corporation	Tesoro Petroleum Corporation
Clark Refining and Marketing, Inc.	Texaco, Inc.
Coastal Corporation	Tosco Corporation
Conoco, Inc	Ultramar Diamond Shamrock Corporation
El Paso Energy Corporation*	Union Pacific Resources Group
Enron Corporation	Unocal Corporation
Equilon Enterprises, L.L.C.	USX Corporation
Exxon Mobil Corporation	Valero Energy Corporation
Fina, Inc.	The Williams Companies, Inc.

The year 1999 began with relatively large levels of petroleum inventories overhanging global energy markets. The stock builds go back to early 1997 when production increases by a number of countries in the Organization of Petroleum Exporting Countries (OPEC) led to a step-up in world oil (crude oil and natural gas liquids (NGL)) production. In mid-1997, financial crises led to economic downturns in some of the fastest growing economies of Asia, a problem that later hit Russia and Brazil. The downturns led to a drop in world petroleum demand growth. The upward pressures on world petroleum inventories were exacerbated by two successively mild winters (1996 to 1997, and 1997 to 1998) in many regions. Taken together, the industrialized countries in the Organization for Economic Cooperation and Development (OECD), including the United States, account for about two-thirds of world petroleum consumption. At the beginning of 1999, petroleum stocks in these countries were at their highest level ever and 7 percent above the average experienced over the 1990 to 1995 period.

During 1999, cuts in oil production and a turnaround in economic growth in the formerly ailing Asia-Pacific nations led to drawdowns of petroleum inventories and a movement toward balance in supply and demand.

On the demand side, worldwide petroleum consumption rose 2 percent between 1998 and 1999.[2] The United States and Asia-Pacific nations accounted for about 90 percent of the growth in world petroleum consumption in 1999. In the United States, real gross domestic product (GDP) grew by 4 percent in 1999. For the Asia-Pacific countries troubled by financial crises in 1997 and 1998, real GDP growth turned around from an overall negative 5 percent in 1998 to a positive 6 percent in 1999.

On the supply side, world oil production in 1999 was down a million barrels per day from 1998 production. Saudi Arabia and Venezuela were largely responsible for the production cutbacks among members of OPEC. These two countries' reduction in output more than offset Iraq's increase in production. Earlier, in mid-1998, Mexico and Norway (not OPEC members) reached an agreement with Saudi Arabia and Venezuela to cut oil production. The continuing downward trend in North American (U.S. and Canadian) oil production also contributed to the drop in world oil supply in 1999.

As world oil demand outpaced supply, petroleum stocks were drawn down throughout 1999. Among the OECD countries, inventory drawdowns put petroleum stocks below their average level by November when compared to the level of November petroleum stocks in prior years. In the United States, the year 1999 began with higher commercial stocks of petroleum than in recent years. Crude oil supply cutbacks and rising prices encouraged stock drawdowns including an extraordinarily rapid drawdown toward the end of the year. In sharp contrast to 1999, the year 2000 began with the lowest level of commercial petroleum inventories since at least 1974.

As a result of these developments, the price of oil (as measured by the U.S. refiner acquisition cost of imported crude oil) went from $10 per barrel in January, a 25-year low, to over $24 per barrel by December, the highest level of oil prices since the Gulf War.

The surge in oil prices greatly benefited the upstream (oil and gas exploration and production) operations of the FRS companies and other oil producers, adding to cash flow and bottom-line income. However, surging oil prices meant higher raw material input (primarily crude oil) costs for refiners. The upswing in costs could not be fully passed along to consumers, as excessive inventories (for most of the year) restrained refined product price increases.

Refiners in the United States experienced lower gross margins in 1999 (i.e., the spread between refined product prices and crude oil input prices) even though U.S. petroleum product demand grew by a healthy 3 percent. Transport fuels (gasoline, diesel, and jet fuel) led the growth in petroleum demand, as greater travel activity usually accompanies strong economic growth. Transport fuels typically yield the highest margins for refiners. However, the depressing effect on prices of the overhang of petroleum stocks overwhelmed the strong growth in petroleum demand, resulting in lower earnings for U.S. refiners.

A similar pattern prevailed in the markets supplied by the FRS companies' foreign refining and marketing operations in 1999. Demand for the FRS companies' refined products outside the United States (mainly in Europe, Asia-Pacific, and Latin America) generally grew in 1999, but the companies reported lower margins in all of these regions.

Large inventories also affected natural gas markets in the United States in 1999. At the beginning of the year, the amount of natural gas in underground storage was at an all-time high because of developments in 1998. The year 1998 was bracketed by two warmer-than-normal winters in the United States. In that year, total heating degree-days were 13 percent less than in 1997. U.S. natural gas consumption was down 3 percent in 1998, as residential and commercial demand fell 8 percent in response to the milder winter temperatures. Supplies of gas from domestic production and imports (largely from Canada) in 1998 were flat compared with 1997. As a result, natural gas in storage soared to a record level.

Although 1999 was warmer than normal, it was cooler than 1998 as heating degree-days were up 6 percent on a year-to-year basis. Residential and commercial demand for natural gas, which was up 3 percent, reflected the cooler winter weather. On the supply side, U.S. natural gas production was flat in 1999, continuing an essentially level trend evident since 1995. Imports largely supplied the growth in U.S. natural gas consumption in 1999. Canada has been, by far, the main source of natural gas imports into the United States, but liquefied natural gas (LNG) shipped in specialized tankers became a noticeable source of gas in 1999. Drawdowns of gas in storage also served to satisfy the growth in demand and moved storage levels toward more typical values. By late 1999, U.S. natural gas supply and demand were closer to being in balance than in 1997 and 1998.

On an annual basis, wellhead natural gas prices were up 7 percent between 1998 and 1999.

Outside the United States, consumption of natural gas rose 3 percent between 1998 and 1999, with the Asia-Pacific region posting a 6-percent increase. Although European consumption was up 4 percent, the FRS companies reported a 14-percent drop in the price they received for sales of natural gas in Europe. However, these same companies realized higher prices in other areas. On balance, the FRS companies' average natural gas price outside the United States was $2.03 per thousand cubic feet in 1999, down slightly from $2.08 in 1998.

In sum, energy market developments in 1999 had a positive effect on the FRS companies' bottom-line income, as the surge in upstream earnings more than offset the decline in refining and marketing earnings. Although financial performance was much improved from the poor results of 1998, the FRS companies' net income in 1999 was well short of that in 1996 and 1997.

The FRS Companies' Importance in the U.S. Economy

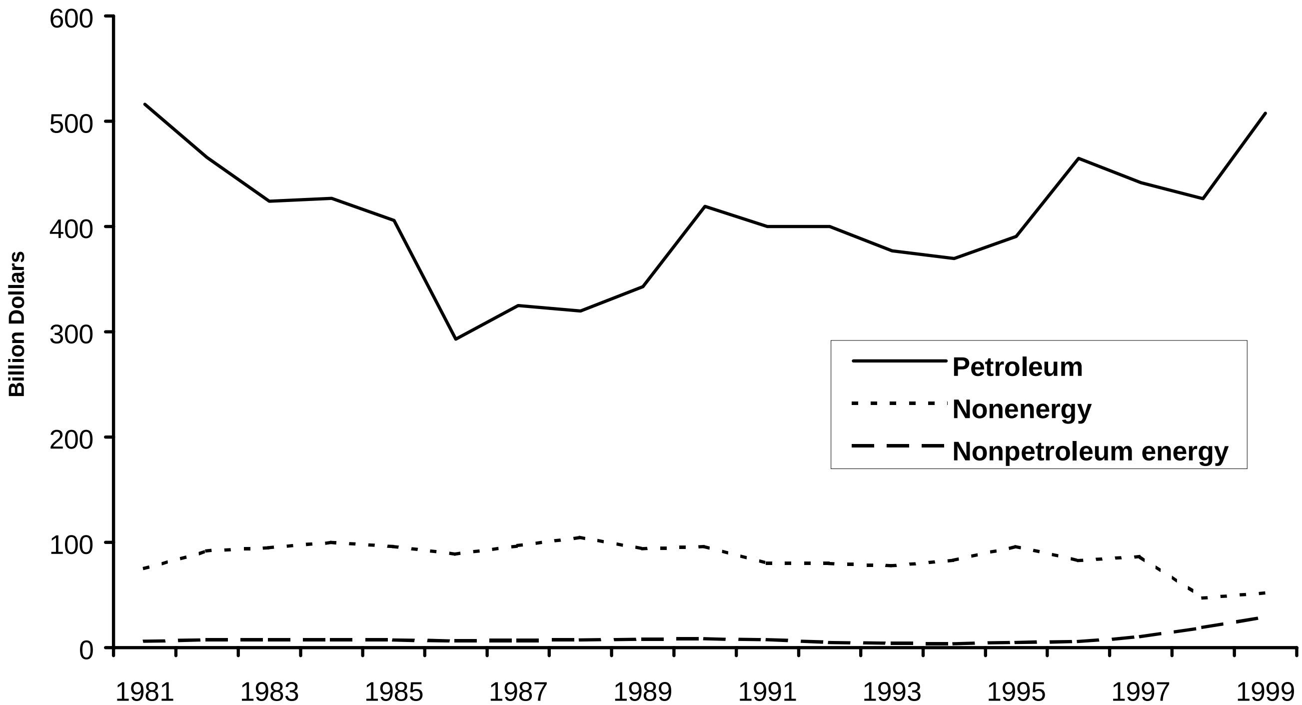
For the reporting year 1999, 32 major energy companies reported their financial and operating data to the EIA Financial Reporting System (FRS) on Form EIA-28.[3] These companies (referred to as the FRS companies in this report) occupy a significant position in the U.S.[4] economy. In 1999, sales of the FRS companies totaled $578 billion, which is equal to 9 percent of the $6.3 trillion in sales of the Fortune 500 largest U.S. corporations.[5]

The reporting companies engage in a wide range of business activities, but their most important activities are in the energy sector. About 91 percent, or $537 billion, of allocated operating revenues were derived from energy sales. Nearly all of these revenues were derived from the companies' core petroleum operations (Figure 1). (For the purposes of this report, the petroleum line of business includes natural gas.)

In 1999, the FRS companies accounted for 46 percent of total U.S. oil (crude oil and natural gas liquids (NGL)) production, 42 percent of U.S. natural gas production, and 86 percent of U.S. refining capacity (Figure 2). The bulk of the FRS companies' assets and new investments were devoted to sustaining various aspects of petroleum production, processing, transportation, and marketing. Nonenergy businesses, mainly chemicals, accounted for about 9 percent, or $52 billion, of the FRS companies' allocated revenues in 1999.

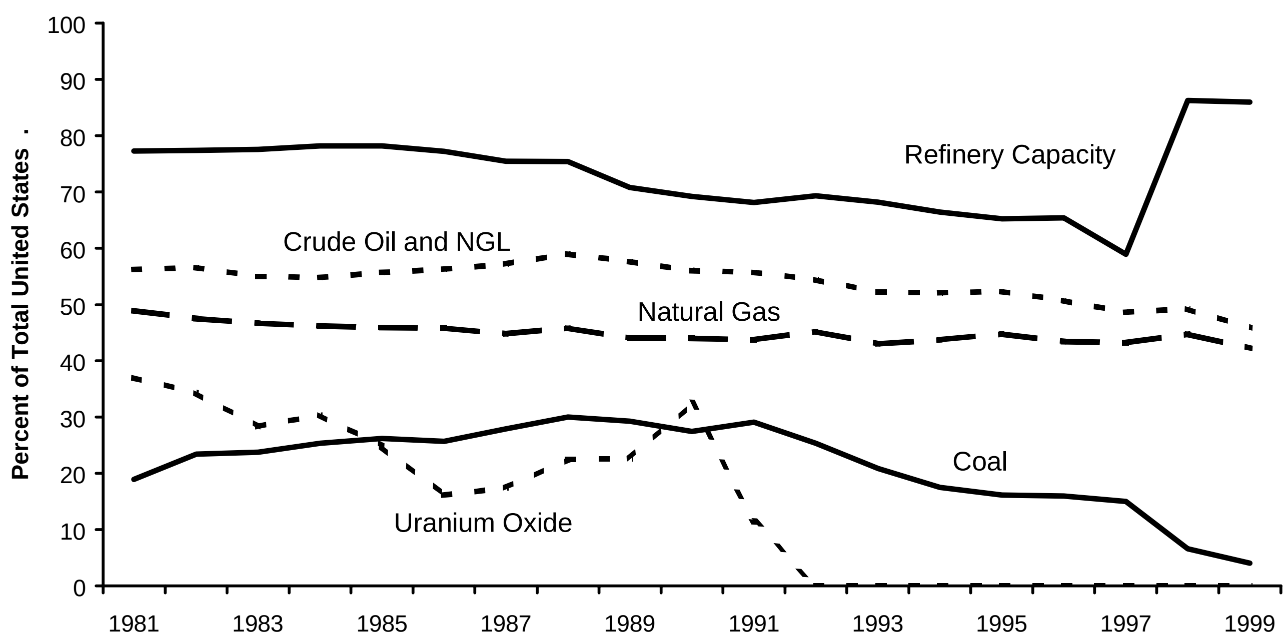
Energy production other than oil and natural gas is a relatively small, but growing, part of the FRS companies' operations. During 1999 the combined operating revenues of the coal and other energy operations of the FRS companies totaled $29 billion, or only 5 percent of allocated revenues. Increased activity in electricity more than offset the abrupt decline in coal activity by the FRS companies in 1999. In particular, the FRS companies accounted for 15 percent of U.S. coal production in 1997, 7 percent in 1998, and a mere 4 percent in 1999. No FRS company has produced uranium oxide since 1991.

Figure 1. Operating Revenues by Line of Business for FRS Companies, 1981-1999



Note: Petroleum includes natural gas.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Figure 2. Shares of U.S. Energy Production and Refinery Capacity for FRS Companies, 1981-1999



Sources: Table B1; Total industry uranium oxide production is from Energy Information Administration, *Uranium Industry Annual 1999,* DOE/EIA-0478(99) (Washington, DC, May 2000).

Endnotes

[1] The companies that reported to the FRS for the years 1974 through 1999 are listed in Appendix A, Table A1 (available on the EIA Web site at http://www.eia.doe.gov/emeu/perfpro/taba1.html). Four of the FRS companies are owned by foreign companies: BP Amoco and BP America--both now owned by BP Amoco plc; Fina--owned by TotalFinaElf; and Shell Oil--owned by Royal Dutch/Shell.
[2] In this chapter, international energy data were obtained from BP Amoco, *Statistical Review of World Energy* (London, June 2000); annual and monthly U.S. energy industry price and quantity data are from Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(00/09) (Washington, DC, September 2000); GDP data are from the WEFA Group, *World Economic Outlook* (August 2000).
[3] Aggregate time series data from Form EIA-28 for 1977 through 1999 and previous editions of this report can be obtained from the EIA (see http://www.eia.doe.gov/emeu/finance/page2.html).
[4] 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.
[5] The Fortune 500 is a list of the 500 largest U.S. industrial corporations, ranked by total sales, published annually by *Fortune* magazine (see http://www.pathfinder.com/fortune/).

2. Financial Developments in 1999

The financial performance of U.S.-based major energy companies improved in 1999 from near record lows in 1998. Income growth stemmed largely from higher oil prices. However, despite higher oil prices in 1999, the majors cut their expenditures for exploration and production of oil and gas by 38 percent from prior-year spending.

Net income of the 32 major energy companies reporting to EIA's Financial Reporting System (FRS) was up 83 percent between 1998 and 1999 (Table 1). Crude oil prices, as measured by the U.S. refiners' acquisition cost of imported crude oil, rose from $9.39 per barrel in December of 1998 to $24.35 in December of 1999. A modest rise in U.S. natural gas wellhead prices, from $1.94 per thousand cubic feet in 1998 to $2.08 on an annual basis, also contributed to the increase in net income. Relatively low price-cost margins for FRS refiners in the United States and in foreign locales partly offset the rise in income from oil and gas production.

The near doubling of net income was not sufficient to raise the profitability of the FRS companies to the average profitability of other large U.S. industrial corporations. Return on equity (net income as a percent of stockholders' equity) of the FRS companies, at 11 percent in 1999, did not even match the FRS companies' long-term 25-year average of 12 percent. In contrast, return on equity of the S&P Industrials[6] in 1999, at 18 percent, matched the record performance of 1998 (Figure 3). Also apparent from Figure 3 is the greater volatility of the FRS companies' profitability compared with the S&P Industrials in recent years. For example, in the 1996 to 1999 period, return on equity for the FRS companies ranged from a near-record high to a near-record low. The wide swings in profitability largely reflected the volatility of oil prices and are in contrast to the generally upward path of the S&P Industrials' return on equity in recent years.

The near doubling of the FRS companies' net income between 1998 and 1999 also exaggerates the strength of the recovery in bottom-line results. Low oil prices in 1998 led U.S. oil and gas producers to write down the balance sheet value of oil and gas assets. The asset writedowns were treated as charges against income as required by generally accepted accounting principles. Largely due to asset writedowns, unusual items[7] reduced the FRS companies' net income by $7.0 billion in 1998. In 1999, unusual items reduced net income by only $0.8 billion. Excluding unusual items, net income of the FRS companies increased 21 percent, considerably less than the 83-percent increase in net income unadjusted for unusual items (Table 1).

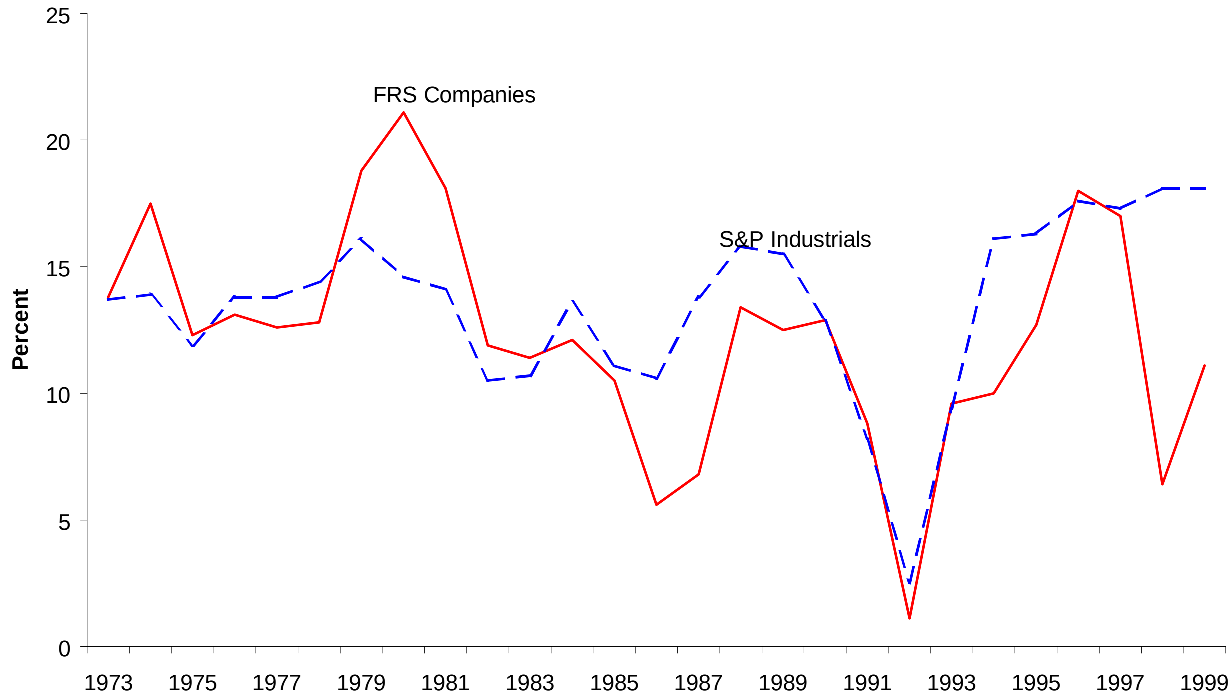
Table 1. Consolidated Income Statement for FRS Companies and the S&P Industrials, 1998 and 1999
(Billion Dollars)

	FRS Companies			S&P Industrials		
Income Statement Items	**1998**	**1999**	**Percent Change 1998-1999**	**1998**	**1999**	**Percent Change 1998-1999**
Operating Revenues	484.2	578.1	19.4	3,923.5	4,253.7	8.4
Operating Expenses	-468.3	-545.9	16.6	-3,502.6	-3,770.6	7.7
Operating Income	15.8	32.2	103.5	420.9	483.0	14.8
Interest Expense	-7.1	-8.5	18.6	-80.6	-84.3	4.5
Other Revenue (Expense)	8.7	10.2	17.6	35.5	47.2	32.9
Income Tax Expense	-4.7	-10.8	130.2	-120.6	-155.3	28.8
Net Income	12.5	22.9	82.7	255.1	290.6	13.9
Net Income Excluding Unusual Items	19.5	23.7	21.4	NA	NA	

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

Sources: **FRS Companies**: Energy Information Administration Form EIA-28 (Financial Reporting System); **S&P Industrials**: Compustat PC Plus, a service of Standard and Poor's.

Figure 3. Return on Equity for FRS Companies and the S&P Industrials, 1973-1999



Sources: **FRS Companies**: Energy Information Administration, Form EIA-28 (Financial Reporting System).
S&P Industrials: Compustat PC Plus, a service of Standard and Poor's.

Income and Cash Flow

Higher Oil Prices Lead to Recovery in Upstream Earnings

Cutbacks in oil production (mainly by Saudi Arabia, Venezuela, Norway, and Mexico during 1999), together with an increase in worldwide demand for petroleum, led to a substantial rise in oil prices in 1999. On an annual basis, wellhead oil prices in the United States rose from $10.87 per barrel in 1998 to $15.56 per barrel in 1999. Wellhead natural gas prices were up 7 percent, or $0.79 per barrel on an oil-equivalent basis.

Lower operating costs in oil and gas production contributed to bottom-line improvements as well. Massive writedowns of upstream asset values in 1998, but not in 1999, had the effect of reducing charges for depreciation and depletion. The FRS companies cut their U.S. exploration expenses (which are included in operating costs) by 31 percent and foreign exploration expenses by 7 percent from prior-year levels. These cutbacks were part of a reduction in spending for upstream prospects in 1999, a development which is reviewed in detail in a later section of this chapter.

The positive effects of higher oil and gas prices were partially offset by a 6-percent decline in the FRS companies' U.S. oil production and a 5-percent reduction in U.S. natural gas production. Net income from U.S. oil and gas production, excluding unusual items, increased by 161 percent between 1998 and 1999 (Table 2).[8] In foreign upstream operations, the FRS companies reported an 87-percent increase in net income, excluding unusual items.

Table 2. Contributions to Net Income by Line of Business for FRS Companies, 1998-1999
(Million Dollars)

Line of Business	Net Income 1998	Net Income 1999	Net Income Percent Change 1998-1999	Net Income Excluding Unusual Items 1998	Net Income Excluding Unusual Items 1999	Net Income Excluding Unusual Items Percent Change 1998-1999
Petroleum						
U.S. Petroleum						
Production	485	7,444	1,434.8	3,170	8,266	160.8
Refining/Marketing	5,932	4,883	-17.7	6,971	4,515	-35.2
Pipelines	1,352	2,424	79.3	2,022	2,261	11.8
Total U.S. Petroleum	7,769	14,751	89.9	12,163	15,042	23.7
Foreign Petroleum						
Production	2,030	8,226	305.2	4,423	8,252	86.6
Refining/Marketing	2,945	1,854	-37.0	3,667	1,796	-51.0
International Marine	93	7	-92.5	93	7	-92.5
Total Foreign Petroleum	5,068	10,087	99.0	8,183	10,055	22.9
Total Petroleum	12,837	24,838	93.5	20,346	25,097	23.4
Coal	500	173	-65.4	224	173	-22.8
Other Energy	944	711	-24.7	947	851	-10.1
Nonenergy	1,831	2,778	51.7	2,222	3,125	40.6
Total Allocated	16,112	28,500	76.9	23,739	29,764	25.4
Nontraceables and Eliminations	-3,593	-5,634	--	-4,229	-5,557	--
Consolidated Net Income[a]	12,519	22,866	82.7	19,510	23,689	21.4

[a]The total amount of unusual items was -$6,991 million and -$823 million in 1998 and 1999, respectively.

-- = Not meaningful.

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

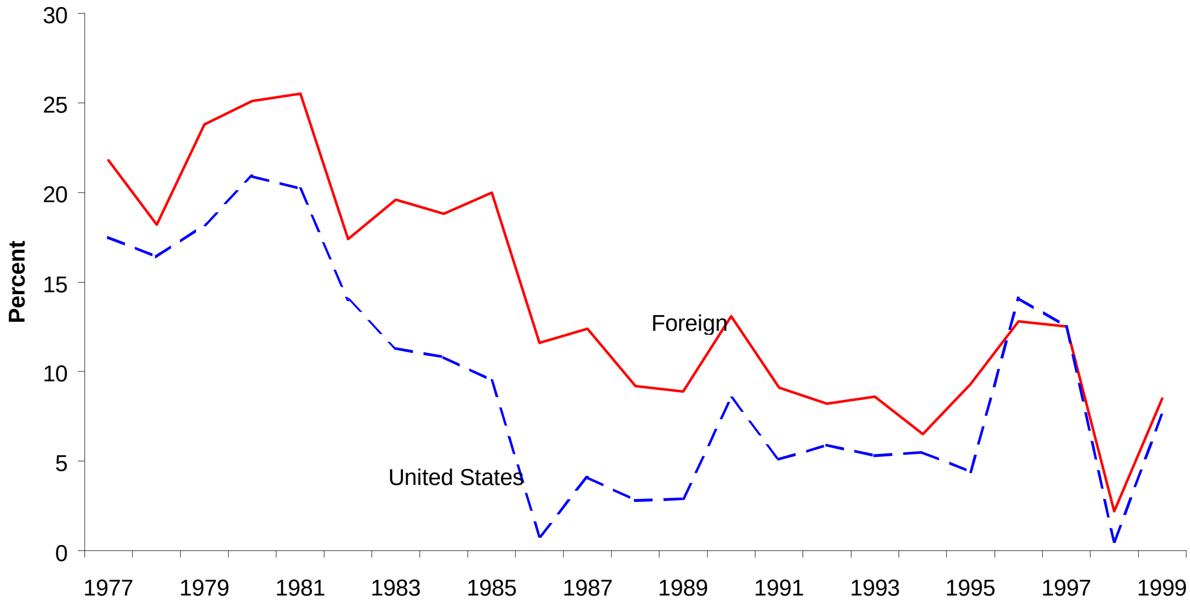
The profitability of U.S. and foreign upstream operations rose in 1999 from the near-zero rates of return in the prior year (Figure 4).[9] However, 1999 oil and natural gas prices, on an annual basis, were below the levels of 1996 and 1997. As a result, the profitability of the FRS companies' upstream operations in 1999 did not match the levels of 1996 and 1997.

Large Inventories Limit Refining Profits

By most indicators, the year 1999 should have seen continued increases in income from U.S. petroleum refining and marketing. Continued strong U.S. economic growth favored increased consumption of petroleum products. Petroleum product demand in the United States was up 3 percent. The increase in demand stemmed largely from transport fuels. Transport fuels (motor gasoline, diesel, and jet fuel) typically yield the highest price-cost margins to refiners. Winter weather in 1999, though milder than normal, was colder than in the previous year. However, despite these favorable developments, petroleum product prices realized by U.S. refiners did not keep pace with rising crude oil prices in 1999.

The year 1999 began with relatively large levels of global petroleum inventories. The stock builds began in early 1997 with a step-up in world oil production. Additional inventory accumulations continued through 1998, spurred by the effects of the Asian financial crisis and two consecutive mild winters in much of the industrialized world. Throughout 1999, refiners steadily drew down petroleum inventories, with extraordinarily rapid drawdowns toward the end of the year. In the United States, end-of-year commercial petroleum inventories in 1999 were at the lowest level since at least 1974. However, the steady drawdowns of inventories tended to restrain the effects of rising crude oil prices on refined product prices. For FRS refiners in the United States, raw material input prices were up $4.61 per barrel between 1998 and 1999, but their overall petroleum product prices were up a lesser $3.95. As a result, the spread between petroleum product prices and raw material input costs deteriorated between 1998 and 1999.

Figure 4. Return on Investment in U.S. and Foreign Oil and Gas Production for FRS Companies, 1977-1999



Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

The FRS companies were able to cut the costs of operating their refineries and marketing networks by $0.17 per barrel between 1998 and 1999 ($0.25 per barrel, excluding energy costs), a 4-percent reduction. On balance, the FRS companies' net income, excluding unusual items, from U.S. refining/marketing operations declined 35 percent in 1999 from the prior-year level.

The FRS companies fared even worse in foreign refining/marketing operations, as net income in 1999 was down 51 percent. As in the United States, the spread between refined product prices and crude oil input costs declined in 1999 in the important Asia-Pacific and European markets (for a detailed discussion, see the section entitled "Foreign Refining and Marketing" in Chapter 3). Most of the FRS companies with significant refining operations abroad registered lower income from those operations. ExxonMobil reported a 71-percent decline in foreign downstream earnings from 1998 to 1999.[10] Chevron, in discussing Caltex, its 50-50 refining and marketing joint venture with Texaco, said that margins declined in Caltex's area of operations (Asia-Pacific) as "… competitive pressures prevented refined products sales realizations from rising sufficiently to recover higher crude oil costs."[11] Texaco noted that refining margins were lower in Europe and Brazil.[12]

Ownership Changes Cloud Results in Other Energy and Pipelines

Other Energy

The upward trend in income from other energy businesses (mostly electricity) of the FRS companies did not continue in 1999. Prior to 1999, net income from the other energy line of business more than doubled between 1990 and 1997, and, in 1998, was triple that of the year before. In 1999, net income, excluding unusual items, was down 10 percent from the especially high prior-year level. Even excluding El Paso Energy, which entered the FRS group in 1999, and Sonat, which was acquired by El Paso Energy, net income from other energy was down 6 percent. The decline in income was widespread. Of the 11 companies that reported ongoing operations in other energy, 8 reported a decline in net income from other energy operations.

Among the FRS companies involved in electricity, Enron has the largest investment commitment. In 1999, Enron reported that income from their Portland General Electric subsidiary dropped 4 percent.[13] El Paso Energy's "Merchant Energy" segment, which includes electricity operations, registered a $53-million decline in income.[14] ExxonMobil reported that its Hong Kong Power subsidiary's earnings were down about 2 percent as electricity demand growth was flat.[15] In contrast, Coastal Corporation, which owns and operates electricity facilities in the United States, Latin America, and China, reported that earnings from its "Power" segment were up 31 percent.[16]

Net income from coal operations declined by 23 percent between 1998 and 1999, as the FRS companies continued to reduce their commitments to coal production. Their share of total U.S. coal production dropped to 4 percent in 1999 from 7 percent in 1998. Ten years earlier, the share of the FRS companies was 30 percent.

Pipelines

The 12-percent increase in net income from pipelines, excluding unusual items, was traceable largely to companies whose pipeline investments are in natural gas transmission. However, ownership changes were responsible for this apparent improvement in earnings. In 1999, Shell Oil made divestitures of pipeline assets following its 1998 acquisition of Tejas Corporation, a large natural gas pipeline operation in Texas. El Paso Energy, which entered the FRS group in 1999, brought billions of dollars of natural gas pipeline revenues to the FRS totals for 1999 but not 1998. Excluding these two companies, net income from pipelines of the other FRS companies with asset commitments to natural gas transmission declined 5 percent between 1998 and 1999.

The FRS companies whose pipeline investments are primarily in liquids transport can be divided into two groups: companies that own the Trans Alaskan Pipeline System (TAPS) and companies that operate in the lower 48 states. The TAPS companies (ARCO, BP Amoco, and ExxonMobil) together reported a 6-percent decline in net income from pipelines. Operating revenues fell as Alaskan oil production continued to decline in 1999, down 11 percent from 1998 production. However, because of the large component of fixed costs in running TAPS, operating costs did not decline as much. Net income from pipelines for the other FRS companies was up 27 percent due to the combination of stable revenues and reductions in out-of-pocket operating expenses.

Nonenergy Businesses Show Mixed Results

The nonenergy line of business is dominated by chemical operations. In 1999, the FRS companies' revenues from chemicals accounted for 76 percent of total nonenergy revenues. Other nonenergy businesses include nonfuel mineral production (e.g., steel, copper), communications, real estate, and trading services.

In 1999, the FRS companies, overall, registered a 41-percent increase in net income from nonenergy businesses. The bulk of this increase is traceable to two financial items. Income from unconsolidated affiliates increased by $178 million between 1998 and 1999, with eight of twelve companies reporting higher equity earnings. Also contributing to the increase in nonenergy income was a turnaround in the effects of asset sales, from a loss of $53 million in 1998 to a gain of $194 million in 1999. Significant divestitures of nonenergy businesses in 1999 included ARCO's sale of Union Texas Petrochemicals and Chevron's sale of San Francisco office buildings.

Operating income,[17] which excludes the two items noted above, suggests that financial results in chemical operations were flat from 1998 to 1999 (Table 3). Income from chemical operations was up 1 percent, with 4 companies reporting an increase and 5 companies reporting a decline in income. Among the companies reporting an increase in chemical earnings was Chevron, which said, “Earnings in 1999 benefited from improved sales margins for major products, higher sales volumes, and lower operating expenses.”[18] ExxonMobil reported a 4-percent decline in income from their chemical operations, explaining that “industry margins declined due to lower product prices and higher feedstock costs.”[19]

The flat year-to-year performance in chemicals could signal an end to the latest downswing in this industry. A flattening of the profitability of chemical operations in 1998 to 1999 is reminiscent of the 1991 to 1992 period that preceded the last upswing in the profitability of chemical operations (Figure 5). The chemical industry entered a downswing after peaking in 1995, as worldwide production capacity increased faster than demand.

Results in the other nonenergy line of business are muddied by one company’s reclassification of certain assets from nonenergy to another line of business. Excluding this company indicates that operating income from the collection of diverse enterprises in the other nonenergy line of business in 1999 was clearly below that of 1998. With this adjustment, operating income for the FRS companies declined from $549 million in 1998 to a loss of $68 million in 1999. USX and Williams Companies registered large declines in income from their other nonenergy businesses in 1999. USX disclosed that operating losses (excluding unusual items) from its U.S. Steel subsidiary were $43 million in 1999 versus operating income of $210 million in 1998.[20] USX attributed the drop in performance to lower average steel prices, lower income from raw materials operations, and an unfavorable product mix. Williams Companies’ other nonenergy business consists largely of its Williams Communications subsidiary. The company reported that operating losses from this subsidiary worsened from $175 million in 1998 to $292 million in 1999, and that the heavier losses were due to provision of services to a growing customer base before completing a new fiber-optic network and start-ups in Australia and Brazil.[21]

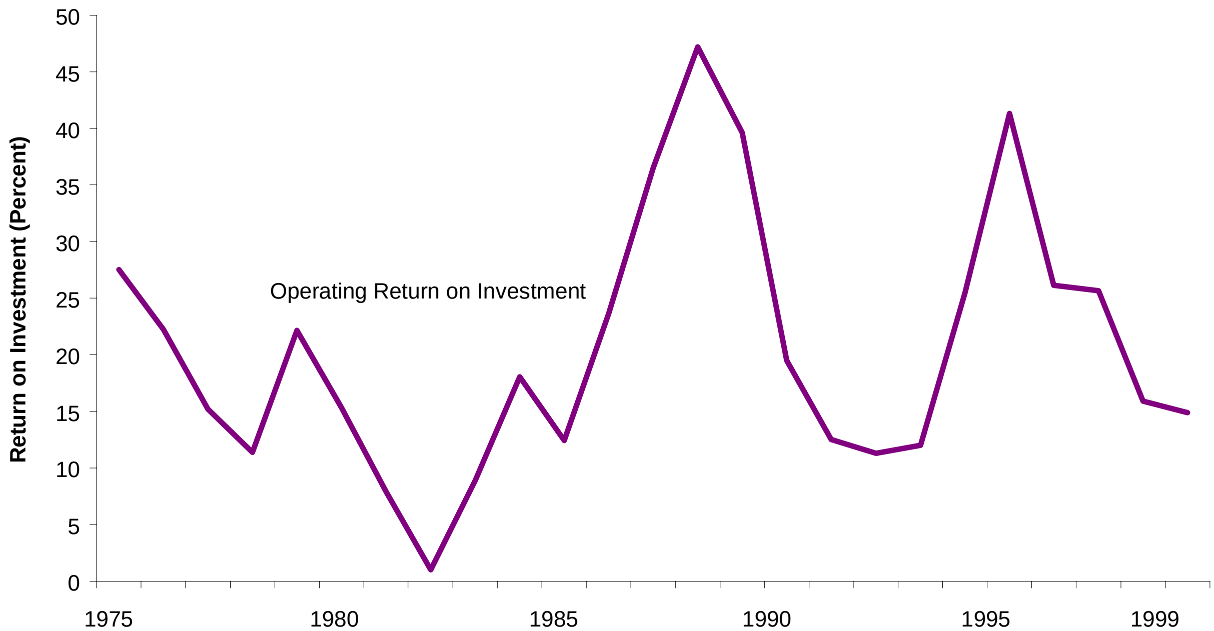
Table 3. Operating Income in Chemicals and Other Nonenergy Segments for FRS Companies, 1998-1999
(Million Dollars)

Segment	1998	1999	Percent Change 1998-1999
Operating Income, Excluding Unusual Items			
Chemicals	4,037	4,085	1.2
Other Nonenergy	-527	-198	--

-- = not meaningful

Sources: Chemicals segment operating income was compiled from company annual reports to shareholders, and other nonenergy income was computed by subtraction from Energy Information Administration, Form EIA-28 (Financial Reporting System).

Figure 5. Operating Return on Investment in Chemicals for FRS Companies, 1975-1999



Note: Operating Return on Investment is operating income as a percent of net property, plant, and equipment.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System); and company annual reports to stockholders.

Cash Flow Recovers

Among the FRS companies, cash generated by operations is the main source of funds with which capital expenditures, payouts to investors, and reduction in debt can be made. The FRS companies' cash flow from operations was $54.8 billion in 1999, up from $48.2 billion in 1998 (Table 4). Cash flow in 1999 was about average for the 1990's but about $10 billion short of the record cash flows of 1996 and 1997. The contributions to pretax cash flow[22] by lines of business paralleled the pattern of income by lines of business. Oil and gas production more than accounted for the overall increase in pretax cash flow, while downstream operations registered a $2.1-billion decline in pretax cash flow.

Until 1998, there was a fairly stable relationship between the FRS companies' cash flow from operations and capital expenditures (measured as additions to investment in place).[23] Prior to 1998, the FRS companies' capital expenditures averaged 86 percent of cash flow from operations and had not exceeded cash flow from operations in any of the 24 previous years of FRS data collection except for the mega-merger years 1982 and 1984. In 1998, capital expenditures exceeded cash flow by 56 percent. This imbalance led to increases in borrowing, cutbacks in investor payouts, and drawdowns of cash balances. In 1999, as the main part of the FRS companies' efforts to repair the damage to their balance sheets and shareholder value, the FRS companies reduced their capital expenditures despite a 14-percent increase in cash flow.

Table 4. Line-of-Business Contributions to Pretax Cash Flow for FRS Companies, 1998-1999
(Billion Dollars)

Contribution to Pretax Cash Flow [a]	1998	1999	Percent Change 1998-1999
Petroleum			
Oil and Gas Production	29.0	43.4	49.8
Refining, Marketing, and Transport	21.3	19.2	-9.7
Coal and Other Energy	1.2	1.1	-9.9
Chemicals	5.5	5.4	-2.6
Other Nonenergy	0.0	0.5	--
Nontraceable	-3.2	-3.2	--
Total Contribution to Pretax Cash Flow[a]	53.8	66.5	23.5
Current Income Taxes	-5.8	-10.7	84.5
Other (Net)	0.1	-1.0	--
Cash Flow from Operations	48.2	54.8	13.8

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

-- = 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 (Financial Reporting System).

Targets of Investment

Capital Expenditures Cut 23 Percent

Capital expenditures of the FRS companies totaled $57.6 billion in 1999, 23 percent below 1998 expenditures (Table 5). A combination of oil prices that were at 25-year lows early in 1999 and the unprecedented excess of capital expenditures over cash flow in 1998 led to sharp spending cutbacks in 1999. The largest reductions were in expenditures for mergers and acquisitions, oil and gas production, and petroleum refining.

Mergers and Acquisitions Sharply Curtailed

Capital expenditures for mergers and acquisitions by the FRS companies fell by nearly $12 billion in 1999 (Table 5 and Figure 6).[24] The mega-merger between Exxon and Mobil in 1999, valued at $79 billion, had no effect on capital expenditures (see the Highlight entitled "Mega-Mergers and New Entrants in 1999"). The absence of large upstream acquisitions in 1999 accounted for most of the decline. In 1998, five upstream acquisitions each exceeded $1 billion in value: Occidental Petroleum's acquisition of the U.S. Government's Elk Hills Naval Petroleum Reserve ($3.5 billion), ARCO's acquisition of Union Texas Petroleum Holdings ($3.3 billion), Union Pacific Resources' acquisition of Norcen Energy Resources ($2.6 billion), USX's acquisition of Tarragon Oil and Gas ($1.2 billion), and Sonat's acquisition of Zilkha Energy ($1.3 billion).[25] In 1999, the only acquisition clearly in the $1-billion-plus league was Burlington Resources' acquisition of Canadian-based Poco Petroleums for $2.5 billion (Table 6). Capital expenditures for all mergers and acquisitions involving oil and gas production in 1999 totaled $5.7 billion, down 62 percent from 1998's outlays of $14.8 billion.

Table 5. Additions to Investment in Place by Line of Business for FRS Companies, 1998-1999
(Billion Dollars)

Line of Business	1998	1999	Percent Change 1998-1999	Percent Change Excluding Mergers and Acquisitions 1998-1999
Petroleum				
U.S. Petroleum				
Production	22.3	13.2	-40.6	-23.0
Refining/Marketing				
Refining	4.4	2.8	-36.4	-21.2
Marketing	2.7	2.6	-0.8	-13.7
Transport	1.1	1.6	39.6	21.1
Total Refining/Marketing	8.2	7.0	-14.4	-11.7
Pipelines	5.4	3.1	-42.1	26.1
Total U.S. Petroleum	35.9	23.4	-34.8	-18.1
Foreign Petroleum				
Production	26.1	17.6	-32.5	-26.7
Refining/Marketing	3.5	2.3	-34.6	-38.9
International Marine	0.0	0.0	-18.8	--
Total Foreign Petroleum	29.6	19.9	-32.7	-28.4
Total Petroleum	65.5	43.3	-33.9	-22.7
Coal	0.2	0.2	-11.9	-11.9
Other Energy	1.5	1.7	12.6	-30.1
Nonenergy				
Chemicals	5.2	4.7	-10.8	-20.7
Other Nonenergy	2.6	6.6	152.3	275.9
Total Nonenergy	7.8	11.3	43.7	53.5
Nontraceables	0.0	1.1	--	--
Additions to Investment in Place	75.1	57.6	-23.3	-10.3
Additions Due to Mergers and Acquisitions	20.7	8.8	-57.6	--
Total Additions Excluding Mergers and Acquisitions	54.4	48.8	-10.3	--
Addendum: Environmental Capital Expenditures	2.3	1.7	-24.8	--

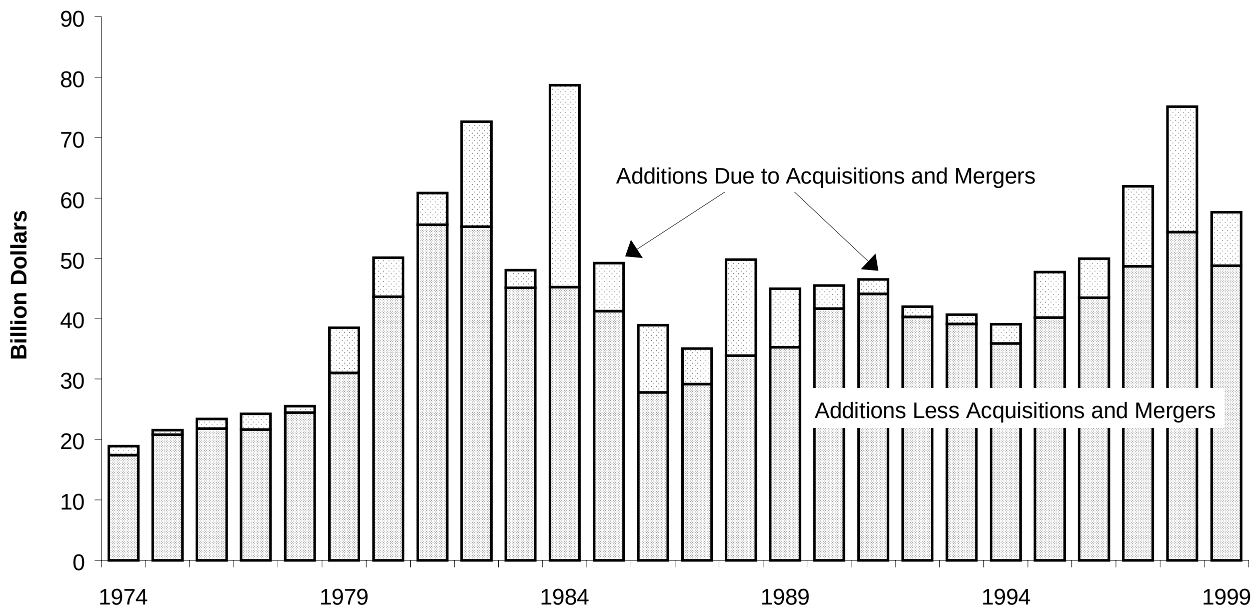
a Measured as additions to property, plant, and equipment, plus additions to investments and advances.

-- = 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 (Financial Reporting System), except for environmental capital expenditures, which came from company filings of Securities and Exchange Commission Form 10-K.

Figure 6. Additions to Investment in Place and Value of Acquisitions and Mergers for FRS Companies, 1974-1999



Source: Energy Information Administration, Form EIA-28 (Financial Reporting System); and company filings of Securities and Exchange Commission Form 10-K.

Nearly All Oil and Gas Regions Hit by Cutbacks

Oil and gas production was the main target of the FRS companies' capital expenditure reductions in 1999, accounting for over 90 percent of the total drop in spending from 1998 levels. The experience of oil prices falling from $15 per barrel to $10 per barrel during the course of 1998 and remaining low in early 1999, led to deferrals of project startups and diminished the expected profitability of upstream acquisitions. Buoyant oil prices in 1997 encouraged oil and gas producers, and the FRS companies in particular, in 1998, to add to their reserve bases through the drill bit and to acquire already proven reserves through mergers and acquisitions. However, as oil prices deteriorated in 1998, hitting a 25-year low by year-end, the FRS companies reined in their spending plans for oil and gas exploration and development.

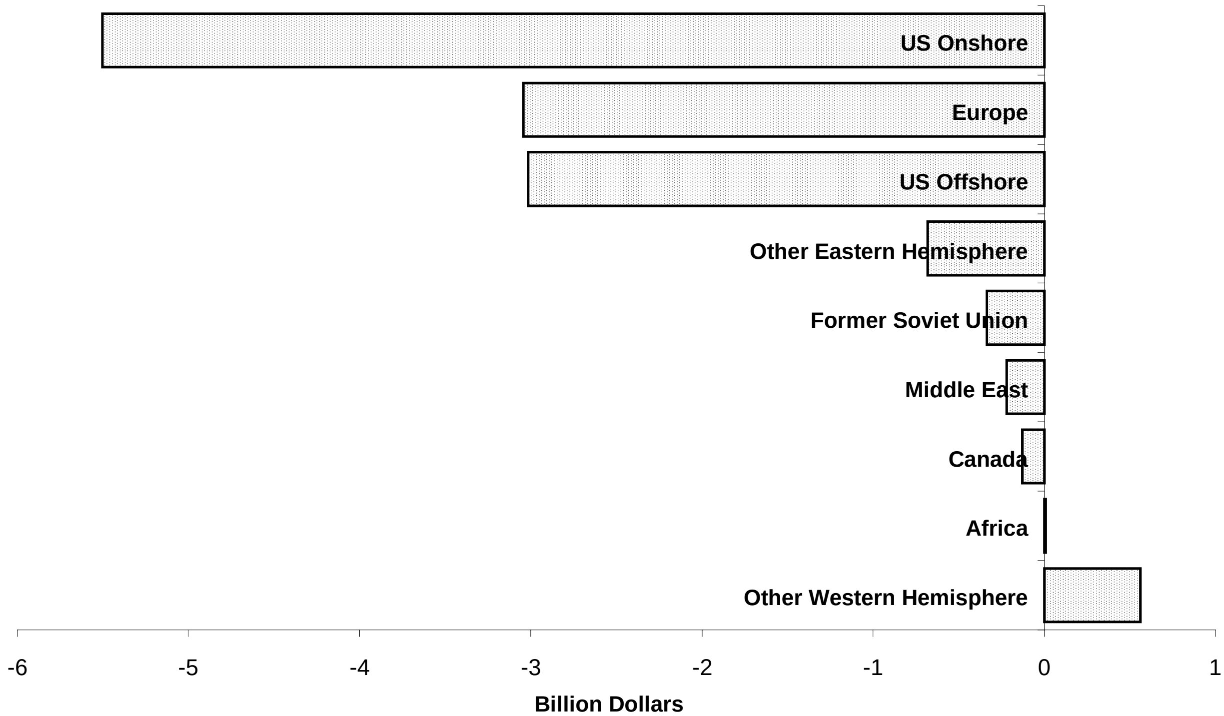
The FRS companies cut their worldwide expenditures for oil and gas exploration and development[26] from $50.8 billion in 1998 to $31.3 billion in 1999 (Table B16 in Appendix B). Excluding expenditures for already proven acreage (i.e., the effect of mergers and acquisitions), the cut in exploration and development expenditures was a slightly less severe reduction from $40.1 billion to $28.1 billion. By this latter measure (i.e., excluding the effects of mergers and acquisitions), nearly all regions were hit by cutbacks (Figure 7). Onshore locales in the United States, the North Sea, and the Gulf of Mexico accounted for the bulk of reductions in exploration and development expenditures.

Table 6. Value of Mergers, Acquisitions, and Related Transactions by FRS Companies, 1999
(million dollars)

Line of Business and Acquiring Company	Acquisition	Reported Value of Acquisition
U.S. Oil and Gas Production		
BP Amoco	Interest in Crescendo Resources L.P. from Repsol-YPF	500
Williams Companies	Oil and gas properties in the western U.S. from MCN Energy	117
Phillips Petroleum	Louisiana properties from Contour Energy Company	83
Unocal	16 percent of Tom Brown, Inc.	76
Coastal	Gulf of Mexico assets from Titan Exploration	71
Foreign Oil and Gas Production		
Burlington Resources	Poco Petroleums Ltd. (Canada)	2,500
Chevron	San Jorge and Glacco Companies (Argentina)	1,000(est.)
Chevron	Rutherford Moran Oil Co	490
Unocal	47.8 percent of Northrock Resources Ltd.(Canada)	205
Refining, Marketing, and Transport		
Williams Companies	33-percent interest and advance to AB Mazeikiu Nafta (Lithuania)	150
Williams Companies	Additional 9.8-percent interest in the Alliance Pipeline project	139
Williams Companies	Pipelines and a 41.7-percent interest in a 1.2 billion-pound-per-year ethylene production facility	116
El Paso Energy	Additional 8-percent interest in El Paso Energy Partners	80
Tosco	43 Smile retail service stations and convenience stores from Boardman Petroleum	70
Tosco	48 retail gasoline and convenience store sites from BP Amoco	50
Other Energy		
El Paso Energy	50-percent interest in CE Generation	254
El Paso Energy	92-percent interest in East Asia Power (China and Philippines)	144
El Paso Energy	Interest in Chaparral Investors	120
Enron	Philip Utilities Management (Canada)	120
El Paso Energy	100-percent interest in the Rio Negro power plant (Brazil)	110
El Paso Energy	25-percent interest in a 762-megawatt coal-fired power plant in the People's Republic of China	68
El Paso Energy	Atlanta Gas and Light's 35-percent interests in Sonat Marketing Company LP and Sonat Power Marketing LP	65
Nonenergy		
Williams Companies	Stock of Algar Telecom Leste S.A.	265
Occidental Petroleum	Remaining ownership of INDSPEC Chemical Corp.	148
El Paso Energy	EnCap, a funds management company	52

Sources: Company annual reports to shareholders and press releases.

Figure 7. Change in Regional Exploration and Development Expenditures (excluding proved acreage) for FRS Companies, 1998-1999



Source: Energy Information Administration, Form EIA-28 (Financial Reporting System)

Onshore locales in the United States (including Alaska) bore the sharpest cutbacks, nearly $6 billion, representing a 50-percent decline. The cutbacks were widespread with 19 of 21 companies reporting reductions ranging from 3 percent to 92 percent. In historical context, 1999 onshore exploration and development expenditures were at the lowest level since at least 1977. The number of onshore wells completed (3,036) by the FRS companies in 1999 was the lowest since at least 1974. With a few exceptions, the onshore United States is a mature and intensively drilled oil and gas province. Most of the FRS companies have been reducing their commitment to U.S. onshore prospects for quite a while, but 1999 showed a significant acceleration of the trend. For example, the FRS companies have been net sellers of onshore oil and gas reserves for 8 of the last 10 years, including 1999. As a share of their worldwide oil and gas reserves, the U.S. onshore has steadily declined from a peak of 58 percent in 1975 to 37 percent in 1999.

Exploration and development spending on European prospects, nearly all of which are in the North Sea, was cut about $3 billion by the FRS companies in 1999. This decline, in part, represents a falloff from heightened development activity in the prior year. In 1998, nearly all of the 13 FRS companies producing oil and gas in Europe reported an increase in development spending or development drilling, as they continued to push ahead with scheduled projects, even as oil prices were heading for a 25-year low by year end. While completions of projects and the low oil prices in early 1999 were strong deterrents to added spending in Europe, the completion of development projects did yield added production. For example, ExxonMobil noted that 6 fields in the North Sea began production in 1999.[27] For the FRS companies overall, European oil production was up 2 percent between 1998 and 1999 and natural gas production was up 12 percent.

The U.S. offshore (almost entirely the Gulf of Mexico) was also targeted for spending cuts, totaling nearly $3 billion. This reduction in spending is in contrast to the 3 years prior to 1999, when the Gulf of Mexico received the greatest increment to exploration and development spending of any region. Offshore U.S.

Mega-Mergers and New Entrants in 1999

The two largest energy company mergers in history involved FRS companies in 1998 and 1999. Exxon's merger with Mobil was the largest acquisition of energy assets ever. ExxonMobil Corporation, the merged company, is the world's largest publicly-traded energy company. In the second largest merger, British Petroleum p.l.c., of the United Kingdom, merged with Amoco. The resulting company, BP Amoco p.l.c., is the third largest energy company in the world. Also in 1999, El Paso Energy became an FRS respondent as a result of its merger with Sonat. El Paso Energy owns and has interests in 40,000 miles of natural gas pipelines, provides energy services in the United States and abroad, and produces oil and natural gas.

On November 30, 1999, the Federal Trade Commission gave its approval to the merger between Exxon Corporation and Mobil Corporation. The merger involved an exchange of Exxon shares for Mobil shares valued at $79 billion. Exxon and Mobil have been in the FRS group of respondents since its inception in 1978. The surviving company, ExxonMobil Corporation, is the FRS respondent beginning in 1999.

The merger was treated as a pooling of interests, rather than as a purchase. In a pooling of interests, the assets and liabilities of the acquired company are added to those of the acquiring company at the book value carried by the acquired company. Since this merger was between FRS respondents, it had no effect on the value of assets and liabilities of the total FRS group because of the pooling of interests treatment. Since the aggregate value of investment in place for the FRS group in total was unaffected, the transaction was not reflected in the capital expenditures of the FRS companies.

British Petroleum merged with Amoco through an exchange of stock valued at $55 billion. The Federal Trade Commission gave final U.S. regulatory approval to the merger on December 30, 1998. British Petroleum changed its name to BP Amoco p.l.c. and is headquartered in London. Amoco and BP America, which was British Petroleum's only U.S. subsidiary prior to the merger, have been in the FRS respondent group since its inception in 1978.

Amoco became a subsidiary of BP Amoco p.l.c. and was renamed BP Amoco Inc. Per the companies' request, BP America, Inc. and BP Amoco, Inc. separately filed Form EIA-28 (Financial Reporting System) for the 1998 and 1999 reporting years.

BP Amoco p.l.c. treated the merger as a pooling of interests. Consequently, the transaction was not reflected in capital expenditures for the FRS companies in 1998.

On October 25, 1999, El Paso Energy Corporation completed its merger with Sonat, Inc. The merger was accomplished through an exchange of El Paso Energy shares for Sonat shares in a transaction valued at $6.8 billion. Sonat had been an FRS respondent beginning with the 1997 reporting year and El Paso Energy became a respondent in 1999. The financial information for El Paso Energy in 1999 includes the operations of Sonat for the full year. El Paso Energy treated the merger as a pooling of interests and, therefore, the transaction was not reflected in FRS capital expenditures in 1999. Prior to the merger, El Paso Energy's total assets had a value of $11.9 billion and net investment in place had a book value of $8.5 billion. Sonat's net investment in place was $3.2 billion prior to the merger. Consequently, the net increase in the FRS companies' net investment in place is $5.3 billion as a result of El Paso Energy's inclusion as an FRS respondent in 1999.

exploration and development expenditures of the FRS companies increased from $4.7 in 1995 to $11.0 billion in 1998. In 1999, as in the North Sea, the combination of project completions and low oil prices led to deferrals of project startups. On the positive side, completion of projects resulted in increased production. Chevron began production from the deepwater Gulf of Mexico fields, Gemini and Genesis, in 1999.[28] Shell Oil reported that they began production from the deepwater Ursa field at a record underwater depth of 3,800 feet.[29] For all FRS companies, total offshore oil production increased 4 percent between 1998 and 1999. Exploratory efforts in the Gulf of Mexico, initiated in prior years, yielded discoveries of oil and gas reserves in 1999. ARCO announced the Mirage deepwater discovery[30] and Mobil, before completion of its merger with Exxon, announced an oil discovery in the Crazy Horse prospect located more than 6,000 feet underwater.[31]

The FRS companies made less severe cuts in expenditures in the other oil and gas producing regions. In one region, the Other Western Hemisphere (almost entirely South America), expenditures were up in 1999. Even excluding the effects of acquisitions in 1998 and 1999, most notably Chevron's acquisitions in Argentina in 1999 (Table 6), the FRS companies' expenditures increased in South America (Figure 7). In 1998, as well, this region registered the largest increase in exploration and development expenditures (excluding the effects of mergers and acquisitions). The attractiveness of South America as an upstream target stems in part from the region's strong prospects for economic growth in general, and energy demand in particular. The FRS companies' investments in South America encompass not only oil and gas production but pipelines, refineries, and gasoline outlets as well. A few FRS companies also are involved in electricity generation and supply in South America.

Greater receptivity to foreign investment is another development favoring oil and gas exploration and development by FRS companies in South America. Most recently, Brazil has opened their offshore fields to oil and gas development by foreign companies. This opening is too recent to have had an impact on expenditures in 1999, but promises hydrocarbon rich areas for future development (for a detailed discussion, see the Special Topic entitled "New Investment Opportunities Created by the Opening of Brazil's Petroleum Sector" in Chapter 4). Earlier in the 1990's, Venezuela opened their oil and gas resources to foreign companies, mainly through joint ventures with Petroleos de Venezuela, the state petroleum company.[32] This opening led to a surge in exploration and development expenditures by FRS companies in 1998. The increase in expenditures for the Other Western Hemisphere region in 1998 was concentrated among the FRS companies involved with joint ventures with Petroleos de Venezuela (ARCO, Chevron, Conoco, Mobil (merged with Exxon in 1999), Phillips Petroleum, and Texaco). However, a significant change in Venezuela's government administration in late 1998 created uncertainties concerning the investment climate in 1999. This development, along with the low oil prices of early 1999, was reflected in the FRS companies' 58-percent reduction in well completions in the Other Western Hemisphere region between 1998 and 1999. Nevertheless, most FRS companies maintained their investments in Venezuela. For example, late in 1999, ExxonMobil announced the first production of extra-heavy oil from the Cerro Negro field in Venezuela.[33]

Exploration and development expenditures held steady in Africa, showing little change between 1998 and 1999 (Figure 7). The main attractions for the FRS companies are the deepwater offshore locales in West Africa (for a detailed discussion, see the Special Topic entitled "Exploration and Development in Sub-Sahara Africa Proceeds" in Chapter 4), where large oil deposits are being made increasingly accessible by advancing deepwater technologies. In 1999, ExxonMobil announced four deepwater discoveries in Angola and one in Nigeria.[34] Texaco announced two deepwater discoveries in Nigeria, one under 4,200 feet of water and the other under 4,700 feet of water.[35]

Upstream spending for Canada nearly matched prior-year levels, being cut a comparatively slight 7 percent (excluding proved acreage expenditures). Canadian well completions of the FRS companies were up a surprising 68 percent between 1998 and 1999. Gas wells led the surge in drilling, accounting for three-quarters of the increase. The preponderance of gas drilling reflects the attraction of developing natural gas reserves in Canada, mainly in anticipation of export of natural gas to the United States. The largest acquisition among the FRS companies in 1999 was directed toward Canadian gas resources. Burlington Resources acquired Poco Petroleums, a western Canadian producer whose reserves are about 80 percent natural gas, in a transaction valued at $2.5 billion.[36] Unocal also added to its western Canadian gas reserves by acquiring a 48-percent share in

Calgary-based Northrock Resources,[37] while Conoco's acquisition of upstream assets from Renaissance Energy doubled its gas reserves in western Canada.[38] On the other side of Canada, in 1999, ExxonMobil announced the year-end completion of the $2-billion Sable Offshore Energy Project. The project produces natural gas from three platforms located 125 miles offshore of Nova Scotia[39] and includes a 650-mile pipeline to New England natural gas markets. Also, off the eastern shore of Canada, ExxonMobil reported that development drilling continued in the Hibernia field, which began producing oil in 1997.[40]

Natural gas was the focus of the FRS companies' efforts in the Other Eastern Hemisphere (Asian and Pacific sovereignties, excluding the Middle East and countries of the Former Soviet Union). Although exploration and development expenditures for this region (excluding proved acreage) in 1999 were down 22 percent from the prior year, drilling for natural gas increased 5 percent even as other well completions fell 62 percent. The demand for natural gas in the Asia-Pacific region is expected to grow, both to fuel expected economic growth and to provide a clean-burning fuel for electric power generation. Chevron, in the acquisition of Rutherford-Moran Oil in 1999, gained a 46-percent interest in the gas-rich Gulf of Thailand block B8/32.[41] Texaco gained a 45-percent interest in the Malampaya Deepwater Natural Gas Project, which is offshore of the Philippines.[42] The production from this project is targeted for power production in the Philippines. Unocal was active in Asia-Pacific gas developments in 1999. The company announced the discovery of its third major gas field in Bangladesh, a natural gas discovery in the Gulf of Thailand in an area that had been closed to exploration since the Vietnam War era, and two natural gas discoveries in Indonesian deepwater properties.[43]

Backslide in Downstream Profitability Discourages Investment

The FRS companies, overall, made a retrenchment in their U.S. refining/marketing operations in 1999. The lower profitability of these operations (Table 7) in 1999 diminished their attractiveness as targets of investment. Domestic refining was hit especially hard. In 1999, the FRS companies cut capital expenditures directed toward domestic refineries by 36 percent from 1998 expenditures (Table 5), which was about as severe a cutback in percentage terms as the companies applied to upstream spending. Capital expenditures in 1999 barely exceeded charges for refinery depreciation (Table B7 in Appendix B). No FRS company acquired a refinery in 1999, and Equilon sold its El Dorado, Kansas refinery as part of an earlier agreement for regulatory approval as a joint venture of Shell Oil and Texaco. As a result, the FRS companies' U.S. refining capacity, measured by crude oil distillation capacity, fell by 1 percent between 1998 and 1999 (Table B29 in Appendix B).

Petroleum marketing operations in the United States fared somewhat better in 1999 than did refining operations. The FRS companies trimmed their capital expenditures in marketing operations by only 1 percent. Some of these expenditures represented asset purchases and sales between FRS companies, including:

- Tosco, who sold 370 retail gasoline outlets in non-core markets in 1999, purchased 48 outlets and convenience stores from BP Amoco.[44]
- USX's Marathon Ashland Petroleum subsidiary purchased 179 retail gasoline outlets in Michigan from Ultramar Diamond Shamrock.[45]
- Equilon purchased refined product terminals from Clark Refining.[46]
- Williams Companies purchased storage and distribution terminals from Amerada Hess.[47]

Significant divestitures in 1999 included Clark Refining's exit from gasoline marketing through the sale of their retail marketing operations to a non-FRS company and Fina's sale of their last 53 company-operated retail gasoline outlets. Overall, the FRS companies had roughly 900 fewer company-operated retail gasoline outlets in 1999 than in 1998 and 3,800 fewer dealer outlets under lease or contract, representing annual reductions of 6 percent and 8 percent, respectively. However, these divestitures tended to increase outlet productivity. Gasoline sales per company-operated outlet increased from 143 thousand gallons per month to 147 thousand gallons per month between 1998 and 1999, and for dealer outlets under lease or contract the increase was from 75 thousand gallons per month to 85 thousand gallons per month.

Table 7. Return on Investment by Line of Business for FRS Companies, 1989-1999
(Percent)

Line of Business	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Petroleum	6.7	9.5	7.0	5.6	6.4	5.6	5.7	10.1	10.8	3.9	7.2
U.S. Petroleum	5.8	7.9	4.9	4.4	4.9	5.2	4.0	9.9	10.0	3.8	7.0
Oil and Gas Production	2.9	8.5	5.1	5.9	5.3	5.5	4.4	14.1	12.5	0.5	7.6
Refining/Marketing	11.5	5.1	2.0	-0.4	3.4	3.6	1.0	4.4	6.6	7.9	6.5
Pipelines	10.2	11.2	10.7	8.4	6.4	7.6	9.1	6.9	6.7	4.4	6.4
Foreign Petroleum	8.7	12.5	11.0	7.9	9.2	6.2	8.4	10.6	11.9	4.0	7.6
Oil and Gas Production	8.9	13.1	9.1	8.2	8.6	6.5	9.3	12.8	12.5	2.2	8.5
Refining/Marketing	8.0	11.2	14.6	7.8	10.6	6.1	7.2	6.0	10.5	8.2	5.1
International Marine	12.4	11.7	15.6	-1.2	1.2	-2.0	-2.5	2.2	11.8	8.9	0.8
Coal	5.0	3.3	8.7	-9.3	7.6	4.0	6.9	9.9	7.2	26.4	9.5
Other Energy	-2.3	2.6	2.8	1.8	4.1	4.8	6.1	7.9	7.0	13.2	7.6
Nonenergy	17.3	7.8	2.9	2.1	4.7	10.5	19.4	15.0	10.9	4.5	5.8

Note: Return on investment measured as contribution to net income/net investment in place.

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Foreign refining/marketing operations registered an even steeper drop in profitability than did U.S. operations from 1998 to 1999 (Table 7). In response to the deterioration in financial results, the FRS companies cut their capital expenditures for foreign refining/marketing by 35 percent (Table 5).

Despite the sharp reduction in capital expenditures, the FRS companies' refinery capacity abroad increased by 9 percent between 1998 and 1999, or by 422 thousand barrels per day (Table B28 in Appendix B). However, nearly all of the increase in capacity was an artifact of Mobil's merger with Exxon in 1999. Before the merger, each company owned less than 50 percent of Japanese refineries in Kawasaki and Wakayama. Consequently, before 1999, financial results from these operations were not included in the companies' consolidated results and the refinery capacities were not included in the FRS aggregated data. After the merger, ExxonMobil's ownership interests in these refineries exceeded 50 percent and the associated capacity was included in the FRS totals for the first time.

Power and Telecommunications Attract Investment

Although the FRS companies reduced their capital expenditures for their worldwide petroleum and natural gas operations by $22.2 billion between 1998 and 1999 (Table 5), they increased capital expenditures for other businesses in total by $3.6 billion, a 37-percent increase. Activities in electric power supply and telecommunications largely underlie this upswing in expenditures.

Capital expenditures for other energy totaled $1.7 billion in 1999. This value understates expenditures since a reorganization by Enron resulted in an accounting change that had the effect of reducing capital expenditures with no corresponding reduction in productive assets.[48] Excluding this amount, capital expenditures for other energy businesses were $2.2 billion in 1999, a 42-percent increase from 1998 expenditures.

The addition of El Paso Energy to the FRS group, through its merger with Sonat in 1999, accounted for a majority of the increase in FRS companies' capital expenditures for other energy. El Paso Energy's activities in the other energy line of business primarily involve electric power generation in the United States, Asia, Europe, and South America and geothermal-based power production in California. In 1999, El Paso Energy acquired power facilities in the United States, Mexico, China, India, and the Philippines (Table 6). Apart from acquisitions, El Paso Energy made capital outlays for power generation facilities in 1999. In the United States, the company reported construction was proceeding on two geothermal facilities in California and a 680-megawatt natural gas-fired generation facility in Georgia.[49]

Coastal continued to be active in electric power in 1999. The company reported an increase of over $300 million in capital expenditures in 1999 over prior-year spending for their power businesses.[50] Coastal directed expenditures toward power facilities in Colorado and New York and interests in power projects in the Dominican Republic and Panama. The company also reported a 69-percent increase in their worldwide net generating capacity in operation between 1998 and 1999.

Likewise, Enron continued its commitment of assets to power supply in 1999. Enron raised its ownership in Elektro Electricidade e Servicos, the sixth largest electricity distributor in Brazil, to almost 100 percent. In the United States, Enron built three natural gas-fired peaking plants - one in Mississippi and two in Tennessee. Abroad, Enron has an oil gasification generating plant under construction on the Mediterranean island of Sardinia and has completed construction of a generating plant in Brazil.[51]

The other nonenergy line of business registered the largest increase in capital expenditures among the FRS lines of business in 1999. Capital expenditures more than doubled between 1998 and 1999, to $6.6 billion (Table 5). Two companies, Enron and Williams, accounted for the bulk of this increase in spending. In 1999, Enron diversified into broadband internet services, stating that "… the public Internet … does not have sufficient bandwidth capacity to carry massive data and rich media content to the desktop."[52] This move complements Enron's venture into e-commerce. In late 1999, Enron launched its first e-commerce site, which will allow wholesale customers worldwide to purchase energy products and services through the Internet. Of longer-standing commitment to telecommunications is Enron's fiber optic network. This network has 14,000 miles of fiber optic lines in the United States through ownership or contractual agreement.

Similarly, Williams Companies, through its subsidiary Williams Communications, also owns a fiber optic network communications service. The company reported that capital expenditures for its "communications" business segment more than quadrupled in 1999, to $2.0 billion.[53] The increase in spending was primarily for the construction of an additional 7,000 miles of fiber optic network.

Sources and Uses of Cash

Low Cash Flow in 1998 Weakens Company Balance Sheets

At the beginning of 1999, the challenge for most of the FRS companies was to repair the balance sheet damage stemming from an unprecedented excess of capital expenditures relative to internally generated cash flow in 1998. In 1998, the FRS companies' capital expenditures exceeded cash flow by 56 percent, or nearly $27 billion (Table 8). Until 1998, capital expenditures averaged 14 percent less than cash flow in the 1990's. The $27-billion excess over cash flow led the FRS companies to make a number of wrenching adjustments in their deployment of capital in 1998, including:

- Increased borrowing. The FRS companies issued more long-term debt (debt with a maturity of more than 1 year) and allocated less cash to reduction of long-term debt. As a result, the role of debt became more important in the companies' balance sheets. The ratio of long-term debt to shareholders' equity, an often-used measure of the importance of debt, increased from 39 percent in 1997 to 49 percent in 1998 (Figure 8).
- Issuance of more stock. Issues of new equity shares by the FRS companies totaled $9.1 billion, a $7.6-billion increase from the prior year.
- Increased asset sales. Cash from asset sales by FRS companies was at a record $16.2 billion in 1998.
- Reduced payouts to shareholders. The FRS companies cut their outlays for share buybacks by $2.5 billion. Cash dividends were reduced by $1.9 billion by FRS companies reporting in both 1997 and 1998.
- Drawdown of cash balances. In 1998, the FRS companies reduced their cash balances by over $4 billion.

Table 8. Sources and Uses of Cash for FRS Companies, 1998-1999
(Billion Dollars)

Sources and Uses of Cash	1998	1999	Percent Change 1998-1999
Main Sources of Cash			
Cash Flow from Operations	48.2	54.8	13.8
Proceeds from Long-Term Debt	27.1	29.9	10.3
Proceeds from Disposals of Assets	16.2	13.3	-18.3
Proceeds from Equity Security Offerings	9.1	3.6	-61.0
Main Sources of Cash			
Additions to Investment in Place	75.1	57.6	-23.3
Reductions in Long-Term Debt	18.0	25.0	38.7
Dividends to Shareholders	17.2	16.1	-6.3
Purchase of Treasury Stock	5.8	0.4	-92.7
Other Investment and Financing Activities, Net	11.1	0.1	--
Net Change in Cash and Cash Equivalents	-4.4	2.5	--

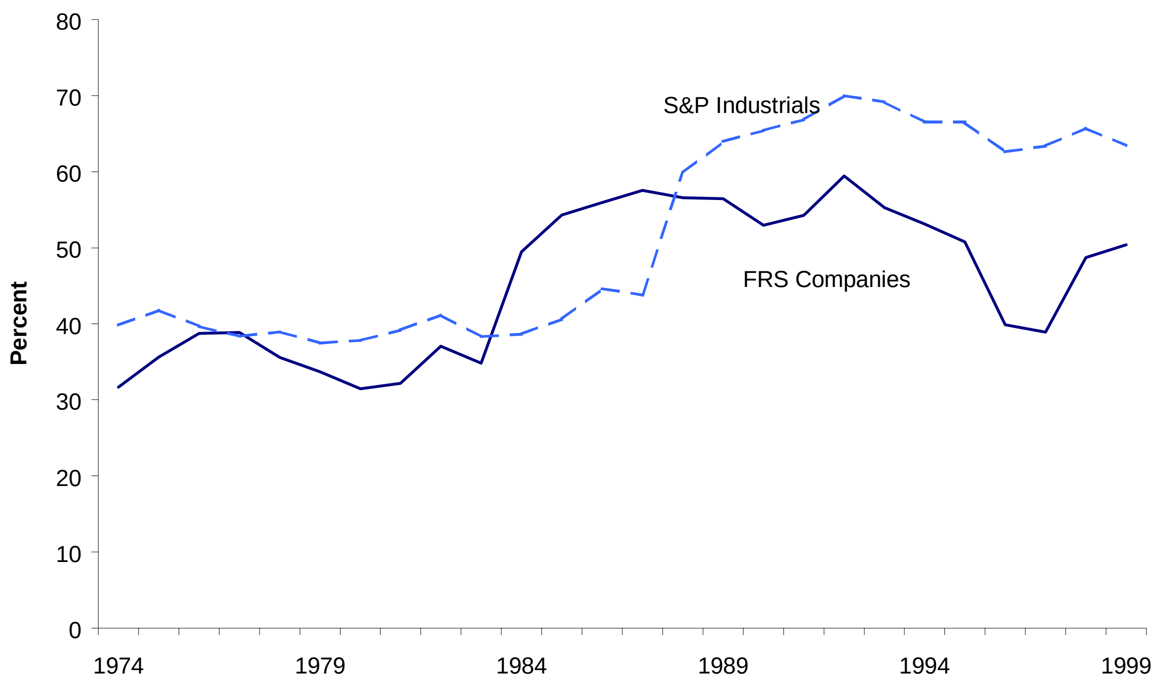
-- = Not meaningful.

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 (Financial Reporting System).

Figure 8. Long-Term Debt/Equity Ratio for FRS Companies and the S&P Industrials, 1974-1999



Sources: **FRS Companies**: Energy Information Administration Form EIA-28, (Financial Reporting System).
S&P Industrials: Compustat PC Plus, a service of Standard and Poor's.

These measures had a number of effects on the FRS companies. The amount of debt in the FRS companies' balance sheets increased and interest expense rose. The issuance of more shares of common stock tended to dilute the values of existing common shares. Reductions in cash payouts to investors, along with share value dilution, tended to increase shareholder discontent. The large drawdowns of cash balances reduced the companies' liquidity. Repairing balance sheet damage and restoring investor confidence became paramount objectives of the FRS companies' deployment of capital in 1999.

Capital Deployment in 1999 Focuses on Balance Sheet Repair

The FRS companies made several adjustments in their sources and uses of cash in 1999 in response to the problems created in 1998. The adjustments included:

- Cutbacks in capital expenditures. The FRS companies reduced capital expenditures from prior-year levels by $17.5 billion in 1999 (Table 8), despite a $15-per-barrel upswing in oil prices during the year. Capital spending exceeded cash flow by only 5 percent in 1999, considerably better than the 56-percent excess in 1998.
- Efforts to reduce debt. The FRS companies increased their cash outlays for debt reduction by $7.0 billion in 1999 from the prior year level to a record $25.0 billion. However, the FRS companies' issuance of new long-term debt of $29.9 billion in 1999 exceeded the $25.0 billion expended for debt reduction. This excess of borrowings over repayments, and the replacement of Sonat by the much larger El Paso Energy in the FRS group of respondents (due to the latter company's acquisition of the former), increased the FRS companies' long-term debt by nearly $9 billion. The FRS companies' debt-equity ratio rose to 50 percent in 1999, the highest level since 1995 (Figure 8).
- Reductions in investor payouts. The FRS companies allocated only $0.4 billion to buybacks of their shares in 1999, $5.4 billion less than was spent in 1998 and the lowest level of share repurchases since the early 1980's. The FRS companies cut their cash dividends by $1.1 billion. Prior to 1998, the FRS companies had increased their dividend payouts for seven consecutive years.

Overall, the FRS companies' attempts to repair their balance sheets and boost investor confidence in 1999 appear to be works of modest progress. Capital expenditures still exceeded cash flow. Debt reduction efforts of earlier years, which lowered the debt-equity ratio from 60 percent in 1992 to less than 40 percent in 1997, continued to be eroded in 1999. The FRS companies slashed their payouts to investors for a second consecutive year, even as the bull market for corporate stocks generally continued its unprecedented run.

Higher oil and gas prices should make significant progress possible after 1999. At the time this report is being written (November 2000), oil prices have been on a course that could result in prices which are over $10 per barrel higher, on an annual basis, in 2000 than in 1999. The comparable increase for U.S. natural gas prices is $7 per barrel of oil equivalent. The likely surge in the FRS companies' cash flow can be utilized to further address the financial weakness of the recent past.

Endnotes

[6]The Standard and Poor's Industrials is a well-recognized database that includes nearly 400 of the largest U.S. industrial companies. In 1998, 17 of the FRS companies were included in the S&P Industrials. Financial statistics for the S&P Industrials were obtained by accessing Compustat PC Plus, a service of Standard & Poor's, Inc.

[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 of reserves for future liabilities.

[8]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 disposals 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 company wide net income figure and line-of-business contributions to net income (see Appendix A for further discussion).

[9] Return on investment (ROI) for a line of business is net income divided by net investment in place. Net investment in place is defined as the book value of net property, plant, and equipment plus investments and advances to unconsolidated affiliates. Line-of-business ROI is based on historical costs and measures ex-post average profitability, not marginal or prospective rates of return.

[10] Exxon Mobil Corporation, *1999 Annual Report*, p. F5.

[11] Chevron Corp., 1999 Securities and Exchange Commission, Form 10K, p. FS-8.

[12] Texaco Inc., 1999 Securities and Exchange Commission, Form 10K, p. 23.

[13] Enron Corp., *1999 Annual Report*, p. 31.

[14] El Paso Energy Corp., 1999 Securities and Exchange Commission, Form 10K, p. 80.

[15] ExxonMobil Corp., *1999 Annual Report*, p. 25.

[16] Coastal Corp., 1999 Securities and Exchange Commission, Form 10K, p. 20.

[17] 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, comparable disclosures in the Form EIA-28 from 1974 through 1986, when income statement items were collected for chemical businesses by the FRS. Thus, the public disclosures of chemical segment revenue and operating income were utilized for 1987 through 1999. 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.

[18] Chevron Corp., 1999 Securities and Exchange Commission, Form 10K, pp. FS-8, 9.

[19] ExxonMobil Corp., *1999 Annual Report*, p. F-6.

[20] USX Corporation, 1999 Securities and Exchange Commission, Form 10K, pp. S-24 to S-26.

[21] The Williams Companies, Inc., 1999 Securities and Exchange Commission, Form 10K, pp. F-6, F-7, and F-62.

[22] 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.

[23] To the extent possible, capital outlays are measured by, *additions to investment in place*, which is defined as additions to property, plant, and equipment (PP&E) plus additions to investment and advances. In 1999, additions to PP&E accounted for 88 percent of capital outlays so measured.

[24] Figure 6 and Table 5 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 value of an acquisition shown in Table 6 can differ from the effect on additions to investment in place due to assumptions of liabilities and goodwill assets acquired.

[25] Energy Information Administration, *Performance Profile of Major Energy Producers 1998*, Table 8.

[26] Exploration and development expenditures include capitalized expenditures for oil and gas production and exploration expenses, which are not capitalized but are charged against income.
[27] ExxonMobil Corp., *1999 Annual Report*.
[28] Chevron Corp., 1999 Securities and Exchange Commission, Form 10K.
[29] Shell Oil Company, News Release, April 13, 1999.
[30] ARCO, Press Release, March 19, 1999.
[31] Mobil Corp., Press Release, July 15, 1999.
[32] See the editions of this report for 1994, 1995, and 1997 for additional discussion of Petroleos de Venezuela.
[33] ExxonMobil Corp., Press Release, December 27, 1999.
[34] ExxonMobil Corp., Press Releases, May 28, June 29, September 1, and September 10, 1999.
[35] Texaco, Inc., Press Releases, January 5 and March 9, 1999.
[36] Burlington Resources, Inc., Press Release, August 16, 1999.
[37] Unocal Corp., Press Release, May 14, 1999.
[38] Conoco Inc., 1999 Securities and Exchange Commission, Form 10K.
[39] ExxonMobil Corp., Press Release, January 4, 2000.
[40] ExxonMobil Corp., *1999 Annual Report.*
[41] Chevron Corp., Press Release, December 23, 1998.
[42] Texaco, Inc., Press Release, October 21, 1999.
[43] Unocal Corp., Press Releases, November 9, December 8, and December 16, 1999.
[44] Tosco Corp., *1999 Annual Report*, p. 15.
[45] USX Corp., 1999 Securities and Exchange Commission, Form 10K.
[46] Equilon Enterprises, 1999 Securities and Exchange Commission, Form 10K, p. 47.
[47] The Williams Companies, Inc., 1999 Securities and Exchange Commission, Form 10K.
[48] Enron Corp., *1999 Annual Report*, Note 2.
[49] El Paso Energy, Inc., 1999 Securities and Exchange Commission, Form 10K, pp. 8, 54-55.
[50] Coastal Corp., 1999 Securities and Exchange Commission, Form 10K, p. F-30.
[51] Enron Corp., *1999 Annual Report*, pp. 6, 9, 11, 22, and 23.
[52] Enron Corp., *1999 Annual Report*, p. 4.
[53] The Williams Companies, Inc., 1999 Securities and Exchange Commission, Form 10K, pp. F-6 and F-15.

3. Behind The Bottom Line

Oil and Gas Production

Earnings Rebound from Near-Record Lows

Net income from the FRS companies' U.S. oil and gas production operations, excluding unusual items, rose 161 percent between 1998 and 1999, to $8.3 billion (Table 9). Higher oil prices led to a substantial rise in revenues from the FRS companies' upstream operations in 1999. In the United States, the FRS companies realized an average U.S. oil (crude oil and natural gas liquids) price of $14.80 per barrel in 1999, nearly $4 above the 1998 price (Table 10).

Table 9. Income Components and Financial Ratios in Oil and Gas Production for FRS Companies, 1998-1999
(Billion Dollars)

Components of Income and Financial Ratios	United States		Foreign	
	1998	1999	1998	1999
Oil and Gas Revenues				
Oil	19.7	22.4	NA	NA
Gas	23.6	23.2	NA	NA
Total Revenues	43.3	45.6	35.5	40.7
Expenses				
DD&A	12.8	10.9	10.4	9.1
Lifting Costs	11.0	11.2	9.7	9.4
Exploration Expenses	1.9	1.3	2.6	2.4
General and Administrative Expenses	1.1	1.3	0.8	1.0
Raw Material Purchases	13.6	11.4	6.7	3.1
Other Costs (Revenues)	2.5	1.0	2.6	2.9
Total Operating Expenses	42.7	36.7	32.8	27.9
Operating Income	0.6	8.9	2.6	12.8
Other Income (Expense)[a]	-0.4	1.8	1.9	1.9
Income Tax Expense	-0.3	3.2	2.4	6.4
Net Income	0.5	7.4	2.0	8.2
Less Unusual Items	-2.7	-0.8	-2.4	0.0
Net Income, Excluding Unusual Items	3.2	8.3	4.4	8.3
Unit Values (Dollars Per BOE)[b]				
Direct Lifting Costs (Excluding Taxes)	3.39	3.48	3.36	3.11
Production Taxes	0.41	0.61	0.57	0.52
Ratios (Percent)				
Return on Investment[c]	0.5	7.6	2.2	8.5
Effective Tax Rate[d]	--	30.0	54.6	44.0

[a]Earnings of unconsolidated affiliates and gain (loss) on disposition of assets.

[b]BOE = Barrels of crude oil equivalent. Dry natural gas was converted at 0.178 barrels of oil per thousand cubic feet.

[c]Net Income divided by net investment in place (Net investment in place = net property, plant, and equipment plus investments and advances).

[d]Income tax expense divided by pretax income.

NA = Not available.

DD&A = Depreciation, depletion, and amortization costs.

-- = Not meaningful.

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

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table 10. Average Prices, Sales, and Production in Oil and Gas for FRS Companies, 1998-1999

Prices, Sales, and Production	1998	1999	Percent Change 1998-1999
Domestic Oil and Gas Production[a]			
Crude Oil and NGL (Million Barrels)	1,388.8	1,305.7	-6.0
Dry Natural Gas (Billion Cubic Feet)	8,395.9	7,994.1	-4.8
Total (Million BOE)[b]	2,883.3	2,728.6	-5.4
Domestic Oil and Gas Sales Volumes			
Crude Oil and NGL (Million Barrels)	1,805.3	1,512.8	-16.2
Dry Natural Gas (Billion Cubic Feet)	11,764.6	10,947.6	-6.9
Total (Million BOE)[b]	3,899.4	3,461.5	-11.2
Domestic Production Segment Per Unit Sales Values			
Crude Oil and NGL (Dollars Per Barrel)	10.91	14.80	35.8
Dry Natural Gas (Dollars Per Thousand Cubic Feet)	2.01	2.12	5.3
Composite (Dollars Per BOE)[b]	11.11	13.16	18.5
Foreign Oil and Gas Production[a]			
Crude Oil and NGL (Million Barrels)	1,546.1	1,576.2	1.9
Dry Natural Gas (Billion Cubic Feet)	5,181.8	5,682.1	9.7
Total (Million BOE)[b]	2,468.5	2,587.6	4.8
Foreign Production Segment Per Unit Sales Values			
Crude Oil and NGL (Dollars Per Barrel)	11.61	16.54	42.5
Dry Natural Gas (Dollars Per Thousand Cubic Feet)	2.08	2.03	-2.4
Canada	1.35	1.68	24.4
OECD Europe	2.56	2.21	-13.7
Other Foreign	1.90	1.95	2.6
Composite (Dollars Per BOE)[b]	11.64	14.53	24.9

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

[b]BOE = Barrels of 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 (Financial Reporting System). 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.

A drop in the FRS companies' U.S. oil production partly offset the favorable effects of higher oil prices. The decline in oil production was concentrated in onshore locales, including Alaska, where the FRS companies' oil production was down 10 percent between 1998 and 1999. Onshore oil production declined because of natural declines in long-producing fields (especially the Prudhoe Bay field in Alaska's North Slope), reserve additions that were insufficient to replace production, and divestitures of onshore properties as FRS companies increasingly focused their exploration and development budgets on large fields abroad and in the Gulf of Mexico. In contrast, the FRS companies' offshore oil production (almost entirely in the Gulf of Mexico) increased by 4 percent.

A 5-percent rise in natural gas prices realized by FRS companies did not fully offset the effects of lower U.S. natural gas production in 1999 with the result that the FRS companies' natural gas revenues were down $0.4 billion (Table 9). The FRS companies' 5-percent drop in natural gas production, mostly from onshore locales, reflected their cutback in natural gas drilling in response to an earlier decline in natural gas prices. Wellhead natural gas prices generally declined during 1997, 1998, and through early 1999, falling by 50 percent from January 1997 to March 1999. Falling gas prices tended to lower the prospective value of gas-rich projects. As a result, the FRS companies cut their drilling for gas in the United States, with gas well completions falling by 40 percent between 1997 and 1999.

On balance, U.S. oil and gas revenues were up $2.3 billion in 1999 from 1998 revenues. Cuts in operating costs appeared to contribute even more to income gains than did higher revenues. In U.S. oil and gas production, the FRS companies registered a drop in operating costs of $6.0 billion. However, upon closer examination, the reduction of $0.6 billion in exploration expenses was the only clear case of cost cutting in U.S. upstream operations in 1999. The largest item of expense is for depreciation, depletion, and amortization (DD&A). In 1998, DD&A was unusually large. As explained in the 1998 edition of this report:

> "A more subtle effect of lower oil and gas prices in 1998 was the unusually large increase in depreciation, depletion, and amortization expense (DD&A). This expense item represents an allowance for the deterioration in value of physical assets over time. In addition, financial accounting standards applicable to the oil and gas industry require a company's asset values to be reduced when oil and gas prices decline if the value of estimated future cash flows from the assets, based on the lower prices, are less than the value of the assets carried on the company's balance sheet. The reduction in value is called an "asset impairment" and is recognized as a charge against income. It is usually included in DD&A and/or other operating expense. In 1998, 18 FRS companies reported such charges, which reduced worldwide operating income from oil and gas production by $8.3 billion."[54]

In 1999, with higher oil and gas prices, asset impairments totaled only $1.5 billion.

Lifting costs (the out-of-pocket expenses to extract oil and gas) and general and administrative expense both increased, even though the FRS companies' U.S. oil and gas production did not. The lower expense for raw material purchases, which are largely for resales of natural gas and natural gas liquids and for inputs to natural gas liquids plants, is mainly attributable to one-time changes in reporting practices by three companies. Excluding these companies, raw material purchases increased by $1.1 billion.

Net income from foreign oil and gas production (excluding unusual items) of $8.3 billion in 1999 was nearly double that of the previous year. The story behind the surge in foreign upstream earnings is broadly similar to U.S. developments, although there were some notable differences. The FRS companies were able to increase their foreign oil production by 2 percent and their foreign natural gas production by 10 percent in 1999 (Table 10). Their foreign natural gas production was again at a record level. The increases reflected production from reserves gained through acquisitions in recent years and the FRS companies' additions to foreign oil and gas reserves in excess of production gained through exploration and development efforts. All regions except for Asia-Pacific and the Middle East had higher production levels in 1999 than in 1998.

On the cost side, as was true for U.S. operations, the absence of asset impairments in 1999 reduced DD&A expenses and the FRS companies chopped exploration expenses. Unlike U.S. oil and gas production operations, the FRS companies reduced foreign lifting costs. Overall, the FRS companies' trimmed foreign lifting costs (excluding taxes) by $0.25 per barrel of oil equivalent, a 7-percent reduction. All foreign regions (except Asia-Pacific locales) had lower lifting costs in 1999 than in 1998 (Table 11).

Lifting Costs Decline Abroad

Lifting costs (production costs) are the out-of-pocket costs per barrel of oil and natural gas produced (measured on a barrel-of-oil-equivalent basis) to operate and maintain wells and related equipment and facilities after hydrocarbons (both crude oil and natural gas) have been found, acquired, and developed for production. Direct lifting costs do not include production taxes, while total lifting costs do. Direct lifting costs increased slightly in the United States in 1999, their second increase since 1992 (Table 11). While one year is not notable in and of itself, a continued increase would begin to reverse the decline of the 1990's. Outside the United States, direct lifting costs declined in all regions except the Other Eastern Hemisphere. In the Former Soviet Union and Eastern Europe, direct lifting costs declined substantially, but to levels similar to those of the other foreign regions. The decrease arose from their unusually high level in 1998, which reflected the fledgling nature of the operations of the FRS companies there. Europe and the Other Western Hemisphere were the other regions that experienced large declines in direct lifting costs. Europe was the region with the highest direct lifting cost for the FRS companies, at $3.74 per barrel, and the Middle East was the lowest, at $1.65 per barrel, a difference of over $2 per barrel.

Table 11. Lifting Costs by Region for FRS Companies, 1998-1999
(Dollars Per Barrel of Oil Equivalent)

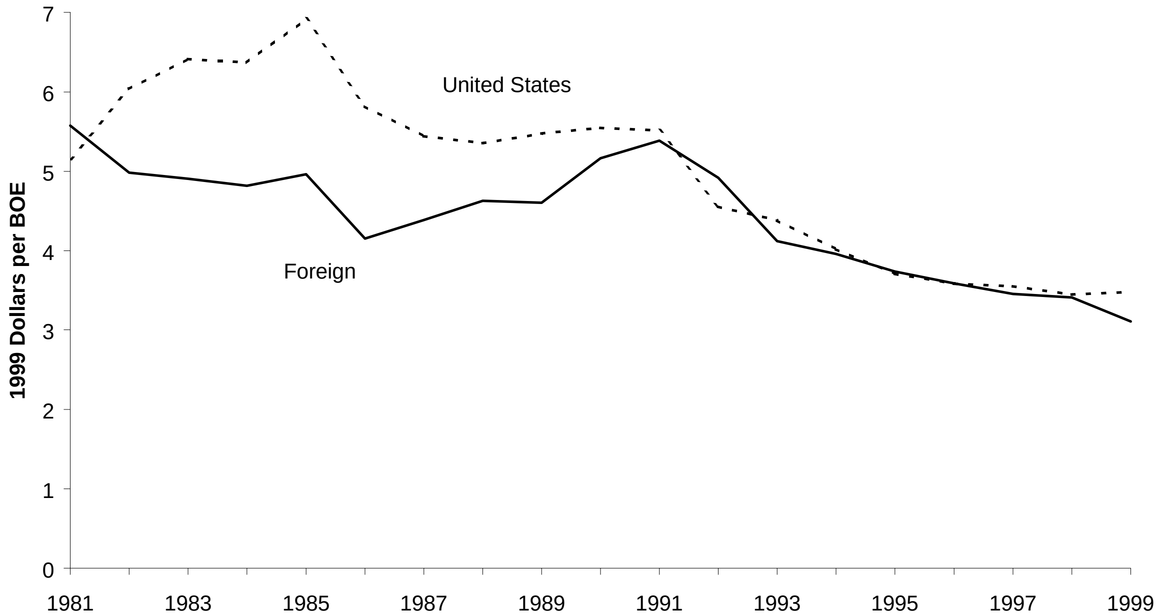
Region	Direct Lifting Costs			Production Taxes			Total		
	1998	1999	Percent Change	1998	1999	Percent Change	1998	1999	Percent Change
United States									
Onshore	--	--	--	--	--	--	4.16	4.44	6.7
Offshore	--	--	--	--	--	--	3.02	3.41	12.6
Total United States	3.39	3.48	2.5	0.41	0.61	50.4	3.80	4.09	7.6
Foreign									
Canada	3.17	3.14	-1.0	0.28	0.27	-4.2	3.45	3.41	-1.3
OECD Europe	4.28	3.74	-12.5	0.56	0.38	-32.4	4.84	4.12	-14.8
Former Soviet Union and Eastern Europe	8.41	3.27	-61.1	0.04	0.76	1,780.5	8.45	4.04	-52.2
Africa	3.66	3.32	-9.2	0.91	0.31	-65.9	4.56	3.63	-20.4
Middle East	1.70	1.65	-2.6	1.21	1.29	6.3	2.91	2.94	1.1
Other Eastern Hemisphere	1.94	2.39	23.1	0.43	0.71	64.6	2.37	3.10	30.7
Other Western Hemisphere	3.48	2.36	-32.2	0.55	0.98	78.8	4.03	3.34	-17.1
Total Foreign	3.36	3.11	-7.6	0.57	0.52	-9.3	3.93	3.63	-7.8
Worldwide Total	3.38	3.30	-2.4	0.48	0.57	17.3	3.86	3.87	0.1

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

Production taxes, which were up 17 percent worldwide between 1998 and 1999, accounted for 15 percent of total lifting costs. The importance of production taxes (which include royalties in lieu of taxes in regions outside the United States) varies considerably across regions. In general, in the regions with the lowest direct lifting costs (Latin America, the Middle East, and Asia, excluding the countries of the Former Soviet Union), production taxes accounted for 28 percent of total lifting costs overall in 1999. Conversely, in the higher-cost regions of Africa, Europe, Canada, and the United States, production taxes accounted for 13 percent of total lifting costs. As a result of this roughly inverse pattern, the range of total lifting costs across regions is only somewhat over $1 per barrel compared with a range of over $2 per barrel for direct lifting costs.

Direct lifting costs for the FRS companies generally have been falling since the early 1990's, despite their small increase domestically in 1999 (Figure 9). Several factors account for this decline, including improved operating practices and techniques (such as the consolidation of producing properties and increased experience in deepwater drilling) and improved technology (such as the use of new materials and computerized information technologies). Direct lifting costs in the United States and overseas converged around 1991, and have followed similar paths since then. One possible explanation for this convergence is that the FRS companies have been operating increasingly overseas and have more fully integrated their operations worldwide, collapsing some of the differences between their U.S. and foreign operations.[55]

Figure 9. Direct Oil and Gas Lifting Costs for FRS Companies, 1981-1999



BOE = Barrels of crude oil equivalent.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Oil and Gas Production Growth Varies by Region

The FRS companies' worldwide production of crude oil and natural gas liquids (oil) declined 2 percent while their production of dry natural gas (gas) rose 1 percent in 1999 (Table 12). However, there was substantial variation in the pattern of FRS production changes across geographic regions. The regions with the most growth in production were Africa for oil and Canada and OECD Europe for gas.

In Africa, ExxonMobil and BP Amoco had substantial increases in the production of crude oil and natural gas liquids. ExxonMobil's primary production areas are in Nigeria and Equatorial Guinea; it is the largest producer in both countries.[56] In Nigeria, the Oso natural gas liquids project completed its first full year of operation in 1999. In Equatorial Guinea, production from the Zafiro field increased almost 20 percent, as a result of added water injection and gas lift systems. ExxonMobil intends to develop several satellite reservoirs in the field through extended-reach drilling from its new Jade platform, which was installed in December 1999.

BP Amoco's major African activity was in the Gulf of Suez and the Western Desert in Egypt.[57] Its joint-venture partnership with Egyptian General Petroleum produced more than one third of Egypt's oil in 1999. BP Amoco is undertaking a major investment program in its Gulf of Suez fields ($50 million of which had been spent by the end of 1999) to develop new reserves, maintain production, and prolong the lives of the fields. Also of note in the Other Western Hemisphere, BP Amoco was able to increase its total hydrocarbon production (primarily natural gas) by about 50 percent from the recently started Mahogany field in Trinidad and Tobago as its market grew because of increased local demand and the start up of a liquefied natural gas plant.

Burlington Resources accounted for the majority of the natural gas production increase by the FRS companies in Canada in 1999. It bought Poco Petroleums that year, whose production was 80-percent natural gas. Burlington had not previously been active in Canada.[58] Poco drilled 153 wells (with a success rate of 93 percent) in the western Canadian sedimentary basin in 1999, of which 119 were completed as natural gas wells.

Table 12. Production of Oil and Natural Gas by Region for FRS Companies, 1998-1999

Region	Oil (million barrels)			Natural Gas (billion cubic feet)		
	1998	1999	Percent Change	1998	1999	Percent Change
United States						
Onshore	991	892	-10.0	5,493	5,158	-6.1
Offshore	397	414	4.1	2,903	2,836	-2.3
Total United States	1,389	1,306	-6.0	8,396	7,994	-4.8
Foreign						
Canada	173	173	0.0	869	1,096	26.2
Europe and Former Soviet Union[a]	582	602	3.5	2,093	2,355	12.5
Africa	320	341	6.6	34	44	28.1
Middle East	130	126	-3.2	97	102	5.3
Other Eastern Hemisphere	251	228	-9.3	1,702	1,627	-4.4
Other Western Hemisphere	90	106	18.3	387	458	18.3
Total Foreign	1,546	1,576	1.9	5,182	5,682	9.7
Worldwide Total	2,935	2,882	-1.8	13,578	13,676	0.7

[a]Amounts for this combined region are predominantly from OECD Europe; the Former Soviet Union and Eastern Europe are a very small part of the totals.

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

In OECD Europe, ExxonMobil was the lead contributor to the FRS companies' natural gas production growth. Europe accounted for one third of ExxonMobil's worldwide net oil and gas production in 1999.[59] Its activity there was focused on North Sea oil and gas production and gas distribution and production systems onshore. Two major contributors to the production increase in the North Sea were the Balder field and the Jotun development, both of which came onstream in the second half of 1999. The company has an extensive natural gas marketing structure in Europe, and, in the United Kingdom, gas sales were at record levels with the start up of several new fields.

Conoco also saw large production increases in OECD Europe in 1999.[60] About half of the company's worldwide production comes from this region. The Britannia gas/condensate reservoir in the North Sea, of which Conoco has a 42-percent share, completed its first full year of production in 1999. This reservoir supplies 8 percent of the United Kingdom's gas consumption. Production also began from the Bell field and from several Norwegian fields, including Visund, Troll C, and (as for ExxonMobil) Jotun, operated by Conoco partners.

Worldwide, the top-producing region for the FRS companies was the U.S. onshore, where they produced 38 percent of their natural gas and 31 percent of their oil in 1999. However, their second highest-ranking region depended on the type of hydrocarbon. It was the U.S. offshore for gas and OECD Europe for oil. Production in the U.S. offshore is primarily in the Gulf of Mexico, and in OECD Europe it is primarily in the North Sea. The U.S. offshore retained its hold on second place in gas production, even though production declined there by 2 percent. The companies that contributed notably to this decline were Burlington Resources and ExxonMobil. In conjunction with its exploration expansion in the deepwater Gulf of Mexico, Burlington decreased its emphasis on the Gulf shelf to the extent that its gas production there fell from 112 to 80 billion cubic feet between 1998 and 1999.[61] ExxonMobil's offshore production fell substantially, despite the addition of deepwater volumes from its Genesis and Ursa projects.[62]

The FRS companies' share of the world's oil production was about 11 percent, and their share of the world's natural gas production was about 17 percent in 1999.[63] These shares are derived only from the amount of their production that the FRS companies own themselves, excluding their production of royalty interests.[64]

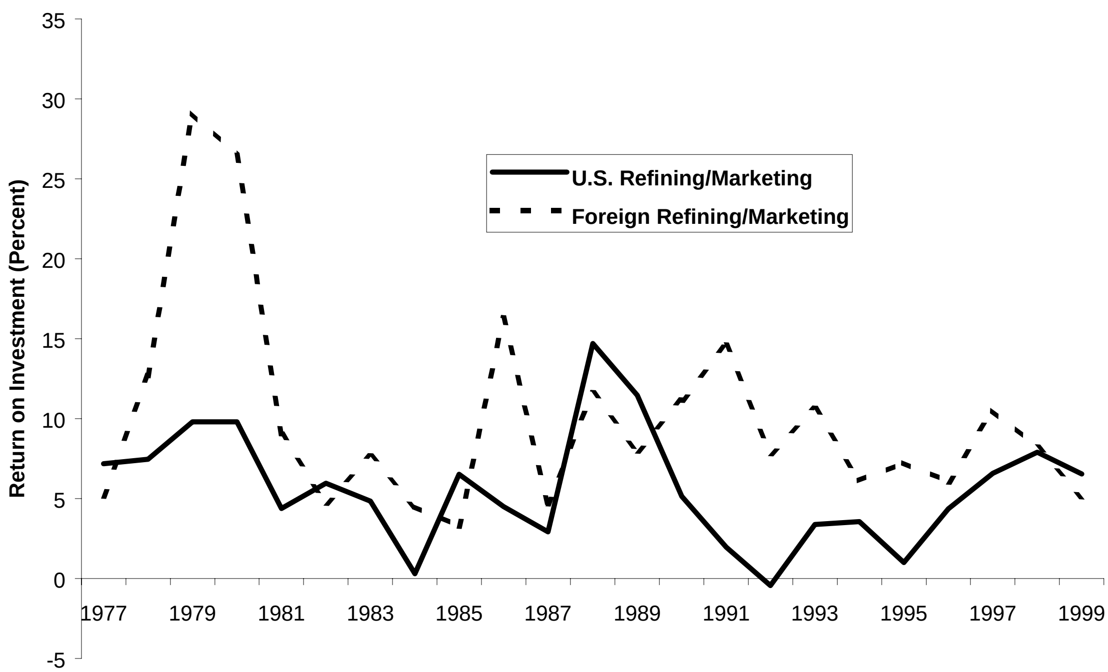
ExxonMobil was the dominant worldwide producer of the group, producing more than twice as much oil and gas as any other FRS company. However, if the current U.S. affiliates of BP (BP America, BP Amoco, and Atlantic Richfield) are added together, their combined worldwide production of oil and of gas reached more than 75 percent of ExxonMobil's in 1999. Domestically, the U.S. affiliates of BP in total produced twice as much oil and 30 percent more gas than did ExxonMobil.

U.S. Refining and Marketing

Profitability of U.S. Refining/Marketing Operations Less Than in 1998, but Remained Near Decade High

The FRS companies' U.S. refining/marketing operations were less profitable (measured by return on investment)[65] during 1999 than in 1998 (but were still the third highest since 1989), falling to 7 percent from the decade high of 8 percent in 1998 (Figure 10). Return on investment is strongly correlated with the net refined product margin (net margin).[66] The net margin is the gross margin (refined product revenues minus purchases of raw materials input to refining and refined product purchases) minus out-of-pocket operating costs per barrel of refined product sold and measures before-tax cash earnings from the production and sale of refined products.[67] During 1999 the net margin for the FRS companies decreased for the first time since 1995, falling 42 cents per barrel (Table 13). Movements in the net margin can be analyzed by examining the spread between refined product prices and raw material input costs and operating costs. (For example, see the Highlight entitled "Refinery Outages and PADD 5 Profitability" for an analysis of net margins and refining/marketing profitability in PADD 5.)

Figure 10. Return on Investment in U.S. and Foreign Refining/Marketing for FRS Companies, 1977-1999



Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Higher prices increase product revenues. Profitability of domestic refining and marketing declined despite a 29-percent increase in refined product sales revenues (Table 14).[68] Part of the reason that product revenues increased during 1999 was the $3.95-per barrel increase in the average price of petroleum products that the companies sold (Table 13). The major reason for this price increase was higher crude oil prices, which rose from $10 per barrel in January, to over $24 per barrel in December.[69] A variety of developments in 1999 affected petroleum prices. Real gross domestic product grew by 4 percent during 1999[70] and consumption of petroleum products grew by nearly 3 percent,[71] putting upward pressure on petroleum product prices. Additionally, the winter weather of 1999, while warmer than normal, was cooler than the winter weather of 1998,[72] which increased the consumption of heating fuels, putting additional upward pressure on product prices.

Table 13. Sales, Prices, and Margins in U.S. Refining/Marketing for FRS Companies, 1998-1999

	1998	1999	Percent Change 1998-1999	Nominal Change 1998-1999
		(million barrels per day)		
Refined Product Sales	19.9	21.4	7.4	1.4
Average Sales Price		(dollars per barrel)		
Motor Gasoline	22.43	26.87	19.8	4.45
Distillate	18.41	22.11	20.1	3.70
Other Products	17.35	20.27	16.8	2.92
All Refined Products	20.31	24.26	19.5	3.95
less Raw Material Input Expense and Product Purchases	14.25	18.78	31.8	4.53
equals Gross Margin	6.05	5.47	-9.6	-0.58
less Direct Operating Costs	4.54	4.37	-3.7	-0.17
equals Net Margin[a]	1.52	1.10	-27.4	-0.42
Motor Gasoline Marketing Margins				
Reseller/wholesaler spread (dealer price - wholesale price)	4.50	4.04	-10.1	-0.45
Retailer spread (company-operated price - dealer price)	2.95	2.99	1.4	0.04

[a] See Appendix B, Table B32, for the components to calculate the refined product margin.

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 (Financial Reporting System).

Greater product sales volumes further increase product revenues. Not only did product prices received by FRS companies rise during 1999, but product sales volumes increased by 7 percent (Table 15). Motor gasoline (up 7 percent), and heating oil and diesel fuel (up 9 percent) led the FRS companies' increase in sales.

Although product sales rose 7 percent, FRS refining (crude oil distillation) capacity fell 1 percent (Table 14) as Equilon's sale of a Midwestern refinery [73] more than offset all capacity expansion reported by other FRS companies. More remarkable was that the FRS companies increased their sales of refined products while their refinery output fell 2 percent. Part of the decline reflected lengthy refinery outages in California and Washington.[74] However, the sizable differences between sales and output mainly reflected the year-long drawdown of the historically high stocks of petroleum at the beginning of 1999.[75] The rapid depletion of petroleum product inventories slowed product price increases during 1999 to the point that crude oil price increases outpaced refined product price increases, leading to reduced margins.

Table 14. U.S. Refining/Marketing Financial and Refining Operating Items for FRS Companies, 1998-1999
(Million Dollars)

	1998	1999	Percent Change 1998-1999
Refined Product Sales Revenue	147,456	189,617	28.6
Other Revenue[a]	17,073	15,476	-9.4
Operating expense[a,b]	157,780	200,028	26.8
Operating income[b]	6,749	5,065	-25.0
Net Income, excluding unusual items	4,865	5,251	7.9
Unusual Items	1,039	-368	-135.4
Net Income	5,904	4,883	-17.3
	(thousand barrels per day)		
Refining Capacity	14,277	14,158	-0.8
Refinery Output	14,929	14,639	-1.9
	(percent)		
Refinery Utilization Rate[c]	93.0	94.7	n.m.

[a] Raw material revenues are netted against total operating expense.

[b] Excludes unusual items.

[c] Refinery utilization rate is calculated by dividing runs to stills at own refineries by the average of the year beginning and year ending crude oil distillation capacity.

n.m. : Not meaningful.

Source: Energy Information Administration,Form EIA-28 (Financial Reporting System).

Table 15. FRS U.S. Refined Product Margins and Costs per Barrel Sold, 1998-1999
(Dollars per Barrel)

	1998	1999	Percent Change 1998-1999
Gross Margin[a]	6.05	5.47	-9.6
less Marketing Costs	1.42	1.42	0.2
less Energy Costs	0.74	0.82	11.8
less Other Operating Costs	2.39	2.13	-10.8
equals Net Margin[b]	1.52	1.10	-27.4
	(million barrels)		
Product Sales Volume	7,277	7,817	7.4
Motor Gasoline Sales Volume	3,789	4,067	7.3
Distillate Sales Volume	2,146	2,344	9.2
Other Products Sales Volume	1,342	1,407	4.8

[a] Refined product revenues less raw material costs and product purchases divided by refined product sales volume.

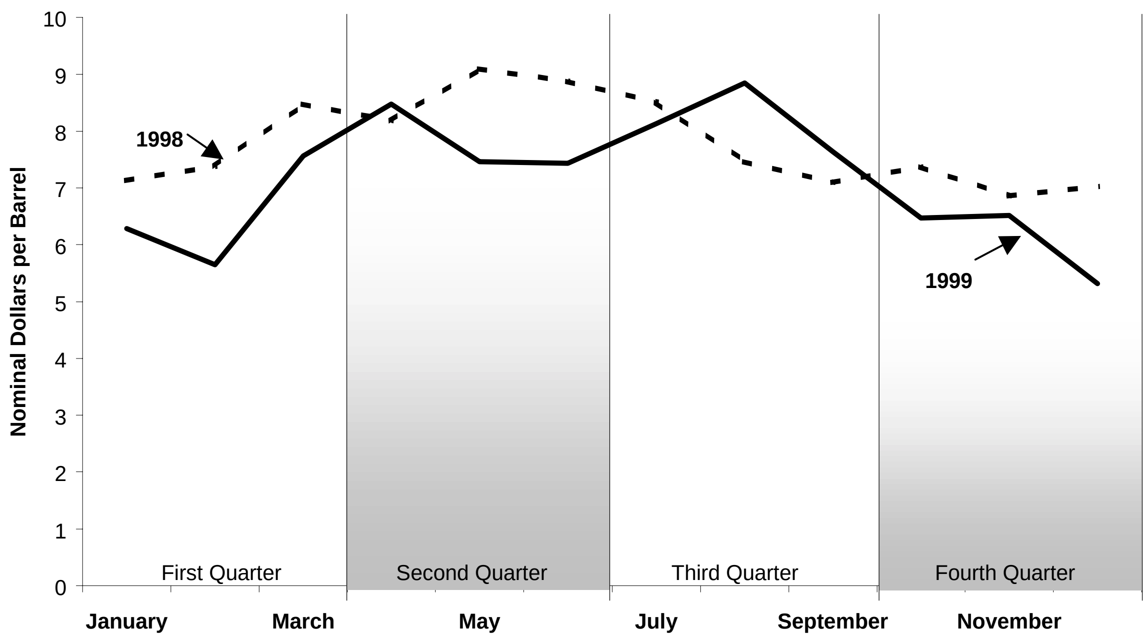
[b] Calculated from unrounded data.

Source: Energy Information Administration,Form EIA-28 (Financial Reporting System).

Gross Margins Lower in 1999

Industry-wide U.S. gross margins were generally lower over the course of 1999 than they were in 1998[76] (Figure 11). Industry-wide gross margins during the first quarter of 1999 were $1.15 per barrel lower than during the first quarter of 1998,[77] despite somewhat colder temperatures,[78] as historically high product stock levels and greater net product imports in 1999 than in 1998[79] (Figure 12) put substantial downward pressure on product prices relative to crude oil. Although the 1999 second-quarter gross margin was higher than the 1999 first-quarter margin, it was 92 cents lower than the 1998 second-quarter gross margin. Product stock levels were still unusually large (relative to the 1993-1997 average), but declining, and product prices continued to increase more slowly than the price of crude oil.[80] In the third quarter of 1999, the gross margin was 50 cents per barrel higher than the third quarter of 1998. However, the gains of the third quarter were reversed in the fourth quarter of 1999 as domestic and foreign crude oil stock levels were dramatically reduced over the last few months of 1999. The result was a $2.09-per-barrel drop in the 1999 fourth-quarter gross margin from the yearly peak of the third quarter, ending the year 98 cents per barrel lower than at the end of 1998. The unusually large level of product stocks present for most of the year exerted significant downward pressure on product prices. Declining crude oil stock levels for much of the year exerted upward pressure on crude oil prices in addition to the rise in oil prices stemming from OPEC production cutbacks in 1999. Consequently, product price increases during most of 1999 were more than offset by crude oil price increases.

Figure 11. Monthly Gross Refined Product Margin for United States, 1998 and 1999



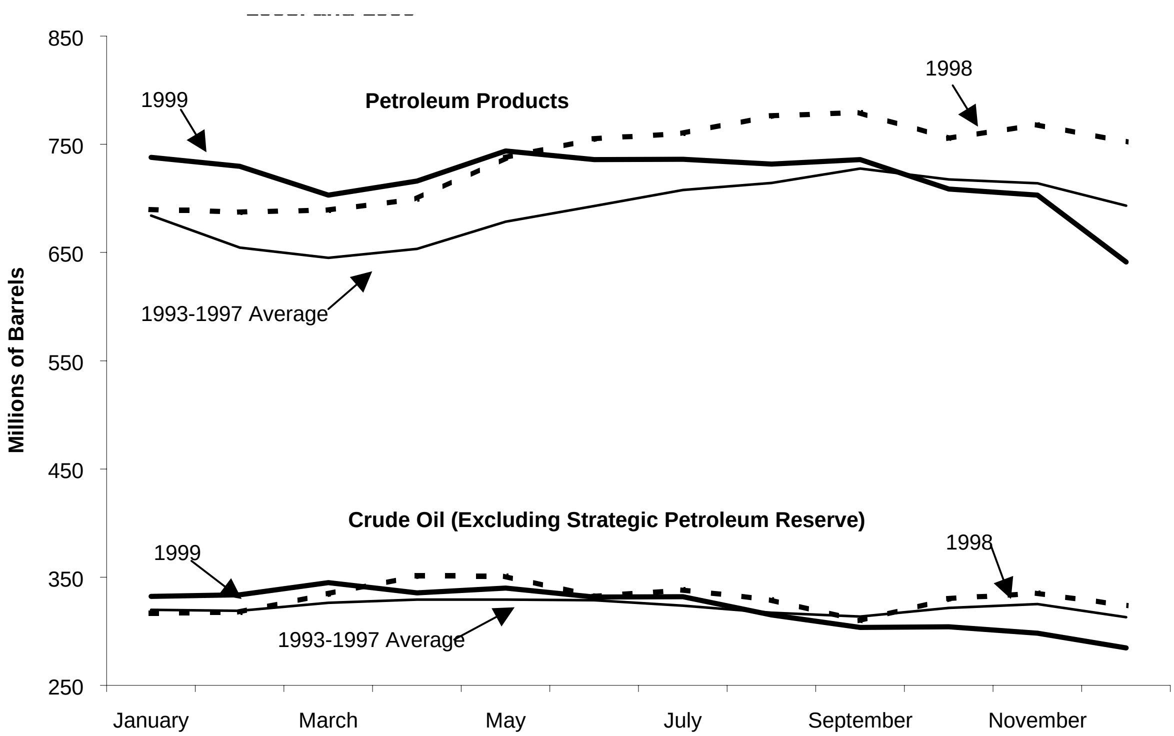
Note: The gross refined product margin is the refined product price to resellers less the composite refiner acquisition cost of crude oil.

Source: Energy Information Administration, *Petroleum Marketing Monthly*, DOE/EIA- 0380(2000/10) (Washington, DC, October 2000), Tables 1, 4, and 5, and Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(2000/10), Table 3.2b.

For the FRS companies, the gross margin in 1999 was 58 cents per barrel lower than in 1998 (Table 13 and Figure 13). Higher petroleum product prices were insufficient to offset higher raw material expenses (chiefly crude oil acquisitions) and product purchases for the FRS companies. Although the price of crude oil and other raw materials rose $4.53 per barrel (as declining crude oil stocks applied upward pressure on prices),[81] overall FRS companies' refined product prices increased $3.95 per barrel.

Reduced costs insufficient to offset lower gross margin. The lower gross margin was the key source of reduced refining/marketing profitability in 1999. Reductions in out-of-pocket expenses were insufficient to offset the decline in the gross margin. Out-of-pocket expenses were lower during 1999 despite unchanged marketing costs (Table 15). Further, although a few FRS companies recently brought cogeneration plants online at refineries and others have announced plans for building such plants,[82] energy costs increased slightly during 1999 relative to 1998.

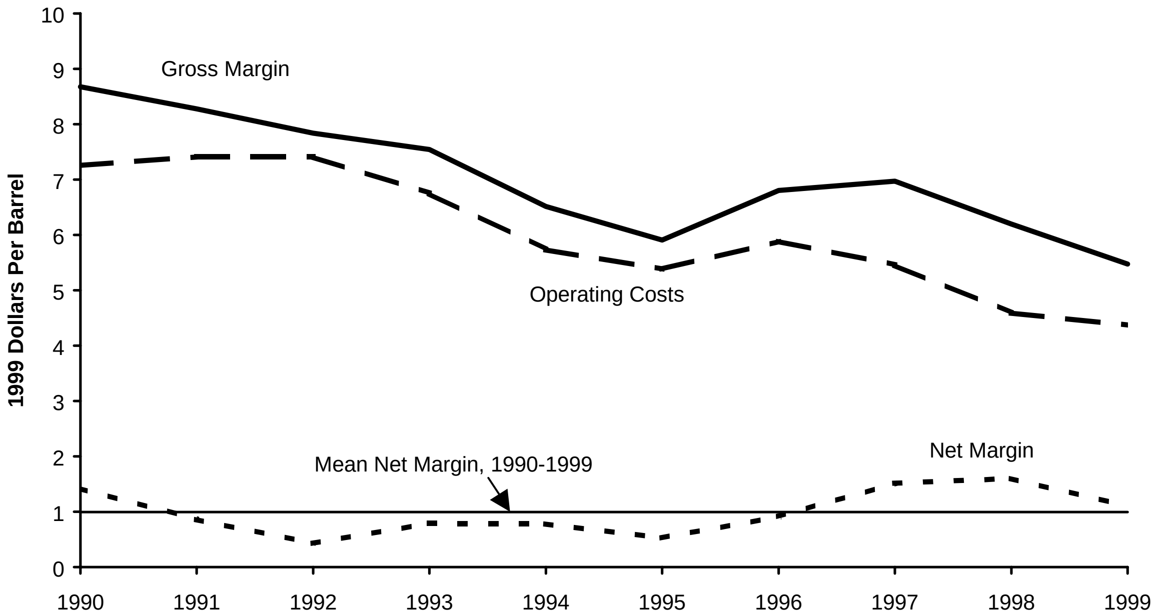
Figure 12. U.S. Crude Oil and Commercial Petroleum Product Stocks, 1993-1997, 1998, and 1999



Source: Energy Information Administration, *Petroleum Supply Monthly*, DOE/EIA-0109 (Washington, DC, 1993-1999), Table 51.

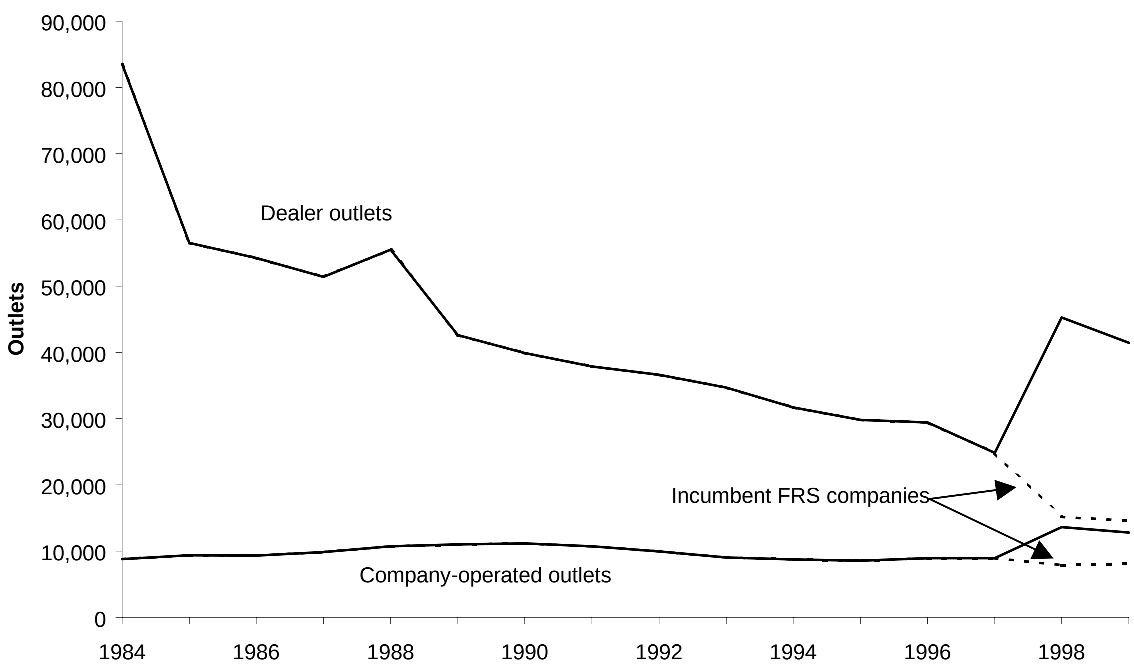
The FRS companies continued to restructure and increase the productivity of their retail outlets in 1999. Wholesale and dealer sales of motor gasoline increased between 1998 and 1999 while sales through company-operated outlets declined (Table 16).[83] Additionally, the FRS companies reduced their number of branded outlets by 8 percent during 1999, falling by more than 4,500 outlets (Figure 14).[84] At the same time, the FRS companies increased average motor gasoline sales through branded retail outlets by 9 thousand gallons per month (a 10-percent increase) between 1998 and 1999. The productivity of dealer outlets increased more than did the productivity of company-operated outlets. Average sales through dealer outlets increased by 10 thousand gallons per month (14 percent) while average sales through company-operated outlets increased 4 thousand gallons per month (3 percent) (Table 16). However, despite these concerted efforts to reduce marketing costs in 1999, they were essentially unchanged relative to 1998.

Figure 13. U.S. Refined Product Margins and Costs per Barrel of Petroleum Product Sold for FRS Companies, 1990-1999



Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Figure 14. Motor Gasoline Retail Outlets for FRS Companies, 1984-1999



Note: Incumbent FRS companies were respondents to Form EIA-28 in both 1997 and 1998.
Source:Energy Information Administration, Form EIA-28 (Financial Reporting System).

Lower costs of operating refineries and supply systems were the only clear cases of cost reduction in 1999. The FRS companies managed to cut other operating costs by 26 cents per barrel (Table 15). Reductions in other operating costs were achieved through both refining (e.g., lower costs resulting from de-bottlenecking investments,[85] incorporation of computer control systems,[86] and fewer maintenance shutdowns[87]) and marketing (e.g., reduced costs associated with lower product stock levels and closing outlets in non-core areas[88]).

Reductions in out-of-pocket costs by the FRS refiners held the decline in the net margin to 42 cents per barrel. Despite the decline in the net margin relative to its 1998 level, the 1999 value remained one of the highest values attained in the 1990's (Figure 13). The decline in the net margin translated into a 1.4-percentage point decrease in the profitability of the domestic refining and marketing operations of the FRS companies (Figure 10).

Table 16. Motor Gasoline Distribution by FRS Companies, 1998-1999

	1998	1999	Percent Change 1998-1999
	(million barrels)		
Wholesale Volume	1,900.7	2,059.0	8.3
Retail Volume			
Dealer Volume	965.0	1,006.2	4.3
Company-Operated Volume	557.7	537.5	-3.6
Total Retail Volume	1,522.7	1,543.8	1.4
Direct Volume	315.7	398.6	26.3
Intersegment Volume	49.6	65.6	32.5
	(number of outlets)		
Dealer Outlets	45,255	41,453	-8.4
Company-Operated Outlets	13,645	12,784	-6.3
Total Retail Outlets	58,900	54,237	-7.9
Average Monthly Outlet Volume	(thousand gallons per month)		
Dealers	74.6	85.0	13.8
Company Operated	143.0	147.2	2.9
All Retail	90.5	99.6	10.1

Note: Percent changes were calculated from unrounded data.

Source: Energy Information Administration,Form EIA-28 (Financial Reporting System).

Highlight —West Coast Operations Remain Profitable Despite Refinery Outages

Significant supply problems plagued the west coast area of the United States during 1999, raising the question of what the financial implications were for the west coast refining and marketing operations of the FRS companies. Two major companies, ARCO[89] and Tosco,[90] experienced lengthy and unscheduled refinery shutdowns during 1999 because of refinery fires, which affected product availability on the west coast of the United States, especially California. These shutdowns disrupted the supply of motor gasoline and diesel fuel that met the requirements of the California Air Resources Board. In June of 1999, the Olympic Pipeline, a key petroleum product route in the state of Washington, was shut down for the remainder of the year due to a fatal fire arising from a leak in the pipeline. The shutdown diverted product shipments to barges, resulting in higher shipping costs.[91]

These developments plus the recurring concern that west coast motor gasoline prices are high raises a new round of questions[92] concerning the profitability of refining and marketing operations on the west coast relative to refining and marketing operations elsewhere in the country. This highlight examines the financial results of west coast refiners relative to other refiners in 1999 using FRS data.

The west coast of the United States is entirely contained within the Petroleum Administration for Defense District[93] Five (PADD 5), which includes Alaska, Arizona, California, Hawaii, Nevada, Oregon, and Washington. In 1999 PADD 5 had 19 percent of the U.S. population; 26 percent of U.S. refineries with 19 percent of U.S. crude oil distillation capacity; 19 percent of downstream processing capacity; and 11 percent of U.S. motor gasoline retail outlets through which 17 percent of U.S. motor gasoline was sold (Table 17). Thus, PADD 5 refineries tend to be somewhat smaller (in terms of crude distillation capacity)[94] than those elsewhere in the country and the motor gasoline outlets are about 50 percent larger (in terms of average sales volume). However, simply examining the physical characteristics of PADD 5 operations provides little insight into the profitability of these operations.

Table 17. Selected Downstream Petroleum Characteristics by Petroleum Administration for Defense District (PADD), 1999

	Population	**Number of Operating Refineries**	**Refinery Operating Crude Oil Distillation Capacity** (Barrels per calendar day)	**Motor Gasoline Retail Outlets**	**Motor Gasoline Sold Through Retail Outlets** (Thousands of Gallons)	**Motor Gasoline Sales Volume per Retail Outlet** (Thousands of Gallons per Month)
PADD 5	50,610,218	40	3,094,770	19,409	22,694,350	97.4
non-PADD 5	222,080,595	115	13,220,201	156,532	111,299,669	59.3
U.S. Total	272,690,813	155	16,314,971	175,941	133,994,019	63.5

Note: PADD 5 consists of Alaska, Arizona, California, Hawaii, Nevada, Oregon, and Washington.

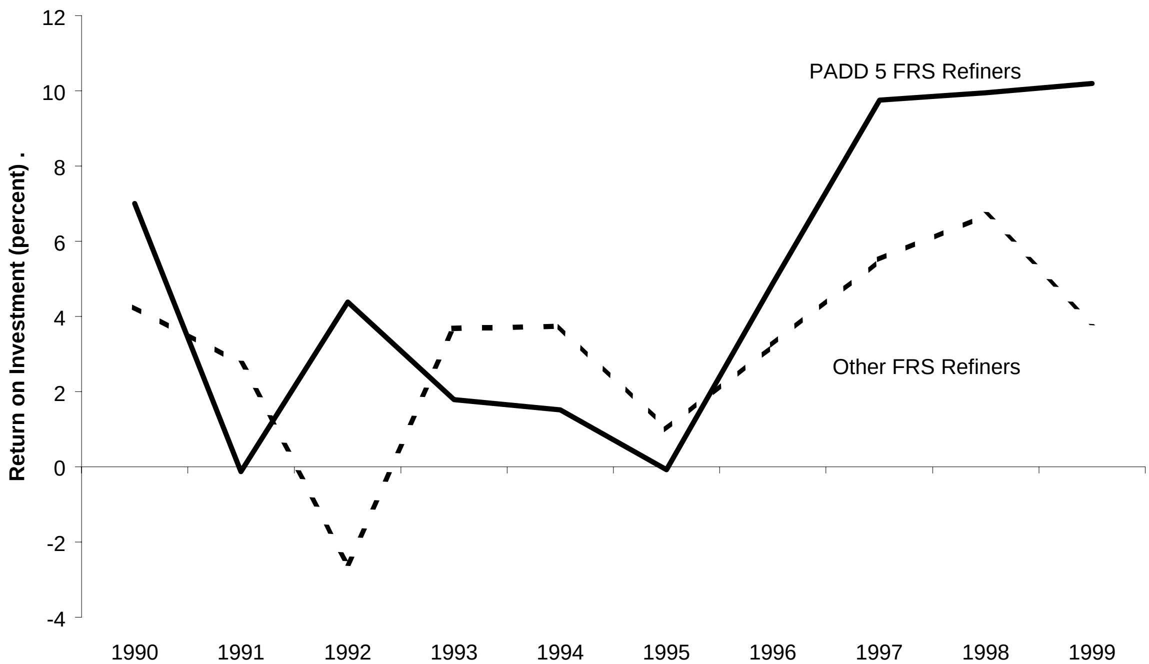
Sources: **Population**: U.S. Department of Commerce, Bureau of the Census, http://www.census.gov/population/estimates/state/st-99-3.txt, (September 20, 2000); **Number and Capacity of Operating Refineries**: Energy Information Administration, *Petroleum Supply Annual 1999*, Volume 1 (Washington, DC, June 2000), Table 36; **Motor Gasoline Outlets**: *National Petroleum News*, *Market Facts 2000*, Volume 92 (July 2000), p. 120; **Motor Gasoline Sold Through Retail Outlets**: Energy Information Administration, *Petroleum Marketing Annual 1999* (Washington, DC, August 2000), Table 43.

One way to examine profitability is to compare the rates of return to refining/marketing operations of PADD 5 refiners with those of non-PADD 5 refiners. The Financial Reporting System (FRS) database lends itself well, but imperfectly, to such a comparison. The FRS companies can be divided into two groups of refiners: those that are primarily based in PADD 5 (measured by crude oil distillation capacity) and those that are primarily based outside of PADD 5 ("Other").[95] The PADD 5 FRS group overall had 68 percent of their domestic refining capacity located in PADD 5 at the end of 1999.[96] The Other FRS had 92 percent of their total domestic refining capacity located outside PADD 5 at the end of 1999.[97]

After 1995 the profitability (measured by net income divided by net investment in place) of refining/marketing operations of the PADD 5 FRS refiners has consistently been greater than the profitability of the Other FRS refiners (Figure 15). During the first half of the 1990's there was, on average, little difference in profitability. Although the difference between the profitability of the two groups appeared to narrow in 1998, it grew during 1999 as the PADD 5 FRS refiners' return on investment increased slightly while the Other FRS refiners' return fell 3 percentage points. Consequently, despite the 1999 refinery/pipeline outages, there was little ill effect on the PADD 5 FRS refiners as the profitability of PADD 5 FRS refiners increased relative to the Other FRS refiners.

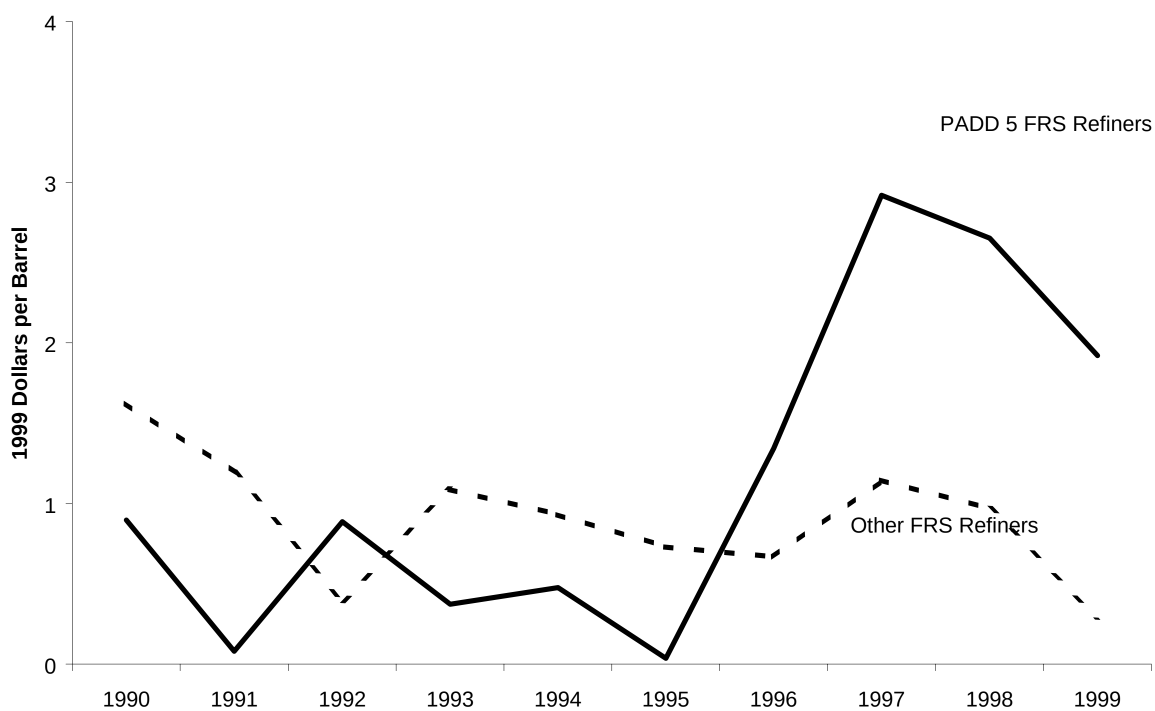
Because the net margin and refining/marketing profitability are highly correlated, examination of differences in the net margins should provide clues as to the source of profitability differences.[98] The net margin is the gross margin (average price received for all petroleum products less raw materials costs and product purchases) less out-of-pocket refining and marketing costs on a per-barrel basis. The net margin for both the PADD 5 FRS refiners and the Other FRS refiners declined between 1998 and 1999 (Figure 16), but the net margin of PADD 5 FRS refiners remained higher than the net margin of Other FRS refiners as has been the case since 1996. Each of the two components of the net margin (i.e., gross margin and operating costs) can be examined to understand why the net margin of the two FRS groups differed in recent years.

Figure 15. U.S. Refining/Marketing Return on Investment for PADD 5 FRS Refiners and Other FRS Refiners, 1990-1999



Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

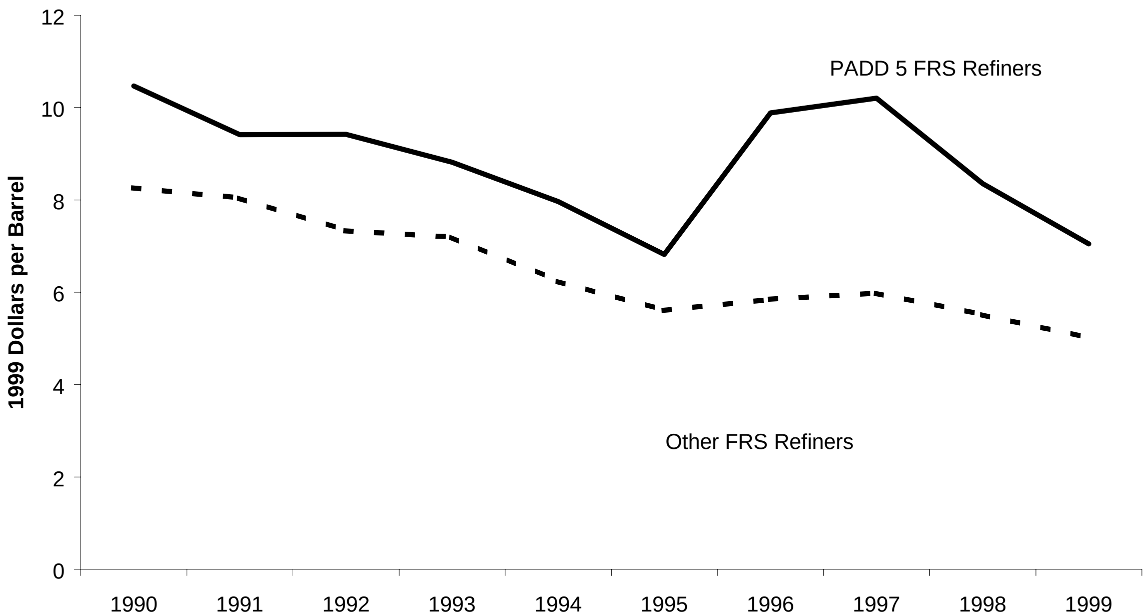
Figure 16. Net Margin for PADD 5 FRS Refiners and Other FRS Refiners, 1990-1999



Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

The gross margin for PADD 5 FRS refiners has been consistently higher than the gross margin for Other FRS refiners during the 1990's (Figure 17). In 1999, refined product price increases were less than crude oil price increases for the FRS companies overall (Table 13). This margin reduction was more severe for the PADD 5 FRS refiners than for the Other FRS refiners. The gross margin of the former group fell $1.30 per barrel (16 percent) and the gross margin of the latter group fell $0.51 per barrel (9 percent). This result suggests that PADD 5 FRS refiners' profitability should have moved nearer, not farther, from the level of profitability of Other FRS refiners. Thus, operating costs associated with producing and selling the petroleum products is the more likely source of the observed differences in profitability in 1999.

Figure 17. Gross Margin for PADD 5 FRS Refiners and Other FRS Refiners, 1990-1999

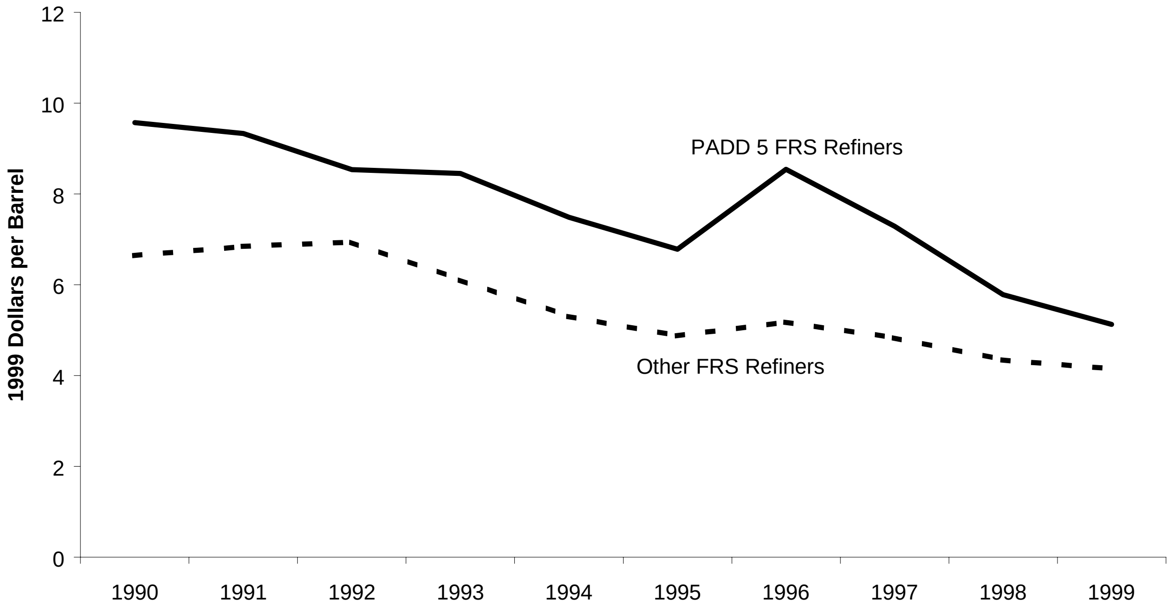


Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Operating costs of the PADD 5 FRS refiners were also higher than those of Other FRS refiners over the 1990's (Figure 18). Between 1998 and 1999 they fell $0.66 per barrel. Meanwhile the operating costs of Other FRS refiners also decreased, but by a smaller $0.20 per barrel. The resulting situation was unprecedented in the decade, as operating costs of PADD 5 FRS refiners were only $0.98 per barrel higher in 1999 than were operating costs of Other FRS refiners. Over the 1990 to 1998 period the operating costs of PADD 5 FRS refiners averaged $2.30 per barrel more than those of the Other FRS refiners, with the difference peaking in 1996 and 1997 as the California Air Resources Board motor fuel regulations went into effect. Company news releases and other public disclosures indicated that companies went to great lengths to reduce costs during 1999.[99]

Although the PADD 5 FRS refiners experienced significant and lengthy refinery outages during 1999, their aggregate profitability changed little. Profitability was largely maintained at 1998 levels through substantial reductions in operating costs, despite declines in gross margins. PADD 5 FRS refiners achieved lower operating costs by generally containing costs aggressively. For Other FRS refiners, gross margins also declined, but operating costs fell less.

Figure 18. Refining/Marketing Operating Costs for PADD 5 FRS Refiners and Other FRS Refiners, 1990-1999



Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Foreign Refining and Marketing

Weak Margins Plague Foreign Downstream Earnings

The FRS companies' overall earnings from foreign refining/marketing in 1999 fell 51 percent, by nearly $1.9 billion (excluding unusual items[100]) (Table 18), a continued decline from the near-record earnings in 1997. (Earnings declined only 7 percent in 1998 compared to 1997 earnings.) The decline in earnings for 1999 can be attributed to consolidated operations (Figure 19). In 1998, the decline in overall earnings was attributed to the operations of unconsolidated affiliates.

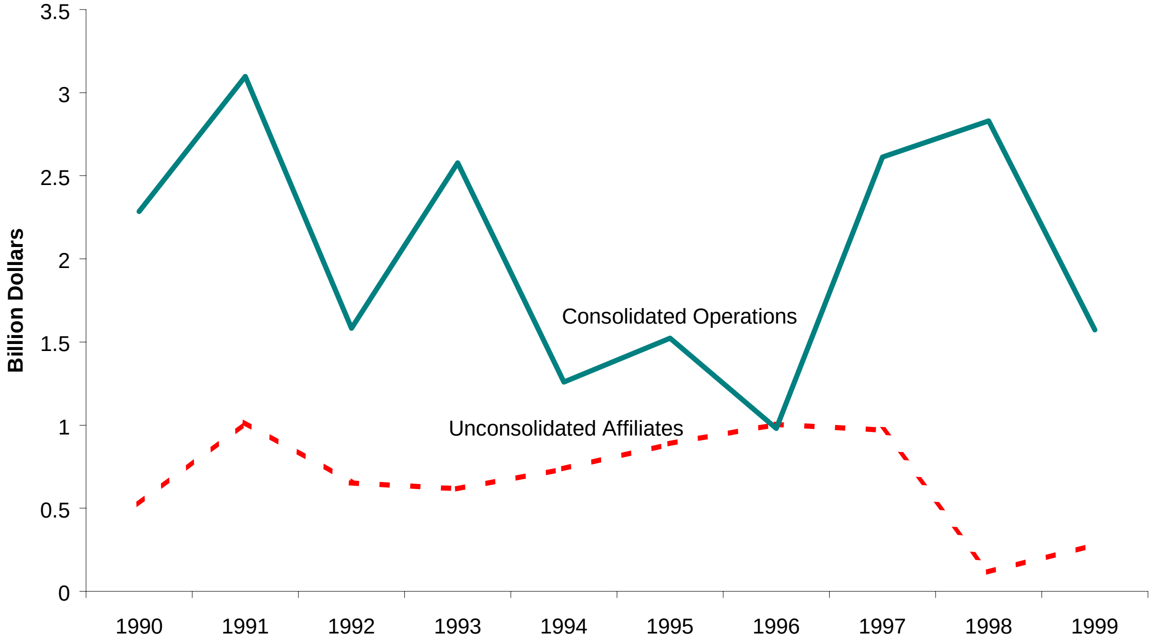
Table 18. Foreign Refining/Marketing Financial Items for FRS Companies, 1998-1999
(Million Dollars)

	1998	1999	Percent Change 1998-1999
Refined Product Revenues	121,344	119,105	-1.8
Net Income from Consolidated Operations	2,830	1,572	-44.5
Net Income from Unconsolidated Affiliates	115	282	145.2
Net Income	2,945	1,854	-37.0
Net Income, excluding unusual items	3,667	1,796	-51.0

Source: Energy Information Administration, Form EIA-28, (Financial Reporting System).

The FRS companies report foreign refining/marketing earnings from two sources: consolidated operations and unconsolidated affiliates. There are basic differences between the two operations. Specifically, a parent corporation directly controls a consolidated affiliate, although it could be owned by several companies with the parent corporation owning more than 50 percent.[101] Conversely, for an unconsolidated affiliate, the parent corporation owns 50 percent or less of the affiliate or does not directly control the entity.[102]

Figure 19. Foreign Refining/Marketing Net Income from Consolidated Operations and Unconsolidated Affiliates for FRS Companies, 1990-1999



Source: Energy Information Administration, Form EIA-28 (Financial Reporting System)

The merger between Exxon and Mobil in 1999, now ExxonMobil[103] and the alliance of British Petroleum's (now BP Amoco) and Mobil's European downstream operations[104] resulted in changes in the regional distributions of the FRS companies' foreign refining capacity. In 1999, the proportion of unconsolidated affiliates' refining capacity in the Asia-Pacific region declined from 57 percent in 1998 to 48 percent[105] (Table 19), as ExxonMobil consolidated its 50-percent ownership interests in each of two Japanese refineries (located in Kawasaki and Wakayama). In addition, ExxonMobil gained controlling interest in a previously unconsolidated affiliate's refinery located in Okinawa, Japan. Nevertheless, even with the shifts in regional distribution, earnings from unconsolidated affiliates mainly reflect activities in the Asia-Pacific region, as a plurality of affiliates' refining capacity remains in this region.

Table 19. Regional Distribution of Foreign Refinery Capacity for FRS Companies, 1998-1999
(percent)

Region	Consolidated Company		Unconsolidated Affiliates	
	1998	1999	1998	1999
Europe	50.4	46.5	32.3	39.2
Asia	26.8	32.4	57.0	47.9
Latin America	10.2	9.4	0.5	0.7
Canada	9.8	9.0	0.0	0.0
Other	2.8	2.6	10.1	12.3
Total	100.0	100.0	100.0	100.0

Note: The region denoted "Other" indicate areas located in Africa and the Middle East.

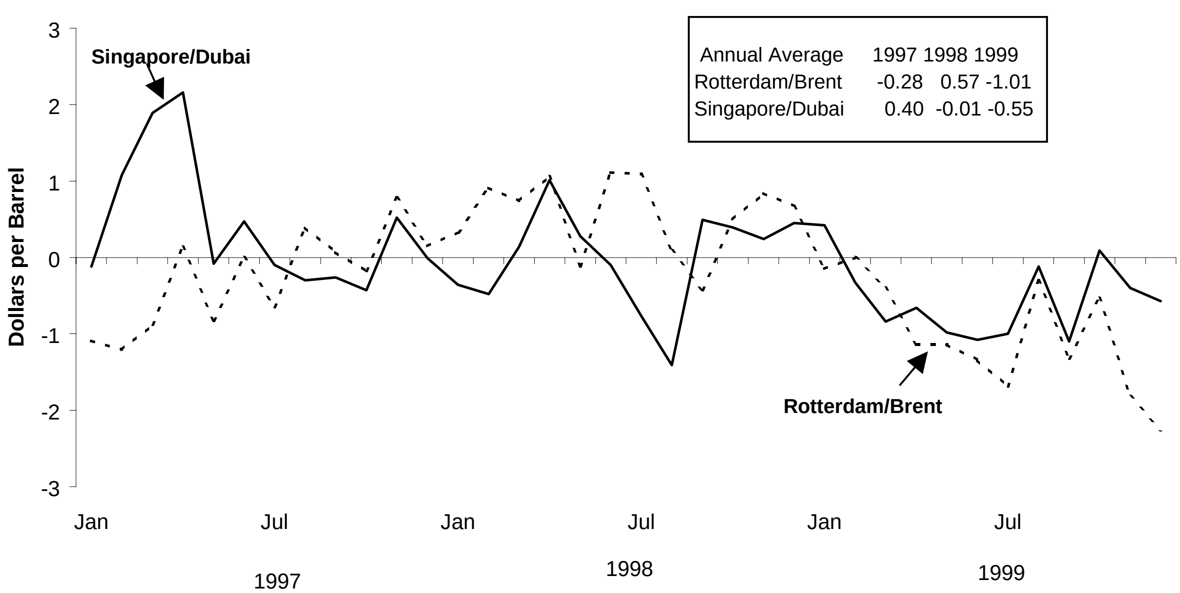
Source: Companies' annual reports and Securites and Commision Form 10-Ks.

For consolidated operations, the regional distribution also changed as a result of the merger between Exxon and Mobil. The share of refining capacity for consolidated operations located in Europe dropped from 50 percent to 46 percent, while capacity in the Asia-Pacific region increased from 27 percent to 32 percent.[106] The balance of these operations is concentrated in Latin America and Canada, both at 9 percent. Still, earnings generated through consolidated operations will tend to reflect developments in Europe more than in any other region.

Increase in Income from Unconsolidated Operations Due to Caltex Efforts in Asia-Pacific

In 1999, income from unconsolidated affiliates more than doubled, to $282 million, compared to 1998 but was far below income of $971 million in 1997. The increase is traceable to Caltex, a 50-50 joint venture of Chevron and Texaco, which operates refineries and petroleum marketing facilities in the Asia-Pacific region. Chevron reported that net income from Caltex was $112 million in 1999 compared to a negative $72 million in 1998.[107] The improvement came despite weak margins for Caltex,[108] as Caltex's refined product sales volumes were up 14 percent, and efforts to reduce cost and improve overall efficiency continued. For example, Caltex completed a major reorganization that resulted in a workforce reduction and changed organizational lines of businesses, and relocated its headquarters from Dallas, Texas to Singapore. Furthermore, Caltex formed a joint-venture company to operate its majority-owned Star Petroleum Refinery in Thailand and Shell Oil's nearby refinery. The company also sold its 50-percent ownership interest in a Japanese refinery business, Koa Oil Company.[109] Excluding Caltex, the FRS companies' income from unconsolidated affiliates in foreign refining/marketing fell from $187 million in 1998 to $170 million in 1999. Gross margins for the Pacific Rim (represented by Singapore/Dubai refining margins) continued to fall (Figure 20), as escalating worldwide crude oil prices coupled with substantial crude oil inventories in the region squeezed refining margins.

Figure 20. Foreign Refining Margins, 1997-1999



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 the 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.

Sources: 1999: *Oil Market Intelligence* (January 2000 and July 1999), p. 12; 1998: *Oil Market Intelligence* (January 1999 and July 1998), p. 12; 1997: *Petroleum Market Intelligence* (January 1998 and July 1997).

Consolidated Operations in Europe and Asia-Pacific Suffer Losses

Gross margins in Europe (represented by Rotterdam/Brent refining margins shown in Figure 20) were down sharply in 1999, registering the largest annual fall since at least 1994. All of the FRS companies with operations in the region reported that higher crude oil prices outpaced refined product prices received in the marketplace, resulting in lower margins. ExxonMobil, the FRS company with the largest consolidated operations in Europe and in the Asia-Pacific region, reported that overall earnings in foreign refining operations declined by $1.9 billion between 1998 and 1999.[110] The company also reported that earnings were negatively impacted by higher maintenance shutdowns for European operations.[111] Similarly, for operations in the Asia-Pacific region, the company reported unfavorable foreign exchange rates and that increased "industry capacity ... exacerbated an already oversupplied market caused by the regional economic slowdown."[112] To reduce cost and improve operations, the company implemented cost-cutting measures, such as combining the marketing and logistics operations in two Japanese refineries (General Sekiyu K.K. and Esso Sekiyu K.K.).[113]

Endnotes

[54] Energy Information Administration, *Performance Profiles of Major Energy Producers 1998*, Chapter 3.
[55] To the extent that measured lifting costs are marginal costs, one would expect them to be similar across regions.
[56] ExxonMobil, *1999 Financial & Operating Review*, online, http://www.exxonmobil.com (November 2, 2000).
[57] BP Amoco, *1999 Securities and Exchange Commission Form 20-F*, online, http://www.sec.gov (November 2, 2000).
[58] Although the acquisition of Poco was completed in November, it was accounted for on a pooling of interests basis, allowing Burlington to take credit for Poco's full year of production. Burlington Resources, *1999 Annual Report*, pp. 9-12.
[59] ExxonMobil, *1999 Financial & Operating Review*, online, http://www.exxonmobil.com/ (November 2, 2000).
[60] Conoco, *1999 Annual Report*, pp. 12-13.
[61] Burlington Resources, *1999 Annual Report*, pp. 16 and 18.
[62] ExxonMobil, *1999 Financial & Operating Review*, online, http://www.exxonmobil.com (November 3, 2000).
[63] World totals are from *BP Amoco Statistical Review of World Energy*, (London, June 2000), pp. 7 and 23.
[64] For foreign-affiliated FRS companies, the shares do not include the production of the foreign parent or its other affiliates.
[65] Return on investment is net income divided by net investment in place.
[66] The net margin and return on investment have a correlation coefficient of 92 percent. See Energy Information Administration, *The Impact of Environmental Compliance Costs on U.S. Refining Profitability* (Washington, DC, October 1997).
[67] The net margin excludes peripheral activities such as non-petroleum product sales at convenience stores.
[68] Although petroleum product sales revenues were somewhat offset by the decline in revenues from sources such as convenience store sales (i.e., "other" revenues), this stream of revenue is unrelated to the production and sale of petroleum products and has no effect on the gross or net margins.
[69] Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(11) (Washington, DC, December 2000), Table 9.1.
[70] Energy Information Administration, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000), Appendix E.
[71] Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(00/10) (Washington, DC, October 2000), Table 1.4.
[72] Energy Information Administration, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000), Table 1.7.
[73] See "Equilon Announces Agreement To Sell El Dorado Refinery To Frontier Oil Corporation," October 20, 1999, at http://www.equilonmotivaequiva.com/content/newsrelease/NewsItem90.htm (October 31, 2000).
[74] See Atlantic Richfield Co, 1999 Securities and Exchange Commission, Form 10-K, p. 9 and Tosco Corporation, *1999 Annual Report*, p. 19.
[75] Between the end of 1998 and the end of 1999, motor gasoline stocks fell by 11 percent, distillate fuel stocks fell by 20 percent, residual fuel stocks fell by 20 percent, jet fuel stocks fell by 9 percent, and stocks of other petroleum products fell by 11 percent. See Energy Information Administration, Monthly Energy Review, DOE/EIA-0035(00/10) (Washington, DC, October 2000), Tables 3.4, 3.5, 3.6, 3.7, and 3.10, respectively.
[76] The average monthly gross margin over 1999 was $7.15 per barrel with a standard deviation of $1.10. During 1998 the average was $7.79 per barrel with a standard deviation of $0.79.
[77] Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(00/10) (Washington, DC, October 2000), Table 3.2b and *Petroleum Marketing Monthly*, DOE/EIA-0380(00/10) (Washington, DC, October 2000), Tables 1, 4, and 5.
[78] Energy Information Administration, *Short-Term Energy Outlook*, DOE/EIA-0202 (Washington, DC, December 1998), Table 1; Energy Information Administration, *Short-Term Energy Outlook*, DOE/EIA-0202 (Washington, DC, July 1999), Table 1; and Energy Information Administration, *Short-Term Energy Outlook*, DOE/EIA-0202 (Washington, DC, July 2000), Table 1.
[79] Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(00/10) (Washington, DC, October 2000), Tables 3.4; 3.5; 3.6; and 3.7.
[80] Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(00/10) (Washington, DC, October 2000), Table 3.2b and *Petroleum Marketing Monthly*, DOE/EIA-0380(00/10) (Washington, DC, October 2000), Tables 1, 4, and 5.
[81] Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(00/10) (Washington, DC, October 2000), Table 3.1a.
[82] For example, companies with cogeneration facilities currently operational include ARCO (1999 Securities and Exchange Commission, Form 10-K, p. 10), ExxonMobil (*1999 Annual Report*, p. 19), and Phillips Petroleum, which plans to expand during 2000 (*1999 Annual Report*, p. 20). Companies that have announced cogeneration projects include Lyondell

(Lyondell-Citgo Refining LP, Financial Statements, December 31, 1999, p. 23) and Sunoco ("Sunoco Announces Agreement with FPL Energy on Cogeneration plant at Marcus Hook Refinery," PRNewswire (October 14, 1999)).

[83] Clark's (now Premcor, see http://www.premcorinc.com/press/newsrelease/newname.html (October 20, 2000)) exit from petroleum retailing strongly affected the change in the distribution of sales through marketing channels as most of their divested outlets (about 700 of the approximately 900 total outlets were company-operated stores, see http://www.premcorinc.com/press/newsrelease/nr-990708-SALEOFMARKETING.html (November 7, 2000)) were company-operated stores. All of Clark's 1999 motor gasoline sales were reported as wholesale sales.

[84] Some companies divested outlets and associated assets while others made similar acquisitions. A few companies did both. For example, ARCO divested 107 outlets and acquired 99 outlets (1999 Securities and Exchange Commission, Form 10-K, p. 27). BP Amoco divested 124 outlets as part of its consent agreement (*1999 Annual Reports and Accounts*, p. 30). Chevron divested 22 outlets (*1999 Supplement to the 1999 Annual Report*, p. 34). Clark USA (now Premcor) sold its 863 outlets and the "Clark" brandname (1999 Securities and Exchange Commission, Form 10-K, p. 23). Motiva divested 228 outlets and added 53 outlets (Texaco *1999 Annual Report*, p. 22). Phillips Petroleum added 17 outlets (*1999 Annual Report*, p. 22). Sunoco added 52 outlets and divested 235 outlets (*1999 Annual Report*, p. 6). Tosco acquired BP Amoco outlets and 43 Boardman (branded "Smile") outlets, but also divested 370 outlets in "non-core" areas (*1999 Annual Report*, p. 15). Ultramar Diamond Shamrock sold its Alma, Michigan refinery, the associated 177 retail outlets, and other assets (1999 Securities and Exchange Commission, Form 10-K, p. 7) to Marathon Ashland Petroleum (USX/Marathon Securities and Exchange Commission, Form 10-K, p. 21). Ultramar Diamond Shamrock divested a total of 416 outlets (including the 177 sold to Marathon) (1999 Securities and Exchange Commission, Form 10-K, p. 8).

[85] For example, Ultramar Diamond Shamrock reported that it had reduced operating costs because of debottlenecking a fluid catalytic cracking unit at one of its refineries (1999 Securities and Exchange Commission, Form 10-K, p. 21).

[86] Tosco noted that it had installed improved computer control systems at its Los Angeles, California; Ferndale, Washington; and Trainer, Pennsylvania refineries (*1999 Annual Report*, pp. 6-7).

[87] Sunoco reported that its operating costs in its lubricants line of business were lower during 1999 than during 1998 (*1999 Annual Report*, p. 14). Additionally, events of 1998 that caused unplanned turnarounds, elevating costs, did not recur during 1999. For example, Hurricane Georges caused a two-week shutdown of the Puerto Rico refinery (*1999 Annual Report*, pp. 14 and 15).

[88] For example, Tosco reported that it divested 370 outlets in 1999 (*1999 Annual Report*, p. 15) and Ultramar Diamond Shamrock reported that it closed or sold 416 convenience stores during 1999 (1999 Securities and Exchange Commission, Form 10-K, p. 8).

[89] In June an explosion occurred at ARCO's Bellingham, Washington refinery. The explosion and subsequent fire closed the portion of the Olympic Pipeline that serves ARCO's Cherry Point Refinery. Repairs were made, but the federal Office of Pipeline Safety has not yet authorized resumption of operations. Prior to the explosion and fire, the vast majority of refined products supplied by Cherry Point to the Pacific Northwest were transported via that pipeline. Loss of its use compelled ARCO to transport those volumes by waterborne vessel or truck. As a result, because of capacity limitations related to these alternate means of transportation, ARCO substantially reduced production volumes at Cherry Point. See ARCO, Securities and Exchange Commission Form 10-K, 1999, p. 9.

[90] A fire occurred on February 23, 1999 at Tosco's Avon Refinery near San Francisco. By the end of July 1999 all major processing units of the refinery had been restarted. See Tosco Corporation, *1999 Annual Report*, p. 19.

[91] Reuters America, December 8, 10, and 13, 1999.

[92] An earlier round of questions prompted " Highlight -- Are Downstream Investments More Profitable in California Than the Rest of the Country?" in *Performance Profiles of Major Energy Producers 1998*.

[93] Energy Information Administration, *Petroleum Supply Annual 1999*, Volume 1, DOE/EIA-0340(99)/1 (Washington, DC, June 2000), p. 122. During World War II, the Federal government created domestic geographic districts in order to administer oil allocation; these geographical districts are still used today by the Energy Information Administration (EIA) as a way to categorize regional energy supply statistics. The continued use of these regions permits EIA to provide sub-national petroleum supply statistics without the expense of collecting state-level data.

[94] As of the end of 1999, the PADD 5 refineries of the FRS companies also tend to be relatively smaller (123 thousand barrels per day) than their refineries elsewhere in the United States (159 thousand barrels per day). See Energy Information Administration, *Petroleum Supply Annual 1999*, Volume 1, DOE/EIA-0340(99)/1 (Washington, DC, June 2000), Table 40.

[95] Because Texaco and Shell formed the joint venture Equilon that included the PADD 5 refineries of both companies, Equilon is included with the PADD 5 refineries for the year 1998, its first year as an FRS respondent. Similarly, although Tosco owns refineries nationwide, the majority of its refining capacity was acquired from Unocal when Unocal exited downstream petroleum operations at the end of 1996. Thus, Tosco also is included with the PADD 5 refineries for 1998, the first year that Tosco was an FRS respondent.

[96] The PADD 5 group consists of ARCO, Chevron, Equilon (which replaced Texaco in 1998), Texaco, Tosco (which replaced Unocal in 1998), and Unocal. These companies have a total of 2.0 million barrels of their domestic capacity of 3.2

million barrels located in PADD 5. See Energy Information Administration, *Petroleum Supply Annual 1999*, Volume 1, DOE./EIA-0340(99)/1 (Washington, DC, June 2000), Table 40.

[97] The group of non-PADD 5 refiners consists of BP Amoco, Ashland, BP America, Coastal, Conoco/duPont, ExxonMobil, Fina, Marathon/USX, Mobil, Phillips, Shell Oil, and Sunoco. These companies have a total of 0.3 million barrels of their total domestic refining capacity of 7.4 million barrels located in PADD5. See Energy Information Administration, *Petroleum Supply Annual 1999*, Volume 1, DOE./EIA-0340(99)/1 (Washington, DC, June 2000), Table 40.

[98] The net margin and return on investment have a correlation coefficient of 92 percent. See Energy Information Administration, *The Impact of Environmental Compliance Costs on U.S. Refining Profitability* (Washington, DC, October 1997).

[99] For example, Atlantic Richfield Corporation, "ARCO's First Quarter Results: Refining and Marketing Strong, Upstream Volumes Grow; Cost Reductions on Target" (May 3, 1999).

[100] Unusual items reduced net income from foreign refining/marketing by $722 million in 1998 but in 1999, unusual items increased net income from foreign refining/marketing by a relatively slight $58 million. In 1998, unusual items consisted of losses of $421 million on inventory holdings, charges against income of $252 million for restructuring, and $49 million in miscellaneous charges. In 1999, unusual items consisted of $171 million in gains on inventory holdings, $111 million in restructuring charges, and $2 million in miscellaneous charges against income.

[101] All financial items for consolidated operations (such as revenues, costs, and asset values) are reported in the public financial disclosures of the parent corporation.

[102] Only the parent's proportional share of the affiliates' net income is reported on the corporate parent's income statement.

[103] ExxonMobil, *1999 Annual Report*, p. F19.

[104] Under the agreement between the two companies in 1996, Mobil contributed its European refining/marketing operations to BP in exchange for a 30-percent ownership share in the BP-Mobil European downstream alliance. For more information on the BP-Mobil Alliance see "Highlight: BP-Mobil alliance of European Refining Operations," *Performance Profiles of Major Energy Producers 1997* (January 1999), p. 31.

[105] In 1996, prior to the BP-Mobil European downstream alliance, the percentage of unconsolidated affiliates' refinery capacity in the Asia-Pacific region was 63 percent.

[106] In 1996, prior to the BP-Mobil European downstream alliance, the percentage of affiliates' refinery capacity in the European region was 20 percent

[107] Chevron Corporation, *1999 Annual Report*, p. 13.

[108] Chevron Corporation, 1999 Securities and Exchange Commission Form 10-K, pp. F5 -F8.

[109] Chevron Corporation, *1999 Annual Report*, p. 13.

[110] ExxonMobil, *1999 Annual Report*, pp. F5 and F6.

[111] Exxon Corporation, *Exxon Announces Estimated Second Quarter 1999 Results* (July 21, 1999).

[112] ExxonMobil, *1999 Financial and Operating Review*, "Downstream: Refining and Supply," http://www.exxonmobil.com/shareholder_publications/c_fo_99/c_downstream_2.html

[113] ExxonMobil, *1999 Financial and Operating Review*, "Downstream: Fuels Marketing."

4. Emerging Patterns: Changes in Corporate Structure and Resource Development Activities

The detailed financial and operating data and information submitted each year to the EIA by major U.S. energy companies enables an examination of annual trends in the financial performance and profitability of the U.S. energy industry. However, the data are not by any means limited to this use.

In fact, the Financial Reporting System (FRS) data also permit analyses of new developments and emerging directions of the larger energy industry. Further, when the FRS data are combined with additional information from company annual reports, press releases, and other energy company public disclosures, the scope of energy industry financial analyses can be expanded.

The uniformity of the data reported to the FRS makes the available detail even more analytically useful, as data can be compared across lines of business (and across years) to elucidate trends and examine the significance of changes in trends.

Restructuring in Energy Industries

This section of *Performance Profiles* provides a window to current changes occurring in the organizational structure of the U.S. energy industry. As of 1999, it has become clear that a divergence in corporate organizational structure has made the current U.S. major energy companies into a heterogeneous group of companies. It is no longer accurate to think of the U.S. majors merely as the organizational “children” of John D. Rockefeller’s Standard Oil Company. The Financial Reporting System’s major U.S. energy companies still include vertically-integrated petroleum companies. However, specialized oil and gas producers, specialized refiners (most of whom are also heavily involved in marketing), and energy service companies have recently come into greater prominence. The energy service company still may be an evolving type of corporate structure, and may require more attention in the future. To clarify these developments, this section presents two analyses ("Special Topics") that discuss:

- The different corporate growth strategies being pursued by the U.S. majors, as they seek to improve their financial performance and position themselves for the future; and
- How those U.S. majors already having natural gas and pipeline assets have moved to add electricity assets in an effort to become major energy service suppliers in multiple markets.

SPECIAL TOPIC: Majors Restructure, but Follow Different Paths to Enhance Value

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Vertically Integrated Majors

The composition of the major U.S. energy companies reporting to EIA’s Financial Reporting System (FRS) has changed noticeably in the 1990’s. For FRS purposes a major U.S. energy company owns at least one percent of U.S. reserves or production of oil or natural gas or one percent of U.S. refining capacity or refined product sales. When the FRS was first implemented in 1979, 24 of the 26 companies selected as respondents were vertically integrated petroleum companies (Figure 21). (Vertically integrated petroleum companies’ operations encompass the functions of oil (and natural gas) production, transport, petroleum refining, and marketing of refined petroleum products.) The other two FRS reporting companies, in 1979, produced oil and gas but were not involved in petroleum refining and marketing.

Figure 21. Companies in the Financial Reporting System, 1979, 1990, and 1999

1979

Vertically Integrated
Exxon
Mobil
Texaco
Chevron
Amoco
Gulf Oil
Shell Oil
Atlantic Richfield
Tenneco
BP America
Conoco
Sunoco
Phillips Petroleum
Getty Oil
Unocal
Occidental Petroleum
Union Pacific Resources
Amerada Hess
Cities Service
Marathon
Coastal
Ashland Oil
Kerr-McGee
Fina

Non-integrated Producers
Burlington Resources
Superior Oil

1990

Vertically Integrated
Exxon
Mobil
DuPont (Conoco)
Chevron
Amoco
Shell Oil
Texaco
Atlantic Richfield
BP America
USX (Marathon)
Phillips Petroleum
Unocal
Coastal
Amerada Hess
Sunoco
Ashland Oil
Kerr-McGee
Fina
Total Petroleum (N. America)

Non-integrated Producers
Occidental Petroleum
Union Pacific Resources
Burlington Resources
Oryx Energy

1999

Vertically Integrated
Exxon Mobil
BP Amoco
Chevron
Texaco
Shell Oil
Atlantic Richfield
USX (Marathon)
Conoco
Phillips Petroleum
Amerada Hess
Coastal
Fina

Non-integrated Producers
Occidental Petroleum
Union Pacific Resources
Unocal
Burlington Resources
Kerr-McGee
Anadarko Petroleum

Non-integrated Refiners
Equilon Enterprises
Motiva Enterprises
Tosco
Ultramar Diamond Shamrock
CITGO Petroleum
Sunoco
Valero Energy
Lyondell-CITGO Refining
Clark Refining and Marketing
Tesoro Petroleum

Energy Services
Enron
Williams Companies
El Paso Energy

By 1990, 19 of the FRS companies were vertically integrated. During the 1980's two companies divested their downstream assets, one company sold all of its petroleum operations in order to leave the energy industry, and three vertically integrated FRS companies were merged with other FRS companies. By 1999, the number of vertically integrated FRS companies was down to 12 as, during the 1990's, three companies divested their downstream assets, one company sold its upstream assets, one company departed U.S. energy operations, and two companies merged with other FRS companies. In 2000, at the time this report was written, two more vertically integrated companies were merged with other FRS companies, reducing to 10 the number of vertically integrated companies in the FRS reporting group.

Non-integrated Majors

While the number of vertically integrated petroleum companies that fit EIA's criteria as major energy companies has dropped by 50 percent since the initial implementation of the FRS, three other types of companies have increasingly met the respondent selection criteria: non-integrated producers, non-integrated refiners, and energy services companies. One category, shown in Figure 21, contains companies that are primarily involved in oil and gas production but do not own petroleum refining and marketing operations ("non-integrated producers"). The number of companies in this category increased from two to six, mainly due to the divestiture of downstream assets. Of the six companies in this category in 1999, four companies were formerly vertically integrated in petroleum operations and were among the original 26 companies selected for the FRS. Occidental Petroleum and Union Pacific Resources sold their downstream assets in the 1980's while Unocal and Kerr-McGee sold their downstream assets in 1997 and 1995, respectively.

Another type of company, petroleum refiners who do not own oil and gas production operations ("non-integrated refiners"), did not appear among the ranks of the major U.S. energy companies until well into the 1990's. Two of the non-integrated refiners, Equilon Enterprises and Motiva Enterprises, are joint ventures formed by the vertically integrated majors Shell and Texaco, and began operations in 1998. The 10 non-integrated refiners listed in Figure 21 accounted for only 7 percent of U.S. refining capacity in 1990. By 1999, these 10 companies accounted for 38 percent of U.S. refining capacity.

The growth of the non-integrated U.S. refiners resulted largely from their acquisitions of refineries and other downstream assets divested by the vertically integrated majors. Nearly all of the FRS companies that were vertically integrated in 1990 sold U.S. refineries in the 1990's and some left downstream operations altogether.

This retrenchment was, in part, a reaction to the low levels of profitability in U.S. refining and marketing during the first half of the 1990's. The divestiture of downstream assets also reflected an increased emphasis by the vertically integrated majors on developing large oil and gas fields, with a consequent diversion of capital expenditures from downstream operations to upstream operations.

Of the 2.4 million barrels per day of U.S. refining capacity added by the non-integrated refiners, between 1990 and 1999, 66 percent came through acquisitions of capacity divested by vertically integrated (and formerly vertically integrated) FRS companies (excluding the formation of the Equilon and Motiva joint ventures).

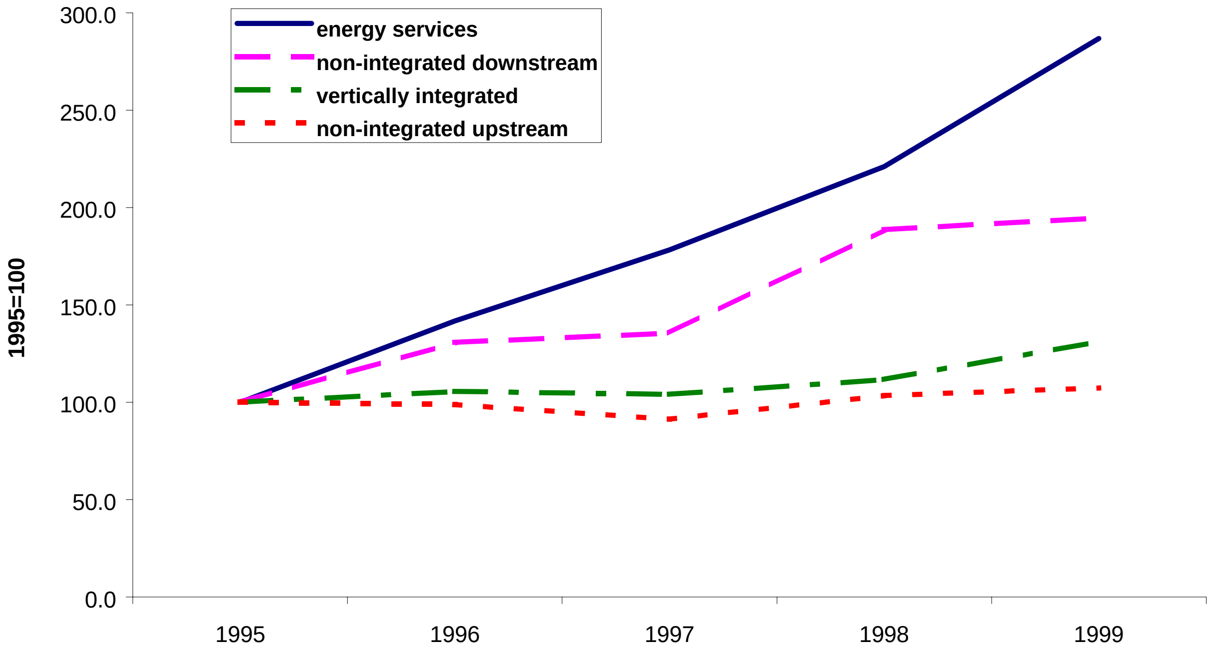
Energy Services Companies

Yet another type of company first appeared among the majors in the 1990's. In this report, this category is termed "energy services companies." This appellation emphasizes the distinctive features of this type of energy company. Services typically provided include natural gas transmission and distribution; electricity generation and distribution; trading, wholesaling, and marketing of natural gas and electricity; and associated customer services such as risk management. Although some energy services companies are involved in natural gas production, this line of business is usually minor in comparison with gas and power services.[a]

Corporate Growth

Although vertically integrated petroleum companies are now a minority of the companies classified as major U.S. energy companies by the EIA, they still account for the bulk of the major U.S. energy companies' assets. In 1999, the 12 vertically integrated companies shown in Figure 21 owned 70 percent of the total assets[b] of FRS companies. However, the share for the vertically integrated majors has been steadily declining, from 98 percent in 1979. The decline in their share does not mean that vertically integrated petroleum companies have declined in size. This type of company has grown in recent years. Between 1995 and 1999, total assets of the 12 vertically integrated companies shown in Figure grew by over 31 percent (Figure 22). However, other types of companies have grown faster.

Figure 22. Total Assets of FRS Companies Grouped by Functional Categories, 1995-1999 (1995=100)



Sources: Energy Information Administration, Form EIA-28 (Financial Reporting System) and company annual reports.

Energy services companies have grown at the most rapid rate in recent years. Figure 22 shows that the energy services companies nearly tripled in size in the 1995 to 1999 period. Non-integrated downstream companies also grew at a very steep rate, nearly doubling in size over the same period. Companies in these two groups grew primarily through mergers and acquisitions.

As noted above, vertically integrated U.S. majors grew at a considerably slower 31-percent rate over the period. However, BP Amoco and ExxonMobil stand apart from the other vertically integrated majors in terms of asset growth. BP Amoco was the result of Amoco's merger into British Petroleum at the end of 1998 and ExxonMobil resulted from Mobil's merger into Exxon in 1999. Together, the two surviving companies' total assets were up 65 percent from 1995 to 1999. The other integrated majors collectively grew only 9 percent over the same period.

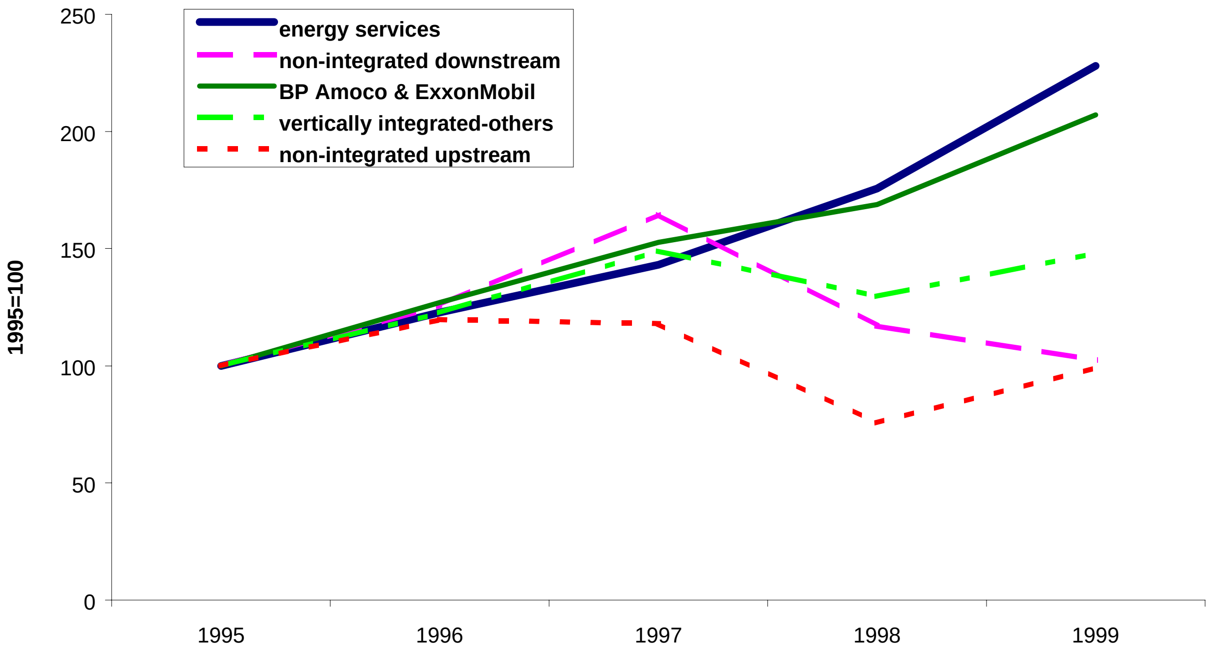
The slowest growing group of companies was the non-integrated producers. Their total asset growth was 8 percent over the period. However, this calculation masks the fact that some of the companies in this group made substantial divestitures of assets as they exited certain lines of business in order to make oil and gas production their core competency. Occidental Petroleum sold their natural gas transmission business and Kerr-McGee and Unocal sold all of their refining and marketing assets. If net investment in place (the book value of net property, plant, and equipment plus investments and advances to unconsolidated subsidiaries) is used to measure company growth, then the assets of divested lines of business can be deleted from the calculation. On this basis, the non-integrated producers grew 52 percent over the 1995 to 1999 period in their core businesses.

Investor Reactions

Are these recent patterns of growth among the major U.S. energy companies likely to continue? The structure of energy industries has been in flux during most of the 1990's. The patterns observed above may be part of a transition yet to be fully played out. Forecasting the future structure of energy industries and the composition of the major energy companies, even for the near term, appears to be largely speculative at this time. Nevertheless, a look at stock prices may provide some clues, since a company's stock price tends to reflect investors' expectations of the company's future earnings and profitability, which are the keys to corporate survival.

The behavior of stock prices varied widely across the groups of major energy companies.[c] The energy services group of companies registered the steepest appreciation in their stock prices (Figure 23). Between 1995 and 1999, the weighted average share price of this group more than doubled, growing at an annual 23-percent clip. The share prices of BP Amoco and ExxonMobil each doubled over the period, growing at a collective 20-percent annual rate. Other integrated companies' share prices overall, through 1997, kept pace with BP Amoco and Exxon. Thereafter, the two groups' share prices tended to diverge, with the latter two companies receiving the more favorable nod from investors. By the end of 1999, the other integrated companies' share prices had almost made up for the drop-off that occurred in 1998.

Figure 23. Weighted Average Share Price for FRS Companies Grouped by Functional Categories, 1995-1999 (1995=100)



Source: Compustat PC Plus, a service of Standard and Poor's.

The share prices of the non-integrated producers and refiners ended the period at roughly the same point as they began. Producers' share prices tend to move with crude oil prices. When crude oil prices rose sharply in 1996 and 1999, producers' share prices were up 20 percent and 31 percent, respectively. Conversely, when crude oil prices plunged in 1997 to 1998, producers' share prices declined 37 percent.

The path of share prices for non-integrated U.S. refiners indicates a change in investor outlook for this type of company. From 1995 through 1997, share prices of the non-integrated refiners were up 65 percent, the steepest growth of any group of companies. However, from 1997 through 1999, nearly all of this gain was lost, indicating lessened assessments by investors of the refiners' financial prospects.

In sum, differing patterns of corporate growth and share price appreciation among major U.S. energy companies, in the 1995 to 1999 period, indicate differing degrees of success of corporate strategies. The two types of companies that stand out by these measures are energy services companies, which have emphasized mergers and acquisitions as a route to corporate growth, and those vertically integrated petroleum companies that effected large mergers in the 1990's.

[a] The three energy services companies in the FRS satisfy the criteria for natural gas production or ownership of refinery capacity.
[b] Citgo Petroleum and Conoco did not disclose total assets for 1995 and are excluded from the total asset calculations.
[c] Citgo Petroleum and Clark Refining did not have outstanding shares over the 1995-1999 period and are excluded from the share price calculations. The share prices for the FRS respondents BP Amoco Inc. and Shell Oil are those of their respective parent corporations BP Amoco plc and Royal Dutch/Shell Group of Companies.

SPECIAL TOPIC: *The Rise of the Energy Services Company—The Convergence of Electric Utilities and Natural Gas*

In recent years, there has been a melding of natural gas assets and electricity assets in the United States. Mergers and acquisitions between companies primarily involved in electricity or natural gas have been the principal route by which the "convergence" of gas and electricity supply is being accomplished. Perhaps the most dramatic manifestation of the trend toward convergence is the merger/acquisition of natural gas transmission and distribution companies by electric utility companies. For example, there were 17 convergence mergers in the past 4 years.[a] During this period, six transactions were completed in 1997, followed by two additional mergers in 1998. In the next two years (1999 and 2000), three and six mergers were completed, respectively. At the time this report was being written, six additional transactions were pending.[b]

Concomitant with the convergence of natural gas and electricity assets, a new form of energy company has evolved--the energy services company. Energy services companies appear to have evolved in response to U.S. electricity restructuring and natural gas deregulation and have become more widespread as increased competition has encouraged these operations to combine. Energy services companies have greater flexibility to market both electricity and natural gas interchangeably, thereby having the opportunity to maintain and/or increase their customer base. Other benefits achieved through mergers could be improved efficiency, lowered operating cost, and the opportunity to participate in the growing market for natural gas-fired power plants.[c]

Energy services companies have little resemblance to the conventional view of a major U.S. energy company. The conventional view is a vertically integrated petroleum company that also produces natural gas. However (as shown in the preceding Special Topic), the number of vertically integrated petroleum companies has declined in recent years. At the same time, the energy services companies have grown rapidly, perhaps signaling a fundamental change in the characteristics of a major U.S. energy company.[d]

The FRS survey group in 1999 contains four of the leading energy services companies in the United States: Enron, Williams Companies, El Paso Energy, and Coastal (pending merger with El Paso Energy in 2000). All of these companies have similar natural gas operations and energy marketing and services operations. For example, Coastal, El Paso Energy, and the Williams Companies have operations in the exploration and production of natural gas, gathering and processing, and transportation and storage. Enron had similar natural gas operations with the exception of natural gas gathering and processing services in 1999.

All of these companies' energy marketing and services operations are generally conducted through subsidiaries and/or affiliates, which engage in the buying and selling of energy commodities, such as natural gas and electricity. These four companies have operations in natural gas-fired power generation and cogeneration and in electric utilities. For example, Coastal has cogeneration operations in the United States and abroad, particularly in Latin America and Asia.[e] El Paso Energy has investment activities in natural gas-fired power generation in the United States and abroad, particularly in Asia, Europe, and Latin America, and geothermal operations in the United States. El Paso Energy also acquired cogeneration facilities through its merger with Sonat.[f] As a result of its purchase of Portland General Corporation in 1997, Enron became the largest wholesaler of gas and electricity in North America, but has now announced plans to divest the electric utility in 2000. Nonetheless, Enron will continue to buy and sell natural gas, electricity, and services through its subsidiaries. Enron also has natural gas-fired power plants in the United States. Abroad, the company has power operations in Europe, South America, and Asia.[g]

[a]Energy Information Administration, *The Changing Structure of the Electric Power Industry 1999: Mergers and Other Corporate Combinations*, DOE/EIA-0562(99) December 1999, pp. 29 -36. Online at ftp://www.eia.doe.gov/pub/pdf/electricity/056299.pdf
[b] For specific details concerning these mergers/acquisitions see Energy Information Administration, *The Changing Structure of the Electric Power Industry 2000: An Update*, DOE/EIA-0562(00) October 2000, http://www.eia.doe.gov/cneaf/electricity/chg_stru_update/update2000.pdf, pp. 99 – 101, and Energy Information Administration, *The Changing Structure of the Electric Power Industry 1999: Mergers and Other Corporate Combinations*, DOE/EIA-0562(99) December 1999, ftp://www.eia.doe.gov/pub/pdf/electricity/056299.pdf
[c] Energy Information Administration, *The Changing Structure of the Electric Power Industry 1999: Mergers and Other Corporate Combinations*, DOE/EIA-0562(99) December 1999, ftp://www.eia.doe.gov/pub/pdf/electricity/056299.pdf, and Energy Information Administration, *Corporate Realignments and Investments in the Interstate Natural Gas Transmission System*, http://www.eia.doe.gov/emeu/finance/sptopics/ng_realign&invest/index.html, p. 5.
[d] Energy Information Administration, *Corporate Realignments and Investments in the Interstate Natural Gas Transmission System*, http://www.eia.doe.gov/emeu/finance/sptopics/ng_realign&invest/index.html, Table 3.
[e] Coastal Corporation, 1999 Securities and Exchange Commission, Form 10-K, p. 1.
[f] El Paso Energy, 1999 Securities and Exchange Commission, Form 10-K, pp. 10, 11, 53 and 54.
[g] Enron Corporation, 1999 Securities and Exchange Commission, Form 10-K, pp. 1- 10.

Resource Development Costs and Potential

This section of *Performance Profiles* addresses the costs of finding oil and gas, and resource development issues. While the costs of adding oil and gas reserves (finding costs) do not directly effect the current-year bottom line of the FRS companies (see Chapter 3), they are important in guiding the scale and scope of the companies' current and future resource development strategies. Accordingly, this chapter also discusses the geographical areas of most importance to the FRS companies' current resource development initiatives. Specifically, this section presents four analyses ("Special Topics") that discuss:

- A change in the level of finding costs experienced by the FRS companies over the last several years
- Africa's potential as a major target for FRS company oil and gas exploration and development efforts
- The opening of Brazil's petroleum sector to competitively bid foreign exploration and development rights
- Options for development and transport of Alaskan North Slope natural gas to the lower-48 market

SPECIAL TOPIC: *Finding Cost Increases Abate, But For How Long?*

Finding costs are the costs of adding oil (crude oil and natural gas liquids (NGL)) reserves and natural gas reserves via exploration and development activity.[a] They are measured for oil and gas on a combined basis in units of dollars per barrel of oil equivalent (BOE). Conceptually, finding costs are all the costs incurred (no matter when these costs were actually recognized on a company's books) in finding any particular proven reserves (except for purchases of already discovered reserves). In practice, finding costs are actually measured as the ratio of exploration and development expenditures (excluding the expenditures on proved acreage) to proven reserve additions (excluding net purchases of proven reserves), over a specified period of time.[b]

To accommodate leads and lags in data reporting, finding costs are generally reported in *Performance Profiles* as a weighted average over a period of three years; if several years of data are presented, they are usually reported in constant dollars.

Measured on this basis (three-year weighted averages) for the 1997 to 1999 period, the FRS companies' worldwide finding costs increased only slightly (2 percent) to $5.65 per BOE compared to the 1996 to 1998 period (Table 20). The small increase in finding costs was largely the result of decreased oil reserve additions by the drill bit rather than increased exploration and development costs. It follows two three-year periods when worldwide finding costs increased substantially.

Table 20. Finding Costs by Region for FRS Companies, 1996-1998 and 1997-1999
(Dollars per Barrel of Oil Equivalent)

Region	1996-1998	1997-1999	Percent Change
United States			
Onshore	5.26	5.26	0.0
Offshore	8.83	9.55	8.1
Total United States	6.47	6.72	3.8
Foreign			
Canada	7.76	5.43	-30.0
OECD Europe	7.49	7.63	1.9
Former Soviet Union	8.34	6.27	-24.8
Africa	3.76	3.71	-1.2
Middle East	2.71	4.18	54.2
Other Eastern Hemisphere	4.55	4.84	6.3
Other Western Hemisphere	2.34	2.99	27.7
Total Foreign	4.81	4.86	1.2
Worldwide	5.54	5.65	2.0

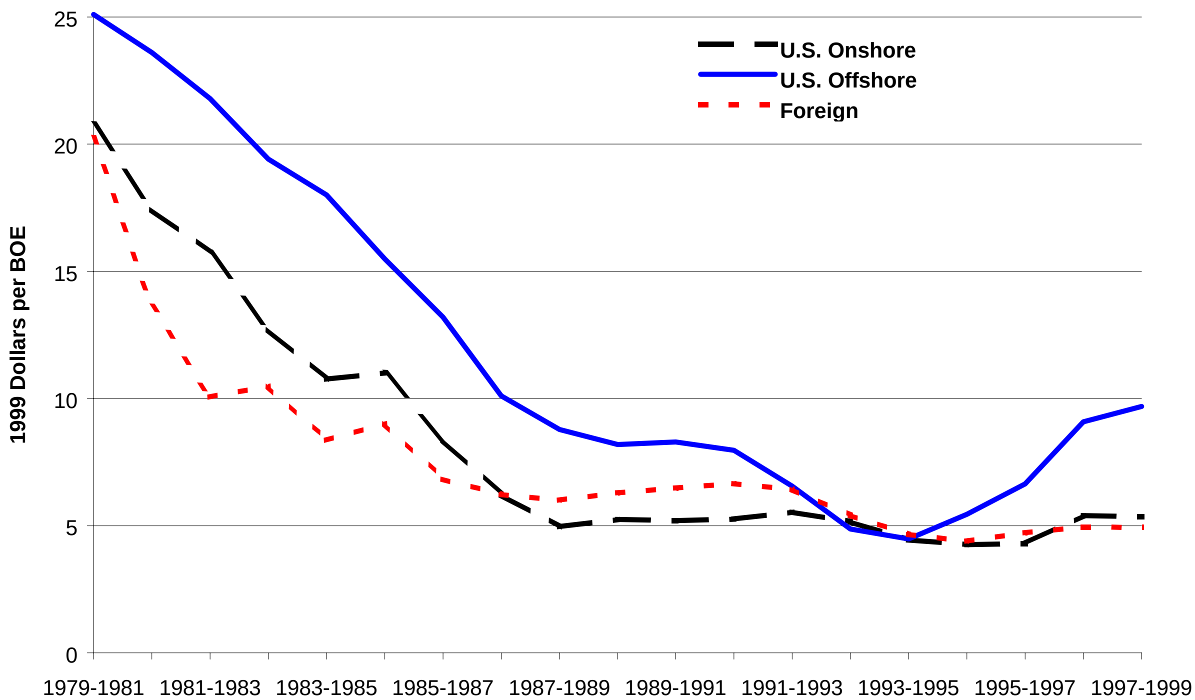
Note: The above figures are 3-year weighted averages of exploration and development expenditures (current dollars), excluding expenditures for proven acreage, divided by reserve additions, excluding net purchases of reserves. Gas is converted to barrels of oil equivalent on the basis of 0.178 barrels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

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

The Middle East and the Other Western Hemisphere regions had large increases in finding costs in the 1997 through 1999 period (Table 20). About two-thirds of the increase in Middle East finding costs was due to Occidental Petroleum's downward revision of its oil reserves in Qatar in 1999. However, these two regions are still among the regions with the lowest finding costs for the FRS companies. Reflecting the movement of exploration and development activities to increasingly deeper waters in the Gulf of Mexico, the U.S. offshore continued to be the region with the highest finding costs, $9.55 per BOE. Two regions, Canada and the Former Soviet Union and Eastern Europe, which were among the four highest cost regions in the previous period, had substantial decreases in finding costs.

In the longer term, finding costs have been increasing in recent years, especially in the U.S. offshore (Figure 24). While U.S. onshore and foreign finding costs have risen about $1 since 1994, U.S. offshore finding costs have risen nearly $6. Nonetheless, finding costs are still lower than they were in the 1980's (in constant dollars). Whether U.S. offshore finding costs will again level off or decline depends, as it does for all regions, on the extent to which new technologies and improvements in exploration and development operating practices can offset the increased costs of finding more oil and gas. For the U.S. offshore, improvements in operating practices may be especially significant, as companies gain more experience in operating in the deepwater arena.

Figure 24. U.S. Onshore, U.S. Offshore, and Foreign Finding Costs for FRS Companies, 1979-1981 to 1997-1999



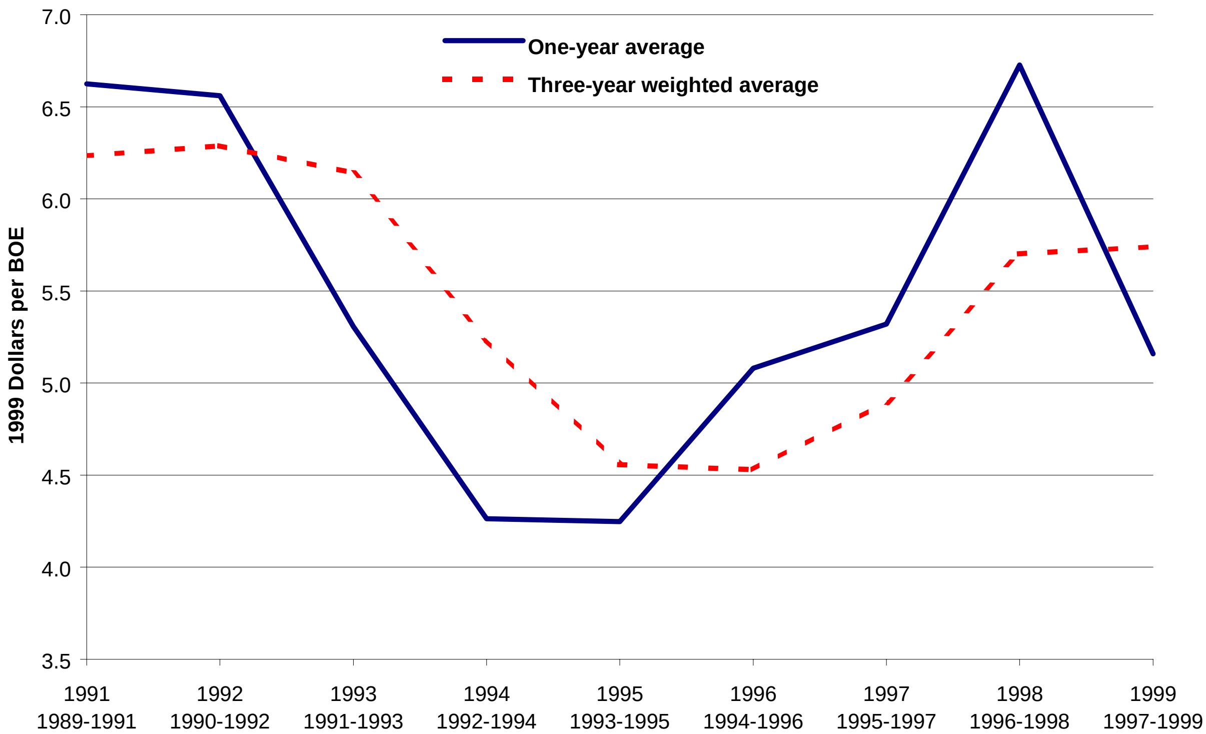
Note: Finding costs are weighted averages of the annual finding costs for the three years specified.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

For a closer look at the most recent changes in finding costs, it may be useful to look at one-year values instead of three-year weighted averages.[c] Although worldwide three-year weighted average finding costs increased slightly in the most recent period, worldwide one-year finding costs fell substantially in 1999 (Figure 25).

This is the first year since 1994[d] that worldwide one-year costs have decreased, and they fell by about $1.50 per BOE in 1999 dollars. Part of the decline, which more than offset the large increase in 1998, was caused by the higher crude oil price at the end of 1999. The higher prices in late 1999 did not require that some proved reserves of crude oil be revised downward, as did the lower prices at the end of 1998.[e] Evidence of this effect is provided by changes in reserves of crude oil by the FRS companies in 1999. Changes in reserves due to revisions increased 131 million barrels, while reserve additions due to improved recovery methods and extensions and discoveries declined. Another part of the decline in finding costs in 1999 resulted from a decrease in exploration and development expenditures (excluding the acquisition of proved acreage) by the FRS companies of $12 billion.

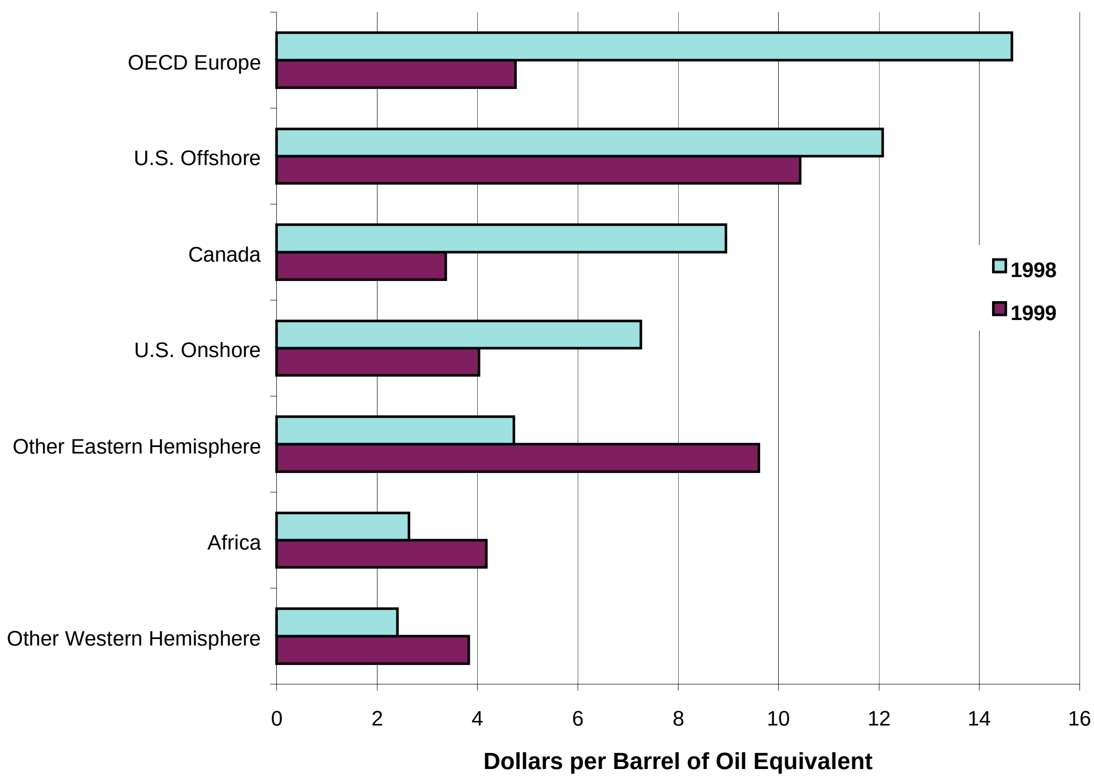
Changes in one-year finding costs varied widely by region. The four regions with the highest one-year finding costs in 1998 experienced decreases ranging from under $2 per barrel in the U.S. offshore to nearly $10 in Europe (Figure 26). For all of these regions except the U.S. offshore, the decline in finding costs in 1999 more than offset the increase in finding costs in 1998. Three of the regions with declining finding costs, the U.S. onshore, the U.S. offshore, and Europe, were the leading producers of oil and gas for the FRS companies in 1999. The regions with the lowest one-year finding costs in 1998 (excluding the Middle East and the Former Soviet Union and Eastern Europe)[f] registered increases in costs ranging from slightly over $1 per barrel in South American locales to over $4 in Asia-Pacific fields. The finding cost changes in 1999 resulted in a narrower range in finding costs across the regions that year than for 1998.

Figure 25. Worldwide Finding Costs for FRS Companies, 1991-1999



Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).
Note: Finding costs are weighted averages of the annual finding costs for the three years specified.

Figure 26. One-Year Finding Costs for the FRS Companies in Selected Regions, 1998 and 1999



Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

[a] Alternatively, finding costs are the exploration and development costs of replacing reserves removed through production.

[b] One inherent limitation of measuring finding costs this way is that the expenditures and the reserve additions recognized in a particular interval do not always correspond exactly with each other. Expenditures are usually recognized in the period that that the payment actually occurred. Proven reserves are usually recognized when there is reasonable certainty that they can be produced economically. There is no reason that these must always occur in the same time period (oil and gas wells are often operated for a long time), so that some expenditures may not be recognized in the same time period that their corresponding reserves are recognized. One way to moderate this limitation is to increase the length of the time period over which finding costs are measured, allowing reserve additions and exploration and development expenditures to match up more closely. However, the longer the time period over which finding costs are measured, the more out of date they become, because they include ever earlier expenditures and reserves, and costs and technology are constantly changing. The only way to solve the correspondence problem would be to calculate an average finding cost for all of the oil and gas produced by a well after it is permanently shut in. But then many costs included would be far out of date.

[c] Because of the leads and lags between expenditures and reserve additions (see previous endnote), one-year finding costs tend to vary more from year to year than three-year finding costs. Because of their higher variability (see Figure 25), one-year finding costs must be interpreted more cautiously. However, because one-year finding costs employ only the most recent annual data, one-year costs can anticipate longer-term trends in finding costs earlier than three-year costs.

[d] Worldwide one-year finding costs fell only $0.01 in real 1999 dollars in 1995.

[e] See the Special Topic entitled "Reserve Revisions Add to Finding Cost Woes" in Energy Information Administration, *Performance Profiles of Major Energy Producers 1998,*
http://www.eia.doe.gov/emeu/perfpro/chapter4.html (December 1, 1999) for a discussion of the reserve revisions for 1998.

[f] The Middle East region is excluded from this discussion because its finding costs were negative in 1999. This is the result of Occidental Petroleum revising its estimate of proved oil reserves in Qatar downward by 87 million barrels in 1999 pursuant to its production sharing agreement (Occidental Petroleum, *1999* Securities and Exchange Commission, Form 10-K, online, http://www.sec.gov (November 29, 2000). The Former Soviet Union and Eastern Europe region is excluded because of the limited activities of the FRS companies there.

SPECIAL TOPIC: *Exploration and Development in Sub-Sahara Africa Proceeds Despite Turmoil*

According to the United States Geological Survey, Sub-Sahara Africa's endowment of undiscovered oil and gas resources is believed to exceed 100 billion barrels of oil equivalent or more than 5 percent of the current worldwide reserves total.[a] Until the 1990's, however, the continent of Africa had historically captured less than 5 percent of the FRS companies' budgets for exploration and development.

At least two factors account for this apparent lack of investment attraction. First, the marketability of Africa's natural gas (which accounts for a large portion of the continent's undeveloped resources) is questionable given the general lack of the required pipeline infrastructure. Second, and perhaps more importantly, the investment climate in many of the potential exploration and development areas has suffered as a result of the region's almost constant state of turmoil over the past few decades.

Despite these factors, Africa's appeal as a target for exploration and development has led the FRS companies to substantially increase their exploration and development spending in Africa in recent years. Africa's share of the FRS companies' worldwide exploration and development expenditures steadily increased from 4 percent in 1990 to 11 percent in 1999. Spending for Africa in 1999 was more than twice as great in real terms than in 1990. Some of the countries in which the FRS companies (highlighted in italics) are currently active are discussed below.

Nigeria

Nigeria is Africa's largest oil producer. Production averaged 2 million barrels per day (bpd) in 1999. Almost all of its 22.5 billion barrels of proven reserves are located along the country's volatile Niger River Delta. This oil-rich region is one of Nigeria's poorest as a result of policies under the previous military government that diverted the country's oil wealth to the northern part of the country. Protests over these policies and the region's oil-related environmental degradation have resulted in disruptions in oil production. Pipeline explosions caused by illegal fuel siphoning have also disrupted production. The cumulative losses resulting from the disruptions are estimated to be over one billion dollars.

The new civilian government headed by President Olusegun Obasanjo would like to increase oil production capacity to 3 million bpd by 2003 and to 5 million bpd by 2010. To accomplish this production goal, Nigeria plans to develop new fields to raise its proven oil reserves to 40 billion barrels by 2010. To help meet this goal, the government in early 2000 opened bidding for 22 oil blocks, including 11 in deep waters.

Projects that may facilitate the meeting of this goal include:

- Erha. The discovery well for this field was drilled in late 1999. The field is being developed by *ExxonMobil* (operator with a 56.25 percent interest) and Royal Dutch/Shell (43.75 percent). The field's estimated recoverable oil is in excess of one billion barrels.
- Agbami. This field has potential recoverable reserves of more than one billion oil-equivalent barrels. The field is being developed by *Texaco* (32 percent interest), Fafma, an independent Nigerian oil company (60 percent) and Braspetro, (8 percent).
- Bonga. This field is about 60 miles off the southern coast of Nigeria in around 3,000 feet of water. A consortium composed of Royal Dutch/Shell (operator), *ExxonMobil*, Agip, and TotalFinaElf is developing the project. The field has estimated recoverable reserves of 600 million barrels. *Shell* has indicated it will spend $1.8 billion over the next four years to develop the field, which is projected to start production in the second quarter 2003 and hit 200,000 bpd output in 2004.
- Era. This field is located near Bonga. *ExxonMobil* has drilled two wells, Era 1 and Era 2. The results showed recoverable reserves of at least 600 million barrels.

Nigeria has also been making a concerted effort to market its natural gas resources. Until recently, about 65 percent of the gas that was produced had no market and thus was flared at the wellhead. The government wants to reduce gas flaring to zero by the year 2008. To meet this goal, the government has endorsed the proposed West African Gas Pipeline Project, which would supply Nigerian gas to Ghana, Benin, and Togo. The pipeline project is being advanced by a consortium of six companies whose members include *Chevron*, Royal Dutch/Shell, Ghana National Petroleum Corp., Nigerian National Petroleum Corp., Societe Beninoise de Gaz S. A., and Societe Togolaise de Gaz S. A..

Nigeria has long sought to export its natural gas as liquefied natural gas (LNG). This ambition became a reality with the September 1999 startup of its $3.8-billion LNG plant at Bonny Island in southeastern Nigeria. The first exports of LNG were scheduled to commence shortly thereafter, but indicative of the tenuous nature of operating in Nigeria, the plant was forced to shut down later in the month as a result of a blockade by protestors who laid siege to the plant to demand money and jobs. The plant has since commenced exports. The plant is capable of processing over 250 billion cubic feet (Bcf) of gas annually. The plant's capacity is currently being expanded to over 380 Bcf per year. A large majority of this LNG comes from natural gas which is produced as a result of oil production, and would typically have been flared.

Angola

Angola has been in a state of almost constant civil war since it achieved independence from Portugal in 1975. Despite this strife, oil production has more than quadrupled since 1980, averaging 766,000 bpd in 1999. Because of this upward trend, Angola is sub-Sahara Africa's second largest oil producer and was the eighth largest supplier of crude oil to the United States in 1999. The Angolan government expects that oil production will increase to 1 million bpd by the end of 2001 and to 1.4 million bpd by 2003.

A hydrocarbon law passed in 1978 made Sonangol, Angola's national oil company, sole concessionaire for exploration and production. In late 1999, Sonangol announced that more than $18 billion in foreign oil investment was being lined up over the next four years. Some of the projects under development include:

- Block 15**.** This block is located in the eastern Atlantic Ocean, off the mouth of the Congo River. The consortium of companies developing the block includes *ExxonMobil* (the operator, with a 40-percent interest), *BP Amoco* (26.67 percent), Agip (20 percent), and Statoil (13.33 percent). The project is believed to have potential recoverable reserves of over two billion barrels.

- Block 17. The consortium exploring this block is comprised of *ExxonMobil* (20 percent), Elf (35 percent), *BP Amoco* (16.67 percent), Statoil (13.33 percent), Norsk Hydro (10 percent), and Fina Exploration (5 percent). In April of 2000, the consortium announced that its Jasmine 1 exploration well had encountered an oil-bearing reservoir that flowed at a test rate of 11,000 bpd.

Chad

In November 1996, a consortium of oil companies, then consisting of *Exxon* (the operator, with a 40-percent interest), Royal Dutch/Shell (40 percent), and Elf (20 percent), signed a memorandum of understanding (MOU) with the government of Chad. The MOU provided the terms of the development of the Doba basin fields, and the construction of a 650-mile export pipeline through Cameroon to offshore export facilities. Membership in the consortium has since changed. Currently, the consortium is comprised of *ExxonMobil* (40 percent), Petronas of Malaysia (35 percent), and *Chevron* (25 percent).

The Doba basin's three fields (Bolobo, Kome, and Miandoun) are projected to produce 900 million to 1 billion barrels of low sulfur oil over 25 to 30 years.

Equatorial Guinea

In less than a decade, Equatorial Guinea has been transformed from a largely insignificant producer to one of the hottest areas for exploration and development in the world. Oil production has risen from 17,000 bpd at the end of 1996 to over 90,000 bpd in 1999. Moreover, given the prospects that are currently being explored and developed, there is every reason to believe that production could triple within the next few years. Some of fields responsible for Equatorial Guinea's new status are:

- Zafiro. *Mobil* (now *ExxonMobil*) discovered this field in 1995. The field has been estimated to contain ultimate recoverable resources of more than 400 million barrels of oil. *ExxonMobil* is the operator with a 71.25-percent interest. The remaining ownership interests are accounted for by Ocean Energy (23.75 percent) and the Equatorial Guinea government (5.00 percent).

- La Ceiba. This deepwater field was discovered in late 1999. It is believed to contain 300-500 million barrels of recoverable oil. The U.S.-based firm Triton has an 85-percent working interest in the licenses and is the operator. Its partner in the project is South Africa-based Energy Africa Ltd., which has a 15-percent working interest.

[a] U.S. Geological Survey, *World Petroleum Assessment 2000.*

SPECIAL TOPIC: *New Investment Opportunities Created by the Opening of Brazil's Petroleum Sector*

In 1953, citing the nationalist slogan "The Oil is Ours," Brazilian policymakers enacted legislation that created the state-owned company Petrobras. To ensure its success, the company was granted a monopoly over oil and natural gas resource development. However, despite Brazil's rich endowment of oil and gas resources of over 80 billion barrels of crude oil equivalent, most of the country's sedimentary basins have remained largely unexplored with the result being that Brazil has remained a net oil importer of around 400,000 bpd.[a]

The deficit between the country's domestic production and its demand would have been far larger had Brazil not subsidized its ethanol producers,[b] thus lowering the price of ethanol and increasing its consumption while simultaneously diminishing the amount of crude oil needed to produce motor gasoline.

In 1995, with the end of the ethanol subsidies being seen as inevitable,[c] it became increasingly clear that Petrobras was unable to fully explore and develop the country's petroleum resources. Recognizing that this lack of adequate exploration and development activity was likely to result in insufficient new reserves to meet near-term domestic demand (much less enable Brazil to become a net exporter), Brazil enacted a 1995 Constitutional Amendment ending Petrobras' state-sanctioned monopoly. Two years later, the government created the National Petroleum Agency (ANP), the regulatory agency responsible for overseeing the process of opening up the country's petroleum industry.

In July 1998, ANP announced that more than 92 percent of the nation's sedimentary basins were to be put up for competitive bidding. The first bidding round occurred in June 1999, when ANP sold the exploration rights to 12 of the 27 blocks being tendered for a total of $183 million.[d] More would have probably been bid except for the fact that the awards were made on a point system that gave preferences to firms based on their commitments to use Brazilian goods and services. These blocks, which are extremely large (the average size of each area is 1,800 square miles, equivalent to 225 blocks in the Gulf of Mexico), were sold to 10 foreign firms, as well as to Petrobras, which won 5 of the 12 blocks. The foreign companies (including some FRS companies, highlighted in italics) who submitted winning bids either individually or as part of a consortium were Agip (4 blocks), YPF (4 blocks), *Texaco* (3 blocks) *ExxonMobil* (2 blocks), *Shell* (1 block), *Amerada Hess* (1), *Unocal* (1), and *Kerr-McGee* (1).

Two-thirds of the bids were for the highly coveted Santos and Campos basins in the deep waters off Brazil's South Atlantic coast. In a few cases, the companies were somewhat exuberant in their bidding. For example, Agip submitted a winning bid of almost $79 million ($40 per acre) or almost half the entire total amount bid in round one on Santos Block BM-S-4. The next highest bids for this block were by BG Group, PLC (the Brazilian subsidiary of British Gas) and a joint venture between *Kerr-McGee* and *Amerada Hess* for approximately $12 million and $5 million, respectively. Agip also submitted a winning bid of $30 million ($42 per acre) for Campos Block BM-C, the second most expensive block. The bids by the other firms were more modest with an average cost of approximately $15 per acre. For example, *Texaco* won Santos Block 2 and Campos Block 5 for a mere $8 and $7 per acre, respectively.

The second licensing round was concluded in June 2000. This round offered 23 blocks in nine sedimentary basins, including Campos, Amazonas, Camamu-Almada, Parana, Para-Maranhao, Potiguar, Reconcavo, Sergipe-Alagoas, and Santos. In contrast to the first round, the second round included smaller blocks intended to be more attractive to smaller oil companies. There were also a wider variety of blocks available, including onshore, shallow offshore, deep offshore, mature, and unexplored blocks.

The second round has been hailed as more successful than anticipated, except for the fact that there was little participation from the large foreign integrated oil companies such as the FRS companies. Despite their absence, the bidding by small independent U.S., Canadian, European, and Brazilian companies earned $261 million for ANP, up more than 40 percent from the $183 million earned in the first round.[e] The Campos and Santos Basin blocks generated the most interest, receiving as many as four bids. Only two blocks received no bids.

To help develop its large stock of acreage, Petrobras has signed about a dozen oil development partnership agreements with private companies, including agreements with some of the companies in the FRS group. Specifically, in October 1998, Petrobras signed its first upstream participation agreement with a U.S. firm when it agreed to partner with *Coastal* and two other firms to begin operations in the offshore Camamu Basin. In 2000, Petrobras signed joint venture agreements with *Coastal*, *Chevron*, *Texaco*, *Shell*, *ExxonMobil*, and Repsol YPF. Because of these agreements and the two blocks it won in the Round 1, *ExxonMobil* now has 8 blocks covering 25 million acres, which makes it the largest non-governmental holder of deepwater Brazilian acreage.

While the opening of the petroleum sector has stripped Petrobas of its former monopoly position, the government of Brazil has vowed not to privatize the company. However, it may not need to privatize. The government has restructured the Petrobras board so as to make the firm more market oriented. Moreover, the government put

28.48 percent of the company's voting stock on the market. While the stock offering received a somewhat lukewarm response among Brazilian workers, it was able to raise $2.5 billion in American Depository Receipts (ADR) sales on the New York Stock Exchange in August of 2000. Reflecting its new orientation, Petrobras announced a sweeping internal restructuring in November of 2000 which it hopes will help it compete in the new environment.[f]

Round 3 of the process is scheduled to be completed by mid-2001. In this round, the ANP will be offering ten onshore and 43 offshore blocks.[g] Most of the offshore blocks are in deep or ultra-deep waters, where production remains a major challenge for all but the most technologically advanced firms.

While it is much too early to judge whether the opening up of Brazil's petroleum sector will be a success, the early indications are promising. *Shell* has recently confirmed that "traces of petroleum" have been discovered in BC-10, an offshore block in the Campos Basin located about 80 miles off the coast of the state of Espiritu Santo. While the size of the discovery has yet to be certified, preliminary results indicated that the field could exceed 500 million barrels.[h] More recent information, however, has indicated that the field could be far smaller.[i] *Shell* has a 35- percent interest in the block. Its partners are Petrobras (35 percent) and *ExxonMobil* (30 percent). *Coastal* recently announced that it has discovered natural gas on its BPAR-10 block, which is located onshore, southeast of Sao Paulo.[j] In other news, *ExxonMobil* and its partners plan on drilling 12 wells by August 2001.

Regardless of the results of drilling over the short run, by bringing 10 international oil companies to the country through an opening of its upstream oil and gas sector, Brazil has transformed the region into one of the hottest exploration areas in the world. While Petrobras still dominates Brazil's petroleum industry, the demise of its monopoly position and the sale of almost 30 percent of its voting shares to outside investors all but ensures that Brazil's petroleum sector over the next 47 years will be vastly different than over the past 47 years.

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[a]This estimate is based on USGS' mean estimates for oil and gas. Gas was converted to its oil equivalent using the conversion factor of 0.178 thousand cubic feet of natural gas per barrel of oil. See USGS World Petroleum Assessment 2000 – Project

[b]Approximately 23 percent of Brazil's energy consumption is accounted for by its transportation sector. Slightly more than 40% of Brazil's transportation fuel demand is met with ethanol. For more information on Brazil's energy consumption and production, see the Energy Information Administration's Brazil country brief (Environment Section) at http://www.eia.doe.gov/emeu/cabs/brazenv.html#renewable (December 13, 2000).

[c]On November 1, 1999, all price subsidies paid to ethanol were eliminated. Even so, 41 percent of Brazil's transport fuel demand is supplied by ethanol.

[d]For complete details on Round 1, see "Brazil Oil and Gas Round 1" at http://www.brazil-round2.com/HTML/Winning_en.htm (December 13, 2000).

[e]For complete details on Round 2, see "Brazil Round 2" at http://www.brazil-round2.com/Idocs/Iinicial/Iframe01.htm (December 13, 2000).

[f]See " Petrobras to restructure for better international position" *Alexander's Gas and Oil Connections*, Volume 5, issue #21 - Thursday, November 16, 2000.

[g]For more information on Round 3, see "Brazil Round 3" at http://www.brazil-round3.com/round3/idocs/index_english.htm (December 13, 2000).

[h]See The Institute of Petroleum, "Petroleum Review-News in Brief" (September 23-30, 2000) at http://www.petroleum.co.uk/prnib_sept2000_04.htm

[i]"ExxonMobil's Thompson: Latin oil potential appealing-if terms are right" *Oil and Gas Journal*, October 30, 2000. http://ogj.pennnet.com/Content/cd_anchor_article/1,1052,OGJ_7_NEWS_DISPLAY_83524_2,00.html

[j]See Coastal Corp., "Coastal Confirms Gas Shows in Brazilian Well" (Nov. 8, 2000) at http://www.coastalcorp.com/news/2000/001109.html (December 13, 2000).

SPECIAL TOPIC: *Alaskan North Slope Gas: From Stranded Asset to a Prize of the Decade*

Alaska's North Slope contains the largest undeveloped natural gas resources in North America. The State of Alaska estimates that the region's gas reserves are approximately 31 trillion cubic feet (Tcf).[a] According to the United States Geological Survey, there are an additional 63.5 Tcf of undiscovered gas resources on the North Slope.[b] The FRS companies BP Amoco, ExxonMobil, and Phillips Petroleum own the vast portion of these resources.[c]

For much of the past decade, the Alaskan North Slope (ANS) gas has largely been considered a stranded asset due to the lack of transportation infrastructure. However, the decline in oil production from Alaska's Prudhoe Bay combined with changes in technology, ownership, and market conditions have prompted a reconsideration of the resource's value. Currently, more than 6 billion cubic feet (Bcf) of ANS gas is produced and then reinjected each day (up from one Bcf in 1981) so as to enhance oil production.[d] With Prudhoe Bay oil production declining at approximately 10 percent per year, the time will eventually come when separating and reinjecting these large quantities of natural gas will no longer be economical. In addition, changes in technology now make it possible to convert the gas to a liquid, which could then be transported to market using the existing pipeline infrastructure.

Decisions about the development of Alaskan North Slope gas were previously complicated by the fact that the ownership of the gas resources did not match either the ownership of the producing infrastructure or the ownership of the oil reserves. With the realignment in ownership interests following the merger between BP Amoco and ARCO in 2000, the gas ownership on the North Slope is almost split evenly among ExxonMobil, BP Amoco, and Phillips Petroleum. This realignment significantly simplifies the process of selecting the development option that maximizes the value of the resource. Finally, economic growth, environmental regulations, and cost conditions that favor the use of gas in power generation have led forecasters to significantly increase their projections of future natural gas demand in the United States. For example, as recently as 1995, EIA projected that the U.S. demand for natural gas would be approximately 25 Tcf in 2010.[e] It now believes that demand in 2010 will be around 28 Tcf and will rise to over 32 Tcf by 2020.[f]

Based on the above factors, it is now fairly clear that one or more of the following development options is likely to be selected within the next few years:

- <u>Liquefied Natural Gas (LNG)</u>. Under this option, a pipeline parallel to the existing Trans Alaska Pipeline System (TAPS) would be constructed. The gas would be liquefied at the pipeline's terminus and exported to Asia.

- <u>Gas-to-Liquids (GTL)</u>. Despite the start-up of several new oil fields on the North Slope, Alaskan oil production has continued to decline by about 10 percent per year. Under some projections, the oil flow through the existing oil pipeline could fall below its estimated minimum economic flow of 200,000 to 400,000 barrels per day within 20 years. Chemically converting the natural gas into a liquid (using the emerging GTL technology) would not only monetize the gas, it would also delay the day by over 25 years when the remaining North Slope oil reserves are "shut-in" due to subeconomic pipeline utilization.

- <u>A Pipeline to the Lower-48 States</u>. Under this option, the gas would be piped to the lower-48 states via Canada. The projected cost of this option is approximately $2.00 per thousand cubic feet (Mcf) of transported gas.[g] At this level of costs, the project would be subeconomic given the natural gas prices of just one year ago. The project is considered economically viable, however, at any price over $5.00 per Mcf for gas delivered to the lower 48 states.

Just three years ago, most analysts believed that the LNG option would be selected.[h] However, recent advances in GTL technology, the merger between BP Amoco and ARCO, the increasingly competitive Asian LNG market, the economic situation in Japan, and the growth in demand for gas in the lower-48 states with the consequent rise in wellhead prices have all served to lessen the relative attractiveness of this option.

Liquefied Natural Gas

Some of the proposed liquefied natural gas projects include:

- TAGS (Trans Alaska Gas System). In November 1989, the U.S. Department of Energy authorized Yukon Pacific to export 660 Bcf per year of LNG from Alaska to Japan, South Korea, and Taiwan over a period of 25 years. As proposed in 1987, this project would have encompassed a proposed intrastate, 800-mile pipeline, the TAGS, to transport Alaskan North Slope gas to Valdez on Alaska's southern coast, along with the liquefaction plant, marine terminal and 12 to 15 vessel tanker fleet. The pipeline would parallel the existing oil pipeline. At the time of its original application to the Department of Energy, Yukon Pacific indicated that it expected LNG exports to begin in 1996. Today, although it holds State and Federal permits, Yukon Pacific has not yet secured gas supplies or market commitments, and there is no timetable for construction.

- The Alaska North Slope LNG Project. The Alaska North Slope LNG Sponsor Group was formed in late 1998 to develop a commercially competitive Alaskan LNG project for the East Asian market. Phillips Alaska, Inc., BP Exploration (Alaska) Inc., Foothills Pipe Line, Ltd., and Marubeni Corporation are the project sponsors. The group has completed a "Stage 1" feasibility study of a 7-million-ton per year, $7-billion project involving an LNG export facility either on the Cook Inlet or in the Port of Valdez. The "Stage 2" effort will focus on reducing the project's costs so as to make it competitive with projects in Australia and Indonesia.

Gas-to-Liquids

The proposed gas-to-liquids projects include:

- BP Amoco's GTL Project. Under current technology, about half the capital cost of a GTL facility is accounted for by the reformer that is needed to make synthetic gas from natural gas. BP Amoco has developed a reformer that is much smaller and thus more cost efficient. Moreover, BP Amoco's technology is also anticipated to reduce the energy that is lost when the gas is converted into a liquid. In an effort to test its technology, BP Amoco unveiled its plans in June 2000 for an $86-million GTL test plant on Alaska's Kenai Peninsula. This plant would initially use 3 MMcf per day of gas to produce 300 barrels per day of diesel and jet fuel.[i] The facility is due to begin operations in the second quarter of 2002.

The Pipeline Option

There are three primary options for transporting Alaskan North Slope gas: the Alaska Natural Gas Transportation System (ANGTS), a pipeline route across northern Canada, and the central pipeline route.

The Alaska Natural Gas Transportation System (ANGTS). In September 1977, President Carter and the U.S. Congress approved a proposal for a transportation system known as the Alaska Natural Gas Transportation System, or ANGTS. The proposal envisioned a nearly 5,000-mile joint U.S.-Canadian overland pipeline capable of delivering up to 2.5 billion cubic feet of gas per day to markets in the lower 48-states (Figure 27). Portions of ANGTS have already been constructed. Over 2,600 miles of the system is in place along two legs from Alberta, Canada into the lower-48 states. Moreover, the statutory framework, including the agreement on principles between the U.S. and Canada, still exists. However, because of the time elapsed since the authorizations were granted, the environmental reviews may have to be revisited. Cost estimates for the unbuilt segments range from $7 to $11 billion.

The Northern Gas Pipeline Project. Arctic Resources Co.'s Northern Gas Pipeline Project would run eastward from Prudhoe Bay and come ashore in the Mackenzie Delta area in northern Canada. It would then follow the Mackenzie River south through the Northwest Territories to interconnect with pipelines in Alberta, Canada which would then move the gas to the market in the lower-48 states. In the eyes of some, the advantage of this option is that it could tap the 12 Tcf of otherwise stranded gas resources in Canada's Mackenzie Delta. Another advantage is that the route is generally considered to be the least expensive, with costs as low as $5 to $6 billion. A disadvantage is that a portion of the pipeline would lie offshore in the environmentally sensitive waters of the Beaufort Sea where the ice has been known to scour the sea floor.

Figure 27. Various Proposals to Transport Canadian Arctic and Alaskan North Slope Natural Gas To Markets

Source: T.J. Glauthier, Deputy Secretary, U.S. Department of Energy, "Testimony to the Senate Committee on Energy and Natural Resources" (September 14, 2000)

The Central Pipeline Route. This route would follow the ANGTS route to just below the Arctic National Wildlife Refuge and then travel southeast through the Yukon Flats National Wildlife Refuge into the Northwest Territories and south through the Mackenzie River Valley into Alberta. The route would avoid the environmental problems of the northern route. It would also facilitate the exploitation of the gas resources in Canada's Mackenzie Delta.

In the eyes of most analysts, BP Amoco (with its huge Alaskan North Slope gas ownership interests) is the key decision-maker. The company's chief executive officer has disclosed that the LNG option faces major obstacles given the current state of the LNG market in Asia. The company has also indicated that it is "aggressively planning" a $10-billion Alaska to Alberta line (with the exact route as yet undetermined) that would have a capacity of 4 Bcf per day.[j] The project's evaluation is expected to be completed by the end of 2000 with the pipeline itself possibly being completed by 2006 to 2007.[k]

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[a]State of Alaska, Department of Natural Resources, *Historical and Projected Oil and Gas Consumption, May 1999* p. 3.
[b]The mean estimate is 63.5 Tcf. See D.L. Gautier, et. al., "1995 National Assessment of United States Oil and Gas Resources – Results, Methodology, and Supporting Data." USGS Digital Data Series DDS-30, Release 2, 1996.
[c]Because of the current lack of a market for the gas, the 31 Tcf of "reserves" are not considered proved and hence are not reflected in the companies' financial statements or EIA's annual reserves report.
[d]T.J. Glauthier, "Testimony to the Senate Committee on Energy and Natural Resources" September 14, 2000. See http://energy.senate.gov/hearings/full_committee/ak_naturalgas/glauthier.htm for the full testimony.
[e]Energy Information Administration, Annual Energy Outlook 1995, DOE/EIA-0383 (95) (January 1995 Washington D.C.). GRI, DRI, and AGA's forecasts of 2010 end-use demand were similar to EIA's.
[f]See Energy Information Administration, Annual Energy Outlook 2000, DOE/EIA-0383(2000). This report is available on the Internet at http://www.eia.doe.gov/oiaf/aeo/index.html.
[g]See "Statement of Robert A. Malone—Regional President, Western U.S. BP to U.S. Senate Energy Committee," September 14, 2000. This testimony is available on the Internet at http://www.bp.com/alaska/bpamoco/testimony.htm.
[h]For example, see "Alaska gas pipeline to Asia could be Feasible," Alexander's Oil and Gas Connections, Volume 3, issue #7, March 12, 1997.
[I]"BP Amoco Gives Go-Ahead For Gas-To-Liquids Test Facility," BP Amoco Press Release, June 27, 2000.
[j]"BP Considers Building Artic Gas Pipeline," Alexander's Oil and Gas Connections, Volume 5, issue #19, October 18, 2000.
[k]ibid.

Appendix A

The Financial Reporting System (FRS)

Appendix A
The Financial Reporting System (FRS)

The legislation establishing the Financial Reporting System (FRS) requires the reporting of individual company financial and operating data to be on a "uniform and standardized basis" so that the data can be aggregated and comparisons can be made across companies and groups of companies.

The legislation also required the EIA to consult with the U.S. Securities and Exchange Commission in an effort to be consistent with other Federal financial accounting practices.

Accordingly, the FRS reporting form (Form EIA-28) necessarily incorporates a number of specific energy financial accounting principles and conventions. Details on these financial accounting concepts and principles can be found on the Energy Information Administration's Worldwide Web site at http://www.eia.doe.gov/emeu/perfpro/appenda.html. In particular, the interested reader is referenced to the following subheadings:

- *Survey Format* (see http://www.eia.doe.gov/emeu/perfpro/appenda.html#rptfrmt),
- *Petroleum Segment Overview* (see http://www.eia.doe.gov/emeu/perfpro/appenda.html#petovw),
- *Selection of Reporting Companies* (see http://www.eia.doe.gov/emeu/perfpro/appenda.html#criteria),
- *Financial Analysis Guide* (see http://www.eia.doe.gov/emeu/perfpro/appenda.html#faguide),
- *Accounting Practices* (see http://www.eia.doe.gov/emeu/perfpro/appenda.html#acctpr).

Appendix B

Detailed Statistical Tables

Table B1. Selected U.S. Operating Statistics for FRS Companies and U.S. Industry, 1993-1999

Operating Statistics	1993	1994	1995	1996	1997	1998	1999
Petroleum and Natural Gas							
Net Production							
Crude Oil and Natural Gas Liquids (million barrels							
FRS Companies	1,632.5	1,593.8	1,570.6	1,532.4	1,458.8	1,388.8	1,305.7
U.S. Industry[1]	3,127.0	3,059.0	3,004.0	3,023.0	3,002.0	2,824.0	2,848.0
FRS as a Percent of U.S. Industry	52.2	52.1	52.3	50.7	48.6	49.2	45.8
Natural Gas (billion cubic feet)							
FRS Companies	7,651.1	7,998.4	8,055.3	8,191.6	8,299.1	8,395.9	7,994.1
U.S. Industry[1]	17,789.0	18,322.0	17,966.0	18,861.0	19,211.0	18,720.0	18,928.0
FRS as a Percent of U.S. Industry	43.0	43.7	44.8	43.4	43.2	44.8	42.2
Net Imports							
Crude Oil and Natural Gas Liquids (million barrels							
FRS Companies	757.5	754.1	612.1	565.7	571.1	634.7	474.9
U.S. Industry[1]	2,640.9	2,788.7	2,810.0	2,946.6	3,191.0	3,358.5	3,366.4
FRS as a Percent of U.S. Industry	28.7	27.0	21.8	19.2	17.9	18.9	14.1
Refinery Capacity (thousand barrels per day)							
FRS Companies	10,714.0	10,642.0	10,427.0	10,477.0	9,410.0	14,277.0	14,158.0
U.S. Industry[1]	15,718.0	16,069.3	15,981.0	16,031.8	16,128.7	16,567.0	16,787.0
FRS as a Percent of U.S. Industry	68.2	66.2	65.2	65.4	58.3	86.2	83.7
Refinery Output[2] (thousand barrels per day)							
FRS Companies	10,822.0	10,812.0	10,652.0	10,954.0	10,030.0	14,929.0	14,639.0
U.S. Industry[1]	16,341.2	16,341.1	16,534.7	16,800.7	17,234.3	17,499.6	17,493.1
FRS as a Percent of U.S. Industry	66.2	66.2	64.4	65.2	58.2	85.3	83.7
Coal Production							
(million tons)							
FRS Companies	197.3	179.7	165.4	169.4	163.3	73.9	44.0
U.S. Industry[1]	941.1	1,028.9	1,028.3	1,059.1	1,085.3	1,112.9	1,099.1
FRS as a Percent of U.S. Industry	21.0	17.5	16.1	16.0	15.0	6.6	4.0

[1] U.S. area is 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.

- = Not available.

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 (Annual Survey of Domestic Oil and Gas Reserves); see U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1999 Annual Report November 2000). 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 2,959 million barrels in 1999 and 3,063 million barrels in 1998. (See Energy Information Administration, Petroleum Supply Annual 1999, Volume I (June 2000), p. 2.) For dry natural gas production, the official Energy Information Administration U.S. totals are 18,709 billion cubic feet in 1999 and 18,708 billion cubic feet in 1998. 2000, p. 8.)

Sources: Industry data - Petroleum net production: Energy Information Administration, Form EIA-23; see U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1999 Annual Report (November 2000). 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 (Annual Refinery Report) and EIA-810 (Monthly Refinery Report); see Petroleum Supply Annual, 1998 and 1999. Coal production: 1993-1998--EIA, *Coal Industry Annual* , annual reports; 1999--EIA estimates and *Quarterly Coal Report October-December 1999* (May 2000), Table 4.

Table B2. Selected Financial Items for the FRS Companies and the S&P Industrials, 1998-1999
(Billion Dollars)

Selected Financial Items	FRS Companies		S&P Industrials	
	1998	1999	1998	1999
Income Statement				
Operating Revenues	484.2	578.2	3,923.5	4,253.7
Operating Expenses	-468.3	-546.0	-3,502.6	-3,770.6
Operating Income	15.9	32.2	420.9	483.0
Interest Expense	-7.3	-8.7	-80.6	-84.3
Other Income[1]	8.6	10.2	35.5	47.2
Income Taxes	-4.7	-10.8	-120.6	-155.3
Net Income	12.5	22.9	255.1	290.6
Cash Flows from Operations[2]				
Net Income	12.5	22.9	255.1	290.6
Other Items, Net[3]	35.6	31.9	196.7	242.4
Net Cash Flow from Operations	48.2	54.8	451.8	533.0
Cash Flows from Investing Activities[2]				
Additions to PP&E	-69.9	-50.7	-311.7	-302.6
Other Investment Activities, Net[4]	15.3	9.9	-115.4	-200.7
Net Cash Flow from Investing Activities	-54.7	-40.8	-427.1	-503.3
Cash Flows from Financing Activities[2]				
Proceeds from Long-Term Debt	27.1	29.9	372.4	412.9
Proceeds from Equity Security Offerings	9.1	3.6	43.1	54.4
Dividends to Shareholders	-17.2	-16.1	-90.8	-90.9
Reductions in Long-Term Debt	-18.0	-25.0	-254.1	-283.5
Stock Repurchases	-5.8	-0.4	-120.7	-115.5
Other Financing Activities, Net	6.9	-3.4	24.9	34.7
Net Cash Flow from Financing Activities	2.1	-11.5	-25.3	12.1
Effect of Exchange Rate Changes on Cash	0.0	0.0	0.4	-2.4
Increase (Decrease) in Cash and Cash Equivalents	-4.4	2.5	-0.2	39.4

[1] "Other Income" includes other revenue and expense (excluding interest 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.

Sources: Standard & Poor's (S&P) Industrials data - Compustat PC Plus, a service of Standard & Poor's. FRS companies' data - Energy Information Administration, Form EIA-28 (Financial Reporting

Table B3. Balance Sheet Items and Financial Ratios for FRS Companies and S&P Industrials, 1998-1999

	FRS Companies		S&P Industrials	
	1998	1999	1998	1999
Balance Sheet	(billion dollars)			
Assets				
Current Assets	94.2	121.0	1,148.1	1,265.4
Noncurrent Assets				
Property, Plant, and Equipment (PP&E)				
Gross	671.0	708.0	2,732.9	2,832.8
Accumulated Depreciation, Depletion, and Amortization (DD&A)	-334.5	-355.5	-1,272.8	-1,304.1
Net	336.5	352.5	1,460.1	1,528.7
Investments and Advances	53.9	58.2	130.3	199.6
Other Noncurrent Assets	35.8	39.6	1,813.6	2,062.6
Subtotal Noncurrent Assets	426.3	450.3	2,269.2	2,535.7
Total Assets	520.4	571.3	4,552.1	5,056.3
Liabilities and Stockholders Equity				
Liabilities				
Current Liabilities	113.9	131.3	1,059.7	1,189.3
Long-Term Debt	94.6	104.0	927.5	1,020.1
Other Long-Term Items	107.1	114.5	1,103.6	1,186.3
Minority Interest	10.4	15.2	50.0	52.8
Subtotal Liabilities and Other Items	326.0	364.9	3,140.8	3,448.5
Stockholders' Equity				
Retained Earnings	165.8	170.6	1,008.0	1,140.6
Other Equity	28.7	35.7	403.2	467.2
Subtotal Stockholders' Equity	194.4	206.3	1,411.3	1,607.8
Total Liabilities and Stockholders' Equity	520.4	571.3	4,552.1	5,056.3
Financial Ratios	(percent)			
Net Income/Stockholders' Equity	6.4	11.1	18.1	18.1
Net Income plus Interest/Total Invested Capital	6.9	10.2	14.4	14.3
Dividends/Net Cash Flow from Operations	35.6	29.3	20.1	17.1
Long-term Debt/Stockholders' Equity	48.7	50.4	65.7	63.4

Sources: Standard & Poor's (S&P) Industrials data - Compustat PC Plus, a services of Standard & Poor's. FRS companies' data - Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B4. Consolidated Balance Sheet for FRS Companies , 1993-1999
(Billion Dollars)

Balance Sheet Items	1993	1994	1995	1996	1997	1998	1999
Assets							
Current Assets							
Cash & Marketable Securities	14.1	13.2	12.2	13.4	12.2	8.1	12.2
Trade Accounts & Notes Receivable	41.7	45.8	48.8	56.2	51.2	47.8	68.1
Inventories							
Raw Materials & Products	23.7	22.9	22.6	22.7	21.4	21.6	23.3
Materials & Supplies	4.3	4.4	4.1	3.8	3.7	3.8	3.9
Other Current Assets	9.6	10.2	10.9	12.1	12.4	12.9	13.4
Total Current Assets	93.5	96.6	98.6	108.2	100.9	94.2	121.0
Non-current Assets							
Property, Plant & Equipment							
Gross	607.9	624.1	640.2	635.0	636.9	671.0	708.0
Accumulated DD&A	300.0	315.4	329.8	331.6	333.3	334.5	355.5
Net	307.9	308.7	310.5	303.4	303.6	336.5	352.5
Investments & Advances to Unconsolidated Affiliates	23.6	25.9	29.0	32.3	44.2	53.9	58.2
Other Non-current Assets	26.3	26.2	26.5	26.8	35.2	35.8	39.6
Total Non-current Assets	357.8	360.8	366.0	362.4	382.9	426.3	450.3
Total Assets	451.3	457.4	464.6	470.6	483.8	520.4	571.3
Liabilities & Stockholders' Equity							
Liabilities							
Current Liabilities							
Trade Accounts & Notes Payable	49.1	51.5	53.1	61.4	57.7	62.8	79.4
Other Current Liabilities	47.0	45.8	50.8	48.8	49.2	51.1	51.9
Long-Term Debt	89.4	88.1	84.6	70.9	73.4	94.6	104.0
Deferred Income Tax Credits	45.5	45.0	45.5	45.5	46.3	49.0	53.1
Other Deferred Credits	15.9	16.8	17.3	19.2	18.8	18.4	18.8
Other Long-Term Items	37.7	39.3	40.7	40.6	41.6	39.7	42.6
Minority Interest in Consolidated Affiliates	5.0	5.1	5.8	6.6	8.2	10.4	15.2
Total Liabilities	289.6	291.7	297.9	292.9	295.1	326.0	364.9
Stockholders' Equity	142.0	145.0	151.4	156.3	160.8	165.8	170.6
Retained Earnings	19.8	20.7	15.3	21.4	27.9	28.7	35.7
Other Equity							
Total Stockholders' Equity	161.8	165.7	166.7	177.8	188.7	194.4	206.3
Total Liabilities & Stockholders' Equity	451.3	457.4	464.6	470.6	483.8	520.4	571.3
Memo:							
Foreign Currency Translation Adjustment Cumulative at Year End	-7.3	0.7	1.5	1.2	-2.7	-2.3	-2.7
Foreign Currency Translation Adjustment for the Current Year	-0.6	1.9	0.7	-0.4	-3.9	0.0	-0.3

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B5. Consolidating Statement of Income for FRS Companies, 1999
(Million Dollars)

Income Statement Items	Consolidated	Eliminations & Nontraceables	Petroleum	Coal	Other Energy	Nonenergy
Operating Revenues	578,197	-10,666	507,664	1,652	27,363	52,184
Operating Expenses						
General Operating Expenses	500,908	-9,660	439,609	1,290	25,838	43,831
DD&A	32,452	591	28,592	171	445	2,653
General & Administrative	12,590	2,168	7,216	27	770	2,409
Total Operating Expenses	545,950	-6,901	475,417	1,488	27,053	48,893
Operating Income	32,247	-3,765	32,247	164	310	3,291
Other Revenue & (Expense)						
Earnings of Unconsolidated Affiliates	5,081	-124	4,370	87	519	229
Other Dividend & Interest Income	1,474	1,474	-	-	-	-
Gain/Loss on Disposition of PP&E	1,922	7	1,709	6	6	194
Interest Expenses & Financial Charges	-8,735	-8,735	-	-	-	-
Minority Interest in Income	-1,161	-1,161	-	-	-	-
Foreign Currency Translation Effects	10	10	-	-	-	-
Other Revenue & (Expense)	2,999	2,999	-	-	-	-
Total Other Revenue & (Expense)	1,590	-5,530	6,079	93	525	423
Pretax Income	33,837	-9,295	38,326	257	835	3,714
Income Tax Expense	10,838	-3,845	13,593	84	124	882
Discontinued Operations	309	101	208	0	0	0
Extraordinary Items and Cumulative Effect of Accounting Changes	-442	-285	-103	0	0	-54
Net Income	22,866	-5,634	24,838	173	711	2,778

- = Not available.
W = Data withheld to avoid disclosure.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B6. Consolidating Statement of Income for FRS Companies, U.S. and Foreign Petroleum Segments, 1999

(Million Dollars)

Income Statement Items	U.S. Petroleum				Foreign Petroleum			
	Consoli-dated	Production	Refining/ Marketing	Pipe-lines	Consoli-dated	Production	Refining/ Marketing	Int'l Marine
Operating Revenues								
Raw Material Sales	114,491	45,570	94,554	3,326	68,147	40,721	49,117	0
Refined Products Sales	189,985	W	189,617	855	119,733	W	119,105	W
Transportation Revenues	9,369	715	2,708	7,626	1,501	355	322	1,873
Management and Processing Fees	1,276	347	1,194	381	2,085	386	1,914	W
Other	13,257	W	11,574	353	2,924	W	2,413	7
Total Operating Revenues	328,378	48,770	299,647	12,541	194,390	47,153	172,871	1,936
Operating Expenses								
General Operating Expenses	288,893	27,722	286,259	7,492	165,786	24,287	167,087	1,799
DD&A	17,527	10,903	5,273	1,351	11,065	9,086	1,907	W
General & Administrative	5,140	1,284	3,050	806	2,110	999	1,255	W
Total Operating Expenses	311,560	39,909	294,582	9,649	178,961	34,372	170,249	1,910
Operating Income	16,818	8,861	5,065	2,892	15,429	12,781	2,622	26
Other Revenue & (Expense)								
Earnings of Unconsolidated Affiliates	2,381	1,003	860	518	1,989	1,704	282	W
Gain(Loss) on Disposition of PP&E	1,611	865	580	166	98	170	-71	W
Total Other Revenue & (Expense)	3,992	1,868	1,440	684	2,087	1,874	211	2
Pretax Income	20,810	10,729	6,505	3,576	17,516	14,655	2,833	28
Income Tax Expense	6,148	3,217	1,714	1,217	7,445	6,445	979	21
Discontinued Operations	W	W	W	W	W	W	0	0
Extraordinary Items and Cumulative Effect of Accounting Changes	W	W	W	W	W	W	0	0
Contribution To Net Income	14,751	7,444	4,883	2,424	10,087	8,226	1,854	7

W = Data withheld to avoid disclosure.

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B7. 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, 1999
(Million Dollars)

	Year End Balance		Activity During Year		
	Net PP&E	Investments & Advances	Additions to PP&E	Additions to Investments & Advances	DD&A
Petroleum					
United States					
Production	92,709	4,811	12,767	481	10,903
Refining/Marketing					
Refining	38,178	8,108	3,453	-630	3,319
Marketing	19,436	1,864	2,328	304	1,565
Refining/Marketing Transport					
Pipelines	2,805	927	489	101	131
Marine	1,020	W	171	W	93
Other	1,686	W	438	W	165
Total U.S. Refining/Marketing	63,125	11,506	6,879	165	5,273
Rate Regulated Pipelines					
Refined Products	1,311	337	97	84	56
Natural Gas	26,817	2,884	1,881	679	927
Crude Oil and Liquids	5,541	923	322	56	368
Total Rate Regulated Pipelines	33,669	4,144	2,300	819	1,351
Total U.S. Petroleum	189,503	20,461	21,946	1,465	17,527
Foreign					
Production	85,076	11,249	16,170	1,432	9,086
Refining/Marketing	26,052	10,076	2,003	302	1,907
International Marine	842	83	26	0	72
Total Foreign Petroleum	111,970	21,408	18,199	1,734	11,065
Total Petroleum	301,473	41,869	40,145	3,199	28,592
Coal					
Foreign	W	W	W	W	54
United States	W	W	W	W	117
Total Coal	1,735	85	174	11	171
Other Energy					
Foreign	2,520	2,404	863	-152	167
United States	3,640	846	776	252	278
Total Other Energy	6,160	3,250	1,639	100	445
Nonenergy					
Foreign Chemicals	7,087	3,593	1,468	418	423
U.S. Chemicals	20,402	2,532	2,793	-19	1,421
Foreign Other Nonenergy	1,690	2,027	W	W	W
U.S. Other Nonenergy	6,914	3,361	W	W	W
Total Nonenergy	36,093	11,513	7,800	3,465	2,653
Nontraceable	7,008	1,480	978	99	591
Consolidated	352,469	58,197	50,736	6,874	32,452

W = Data withheld to avoid disclosure.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B8. Return on Investment for Lines of Business for FRS Companies Ranked by Total Energy Assets, 1998-1999
(Percent)

Line of Business	All FRS		Top Four		Five through Twelve		All Other	
	1998	1999	1998	1999	1998	1999	1998	1999
Petroleum	3.9	7.2	7.2	7.6	1.8	7.8	1.7	5.9
U.S. Petroleum	3.8	7.0	6.5	8.4	2.7	6.8	3.1	5.9
Oil and Gas Production	0.5	7.6	3.9	7.6	-1.4	8.9	-0.3	5.9
Refining/Marketing	7.9	6.5	9.9	9.6	13.7	4.6	3.6	5.7
Pipelines	4.4	6.4	12.6	9.3	-0.2	5.8	7.8	7.5
Foreign Petroleum	4.0	7.6	7.6	7.0	-0.4	11.6	-4.8	5.9
Oil and Gas Production	2.2	8.5	7.0	8.9	-1.4	10.1	-5.7	6.1
Refining/Marketing	8.2	5.1	8.4	3.7	7.5	20.3	5.9	3.7
International Marine	8.9	0.8	11.1	2.7	W	-566.7	W	-100.0
Coal	26.4	9.5	8.7	5.7	W	W	75.5	24.4
Other Energy	13.2	7.6	18.6	12.4	11.0	5.7	8.2	6.1
Nonenergy	4.5	5.8	4.4	8.2	5.3	4.6	2.7	4.5

W = Data withheld to avoid disclosure.
Note: Return on investment measured as contribution to net income/net investment in place.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B9. Research and Development Expenditures for FRS Companies, 1993-1999
(Million Dollars)

	1993	1994	1995	1996	1997	1998	1999
Sources of R&D Funds							
Federal Government	16	15	W	W	W	W	27
Internal Company	3,308	2,985	2,817	2,675	2,841	1,668	1,377
Other Sources	26	50	W	W	W	W	20
Total Sources	3,350	3,050	2,861	2,717	2,885	1,707	1,424
Breakdown of R&D Expenditures							
Oil & Gas Recovery	671	572	494	482	585	606	430
Other Petroleum	569	531	461	432	380	365	345
Coal Gasification/Liquefaction	W	W	W	W	W	W	W
Other Coal	W	W	W	W	W	W	W
Nuclear and Other Energy	121	116	50	51	54	28	34
Nonenergy	1,902	1,741	1,744	1,617	1,738	616	538
Unassigned	77	71	100	127	120	85	W
Total Expenditures	3,350	3,050	2,861	2,717	2,885	1,707	1,424

W = Data withheld to avoid disclosure.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B10. Size Distribution of Net Investment in Place for FRS Companies Ranked by Total Energy Assets, 1999
(Percent)

Line of Business	Top Four	Five through Twelve	All Other	All FRS
Petroleum	45.1	29.8	25.1	100.0
United States	29.7	38.9	31.4	100.0
Production	37.9	36.4	25.6	100.0
Refining/Marketing	29.3	25.0	45.7	100.0
Refining	25.8	25.0	49.3	100.0
Marketing	38.2	21.1	40.8	100.0
Rate Regulated Pipelines	9.3	72.7	18.0	100.0
Foreign	69.2	15.5	15.3	100.0
Production	62.0	18.2	19.8	100.0
Refining/Marketing	87.5	8.8	3.7	100.0
International Marine	99.6	0.3	0.1	100.0
Coal	65.2	4.6	30.2	100.0
Other Energy	26.8	61.7	11.5	100.0
Nonenergy	35.3	45.5	19.2	100.0
Chemicals	46.7	27.5	25.9	100.0
Other Nonenergy	8.1	88.7	3.2	100.0
Consolidated	44.3	31.8	23.9	100.0

Note: Sum of components may not equal total due to independent rounding, eliminations, and nontraceables.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B11. Consolidated Statement of Cash Flows for FRS Companies, 1993-1999
(Million Dollars)

Cash Flows [1]	1993	1994	1995	1996	1997	1998	1999
Cash Flows From Operations							
Net Income	15,488	16,547	21,131	32,029	32,082	12,519	22,866
Minority Interest in Income	397	513	731	845	896	764	1,161
Noncash Items:							
DD&A	30,355	30,667	36,698	29,331	29,569	35,445	32,452
Dry Hole Expense, This Year	1,673	1,805	1,510	1,812	2,069	2,518	1,808
Deferred Income Taxes	-990	509	-327	2,863	2,301	-1,123	-25
Recognized Undistributed (Earnings)/Losses of Unconsolidated Affiliates	-137	-372	-845	-226	-374	2,987	136
(Gain)/Loss on Disposition of PP&E	-941	-570	-2,445	-1,940	-2,716	-2,658	-1,922
Changes in Operating Assets and Liabilities and Other Noncash Items	2,646	-1,884	-763	-365	298	-3,792	-2,259
Other Cash Items, Net	1,705	1,084	2,808	-165	1,197	1,502	581
Net Cash Flow From Operations	50,196	48,299	58,498	64,184	65,322	48,162	54,798
Cash Flows From Investing Activities							
Additions to PP&E:							
Due to Mergers and Acquisitions	-306	-2,271	-4,137	-2,281	-5,579	-18,868	-7,111
Other	-37,755	-35,217	-40,356	-41,872	-48,666	-51,046	-43,625
Total Additions to PP&E	-38,061	-37,488	-44,493	-44,153	-54,245	-69,914	-50,736
Additions to Investments and Advances	-2,318	-1,588	-3,208	-5,799	-7,685	-5,223	-6,874
Proceeds From Disposals of PP&E	11,757	6,447	9,063	10,942	9,320	16,243	13,267
Other Investment Activities, Net	-2,242	-2,363	4,086	1,608	6,587	4,235	3,523
Cash Flow From Investing Activities	-30,864	-34,992	-34,552	-37,402	-46,023	-54,659	-40,820
Cash Flows From Financing Activities							
Proceeds From Long-Term Debt	18,982	12,500	19,929	10,708	17,901	27,072	29,862
Proceeds From Equity Security Offerings	2,146	2,614	3,471	1,171	1,507	9,112	3,557
Reductions in Long-Term Debt	-20,886	-13,760	-18,657	-18,883	-19,774	-18,019	-24,988
Purchase of Treasury Stock	-514	-1,010	-10,035	-1,299	-7,910	-5,776	-424
Dividends to Shareholders	-13,563	-14,906	-15,238	-15,585	-16,941	-17,169	-16,081
Other Financing Activities, Including Net Change in Short-Term Debt	-4,102	-1,091	-2,350	-578	5,537	6,859	-3,377
Cash Flow From Financing Activities	-17,937	-15,653	-22,880	-24,466	-19,680	2,079	-11,451
Effect of Exchange Rate on Cash	-198	131	14	3	-255	-13	-24
Net Increase/(Decrease) in Cash and Cash Equivalents	1,197	-2,215	1,080	2,319	-636	-4,431	2,503

[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 (Financial Reporting System).

Table B12. Composition of Income Taxes for FRS Companies, 1993-1999
(Million Dollars)

	1993	1994	1995	1996	1997	1998	1999
Income Taxes (as per Financial Statements)							
Current Paid or Accrued:							
U.S. Federal, before Investment Tax Credit & Alternative Minimum Tax	2,584	1,907	4,486	6,141	5,656	603	1,390
U.S. Federal Investment Tax Credit	-76	0	-162	-146	-93	-85	-90
Effect of Alternative Minimum Tax	-158	30	151	-325	-400	-16	430
U.S. State & Local Income Taxes	462	528	649	745	794	443	371
Foreign Income Taxes							
Canada	660	705	634	745	932	456	597
Europe and Former Soviet Union [1]	1,947	2,300	2,752	3,862	2,927	1,798	3,110
Africa	1,256	1,127	1,204	1,956	1,926	449	1,607
Middle East	893	835	1,024	1,326	802	745	1,286
Other Eastern Hemisphere	2,075	2,085	1,882	2,195	1,901	992	1,679
Other Western Hemisphere	440	464	514	729	1,739	428	346
Total Foreign	7,271	7,516	8,010	10,813	10,227	4,868	8,625
Total Current	10,083	9,981	13,134	17,228	16,184	5,813	10,726
Deferred							
U.S. Federal, before Investment Tax Credit	-549	691	-793	1,410	1,477	-373	1,480
U.S. Federal Investment Tax Credit	-32	26	61	69	-2	-28	-9
Effect of Alternative Minimum Tax	117	-51	-158	312	400	-16	-415
U.S. State & Local Income Taxes	-19	-56	-30	56	54	104	131
Foreign	-456	43	537	930	519	-791	-1,075
Total Deferred	-939	653	-383	2,777	2,448	-1,104	112
Total Income Tax Expense	9,144	10,634	12,751	20,005	18,632	4,709	10,838
Reconciliation of Accrued U.S. Federal Income Tax Expense To Statutory Rate							
Consolidated Pretax Income/(Loss)	24,777	29,592	34,233	52,808	51,453	16,017	33,837
Less: Foreign Source Income not Subject to U.S.	3,233	3,575	4,038	6,230	5,827	251	2,160
Equals: Income Subject to U.S. Tax	21,544	26,017	30,195	46,578	45,626	15,766	31,677
Less: U.S. State & Local Income Taxes	509	438	440	782	785	570	486
Less: Applicable Foreign Income Taxes Deducted	638	327	377	554	312	32	107
Equals: Pretax Income Subject to U.S. Tax	20,397	25,252	29,378	45,242	44,529	15,164	31,084
Tax Provision Based on Previous Line	7,138	8,842	10,281	15,834	15,621	5,332	10,902
Increase/(Decrease) in Taxes Due To:							
Foreign Tax Credits Recognized	-4,754	-4,831	-5,661	-6,926	-6,982	-3,563	-5,963
U.S. Federal Investment Tax Credit Recognized	-108	-34	-97	-123	-137	-124	-98
Statutory Depletion	-39	-52	-70	-54	-63	-30	-8
Effect of Alternative Minimum Tax	-1	-14	0	1	0	-16	23
Other	-352	-1,314	-868	-1,273	-1,399	-1,485	-1,947
Actual U.S. Federal Tax Provision (Refund)	1,884	2,597	3,585	7,459	7,040	114	2,909

[1] 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 (Financial Reporting System).

Table B13. U.S. Taxes Other Than Income Taxes for FRS Companies, 1993-1999
(Million Dollars)

	1993	1994	1995	1996	1997	1998	1999
Production Taxes							
Oil and Gas Production	1,906	1,719	1,693	2,098	1,965	1,176	1,674
Coal	187	126	157	139	172	47	43
Other [1]	5	5	11	1	1	0	0
Total Production Taxes	2,098	1,850	1,861	2,238	2,138	1,223	1,717
Superfund	320	291	293	14	W	W	W
Import Duties	127	122	104	260	W	W	W
Sales, Use, and Property	3,104	3,089	2,886	2,516	2,407	2,648	2,268
Payroll	2,134	1,986	1,844	1,531	1,406	1,357	1,289
Other Taxes	638	630	566	514	559	360	467
Total Taxes Paid (Other Than Income Taxes)	8,421	7,968	7,554	7,073	6,601	5,660	5,825
Excise Taxes Collected	25,317	30,092	30,813	32,426	30,984	39,918	46,293

[1] Nuclear, Other Energy, and Nonenergy.
W = Data withheld to avoid disclosure.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B14. Oil and Gas Exploration and Development Expenditures for FRS Companies, United States and Foreign, 1993-1999
(Million Dollars)

	1993	1994	1995	1996	1997	1998	1999
United States							
Exploration							
Acquisition of Unproved Acreage	355	477	595	997	2,653	3,912	633
Geological and Geophysical	409	405	486	625	750	916	621
Drilling and Equipping [1]	1,370	1,887	1,833	2,338	2,905	2,964	1,921
Other	652	619	596	693	690	954	659
Total Exploration	2,786	3,388	3,510	4,653	6,998	8,746	3,834
Development							
Acquisition of Proved Acreage	599	1,576	980	922	2,928	3,568	1,144
Lease Equipment	1,640	1,386	1,425	1,613	1,823	2,688	2,431
Drilling and Equipping [1]	4,012	4,524	5,433	6,154	8,540	7,769	5,022
Other	1,895	1,714	1,086	1,290	1,557	1,657	1,056
Total Development	8,146	9,200	8,924	9,979	14,848	15,682	9,653
Total U.S. Exploration and Development	10,932	12,588	12,434	14,632	21,846	24,428	13,487
Foreign							
Exploration							
Acquisition of Unproved Acreage	291	343	214	745	565	2,159	2,252
Geological and Geophysical	813	932	843	869	897	1,065	885
Drilling and Equipping [1]	1,564	1,595	2,114	2,277	2,684	2,650	1,579
Other [2]	1,011	960	989	919	1,128	1,299	903
Total Exploration	3,679	3,830	4,160	4,810	5,274	7,173	5,619
Development							
Acquisition of Proved Acreage	407	737	371	1,932	1,641	7,121	2,357
Lease Equipment	2,476	1,329	1,537	2,064	2,207	2,505	2,142
Drilling and Equipping [1]	4,118	4,085	4,535	5,278	6,426	6,206	5,143
Other [2]	1,866	1,928	2,568	2,534	2,383	3,388	2,531
Total Development	8,867	8,079	9,011	11,808	12,657	19,220	12,173
Total Foreign Exploration and Development	12,546	11,909	13,171	16,618	17,931	26,393	17,792

[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 (Financial Reporting System).

Table B15. Components of U.S. and Foreign Exploration and Development Expenditures for FRS Companies, 1999
(Million Dollars)

	Worldwide	United States Total	United States Onshore	United States Offshore	Foreign
Exploration and Development Expenditures					
Exploration Expenditures					
Unproved Acreage	2,885	633	343	290	2,252
Drilling and Equipping:					
Completed Well Costs	-	1,641	353	1,288	-
Work-in-progress Adjustment	-	280	33	247	-
Total Drilling and Equipping	3,500	1,921	386	1,535	1,579
Geological and Geophysical	1,506	621	166	455	885
Other, Including Direct Overhead	1,562	659	279	380	903
Total Exploration Expenditures	9,453	3,834	1,174	2,660	5,619
Development Expenditures					
Proved Acreage (Including Mergers and Acquisitions)	3,501	1,144	1,025	119	2,357
Drilling and Equipping:					
Completed Well Costs	-	3,928	2,361	1,567	-
Work-in-progress Adjustment	-	1,094	339	755	-
Total Drilling and Equipping	10,165	5,022	2,700	2,322	5,143
Lease Equipment	4,573	2,431	1,023	1,408	2,142
Other Development					
Support Equipment	872	172	146	26	700
Other, Including Direct Overhead	2,715	884	502	382	1,831
Total Development Expenditures	21,826	9,653	5,396	4,257	12,173
Total Exploration and Development Expenditures	31,279	13,487	6,570	6,917	17,792

- = Not available.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B16. Exploration and Development Expenditures by Region, 1993-1999
(Million Dollars)

	1993	1994	1995	1996	1997	1998	1999
Exploration Expenditures							
U.S. Onshore	1,371	1,491	1,644	1,826	3,396	3,432	1,174
U.S. Offshore	1,415	1,897	1,866	2,827	3,602	4,805	2,660
Total United States	2,786	3,388	3,510	4,653	6,998	8,746	3,834
Canada	403	573	493	355	310	638	420
OECD Europe	1,313	1,063	1,242	1,345	1,684	1,916	767
Former Soviet Union and E. Europe	163	204	181	194	285	630	354
Africa	599	678	707	779	807	1,092	1,268
Middle East	225	104	90	45	53	141	96
Other Eastern Hemisphere	736	888	1,016	1,462	1,341	1,563	1,192
Other Western Hemisphere	240	320	431	630	794	1,193	1,522
Total Foreign	3,679	3,830	4,160	4,810	5,274	7,173	5,619
Worldwide Exploration Expenditures	6,465	7,218	7,670	9,463	12,272	15,919	9,453
Development Expenditures							
U.S. Onshore	5,843	6,324	6,051	6,087	9,624	9,519	5,396
U.S. Offshore	2,303	2,876	2,873	3,892	5,224	6,163	4,257
Total United States	8,146	9,200	8,924	9,979	14,848	15,682	9,653
Canada	1,156	1,262	1,406	1,210	1,688	4,168	1,910
OECD Europe	4,169	3,376	3,962	4,222	5,368	6,670	3,370
Former Soviet Union and E. Europe	100	93	178	267	343	637	252
Africa	873	714	1,336	2,014	2,171	2,042	1,826
Middle East	460	341	271	418	590	801	297
Other Eastern Hemisphere	1,733	1,870	1,414	2,670	1,643	2,386	2,250
Other Western Hemisphere	376	423	444	1,007	854	2,516	2,268
Total Foreign	8,867	8,079	9,011	11,808	12,657	19,220	12,173
Worldwide Development Expenditures	17,013	17,279	17,935	21,787	27,505	34,902	21,826
Total Exploration and Development Expenditures							
U.S. Onshore	7,214	7,815	7,695	7,913	13,020	13,460	6,570
U.S. Offshore	3,718	4,773	4,739	6,719	8,826	10,968	6,917
Total United States	10,932	12,588	12,434	14,632	21,846	24,428	13,487
Canada	1,559	1,835	1,899	1,565	1,998	4,806	2,330
OECD Europe	5,482	4,439	5,204	5,567	7,052	8,586	4,137
Former Soviet Union and E. Europe	263	297	359	461	628	1,267	606
Africa	1,472	1,392	2,043	2,793	2,978	3,134	3,094
Middle East	685	445	361	463	643	942	393
Other Eastern Hemisphere	2,469	2,758	2,430	4,132	2,984	3,949	3,442
Other Western Hemisphere	616	743	875	1,637	1,648	3,709	3,790
Total Foreign	12,546	11,909	13,171	16,618	17,931	26,393	17,792
Worldwide Exploration and Development Expenditures	23,478	24,497	25,605	31,250	39,777	50,821	31,279

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B17. Production (Lifting) Costs by Region for FRS Companies, 1993-1999
(Million Dollars)

	1993	1994	1995	1996	1997	1998	1999
United States							
Taxes Other Than Income Taxes	1,906	1,719	1,693	2,098	1,965	1,176	1,674
Other Costs	11,777	11,107	10,429	10,221	10,147	9,787	9,494
Total Production Costs	13,683	12,826	12,122	12,319	12,112	10,963	11,168
U.S. Onshore	11,148	10,342	9,769	9,855	9,604	8,198	8,039
U.S. Offshore	2,535	2,484	2,353	2,464	2,508	2,765	3,129
Canada							
Royalty Expenses	19	W	W	W	W	W	W
Taxes Other Than Income Taxes	56	W	W	W	W	W	W
Other Costs	1,210	1,141	1,082	993	961	1,037	1,153
Total Production Costs	1,285	1,234	1,174	1,082	1,049	1,129	1,252
OECD Europe							
Royalty Expenses	305	206	235	251	217	251	62
Taxes Other Than Income Taxes	214	274	311	400	360	269	310
Other Costs	3,617	4,128	4,116	3,996	3,950	3,980	3,686
Total Production Costs	4,136	4,608	4,662	4,647	4,527	4,500	4,058
Former Soviet Union and E. Europe							
Royalty Expenses	0	0	0	0	0	0	0
Taxes Other Than Income Taxes	0	W	W	W	W	W	W
Other Costs	54	W	W	W	W	W	W
Total Production Costs	54	65	128	134	192	208	148
Africa							
Royalty Expenses	W	W	W	W	W	W	66
Taxes Other Than Income Taxes	W	W	W	W	W	W	42
Other Costs	821	740	607	812	861	1,194	1,160
Total Production Costs	1,122	1,011	916	1,259	1,310	1,490	1,268
Middle East							
Royalty Expenses	W	W	W	W	W	W	W
Taxes Other Than Income Taxes	W	W	W	W	W	W	W
Other Costs	313	340	258	296	280	250	238
Total Production Costs	424	435	403	483	491	429	424
Other Eastern Hemisphere							
Royalty Expenses and Taxes Other Than Income Taxes	630	433	400	542	456	240	369
Other Costs	1,173	1,132	1,110	1,161	1,144	1,074	1,235
Total Production Costs	1,803	1,565	1,510	1,703	1,600	1,314	1,604
Other Western Hemisphere							
Royalty Expenses and Taxes Other Than Income Taxes	122	83	129	180	156	87	184
Other Costs	374	346	428	389	470	552	443
Total Production Costs	496	429	557	569	626	639	627
Total Foreign							
Royalty Expenses	789	613	680	901	891	740	384
Taxes Other Than Income Taxes	969	843	942	1,196	1,050	675	962
Other Costs	7,562	7,891	7,728	7,780	7,854	8,294	8,035
Total Production Costs	9,320	9,347	9,350	9,877	9,795	9,709	9,381

W = Data withheld to avoid disclosure.
-- = Not applicable.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B18. Oil and Gas Acreage for FRS Companies, 1993-1999
(Thousand Acres)

	1993	1994	1995	1996	1997	1998	1999
Net Acreage							
U.S. Onshore							
Developed	28,856	28,744	27,429	26,733	25,474	26,396	25,895
Undeveloped	42,196	35,698	38,792	31,659	31,154	30,598	25,880
U.S. Offshore							
Developed	4,799	4,818	6,154	5,470	5,343	4,634	4,988
Undeveloped	16,175	13,925	14,334	16,880	22,983	23,168	24,940
Foreign							
Developed	22,050	20,505	18,063	22,574	21,984	24,887	26,337
Undeveloped	500,238	444,427	449,255	445,176	472,106	514,511	416,209
Gross Acreage							
U.S. Onshore							
Developed	50,640	51,846	50,016	46,887	45,249	49,097	45,978
Undeveloped	65,051	57,865	61,651	53,775	55,530	51,364	42,325
U.S. Offshore							
Developed	9,753	10,112	11,291	9,668	10,665	8,861	9,534
Undeveloped	20,233	19,128	18,595	21,786	30,845	32,439	35,689
Foreign							
Developed	61,274	57,885	49,946	59,926	58,198	64,358	59,247
Undeveloped	937,683	855,790	892,178	857,130	924,839	1,083,355	835,615

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B19. U.S. Net Wells Completed for FRS Companies and U.S. Industry, 1993-1999

	1993	1994	1995	1996	1997	1998	1999
Number of Net Wells Completed During Year for FRS Companies							
Onshore							
Net Exploratory Wells							
Dry Holes	231	175	232	274	163	159	93
Oil Wells	108	101	104	91	90	55	26
Gas Wells	127	167	201	207	170	142	105
Total Exploratory Wells	466	443	538	572	424	356	225
Net Development Wells							
Dry Holes	236	203	262	319	301	256	162
Oil Wells	1,966	1,980	1,908	2,095	3,016	2,510	1,130
Gas Wells	1,664	1,865	2,156	2,049	2,261	2,074	1,519
Total Development Wells	3,865	4,048	4,326	4,463	5,577	4,841	2,812
Offshore							
Net Exploratory Wells							
Dry Holes	69	78	72	84	98	91	59
Oil Wells	22	13	32	36	31	22	28
Gas Wells	42	47	53	87	73	63	61
Total Exploratory Wells	133	138	157	206	202	176	148
Net Development Wells							
Dry Holes	13	17	18	23	46	32	26
Oil Wells	125	150	151	158	181	115	145
Gas Wells	98	120	95	153	168	133	153
Total Development Wells	236	287	265	334	396	280	324
Total United States							
Net Exploratory Wells							
Dry Holes	300	253	304	358	261	249	153
Oil Wells	130	114	137	127	121	77	54
Gas Wells	169	214	255	293	243	205	166
Total Exploratory Wells	599	581	695	778	626	531	372
Net Development Wells							
Dry Holes	249	220	280	342	347	288	188
Oil Wells	2,091	2,130	2,059	2,253	3,197	2,625	1,275
Gas Wells	1,761	1,985	2,252	2,202	2,429	2,208	1,672
Total Development Wells	4,101	4,335	4,591	4,797	5,973	5,121	3,136
Number of Net Wells Completed During Year for Total U.S. Industry							
Net Exploratory Wells							
Dry Holes	2,604	2,479	2,302	2,154	2,131	1,840	1,363
Oil Wells	876	836	866	484	431	304	153
Gas Wells	888	994	992	575	539	586	587
Total Exploratory Wells	4,367	4,309	4,160	3,213	3,101	2,730	2,103
Net Development Wells							
Dry Holes	3,666	2,862	2,778	3,184	3,619	3,103	2,215
Oil Wells	7,459	5,905	6,788	7,911	9,904	6,559	3,906
Gas Wells	9,079	8,517	7,284	8,729	10,555	11,473	9,936
Total Development Wells	20,204	17,284	16,849	19,824	24,078	21,135	16,057
Number of Net In-Progress Wells At Year End for FRS Companies							
Onshore							
Exploratory Wells	106	90	135	133	135	51	40
Development Wells	709	524	541	675	929	392	464
Total In-Progress Wells	815	614	676	808	1,064	444	504
Offshore							
Exploratory Wells	35	46	46	45	92	52	68
Development Wells	68	91	57	93	128	73	87
Total In-Progress Wells	103	137	103	138	220	124	155
Total United States							
Exploratory Wells	141	136	181	178	226	103	108
Development Wells	777	615	598	768	1,058	465	551
Total In-Progress Wells	918	751	779	946	1,284	568	659

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 Adminstration. Totals are based on data which appeared in the Energy Information Administration's Monthly Energy Review, September 2000, p. 81. FRS companies' data - Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B20. U.S. Net Drilling Footage and Net Producing Wells For FRS Companies and U.S. Industry, 1993-1999

(Thousand Feet)

	1993	1994	1995	1996	1997	1998	1999
FRS Companies							
Onshore							
Exploratory Well Footage							
Dry Hole Footage	2,341	1,699	1,799	2,052	1,700	1,714	921
Oil Well Footage	974	796	836	732	1,027	406	312
Gas Well Footage	1,072	1,464	1,456	1,860	1,521	1,548	1,150
Total Exploratory Footage	4,387	3,959	4,091	4,644	4,248	3,668	2,383
Development Well Footage							
Dry Hole Footage	1,429	1,177	1,550	2,224	1,926	1,939	1,252
Oil Well Footage	11,407	10,269	10,053	10,956	14,534	12,513	4,449
Gas Well Footage	11,558	12,955	14,468	14,304	16,751	16,521	12,291
Total Development Footage	24,394	24,401	26,071	27,484	33,211	30,973	17,992
Offshore							
Exploratory Well Footage							
Dry Hole Footage	710	911	891	1,091	1,362	1,345	848
Oil Well Footage	304	132	408	408	397	443	434
Gas Well Footage	488	568	702	1,824	981	1,285	1,002
Total Exploratory Footage	1,502	1,611	2,001	3,323	2,740	3,073	2,284
Development Well Footage							
Dry Hole Footage	158	124	155	244	459	344	199
Oil Well Footage	1,267	1,597	1,588	1,704	1,736	1,428	1,280
Gas Well Footage	975	1,025	1,011	1,538	1,584	1,398	1,295
Total Development Footage	2,400	2,746	2,754	3,486	3,779	3,170	2,774
Total United States							
Exploratory Well Footage							
Dry Hole Footage	3,051	2,610	2,690	3,143	3,062	3,059	1,769
Oil Well Footage	1,278	928	1,244	1,140	1,424	849	746
Gas Well Footage	1,560	2,032	2,158	3,684	2,502	2,833	2,152
Total Exploratory Footage	5,889	5,570	6,092	7,967	6,988	6,741	4,667
Development Well Footage							
Dry Hole Footage	1,587	1,301	1,705	2,468	2,385	2,283	1,451
Oil Well Footage	12,674	11,866	11,641	12,660	16,270	13,941	5,729
Gas Well Footage	12,533	13,980	15,479	15,842	18,335	17,919	13,586
Total Development Footage	26,794	27,147	28,825	30,970	36,990	34,143	20,766
Total United States Industry							
Exploratory Well Footage							
Dry Hole Footage	14,752	14,570	13,562	13,199	13,705	12,201	8,365
Oil Well Footage	5,449	5,277	5,502	3,504	3,402	2,502	1,034
Gas Well Footage	5,020	5,934	6,398	3,782	3,941	4,194	3,548
Total Exploratory Footage	25,222	25,781	25,462	20,485	21,048	18,896	12,947
Development Well Footage							
Dry Hole Footage	17,610	14,807	14,353	16,656	19,430	17,672	12,511
Oil Well Footage	36,632	30,824	32,776	36,988	47,908	32,279	17,670
Gas Well Footage	54,846	54,066	45,098	54,376	65,921	71,336	56,131
Total Development Footage	109,088	99,696	92,227	108,020	133,258	121,287	86,312
Number of Net Producing Wells for FRS Companies							
Onshore							
Oil Wells	106,760	105,679	94,867	87,461	75,493	69,401	58,987
Gas Wells	46,535	49,237	50,388	48,779	48,779	49,429	44,880
Total Producing Wells	153,295	154,916	145,256	136,240	124,272	118,830	103,867
Offshore							
Oil Wells	4,274	4,179	4,180	3,552	3,760	3,421	2,855
Gas Wells	2,643	2,895	3,042	2,556	2,898	2,737	2,707
Total Producing Wells	6,917	7,074	7,221	6,108	6,658	6,158	5,562
Total United States							
Oil Wells	111,034	109,858	99,047	91,013	79,253	72,822	61,842
Gas Wells	49,178	52,132	53,430	51,335	51,677	52,166	47,587
Total Producing Wells	160,212	161,990	152,477	142,348	130,930	124,987	109,429

Sources: Well footage, U.S. - 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 2000, p. 81. FRS companies' data - Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B21. Number of Net Wells Completed, In-Progress Wells, and Producing Wells by Foreign Regions for FRS Companies, 1993-1999

	1993	1994	1995	1996	1997	1998	1999
Canada							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	71.7	111.2	107.5	86.2	22.8	54.8	36.4
Oil Wells	47.9	42.0	66.6	46.0	10.7	10.0	25.8
Gas Wells	46.8	105.1	74.0	96.1	49.2	66.3	127.5
Total Exploratory Wells	166.4	258.3	248.1	228.3	82.7	131.1	189.7
Development Wells							
Dry Holes	47.4	59.6	42.7	48.1	59.6	58.8	58.3
Oil Wells	334.6	174.2	569.5	559.4	778.6	198.9	352.1
Gas Wells	292.9	416.6	189.6	233.7	275.1	422.4	758.7
Total Development Wells	674.9	650.4	801.8	841.2	1,113.3	680.1	1,169.1
Net In-Progress Wells at Year End	65.3	57.6	43.1	17.2	30.6	24.3	81.5
Net Producing Wells							
Oil Wells	11,704.3	11,268.5	9,793.9	8,719.5	9,364.7	10,532.3	10,155.9
Gas Wells	5,740.2	5,953.3	5,998.6	5,784.8	6,199.5	8,872.7	10,038.7
Total Producing Wells	17,444.5	17,221.8	15,792.5	14,504.3	15,564.2	19,405.0	20,194.6
Europe and Former Soviet Union [1]							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	33.4	33.7	42.1	49.4	56.6	36.3	15.4
Oil Wells	11.8	13.3	21.4	14.5	19.2	11.8	9.2
Gas Wells	14.6	11.2	10.6	11.4	8.9	12.0	4.0
Total Exploratory Wells	59.8	58.2	74.1	75.3	84.7	60.1	28.6
Development Wells							
Dry Holes	3.6	1.5	2.2	5.3	3.2	7.8	2.6
Oil Wells	59.9	60.4	72.4	77.6	80.7	118.5	75.4
Gas Wells	28.8	24.5	29.0	31.0	25.1	60.5	30.4
Total Development Wells	92.3	86.4	103.6	113.9	109.0	186.8	108.4
Net In-Progress Wells at Year End	76.3	74.5	73.0	68.7	62.7	54.5	31.6
Net Producing Wells							
Oil Wells	1,479.3	1,430.2	1,359.4	1,445.5	1,328.0	1,294.4	1,218.8
Gas Wells	687.0	720.7	741.9	765.2	766.8	805.3	626.6
Total Producing Wells	2,166.3	2,150.9	2,101.3	2,210.7	2,094.8	2,099.7	1,845.4
Africa and Middle East							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	37.9	32.0	28.4	19.8	25.3	33.1	14.9
Oil Wells	W	W	W	W	W	W	9.9
Gas Wells	W	W	W	W	W	W	10.0
Total Exploratory Wells	52.8	47.9	42.8	44.0	46.1	65.0	34.8
Development Wells							
Dry Holes	W	W	W	W	W	W	5.8
Oil Wells	72.2	105.7	109.7	133.0	151.6	218.4	206.3
Gas Wells	W	W	W	W	W	W	8.6
Total Development Wells	81.8	117.7	119.2	144.0	157.8	225.6	220.7
Net In-Progress Wells at Year End	21.3	45.1	41.9	36.9	29.0	18.0	36.8
Net Producing Wells							
Oil Wells	1,322.9	1,442.2	1,509.0	1,688.9	1,644.6	1,924.2	1,969.8
Gas Wells	25.8	34.4	41.9	49.9	59.5	62.7	83.2
Total Producing Wells	1,348.7	1,476.6	1,550.9	1,738.8	1,704.1	1,986.9	2,053.0

See footnotes at end of table.

Table B21. Number of Net Wells Completed, In-Progress Wells, and Producing Wells by Foreign Regions for FRS Companies, 1993-1999 (Continued)

	1993	1994	1995	1996	1997	1998	1999
Other Eastern Hemisphere							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	43.9	47.4	47.4	42.6	39.8	47.1	35.4
Oil Wells	8.3	11.6	13.1	21.6	16.1	36.6	31.6
Gas Wells	16.4	14.5	44.4	46.3	15.8	13.8	16.0
Total Exploratory Wells	68.6	73.5	104.9	110.5	71.7	97.5	83.0
Development Wells							
Dry Holes	8.7	5.2	1.5	3.7	4.7	11.5	1.9
Oil Wells	124.9	115.7	92.7	103.1	162.6	149.5	82.4
Gas Wells	62.7	45.9	32.4	91.7	116.5	101.2	104.5
Total Development Wells	196.3	166.8	126.6	198.5	283.8	262.2	188.8
Net In-Progress Wells at Year End	83.8	71.9	92.5	72.4	61.4	64.5	56.2
Net Producing Wells							
Oil Wells	1,666.0	1,714.9	1,476.2	1,622.0	1,767.0	1,707.2	1,654.2
Gas Wells	393.9	437.9	401.4	561.2	633.8	862.2	882.2
Total Producing Wells	2,059.9	2,152.8	1,877.6	2,183.2	2,400.8	2,569.4	2,536.4
Other Western Hemisphere							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	8.1	7.5	9.2	12.4	5.7	14.6	7.9
Oil Wells	10.7	8.0	4.7	9.0	4.7	10.4	3.2
Gas Wells	1.0	0.0	0.0	2.0	0.0	4.5	3.8
Total Exploratory Wells	19.8	15.5	13.9	23.4	10.4	29.5	14.9
Development Wells							
Dry Holes	W	W	W	W	W	W	W
Oil Wells	78.8	85.6	120.5	123.3	141.4	212.8	81.4
Gas Wells	W	W	W	W	W	W	W
Total Development Wells	87.2	94.3	133.1	129.8	148.3	224.5	91.7
Net In-Progress Wells at Year End	15.6	14.8	20.2	16.1	24.4	28.9	27.2
Net Producing Wells							
Oil Wells	3,032.6	2,939.6	2,980.6	2,478.9	605.0	2,045.6	2,426.5
Gas Wells	65.4	48.7	57.6	77.3	72.2	190.9	161.4
Total Producing Wells	3,098.0	2,988.3	3,038.2	2,556.2	677.2	2,236.5	2,587.9
Total Foreign							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	195.0	231.8	234.6	210.4	150.2	185.9	110.0
Oil Wells	93.0	88.5	119.7	110.9	71.0	97.6	79.7
Gas Wells	79.4	133.1	129.5	160.2	74.4	99.7	161.3
Total Exploratory Wells	367.4	453.4	483.8	481.5	295.6	383.2	351.0
Development Wells							
Dry Holes	71.1	77.2	51.9	67.9	75.5	83.7	70.1
Oil Wells	670.4	541.6	964.8	996.4	1,314.9	898.1	797.6
Gas Wells	391.0	496.8	267.6	363.1	421.8	597.4	911.0
Total Development Wells	1,132.5	1,115.6	1,284.3	1,427.4	1,812.2	1,579.2	1,778.7
Net In-Progress Wells at Year End	262.3	263.9	270.7	211.3	208.1	190.2	233.3
Net Producing Wells							
Oil Wells	19,205.1	18,795.4	17,119.1	15,954.8	14,709.3	17,503.7	17,425.2
Gas Wells	6,912.3	7,195.0	7,241.4	7,238.4	7,731.8	10,793.8	11,792.1
Total Producing Wells	26,117.4	25,990.4	24,360.5	23,193.2	22,441.1	28,297.5	29,217.3

[1]OECD Europe combined with the former Soviet Union and Eastern Europe to avoid disclosure.

W = data withheld to avoid disclosure.

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B22. Completed Wells and Average Depth, Onshore and Offshore, for FRS Companies, 1998 and 1999

Drilling and Equipping Measures	Total United States			U.S. Onshore			U.S. Offshore		
	1998	1999	Percent Change	1998	1999	Percent Change	1998	1999	Percent Change
Exploration									
Oil Wells									
Wells Completed	76.5	54.1	-29.3	55.0	26.1	-52.5	21.5	28.0	30.2
Average Depth (thousand feet)	11.1	13.8	24.2	7.4	12.0	61.9	20.6	15.5	-24.8
Gas Wells									
Wells Completed	205.3	165.7	-19.3	142.0	105.2	-25.9	63.3	60.5	-4.4
Average Depth (thousand feet)	13.8	13.0	-5.9	10.9	10.9	0.3	20.3	16.6	-18.4
Dry Holes									
Wells Completed	249.4	152.5	-38.9	158.5	93.3	-41.1	90.9	59.2	-34.9
Average Depth (thousand feet)	12.3	11.6	-5.4	10.8	9.9	-8.7	14.8	14.3	-3.2
Development									
Oil Wells									
Wells Completed	2,625.1	1,275.4	-51.4	2,510.1	1,130.1	-55.0	115.0	145.3	26.3
Average Depth (thousand feet)	5.3	4.5	-15.4	8.0	3.9	-21.0	12.4	8.8	-29.1
Gas Wells									
Wells Completed	2,207.6	1,672.0	-24.3	2,074.4	1,519.4	-26.8	133.2	152.6	14.6
Average Depth (thousand feet)	8.1	8.1	0.1	5.0	8.1	1.6	10.5	8.5	-19.1
Dry Holes									
Wells Completed	288.0	188.4	-34.6	256.2	162.1	-36.7	31.8	26.3	-17.3
Average Depth (thousand feet)	7.9	7.7	-2.8	7.6	7.7	2.1	10.8	7.6	-30.1

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B23. Oil and Gas Reserves for FRS Companies and U.S. Industry, 1999

	Beginning Reserves	Plus Reserve Additions[1]	Plus Net Purchases	Less Production	Equals Ending Reserves	Replacement Rate (percent)
Crude Oil and Natural Gas Liquids	(million barrels)					
U.S. Onshore						
Total U.S. Industry	24,080.0	3,130.0	0.0	2,178.0	25,032.0	143.7
FRS Companies	12,056.2	592.7	-243.9	892.1	11,512.9	66.4
All Other	12,023.8	2,537.3	243.9	1,285.9	13,519.1	197.3
U.S. Offshore						
Total U.S. Industry	4,478.0	831.0	0.0	670.0	4,639.0	124.0
FRS Companies	3,334.0	440.9	-231.7	413.6	3,129.6	106.6
All Other	1,144.0	390.1	231.7	256.4	1,509.4	152.1
U.S. Total						
Total U.S. Industry	28,558.0	3,961.0	0.0	2,848.0	29,671.0	139.1
FRS Companies	15,390.2	1,033.6	-475.6	1,305.7	14,642.5	79.2
All Other	13,167.8	2,927.4	475.6	1,542.3	15,028.5	189.8
FRS Companies' Foreign Oil Reserves						
Canada	2,061.5	364.9	-289.8	172.6	1,963.9	211.4
Europe	4,429.7	W	W	569.5	4,398.2	94.2
FSU and Eastern Europe	499.2	W	W	32.5	568.3	300.2
Africa	4,093.4	621.9	-119.9	341.5	4,254.0	182.1
Middle East	1,036.0	W	W	126.1	850.4	-45.7
Other Eastern Hemisphere	1,814.9	52.2	139.5	227.8	1,778.7	22.9
Other Western Hemisphere	1,521.8	198.6	217.1	106.2	1,831.4	187.0
Total Foreign	15,456.5	1,814.2	-49.6	1,576.2	15,644.9	115.1
Worldwide Total for FRS Companies	30,846.7	2,847.8	-525.2	2,881.9	30,287.5	98.8
Dry Natural Gas	(billion cubic feet)					
U.S. Onshore						
Total U.S. Industry	136,196.0	17,915.0	0.0	13,814.0	140,297.0	129.7
FRS Companies	54,949.7	4,402.8	-1,373.8	5,157.7	52,821.0	85.4
All Other	81,246.3	13,512.2	1,373.8	8,656.3	87,476.0	156.1
U.S. Offshore						
Total U.S. Industry	27,845.0	4,378.0	0.0	5,114.0	27,109.0	85.6
FRS Companies	20,376.3	1,185.2	-626.7	2,836.4	18,098.4	41.8
All Other	7,468.7	3,192.8	626.7	2,277.6	9,010.6	140.2
U.S. Total						
Total U.S. Industry	164,041.0	22,293.0	0.0	18,928.0	167,406.0	117.8
FRS Companies	75,326.0	5,588.0	-2,000.5	7,994.1	70,919.3	69.9
All Other	88,715.0	16,705.0	2,000.5	10,933.9	96,486.7	152.8
FRS Companies' Foreign Gas Reserves						
Canada	10,379.3	981.7	-255.7	1,095.9	10,009.4	89.6
Europe	23,154.8	W	W	2,332.1	22,698.1	78.8
FSU and Eastern Europe	343.4	722.9	0.0	23.2	1,043.1	3,115.6
Africa	1,804.2	W	W	44.1	2,402.3	1,495.1
Middle East	644.1	51.2	0.0	101.6	593.7	50.4
Other Eastern Hemisphere	23,170.4	1,143.5	1,341.0	1,627.4	24,027.5	70.3
Other Western Hemisphere	10,940.1	3,265.2	-805.0	457.8	12,942.6	152.5
Total Foreign	70,436.3	8,662.6	299.8	5,682.1	73,716.6	152.5
Worldwide Total for FRS Companies	145,762.3	14,250.6	-1,700.7	13,676.2	144,636.0	104.2

[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 oil 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.

W = Data withheld to avoid disclosure.

Note: "Net Ownership Interest" is defined as net working interest plus own royalty interest.

Sources: Industry data - Energy Information Administration Form EIA-23 (Annual Survey of Domestic Oil and Gas Reserves); see *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves Annual Report*, 1998 and 1999 (December 1999 and November 2000). FRS companies' data - Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B24. Oil and Gas Reserve Balances by Region for FRS Companies, 1999

Reserves Statistics	Worldwide Total	United States Total	United States Onshore	United States Offshore	Total Foreign
Crude Oil and Natural Gas Liquids	(million barrels)				
Beginning of Period	30,847	15,390	12,056	3,334	15,456
Revisions of Previous Estimates	637	214	169	45	423
Improved Recovery	500	253	246	7	247
Purchases of Minerals-in-Place	546	100	82	18	446
Extensions & Discoveries	1,710	566	177	389	1,144
Production	-2,882	-1,306	-892	-414	-1,576
Sales of Minerals-in-Place	-1,072	-576	-326	-250	-496
End of period	30,287	14,643	11,513	3,130	15,645
Proportionate Interest in Investee Reserves and Foreign Access Reserves	--	--	--	--	3,721
Natural Gas Reserves	(billion cubic feet)				
Beginning of Period	145,762	75,326	54,950	20,376	70,436
Revisions of Previous Estimates	1,146	-384	58	-442	1,531
Improved Recovery	1,199	428	333	95	771
Purchases of Minerals-in-Place	4,111	1,805	1,522	283	2,306
Extensions & Discoveries	11,905	5,544	4,012	1,533	6,361
Production	-13,676	-7,994	-5,158	-2,836	-5,682
Sales of Minerals-in-Place	-5,811	-3,805	-2,896	-909	-2,006
End of Period	144,636	70,919	52,821	18,098	73,717
Proportionate Interest in Investee Reserves and Foreign Access Reserves	--	--	--	--	21,182

See footnotes at end of table.

Table B24. Oil and Gas Reserve Balances by Region for FRS Companies,1999 (Continued)

Reserves Statistics	Foreign					
	Total	Canada	Europe and Former Soviet Union [1]	Africa and Middle East	Other Eastern Hemisphere	Other Western Hemisphere
Crude Oil and Natural Gas Liquids	(million barrels)					
Beginning of Period	15,456	2,061	4,929	5,129	1,815	1,522
Revisions of Previous Estimates	423	-1	210	124	-23	114
Improved Recovery	247	52	68	W	14	W
Purchases of Minerals-in-Place	446	42	W	W	141	244
Extensions & Discoveries	1,144	314	357	355	62	56
Production	-1,576	-173	-602	-468	-228	-106
Sales of Minerals-in-Place	-496	-332	W	-130	W	-27
End of period	15,645	1,964	4,967	5,104	1,779	1,831
Proportionate Interest in Investee Reserves and Foreign Access Reserves	3,721	W	806	1,470	W	854
Natural Gas Reserves	(billion cubic feet)					
Beginning of Period	70,436	10,379	23,498	2,448	23,170	10,940
Revisions of Previous Estimates	1,531	-32	1,184	112	-11	278
Improved Recovery	771	62	422	W	W	0
Purchases of Minerals-in-Place	2,306	587	W	0	1,499	W
Extensions & Discoveries	6,361	952	956	579	887	2,988
Production	-5,682	-1,096	-2,355	-146	-1,627	-458
Sales of Minerals-in-Place	-2,006	-843	W	W	W	W
End of Period	73,717	10,009	23,741	2,996	24,027	12,943
Proportionate Interest in Investee Reserves and Foreign Access Reserves	21,182	W	16,205	W	W	W

[1] OECD Europe combined with the former Soviet Union and Eastern Europe to avoid disclosure. Prior to 1993, only OECD Europe is include

-- = Not applicable.

W = Data withheld to avoid disclosure.

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B25. Oil and Gas Exploration and Development Expenditures, Reserves, and Production by Region for FRS Companies and Total Industry, 1999 and Percent Change from 1998

	United States			Foreign Total
	Total	Onshore	Offshore	
Exploration and Development Expenditures (million dollars)				
FRS Companies	13,487.0	6,570.0	6,917.0	17,792.0
Percent Change	-44.8	-51.2	-36.9	-32.6
Wells Completed				
FRS Companies	3,508.1	3,036.2	471.9	2,129.7
Percent Change	-37.9	-41.6	3.6	8.5
Industry[1]	18,161.0	17,992.0	168.0	16,901.0
Percent Change	-23.9	-22.7	-71.6	1.8
Success Rate[2]				
FRS Companies	90.3	91.6	81.9	91.5
Industry[1]	80.3	80.7	37.5	84.7
Crude Oil and NGL Production[3] (million barrels)				
FRS Companies	1,305.7	892.1	413.6	1,605.7
Percent Change	-6.0	-10.0	4.1	-10.4
Industry [1]	2,848.0	2,178.0	670.0	55,206.5
Percent Change	0.8	-2.1	11.7	144.3
Crude Oil and NGL Reserve Interests[4] (million barrels)				
FRS Companies	14,642.5	11,512.9	3,129.6	19,366.0
Percent Change	-4.9	-4.5	-6.1	3.1
Natural Gas Production (billion cubic feet)				
FRS Companies	7,994.1	5,157.7	2,836.4	5,682.1
Percent Change	-4.8	-6.1	-2.3	10.6
Industry[1]	18,928.0	13,814.0	5,114.0	62,999.0
Percent Change	1.1	1.5	0.2	4.6
Natural Gas Reserve Interests (billion cubic feet)				
FRS Companies	70,919.3	52,821.0	18,098.4	94,898.6
Percent Change	-6.1	-4.2	-11.3	4.6

See footnotes at end of table.

Table B25. Oil and Gas Exploration and Development Expenditures, Reserves, and Production by Region for FRS Companies and Total Industry, 1999 and Percent Change from 1998 (Continued)

	Foreign						
	Total	Canada	Europe & Former Soviet Union [5]	Africa	Middle East	Other Eastern Hemisphere	Other Western Hemisphere
Exploration and Development Expenditures (million dollars)							
FRS Companies	17,792.0	2,330.0	4,743.0	3,094.0	393.0	3,442.0	3,790.0
Percent Change	-32.6	-51.5	-51.9	-1.3	-58.3	-12.8	2.2
Wells Completed							
FRS Companies	2,129.7	1,358.8	137.0	87.4	168.1	271.8	106.6
Percent Change	8.5	67.5	-44.5	-40.5	17.0	-24.4	-58.0
Foreign Industry[1]	16,901.0	11,097.0	968.0	568.0	658.0	1,828.0	1,782.0
Percent Change	1.8	15.7	-21.0	-23.6	-4.9	-3.9	-27.1
Success Rate[2] (percent)							
FRS Companies	91.5	93.0	86.9	86.6	94.6	86.3	91.2
Foreign Industry[1]	84.7	82.9	81.9	86.1	95.7	85.8	91.8
Crude Oil and NGL Production[3] (million barrels)							
FRS Companies	1,605.7	172.6	602.0	341.5	155.6	227.8	106.2
Percent Change	-10.4	0.0	6.2	-39.6	6.2	-9.3	18.3
Foreign Industry[1]	55,206.5	947.2	5,305.3	2,717.4	7,988.0	1,620.6	3,662.8
Percent Change	144.3	-2.8	2.0	-1.1	-4.0	0.0	-1.9
Crude Oil and NGL Reserve Interests[4] (million barrels)							
FRS Companies	19,366.0	2,007.6	5,772.8	4,255.4	2,318.6	2,326.6	2,685.1
Percent Change	3.1	-1.2	-14.2	4.0	22.2	-7.0	75.4
Natural Gas Production (billion cubic feet)							
FRS Companies	5,682.1	1,095.9	2,355.3	44.1	101.6	1,627.4	457.8
Percent Change	10.6	26.2	14.9	28.1	5.3	-4.4	18.3
Foreign Industry[1]	62,999.0	5,730.5	33,762.5	4,015.0	6,606.5	8,176.0	4,708.5
Percent Change	4.6	1.5	4.1	12.3	3.4	3.4	9.7
Natural Gas Reserve Interests (billion cubic feet)							
FRS Companies	94,898.6	10,141.9	39,946.3	2,402.3	3,605.6	24,161.5	14,641.0
Percent Change	4.6	11.5	-4.5	33.2	5.4	3.6	29.9

[1]Foreign industry levels defined as total activity outside of the United States except the People's Republic of China.

[2]Success Rate defined as the total number of successful well completions during the period divided by the total number of wells drilled.

[3]Crude oil plus natural gas liquids. Foreign includes ownership interest production and foreign access production.

[4]Foreign includes net ownership interest reserves (80.8 percent of total foreign) and "Other Access" reserves (19.2 percent of total foreign). "Other Access" reserves include proportional interest in investee reserves and foreign access reserves.

Sources: Reserve additions, U.S. - Energy Information Administration Form EIA-23 (Annual Survey of Domestic Oil and Gas Reserves); see *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves* , 1998, and 1999 Annual Reports. Wells completed, U.S. - 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 2000, p. 81. Reserve Additions, Foreign - *British Petroleum Statistical Review of World Energy 1999 and 2000.* Wells Completed, Foreign - *World Oil* , August 1999 and 2000. FRS companies'

Table B26. U.S. and Foreign Refining/Marketing Sources and Dispositions of Crude Oil and Natural Gas Liquids for FRS Companies,1993-1999
(million barrels)

	1993	1994	1995	1996	1997	1998	1999
U.S. Refining/Marketing							
Sources							
Acquisitions from U.S. Production Segment	1,743	2,014	1,658	1,599	1,542	1,484	1,362
Purchases from Other U.S. Segments and Unconsolidated Affiliates	607	385	432	459	468	1,935	2,335
Purchases from Third Parties	3,925	3,937	4,100	4,488	4,444	4,968	5,205
Net Transfers from Foreign Refining/Marketing Segment	757	754	612	566	571	635	475
Total Sources	7,032	7,090	6,802	7,112	7,025	9,021	9,377
Dispositions							
Net Change in Inventories	31	48	23	21	14	31	-1
Input to Refineries	3,565	3,636	3,565	3,563	3,259	4,883	4,872
Sales to:							
Unaffiliated Third Parties	3,261	3,235	2,961	3,291	3,424	3,730	4,147
Other Segments Excluding Foreign Refining/Marketing	175	172	252	237	328	377	359
Total Dispositions	7,032	7,090	6,802	7,112	7,025	9,021	9,377
Foreign Refining/Marketing							
Sources							
Acquisitions from Foreign Production Segment	1,163	1,335	1,249	1,371	1,391	1,380	1,462
Purchases							
Other Foreign Segments	85	95	93	88	W	W	W
Unconsolidated Affiliates	2	63	89	89	W	W	W
Unaffiliated Third Parties							
Foreign Access	114	120	107	145	228	209	W
Foreign Governments (Open Market)	725	726	621	844	851	679	W
Other Unaffiliated Third Parties	2,653	2,147	2,063	1,819	1,785	2,000	2,244
Net Transfers to U.S. Refining/Marketing	-757	-754	-612	-566	-571	-635	-475
Total Sources	3,986	3,731	3,610	3,790	3,699	4,021	4,307
Dispositions							
Net Change in Inventories	-1	0	1	38	18	155	-19
Input to Refineries	1,530	1,535	1,520	1,605	1,435	1,419	1,641
Sales	2,456	2,195	2,090	2,147	2,246	2,446	2,685
Total Dispositions	3,986	3,731	3,610	3,790	3,699	4,021	4,307

W = Data withheld to avoid disclosure.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B27. U.S. Purchases and Sales of Oil, Natural Gas, Other Raw Materials, and Refined Products for FRS Companies, 1993-1999

	1993	1994	1995	1996	1997	1998	1999
Purchases	Values (million dollars)						
U.S. Refining/Marketing Segment							
Raw Materials							
Crude Oil and NGL	111,654	104,471	111,556	138,397	126,535	106,128	152,880
Natural Gas	10,678	12,360	9,747	15,651	18,657	15,177	20,387
Other Raw Materials	3,196	3,498	3,892	2,697	3,159	5,348	5,705
Total Raw Materials	125,528	120,329	125,195	156,745	148,351	126,653	178,972
Refined Products							
Motor Gasoline	11,831	12,430	14,131	18,078	18,613	24,249	36,095
Distillate Fuels	6,629	6,626	6,773	9,634	9,565	10,574	17,433
Other Refined Products	8,467	8,389	10,114	10,246	9,141	8,786	9,963
Total Refined Products	26,927	27,445	31,018	37,958	37,319	43,609	63,491
U.S. Production Segment							
Crude Oil and NGL	2,458	2,660	3,353	5,163	5,399	4,694	2,929
Natural Gas	5,042	5,950	6,981	10,715	11,220	8,922	8,422
Total Raw Materials	7,500	8,610	10,334	15,878	16,619	13,616	11,351
Sales							
U.S. Refining/Marketing Segment							
Raw Materials							
Crude Oil and NGL	56,612	49,752	53,544	69,485	70,437	50,702	72,955
Natural Gas	10,527	12,432	9,295	15,790	18,252	15,270	20,023
Other Raw Materials	1,720	2,201	2,325	1,276	1,499	2,172	1,576
Total Raw Materials	68,859	64,385	65,164	86,551	90,188	68,144	94,554
Refined Products							
Motor Gasoline	63,476	61,032	65,701	75,330	71,185	84,968	109,301
Distillate Fuels	33,064	30,568	30,420	41,618	36,962	39,513	51,810
Other Refined Products	21,107	23,190	24,577	24,577	20,964	23,283	28,506
Total Refined Products	117,647	114,790	120,698	141,525	129,111	147,764	189,617
U.S. Production Segment							
Crude Oil and NGL	25,734	23,468	26,303	32,948	30,604	19,688	22,397
Natural Gas	20,238	19,757	18,696	26,840	29,459	23,649	23,173
Total Raw Materials	45,972	43,225	44,999	59,788	60,063	43,337	45,570
Purchases	Volumes						
U.S. Refining/Marketing Segment							
Raw Materials							
Crude Oil and NGL (million barrels)	7,032	7,090	6,802	7,112	7,025	9,021	9,377
Natural Gas (billion cubic feet)	6,022	7,479	6,543	7,506	7,573	7,425	9,285
Refined Products (million barrels)							
Motor Gasoline	487	563	588	677	689	1,272	1,533
Distillate Fuels	288	322	321	380	397	625	837
Other Refined Products	378	345	422	363	329	464	446
Total Refined Products	1,153	1,230	1,330	1,420	1,415	2,361	2,815
U.S. Production Segment							
Crude Oil and NGL (million barrels)	178	201	237	300	308	394	212
Natural Gas (billion cubic feet)	2,569	3,276	4,395	4,723	4,551	4,295	3,745
Sales							
U.S. Refining/Marketing Segment							
Raw Materials							
Crude Oil and NGL (million barrels)	3,436	3,406	3,213	3,528	3,752	4,107	4,506
Natural Gas (billion cubic feet)	5,416	6,960	6,089	7,195	7,242	6,764	8,834
Refined Products (million barrels)							
Motor Gasoline	2,327	2,347	2,422	2,488	2,371	3,789	4,067
Distillate Fuels	1,400	1,392	1,374	1,562	1,473	2,146	2,344
Other Refined Products	1,082	1,172	1,183	1,069	1,008	1,342	1,407
Total Refined Products	4,810	4,911	4,979	5,119	4,852	7,277	7,817
U.S. Production Segment							
Crude Oil and NGL (million barrels)	1,898	1,889	1,875	1,933	1,860	1,805	1,513
Natural Gas (billion cubic feet)	9,801	10,810	12,108	12,281	12,421	11,765	10,948

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B28. U.S. and Foreign Petroleum Refining Statistics for FRS Companies, 1993-1999

	1993	1994	1995	1996	1997	1998	1999
U.S. Refining	(thousand barrels per calendar day)						
Runs to Stills							
At Own Refineries	9,676	9,809	9,669	9,777	9,060	13,699	13,476
By Refineries of Others	5	5	5	5	5	0	82
Total Runs to Stills	9,681	9,814	9,674	9,782	9,065	13,699	13,558
Refinery Output at Own Refineries and Refineries of Others							
Reformulated Motor Gasoline	-	-	-	1,302	768	1,552	1,792
Oxygenated Motor Gasoline	-	-	-	165	749	1,018	609
Other Motor Gasoline	-	-	-	3,410	2,980	4,665	4,588
Total Motor Gasoline	4,953	4,936	4,849	4,877	4,497	7,235	6,989
Distillate Fuels	2,916	3,030	2,901	3,323	2,921	4,278	4,167
Other Refined Products	2,953	2,846	2,902	2,754	2,612	3,416	3,483
Total Refinery Output	10,822	10,812	10,652	10,954	10,030	14,929	14,639
Refinery Capacity at End of Year	10,714	10,642	10,427	10,477	9,410	14,277	14,158
	(number of refineries)						
Number of Wholly-Owned Refineries	75	74	69	69	60	95	94
	(thousand barrels per calendar day)						
Foreign Refining							
Runs to Stills							
At Own Refineries	3,823	3,829	3,962	3,936	3,961	4,043	4,407
By Refineries of Others	312	304	323	506	340	292	397
Total Runs to Stills	4,135	4,133	4,285	4,442	4,301	4,335	4,804
Refinery Output at Own Refineries							
Motor Gasoline	1,114	1,122	1,175	1,172	1,041	1,135	1,247
Distillate Fuels	1,634	1,674	1,662	1,690	1,648	1,787	1,901
Other Refined Products	1,148	1,102	1,183	1,280	1,283	1,213	1,315
Total Refinery Output at Own Refineries	3,896	3,898	4,020	4,142	3,972	4,135	4,463
Refinery Output at Refineries of Others							
Motor Gasoline	85	85	70	107	75	83	122
Distillate Fuels	136	140	140	234	154	121	135
Other Refined Products	88	82	113	165	110	87	146
Total Refinery Output at Refineries of	309	307	323	506	339	291	403
Total Refinery Output	4,205	4,205	4,343	4,648	4,311	4,426	4,866
Refinery Capacity at End of Year	4,692	4,766	4,450	4,346	4,270	4,508	4,930
	(number of refineries)						
Number of Wholly-Owned Refineries	26	26	24	20	20	20	19
Number of Partially-Owned Refineries	14	14	13	12	15	15	18

- = Not available.

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B29. U.S. and Foreign Refinery Output and Capacity for FRS Companies, Ranked by Total Energy Assets, and Industry, 1999
(Thousand Barrels per Day)

Refined Product Statistics [1]	FRS Companies				Total Industry	FRS Percent of Industry
	All FRS	Top Four	Five through Twelve[2]	All Other[2]		
United States						
Refinery Output Volume[3]	14,639	3,977	3,323	7,339	17,493	83.7
Percent Gasoline						
Reformulated/Oxygenated	16.4	18.5	4.9	20.5	15.7	87.7
Other	31.3	26.2	47.3	26.9	30.8	85.1
Percent Distillate	28.5	27.5	29.8	28.4	29.6	80.5
Percent Other	23.8	27.8	18.0	24.3	23.9	83.3
Refinery Capacity						
Years Change (Net)	-119	474	-82	-511	221	(5)
At Year End	14,158	3,444	3,465	7,249	16,787	84.3
Utilization Rate[4]	94.8	100.6	91.5	93.8	91.4	(5)
Foreign						
Refinery Output Volume[3]	4,866	4,147	0	719	-	-
Percent Gasoline	28.1	27.3	0.0	32.7	-	(5)
Percent Distillate	41.8	41.1	0.0	45.9	-	(5)
Percent Other	30.0	31.5	0.0	21.4	-	(5)
Refinery Capacity						
Years Change (Net)	422	420	0	2	320	(5)
At Year End	4,930	4,240	0	690	64,930	7.6
Utilization Rate[3]	93.4	92.3	0.0	99.6	-	(5)

[1]U.S. FRS and U.S. industry data include operations in Puerto Rico and the U.S. Virgin Islands. Foreign FRS and foreign industry data exclude operations in Puerto Rico and the U.S. Virgin Islands, as well as China.

[2]For foreign FRS, the "Five through Twelve" and "All Other" groups are 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]Defined as average daily crude runs at own refineries, for own account, and for account of others, divided by average daily crude distillation capacity.

[5]Not meaningful.

- = Not available.

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

Sources: Industry data, U.S. - Refinery output and refinery capacity: Energy Information Administration, Forms EIA-820 (Annual Refinery Report) and EIA-810 (Monthly Refinery Report); see *Petroleum Supply Annual,* 1998 and 1999. Industry data, Foreign - Refinery Capacity: *British Petroleum Statistical Review of World Energy*, 1999 and 2000. FRS companies data - Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B30. U.S. Refining/Marketing Dispositions of Refined Products by Channel of Distribution for FRS Companies, 1993-1999

U.S. Dispositions	1993	1994	1995	1996	1997	1998	1999
	Values (million dollars)						
Motor Gasoline							
Intersegment Sales	196	268	365	400	581	966	1,521
U.S. Third-Party Sales							
Wholesale-Resellers	24,954	24,923	27,386	32,500	31,895	38,659	51,908
Company Operated Automotive Outlets	11,018	9,694	10,088	11,293	11,855	15,497	17,334
Company Lessee and Open Automotive	21,917	20,948	20,494	21,725	20,517	23,966	29,434
Other (Industrial, Commercial and Other	5,391	5,199	7,368	9,412	6,337	5,880	9,104
Total Third-Party Sales	63,280	60,764	65,336	74,930	70,604	84,002	107,780
Total Motor Gasoline Sales	63,476	61,032	65,701	75,330	71,185	84,968	109,301
Distillate Fuels							
Intersegment Sales	440	211	219	291	191	682	708
Third-Party Sales	32,624	30,357	30,201	41,327	36,771	38,831	51,102
Total Distillate Fuels Sales	33,064	30,568	30,420	41,618	36,962	39,513	51,810
Other Refined Products							
Intersegment Sales	4,213	3,824	3,952	4,124	3,322	2,059	2,779
Third-Party Sales	16,894	19,366	20,625	20,453	17,642	21,224	25,727
Total Other Refined Products Sales	21,107	23,190	24,577	24,577	20,964	23,283	28,506
Total U.S. Refined Products							
Intersegment Sales	4,849	4,303	4,536	4,815	4,094	3,707	5,008
Third-Party Sales	112,798	110,487	116,162	136,710	125,017	144,057	184,609
Total U.S. Refined Products Sales	117,647	114,790	120,698	141,525	129,111	147,764	189,617
	Volumes (million barrels)						
Motor Gasoline							
Intersegment Sales	9	9	11	12	18	50	66
U.S. Third-Party Sales							
Wholesale-Resellers	1,012	1,064	1,117	1,154	1,150	1,901	2,059
Company Operated Automotive Outlets	342	308	309	319	335	558	538
Company Lessee and Open Automotive	731	736	680	653	615	965	1,006
Other (Industrial, Commercial and Other	233	229	304	350	253	316	399
Total Third-Party Sales	2,318	2,338	2,411	2,476	2,353	3,739	4,001
Total Motor Gasoline Sales	2,327	2,347	2,422	2,488	2,371	3,789	4,067
Distillate Fuels							
Intersegment Sales	20	11	11	12	8	38	33
Third-Party Sales	1,380	1,381	1,363	1,550	1,464	2,109	2,310
Total Distillate Fuels Sales	1,400	1,392	1,374	1,562	1,473	2,146	2,344
Other Refined Products							
Intersegment Sales	240	226	222	209	254	141	153
Third-Party Sales	843	946	961	860	755	1,201	1,254
Total Other Refined Products Sales	1,082	1,172	1,183	1,069	1,008	1,342	1,407
Total U.S. Refined Products							
Intersegment Sales	269	246	245	232	280	229	252
Third-Party Sales	4,541	4,665	4,734	4,886	4,572	7,048	7,566
Total U.S. Refined Products Sales	4,810	4,911	4,979	5,119	4,852	7,277	7,817
Number of Active Automobile Outlets at Year End	Number of Automotive Outlets						
Company Operated	9,021	8,755	8,549	8,927	8,942	13,645	12,784
Lessee Dealers	18,588	16,385	15,861	15,247	12,852	16,396	14,828
Open Dealers	16,088	15,320	13,950	14,151	11,959	28,859	26,625
Total Outlets	43,697	40,460	38,360	38,325	33,753	58,900	54,237

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B31. Sales of U.S. Refined Products, by Volume and Price, for FRS Companies Ranked by Total Energy Assets, 1998-1999

(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								
1999	65.6	23.17	35.2	24.26	W	W	W	W
1998	49.6	19.49	18.3	20.57	W	W	W	W
Percent Change	32.5	18.9	92.3	17.9	W	W	W	W
Wholesale/Resellers								
1999	2,059.0	25.21	467.5	25.65	397.5	25.52	1,194.0	24.94
1998	1,900.7	20.34	443.4	20.53	435.8	21.09	1,021.5	19.93
Percent Change	8.3	23.9	5.4	24.9	-8.8	21.0	16.9	25.1
Dealer-Operated Outlets								
1999	1,006.2	29.25	351.4	30.33	153.3	27.85	501.5	28.92
1998	965.0	24.83	262.8	25.99	221.0	25.71	481.2	23.80
Percent Change	4.3	17.8	33.7	16.7	-30.6	8.3	4.2	21.5
Company-Operated Outlets								
1999	537.5	32.25	131.0	33.44	148.5	31.23	258.1	32.23
1998	557.7	27.79	86.1	30.03	189.5	28.17	282.1	26.85
Percent Change	-3.6	16.0	52.2	11.4	-21.7	10.9	-8.5	20.0
Other [1]								
1999	398.6	22.84	18.6	19.81	145.8	23.29	234.2	22.80
1998	315.7	18.63	21.4	18.62	110.9	18.57	183.3	18.66
Percent Change	26.3	22.6	-13.1	6.4	31.5	25.4	27.7	22.2
Total Gasoline								
1999	4,067.1	26.87	1,003.7	28.15	875.6	26.40	2,187.8	26.48
1998	3,788.7	22.43	832.0	23.19	957.3	23.27	1,999.3	21.71
Percent Change	7.3	19.8	20.6	21.4	-8.5	13.5	9.4	22.0
Distillate								
1999	2,343.7	22.11	613.9	21.97	500.4	22.42	1,229.5	22.04
1998	2,146.3	18.41	515.3	18.11	563.9	18.98	1,067.1	18.25
Percent Change	9.2	20.1	19.1	21.3	-11.3	18.2	15.2	20.8
All Other Products								
1999	1,406.6	20.27	371.2	23.24	244.2	18.52	791.2	19.41
1998	1,341.9	17.35	320.7	19.25	257.2	17.29	764.1	16.57
Percent Change	4.8	16.8	15.7	20.7	-5.0	7.1	3.5	17.1
Total Refined Products								
1999	7,817.4	24.26	1,988.8	25.32	1,620.2	23.98	4,208.4	23.86
1998	7,276.9	20.31	1,667.9	20.86	1,778.5	21.04	3,830.5	19.72
Percent Change	7.4	19.5	19.2	21.4	-8.9	14.0	9.9	21.0

[1] Includes direct sales to industrial and commercial customers and sales to unconsolidated affiliates.

W = Data withheld to avoid disclosure.

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

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B32. U.S. Refining/Marketing Revenues and Costs for FRS Companies, 1993-1999
(Million Dollars)

Revenues and Costs	1993	1994	1995	1996	1997	1998	1999
Refined Product Revenues	117,647	114,790	120,698	141,525	129,111	147,764	189,617
Refined Product Costs							
Raw Materials Processed [1]	58,161	58,025	62,142	70,339	58,888	60,094	83,348
Refinery Energy Expense	5,636	4,702	4,101	5,480	5,005	5,349	6,427
Other Refinery Expense	8,889	8,854	8,854	9,882	8,436	12,219	11,734
Product Purchases	26,927	27,445	31,018	37,958	37,319	43,609	63,491
Other Product Supply Expense	4,153	3,432	3,432	4,072	3,777	5,160	4,915
Marketing Expense [2]	10,463	8,822	8,709	9,318	8,538	10,308	11,100
Total Refined Product Costs	114,229	111,280	118,256	137,049	121,963	136,739	181,015
Refined Product Margin	3,418	3,510	2,442	4,476	7,148	11,025	8,602
Refined Products Sold (million barrels)	4,810.0	4,911.0	4,978.8	5,118.6	4,852.2	7,276.9	7,817.4
Dollars per Barrel Margin [3]	0.71	0.71	0.49	0.87	1.47	1.52	1.10
Other Refining/Marketing Revenues [4]	10,614	10,586	10,449	10,731	9,693	15,997	14,282
Other Refining/Marketing Expenses							
DD&A	3,659	3,780	4,732	3,847	3,674	4,700	5,273
Other [5]	7,796	7,454	7,166	7,873	8,419	15,547	12,546
Total Other Expenses	11,455	11,234	11,898	11,720	12,093	20,247	17,819
Refining/Marketing Operating Income	2,577	2,862	993	3,487	4,748	6,775	5,065
Miscellaneous Revenue & Expense [6]	207	289	-107	-101	204	1,315	1,367
Less Income Taxes	1,099	1,306	371	1,135	1,876	2,142	1,714
Refining/Marketing Net Income	1,685	1,845	508	2,251	3,106	5,932	4,883

[1]Represents reported cost of raw materials processed at refineries, less any profit from raw material trades or exchanges by refining/marketing.

[2]Excludes costs of nofuel goods and services and 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, 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 (Financial Reporting System).

Table B33. U.S. Petroleum Refining/Marketing General Operating Expenses for FRS Companies, 1993-1999
(Million Dollars)

General Operating Expenses	1993	1994	1995	1996	1997	1998	1999
Raw Material Supply							
Raw Material Purchases	125,528	120,329	125,195	156,745	148,351	126,653	178,972
Other Raw Material Supply Expense	5,084	5,014	4,699	4,067	4,523	5,183	3,184
Total Raw Material Supply Expense	130,612	125,343	129,894	160,812	152,874	131,836	182,156
Less: Cost of Raw Materials Input To Refining	60,989	59,336	64,086	75,892	64,132	62,955	85,270
Net Raw Material Supply	69,623	66,007	65,808	84,920	88,742	68,881	96,886
Refining							
Raw Materials Input to Refining	60,989	59,336	64,086	75,892	64,132	62,955	85,270
Less: Raw Material Used as Refinery Fuel	3,592	2,933	2,588	3,922	3,798	3,598	4,254
Refinery Process Energy Expense	5,636	4,702	4,101	5,480	5,005	5,349	6,427
Other Refining Operating Expenses	9,803	9,658	9,551	10,631	9,173	12,984	12,928
Refined Product Purchases	26,927	27,445	31,018	37,958	37,319	43,609	63,491
Other Refined Product Supply Expenses	4,153	3,432	3,432	4,072	3,777	5,160	4,915
Total Refining	103,916	101,640	109,600	130,111	115,608	126,459	168,777
Marketing							
Cost of Other Products Sold	4,734	4,074	4,389	5,449	6,255	6,844	5,305
Other Marketing Expenses	10,463	8,822	8,709	9,318	8,538	10,308	11,100
Subtotal	15,197	12,896	13,098	14,767	14,793	17,152	16,405
Expense of Transport Services for Others	950	1,125	627	507	376	4,297	4,191
Total Marketing	16,147	14,021	13,725	15,274	15,169	21,449	20,596
Total U.S. Refining/Marketing Segment General Operating Expenses	189,686	181,668	189,133	230,305	219,519	216,789	286,259

Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B34. U.S. Coal Reserves Balance for FRS Companies, 1993-1999
(Million Tons)

Reserves and Production Statistics	1993	1994	1995	1996	1997	1998	1999
Changes to U.S. Coal Reserves							
Beginning of Period	18,593	16,142	13,395	10,493	9,410	7,502	5,334
Changes due to:							
Leases/Purchases of Minerals-in-Place	145	W	W	W	W	W	W
Corporate Mergers and Acquisitions	0	W	W	W	W	W	0
Other Reserve Changes	-325	-61	-699	8	-127	W	W
Production	-197	-180	-165	-169	-163	-74	-44
Dispositions of Minerals-in-Place	-2,074	-2,591	-2,128	-1,150	-774	-2,113	-802
End of Period Reserves	16,142	13,381	10,493	9,542	8,498	5,334	4,507
Weighted Average Annual Production Capacity	236	201	184	192	215	65	55
Reserves and Production:							
Total United States							
FRS Companies' Reserves	16,142	13,381	10,493	9,542	8,498	5,334	4,507
FRS Companies' Production	197	180	165	169	163	74	44
U.S. Industry Production	941	1,029	1,028	1,059	1,085	1,113	1,099
Region							
East							
FRS Companies' Reserves	2,946	2,833	2,763	2,675	2,477	1,774	1,676
FRS Companies' Production	41	46	46	44	43	24	21
U.S. Industry Production	405	441	430	447	463	455	-
Midwest							
FRS Companies' Reserves	3,673	3,212	3,206	2,467	2,080	1,372	1,055
FRS Companies' Production	14	16	17	18	17	12	W
U.S. Industry Production	107	121	109	112	112	110	-
West							
FRS Companies' Reserves	9,523	7,336	4,524	4,400	3,940	2,188	1,776
FRS Companies' Production	143	118	103	107	104	38	W
U.S. Industry Production	429	467	489	500	511	548	538
Mining Method							
Underground							
FRS Companies' Reserves	6,068	5,479	5,337	4,571	3,880	2,352	1,853
FRS Companies' Production	53	59	62	59	51	28	21
U.S. Industry Production	351	399	396	409	420	417	411
Surface							
FRS Companies' Reserves	10,074	7,902	5,156	4,970	4,618	2,982	2,654
FRS Companies' Production	145	121	103	110	112	46	23
U.S. Industry Production	591	630	633	650	665	696	688

W = Data withheld to avoid disclosure.
- = Not available.
Sources: Energy Information Administration, Form EIA-28 (Financial Reporting System). Coal production: 1993-1998--EIA, *Coal Industry Annual*, annual reports; 1999--EIA estimates and *Quarterly Coal Report October-December 1999* (May 2000), Table 4.