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Performance Profiles of Major Energy Producers 2000

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This report was prepared in the Office of Energy Markets and End Use of the Energy Information Administration (EIA), U.S. Department of Energy, under the general direction of W. Calvin Kilgore. The project was directed by Mark E. Rodekohr, Director of the Energy Markets and Contingency Information Division (202) 586-1130, and Mary E. Northup, the Team Leader for Financial Analysis (202) 586-1383. Specific technical information concerning this report and the associated data survey (Form EIA-28) may be obtained from Jon A. Rasmussen (202) 586-1449. The following authors contributed to this report: Neal Davis, Jon Rasmussen, Bob Schmitt, and Larry Spancake. In addition, Kevin Forbes of SAIC provided essential research into major resource development areas.

Data File Information

Historical Financial Reporting System (FRS) data are available from the Energy Information Administration's File Transfer Protocol (FTP) site. These data cover the years 1977 through 2000, 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 1977-2000 data files can be downloaded from the Energy Information Administration's FTP site by accessing the following EIA 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 by email: 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.[1] (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 2000" on page 1.) 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[2] (trends and transactions) in U.S. energy resources, assets, and companies was previously included as a separate chapter in the report. However, the Foreign Direct Investment report is now published separately on the Internet (see http://www.eia.doe.gov/emeu/finance/fdi/index.html).

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 2000. Although the focus is on 2000 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 Energy Information Administration (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 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.

Endnotes

[1] The U.S.-based energy companies that respond to the Financial Reporting System (FRS) Form EIA-28 are considered to be U.S. majors by the Energy Information Administration (see P.L. 95-91, Sec. 205 (h)). Per the requirements of that statute, the Administrator of the Energy Information Administration designates "major energy-producing companies" and selects them as respondents to the FRS. Currently, the Administrator uses the following selection criteria: at least 1 percent of U.S. oil (crude oil and natural gas liquids) reserves or production, or at least 1 percent of U.S. natural gas reserves or production, or at least 1 percent of U.S. crude oil distillation capacity, or 1 percent of refined petroleum product sales.

[2]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

Tight supply conditions in global petroleum markets and U.S. natural gas markets led to record high profits for major energy companies in 2000. Key developments in 2000 included:

- Global petroleum inventories began the year well below normal levels
- In the United States, petroleum stocks at the beginning of 2000 were 15 percent below those of the prior year
- Natural gas demand in the United States outpaced supplies coming from U.S. and Canadian producers, resulting in a record drawdown of natural gas inventories
- Crude oil prices rose for most of the year, averaging over $10 per barrel more than in 1999
- Natural gas prices at the U.S. wellhead rose from $2.12 per thousand cubic feet in January to $6.35 in December, an increase of $25 per barrel of oil equivalent.

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).

Through Form EIA-28, major U.S. energy companies annually report to the FRS (see the box entitled "The FRS Companies in 2000" on page 1 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 businesses.

Profits of Major Energy Companies Soar to a Record High in 2000

Net income of the FRS companies totaled $53.2 billion in 2000, a 133-percent increase from 1999's results. Excluding the effects of unusual items (such as asset writedowns), the increase was 134 percent. This was the highest level of net income over the 1974 through 2000 period of FRS data collection. The corporate profitability of the FRS companies in 2000 was second only to that of 1980 and clearly exceeded that of other large industrial corporations generally, as represented by the Standard & Poor's Industrials, for only the second time in nearly two decades.

The upswing in the FRS companies' bottom-line results was mainly driven by sharply higher prices for oil and natural gas in 2000. In the United States, oil prices (as measured by the refiner acquisition cost of imported crude oil) continued a rise that began in early 1999, when prices were $10 per barrel, and lasted through the fall of 2000, when prices averaged $30 per barrel. Natural gas prices tripled during 2000, from January's $2.12 per thousand cubic feet at the wellhead to $6.35 in December. The FRS companies' net income from worldwide oil and gas production totaled $40.6 billion in 2000, up 159 percent from 1999's results.

The FRS companies' petroleum refining and marketing operations also posted strong gains in income in 2000. Net income from U.S. refining and marketing in 2000 was up 57 percent from net income in 1999 and up 56 percent in foreign refining and marketing.

A steep rise in refining/marketing income is uncharacteristic of periods in which oil prices are also rising steeply. However, the year 2000 was unusual. The year began with lower-than-normal petroleum inventories and high rates of refinery utilization. Tight supply conditions, together with general growth in petroleum product demand, made it possible to fully pass along crude oil price rises. Also, in 2000, sporadic price spikes for gasoline and distillate, brought on by refinery outages and temporary petroleum transport bottlenecks, added to upward pressures on petroleum product prices.

The FRS companies' other businesses overall contributed $6.3 billion to bottom-line net income in 2000, a 71-percent increase. This surge was led by the near quadrupling of earnings from the other energy line of business. The other energy line of business is mainly composed of electricity supply and trading, natural gas trading at wholesale and retail, and provision of associated services such as risk management (e.g., price hedging). Among the FRS lines of business, other energy accounted for 5 percent of the investment base and has been the most rapidly growing in recent years. Between 1995 and 2000, the investment base for this line of business increased eightfold compared to a 33-percent increase for the rest of the lines of business combined.

Led by Mergers and Acquisitions, Capital Expenditures Nearly Double

Capital expenditures of the FRS companies totaled $109.3 billion in 2000, up 90 percent from expenditures in 1999 to an all-time high. Mergers and acquisitions accounted for nearly all of the growth in capital expenditures. Based on dollar value, most of the merger and acquisition activity in 2000 involved transactions between FRS companies. Excluding the effects of mergers and acquisitions, the FRS companies' capital expenditures increased by only 3 percent between 1999 and 2000. Over the past five years, intra-FRS transactions have played an important role in changing the cast of U.S. major energy companies (see the Special Topic on this subject on page 47).

The bulk of the capital expenditures were for oil and gas exploration and development, and most of the increase in expenditures for oil and gas exploration and development involved mergers and acquisitions. However, excluding the effects of mergers and acquisitions, some regions stood out as targets of upstream investment. The U.S. onshore, which includes Alaska, registered the largest increase in expenditures. Areas of increased activity, based on the FRS companies' public disclosures, included gas projects in the Rocky Mountains, oil projects in Alaska's North Slope, and rejuvenation of long-producing fields such as Texas' Permian Basin through application of advanced technologies. Offshore projects, almost entirely in the Gulf of Mexico, also registered a notable increase in expenditures for exploration and development.

Outside the United States, the prospects for natural gas exports from Canada continued to attract exploration and development activity by FRS companies. In South America, the FRS companies' drilling activity bounced back in 2000 from a sharp dip in 1999 and nearly matched the elevated levels of drilling of 1998. In the Asia-Pacific region, the FRS companies maintained a focus on natural gas development. Even though economic growth in the region began to slow in 2000, the demand for natural gas in this region is expected to grow in the longer term both to fuel future economic growth and to provide a clean-burning fuel for electric power generation.

Other lines of business registering notable increases in capital expenditures were U.S. refining and other energy. Capital expenditures for U.S. refining nearly tripled between 1999 and 2000, from $2.8 billion to $8.2 billion. Most of the increase was the result of intra-FRS mergers and acquisitions. Excluding the effects of mergers and acquisitions, capital expenditures for U.S. refining were still up a solid 19 percent. Expenditures were primarily directed at refinery capacity upgrades rather than expansion of basic capacity. The FRS companies' capital expenditures for the other energy line of business more than tripled between 1999 and 2000, to $5.4 billion. Most of the growth in capital expenditures appeared to be related to internal expansion, as the value of acquisitions in other energy totaled less than $200 million.

Reserves Added Through the Drill Bit at Second Highest Level in at Least 27 Years

The high level of capital expenditures for acquisitions of oil and natural gas producers is part of a recent trend among the majors. In recent years, the growth in the FRS companies' U.S. reserve base has increasingly come from mergers and acquisitions. By 2000, over 60 percent of the FRS companies' total additions to reserves were gained in this way, up from an average of slightly over 10 percent in the 1990 to 1996 period. Nevertheless, major energy companies' performance through the drill bit in 2000 was among the best in the 27 years spanned by the FRS data.

The FRS companies' worldwide additions to their oil and gas reserves from exploration and development activities, mainly drilling -- hence, through the drill bit, totaled 6.6 billion barrels (crude oil equivalent) in 2000. Only the 6.8 billion barrels added in 1997 exceeded this level. Reserve additions exceeded worldwide oil and gas production by 22 percent in 2000. That is, the "replacement ratio," an often-used measure of exploration and development performance, hit 122 percent worldwide in 2000, again the second best since at least 1974 for the FRS companies. The FRS companies' worldwide replacement ratio for oil was 135 percent and 108 percent for natural gas.

The U.S. onshore stood out among the regions in terms of replacing production. The FRS companies replaced 166 percent of their oil production from onshore U.S. locales in 2000, compared with 136 percent in the U.S. offshore (almost entirely the Gulf of Mexico), and 119 percent abroad. The regional differences were more pronounced for natural gas. The FRS companies replaced 144 percent of their U.S. onshore natural gas production compared with 90 percent offshore and 84 percent abroad.

Epilog

Enron Restates Financial Results, Files for Bankruptcy Protection

While this report was undergoing review, Enron Corporation, an FRS company, restated its financial results and subsequently filed for bankruptcy protection. In 2000, Enron was among the largest of the 33 respondents to the FRS, ranking second on the basis of operating revenues, third on the basis of total assets, and tenth on the basis of net income. For the purposes of this report, these developments raise two issues. First, do the restatements affect the data presented in this report? Second, might the possible absence of Enron from the FRS group in the 2001 reporting year (due to the uncertain timing and outcome of the bankruptcy proceedings) significantly affect the interpretation of overall financial results for FRS companies in 2001?

The Restatements

In a filing of a Form 8-K Report with the Securities and Exchange Commission on November 8, 2001, Enron provided a restatement of its financial statements for 1997 through the second quarter of 2001. The restatements stemmed from Enron and its auditors' determination that certain off-balance sheet entities should have been included in Enron's consolidated financial statements according to generally accepted accounting principles. Restatements by FRS companies have been infrequent during the 27 years spanned by the FRS data. Restatements typically have no material effect on previously published FRS data. For that reason, respondents have not been required to provide restatements of Form EIA-28 information.

Enron's restatements are also immaterial, relative to the Form EIA-28 data contained in this report. The effect on the aggregate FRS data of the four financial items restated by Enron (net income, long-term debt, stockholders' equity, and total assets) for 1997 through 2000 is 1 percent or less except for long-term debt in 1999 and 2000 for which the effect of the restatements is 2 percent. Thus, Enron's restatements have no material effects on the FRS data and can be omitted from the FRS database.

The Bankruptcy Filing

Enron filed for bankruptcy protection under Chapter 11 on December 2, 2001. Due to the uncertain timing and outcome of the bankruptcy process, Enron might not submit a Form EIA-28 for the 2001 reporting year. Will the possible absence of Enron affect the interpretation of information contained in the next edition of this report?

To address this question, tables in this report were run with Enron deleted for 2000. In general, the year-to-year changes in the data are qualitatively unaffected. That is, percentage changes that are reported as positive remained positive when Enron was omitted for 2000 and so too for negative changes. The only exceptions were for net income from the nonenergy line of business and proceeds from the issuance of long-term debt.

These results should not be surprising. Financial flows such as revenues, income, cash flow, and investment tend to move in the same direction for most FRS companies since they generally face similar market developments in a given year. Although a single FRS company may be among the worlds largest, its financial results are rarely contrary enough to reverse the aggregate results for all companies. Thus, interpretation of FRS data for the 2001 reporting year appears likely to be largely unaffected if Enron should be absent from the database in that year.

1. Market Developments and FRS Companies in 2000

Developments in Global Oil and Gas Markets

The major U.S. energy companies[3] derive the bulk of their revenues and income from petroleum operations, including natural gas production. A majority of these companies are multinational, with 35 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 below entitled "The FRS Companies in 2000.")

The FRS Companies in 2000 (* Denotes new survey entrant in 2000)	
Amerada Hess Corporation	Exxon Mobil Corporation
American Petrofina Holding Company	Kerr-McGee Corporation
(formerly known as Fina, Inc.)	Lyondell-CITGO Refining, L.P.
Anadarko Petroleum Corporation	Motiva Enterprises, L.L.C.
Apache Corporation *	Occidental Petroleum Corporation
BP America, Inc.	Phillips Petroleum Company
Burlington Resources, Inc.	Premcor, Inc.
Chevron Corporation	Shell Oil Company
CITGO Petroleum Corporation	Sunoco, Inc.
Coastal Corporation	Tesoro Petroleum Corporation
Conoco, Inc.	Texaco, Inc.
Devon Energy Corporation*	Tosco Corporation
Dominion Resources, Inc.*	Ultramar Diamond Shamrock Corporation
El Paso Energy Corporation	Unocal Corporation
Enron Corporation	USX Corporation
EOG Resources, Inc.*	Valero Energy Corporation
Equilon Enterprises, L.L.C.	The Williams Companies, Inc.

In 2000, oil and natural gas markets were characterized by tightness of supplies. In commodity markets generally, and oil and natural gas markets in particular, inventory levels substantially below normal are symptomatic of growth in demand outpacing the ability and willingness of producers to supply the market.

Holdings of petroleum stocks by the nations of the Organization for Economic Cooperation and Development (OECD) provide clear evidence of the tightness of global oil markets in 2000. The 12 industrialized nations of the OECD account for 62 percent of world petroleum consumption. The OECD petroleum stocks in 2000 began the year 311 million barrels below the beginning of the prior year, and were below normal levels until the end of 2000.[4] The United States, with petroleum stocks registering

15 percent below those of the prior year, accounted for about half of the gap. As with the rest of the OECD nations, the gap steadily narrowed and was closed at year end.

Tight supplies put upward pressures on prices. In 2000, crude oil prices continued the rise that began in early 1999, and hit a plateau of $30 per barrel (as measured by the U.S. refiner acquisition cost of imported crude oil) in the Fall of 2000. On an annual basis, the price of crude oil in 2000 averaged more than $10 per barrel over the price in 1999.

Natural gas prices in the United States also registered a steep rise in 2000. The average wellhead price of natural gas rose from $2.12 per thousand cubic feet in January to $6.35 in December. In terms of oil equivalence, this equates to a $25-per-barrel increase. Similar to oil prices, the increase in natural gas prices reflected tight market conditions.

Natural gas demand in the United States was up 5 percent between 1999 and 2000. Increased demand came from industrial users (including non-utility electricity generators) for much of the year and from space heating demand stemming from colder winter temperatures compared to 1999. Indigenous production and natural gas imports (nearly all from Canada) were not sufficient to satisfy the growth in U.S. natural gas demand. Over half of the growth in demand during the year was met by withdrawals of natural gas from storage in excess of the amount of natural gas added. Net withdrawals from storage, on an annual basis, were at an all-time high in 2000. This heavy draw on natural gas inventories resulted in continued price rises to allocate the tightening supplies.

Higher prices for oil and natural gas in 2000 led to soaring bottom-line results for U.S. oil and gas producers, including the FRS companies' upstream operations. Income from petroleum refining and marketing was also up sharply in 2000, a rare occurrence in a period of sharply rising crude oil prices.

As in upstream operations (i.e., oil and gas production), petroleum product price rises reflected tight supply conditions. Prices of refined products, over the course of 2000, outpaced the rise in crude oil input costs. The spread between prices and costs for U.S. refiners widened, largely due to low holdings of petroleum products and sporadic spikes in petroleum product prices stemming from refinery outages and transport bottlenecks. Also, U.S. refineries ran at high utilization rates during 2000, putting additional upward pressures on petroleum product prices.

In the United States, the overall spread between refiners' product prices and crude oil input costs, at just under $10 per barrel on an annual basis, was at an all-time high (at least since 1983 when these data were initially collected by EIA). Abroad, price-cost margins for refiners in 2000, on an annual basis, were above 1999 levels in European and Asia-Pacific markets. These two areas account for roughly 75 percent of the FRS companies' foreign refining capacity.

Chemical operations generally, and those of the FRS companies as well, were adversely affected by energy market developments in 2000. Higher prices for petroleum and natural gas led to cost increases for chemicals manufacturers. Chemical prices rose in response to these costs increases. However, the cost increases could not be fully passed through as worldwide capacity continued to exceed global demand.

Changes in the FRS Group in 2000

Mergers and Acquisitions

Two companies, Atlantic Richfield (ARCO) and Union Pacific Resources Group, departed the FRS respondent group as a result of their acquisition by other FRS companies.

Former FRS respondent Amoco was merged with London-based British Petroleum plc in December 1998 to become BP Amoco plc. Subsequently, in April 2000, BP Amoco plc (a British company) acquired ARCO for $26.8 billion in stock. For the 2000 reporting year, former FRS respondent ARCO's operations are combined with FRS respondent BP America (BP Amoco plc's U.S.-based subsidiary). On a simultaneous track, also for the 2000 reporting year, BP Amoco Inc. (a formerly separate U.S. subsidiary of the British parent, BP Amoco plc) ceased to exist, as the U.S. BP America, Inc. began consolidating their operations with those of U.S.-based BP Amoco Inc.'s financial information. In order to hereafter simplify the exposition in this report, the FRS respondent and its parent will be referred to as BP Amoco.

In another intra-FRS combination, Anadarko Petroleum, an FRS respondent since 1992, merged with FRS respondent Union Pacific Resources Group in a $4.4-billion transaction in July 2000.

The ARCO acquisition, excluding subsequent divestitures, raised BP Amoco's share of U.S. oil production from 10 percent to 16 percent and U.S. natural gas production from 5 percent to 7 percent. BP Amoco's share of U.S. refinery capacity, excluding subsequent divestitures, rose from 10 percent to 13 percent. The merger between Anadarko Petroleum and Union Pacific Resources Group raised Anadarko's shares of U.S. oil and natural gas production by 1 percentage point and 2 percentage points, respectively.

New Entrants

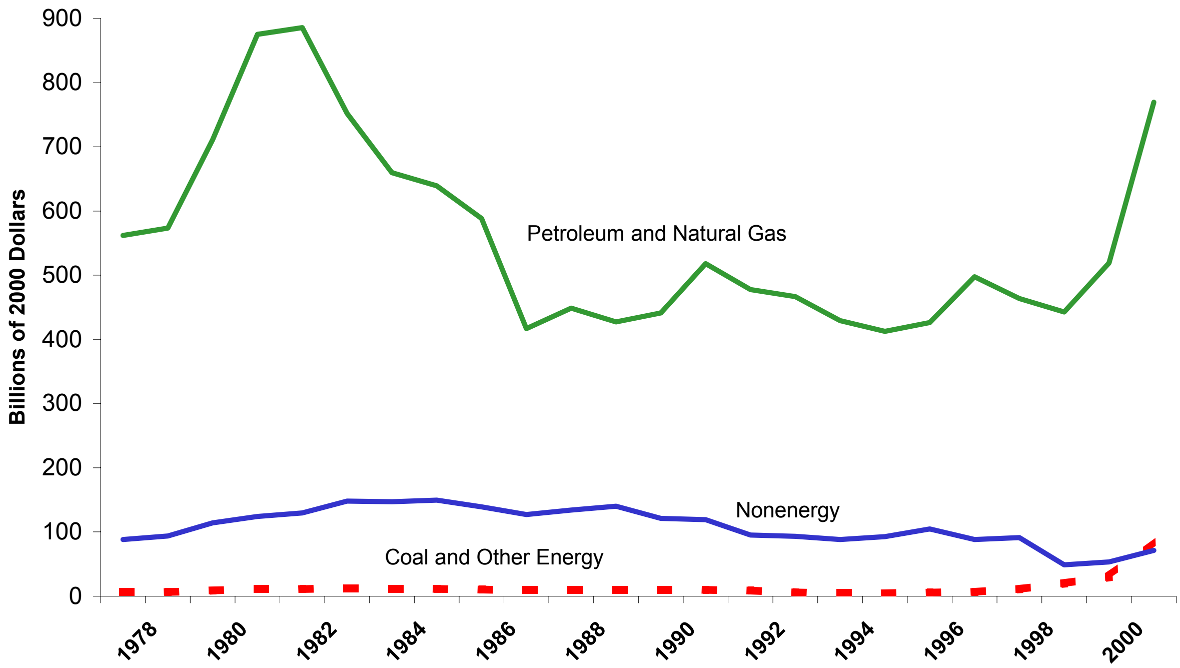
Four companies were added to the FRS respondent group for the 2000 reporting year: Apache Corporation, Devon Energy Corporation, Dominion Resources Inc., and EOG Resources Inc. (a spinoff of FRS respondent Enron Corporation). These companies were selected primarily for their shares of U.S. natural gas production and reserves.

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

For the reporting year 2000, 33 major energy companies reported their financial and operating data to the EIA Financial Reporting System (FRS) on Form EIA-28.[5] These companies (referred to as the FRS companies in this report) occupy a significant position in the U.S.[6] economy. In 2000, operating revenues of the FRS companies totaled $911 billion, which is equal to 13 percent of the $7.2 trillion in revenues of the Fortune 500 largest U.S. corporations.[7]

The reporting companies engage in a wide range of business activities, but their most important activities are in the energy sector. About 93 percent of allocated operating revenues were derived from energy sales. Nearly all of these revenues were derived from the companies' core petroleum and natural gas operations (Figure 1).

Figure 1. Operating Revenues by Line of Business for FRS Companies, 1977-2000



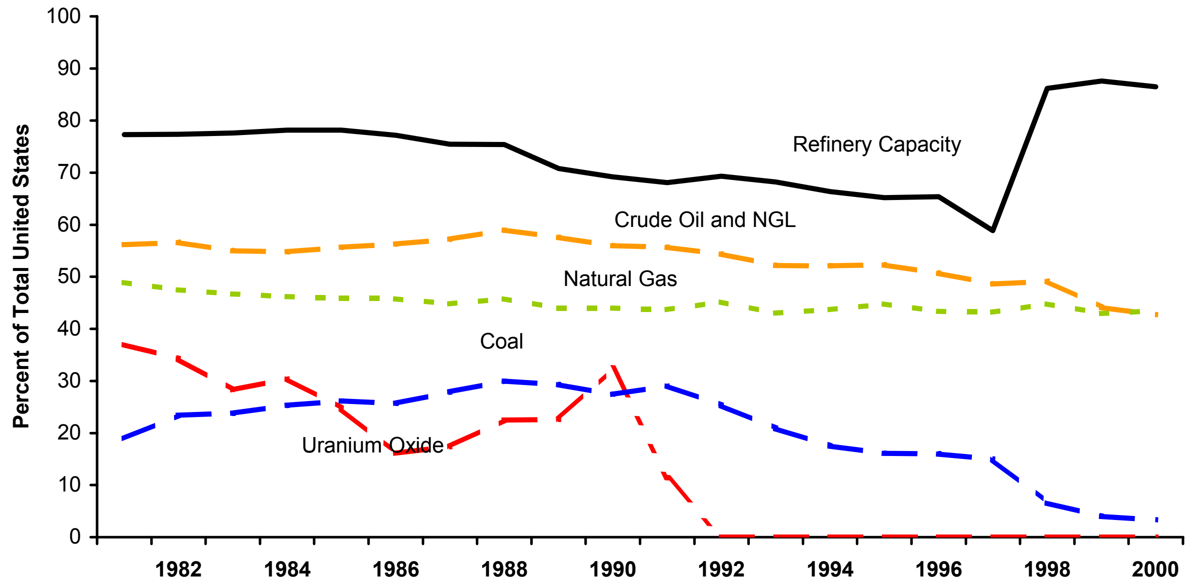
Source: Energy Informatin Administration, Form EIA-28 (Financial Reporting System)

In 2000, the FRS companies accounted for 43 percent of total U.S. oil (crude oil and natural gas liquids (NGL)) production, 44 percent of natural gas production, and 87 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.

Energy production other than oil and natural gas is a relatively small, but growing, part of the FRS companies' operations. During 2000 the combined operating revenues of the coal and other energy operations of the FRS companies totaled $87 billion, or 10 percent of allocated revenues. Increased activity in electricity more than offset the continued decline in coal activity by the FRS companies in 2000. In particular, the FRS companies accounted for 15 percent of U.S. coal production in 1997, 7 percent in 1998, 4 percent in 1999, and 3 percent in 2000. No FRS company has produced uranium oxide since 1991.

Nonenergy businesses, mainly chemicals, accounted for about 8 percent, or $71 billion, of the FRS companies' allocated revenues in 2000.

Figure 2. Shares of U.S. Energy Production and Refinery Capacity for FRS Companies, 1981-2000



Note: The FRS companies last produced uranium oxide in 1991.

Sources: Table B1; Total industry uranium oxide production is from Energy Information Administration, Uranium Industry Annual 1992, DOE/EIA-0478(92) (Washington, DC, October 1993).

Endnotes

[3]The U.S.-based energy companies that respond to the Financial Reporting System (FRS) Form EIA-28 are considered to be U.S. majors by the Energy Information Administration (see P.L. 95-91, Sec. 205 (h)). Per the requirements of that statute, the Administrator of the Energy Information Administration designates "major energy-producing companies" and selects them as respondents to the FRS. Currently, the Administrator uses the following selection criteria: at least 1 percent of U.S. crude oil or natural gas liquids reserves or production, or at least 1 percent of U.S. natural gas reserves or production, or at least 1 percent of U.S. crude oil distillation capacity. The companies that reported to the FRS for the years 1974 through 2000 are listed in Appendix A, Table A1 (available on the EIA Web site at http://www.eia.doe.gov/emeu/perfpro/taba1.html). Three of the FRS companies are owned by foreign companies: BP America—owned by BP Amoco plc; American Petrofina Holding Company—owned by TotalFinaElf; and Shell Oil—owned by Royal Dutch/Shell.

[4]In this chapter, energy data were obtained from Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(01/09) (Washington, DC, September 2001). Chemical price index is from Bureau of Labor Statistics.

[5] Aggregate time series data from Form EIA-28 for 1977 through 2000 and previous editions of this report can be obtained from the EIA (see http://www.eia.doe.gov/emeu/finance/page2.html).

[6] For the 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.

[7] The Fortune 500 is a list of the 500 largest U.S. corporations, ranked by revenues, published annually by *Fortune* magazine (see http://www.fortune.com/indexw.jhtml?channel=list.jhtml&list_frag=list_3column_fortune500_list.jhtml&list=15&_requestid=11108/).

2. Financial Developments in 2000

Profits of major energy companies soared to a record level in 2000. Net income of the major energy companies reporting to EIA's Financial Reporting System (FRS) totaled $53.2 billion in 2000, a 133-percent increase from 1999's results (Table 1).[8] Even if the effects of general price inflation are excluded, net income of the FRS companies in 2000 was exceeded only by that in 1980 when crude oil prices averaged, in year 2000 dollars, $64 per barrel and motor gasoline prices averaged $2.29 per gallon. Excluding unusual items,[9] the increase in net income between 1999 and 2000 was 134 percent.

Total profitability of the major energy companies, as measured by return on equity,[10] at 20 percent in 2000 was second only to 1980's 21-percent return in historical context (Figure 3). For only the second time in nearly two decades, the FRS companies clearly outperformed other large U.S. corporations overall. The profitability of other large U.S. industrial corporations, as represented by the S&P Industrials,[11] fell to an 8-year low as an economic slowdown hit many manufacturing industries in the second half of 2000.

The upswing in the FRS companies' bottom-line results was led by income gains from oil and gas production. Petroleum refining and marketing also contributed substantially to higher income in 2000. Nearly all of the FRS companies' lines of business registered improved income and cash flow.

Income and Cash Flow

Upstream Profit Growth Driven by Higher Oil and Gas Prices

The upswing in the FRS companies' bottom-line results was mainly driven by sharply higher prices for oil and natural gas in 2000. On an annual basis, the price of oil was $28 per barrel in 2000 (measured by the U.S. refiners' cost of imported crude oil), $10 above the prior year's price. U.S. natural gas prices at the wellhead averaged $3.60 per thousand cubic feet in 2000, a 66-percent increase over the 1999 price. Natural gas prices outside the United States generally increased less.[12]

In the United States, the FRS companies' net income from oil and gas production[13] (also termed upstream[14]) increased 176 percent between 1999 and 2000, excluding the effects of unusual items (Table 2). Foreign upstream operations posted a 119-percent gain. This somewhat greater earnings growth in the United States was largely due to a steeper rise in natural gas prices in the United States in 2000.

Reflecting the volatility of oil and natural gas prices, the profitability of oil and natural gas production in the U.S. swung from near zero as recently as 1998 to the highest level since the early 1980's in 2000 (Figure 4). Returns on investment[15] in U.S. oil and natural gas production in 2000 were only exceeded by the returns realized in the context of the oil price escalations of 1979 to 1981.

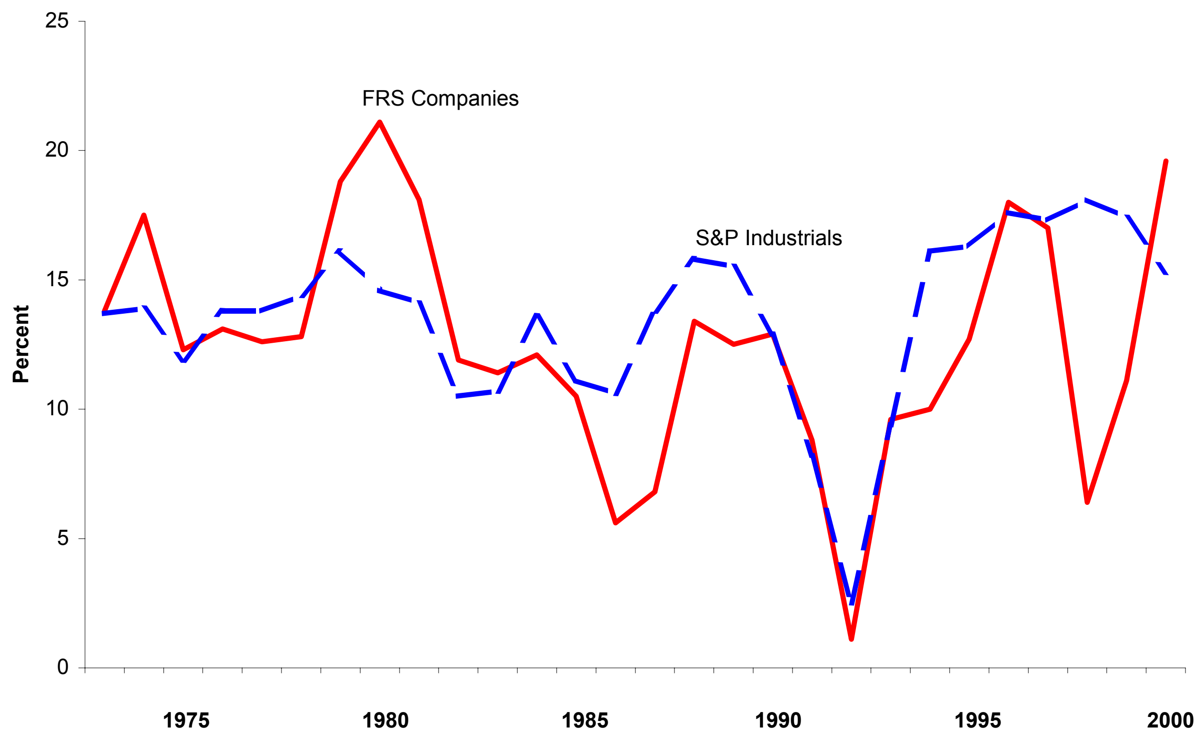
Table 1. Consolidated Income Statement for FRS Companies and the S&P Industrials, 1999 - 2000
(Billion Dollars)

Income Statement Items	FRS Companies 1999	FRS Companies 2000	FRS Companies Percent Change 1999-2000	S&P Industrials 1999	S&P Industrials 2000	S&P Industrials Percent Change 1999-2000
Operating Revenues	578.2	910.6	57.5	4,231.2	4,743.9	12.1
Operating Expenses	-546.0	-826.8	51.4	-3,747.2	-4,180.7	11.6
Operating Income	32.2	83.8	159.8	484.0	563.2	16.4
Interest Expense	-8.7	-10.6	21.0	-81.4	-98.0	20.5
Other Revenue (Expense)	10.2	15.0	47.2	34.1	30.0	-12.0
Income Tax Expense	-10.8	-35.0	223.2	-153.7	-186.3	21.2
Net Income	22.9	53.2	132.6	283.1	308.9	9.1
Net Income Excluding Unusual Items	23.7	55.5	134.2	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, 1973-2000



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.

Table 2. Contributions to Net Income by Line of Business for FRS Companies, 1999-2000
(Million Dollars)

Line of Business	Net Income			Net Income Excluding Unusual Items		
	1999	2000	Percent Change 1999-2000	1999	2000	Percent Change 1999-2000
Petroleum[a]						
U.S. Petroleum						
Production	7,444	22,609	203.7	8,266	22,775	175.5
Refining/Marketing	4,883	7,659	56.9	4,515	8,657	91.7
Pipelines	2,424	2,302	-5.0	2,261	2,377	5.1
Total U.S. Petroleum	14,751	32,570	120.8	15,042	33,809	124.8
Foreign Petroleum[a]						
Production	8,226	18,029	119.2	8,252	18,074	119.0
Refining/Marketing	1,854	2,900	56.4	1,796	3,065	70.7
International Marine	7	49	600.0	7	49	600.0
Total Foreign Petroleum	10,087	20,978	108.0	10,055	21,188	110.7
Total Petroleum	24,838	53,548	115.6	25,097	54,997	119.1
Coal	173	27	-84.4	173	34	-80.3
Other Energy	711	2,743	285.8	851	2,763	224.7
Nonenergy	2,778	3,493	25.7	3,125	4,463	42.8
Total Allocated	28,500	59,811	109.9	29,246	62,257	112.9
Nontraceables and Eliminations	-5,634	-6,619	--	-5,557	-6,779	--
Consolidated Net Income[b]	22,866	53,192	132.6	23,689	55,478	134.2

[a]The Petroleum line of business includes natural gas operations.

[b]The total amount of unusual items was -$823 million and -$2,286 million in 1999 and 2000, respectively.

-- = Not meaningful.

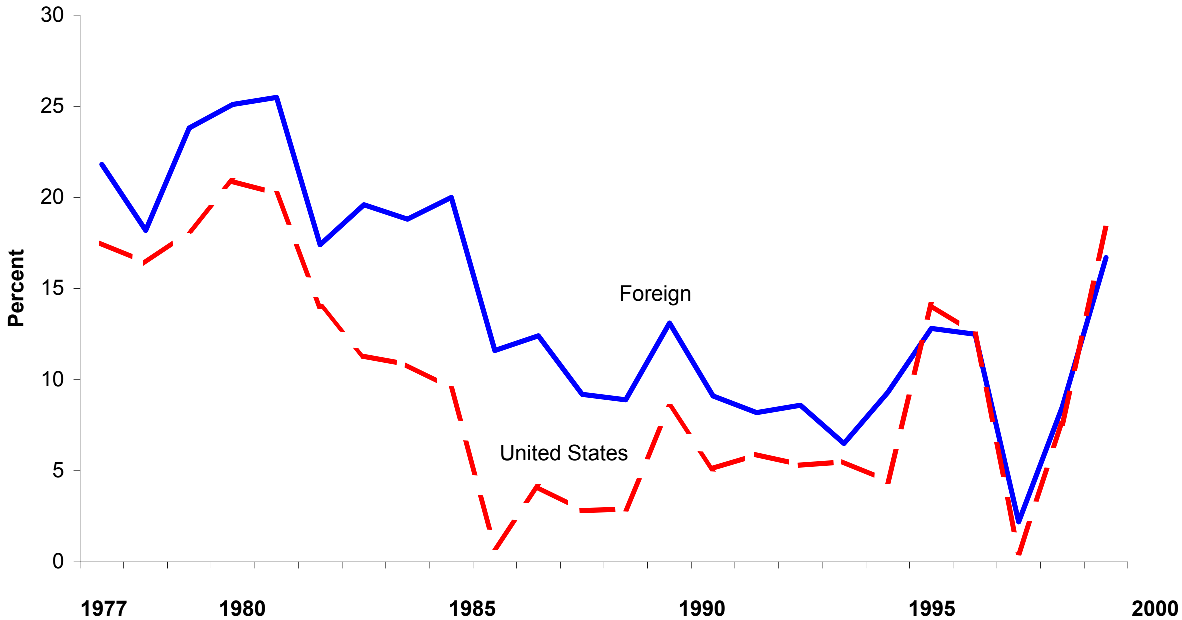
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Refining and Marketing Earnings Rise Despite Higher Crude Oil Costs

The FRS companies' petroleum refining and marketing operations also posted strong gains in income in 2000. Net income, excluding unusual items, from U.S. refining and marketing in 2000 was up 92 percent from net income in 1999. Abroad, the FRS companies' net income from refining and marketing was up 71 percent. A steep rise in refining/marketing income is uncharacteristic of periods in which oil prices are also rising steeply.

Sharply rising crude oil prices mean increased costs of petroleum refining, as crude oil is the major cost component for refiners. When petroleum inventories are normal or ample, refiners generally cannot immediately pass along crude oil price increases: higher product prices tend to reduce demand, adding

Figure 4. Return on Investment in U.S. and Foreign Oil and Natural Gas Production for FRS Companies, 1977-2000



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

to inventories and placing downward pressures on prices. After crude oil prices peak and then decline, the process tends to move in reverse. Usually, then, the margin between refined product prices and crude oil input prices is squeezed when crude oil prices rise.

However, the year 2000 was unusual. The year began with lower-than-normal petroleum inventories and high rates of refinery utilization. Tight supply conditions, together with general growth in petroleum product demand, made it possible to fully pass along crude oil price rises. Also, in 2000, sporadic price spikes for gasoline and distillate, brought on by refinery outages and temporary petroleum transport bottlenecks, added to upward pressures on petroleum prices

The price-cost spread of U.S. refiners as a whole averaged $9.91 per barrel in 2000, the highest level since at least 1983, the year EIA first collected these data. Abroad, margins were also up in European and Asia-Pacific petroleum product markets, the principle areas of the FRS companies' foreign refining/marketing operations.

Electricity and Energy Trading Boost Other Energy Earnings

The other energy line of business registered an even steeper rise in income between 1999 and 2000 than did the FRS companies' worldwide petroleum and natural gas operations. Net income, excluding unusual items, more than tripled, to $2.8 billion.

The other energy line of business is mainly composed of electricity supply and trading (from generation through retail sales), and natural gas trading at wholesale and retail, and provision of associated services such as risk management (e.g., price hedging), in the United States and abroad. Among the FRS lines of business, other energy has been the most rapidly growing in recent years. Between 1995 and 2000, net investment in place (i.e., the balance sheet value of net property, plant, and equipment plus investments and advances to subsidiaries) for this line of business increased eightfold compared to 33 percent for the rest of the lines of business combined. This growth reflects the expansion in trading and supply activities in electricity and natural gas by FRS companies that were earlier established in these activities (Coastal, Enron, and Exxon Mobil), FRS companies that have more recently established a presence in this area (BP Amoco, Chevron (through its Dynegy subsidiary), Shell Oil, and Texaco), and companies that have been added to the FRS respondent group in recent years (Dominion Resources, El Paso, and The Williams Companies). Even excluding Dominion Resources, which was added to the FRS group in 2000 and which operates primarily in the other energy line of business, net income from this line of business more than doubled between 1999 and 2000. All but one of the companies reported income gains.

The FRS companies' net income from coal production continued to shrink. In 2000, net income declined by 80 percent, to $34 million, the lowest total for any line of business. The FRS companies again reduced their interest in coal. Phillips Petroleum sold their U.S. coal properties for $191 million[16] and Exxon Mobil agreed to sell their remaining Australian coal operations.[17] The FRS companies' U.S. coal production declined to 3 percent of the U.S. total. In 1989, FRS companies' U.S. coal production peaked at 30 percent of total U.S. production, but has steadily declined since.

Pipelines appeared to be financially stable in 2000. Net income, excluding unusual items, from natural gas and petroleum liquids pipelines was up 5 percent between 1999 and 2000.

Enterprises Beyond Energy Yield Overall Income Gains

The nonenergy line of business consists of chemical manufacture and a variety of products and services that do not produce energy. The FRS companies' net income from the nonenergy line of business was up $1.3 billion, a 43-percent rise, between 1999 and 2000. The earnings improvement came from ongoing operations, as operating income was $3.1 billion greater in 2000 than in 1999.

Operating income from the FRS companies' chemical operations,[18] excluding unusual items, was up a slight 3 percent, to $4.2 billion in 2000 (Table 3). However, this increase was due to the mergers of the European petroleum companies of Total Petroleum (France), Petrofina (Belgium), and Elf Aquitane (France) into TotalFinaElf. The U.S. subsidiary of Petrofina and long-time FRS respondent Fina (now the American Petrofina Holding Company), beginning in 2000, also includes the U.S. chemical operations of Total and Elf. Excluding Fina, the FRS companies' operating income from chemical manufacturing was down 10 percent.

Chemical manufacturers were adversely affected by higher raw material costs and feedstock costs stemming from the rise in oil and natural gas prices in 2000. An excess of worldwide production capacity continued to hang over the chemical industry in 2000. As a result, higher costs could not be fully passed on to customers, which tended to squeeze price-cost margins and reduce profits. Chevron's remark that "… commodity chemicals businesses suffered in the second half of 2000 from generally weak product demand, industry additions to manufacturing capacity and high raw material costs" typified conditions for most FRS chemical manufacturers in 2000, while Exxon Mobil noted that "the decline in [chemical] earnings was driven by higher feedstock and energy costs and unfavorable foreign exchange effects."[19]

Table 3. Operating Income in Chemicals and Other Nonenergy Segments for FRS Companies, 1999-2000
(Million Dollars)

Segment	1999	2000	Percent Change 1999-2000
Operating Income, Excluding Unusual Items			
Chemicals	4,085	4,223	3.4
Other Nonenergy	-198	2,808	nm

nm = not meaningful

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

Other nonenergy businesses of the FRS companies in 2000 consisted of diverse enterprises including (but not limited to) steel manufacturing (USX), metals trading and water supply (Enron), non-fuel minerals mining (Exxon Mobil, Unocal), real estate (Chevron), and telecommunications (El Paso, Enron, Williams Companies). These other nonenergy businesses had operating income of $2.8 billion in 2000, a turnaround from operating losses of $0.2 billion in 1999. Nearly $1 billion of the increase was due primarily to reporting reclassifications by one company and to a lesser extent to the entry of Dominion Resources into the FRS group.

Not all companies reported better results in nonenergy in 2000. The chairman of U.S. Steel, a subsidiary of FRS respondent USX, noted that economic conditions in the second half of the year lowered steel prices and were compounded by the "skyrocketing cost of natural gas" and that "For the third year in a row, the steel industry was affected by an enormous volume of dumped and subsidized foreign steel."[20] Williams Companies reported that operating losses from its "communications" business segment widened, from $269 million in 1999 to $460 million in 2000.[21]

Cash Flow Up for All Lines of Business

Cash generated by operations is the main source of funds with which the FRS companies make capital expenditures, payouts to investors, and reductions of debt. The FRS companies' cash flow from operations totaled $88.7 billion in 2000, up 62 percent from the prior year (Table 4), and reaching the highest level since at least 1986.[22]

The pattern of pretax cash flow contributions by lines of business was roughly similar to the pattern of contributions to net income. Oil and natural gas production generated the bulk of cash flow while downstream petroleum operations ranked a distant second. All lines of business shown in Table 4 registered higher cash flow in 2000 compared to the prior year.

One notable offset to the growth in cash flow was the disproportionate increase in current income taxes, up 176 percent compared to an 85-percent increase in pretax cash flow. Current income taxes are deemed payable in the reporting year, and for the most part involve actual cash outlays. Deferred taxes are the other component of income tax expense per generally accepted accounting principles. Deferred taxes are recognized as payable in the future and generally do not incur cash outlays in the reporting year. The biggest share of deferred taxes stems from differences in the rate at which productive assets are depreciated for purposes of financial reporting and the requirements of income tax codes. These differences are not tied to swings in income. However, in many taxing jurisdictions, marginal tax rates increase or at least remain the same when income increases. Also, some tax credits are reduced when income increases. Both of these features will tend to increase current taxes.

Table 4. Line-of-Business Contributions to Pretax Cash Flow for FRS Companies, 1999-2000
(Billion Dollars)

Contribution to Pretax Cash Flow [a]	1999	2000	Percent Change 1999-2000
Petroleum[b]			
Oil and Gas Production	43.4	88.4	103.5
Refining, Marketing, and Transport	19.2	27.4	42.4
Coal and Other Energy	1.1	4.4	305.8
Chemicals	5.4	5.8	7.8
Other Nonenergy	0.5	2.9	431.4
Nontraceable	-3.2	-6.2	--
Total Contribution to Pretax Cash Flow[a]	66.5	122.7	84.5
Current Income Taxes	-10.7	-29.6	175.7
Other (Net)	-1.0	-4.5	--
Cash Flow from Operations	54.8	88.7	61.8

[a]Defined as the sum of operating income, depreciation, depletion, and amortization, and dry hole expense.
[b]The Petroleum line of business includes natural gas operations.
-- = 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 Increase 90 Percent, Led by Mergers and Acquisitions

Capital expenditures of the FRS companies (as measured by additions to investment in place[23]) totaled $109.3 billion in 2000, up 90 percent from expenditures in 1999 to an all-time high (Figure 5). Mergers and acquisitions accounted for nearly all of the growth in capital expenditures. Excluding the effects of mergers and acquisitions, the FRS companies' capital expenditures increased by only 3 percent between 1999 and 2000 (Table 5).

Mergers and Acquisitions at Record Level

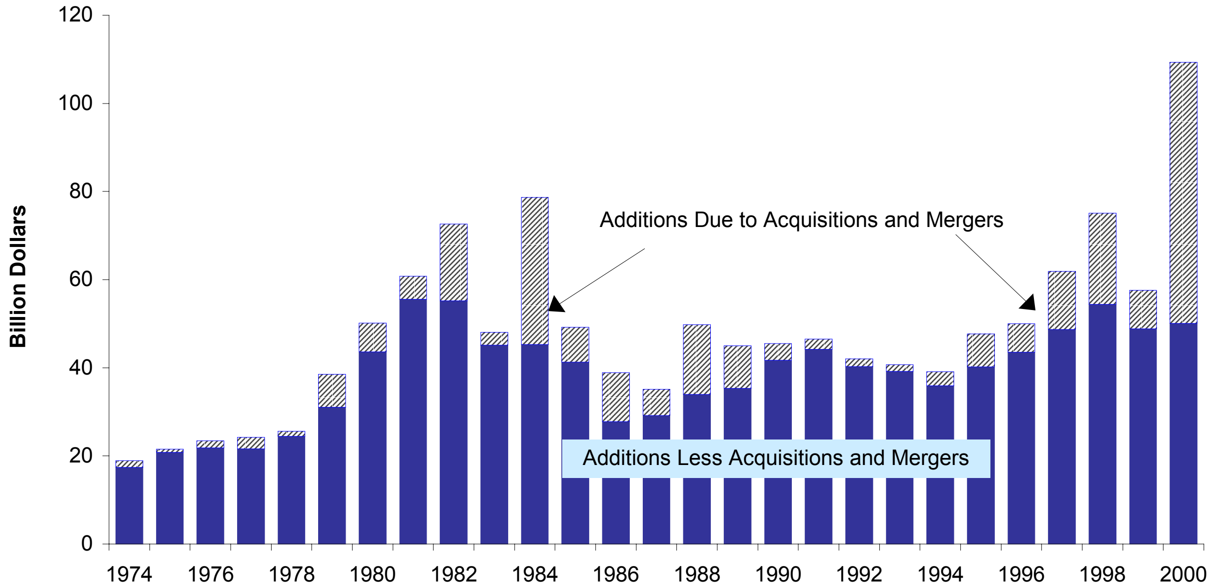
The value of mergers and acquisitions by FRS companies was at a record high in 2000 (Figure 5). Most of the mergers and acquisition activity in 2000, as measured by dollar value,[24] involved transactions between FRS companies. The largest transaction was BP Amoco's acquisition of Atlantic Richfield (ARCO), a then FRS respondent, for $27 billion (Table 6). The bulk of ARCO's assets were in oil and gas production but also included West Coast refining and marketing operations. In order to receive antitrust approval from the Federal Trade Commission, ARCO's Alaskan properties and pipeline interests were sold to Phillips Petroleum, an FRS respondent, for $6.8 billion, the second largest transaction in 2000.

Table 5. Additions to Investment in Place by Line of Business for FRS Companies, 1999-2000

(Billion Dollars)	1999	2000	Percent Change 1999-2000	Percent Change Excluding Mergers and Acquisitions 1999-2000
Petroleum [a]				
U.S. Petroleum				
Production	13.2	44.8	238.0	-1.0
Refining/Marketing				
Refining	2.8	8.2	189.4	70.1
Marketing	2.6	3.4	29.2	16.0
Transport	1.6	0.5	-71.2	-66.8
Total Refining/Marketing	7.0	12.0	70.8	20.8
Pipelines	3.1	4.0	28.3	-55.6
Total U.S. Petroleum	23.4	60.8	159.7	1.4
Foreign Petroleum[a]				
Production	17.6	29.5	67.6	12.8
Refining/Marketing	2.3	2.4	4.0	-4.4
International Marine	0.0	0.0	-46.2	-46.2
Total Foreign Petroleum	19.9	31.9	60.1	10.3
Total Petroleum[a]	43.3	92.7	113.9	5.0
Coal	0.2	0.2	-8.1	-8.1
Other Energy	1.7	5.4	212.8	692.9
Nonenergy				
Chemicals	4.7	3.7	-21.4	-23.5
Other Nonenergy	6.6	6.5	-1.7	-42.7
Total Nonenergy	11.3	10.2	-9.9	-35.2
Nontraceables	1.1	0.9	-20.3	--
Additions to Investment in Place[b]	57.6	109.3	89.8	3.5
Additions Due to Mergers and Acquisitions	8.8	58.8	569.0	--
Total Additions Excluding Mergers and Acquisitions	48.8	50.5	3.5	--
Addendum: Environmental Capital Expenditures	1.7	2.1	19.3	--

[a]The Petroleum line of business includes natural gas operations.
[b]Additions to investment in place = 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 5. Additions to Investment in Place and Value of Acquisitions and Mergers for FRS Companies, 1974-2000



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

Another FRS oil and gas producer, Union Pacific Resources Group, also was acquired by an FRS company in 2000. Anadarko Petroleum, an FRS respondent since 1992, merged with Union Pacific Resources Group, a 1996 spinoff of original (1977) FRS respondent Union Pacific, in a \$4.4-billion transaction. Occidental Petroleum continued to add to its U.S. oil and natural gas assets by purchasing Altura Energy, a Texas-based joint venture of FRS companies BP Amoco and Shell Oil for \$3.6 billion in 2000. In yet another billion-dollar-plus intra-FRS upstream transaction, BP Amoco acquired the 18 percent of ARCO's oil and natural gas producing subsidiary Vastar, for \$1.6 billion that it did not gain in its purchase of ARCO.

The high level of capital expenditures for acquisitions of oil and natural gas producers is part of a recent trend among the majors. In recent years, a major share of the growth in the FRS companies' U.S. reserve base came from mergers and acquisitions. In the 1998 to 2000 period, the share of FRS companies' additions to their U.S. oil and gas reserves due to mergers and acquisitions averaged over 50 percent (Figure 6) including the mega-mergers of BP with Amoco and ARCO and Exxon with Mobil. Even excluding the effects of the mega-mergers, acquisitions of already developed reserves accounted for nearly 60 percent of the FRS companies' total additions to their U.S. oil and natural gas reserves in 2000, a level not seen since the consolidation of the U.S. oil and natural gas industry in the 1980's.

Refining and marketing assets were also in play as targets of intra-FRS acquisitions in 2000. Antitrust approval of the Exxon Mobil merger in 1999 and BP Amoco's acquisition of ARCO in 2000 required divestitures of certain downstream assets. Exxon Mobil sold its Benecia, CA refinery to Valero Energy, an FRS respondent since 1998, for \$1.0 billion, while Tosco, an FRS respondent since 1998, purchased Exxon Mobil's retail gasoline outlets in the northeast United States for \$0.4 billion. Tosco also purchased BP Amoco's Louisiana refinery and the Illinois refinery of Equilon, a joint venture of FRS respondents Shell Oil and Texaco, for \$0.8 billion each.

Table 6. Value of Mergers, Acquisitions, and Related Transactions by FRS Companies, 2000
(Million Dollars)

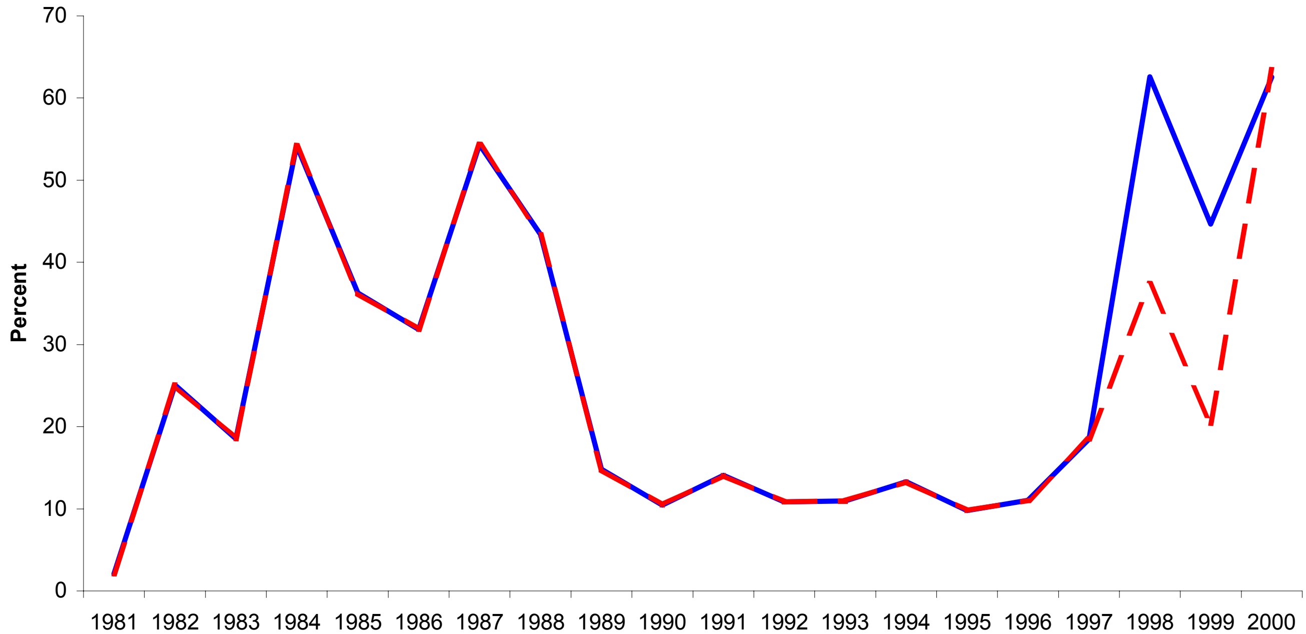
Line of Business and Acquiring Company	Acquisition	Reported Value of Acquisition
Mergers and Acquisitions between FRS Companies		
BP Amoco	Atlantic Richfield Company (ARCO)	26,968
Phillips Petroleum	ARCO's Alaskan oil and natural gas assets from BP Amoco	6,800
Anadarko Petroleum	Union Pacific Resources Group	4,400
Occidental Petroleum	Altura Energy, a Texas-based oil and natural gas joint venture of BP Amoco and Shell Oil	3,600
BP Amoco	Remaining 18 percent of Vastar	1,618
Valero Energy	Exxon Mobil's Benecia, CA refinery	1,045
Tosco	BP Amoco's Alliance, LA refinery	907
Ultramar Diamond Shamrock	Tosco's Avon, CA refinery	808
Tosco	Wood River, IL refinery from Equilon	760
Apache Petroleum	Canadian oil and natural gas properties from Phillips Petroleum	490
Tosco	1,740 retail gasoline outlets from Exxon Mobil	368
Apache Petroleum	Gulf of Mexico oil and natural gas properties from Occidental Petroleum	365
Amerada Hess	178 retail gasoline outlets from USX	168
Other Acquisitions by FRS Companies		
U.S. Oil and Natural Gas Production		
Devon Energy	Santa Fe Snyder Corp.	2,350
Unocal	Titan Exploration	853
Apache Petroleum	Oil and natural gas properties (TX) from Collins & Ware	321
Devon Energy	Gulf of Mexico properties from USX	160
Apache Petroleum	Oil and natural gas properties (OK and TX) from Repsol	149
Phillips Petroleum	River Gas Co. (WY)	123
Foreign Oil and Natural Gas Production		
Kerr-McGee	North Sea (UK) interests from Repsol	555
Conoco	North Sea (Norway) interests from Norsk Hydro	540
Williams Companies	Natural gas liquids (NGL) extraction and fractionation plants	540
Unocal	Remaining interests in Northrock Resources (Canada)	161
Conoco	Natural gas properties (Canada) from PetroCanada	160
Unocal	Interersts in the Makassar Strait and Rapak Production Sharing contract offshore Indonesia	157
Pipelines		
Dominion Resources	Consolidated Natural Gas	6,400
El Paso	PG&E's midstream natural gas operations (TX)	887
Enron	Wyoming pipeline interests	200
El Paso	Crystal Gas Storage	160
Williams Companies	Cove Point LNG Partnership (MD)	150
El Paso	Portion of the All American Pipeline	129
Nonenergy		
Enron	MG plc, metals marketer (UK)	2,000
Exxon Mobil	19 percent interest in China Petroleum and Chemical Corporation	658
Kerr-McGee	Titanium dioxide pigment operations (GA) from Kemira Oy	403
USX	U.S. Steel Kosice (Slovak Republic)	400
Williams Companies	Advance to Algar Telecom Leste, S.A.	150
Williams Companies	Long distance network assets	145
Williams Companies	Two undersea communication cables	111

Sources: Company annual reports to shareholders and press releases.

New entrants to the FRS group were active in the market for acquisitions in 2000. Dominion Resources, a company that generates and distributes electricity and provides energy services in the mid-Atlantic region, acquired Consolidated Natural Gas in a transaction valued at $6.4 billion. The acquisition of

Consolidated Natural Gas' U.S. natural gas reserves brought Dominion Resources into the group of major energy companies reporting to the FRS. Devon Energy had been making additions to its U.S. natural gas reserve base in recent years through its exploration and development efforts and acquisitions of already producing properties. The U.S. reserves added through its $2.4-billion acquisition of Santa Fe Snyder brought Devon Energy into the FRS group in 2000. Apache Petroleum, whose growth in U.S. natural gas production brought it to the FRS group in 2000, continued to add to its U.S. reserves through acquisitions totaling $0.8 billion in value.

Figure 6. Share of Total U.S. Oil and Natural Gas Reserve Additions due to Mergers and Acquisitions for FRS Companies, 1981-2000



Note: Solid line includes U.S. reseves added in BP-Amoco (1998), Exxon-Mobil (1999), and BP Amoco-ARCO (2000) mergers as purchases. Dashed line excludes these effects.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

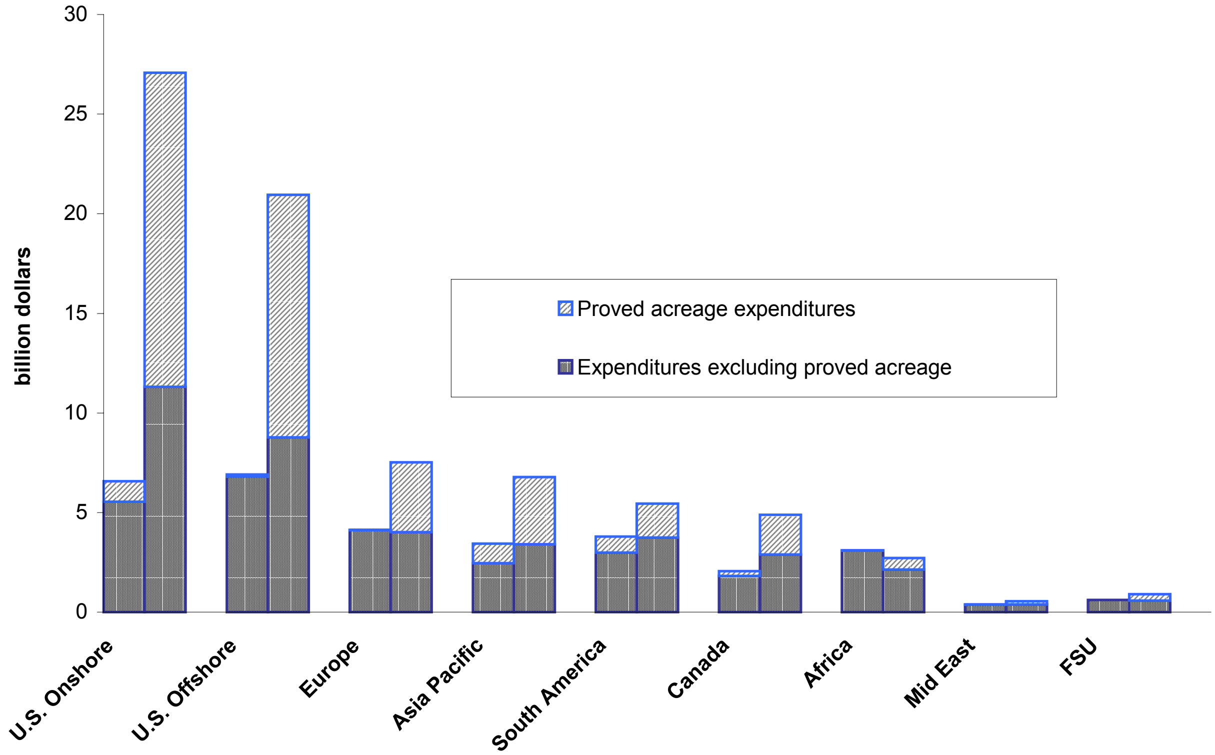
Expenditures for Oil and Gas Production More than Double

Worldwide exploration and development expenditures[25] of the FRS companies increased 148 percent (130 percent excluding the new FRS respondents) between 1999 and 2000, to $76.8 billion (Table B16 in Appendix B). All regions except Africa registered increased expenditures (Figure 7).

Onshore locales in the United States received the largest boost in expenditures for oil and natural gas exploration and development, with 2000 expenditures triple those of 1999. It should be noted that the FRS companies cut back their expenditures for onshore exploration and development by the most for any region in 1999, with a reduction of over 50 percent from prior-year spending.

Most of the increase was for proved property expenditures, which for financial reporting purposes is where the effects of mergers and acquisitions are primarily allocated. Even excluding the effects of mergers and acquisitions, the FRS companies doubled their exploration and development expenditures for onshore locales. This upswing may in part represent a resumption of projects that were deferred in 1999's cutbacks. Some support to this view comes from the fact that only one FRS company, and a small player at that, cut back expenditures for onshore oil and natural gas development in the United States.

Figure 7. Exploration and Development Expenditures by Region for FRS Companies, 1999 and 2000



Note: In each pair of bars, the first bar depicts 1999 and the second 2000. FSU = Former Soviet Union and Eastern Bloc countries.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

A few areas stood out as targets for development among companies that noticeably increased their investment commitments to the U.S. onshore. The Rocky Mountain area has several natural gas plays, including coalbed methane deposits in Colorado, New Mexico, Utah, and Wyoming. FRS companies that noted activity in this area included Anadarko Petroleum, BP Amoco (mainly through their acquisitions of Amoco in 1998 and ARCO in 2000), Conoco, El Paso (mostly through recently acquired FRS respondent Coastal), and Texaco. Alaska is part of the U.S. onshore for FRS purposes. BP Amoco noted that development is ongoing to mitigate the decline of Prudhoe Bay, Alaska's largest producing field. With an eye toward future oil production, BP Amoco is developing the Northstar field on Alaska's North Slope, having upped spending on this project from $100 million to $320 million in 2000, with production planned to begin in late 2001.[26] Anadarko and Occidental Petroleum noted their activities in the long-producing fields in Texas' Permian Basin. Fields in the Permian Basin are now being further developed through drilling below existing producing formations, applying advancing technologies to improve recovery from currently producing areas, and in-fill drilling that places producing wells closer together.

The FRS companies' exploration and development expenditures for U.S. offshore projects exhibited a similar, though less pronounced, pattern as that of U.S. onshore spending.

The prospect of growth in Canadian natural gas exports to the United States continued to attract investment. The FRS companies' exploration and development expenditures in Canada in 2000 were the highest in a decade, both with and without the effects of mergers and acquisitions. Drilling for natural gas in Canada has steadily increased: The FRS companies' Canadian natural gas well completions in 2000, at 1,088 wells, were four times greater than completions in 1995, the most recent trough in Canadian drilling. Canadian natural gas production of the FRS companies was up 65 percent from production in 1997, which was the most recent trough in production.

Outside North America, the FRS companies increased their exploration and development expenditures, with and without the effects of mergers acquisitions, in the Other Western Hemisphere region (mostly South America) and the Other Eastern Hemisphere region (Asian and Pacific sovereignties, excluding the Middle East and countries of the Former Soviet Union).

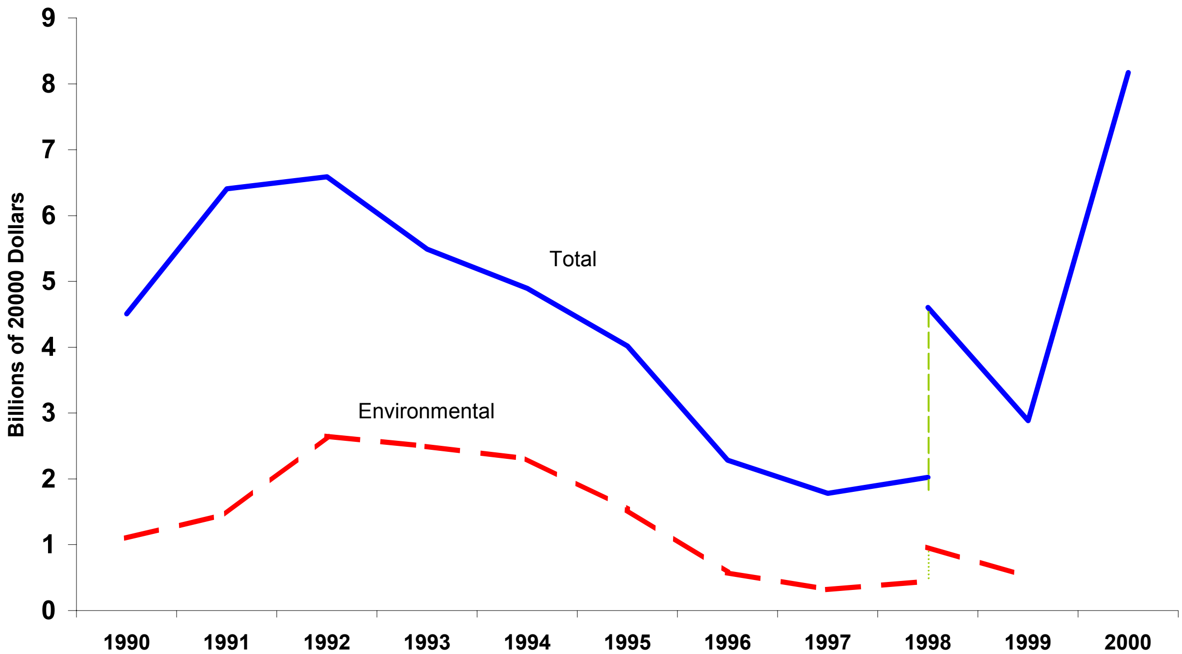
In South America, the FRS companies' drilling activity bounced back in 2000 from the sharp dip in 1999 and nearly matched the elevated levels of drilling of 1998. The earlier upswing was largely driven by the development of joint ventures in Venezuela with the state petroleum company, Petroleos de Venezuela (PDVSA) that were initiated earlier in the 1990's. In 2000, Venezuela generally appeared less attractive as the political uncertainties with respect to foreign investment, taxation, and production sharing arrangements increased. The FRS companies involved in Venezuela cut their exploration and development spending in South America by 42 percent between 1999 and 2000. On the positive side in South America, other FRS companies increased their exploration and development expenditures. BP Amoco noted its natural gas-related developments in Argentina and Trinidad-Tobago and its projects to mitigate the natural decline in oil production from the Cusiana field in Colombia. Anadarko stepped up its drilling in Guatemala in 2000.

In the Other Eastern Hemisphere region, the FRS companies maintained a focus on natural gas development. Even though economic growth in the region began to slow in 2000, the demand for natural gas in this region is expected to grow in the longer term both to fuel future economic growth and to provide a clean-burning fuel for electric power generation. The FRS companies' natural gas drilling in this region was up 11 percent in 2000 following a 5-percent rise in the prior year. However, the rebound in Asian-Pacific exploration and development activity appeared to be largely directed toward oil-related projects. The FRS companies' oil well completions in the Other Eastern Hemisphere in 2000 were up 39 percent over 1999 completions, and just below the levels of 1997 and 1998.

Investment in Refining and Marketing Responds to Increased Profitability

During the 1990's, the FRS companies' capital expenditures for U.S. refining operations followed a course that appeared to be contrary to profit goals. In the first half of the 1990's, capital expenditures for refining tended to increase as the profitability of these operations were declining, and after 1995, capital expenditures tended to decline (after allowing for the entrance of several new refining/marketing companies to the FRS group in 1998) (Figure 8). In large part, the path of expenditures was driven by the requirements of environmental regulations placed on U.S. refiners. As can be seen in Figure 8, overall FRS capital expenditures for U.S. refining roughly paralleled the capital expenditures incurred to meet environmental requirements. The timing of environmental requirements is essentially independent of profit performance.

Figure 8. Total Capital Expenditures and Environmental Capital Expenditures in U.S. Refining for FRS Companies, 1990-2000



Note: 11 refiners were added to the FRS group in 1998.
Sources: Total refining capital expenditures: Energy Information Administration, Form EIA-28 (Financial Reporting System). Environmental capital expenditures: 1990-1999: American Petroleum Institute, U.S. Petroleum Industry's Environmental Expenditures, 1990-1999 (Washington, DC, January 19, 2001). FRS share based on refinery capacity.

The FRS companies broke with this pattern in 2000. The profitability of the FRS companies' U.S. refining/marketing operations reached a 12-year high, and capital expenditures for U.S. refining nearly tripled between 1999 and 2000, from $2.8 billion to $8.2 billion (Table 5). Most of the increase was the result of intra-FRS mergers and acquisitions, noted above. Excluding the effects of mergers and acquisitions and survey group entrants, capital expenditures for U.S. refining were still up a solid 19 percent. Expenditures appeared to be primarily directed at capacity upgrades rather than expansion of basic capacity: additions to crude distillation capacity by the FRS companies in 2000 totaled less than 1 percent of beginning-of-year crude distillation capacity.

Several FRS companies reported upgrades to increase their refineries' capability to process heavy crude oils. Conoco completed an upgrade to its Lake Charles, LA refinery in order to process synthetic crude oil from its Petrozuata heavy-oil joint venture in Venezuela.[27] Phillips Petroleum started up a coker unit at its Sweeny, TX refinery in 2000. A coker extracts large amounts of petroleum coke, a coal-like material that can be marketed or further purified by calcining. The coker unit is a joint venture with PDVSA[28] that enables processing of heavy, high-sulfur crude oil. Exxon Mobil's Chalmette, LA refinery began processing very heavy crude oil from its Cerro Nego project in Venezuela. Exxon Mobil also reported that it is constructing a coker at its Baytown, TX refinery that will increase the processing of heavy, high-sulfur Mexican Maya crude oil.[29] Processing heavy Mayan crude is also the aim of

USX's construction of a coker at its Garyville, LA refinery.[30] Other FRS companies reporting process-oriented refinery upgrades included Premcor,[31] Tesoro Petroleum,[32] and Valero Energy.[33]

The FRS companies also made gasoline marketing a target of investment. Most of the growth in gasoline marketing investment was related to merger and acquisition activity between FRS companies. These transactions include the aforementioned acquisition of ARCO by BP Amoco and Tosco's purchase of Exxon Mobil's Northeast gasoline stations plus Amerada Hess' acquisition of 178 Merit stations from USX's Marathon Ashland Petroleum. Excluding acquisitions between FRS companies and the impact of entrants to the FRS group in 2000, capital expenditures for petroleum marketing held steady at $2.3 billion.

Although foreign refining/marketing profitability improved in 2000 (Table 7), the FRS companies' capital expenditures for these operations were relatively flat compared with expenditures in 1999. Capital expenditures for foreign refining/marketing operations were up a slight 4 percent between 1999 and 2000, and down a slight 4 percent excluding the effects of mergers and acquisitions. In part, this response reflected the modest size of the upswing in profitability. In the context of the past decade or so, foreign refining/marketing profitability in 2000 was only middling, whereas in the United States, the profitability of the FRS companies' refining/marketing operations hit a 12-year high. In larger part perhaps, the flatness in expenditures reflected the general reduction in expected economic growth in the Asia-Pacific region that began when the region's financial crisis hit in mid-1997. The Asia Pacific region accounts for 35 percent of the FRS companies refinery capacity outside the United States. Investment in downstream petroleum facilities serving Asia-Pacific markets grew rapidly through 1997. However, the impact of the financial crisis and its continuing aftermath on the region's demand for petroleum products created a glut of refining capacity. Also, in Europe, the other main area of the FRS companies' foreign refining/marketing operations, sporadic gluts of refining capacity have occurred in recent years. Accordingly, the FRS companies' capital expenditures for foreign refining/marketing operations have declined 31 percent between 1997 and 2000.

Investment in Electricity and Energy Services Surges

The other energy line of business increasingly encompasses electric power, marketing of electricity and natural gas, and provision of associated services. Since 1995, the investment base in the FRS companies' other energy line of business has grown eight-fold compared to 33 percent for the rest of their businesses combined.

The FRS companies' capital expenditures for the other energy line of business more than tripled between 1999 and 2000, to $5.4 billion (Table 5). About 20 percent of the growth in capital expenditures was due to the addition of Dominion Resources to the FRS group in 2000. Most of the growth in capital expenditures appeared to be related to internal expansion as the value of acquisitions in other energy totaled less than $200 million.

Beyond Energy, Capital Expenditures Trimmed

The FRS companies reduced their capital expenditures for chemical operations by $1 billion, a 21-percent drop, between 1999 and 2000 as these operations remained at a low level of profitability in 2000 (Figure 9). The spending cutbacks were generally widespread. Kerr-McGee was a notable exception as

Table 7. Return on Investment by Line of Business for FRS Companies, 1990-2000
(Percent)

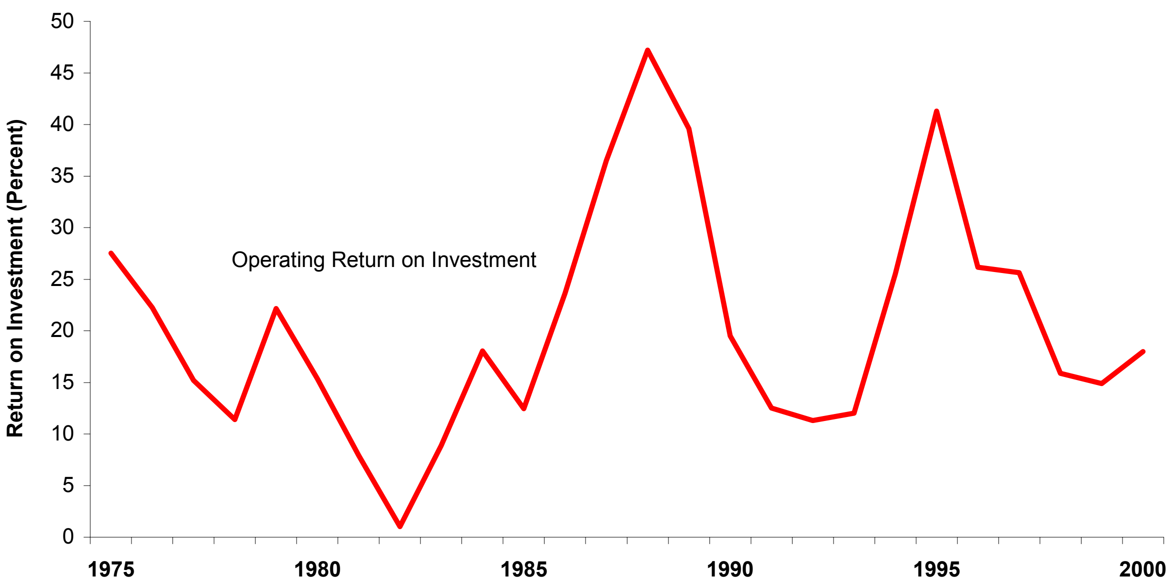
Line of Business	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Petroleum [a]	9.5	7.0	5.6	6.4	5.6	5.7	10.1	10.8	3.9	7.2	14.0
U.S. Petroleum	7.9	4.9	4.4	4.9	5.2	4.0	9.9	10.0	3.8	7.0	13.5
Oil and Gas Production	8.5	5.1	5.9	5.3	5.5	4.4	14.1	12.5	0.5	7.6	18.3
Refining/Marketing	5.1	2.0	-0.4	3.4	3.6	1.0	4.4	6.6	7.9	6.5	9.6
Pipelines	11.2	10.7	8.4	6.4	7.6	9.1	6.9	6.7	4.4	6.4	5.9
Foreign Petroleum[a]	12.5	11.0	7.9	9.2	6.2	8.4	10.6	11.9	4.0	7.6	14.8
Oil and Gas Production	13.1	9.1	8.2	8.6	6.5	9.3	12.8	12.5	2.2	8.5	16.7
Refining/Marketing	11.2	14.6	7.8	10.6	6.1	7.2	6.0	10.5	8.2	5.1	8.8
International Marine	11.7	15.6	-1.2	1.2	-2.0	-2.5	2.2	11.8	8.9	0.8	6.4
Coal	3.3	8.7	-9.3	7.6	4.0	6.9	9.9	7.2	26.4	9.5	1.7
Other Energy	2.6	2.8	1.8	4.1	4.8	6.1	7.9	7.0	13.2	7.6	11.0
Nonenergy	7.8	2.9	2.1	4.7	10.5	19.4	15.0	10.9	4.5	5.8	7.2

[a]The Petroleum line of business includes natural gas operations

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

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

Figure 9. Operating Return on Investment in Chemicals for FRS Companies, 1975-2000



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.

the company acquired titanium dioxide pigment operations in Georgia from Kemira Oy for $403 million.

Capital expenditures for other nonenergy businesses changed little between 1999 and 2000 but remained at a historically high level of $6.5 billion. The growth occurred in 1999, led by outlays for telecommunications and broadband Internet services. Enron and Williams Companies accounted for most of the increase in investment in 1999. In 2000, Williams continued to increase its investment outlays for its "communications" business to $3.4 billion, up from $1.7 billion in 1999.[34] Excluding Williams Companies, the FRS companies' capital expenditures directed to businesses outside energy and chemicals were down 37 percent, with most companies reporting declines. The decline may have reflected the economic downturn that began to be felt by many manufacturing industries in the second half of 2000.

Sources and Uses of Cash

Financial Flows Approach Normality in 2000

After wrenching adjustments to their deployment of capital in 1998 and 1999[35], the FRS companies' sources and uses of cash in 2000 more closely resembled patterns in earlier years. However, before reviewing the developments in this area, it must be noted that some financial flows shown in Table 8 were strongly affected by BP Amoco's acquisition of Atlantic Richfield (ARCO) in 2000. In particular, this acquisition added $19.8 billion to total capital expenditures for what amounted to a transfer of assets between FRS companies and was financed through payment of BP Amoco shares that totaled $27.0 billion.

Apart from the ARCO acquisition, capital expenditures in 2000 increased $31 billion, which just about matched the increase in cash flow from operations of $33 billion. This rough balance between capital expenditures and cash flow was in contrast to the imbalances in 1998 and 1999. In 1998, in the context of oil prices that plunged to $10 per barrel, the FRS companies' capital expenditures exceeded cash flow by $27 billion, or by 56 percent. The resulting surge in debt, draw down of cash reserves, and cutbacks in payouts to investors (i.e., dividends and stock repurchases) led the FRS companies to emphasize balance sheet repair in their deployment of capital in 1999. Part of the repair included cutbacks in capital expenditures. As a result, although cash flow increased by $7 billion in 1999, the FRS companies cut capital expenditures by $17 billion.

Debt management returned to a more customary pattern in 2000. Another component of the FRS companies' efforts to repair their balance sheets in 1999 was reduction of the runup in debt that they incurred in 1998. The FRS companies allocated $7 billion more to debt reduction in 1999 than they did in 1998. Table 8 indicates that the FRS companies again increased their outlays for this purpose, by $4.3 billion, in 2000. However, this apparent increase was due to the entry of Apache, Devon Energy, and Dominion Resources into the FRS reporting group in 2000. Excluding these first-time respondents, cash used for debt reduction fell to $18.8 billion, a value more typical of recent years apart from 1999. Overall, the FRS companies were able to reduce the role of debt in their balance sheets. Figure 10 shows a noticeable drop in the FRS companies' debt-equity ratio in 2000 compared to 1998 and 1999.

Cash payouts to shareholders (dividends and stock repurchases) also returned to levels comparable to recent years apart from 1999. The FRS companies increased payouts to stockholders from $16.5 billion in 1999 to $24.3 billion in 2000 ($22.0 billion excluding new respondents in 2000).

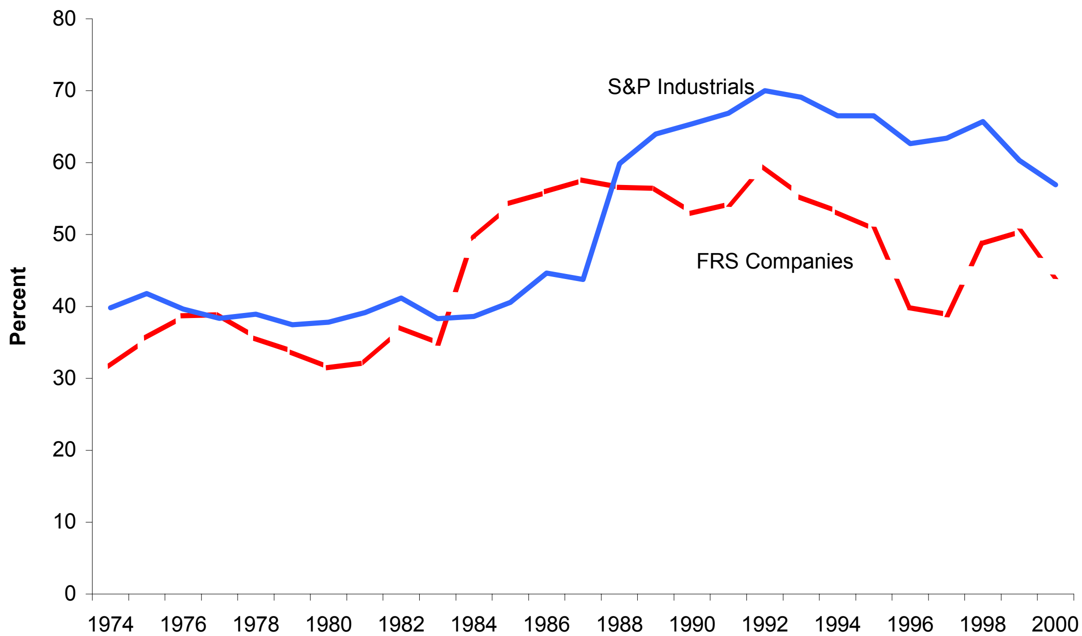
The large increase in cash from asset sales in 2000, to a record $26.7 billion in 2000, was largely traceable to divestitures required for antitrust approval of the merger between Exxon and Mobil and BP Amoco's acquisition of ARCO. As a condition for approval of the Exxon Mobil merger by antitrust

Table 8. Sources and Uses of Cash for FRS Companies, 1999-2000
(Billion Dollars)

Sources and Uses of Cash	1999	2000	Percent Change 1999-2000
Main Sources of Cash			
Cash Flow from Operations	54.8	88.7	61.8
Proceeds from Long-Term Debt	29.9	33.3	11.5
Proceeds from Disposals of Assets	13.3	26.7	101.0
Proceeds from Equity Security Offerings	3.6	30.6	760.4
Main Uses of Cash			
Additions to Investment in Place	57.6	109.3	89.8
Reductions in Long-Term Debt	25.0	29.3	17.3
Dividends to Shareholders	16.1	19.0	18.0
Purchase of Treasury Stock	0.4	5.4	1,164.6
Other Investment and Financing Activities, Net	0.1	-8.6	--
Net Change in Cash and Cash Equivalents	2.5	7.6	--

-- = 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 10. Long-Term Debt/Equity Ratio for FRS Companies and the S&P Industrials, 1974-2000



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.

authorities in the United States and Europe, the resulting company, Exxon Mobil, had to sell certain downstream petroleum assets. These assets included Mobil's interest in its refining/marketing joint venture in Europe, retail gasoline outlets in the northeastern United States, a west coast refinery and associated marketing assets, U.S. liquids pipeline interests, and natural gas marketing assets in Europe. Exxon Mobil reported $5.8 billion of asset sales in 2000.[36] BP Amoco realized $11.4 billion from asset sales in 2000,[37] most of which was in connection with gaining antitrust approval for the company's acquisition of ARCO in 2000. The main divestiture was the sale of ARCO's Alaska oil and gas assets to FRS respondent Phillips Petroleum for $6.8 billion. BP Amoco also sold their Louisiana refinery to FRS respondent Tosco for $0.9 billion and its share of the Texas-based Altura Energy oil and natural gas joint venture to Occidental Petroleum, another FRS respondent, for $1.2 billion. Excluding BP Amoco and Exxon Mobil, the FRS companies' cash from asset sales of $9.2 billion in 2000 was in the range of values typical before 1998.

Endnotes

[8]For a list of the FRS companies in 2000, see the box entitled, "The FRS Companies in 2000," in Chapter 1, page 1.
[9]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.
[10]Return on equity, a frequently used measure of corporate profitability, is measured by the ratio of net income to stockholders' equity.
[11]The Standard and Poor's Industrials is a well-recognized database that includes nearly 400 of the largest U.S. industrial companies. Financial statistics for the S&P Industrials were obtained by accessing Compustat PC Plus, a service of Standard & Poor's, Inc.
[12]http://www.eia.doe.gov/emeu/mer/, Tables 9.1 and 9.11. For foreign prices, see Table 3-2 in Chapter 3.
[13]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).
[14]For FRS purposes, the petroleum line of business includes natural gas. At the wellhead, oil and natural gas are not subject to separate financial reporting as a matter of long-standing industry practices.
[15]Return on investment (ROI) for a line of business is contribution to 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.
[16]Phillips Petroleum Companies, *2000 Annual Report*, p. 45.
[17]Exxon Mobil Corporation, *2000 Annual Report*, p. 25.
[18] For FRS purposes, separate reporting of income for chemical and other nonenergy segments was discontinued beginning with the 1987reporting 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.
[19]Chevron Corp., *2000 Annual Report*, p. 33 and Exxon Mobil, 2000 Securities and Exchange Commission Form 10K, pp. 20-21.
[20]USX Corp., *The 2000 U.S. Steel Group Annual Report*, Chairman's Message.
[21]The Williams Companies, 2000 Securities and Exchange Commission Form 10K, p. 104.
[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. Prior to 1986, cash flow included changes in working capital.
[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 2000, additions to PP&E accounted for 93 percent of capital outlays so measured.
[24]Figure 5 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]Exploration and development expenditures include capitalized expenditures for oil and gas production and exploration expenses, which are not capitalized but are charged against income.

[26]BP Amoco plc, 2000 Securities and Exchange Commission Form 20F, p. 25.

[27]Conoco, Inc., *2000 Annual Report*, p. 17.

[28]Phillips Petroleum Company, *2000 Annual Report*, p. 21.

[29]Exxon Mobil Corporation, *2000 Financial and Operating Review*, p. 4.

[30]USX Corporation, 2000 Securities and Exchange Commission Form 10K, p. M-36.

[31]The Premco Refining Group, Inc., Securities and Exchange Commission Form 10K, p. 3.

[32]Tesoro Petroleum Corporation, *2000 Annual Report*, p. 6.

[33]Valero Energy Corporation, *2000 Annual Report*, pp. 12-13.

[34]The Williams Companies, Inc., 2000 Securities and Exchange Commission Form 10K, p. 105.

[35] See Chapter 2 of *Performance Profiles of Major Energy Producers 1998* and *1999* for a review of these adjustments.

[36]Exxon Mobil Corp., 2000 Securities and Exchange Commission Form 10K, p. 31.

[37]BP America Inc., *Consolidated Financial Statements December 31, 2000*, p. 6.

3. Behind the Bottom Line

Oil and Natural Gas Production

Upstream Profits Hit New Peak

The FRS companies' net income from worldwide oil and natural gas production operations in 2000 totaled $40.9 billion, up 159 percent from 1999 net income (Table 9). Results for 2000 set a record for U.S. and foreign upstream net income. Return on investment (net income divided by net investment in place), which is a measure of line-of-business profitability, at 18 percent for worldwide oil and natural gas production, was at the highest level since the oil price escalations of the 1979 through 1981 period.

Higher prices for oil and natural gas largely drove the gains in upstream income. Oil prices realized by the FRS companies in their U.S. operations in 2000, on average, were $11 per barrel higher than in 1999 (Table 10). In their foreign operations, their average realized price for oil registered a $10-per-barrel gain. Natural gas prices realized in the United States by the FRS companies rose more sharply than did overall natural gas prices abroad: a $1.47-per-thousand cubic feet (Mcf) rise in the United States ($8.26 per barrel of oil equivalent (BOE)), versus a $0.56-per-Mcf rise outside the United States ($3.15 per BOE). The market developments underlying oil and natural gas price rises in 2000 are reviewed in Chapter 1 of this report.

Worldwide Oil and Natural Gas Production Up 2 Percent

The FRS increased their worldwide combined oil and natural gas production by 2 percent between 1999 and 2000. Worldwide oil production by the FRS companies was down slightly in 2000, while natural gas production increased (Table 10).

Changes in oil and natural gas production, on balance, contributed almost nothing to U.S. revenue growth as the FRS companies' 3-percent drop in oil production more than offset the effects of their 5-percent rise in natural gas production. The decline in the FRS companies' U.S. oil production came from onshore locales, the continuation of an unabated decline that began in 1989 (Figure 11a). Alaska accounted for a major share of the FRS companies' 7-percent decline in onshore oil production. In Alaska, the reserve base has shrunk since 1987, as declines in the giant, but aging, Prudhoe Bay field on Alaska's North Slope have not been fully offset by reserves added through exploration and development. Offshore, the FRS companies' oil production was up 7 percent, as additions to their reserve base, almost entirely in the Gulf of Mexico, continued to outpace production.

Natural gas production of the FRS companies was up 4 percent onshore and 5 percent offshore (Figure 11b). However, the uptick in the FRS companies' U.S. natural gas production was attributable to additional FRS respondents in 2000. Excluding the new respondents, natural gas production was down 5 percent onshore and 6 percent offshore. Drops of 6 percent and 2 percent in 1999, respectively, preceded these declines. The production declines follow a sharp dip earlier in the FRS companies'

Table 9. Income Components and Financial Ratios in Oil and Natural Gas Production for FRS Companies, 1999-2000
(Billion Dollars)

Components of Income and Financial Ratios	Worldwide		United States		Foreign	
	1999	2000	1999	2000	1999	2000
Oil and Natural Gas Revenues						
Oil	NA	NA	25.2	38.4	NA	NA
Natural Gas	NA	NA	23.2	40.8	NA	NA
Total Revenues	89.1	147.2	48.4	79.3	40.7	68.0
Expenses						
DD&A	20.0	23.9	10.9	13.1	9.1	10.8
Lifting Costs	20.5	21.8	11.2	11.0	9.4	10.7
Exploration Expenses	3.2	5.4	1.0	3.2	2.1	2.3
General and Administrative Expenses	2.3	2.3	1.3	1.3	1.0	1.0
Raw Material Purchases	17.4	27.3	14.3	16.8	3.1	10.5
Other Costs (Revenues)	4.3	3.6	1.1	2.2	3.2	1.4
Total Operating Expenses	67.4	84.1	39.5	47.4	27.9	36.7
Operating Income	21.6	63.1	8.9	31.8	12.8	31.3
Other Income (Expense)[a]	3.7	5.5	1.8	1.5	1.9	4.0
Income Tax Expense	9.7	28.0	3.2	10.7	6.4	17.3
Net Income	15.7	40.6	7.4	22.6	8.2	18.0
Less Unusual Items	-0.8	-0.2	-0.8	-0.2	0.0	0.0
Net Income, Excluding Unusual Items	16.5	40.9	8.3	22.8	8.3	18.1
Unit Values (Dollars Per Barrel of Production COE)[b]						
Direct Lifting Costs (Excluding Taxes)	3.26	3.10	3.48	3.05	3.02	3.14
Production Taxes	0.61	0.92	0.61	0.95	0.60	0.90
Ratios (Percent)						
Return on Investment[c]	8.1	17.6	7.6	18.3	8.5	16.7
Effective Tax Rate[d]	38.1	40.8	30.0	32.1	44.0	49.0

[a]Earnings of unconsolidated affiliates and gain (loss) on disposition of assets.
[b]COE = Crude oil equivalent. Dry natural gas w as 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).

natural gas drilling in the United States. The FRS companies' U.S. natural gas well completions fell 31 percent between 1997 and 1999 before recovering in 2000 (Table B19 in Appendix B).

Abroad, the FRS companies' increased production of both oil and natural gas accounted for 2 percent of the growth in foreign upstream revenues in 2000. Nearly all the gain in oil production was in Europe (almost entirely from the North Sea) (Table 11), where the FRS companies' oil production reached a new peak in 2000.

The largest gains in foreign natural gas production were in Canada, where the FRS companies have been developing and acquiring reserves in order to export natural gas to the United States, and in South America, where production serves the growing indigenous demand for natural gas and the liquefied natural gas (LNG) export facilities in Trinidad-Tobago. The FRS companies continued to increase their

Table 10. Average Prices, Sales, and Production in Oil and Gas for FRS Companies, 1999-2000

Prices, Sales, and Production	1999	2000	Percent Change 1999-2000
Worldwide Oil and Gas Production[a]			
Crude Oil and NGL (Million Barrels)	2,882	2,864	-0.6
Dry Natural Gas (Billion Cubic Feet)	13,676	14,320	4.7
Total (Million Barrels COE)[b]	5,316	5,413	1.8
Domestic Oil and Gas Production[a]			
Crude Oil and NGL (Million Barrels)	1,306	1,268	-2.9
Dry Natural Gas (Billion Cubic Feet)	7,994	8,354	4.5
Total (Million Barrels COE)[b]	2,729	2,755	1.0
Domestic Oil and Gas Sales Volumes			
Crude Oil and NGL (Million Barrels)	1,667	1,484	-11.0
Dry Natural Gas (Billion Cubic Feet)	10,952	11,367	3.8
Total (Million Barrels COE)[b]	3,616	3,507	-3.0
Domestic Production Segment Per Unit Sales Values			
Crude Oil and NGL (Dollars Per Barrel)	15.11	25.88	71.3
Dry Natural Gas (Dollars Per Thousand Cubic Feet)	2.12	3.59	69.8
Composite (Dollars Per Barrel COE)[b]	13.37	22.60	69.0
Foreign Oil and Gas Production[a]			
Crude Oil and NGL (Million Barrels)	1,576	1,596	1.3
Dry Natural Gas (Billion Cubic Feet)	5,682	5,966	5.0
Total (Million Barrels COE)[b]	2,588	2,658	2.7
Foreign Production Segment Per Unit Sales Values			
Crude Oil and NGL (Dollars Per Barrel)	16.54	26.34	59.3
Dry Natural Gas (Dollars Per Thousand Cubic Feet)	2.03	2.59	27.6
Canada	1.68	3.60	114.3
OECD Europe	2.21	2.63	19.0
Other Foreign	1.95	2.18	11.8
Composite (Dollars Per Barrel COE)[b]	14.53	21.95	51.1

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

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

Sources: Energy Information Administration, Form EIA-28 (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.

European natural gas production, up 3 percent in 2000. A somewhat surprising result was the 162-percent rise in African natural gas production between 1999 and 2000. This growth was largely attributable to growth in production from Egypt, where BP Amoco has been developing natural gas projects and FRS survey entrant Apache Petroleum added 17 billion cubic feet of Egyptian natural gas production to the FRS total, and Nigeria, where Exxon Mobil and Phillips Petroleum put in a full year's production for an LNG project that started up in 1999.[38]

Cost-Cutting Evident Only in Lifting Costs

Little evidence of cost cutting in 2000 is apparent from Table 9. The one exception was the cost of extracting oil and natural gas in the United States, termed lifting costs. Lifting costs (production costs) are the out-of-pocket costs per barrel of oil and natural gas produced (measured on a barrel-of-oil

Figure 11a. Oil Production for FRS Companies, 1981-2000

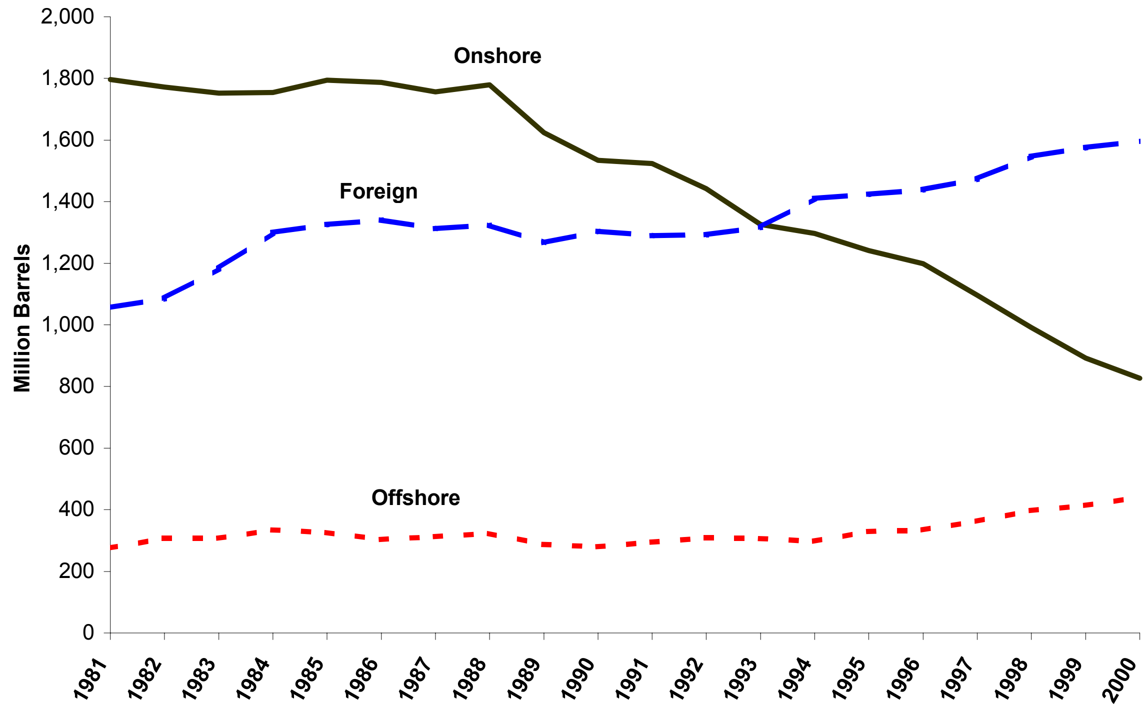
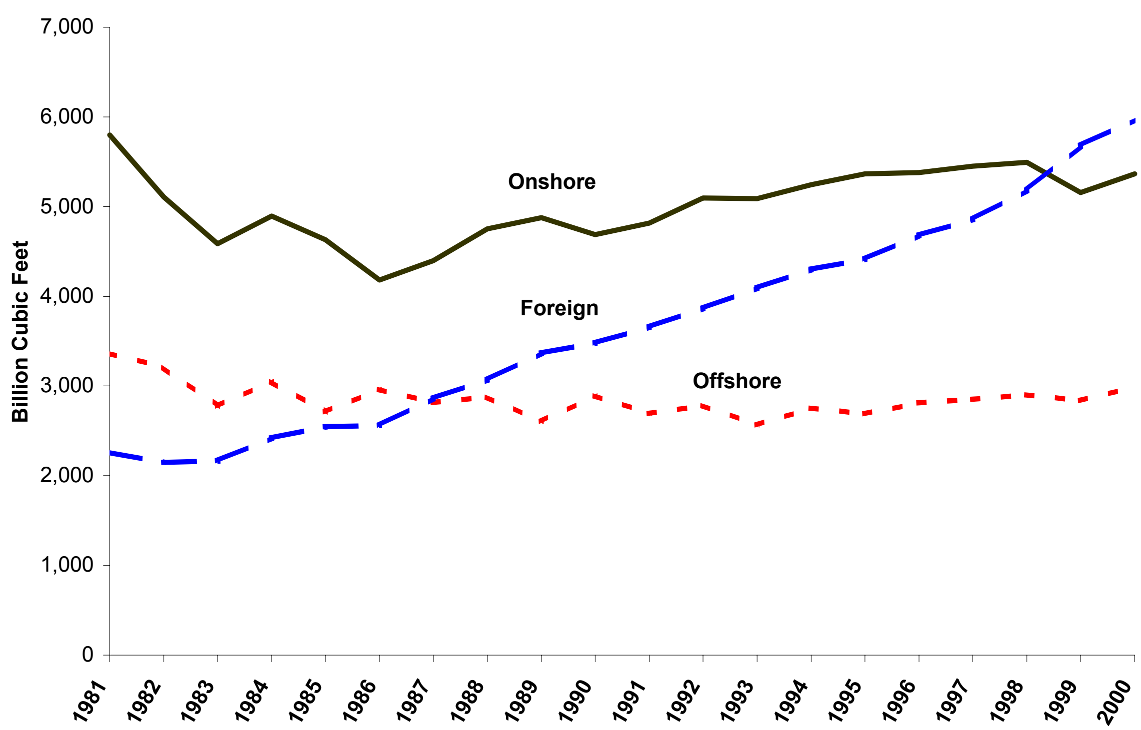


Figure 11b. Natural Gas Production for FRS Companies, 1981-2000



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

Table 11. Production of Oil and Natural Gas by Region for FRS Companies, 1999-2000

Region	Oil (million barrels)			Natural Gas (billion cubic feet)		
	1999	2000	Percent Change	1999	2000	Percent Change
United States						
Onshore	892	827	-7.3	5,158	5,364	4.0
Offshore	414	441	6.7	2,836	2,990	5.4
Total United States	1,306	1,268	-2.9	7,994	8,354	4.5
Foreign						
Canada	173	167	-3.1	1,096	1,221	11.4
Europe and Former Soviet Union[a]	602	634	5.4	2,355	2,416	2.6
Africa	341	350	2.6	44	116	162.0
Middle East	126	120	-4.6	102	98	-3.7
Other Eastern Hemisphere	228	224	-1.9	1,627	1,568	-3.6
Other Western Hemisphere	106	101	-5.3	458	548	19.8
Total Foreign	1,576	1,596	1.3	5,682	5,966	5.0
Worldwide Total	2,882	2,864	-0.6	13,676	14,320	4.7

[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).

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. Total lifting costs are direct lifting costs plus production taxes. The FRS companies were able to reduce direct lifting costs (i.e., lifting costs excluding production taxes) per barrel of U.S. oil and natural gas produced in 2000 by 12 percent from the prior year. Using the methodology of a recent EIA report suggests that most of the decline was for both oil lifting costs and natural gas lifting costs in offshore locales (see the box entitled, "Long-term Trends in Lifting Costs: Oil vs. Natural Gas).

Foreign direct lifting costs were up slightly as four regions registered increases and three regions registered declines (Table 12). Direct lifting costs declined in OECD Europe, where they had been declining for the previous eight years. Both U.S. and foreign lifting costs in 2000 were close to the downward trend of the past decade (Figure 13). 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.[39]

Production taxes (including royalties in foreign regions) generally increased markedly in 2000 (Table 12). Production taxes are determined, in part, by the prices of oil and natural gas, and both of those prices increased substantially in 2000. The United States, the Other Western Hemisphere, and particularly Africa had the largest increases in production taxes. Diverging from the other regions,

Long-term Trends in Lifting Costs: Oil vs. Gas

A recent EIA report, *The Majors' Shift to Natural Gas* (http://www.eia.doe.gov/emeu/finance/sptopics/majors/index.html), contains estimates of lifting costs in the United States for oil and gas separately. The FRS data for the 1977 through 1999 period were utilized. Lifting costs were separately estimated for onshore and offshore locales since data for these regions are separately collected on Form EIA-28.

Although oil production and gas production are separately reported by FRS companies in their public disclosures and on Form EIA-28, companies report lifting costs only on a combined basis for oil and gas. To estimate lifting costs for oil and gas separately, the study noted that reported lifting costs (i.e., for oil and gas combined) could be characterized as a weighted average of natural gas lifting costs and oil lifting costs with the weights being each fuel's share of total oil and natural gas production (in barrels of oil equivalent (BOE)). Formally,

$$L = s L_g + (1-s)L_o$$

Where L = reported lifting costs per BOE of combined oil and natural gas production, s = natural gas share of total BOE production, L_g = lifting costs for natural gas per BOE of natural gas production, and L_o = lifting costs for oil per BOE of oil production.

The above equation was estimated annually for 1977 through 1999. For the purposes of this report, estimates for 2000 are included. Estimated lifting costs for oil and gas separately by onshore and offshore are shown in Figures 12a and 12b.

Some observations from the study include:

- Oil lifting costs are higher than natural gas lifting costs both onshore and offshore, the only exceptions being 1986 and 1987 for onshore locales when companies made sharp cutbacks in production from high-cost oil wells following the oil price crash in 1986.
- Lifting costs for natural gas are generally lower offshore than onshore, but there is no statistically significant difference for oil lifting costs.
- Since the mid-1980's, natural gas lifting costs have been on a downward trend both onshore and offshore.
- By contrast, the trend in oil lifting costs, since the mid-1980's, has been essentially flat, both onshore and offshore.

production taxes in Canada and the Former Soviet Union and Eastern Europe declined; however the latter region is where the FRS companies produce the least. Canada already had the lowest production taxes of any of the regions. Canadian production taxes were only 8 percent of total lifting costs in 2000, compared to a worldwide average of 23 percent. Because of increased production taxes, worldwide total lifting costs increased moderately for the FRS companies in 2000.

Figure 12a. U.S. Onshore Lifting Costs (including production taxes) for FRS Companies, 1977-2000

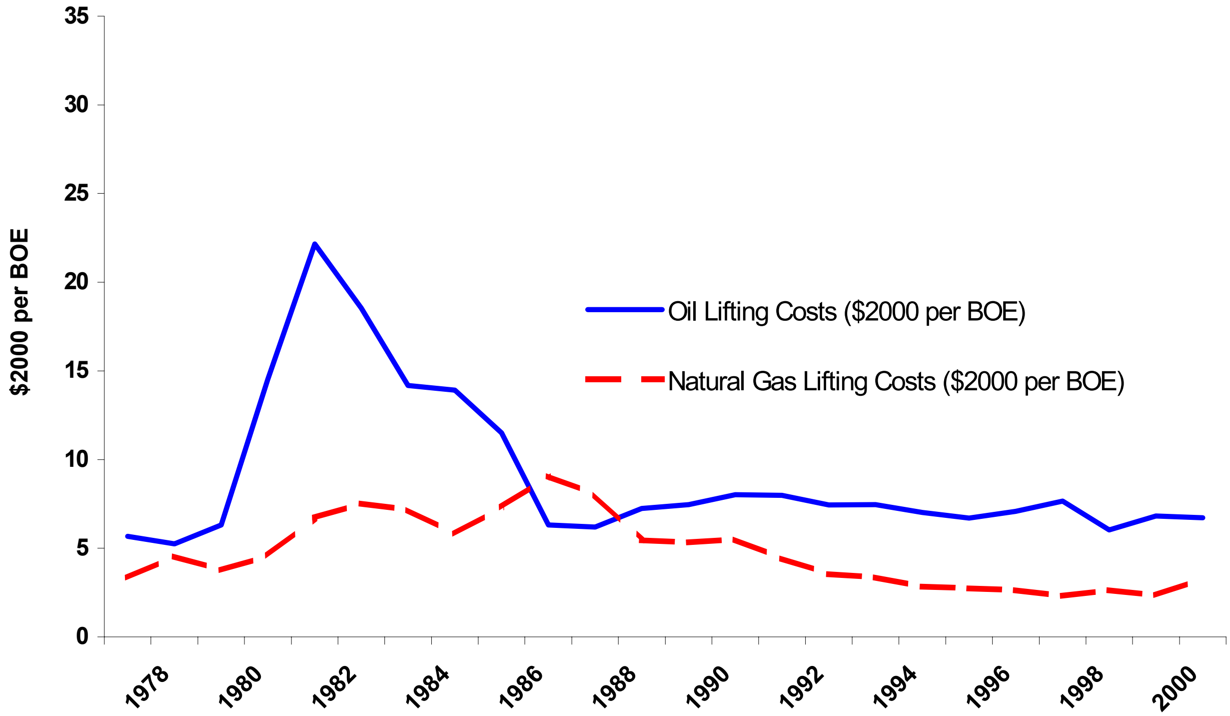
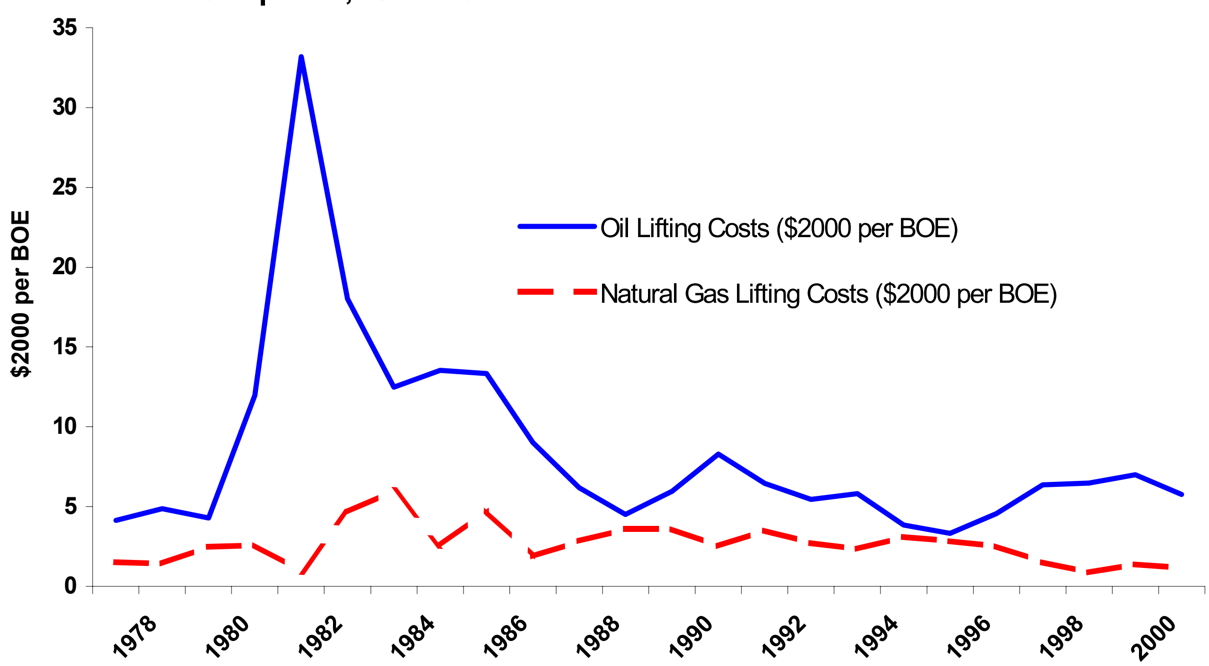


Figure 12b. U.S. Offshore Lifting Costs (including production taxes) for FRS Companies, 1977-2000



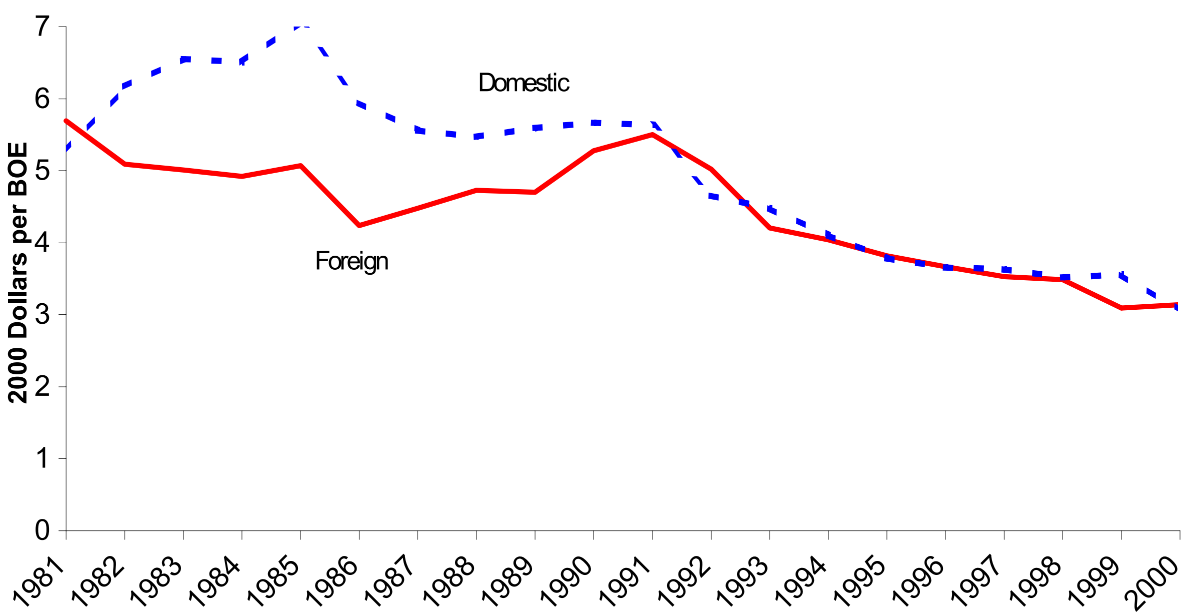
Note: BOE= barrels of oil equivalent. Natural gas converted at 1 mcf= 0.178 barrels.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table 12. Lifting Costs by Region for FRS Companies, 1999-2000
(Dollars per Barrels of Oil Equivalent)

Region	Direct Lifting Costs			Production Taxes			Total		
	1999	2000	Percent Change	1999	2000	Percent Change	1999	2000	Percent Change
United States									
Onshore	--	--	--	--	--	--	4.44	4.63	4.3
Offshore	--	--	--	--	--	--	3.41	2.84	-16.6
Total United States	3.48	3.05	-12.2	0.61	0.95	54.1	4.09	4.00	-2.3
Foreign									
Canada	3.05	3.59	17.8	0.36	0.30	-15.2	3.41	3.89	14.3
OECD Europe	3.72	3.40	-8.8	0.40	0.53	32.2	4.12	3.92	-4.8
Former Soviet Union and Eastern Europe	3.03	4.70	55.3	1.01	0.45	-55.8	4.04	5.15	27.5
Africa	3.30	3.26	-1.3	0.33	1.55	371.8	3.63	4.81	32.5
Middle East	1.63	1.27	-22.0	1.31	1.54	17.5	2.94	2.81	-4.4
Other Eastern Hemisphere	2.12	2.77	30.6	0.98	1.23	25.5	3.10	4.00	29.0
Other Western Hemisphere	2.36	2.69	14.0	0.98	1.53	56.5	3.34	4.22	26.4
Total Foreign	3.02	3.14	3.9	0.60	0.90	49.1	3.63	4.04	11.4
Worldwide Total	3.26	3.10	-4.9	0.61	0.92	51.7	3.87	4.02	4.0

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

Figure 13. Direct Oil and Natural Gas Lifting Costs for FRS Companies, 1981-2000



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

U.S. Refining and Marketing

Profitability of U.S. Refining/Marketing Operations Highest Since 1989

In 2000, the profitability (measured by return on investment)[40] of the U.S. refining/marketing operations of the FRS companies was at its highest level since 1989 (Figure 14). Further, 2000 was the third consecutive year that the profitability of the U.S. refining/marketing operations of the FRS companies was close to the overall profitability of the other lines of business of the FRS companies. In fact, the past three years constitute a golden, albeit short, period of U.S. refining/marketing performance for the FRS companies as each of the years, in the absence of the other two, would have been the most profitable year since 1989.

The similarity of the results of the past three years suggests that profitability in 2000 was achieved in much the same way as in 1998 and 1999. However, as the following discussion will demonstrate, this was not quite the case.

Return on investment, which is used to measure profitability, is closely correlated with the net refined product margin (net margin).[41] 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. The net margin measures before-tax cash earnings from the production and sale of refined products.[42] The $2.23-per-barrel net margin was the second-highest level (after adjusting for the rate of inflation) in the history of the Financial Reporting System, which began in 1977, falling somewhat short of the all-time high of $2.34 per barrel in 1988 (Figure 15). Perhaps equally remarkable was the doubling of the net margin between 1999 and 2000, even as crude oil input costs rose by nearly $11 per barrel.

To understand what happened to the net margin and profitability, changes in the net margin can be analyzed by examining the spread between refined product prices and raw material input costs and operating costs.

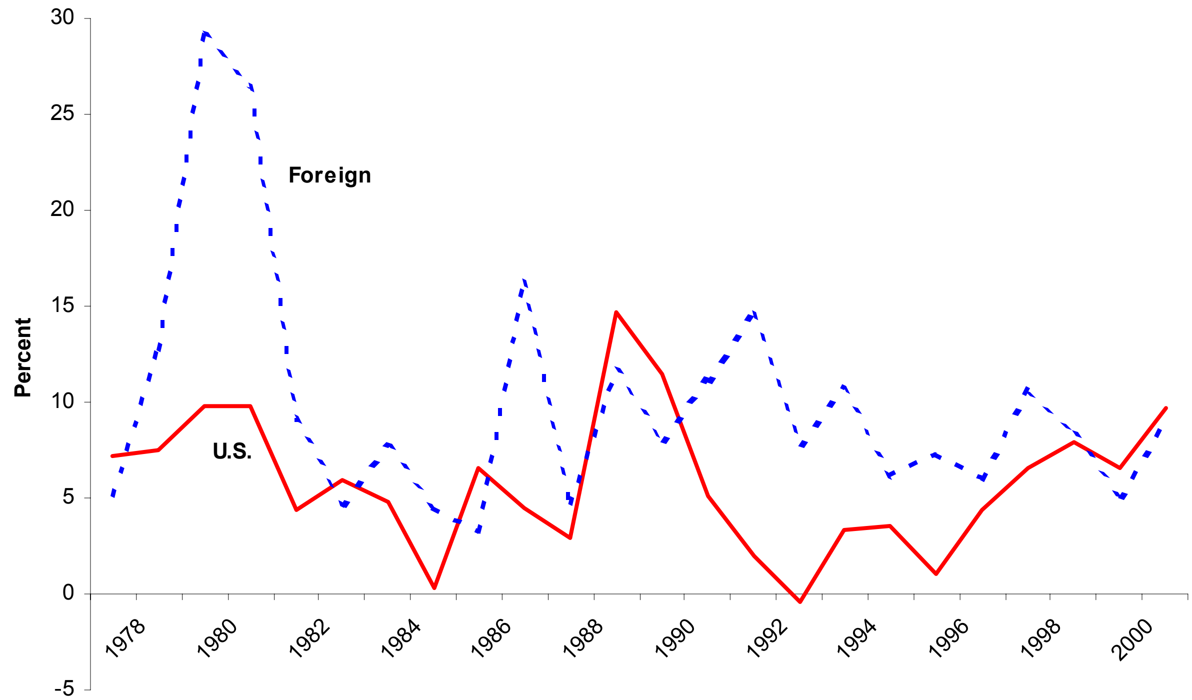
Refined Product Revenues Increase on Strength of Product Price Increases

Revenues from domestic refined product sales increased by 64 percent between 1999 and 2000 (Table 13). The $14.01-per-barrel (58-percent) increase in the average sales price of petroleum products, relative to 1999, accounted for much of the higher revenue level (Table 14). Unusually low levels of petroleum product stocks relative to both 1999[43] and the average for the 1994 through 1998 period (Figure 16) put upward pressure on petroleum prices. Further, the 5-percent increase in U.S. GDP, and cooler weather during 2000 relative to 1999 (7-percent more heating degree-days),[44] put additional upward pressures on product prices in 2000 compared to 1999.

Increase in Sales Volume Augments Revenue Increase

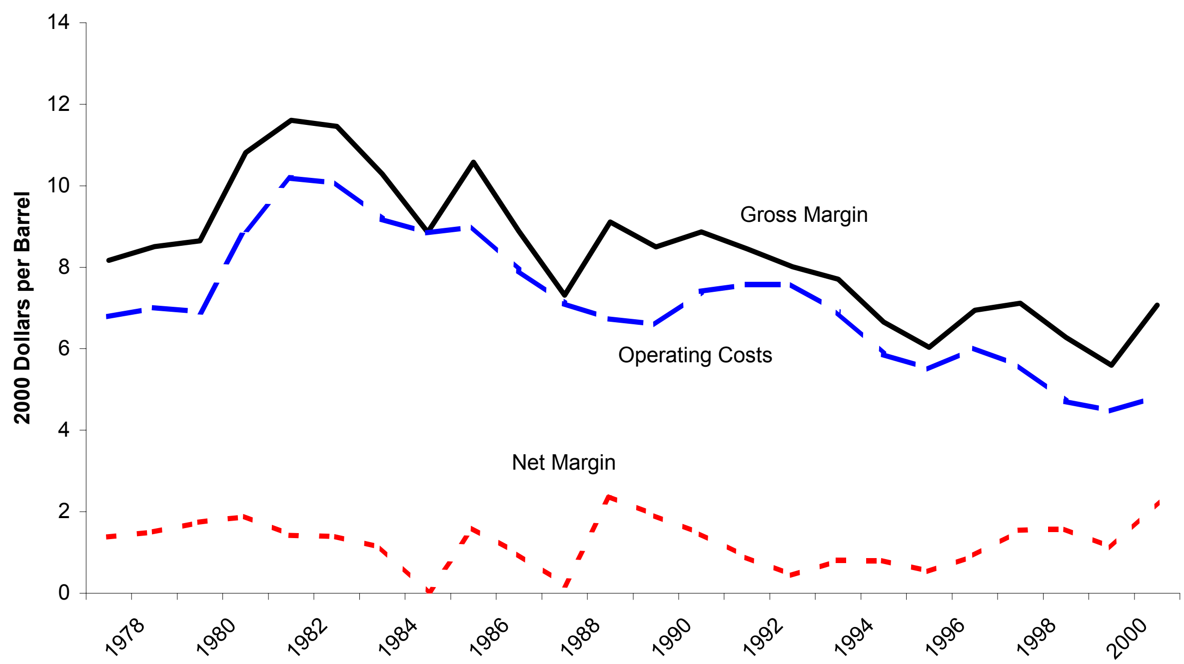
The 58-percent increase in the average price received by the FRS companies for petroleum products was magnified by a 4-percent increase in product sales (Table 14). The FRS companies' sales of motor gasoline grew by 5 percent relative to 1999, and heating oil and diesel fuel sales increased by 4 percent. Although FRS sales of other products declined 1 percent (Table 15), increased sales were associated with the most highly valued products produced by the FRS companies (Table 14).

Figure 14. Return on Investment in U.S. and Foreign Refining/Marketing for FRS Companies, 1977-2000



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

Figure 15. U.S. Refined Product Margins and Costs per Barrel of Petroleum Product Sold for FRS Companies, 1977-2000



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

Table 13. U.S. Refining/Marketing Financial Items for FRS Companies, 1999-2000

	Domestic Refining			Foreign Refining		
	1999	2000	Percent Change 1999-2000	1999	2000	Percent Change 1999-2000
	(Million Dollars)			(Million Dollars)		
Refined Product Sales Revenue	189,617	310,661	63.8	119,105	147,597	23.9
Other Revenue[a]	15,476	17,236	11.4	4,649	4,754	2.3
Operating Expense[a,b]	200,028	317,137	58.5	121,132	147,956	22.1
Operating Income[b]	5,065	10,760	112.4	2,622	4,395	67.6
Net Income, excluding unusual items	4,515	8,657	91.7	1,796	3,065	70.7
Unusual Items	-368	998	n.m.	-58	165	n.m.
Net Income	4,883	7,659	56.9	1,854	2,900	56.4

[a]Raw materials revenues are netted against total operating expense.
[b]Excludes unusual items.
n.m.: not meaningful
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

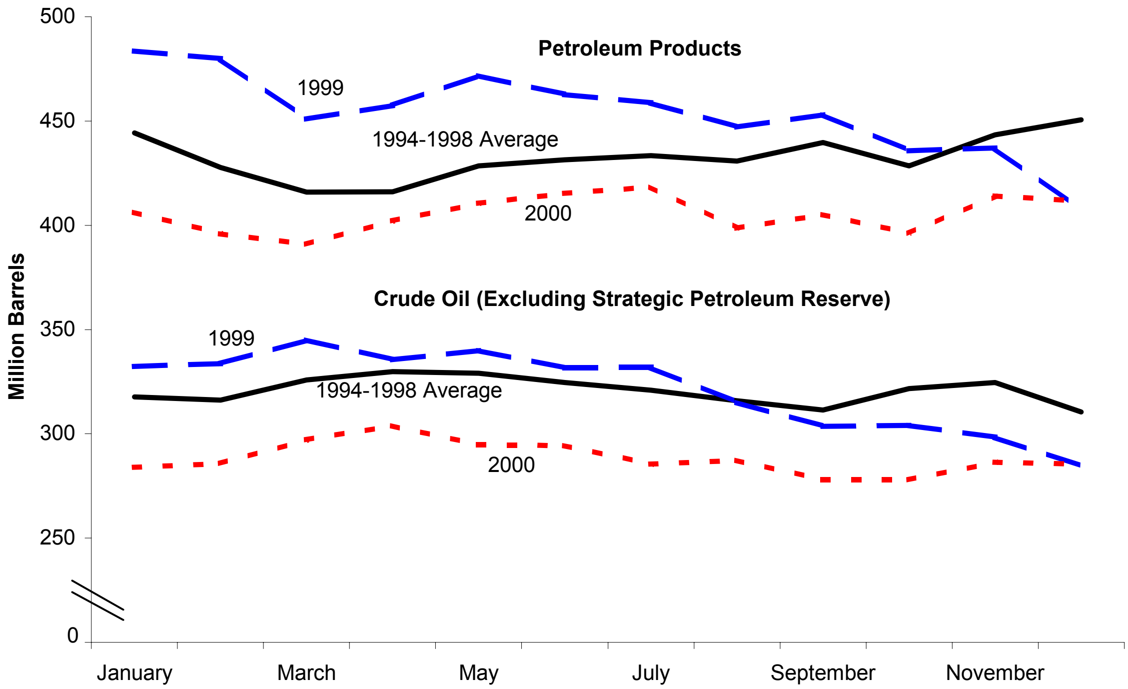
Table 14. Sales, Prices, Costs, and Margins in U.S. Refining/Marketing for FRS Companies, 1999-2000

	1999	2000	Percent Change 1999 to 2000
	(Million Barrels per Day)		
Refined Petroleum Product Sales	21.4	22.2	3.8
Average Sales Price	(Dollars per Barrel)		
Motor Gasoline	26.86	41.15	53.2
Distillate	22.11	37.65	70.3
Other Products	20.27	30.42	50.1
All Refined Products	24.25	38.26	57.8
less Raw Material Input Expense and Product Purchases	18.78	31.19	66.1
equals Gross Margin	5.47	7.07	29.2
less Direct Operating Costs	4.37	4.83	10.6
equals Net Margin[a]	1.10	2.23	103.1
Motor Gasoline Marketing Margins	(Dollars per Barrel)		
Reseller/wholesaler spread (dealer price - wholesale price)	4.04	4.94	22.3
Retailer spread (company-operated price - dealer price)	2.82	1.69	-40.1

[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).

Unlike a year earlier, the refining capacity of the FRS companies increased, if only marginally, during 2000 as all refinery sales and acquisitions were intra-group transactions.[45] Similarly, most of the growth in capital expenditures for U.S. refining (Table 16) was due to mergers and acquisitions. Debottlenecking and upgrading investments[46] generated a 2-percent increase in FRS total domestic refining capacity (Table 16). However, planned and unplanned maintenance and unit failures[47] resulted in the domestic refinery utilization rate falling 1 percentage point relative to 2000 (from 95 to 94 percent). Domestic refinery output also fell 1 percent, putting further upward pressure on product prices relative to a year earlier.

Figure 16. U.S. Crude Oil and Commercial Petroleum Product Stocks, 1994-1998, 1999, and 2000



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

Table 15. U.S. Refined Product Margins and Costs per Barrel Sold and Product Sales Volume for FRS Companies, 1999-2000
(Dollars per Barrel)

	1999	2000	Percent Change 1999-2000
Gross Margin[a]	5.47	7.07	29.2
Marketing Costs	1.42	1.37	-3.4
Energy Costs	0.82	1.33	62.4
Other Operating Costs	2.13	2.13	0.0
Net Margin[b]	1.10	2.23	103.1
	(Million Barrels)		
Product Sales Volume	7,820	8,119	3.8
Motor Gasoline	4,070	4,286	5.3
Distillate	2,344	2,444	4.3
Other Products	1,407	1,390	-1.2

[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).

Table 16. U.S. and Foreign Refining Investment and Operating Items for FRS Companies, 1999-2000

	1999	2000	Percent Change 1999-2000
	(Billions of Dollars)		
U.S. Refining Additions to Investment in Place	2.8	8.2	189.4
U.S. Marketing Additions to Investment in Place	2.6	3.4	29.2
Foreign Refining/Marketing Additions to Investment in Place	2.3	2.4	4.0
	(Thousands of Barrels per Day)		
U.S. Refining Capacity	14,158	14,393	1.7
U.S. Refinery Output	14,639	14,499	-1.0
Foreign Refining Capacity	4,930	5,134	4.1
Foreign Refinery Output	4,866	5,124	5.3
	(Percent)		
U.S. Refinery Utilization Rate[a]	94.7	93.6	n.m.
Foreign Refinery Utilization Rate[a]	93.4	89.7	n.m.

[a]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

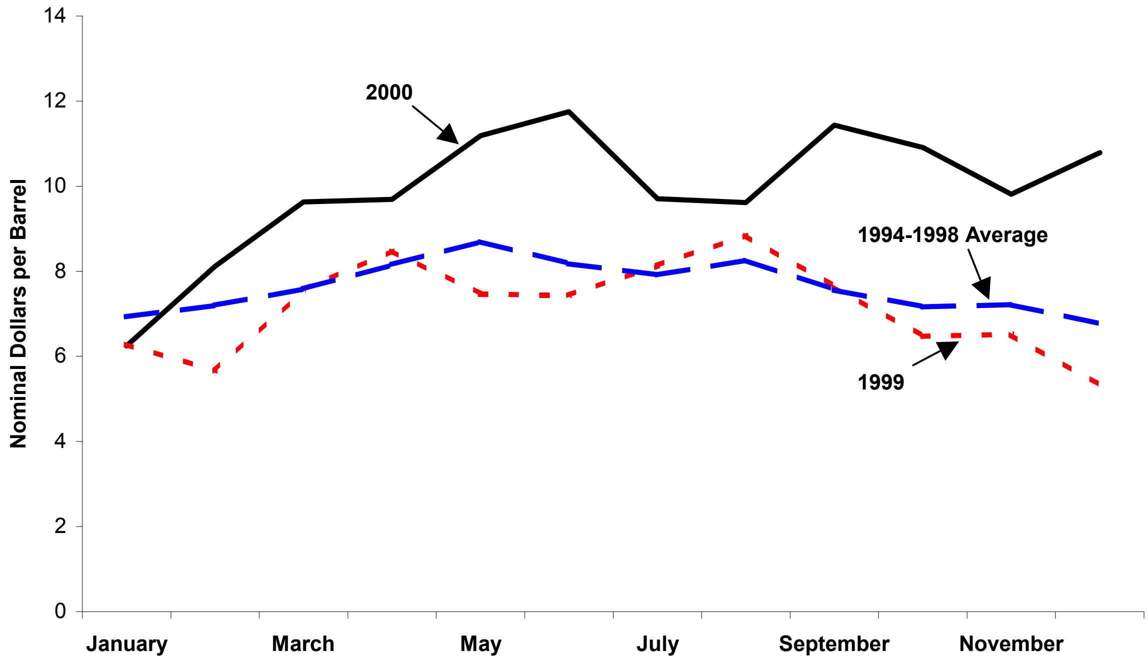
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Gross Margin Increases 29 Percent in 2000

Industry-wide gross product margins were consistently higher throughout the year relative to a year earlier (Figure 17). The gross margin was boosted by unusually low product stock levels in 2000 relative to both 1999, when petroleum stocks began the year at a higher than normal level and ended the year well below normal, and the average level for the period 1994 through 1998 (Figure 16). The story that the gross margin conveyed was remarkably consistent from one quarter to the next, as it was higher each quarter in the year 2000 than it was in 1999. In particular, the first quarter (January through March) was $1.50 per barrel higher, the second quarter (April through June) was $2.11 per barrel higher, the third quarter (July through September) was $2.03 per barrel higher, and the fourth quarter (October through December) was $4.34 per barrel higher. Overall, the yearly average gross refining margin of 2000 was $2.73 per barrel higher than the average of 1999 ($9.91 per barrel compared to $7.18 per barrel).[48]

However, the FRS refiners were not quite as successful as the industry as a whole, generating a smaller $1.60-per-barrel increase in their gross margin for 2000 relative to 1999 (a 29-percent increase). U.S. crude oil stock levels in the year 2000 were lower than 1999 levels, as well as the average for the 1994 through 1998 period, for much of the year, in part resulting in a $10.75-per-barrel (61-percent) increase in the industry-wide composite refiner acquisition cost of crude oil. However, the FRS companies were encumbered by an even larger $12.42-per-barrel increase in raw materials acquisition costs (chiefly crude oil) and product purchases despite having extremely complex refineries capable of processing large amounts of relatively inexpensive heavy, sour crude oil into large amounts of relatively expensive light products.[49] One explanation for this conundrum is that the FRS companies bought an unusually large amount of refined products during 2000, which were 370 million barrels more than during 1999, a

Figure 17. Monthly Gross Refined Product Margin for United States, 1994-1998,1999, and 2000



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

13-percent increase relative to 1999 (Table B27 of Appendix B), in part due to refinery outages and petroleum transport bottlenecks in 2000.

Higher Operating Costs Fail to Offset Increased Gross Margin

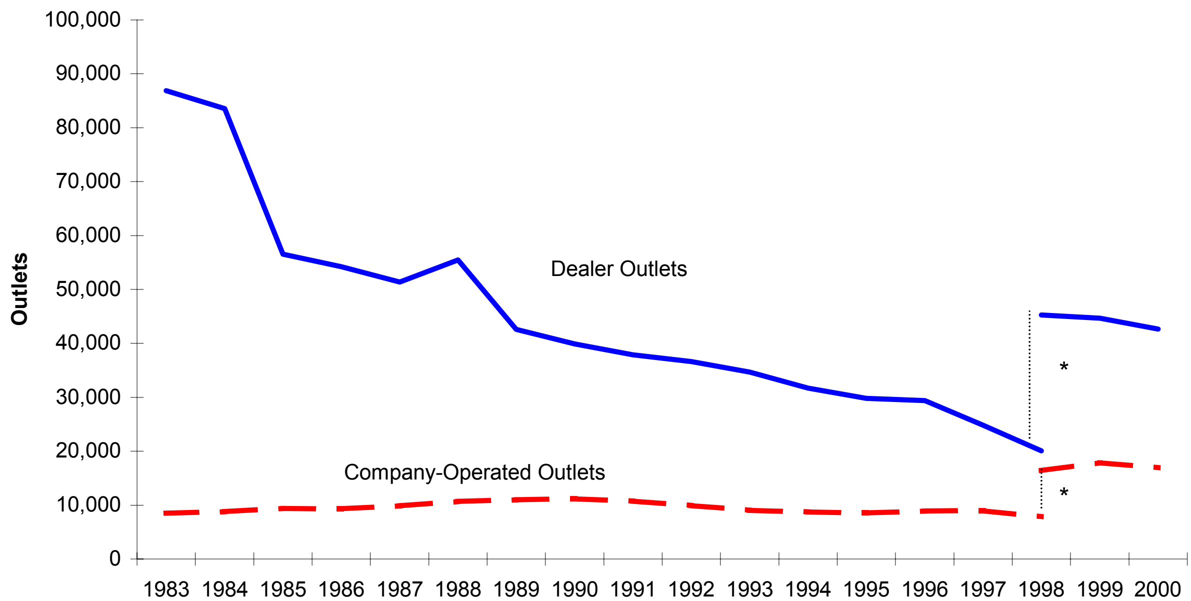
Unlike recent years, operating costs rose in 2000 relative to 1999 apparently reversing a 3-year trend of falling operating costs (after adjusting for inflation) (Figure 15). Decomposing operating costs into its components (energy costs, marketing costs, and other costs) may provide insight into how and why operating costs increased in 2000 relative to 1999.

Energy costs (chiefly associated with refining) accounted for the entire increase in operating costs (Table 15), increasing by 51 cents per barrel (62 percent), compared to a year earlier. The refiners consistently blamed higher natural gas costs,[50] while a few cited electricity costs,[51] for the increased expense.

Cost-Cutting Efforts Reduce Marketing Costs

Marketing costs (chiefly associated with retailing) fell slightly (5 cents per barrel, or 3 percent) between 1999 and 2000, as the FRS companies continued to restructure their marketing operations. Every year since 1988, the total number of company-operated and dealer outlets supplied by the FRS companies declined (Figure 18). Between 1999 and 2000, the number of outlets declined by 1,427 (3 percent) (Table 17). Although the result for the entire FRS reporting group was a decline in branded outlets, company-level results varied as some companies acquired outlets,[52] others divested outlets,[53] and a few did both.[54]

Figure 18. Motor Gasoline Retail Outlets for FRS Companies, 1983-2000



*: The addition of 11 companies to the group of U.S. majors in 1998, the largest single-year change in the history of the Financial Reporting System, resulting in the vertical displacement of the series in 1998.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table 17. Motor Gasoline Distribution by FRS Companies, 1999-2000

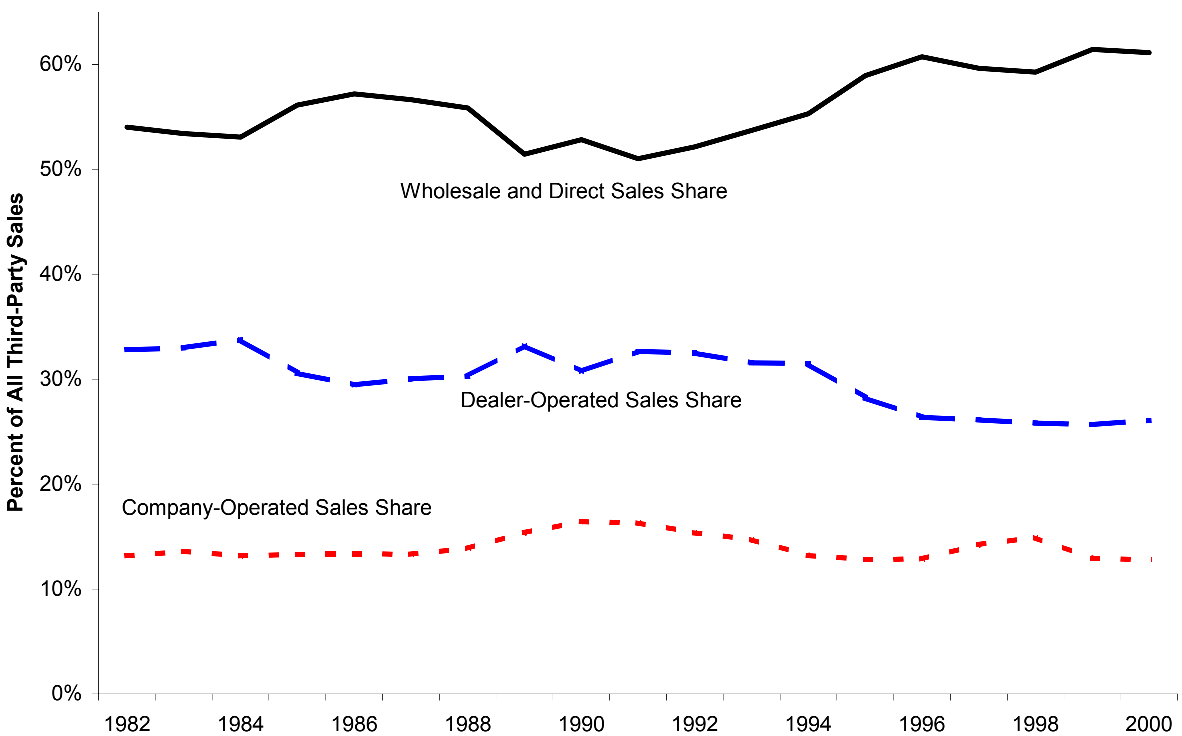
Distribution Category	1999	2000	Percent Change 1999-2000
	(Million Barrels)		
Wholesale Volume	2,009.5	2,125.9	5.8
Retail Volume			
Dealer Volume	1,006.3	1,104.6	9.8
Company-Operated Volume	506.2	543.3	7.3
Total Retail Volume	1,512.5	1,647.9	9.0
Direct Volume	398.6	464.9	16.6
Intersegment Volume	65.6	47.4	-27.8
	(Number of Outlets)		
Dealer Outlets	44,652	42,660	-4.5
Company-Operated Outlets	12,018	12,583	4.7
Total Retail Outlets	56,670	55,243	-2.5
Average Monthly Outlet Volume	(Thousands of Gallons per Month)		
Dealers	78.9	90.6	14.9
Company-Operated	147.4	151.1	2.5
All Retail	93.4	104.4	11.8

Note: Percent changes calculated from unrounded data.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Not only were the FRS companies refocusing their marketing operations, they also were increasing the productivity of their outlets as average monthly sales of dealer outlets increased from 78,900 gallons per month to 90,600 gallons per month (15 percent) in 2000 relative to 1999. Meanwhile, average monthly sales of company-operated outlets increased from 147,400 gallons per month to 151,100 gallons per month (3 percent) (Table 17). Although efforts to reduce marketing costs in 2000 relative to 1999 were not overwhelmingly successful, the FRS companies continued to attempt to reduce them. One strategy apparently employed over the last few years is a growing reliance on direct sales and wholesale sales, and a concomitant declining use of company-operated and dealer-operated outlets to market motor gasoline (Figure 19). (See the Special Topic "Marketing Operations of Industry Coalesce" for a more detailed discussion of recent U.S. marketing developments.)

Although both out-of-pocket costs and the gross margin increased during the year 2000, the former rose more slowly than did the latter. The difference in the two rates of increase generated the highest net margin since 1988 and the highest level of profitability of domestic refining/marketing operations since 1989.

Figure 19. Third Party Motor Gasoline Distribution by FRS Companies, 1982-2000



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

Foreign Refining and Marketing

Profitability of Foreign Refining/Marketing Operations Highest Since 1997

Foreign refining/marketing generated $148 billion in sales revenues in 2000, resulting in net income before unusual items of $3.1 billion. Sales revenues in 2000 were $28.5 billion (24 percent) higher than those of 1999 and net income exclusive of unusual items was $3.1 billion (71 percent) higher (Table 13). Profitability was 9 percent, the highest since 1997 (Figure 14).

The FRS companies' foreign refining/marketing earnings are derived from two sources: unconsolidated affiliates and consolidated operations. The corporate parent of an unconsolidated affiliate owns 50 percent, or less, of the affiliate, and does not directly control the affiliate. Essentially, the unconsolidated affiliate is more of a property or holding of the parent corporation than it is a company that the parent actually operates. The effect on financial operations of an unconsolidated affiliate can only be seen on the parent corporation's income statement, where the parent company's proportional share of the affiliate's net income is reported. Conversely, a fully consolidated affiliate is directly controlled by the parent corporation (although it could be owned by several companies, with the parent corporation owning more than 50 percent). In addition, all operating and financial information about a fully consolidated affiliate (such as revenues) is reported in the public financial disclosures of the parent corporation.

Asia-Pacific and European Regions Dominate Foreign Refining/Marketing

Historically, the operations of the FRS companies' unconsolidated foreign refining/marketing affiliates have been mainly in the Asia-Pacific region. About 67 percent of the refinery capacity of unconsolidated affiliates in 2000 was in the Asia-Pacific region, a 1-percentage point increase since 1999 (Table 18). Although the change was negligible, numerous marginal changes in refinery capacity, many of which were declines, underlay the summary statistics. Further, Exxon Mobil's slightly reduced ownership of the Sakai refinery in Japan shifted 70,100 barrels of capacity from consolidated operations to unconsolidated affiliates.[55] Additionally, the 120,000-barrels-per-day Melaka, Malaysia refinery (of which Conoco has a 40-percent share) began operation.[56]

The FRS companies' consolidated foreign/marketing operations tend to be located in Europe. In 2000, 49 percent of consolidated refinery capacity was located in Europe, a 1-percentage point increase since 1999. The main sources of the change were marginal declines in the reported capacities of several refineries, which slightly shifted the proportions (Table 18). Although little change occurred during 2000, two transactions will affect next year's results. Phillips Petroleum sold its ownership in the 117,000 barrels per day Teesside, U.K. refinery at the end of the year.[57] Further, Tosco indicated during 2000 that it intended to buy Ireland's 70,000 barrels per day Whitegate refinery, but did not actually do so until May 28, 2001.[58]

Consolidated Operations Dwarf Unconsolidated Affiliates As A Net Income Contributor

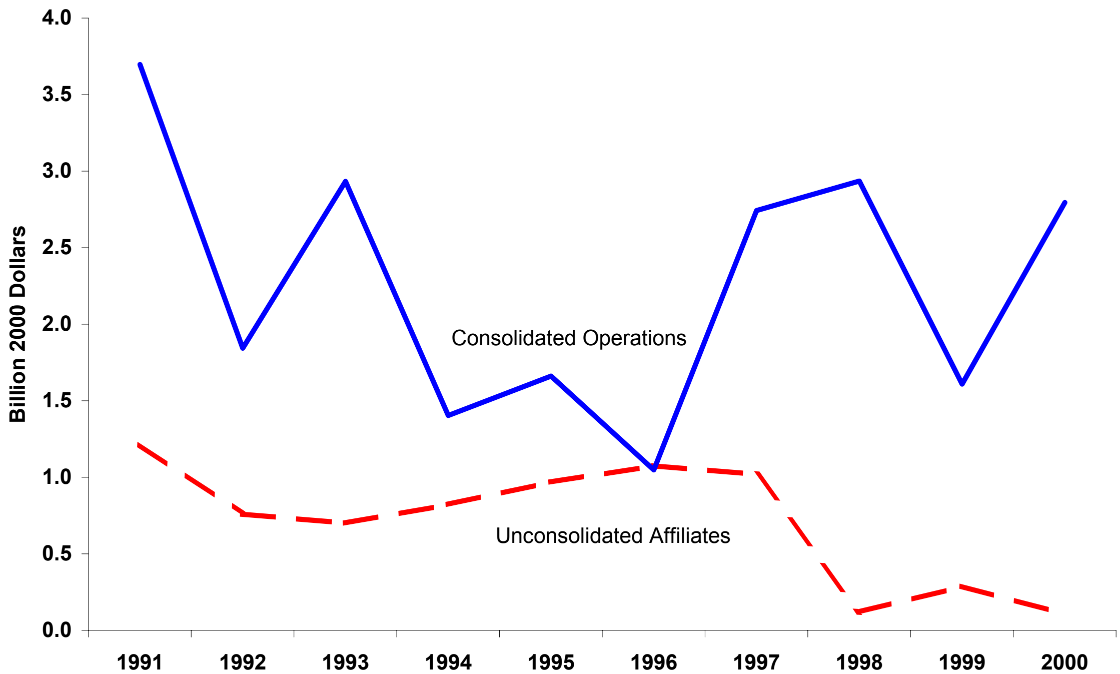
The contribution to net income from unconsolidated affiliates has been significantly lower than earnings from consolidated operations since 1997 (Figure 20). Between 1991 and 1997 the ratio of net income from unconsolidated affiliates to the net income from consolidated operations averaged 43 percent, ranging between a high of 103 percent and a low of 24 percent. Since 1997 the ratio has averaged 7

Table 18. Regional Distribution of Foreign Refinery Capacity for FRS Companies, 1999-2000
(Percent)

	Consolidated Operations		Unconsolidated Affiliates	
	1999	2000	1999	2000
Europe	48.1	49.4	21.0	20.5
Asia	25.3	24.0	66.1	66.8
Latin America	10.3	10.0	0.6	0.6
Canada	13.6	13.9	0.0	0.0
Other	2.7	2.8	12.2	12.0
Total	100.0	100.0	100.0	100.0

Sources: Company Annual Reports and filings of Securities and Exchange Commission Form 10-K.

Figure 20. Foreign Refining/Marketing Net Income from Consolidated Operations and Unconsolidated Affiliates for FRS Companies, 1991-2000



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

percent, ranging between a high of 18 percent and a low of 4 percent, providing some indication of the ongoing economic troubles of the Asia-Pacific region. For example, Exxon Mobil noted that Asia-Pacific refining margins were low for the third-consecutive year.[59] Despite the lingering economic problems following the Asian financial crisis, the Asia-Pacific region (with a growth rate of 10 percent) has experienced the highest growth rate in the consumption of petroleum products of any region in the world since 1996 (Figure 21).

Mixed Results in Asia-Pacific Markets

During 2000, net income from unconsolidated affiliates was $0.1 billion, down from 1999's level of $0.3 billion, a 64-percent reduction. The results were mixed, with some companies reporting gains and others reporting losses. Results for unconsolidated affiliates largely reflect conditions in the Asia-Pacific region (Table 18). Refining margins for Asia-Pacific (represented by the Singapore/Dubai refining margin) were higher than a year earlier except for the fourth quarter of 2000 (Figure 22). However, after rising dramatically during the first quarter of 2000, the Asia-Pacific refining margin fell throughout the balance of the year. Consequently, some companies reported higher earnings while others reported lower earnings in this region. For example, Conoco reported higher margins from Asia's strengthening economy.[60] However, Chevron noted that excess refining capacity and the still-struggling Asia-Pacific economies resulted in losses of $16 million.[61]

Rising Margins in Europe Raise Earnings

Net income from consolidated operations (bottom line net income from foreign refining/marketing less income from unconsolidated affiliates) was higher in 2000 than a year earlier, reaching $2.8 billion, a 74-percent increase. This increase was realized despite Europe having the lowest positive growth since 1996 (Figure 21) over the 4-year period.

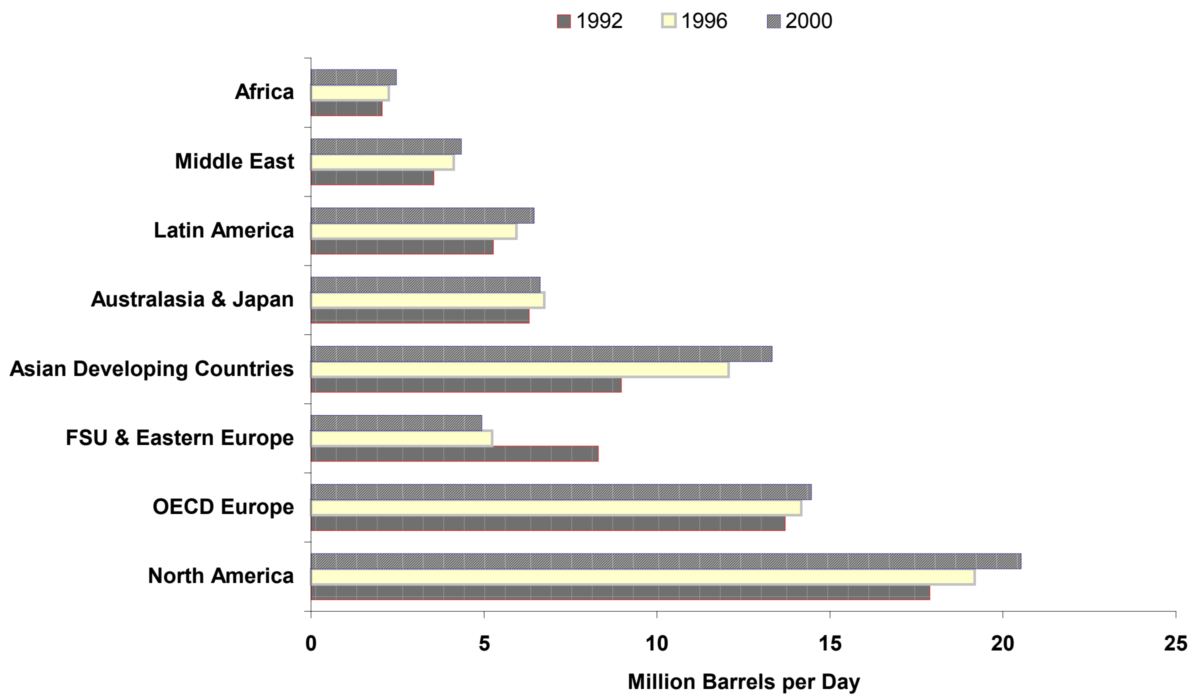
As seen in Figure 22, European refining margins (represented by the Rotterdam/Brent refining margin) followed a path during 2000 that was essentially the opposite of the path traveled by Asia-Pacific refining margins. Asia-Pacific refining margins peaked during the first quarter, fell the entire year, and by the fourth quarter were lower than the refining margin of a year earlier. In contrast, the European refining margin was at its 2000 nadir during the first quarter when it was lower than the margin of a year earlier. However, throughout the year, the European refining margin increased, ending the year at its highest value for the entire year. Similarly, the financial results of the FRS companies reporting consolidated refining/marketing operations were consistently good, as almost all companies reported higher net income than a year ago, citing higher margins[62] and sales.[63]

Refocusing Foreign Marketing Operations

Just as the FRS companies refocused their domestic motor gasoline marketing operations during 2000, so, too, did they refocus their foreign motor gasoline marketing operations. For example, Texaco exchanged retail assets in Greece and in Poland for Shell stations in the UK and announced a joint venture with Russia's Tyumen Oil Company. Texaco will build and operate Star Mart convenience stores at Tyumen retail locations in Russia and Ukraine.[64] Conoco opened 4 Jet/Jiffy convenience stores during 2000 and plans to build about 40 more over the next 2 years in central and eastern Europe.[65] Meanwhile, Phillips Petroleum sold its UK marketing and distribution business during 2000.[66]

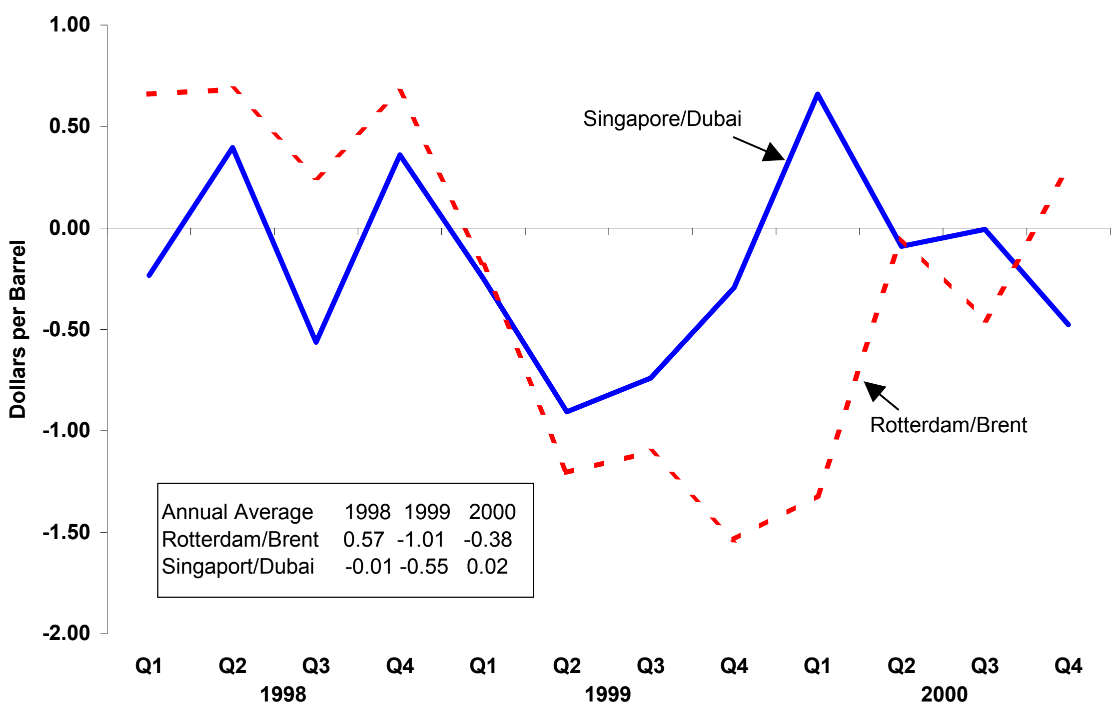
Additionally, Conoco gained experience in Scandinavia with an approach toward motor gasoline marketing that is rarely employed in the United States: unattended, automated outlets.[67] Lastly, an interesting development was reported by Exxon Mobil, which complained about low marketing margins, citing "… nontraditional retailers …,"[68] but also noted that it had finalized an alliance with a UK grocery chain to build and operate co-branded sites.[69] Exxon Mobil also is testing unattended outlets in France and the UK.[70]

Figure 21. Petroleum Consumption by Region, 1992, 1996, and 2000



Source: BP Amoco, Statistical Review of World Energy (June 2001).

Figure 22. Foreign Refining Margins, 1998 - 2000



Sources: Energy Intelligence Group, Oil Market Intelligence 1998: January 1999 and July 1999, p. 12; 1999: January 2000 and July 1999, p. 12; and 2000: January 2001and July 2000, p. 12.

Other Energy

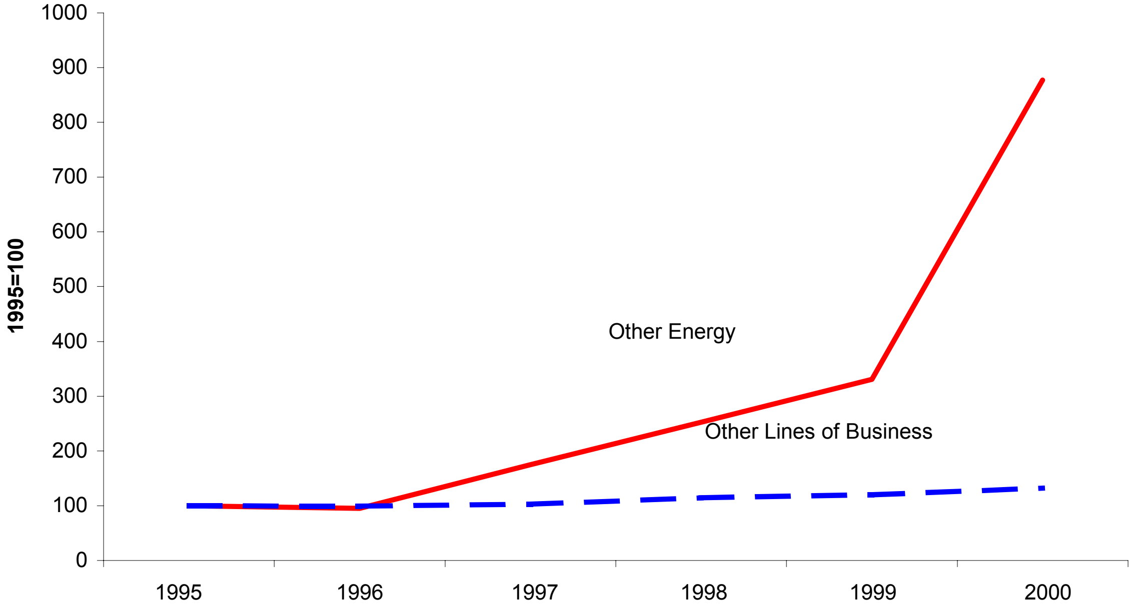
The other energy line of business consists of energy operations other than the production of oil, natural gas, or coal. This includes electric power production and supply, energy trading operations, energy management services, and nonconventional energy production. Whether measured by asset growth or revenues, the other energy line of business has grown much more rapidly in recent years than the FRS companies' other lines of business (Figure 23).

Revenues from the FRS companies' other energy line of business were up a whopping 211 percent between 1999 and 2000 (Table 19). Enron and El Paso were the largest FRS companies in other energy, based on revenues. El Paso attributed their growth in revenues to higher trading margins, higher electricity rates and the opening and expansion of power production capacity.[71] Enron noted that revenues from their wholesale services business, which includes the marketing of energy commodities and services, managing the associated contract portfolios and investing in, developing, constructing and operating energy-related and other assets, were up 162 percent between 1999 and 2000.[72] Dominion Resources, a new FRS respondent in 2000, contributed about 16 percent to the growth in other energy revenue. Dominion's other energy activities consist mainly of electricity generation, transport, and distribution, but also include gas sales. Coastal has been involved for the longest time among the FRS companies in power and gas production and trading, going back to the mid-1980's with its investment in the Midland Cogeneration Venture. In 2000, Coastal owned and operated electricity production facilities in the United States, Latin America, and China. Coastal's revenue from their "Power" segment was up 30 percent. By contrast, Shell Oil is a more recent entrant to the power business. Shell's "Downstream Gas and Power" segment is engaged in wholesale marketing and trading of natural gas and electric power and energy management services. In 2000, this segment registered considerable growth, with revenues increasing by $6.0 billion to $14.9 billion.[73]

Although electric power and energy trading now account for the bulk of the FRS companies' activity in the other energy line of business, this was not always the case. Until the mid-1990's, nonconventional energy was the core competency of this line of business. Nonconventional energy includes renewable resources, such as wind, solar, and geothermal energy, and hydrocarbons from tar sands, oil shale, coal gasification and liquefaction, among other sources. Generally, the FRS companies' experiences with nonconventional energy development were very unprofitable. Most of the companies retreated from this line of activity during the 1980's. The two exceptions are production of oil from tar sands in Canada and geothermal power development. Exxon Mobil has been extracting oil from Canadian tar sands since the 1970's. Their Canadian tar sand reserve level at year-end 2000 was 610 million barrels, compared to 577 million barrels in 1999. Gross synthetic crude oil produced from those tar sands was 73.2 million barrels in 2000, down from 83.6 million barrels in 1999, but this production decline was more than offset by the 61 percent increase in crude oil prices from 1999 to 2000. Unocal has been tapping geothermal resources to generate electricity for decades. The company operates three of the world's major geothermal electricity projects: Tiwi and Mak-Ban in the Philippines and Gunung Salak in Indonesia, with a combined generating capacity of 1,100 megawatts. In 2000, Unocal's daily geothermal energy production averaged 16 million kilowatt-hours, or the equivalent of 25,000 barrels of oil. Net proved geothermal reserves at year-end 2000 were the equivalent of 170 million barrels of oil. Geothermal and Power Operations after-tax earnings, adjusted for special items, remained flat at $24 million in 2000, the same level as in 1999, as the effect of higher geothermal electricity sales in Indonesia in 2000 was offset by higher foreign exchange losses.

Although other energy revenue increased sharply between 1999 and 2000, so too did operating expenses

Figure 23. Net Investment in Place in Other Energy and All Other Businesses for FRS Companies, 1995-2000
(1995=100)



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

Table 19. Income Components for Other Energy for FRS Companies, 1999-2000
(Million Dollars)

Income Components	1999	2000	Percent Change 1999-2000
Operating Revenues	27,363	84,987	210.6
Operating Expenses	27,053	81,949	202.9
Operating Income	310	3,038	880.0
Equity Income	519	755	45.5
Net Income	711	2,743	285.8
unusual items	-140	-20	--
Net Income less unusual items	851	2,763	224.7

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

(Table 19). However, revenue gains outpaced cost increases overall. On balance, after taxes, the FRS companies' net income, excluding unusual items, from other energy was up 225 percent between 1999 and 2000, and up nearly 150 percent excluding Dominion Resources. The gains in income were widespread. Of the 11 companies reporting in this line of business, only one did not register higher income in 2000 compared with the year before.

Endnotes

[38] BP Amoco plc, Security and Exchange Commission Form 20F, p. 35; Apache Corporation, Securities and Exchange Commission Form 10K; Exxon Mobil Corporation, Securities and Exchange Commission Form 10K, p. 54; and Phillips Petroleum Company, Securities and Exchange Commission Form 10K, pp. 14, 137.
[39] To the extent that measured lifting costs are marginal costs, one would expect them to be similar across regions.
[40] Return on investment is net income divided by net investment in place.
[41] 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).
[42] The net margin excludes peripheral activities such as non-petroleum product sales at convenience stores.
[43] The average monthly value for petroleum product stocks in 1999 was 454 million barrels with a standard deviation of 20.1 million barrels. In 2000 the average monthly level of petroleum product stocks was 405 million barrels with a standard deviation of 8.4 million barrels. See Energy Information Administration, *Petroleum Supply Monthly*, DOE/EIA-0109 (Washington, DC), Table 51.
[44] Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0034(2001/10) (Washington, DC, October 2001), Table 1.7.
[45] A total of 4 refineries changed hands as Tosco acquired BP America's Alliance, Louisiana refinery and Equilon's Wood River, Illinois refinery, while selling Ultramar Diamond Shamrock (UDS) its Avon, California refinery (which UDS renamed "Golden Eagle"). Finally, Valero acquired Exxon Mobil's Benicia, California refinery. A related matter is Premcor's closure of its Blue Island, Illinois refinery at the end of January 2001, which had no material effect on Premcor's or the FRS companies' operations in 2000.
[46] For example, Conoco upgraded its Lake Charles, Louisiana refinery to process synthetic crude oil (Conoco Inc., *2000 Annual Report*, p. 17) while Exxon Mobil constructed a 40,000-barrels-per-day coker at its Baytown, Texas refinery in order to process more heavy Mexican crude oil (Exxon Mobil Corporation, *2000 Annual Report*, p. 4)
[47] For example, Chevron noted that it restarted a hydrocracker at its Richmond, California refinery in March 2000, about one year after mechanical failure and a subsequent fire shutdown the unit (Chevron Corporation, *Supplement to the 2000 Annual Report*, p. 35). Meanwhile, upgrades to its Lake Charles, Louisiana refinery lowered Conoco's corporate refinery throughput (Conoco Inc., *2000 Annual Report*, p. 17). Similarly, a fire shutdown Sunoco's Philadelphia, Pennsylvania's crude oil distillation unit for 3 weeks, beginning in September 2000, in addition to the 4 weeks that a scheduled turnaround halted the unit (Sunoco Inc., 2000 Securities and Exchange Commission Form 10-K, p. 4.).
[48] Note the quarterly gross margin is the weighted average product price for the quarter less the weighted average refiner acquisition cost of crude oil. The average product price is computed using product prices and quantities from Energy Information Administration, *Petroleum Marketing Monthly*, DOE/EIA-0109 (Washington, DC), Tables 4 and 5. The average raw material price is computed using refiner acquisition cost of crude oil (Energy Information Administration, *Petroleum Marketing Monthly*, DOE/EIA-0109 (Washington, DC), Table 1) weighted by refinery runs (Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035 (Washington, DC), Table 3.2a).
[49] For example, see Energy Information Administration, "Updated Selected Tables and Figures from *The U.S. Petroleum Refining and Motor Gasoline Marketing Industry*" (September 2001), Table 6.
[50] For example, Coastal Corporation indicated that higher operating expenses were primarily due to higher fuel costs, among other factors (Coastal Corporation, *2000 Annual Report*, p. 20). Premcor, one of two merchant refiners included in the FRS group, noted that "Operating expenses were higher in 2000 due to the dramatic increase in natural gas prices …" (Premcor Inc., 2000 Security and Exchange Commission Form 10-K, p. 19). Texaco also noted that significantly higher U.S. natural gas prices increased purchases and other costs during 2000 (Texaco Inc., *2000 Annual Report*, p. 30).
[51] For example, Phillips Petroleum Company noted that higher fuel and utility costs at the refineries offset higher net income from refining, marketing, and transportation (Phillips Petroleum Company, *2000 Annual Report*, p. 36).
[52] Amerada Hess was one of the few companies that acquired outlets, purchasing the balance (178 outlets) of the Merit-branded outlets that it had not already acquired (Amerada Hess Corporation, *2000 Annual Report*, p. 15). Following El Paso Energy's acquisition of Coastal Corporation, El Paso divested several retail outlets. Phillips Petroleum acquired 101 company-operated outlets in "... the Midcontinent region ..." with the transaction expected to close during 2001 (Phillips Petroleum Company, *2000 Annual Report*, p. 49). Meanwhile Sunoco Inc., acquired 245 outlets in the northeast (Sunoco Inc., *2000 Annual Report*, p. 2). Other merger-related acquisitions were Valero's acquisition of 340 west coast Exxon-branded outlets (Valero Energy Corporation, *2000 Annual Report*, p. 16) and Tosco's acquisition of 1,740 east coast Exxon and Mobil outlets (Tosco Corporation, *2000 Annual Report*, p. 8).
[53] Coastal Corporation agreed in late 2000 to sell about 200 company-operated outlets by the middle of 2001 while effectively exiting 11 states out of a total of 34 in which it had operations during 2000 (Coastal Corporation, 2000 Securities

and Exchange Commission Form 10-K, p. 7). Marathon Ashland Petroleum sold about 160 non-core Speedway SuperAmerica outlets during 2000 (USX Corporation, 2000 Securities and Exchange Commission Form 10-K, p. M-36).

[54] Ultramar Diamond Shamrock acquired Valley Shamrock's 23 convenience stores while divesting 92 convenience stores (Ultramar Diamond Shamrock Corporation, 2000 Securities and Exchange Commission Report 10-K, p. 7).

[55]Exxon Mobil Corporation, *Statistical Supplement to the 2000 Annual Report*, p. 70; and *Statistical Supplement to the 1999 Annual Report*, p. 66.

[56]Conoco, Inc., *2000 Annual Report*, p. 18.

[57]Phillips Petroleum Company, *2000 Annual Report* , p. 45.

[58]See, Tosco Corporation, *2000 Annual Report,* p. 9; and "Tosco to Pay $100 Million for Irish State Oil Refinery," *Financial Times* (May 28, 2001).

[59]Exxon Mobil Corporation, *2000 Annual Report,* p. 17.

[60]Conoco, Inc., *2000 Annual Report*, p. 16.

[61]Chevron Corporation, *2000 Annual Report*, p. 6.

[62] Exxon Mobil Corporation, *2000 Annual Report*, p. 17.

[63] Texaco Inc., *2000 Annual Report*, p. 29.

[64]Texaco, Inc., *2000 Annual Report* , p. 16.

[65]Conoco, Inc., *2000 Annual Report*, p. 18.

[66]Phillips Petroleum Company, *2000 Annual Report*, p. 45.

[67]Conoco, Inc., *2000 Annual Report*, pp. 16-17.

[68]Exxon Mobil Corporation, *2000 Annual Report,* p. 17.

[69]Exxon Mobil Corporation, *2000 Annual Report,* p. 20.

[70]Exxon Mobil Corporation, *2000 Annual Report,* p. 20.

[71] El Paso 2000 Report to Shareholders Supplemental Financial Information, pp. 8-9.

[72] Enron Annual Report 2000, p. 51.

[73] Shell Oil Company 2000 Financial Review pp. 35-36.

4. Resource Development Trends

Resource Development Costs and Potential

This chapter 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 chapter presents five analyses ("Special Topics") that discuss:

- Variances in regional finding costs
- The ways in which the U.S. majors are acquiring additional oil and gas reserves
- The movement of Brazil's Petrobras from a state-owned monopoly to an evolving corporate structure
- The factors that most likely will play a critical role in the success or failure of oil and gas development in the Caspian Sea
- The potential for development of the Rocky Mountain's substantial natural gas reserves

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SPECIAL TOPIC*: Finding Costs Vary by Region*

Declines in Africa, U.S. Onshore, and OECD Europe Hold Down Finding Cost Increases in 2000

Finding costs are the costs of adding oil (crude oil and natural gas liquids) and gas (dry natural gas) proven reserves via exploration and development activities.[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 incurred or actually recognized on a company's books) in finding any particular proven reserves (not including the purchases of already discovered reserves). In practice, finding costs are actually measured as the ratio of exploration and development expenditures (except the expenditures on proved acreage) to proven reserve additions (excluding net purchases of proven reserves) over a specified period of time.[b] Finding costs are generally measured in *Performance Profiles* as a weighted average over a period of three years (to accommodate leads and lags in data reporting), and, if several years of data are presented, they are usually reported in constant dollars (to facilitate comparisons over time).

For the FRS companies in the 1998 to 2000 period, worldwide finding costs increased slightly to $5.83 per BOE (3 percent) compared to the 1997 to 1999 period (Table 20). The small increase in finding costs was the result of a slight decrease in reserve additions through the drill bit combined with very little change in exploration and development spending (in constant dollars) over the more recent period. These small changes occurred despite the strong increases in reserve additions through the drill bit and

Table 20. Finding Costs by Region for FRS Companies, 1997-1999 and 1998-2000
(Dollars per Barrel of Oil Equivalent)

Region	1997-1999	1998-2000	Percent Change
United States			
Onshore	5.26	4.95	-5.9
Offshore	9.55	9.99	4.6
Total United States	6.72	6.51	-3.1
Foreign			
Canada	5.43	6.84	25.9
OECD Europe	7.63	7.43	-2.7
Former Soviet Union	6.27	7.01	11.8
Africa	3.71	2.78	-25.1
Middle East	4.18	5.61	34.2
Other Eastern Hemisphere	4.84	7.49	54.8
Other Western Hemisphere	2.99	4.37	46.0
Total Foreign	4.86	5.26	8.2
Worldwide	5.65	5.83	3.1

Notes: 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).

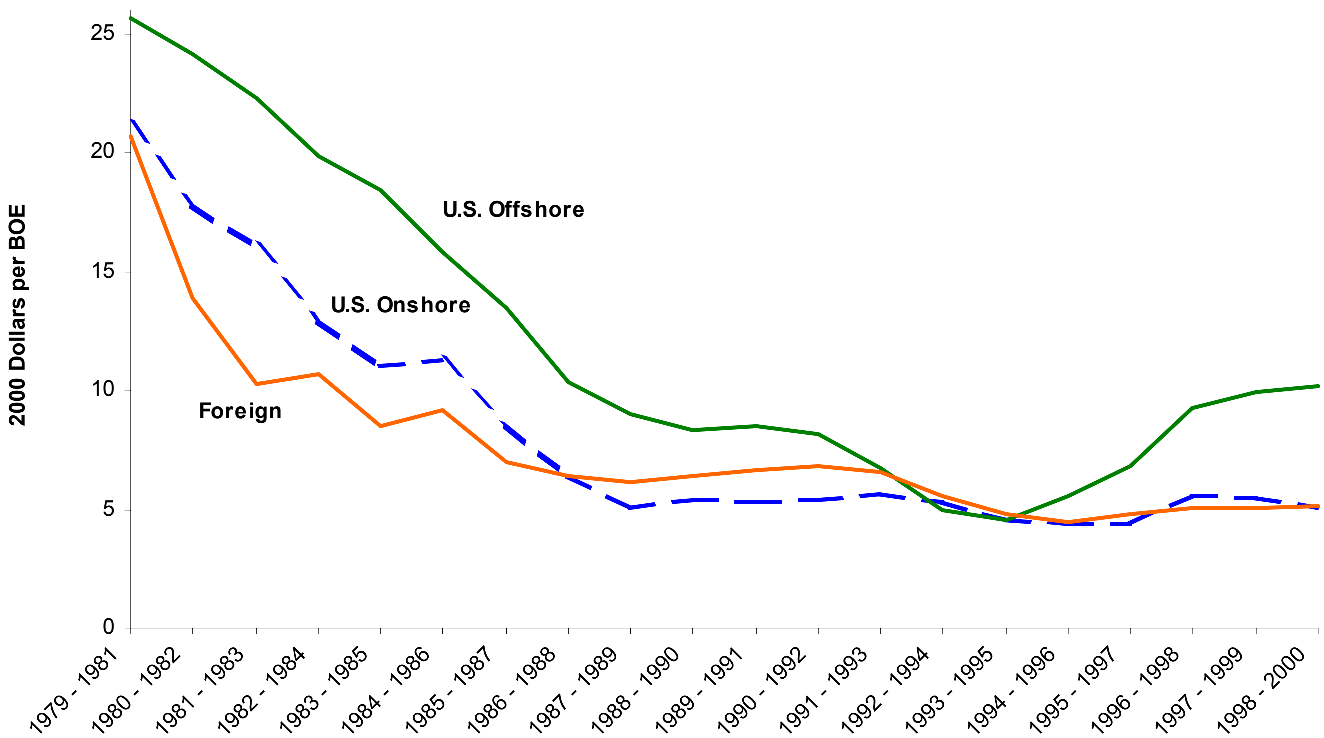
exploration and development spending in 2000, because their levels in 2000 were about the same amount as they were in 1997, the year that 2000 replaced in the three-year average.

The Other Eastern Hemisphere region had the largest proportional increase in finding costs from the 1997 to 1999 period to the 1998 to 2000 period, eclipsing OECD Europe as the foreign region with the highest costs. The increase was mainly the result of a substantial decline in reserve additions through the drill bit in the 1998 to 2000 period, the largest of any region, while spending changed little. A major contribution to the reserve decline came from the deletion of a large reserve addition by Exxon (now Exxon Mobil) in 1997 (that was included in 1997-1999 finding costs) from the 1998 to 2000 finding cost calculation. In 1997, Exxon's natural gas reserve additions increased thirteen-fold in their Asia-Pacific Region, largely as a result of its "expanded involvement in Malaysia's long-term natural gas business through the signing of a new Gas Production Sharing Agreement" and upward revisions of reserves in the Marlin Field in Australia.[c]

Over the longer term, both foreign finding costs and those for the U.S. Onshore for the FRS companies have remained in the neighborhood of five dollars (2000 dollars) for several years. In contrast U.S. Offshore finding costs have been climbing since the 1994 to 1996 period (although the rate of increase slowed in the 1998 to 2000 period) and reached nearly twice the level of U.S. Onshore and foreign finding costs in the 1998 to 2000 period (Figure 24). This contrasts with the 1980's and early 1990's, when finding costs fell significantly. Finding costs for the U.S. Offshore region have been the highest of any region since the 1996 to 1998 period.

Recent trends in three-year finding costs can be illuminated by examining their one-year levels. Although one-year finding costs are more variable than those over three years, they also pick up trends sooner than will three-year costs and provide information regarding the level of three-year costs in the next period. Recently one-year finding costs have been declining in the United States and fluctuated around $5.25 overseas (Figure 25). One-year finding costs for both the U.S. Onshore and the U.S. Offshore regions were at their highest level in many years in 1998, when some proved reserves of oil were written off by the FRS companies because of low prices at the end of the year. Since 1998 data will be dropped from the next three-year finding costs calculation (1999 to 2001), one-year finding costs in the U.S. Onshore and Offshore in 2001 would have to exceed those 1998 peak levels for their 1999 to 2001 period finding costs to increase.[d]

Figure 24. U.S. Onshore, U.S. Offshore, and Foreign Finding Costs for FRS Companies, 1979-1981 to 1998-2000

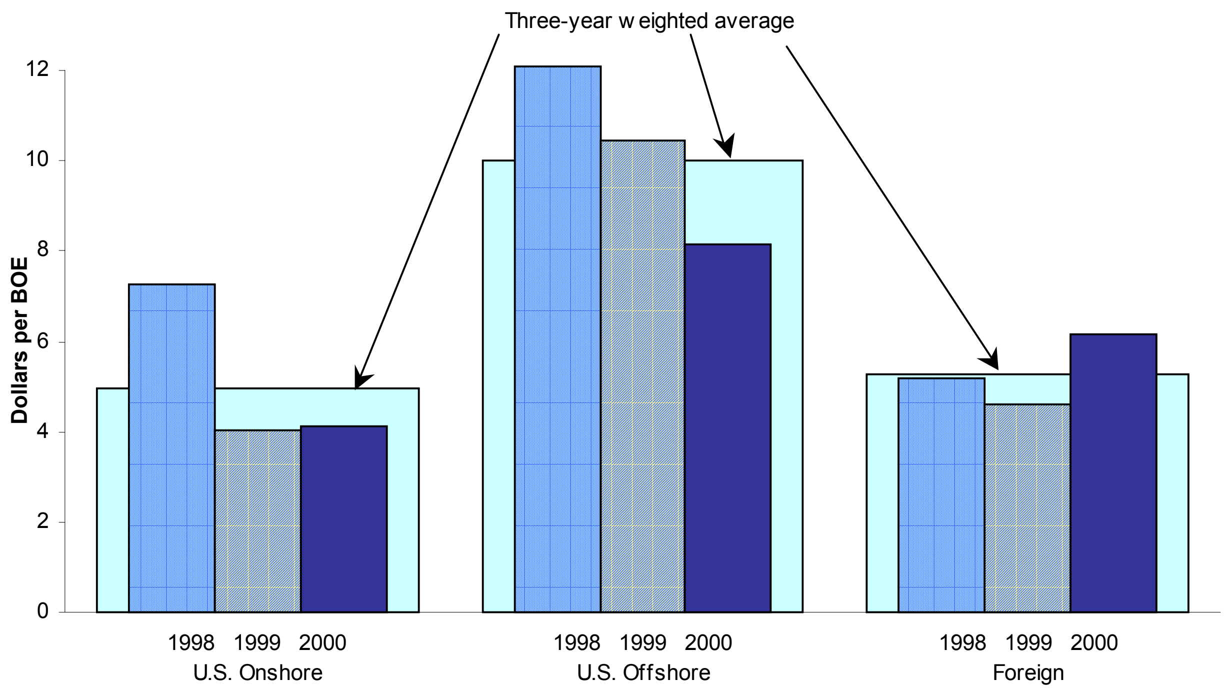


Note: Finding costs are weighted averages of the annual finding costs for the three years specified.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Sources of Finding Cost Increases Vary

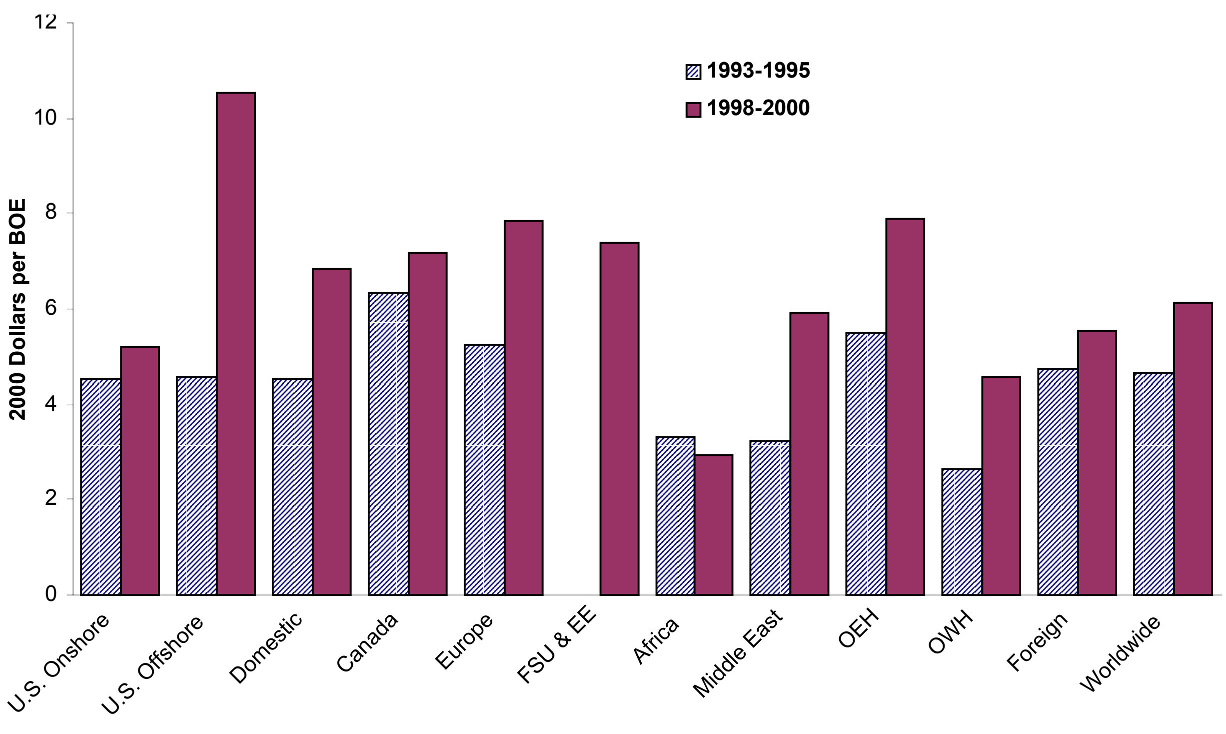
Finding costs for the FRS companies reached their lowest level worldwide in the 1993 to 1995 period. Between then and the 1998 to 2000 period, they have increased an average of $1.37 per BOE (2000 dollars), rising in every region except Africa (Figure 26). Overall, the largest contributor to the increase has been expenditures for the acquisition of unproved acreage, which accounts for a bit more than half of the total increase in worldwide finding costs. From 1998 to 2000, in constant dollars, worldwide expenditures on unproved acreage were seven times their value compared with similar expenditures from the 1993 to 1995 period, and higher than experienced since the 1983 to 1985 period. The acquisition of unproved acreage was the largest component of the change in finding costs in the U.S. Onshore, Canada, Africa, and the Other Western Hemisphere regions by a considerable amount.[e]

Figure 25. Finding Costs for FRS Companies, Annual and Three-year Weighted Average, 1998-2000



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

Figure 26. Finding Costs for FRS Companies, 1993-1995 and 1998-2000



Notes: BOE = barrels of oil equivalent. FSU & EE = Former Soviet Union and Eastern Europe. OEH = Other Eastern Hemisphere. OWH = Other Western Hemisphere. FSU & EE withheld for 1993-1995 to prevent disclosure of individual company data.

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

The major deals that have fueled the increase in unproved acreage acquisition in 2000 are BP Amoco's purchase of Atlantic Richfield (particularly unproved acreage in the U.S. Offshore, the Asia-Pacific region, and Latin and South America), Anadarko Petroleum's acquisition of Union Pacific Resources (U.S. Onshore), and Phillips Petroleum's purchase of Atlantic Richfield's Alaskan assets. Similarly in 1998 and 1999, the major deals fueling this increase were Occidental Petroleum's 1998 purchase of the Elk Hills Naval Petroleum Reserve (U.S. Onshore), Sonat's 1998 acquisition of Zilkha Energy (Gulf of Mexico), and Chevron's 1999 purchase of the San Jorge and Glacco Companies in Argentina.

In contrast, exploration and development spending per BOE was the largest contributor in the U.S. Offshore, OECD Europe, and the Middle East regions (Table 21). Reserves added through the drill bit were down in all three regions, while expenditures were up in the U.S. Offshore and flat in OECD Europe and the Middle East. In two of these regions (the U.S. Offshore and OECD Europe), most of the reserves are offshore, making drilling expensive; as a result, finding costs there in the 1998 to 2000 period were among the highest anywhere. In addition, drilling costs were the largest factor in the U.S. Offshore cost increase.[f]

Finding costs also can be expressed as the product of expenditures (to find additional reserves) per well completed and wells completed per BOE addition to proven reserves. Conceptually, wells per reserve addition are all the number of wells that were drilled to find a barrel of proven reserves (no matter when the wells were completed or reserves added). In practice, wells per addition to reserves are actually measured as the ratio of wells completed (including dry holes) to proven reserve additions (excluding net purchases of proven reserves) over a specified period of time.[g] Expenditures per well and wells per reserve addition are generally measured in *Performance Profiles* as a weighted average over a period of three years (to accommodate leads and lags in data reporting), and, if several years of data are presented, expenditures are usually reported in constant dollars (to facilitate comparisons over time).

Table 21. Change in Finding Costs for FRS Companies, 1993-1995 and 1998-2000
(2000 Dollars per BOE)

	U.S. Onshore	U.S. Offshore	Domestic	Canada	OECD Europe	Africa	Middle East	OEH	OWH	Foreign	Worldwide
Finding Costs (Three-Year Weighted											
1993-1995	4.53	4.58	4.55	6.35	5.25	3.32	3.23	5.51	2.66	4.76	4.65
1998-2000	5.21	10.52	6.86	7.18	7.85	2.93	5.92	7.88	4.59	5.54	6.14
Change	0.68	5.95	2.31	0.83	2.60	-0.39	2.68	2.37	1.93	0.78	1.48
Components of Change in Finding Costs											
Acquisition of Unproved Acreage	0.87	0.99	0.90	0.75	0.42	0.15	0.06	1.18	1.84	0.79	0.84
Exploration & Development Spending	-0.19	4.96	1.41	0.08	2.17	-0.54	2.63	1.19	0.09	-0.01	0.64
Change in						(Percent)					
Expenditures per Well	31	69	54	-12	0	29	-60	-17	123	-5	31
Wells per BOE Reserve Addition	-12	36	-2	29	49	-31	359	73	-23	23	1

Notes: OEH = Other Eastern Hemisphere. OWH = Other Western Hemisphere. W = Withheld to prevent disclosure of individual company data. NA = Not Available. Sum of components may not equal totals due to independent rounding.

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

Changes in either expenditures per well or wells per reserve addition have proportional effects on finding costs. In most regions these two factors moved in opposite directions between the 1993 to 1995 period and the 1998 to 2000 period (Table 21). However, in the U.S. Offshore and OECD Europe regions, neither expenditures per well nor wells per reserve addition declined, and in the Middle East wells per reserve addition increased well over three fold, much more than in any other region. These are the same regions where exploration and development spending was a much larger component of the increase in finding costs than the acquisition of unproved acreage.

Gulf of Mexico Emerges as Highest Cost Region

The strongest contrast in finding cost changes between the 1993 to 1995 period and the 1998 to 2000 period was the sharp upward movement in the U.S. Offshore (almost entirely the Gulf of Mexico) (Table 21). In the earlier period, finding costs were lower in the U.S. Offshore than in Canada, OECD Europe and the Other Eastern Hemisphere regions. For the most recent period, U.S. Offshore finding costs rose nearly $6 per barrel, more than twice as much as any other region. What accounts for this divergence?

Although the contribution of increased expenditures for unproved acreage was $0.15 per barrel above the worldwide average for the U.S. Offshore, it was not the most important component in distinguishing its increase in finding costs (Table 21). Exploration and development spending increases, particularly drilling costs, were far more important. Drilling costs per barrel of reserves added in the U.S. Offshore were up $3.23 and accounted for over 50 percent of the increase in finding costs in that region. For the U.S. Onshore, the comparable rise was a slight $0.18 and averaged only $0.03 for the foreign regions. Other exploration and development costs, which include seismic work, pumps and motors, and improved recovery, added $1.64 per BOE to U.S. Offshore finding costs. In contrast, other exploration and development costs per BOE went down elsewhere.

Both higher expenditures per well and increased drilling per barrel of reserve additions contributed to the more than doubling of U.S. Offshore finding costs (Table 21). In this region, expenditures per well rose 69 percent between the two periods, while wells drilled per barrel of reserve additions went up 36 percent. Expenditures per well increased by a greater proportion only in the Other Western Hemisphere, while decreasing in several regions. Drilling productivity improved in the U.S. Onshore, Africa, and the Other Western Hemisphere, as the number of wells drilled to add a barrel of reserves fell in each of these regions.

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[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 usually 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 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 older and older 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] Exxon, Press Release, February 5, 1998 and 1997 Report to the Securities and Exchange Commission on Form 10-K405.

[d] See the Special Topic entitled "Reserve Revisions Add to Finding Cost Woes" in Energy Information Administration, *Performance Profiles of Major Energy Producers 1998,* http://tonto.eia.doe.gov/FTPROOT/financial/020698.pdf, January 2000, for a discussion of the effect of low oil prices on reserve revisions in 1998.

[e] While finding costs decreased in Africa, their component due to the purchase of unproved acreage increased.

[f] Data detailing drilling costs are not available for individual foreign regions.

[g] As with finding costs, measurements of wells per reserve addition are imprecise because the reserves added and the wells completed during a particular interval of time do not necessarily correspond exactly with each other. (See note b, above.)

SPECIAL TOPIC: *Reserve Replacement in the United States Bounces Back*

The FRS companies, in total, added 7.9 billion barrels of oil equivalent to their worldwide oil and gas reserves in 2000 (Table 22). Although most of the FRS companies' considerable merger and acquisition activity in 2000 was directed toward gaining already discovered oil and gas reserves, much of this activity involved intra-group transactions. (Mergers and acquisitions within the FRS group of companies have no effect on aggregate net purchases of reserves, because purchases of reserves by the acquiring company are offset by sales of reserves from the selling company.) On balance, net purchases of reserves added 1.3 billion barrels of oil equivalent to the FRS companies' total worldwide oil and gas reserve base in 2000. Additions from exploration and development activity (i.e., through the drill bit) were much more important.

The FRS companies added 6.6 billion barrels of crude oil equivalent to their worldwide oil and gas reserves in 2000, consisting of 3.9 billion barrels of oil (crude oil and natural gas liquids) and 15.4 trillion cubic feet of gas (dry natural gas) by finding more oil and gas via the drill bit (Table 22). In fact, drill-bit reserve additions alone exceeded worldwide production of oil and gas by 22 percent. In contrast, 1999 drill-bit reserve additions worldwide barely exceeded production, and fell short in both the U.S. Onshore and Offshore regions. For the U.S. Onshore, drill-bit reserve additions replaced 166 percent of oil and 144 percent of natural gas production in 2000. In addition, and also in contrast to 1999, worldwide net purchases (purchases minus sales) of reserves were positive for both oil and gas. For the first time since 1989, addition of oil reserves by domestic drilling in 2000 exceeded that by foreign drilling. Also drill-bit oil reserve additions in the Africa region fell below those in the U.S. Onshore, after exceeding it for the previous two years. The U.S. Onshore had been the region with the largest oil reserve additions through the drill bit before then.

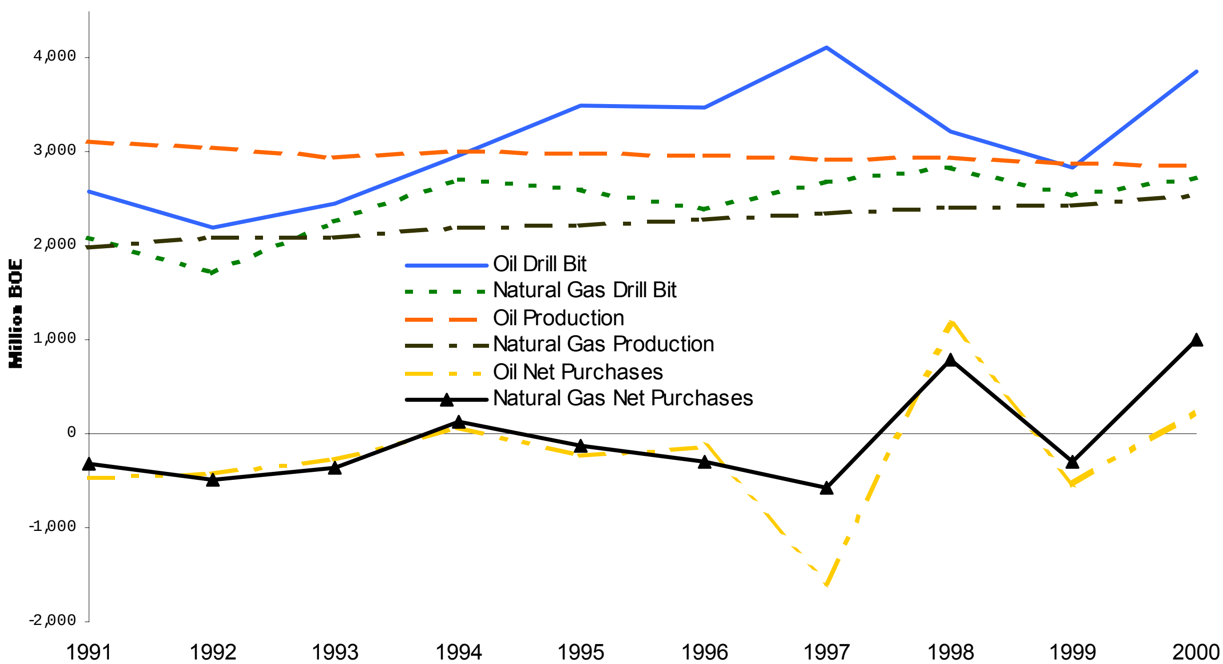
Several trends in worldwide reserve changes for the FRS companies are apparent over the last decade (Figure 27). One is that reserve additions through the drill bit are trending upward for both oil and gas, while production is decreasing for oil and increasing for gas. The FRS companies are shifting from oil into gas production but less so for oil into gas exploration and development results. Except for the early 1990's, drill-bit reserve additions have generally exceeded production for both oil and gas. The effects of net purchases over time have been substantially smaller than for drill-bit additions and production for both oil and gas, but they have begun to vary more year-to-year in the latter half of the decade. Worldwide, the effect of net purchases of oil reserves between 1997 and 1998 swung 2,750 million barrels, from -1,600 million barrels in 1997 to +1,150 barrels in 1998. This variance reflects the increasing tendency of the FRS companies to engage in mergers with and acquisitions of non-FRS oil and gas companies.

Table 22. Changes in Oil and Natural Gas Reserves for FRS Companies, 1999-2000

	U.S. Onshore		U.S. Offshore		Foreign		Worldwide	
	1999	2000	1999	2000	1999	2000	1999	2000
Oil (million barrels)								
Reserve Additions	593	1,370	441	600	1,814	1,894	2,848	3,863
Net Purchases	-244	-431	-232	159	-50	529	-525	257
Production	892	827	414	441	1,576	1,596	2,882	2,864
Total Reserves at Year End	11,513	11,971	3,130	3,541	15,645	16,706	30,287	32,218
Reserve Additions[a] / Production (percent)	66	166	107	136	115	119	99	135
Natural Gas (billion cubic feet)								
Reserve Additions	4,403	7,726	1,185	2,683	8,663	4,986	14,251	15,395
Net Purchases	-1,374	3,261	-627	835	300	1,584	-1,701	5,679
Production	5,158	5,364	2,836	2,990	5,682	5,966	13,676	14,320
Total Reserves at Year End	52,821	61,177	18,098	19,475	73,717	77,151	144,636	157,804
Reserve Additions[a] / Production (percent)	85	144	42	90	152	84	104	108
Oil Equivalent (million barrels)								
Reserve Additions	1,376	2,745	652	1,077	3,356	2,782	5,384	6,603
Net Purchases	-488	149	-343	307	4	811	-828	1,268
Production	1,810	1,782	918	973	2,588	2,658	5,316	5,413
Total Reserves at Year End	20,915	22,860	6,351	7,008	28,766	30,439	56,033	60,307
Reserve Additions[a] / Production (percent)	76	154	71	111	130	105	101	122
Addendum: Purchases and Sales								
Purchases	353	4,845	69	857	857	2,850	1,278	8,552
Sales	-841	-4,696	-412	-550	-853	-2,038	-2,106	-7,284

[a]Excludes net purchases (purchases and sales) of reserves.
Note: Sum of components may not equal totals due to independent rounding.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Figure 27. Changes in Worldwide Oil and Natural Gas Reserves for the FRS Companies, 1991-2000



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

SPECIAL TOPIC: *The Transformation of Petrobras*

In 1953, citing the nationalist slogan, "The Oil is Ours," Brazilian policymakers enacted legislation that created the state-owned company known as Petrobras.[a] The company was granted a monopoly over oil and natural gas resource development in Brazil. 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. As a result, Brazil has remained a net oil importer of around 400,000 barrels per day.[b] With a growing recognition that the continuation of the *status quo* was unlikely to result in the exploration and development of enough supply to meet domestic demand in the near future, a Constitutional Amendment was enacted in 1995 which ended Petrobras' state sanctioned monopoly.[c] Two years later, the government created the National Petroleum Agency (ANP), the regulatory agency responsible for overseeing the process of opening up the industry.[d]

In July 1998 ANP announced that more than 92 percent of the nation's sedimentary basins were to be put up for competitive bidding.[e] Between June 1999 and June 2001, ANP conducted three bidding rounds.[f] The FRS companies who have submitted winning bids either individually or as part of a consortium include Exxon Mobil, El Paso, Phillips, Texaco, Shell, Amerada Hess, Unocal, and Kerr-McGee.[g] Many of the blocks have been awarded to joint ventures in which Petrobras is a partner. For example, in round three, there were 11 blocks in which a FRS company either individually or as part of a consortium submitted a winning bid. In five of these winning bids, Petrobras was a partner in the consortium.[h] In addition, Petrobras has signed about a dozen oil development partnerships with private firms including some agreements with companies in the FRS group to explore the 115 exploration concessions that it was granted by ANP in 1998 in what some have called "round zero."[i] 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.[j] In 2000, Petrobras signed joint venture agreements with Coastal, Chevron, Texaco, Shell, and Exxon Mobil.[k] In light of these agreements as well as Petrobras' recent release of financial reports comparable to those issued by U.S. companies it is useful to review various aspects of Petrobras' operations.

In addition to the demise of Petrobras' monopoly status, the change in the Brazilian government's policy toward its energy sector has resulted in the partial privatization of Petrobras. In August of 2000, the Federal Government of Brazil sold approximately 180 million shares of Petrobras' stock, of which 108 million shares were sold as American Depositary Shares on the New York Stock Exchange. This sale has reduced the Brazilian Federal Government's share of the voting stock to 55.7 percent from 84.1 percent. Current law requires that the Federal Government of Brazil retain ownership of 50 percent plus one share of Petrobras' voting stock.[l]

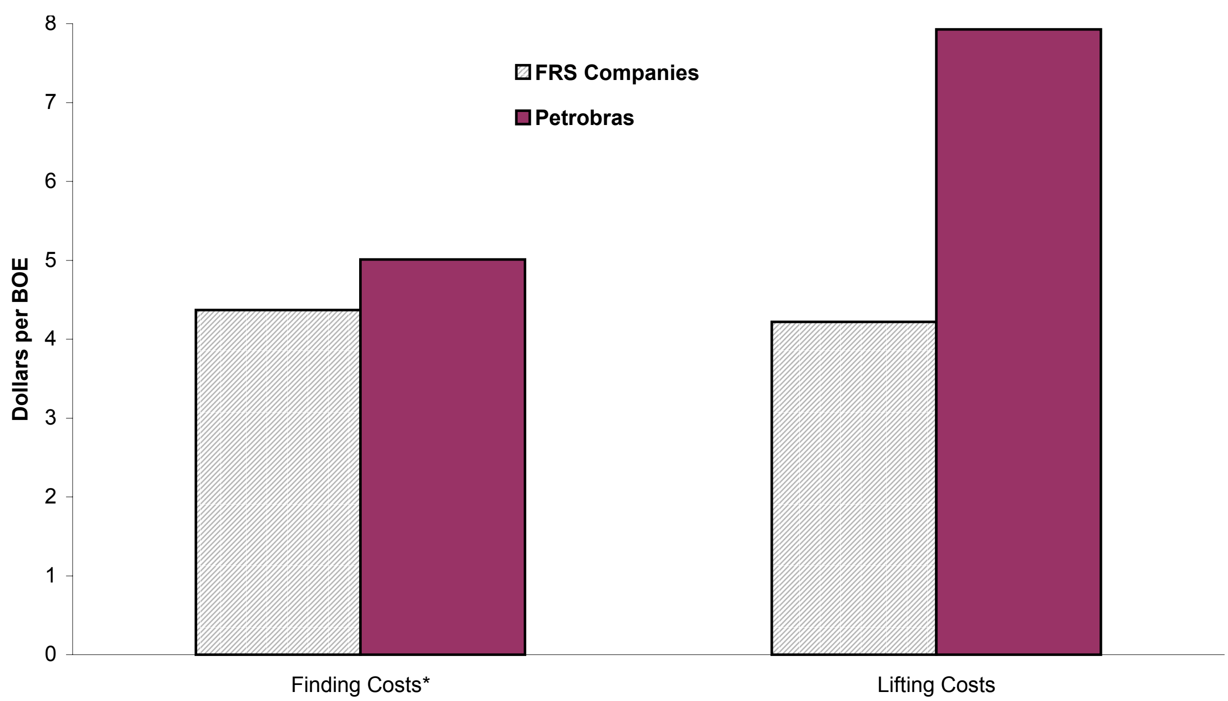
Because of the absence of the profit motive, economists tend to question the efficiency of state-owned monopolies. It is therefore interesting to note that Petrobras' new status has prompted the firm to implement a sweeping reorganization with the stated aim of improving the firm's competitiveness. Petrobras' new status has also provided the firm with greater flexibility in financing. In one recent case, the firm announced plans to raise up to $1.07 billion by issuing non-convertible debentures to finance an increase in production at its Marlim oil field in the Campos Basin, offshore from Rio de Janeiro -- by 13 percent , from 517,000 barrels per day to 584,000 barrels per day.[m]

Petrobras' new status has coincided with a dramatic increase in its developed reserves and production. Specifically, net proved developed oil reserves have increased by 36 percent between 1998 and 2000.[n] This increase in developed reserves has led to a 29-percent increase in oil production. Likewise, net proved developed gas reserves increased by 95 percent between 1998 and 2000. This increase in developed reserves has led to a 64-percent increase in natural gas production.[o]

Despite these increases in developed reserves and production, Petrobras continues to operate at a cost disadvantage relative to the Latin American operations of the FRS companies. Specifically, both its costs of finding and extracting oil and gas are higher than those corresponding to the Latin American operations of the FRS companies.

Finding Costs. These are the costs of finding new reserves. They are measured for oil and gas together in units of dollars per barrel of oil equivalent (BOE). Over the period 1998 to 2000, Petrobras' average cost of adding an additional barrel of reserves was $5.01 per barrel of oil equivalent (BOE) (Figure 28).[p] In contrast, the average Latin American finding costs for the FRS companies was $4.37 per BOE.[q]

Figure 28. Finding and Lifting Costs for FRS Companies in Latin America, and for Petrobras in Brazil, 2000



*Three-year weighted average.
Note: BOE = barrels of oil equivalent.
Sources: Energy Information Administration, Form EIA-28 (Financial Reporting System) and Petrobras 2000 Annual Report.

Lifting Costs. These are the costs of extracting oil and gas out of existing proved reserves. Petrobras' lifting costs are substantially above the lifting costs for the Latin American operations of the FRS companies (Figure 28). One of reasons for this is Petrobras' greater emphasis on oil as opposed to natural gas production. In 2000, for example, 90 percent of Petrobras' BOE production was accounted for by oil.[r] The comparable figure for the Latin American operations of the FRS companies was 47 percent lower.[s]

Petrobras expects to more than double its natural gas sales to 2.6 billion cubic feet per day by 2005.[t] Brazil can certainly use the gas. The country has been hard hit by a drought that has sharply reduced the supply of hydroelectricity. A large portion of the projected incremental supplies is expected to come from the San Alberto and San Antonio fields in Boliva, in which Petrobras has a 35-percent stake. Output from the fields is currently being transported to Brazil using the recently completed Bolivia-to-Brazil pipeline.

Petrobras also has plans to increase its international operations outside Latin America. Specifically, the firm is seeking to acquire an independent U.S. oil company with operations in the Gulf of Mexico.[u] While an acquisition may make good use of Petrobras' expertise operating in the offshore, the strategy is nevertheless surprising given the company's need to finance its exploration and development projects in Latin America.

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[a] Moutinho dos Santos, Edmilson, *The Brazil Oil and Gas Sector*, CWC Publishing, London 2001, p 67.
[b] 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**.
[c] EIA *Country Analysis Briefs*. http://www.eia.doe.gov/emeu/cabs/brazil.html
[d] Petrobras 2000 Annual Report.
[e] EIA *Country Analysis Briefs*. http://www.eia.doe.gov/emeu/cabs/brazil.html
[f] For detailed information on the bidding rounds, see ANP's website: www.anp.gov.br
[g] ibid.
[h] For details on the results of round 3, see http://www.brasil-rounds.gov.br/english/index.html
[i] Petrobras 2000 Annual Report
[j] "Petrobras signs four more exploration JVs," *Oil and Gas Journal Online*, February 7, 2000
[k] "Petrobras inks exploration JVs off Brazil," *Oil and Gas Journal Online*, January 2, 2000
[l] Petrobras 2000 Annual Report
[m] "Petrobras raises $ 1.07 bn to finance production increase," Alexanders Gas and Oil Connections, Volume 6, issue #21 - Wednesday, November 07, 2001
[n] Based on data in Petrobras' 2000 Annual Report.
[o] ibid.
[p] ibid.
[q] Based on EIA Form-28.
[r] Based on data in Petrobras' 2000 Annual Report.
[s] Based on EIA Form-28.
[t] "Petrobras projects 90 mm cmpd of domestic gas sales in 2005," Alexanders Gas and Oil Connections, Volume 6, issue #16 - Tuesday, August 28, 2001
[u] "Petrobras plans to acquire foreign companies to increase reserves," Alexanders Gas and Oil Connections, Volume 6, issue #18 - Tuesday, September 25, 2001

SPECIAL TOPIC: *The Rocky Mountains -- A Persian Gulf for Natural Gas?*

In its 2002 *Annual Energy Outlook (AEO)*, EIA forecasted that U.S. consumption of natural gas would grow by 60 percent to 34 trillion cubic feet (Tcf) between 2001 and 2020.[a]

A substantial portion of this increase is expected to originate in the Rocky Mountains, where production is forecasted to increase by 93 percent to 5.5 Tcf. There is no question that the resources are more than adequate to meet the expected increase in demand. According to Colorado School of Mines geologist Fred F. Meissner, "The Rocky Mountains are a Persian Gulf of Gas."[b] The statistics support this view. According to the *AEO*, the region has over 165 Tcf of technically recoverable resources.[c]

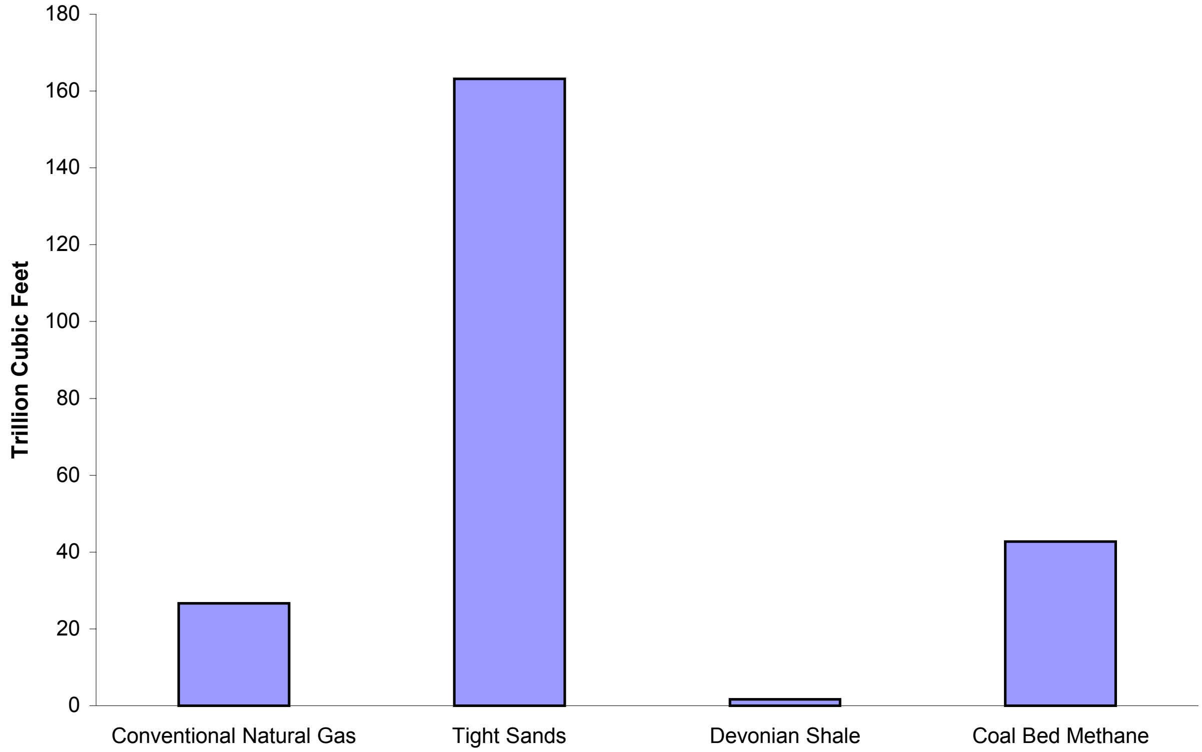
The vast proportion of these resources are accounted for by the unconventional categories known as tight sands and coal bed methane (Figure 29). Because coal bed methane (CBM) and tight sands wells tend to have to lower flow rates than otherwise identical conventional wells, their unit operating costs tend to be higher. However, improvements in technology over the past decade and improved understanding of how to optimize the performance of the wells have substantially improved their economics. This has been especially true in the case of Rocky Mountain CBM where the combination of coal seams that are hundreds of feet thick but less than a thousand feet from the surface all but ensures that CBM wells will have an adequate flow rate, and yet be relatively cheap to drill.

Some of the basins of interest (see map in Figure 35) include:

San Juan. This basin is located in northwestern New Mexico and southwestern Colorado. Historically, it has been the most productive CBM basin, with about two thirds of the proved reserves and 80 percent of the production.[d] Stimulated by the Section 29 tax credit, production grew rapidly in the early 1990s (Figure 30). Production grew more moderately throughout the remainder of the 1990's after the tax credit expired for wells spudded after January 1, 1993.[e] More recently, production in New Mexico's portion of the Basin has declined somewhat. This decline is most likely only temporary given that the U.S. Bureau of Land Management's Farmington office in New Mexico has reported a jump in applications for new wells.[f]

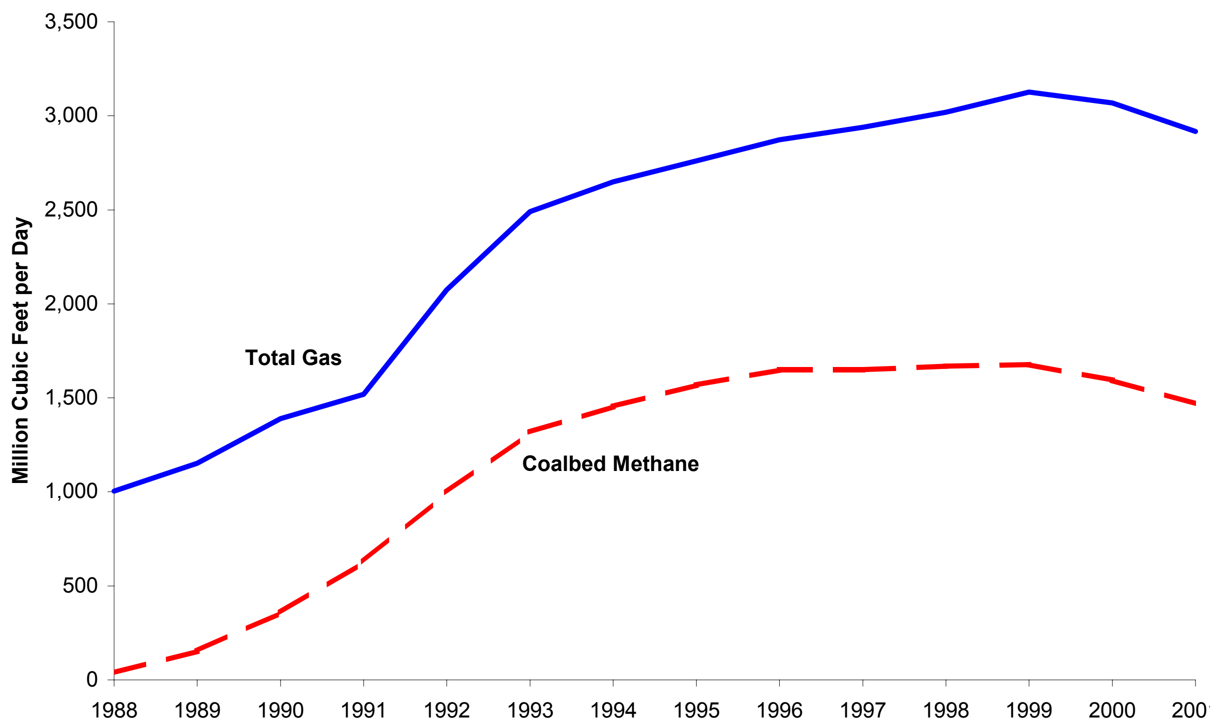
Powder River Basin. This basin is located in northeastern Wyoming and southeastern Montana. The U.S. Geologic Survey (USGS) has increased its estimate of the basin's technically recoverable CBM resources to 14.26 Tcf, up from 1.11 Tcf in 1995.[g] The coal beds are near the surface but are up to 300 feet thick. These factors tend to make the wells inexpensive to drill and operate yet highly productive relative to other CBM wells. Given these fundamentals, the basin has been undergoing a boom as producers increase their understanding of the techniques needed to produce the gas. Indicative of the magnitude of the boom, the number of producing wells has increased to 6,469 in July 2001, the latest month for which statistics were available, from 515 in July 1998.[h] In terms of production, output in July 2001 in the Wyoming portion of the basin reached 784 million cubic feet per day. This represents an almost 40-percent increase over July 2000 and a 190-percent increase over July 1999. Production would have been even higher if it were not for the fact that there were over 2,200 wells drilled but shut in, dewatering, or awaiting dewatering permits.

Figure 29. The Technically Recoverable Gas Resources of the Rocky Mountain Region



Note: Excludes current proved reserves.
Source: Office of Integrated Analysis and Forecasting, Energy Information Administration.

Figure 30. Gas Production in the San Juan Basin, 1988-2001



Notes: Data are for New Mexico's portion of the Basin. Data for 2001 are based on monthly data through May 2001.
Source: New Mexico's Oil and Gas Conservation Commission.

As of July 2001, the basin contained less than 15 percent of the 50,000 wells that are believed to be needed to fully tap the resource.[i] Based on the productivity of the wells drilled to date, this would mean that the basin could produce over 5 billion cubic feet per day or more than the capacity of the proposed pipeline that would bring gas from Prudhoe Bay to the Lower 48 States. A major impediment to attaining this potential are the delays in the completion of the Powder River basin CBM environmental impact statement (EIS). However, it is not clear that the release of the EIS will lift all the current limitations on drilling. Specifically, the U.S. Environmental Protection Agency has received complaints of groundwater well contamination that are believed to be the result of the hydraulic fracturing needed to release the methane from the coal.[j]

Uinta-Piceance. This basin is located in western Colorado and eastern Utah. The USGS recently reassessed its estimate of this basin's resources. In 1995, its mean estimate of the basin's CBM resources was 10.7 Tcf.[k] It has since reduced its mean estimate to 2.3 Tcf of undiscovered, technically recoverable CBM.

Green River Basin. Located in southern Wyoming and northeastern Colorado, this basin contains 160 Tcf of potential natural gas resources which makes it the largest potential source of natural gas in North America. Most of the natural gas in this basin is tight sands. Tight sands prospects are often times subeconomic because of low flow rates. To promote the development of this resource the U.S. Department of Energy in 1995 awarded Union Pacific Resources Company (now a wholly owned subsidiary of Anadarko) a contract to drill a test well that would examine how to reduce the technical risks and economic uncertainty associated with drilling for the tight gas in the Greater Green River basin.[l] Union Pacific Resources began drilling its Rock Island #4H well in late 1997 and continued until February 1999. This well is one of the deepest horizontal tight gas sandstone wells in the world (14,950 feet). The well was placed into production on May 15, 1999. Because of its depth, there was sufficient pressure to offset the low flow rate problem. Specifically, the well had an initial rate flow rate of 13.6 million cubic feet per day which is roughly comparable to what a good producing well in the Gulf of Mexico might produce or more than 30 times the flow rate of the typical CBM well. Moreover, in contrast to conventional wells where production declines 10 percent or more every year, the well has continued to produce at a roughly constant rate. As of November 22, 1999, the well had produced an impressive cumulative total production of 2.2 billion cubic feet of gas. In addition, Union Pacific Resources was able to reduce the time required to drill to about half of what would otherwise be expected.

A recent report by the U.S. Department of Energy examined the issue of drilling access in this region.[m] Working virtually on a tract-by-tract basis, the study concluded that over two-thirds of the Green River Basin's recoverable gas resources are either closed to development or under significant access restrictions. While only about 1 percent of the resources are off limits as a result of statute, 29 percent of the resources are inaccessible due to administrative actions such as the implementation of a forest plan under which drilling is not permitted. An additional 38 percent of the resources are believed to be effectively inaccessible due to restrictions that seek to minimize the possible adverse impact on wildlife of drilling by limiting the time of year in which drilling can occur. For instance, the time required to drill in Mesaverdie and Frontier/Cloverly, two of the deeper unconventional high-potential plays in the basin, could exceed the time permitted. While the driller constrained by the restriction could always return and complete the well in the next year, the delay may make the drilling prospect subeconomic. Environmental groups, including the Wilderness Society, have disputed the report's findings.[n]

Regardless of the merits of the report in terms of gas production from the basin over the longer run, its conclusions regarding the constraints on drilling and production do not appear be especially binding at this point in time. Production in Wyoming's portion of the Green River Basin for the first six months of 2001 averaged 1.7 billion cubic feet per day or almost 12 percent higher than in the comparable period in 2000.[o]

Wind River. This basin is located in Wyoming. In 1995, the latest year for which an assessment for this basin is available, the USGS's mean estimate of the basin's CBM resources was 0.43 Tcf.[p] For the first six months of 2001, production averaged 530 million cubic feet per day. While this was down somewhat from the comparable period in 2000, it was 22 percent higher than during the first six months of 1999.[q]

The FRS companies active in Rocky Mountain gas include:

Anadarko. Anadarko more than doubled its size with its recent acquisition of Union Pacific Resources. The acquisition gives Anadarko millions of acres awarded to Union Pacific Resource's former railroad parent in the 19th century as part of the national effort to build the transcontinental railroad. Much of that acreage is in the Rockies. The company has embarked on an aggressive drilling program in the Rockies in which Anadarko and its partners project that they will drill almost 400 wells.[r] Approximately 80 percent of these wells will be gas wells. While some will be CBM wells, most of the natural gas drilling will be in the conventional natural gas producing areas of the Rockies.

BP Amoco. In 2000, BP Amoco had ownership interests in 563 million cubic feet per day of coalbed methane and an additional 185 million cubic feet per day of conventional natural gas in the San Juan Basin. It is also the largest operator of natural gas wells in the Green River Basin.[s] These properties were gained through the acquisitions of Amoco and ARCO.

Burlington Resources. Burlington was one of the first companies to develop CBM production. Its focus in terms of the Rocky Mountains is in the San Juan and Wind River Basins.[t]

Conoco. Conoco is active in the San Juan Basin where it operates 1,700 natural gas wells that produce approximately 170 million cubic feet per day. The firm recently completed a 355-square-mile seismic survey of an environmentally sensitive portion of the basin. The crew was able to minimize the impact of the survey on historic native American sites and endangered plants by using radio receivers and transmitters.

Phillips Petroleum. Jim Bowles, the president of Phillips' Americas Division, has gone on record indicating that while the firm will continue to explore in the Gulf of Mexico and Alaska, the future of the firm, domestically, is in Rockies coal bed methane.[u] If one includes the San Juan Basin, Phillips is producing 580 million cubic feet per day in the region from 1,700 wells on 800,000 acres. Much of its holdings consist of undeveloped acreage in the Powder River Basin.

Williams. As of the end of 2000, Williams was best known for being the nation's second-largest transporter of natural gas, as well as for its energy trading and power generation operations. This changed in 2001, when the firm acquired Barrett Resources for $2.8 billion in cash, stock and assumed debt, besting an earlier hostile bid for the Rocky Mountain-based firm by Shell Oil. With the acquisition, Williams can take advantage of Barrett's over one million net acres of exploration and production properties in several largely unconventional Rocky Mountain natural gas basins including the Wind River Basin. In terms of reserves, the acquisition nearly tripled William's gas reserves to 3.3 Tcf.

The acquisition also gives Williams an additional 3.6 Tcf of undeveloped gas reserves. Complementing its acquisition of Barrett, the company recently announced plans to spend $1 billion to expand its Kern River pipeline, the system that supplies Rocky Mountain natural gas to California.[v]

Shell Oil. In the wake of its unsuccessful attempt to acquire Barrett, Shell entered into a joint venture with the independent producer Wolverine to develop Wolverine's 120,000-acre leasehold in Wyoming. In contrast to its earlier bid for coalbed methane-rich Barrett, the joint venture will explore for deep conventional natural gas.[w]

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[a] *Annual Energy Outlook 2002*, Energy Information Administration.
[b] "Rockies : A Persian Gulf of Gas," Oil and Gas Journal, November 6, 2000.
[c] Assumptions to the *Annual Energy Outlook 2002*, Energy Information Administration, DOE/EIA – 0554(2002) December 2001. These assumptions are based on USGS estimates updated to take into account discoveries that have taken place since the estimate was made. The USGS estimates are also modified to take into account differences between EIA and USGS concerning unconventional gas.
[d] *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 2000 Report*, Energy Information Administration, DOE/EIA-0216(2000) December 2001.
[e] *Natural Gas 1992: Issues and Trends*, Energy Information Administration, DOE/EIA-0560(92) March 1993.
[f] "Officials Report Marked Increase of Development Interest in New Mexico," Alexander Oil and Gas Connections vol 6 issue 3 Tuesday July 17 2001.
[g] Testimony of Dr. Gene Whitney, Supervisory Geologist, U.S. Geological Survey before the Subcommittee on Energy and Mineral Resources, U.S. House of Representatives,
September 6, 2001
[h] Based on data from the Wyoming Oil and Gas Conservation Commission
[i] "US Coalbed Methane Resource Estimates, Issues Aired," *Oil and Gas Journal*, September 24, 2001
[j] "Policymakers eye frac regulation to protect groundwater," *Oil and Gas Journal*, Volume: 99 Issue: 37 September 10, 2001
[k] Testimony of Dr. Gene Whitney, Supervisory Geologist, U.S. Gelogical Survey before the Subcommittee on Energy and Mineral Resources, U.S. House of Representatives,
September 6, 2001
[l] Greater Green River Basin Production Improvement Basic Program . http://www.osti.gov/servlets/purl/653599-xrTmFw/webviewable/653599.pdf
[m] The Greater Green River Basin Study: Federal Lands Analysis, Natural Gas Assessment, Southern Wyoming and Northwestern Colorado, Office of Fossil Energy, U.S. Department of Energy, Washington, DC, 20585. This Study is available at the following url: http://www.fe.doe.gov/oil_gas/reports/fla/
[n] "Energy Department Study Faulty, Misleading, and Biased : Would Rollback Protections for Wildlife, Water, and Wilderness," Wilderness Society Press Release June 6, 2001.
[o] Based on data from the Wyoming Oil and Gas Conservation Commission
[p] Testimony of Dr. Gene Whitney, Supervisory Geologist, U.S. Geological Survey before the Subcommittee on Energy and Mineral Resources, U.S. House of Representatives,
September 6, 2001
[q] Wyoming Oil and Gas Conservation Commission
[r] Producers call for more access, pipes in Rockies OGJ Vol. 29, No. 33 August 13, 2001
[S] British Petroleum USA Datadesk. This data is available at the following url:
http://www.bp.com/centres/investor/location_datadesk.asp
[t] Powder River Basin Reaches 630 MMCF/D Gas Processors Report, August 27, 2001.
[u] Ibid.
[V] "Williams Cos. completes buyout of Barrett Resources" Alexanders Oil and Gas Connections, Volume 6, issue #16 - Tuesday, August 28, 2001
[w] "Wolverine and Shell link up in joint natgas exploration venture, "Alexanders Oil and Gas Connections, Volume 6, issue #13 - Tuesday, July 17, 2001

SPECIAL TOPIC: *The Caspian Sea -- Fields of Dreams?*

For much of the past decade, the Caspian Sea region has been a major source of both hope and frustration with respect to oil and gas. The region is believed to have over 250 billion barrels of oil resources and another 570 trillion cubic feet of natural gas resources.[a]

Billions of dollars have been spent over the past decade trying to develop these resources. In April 1993, Chevron concluded a historic $20-billion, 50-50 deal with Kazakhstan to develop the Tengiz oil field with its estimated recoverable oil reserves of six to nine billion barrels.[b] In what was then described as "the deal of the century," in September 1994, the Azerbaijan International Oil Consortium (AIOC) signed an $8-billion, 30-year contract to develop three Caspian Sea fields--Azeri, Chirag, and the deepwater portions of Gunashli (ACG).[c] Partners in this consortium include BP (34.1%, operator), SOCAR, the Azerbaijan state oil company (10.0%), Statoil (8.6%), Exxon Mobil (8.0%), and Amerada Hess (1 %).[d] Until recently, there has been little to show for these investments. For instance, while TengizChevroil has increased daily oil production at Tengiz to 280,000 barrels per day, compared with 30,000 barrels per day when the joint venture was formed in 1993, oil production for the region as whole in 2000 was only nominally higher than in 1990.[e,f]

Disappointing exploration results have contributed to the Caspian's failure to live up to expectations. As recently as June 2001, TotalFinaElf expressed a willingness to pay $12 million to get out of its exploration commitment on the Lenkoran-Talysh-Deniz prospect in the southern Caspian after drilling a dry hole. There is also the report that Exxon Mobil's first well on the Oguz concession was a dry hole.[g] Believers in the region's potential, however, like to point out that the history of successful exploration includes the drilling of many dry holes. For example, the well that discovered the enormous Prudhoe Bay field in Alaska had been preceded by a decade of exploration in which a number of dry holes were drilled.[h]

Not all of the recent exploration has been fruitless. The initial logs of the exploration well at the Kashagan prospect in Kazakhstan's sector in the Caspian Sea suggest that this may be one of the most important discoveries of the last 30 years.[i] The prospect is being explored by the Offshore Kazakhstan International Operation Company (OKIOC) whose partners are ENI, TotalFinaElf, Royal Dutch/Shell, BG, Exxon Mobil, Phillips Petroleum, and Inpex Masela. In a promising sign, the prospect's first appraisal well, Kashagan East 2, flowed 7,400 barrels per of oil in a constrained test.[j] While some have compared the prospect to Prudhoe Bay (16 billion barrels), others have speculated that the field could even have 60 billion barrels of oil.[k]

In any event, while not always easily found, the oil and gas is there. For instance, the ACG oil fields have reserves of over six billion barrels of oil and nearly six trillion cubic feet of gas.[l] There is also the giant Shah Daniz gas condensate project. BP, the operator of the consortium that discovered the field has reported that it contains 15 trillion cubic feet of natural gas reserves.[m] Others have speculated that the field could contain as much as 35 trillion cubic feet of gas.[n]

While the disappointing exploration results to date have played a role in the region's failure to live up to expectations, there are also questions about how much pipeline capacity the region's needs to export its output to world markets. The lack of adequate pipeline infrastructure has in turn slowed the pace of development of existing successful prospects. For example, the AIOC has announced that the planned Phase-1 program to develop the ACG, will be effectively delayed until a decision has been made on the export options.

Indeed, the principal factor causing concerns about the success of the region has been the lack of pipeline infrastructure to move the oil and gas west onto world markets. Recognizing the lack of adequate infrastructure, the countries of Georgia and Azerbaijan signed a 30-year agreement in 1996 to pump a portion of the "early oil" from the Azerbaijan International Operating Company (AIOC)'s ACG from Baku to the Georgian port of Supsa on the Black Sea. (Figure 31) Following the agreement, the AIOC made substantial upgrades to the existing pipeline along this route and built the $565-million Supsa terminal on the Black Sea. The 515-mile pipeline became operational in April 1999. However, the pipeline's capacity is a fraction of the region's export potential.[o]

Figure 31. Selected Oil Infrastructure in the Caspian Sea Region

More recently, the Caspian Pipeline Consortium (CPC) opened the valves on its 980-mile pipeline which connects the Tengiz oilfield in western Kazakstan to Russia's Black Sea port of Novorossiysk. Ten international companies financed the $2.6-billion initial capital costs of the pipeline. The FRS companies Chevron, Exxon Mobil, and Kerr-McGee are among the partners in the venture. The pipeline was filled and the first tanker was loaded in late October 2001.[p] The pipeline's current capacity is approximately 565,000 barrels per day and is expected to increase to 1.35 million barrels a day by 2015. While only about 240,000 barrels a day have been committed to the pipeline as of late October 2001, there are indications that the completion of the pipeline is prompting an expansion of the productive capacity of the Tengiz oil field.[q]

One of the disadvantages of the CPC export route is that the port of Novorossiysk can be closed up to 2 months per year due to bad weather.[r] In addition, there are the potential risks associated with having to navigate the Bosporus, the narrow waterway that connects the Black Sea with the Sea of Marmaru and ultimately the Mediterranean. This waterway is one of the world's busiest (50,000 vessels annually, including 5,500 oil tankers), and one of most difficult-to-navigate in the world. Six accidents occur on the Bosporus every 1 million transit miles, which is twice the accident rate of the Suez Canal.[s] Moreover, unlike the Suez Canal, which largely cuts through desert, the Bosporus flows through Istanbul, a city of 12 million, dramatically increasing the damage from a collision.

Concerned about possible Russian control over the flow of oil, the U.S. government has long supported the proposed Baku-Ceyhan route.[t] Unlike the CPC route, this route would avoid Russian territory and instead pass through Azerbaijan, Georgia, and Turkey to the Mediterranean Sea. The estimated cost of $2.8 to $2.9 billion of the route has been a major issue.[u] On a per- barrel basis, this works out to about $3.00 per barrel which is about twice the unit transportation costs of the CPC route. Another key question is the volume of oil potentially available for export through the pipeline. As of late 2000, it was unclear whether the ACG fields had sufficient potential reserves to produce the roughly 1 million barrels per day that some analysts have cited as needed to make the pipeline economical.[v]

In February 2001, Chevron, which has long opposed Baku-Ceyhan (along with Exxon Mobil), decided to join the group of its sponsors, becoming the first oil company outside of the AIOC (which is developing the Azeri-Chirag-Gunashli deposits that will provide much of the oil for export) to join the sponsorship group.[w] BP, the leader of the AIOC consortium which had also opposed the project, announced in June 2001 that the Baku-Tbilisi-Ceyhan project is economic based on the volumes which will be available from the fields now being developed in Azerbaijan.[x] The project has moved into the "detailed engineering phase" with a completion target of 2004. However, some have questioned the viability of the route following the improvement in relations between the U.S. and Russia following the September 11th terrorist attacks on the World Trade Center and the Pentagon.[y]

With the discovery of the Shah Deniz field, mainly natural gas, in mid-1999, the issue of natural gas exports has become a pressing issue. This field is located in the western portion of the Caspian. It is envisioned that the production from Shah Deniz will be transported by pipeline from Baku via Tbilisi in Georgia to Erzerum in Turkey. The 600-mile pipeline will have a capacity of 700 million cubic feet per day and is expected to cost $1 billion.[z] Shareholders in the project include BP (25.5 percent), Statoil (25.5 percent), LukAGIP (10 percent), SOCAR, the Azerbaijan state oil company (10 percent), Offshore Iran Energy Company (10 percent), and TPAO, the Turkish state oil company (9 percent).[aa]

On May 21, 1999, Turkey's state owned pipeline company signed an agreement to build a $2-$2.4 billion, 1,050-mile gas pipeline from Turkmenistan, underneath the Caspian Sea, across Azerbaijan and Georgia, and on to Turkey and then Europe.[ab] However, the economic viability of the project is now considered doubtful by some, given the discovery of the far more accessible natural gas supplies from Shah Deniz, the construction of the "Blue Stream" pipeline that will transport natural gas from Russia to Turkey, and the continuing legal issues concerning the ownership of the Caspian.

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[a] See http://www.eia.doe.gov/emeu/cabs/caspgrph.html#TAB1
[b] http://www.eia.doe.gov/emeu/cabs/caspian.html
[c] ibid.
[d] http://www.eia.doe.gov/emeu/cabs/azerproj.html
[e] "Tengizchevroil to Increase Production Capacity as CPC Opens," Interfax News Agency Petroleum Report August 01, 2001,

[f] EIA Country Analysis Briefs
[g] "Watching the World: Caspian Hopes Head North," Oil and Gas Journal OnLine, July 16, 2001.
[h] http://www.bp.com/alaska/history/PrudhoeBay.htm
[i] "OKIOC reveals details on Kashagan discovery well, "Oil and Gas Journal OnLine, July 24 2000.
[j] Kashagan East-2 well in Caspian Sea flows 7,400 b/d of oil, Oil and Gas Journal OnLine, July 16, 2001.
[k] "Watching the World: Caspian Hopes Head North," Oil and Gas Journal OnLine, July 16 2001.
[l] ibid.
[m] "Baku-Tbilisi-Ceyhan becoming a reality", BP Press Release, 20th June 2001
[n] EIA Country Analysis Briefs. http://www.eia.doe.gov/emeu/cabs/caspian.html
[o] ibid
[p] " ChevronTexaco Loads First Oil From Russian-Kazak Pipeline," WSJ.com , October 15 2001.
[q] "Tengizchevroil to Increase Production Capacity as CPC Opens," Interfax News Agency, Petroleum Report August 01, 2001.
[r] http://www.eia.doe.gov/emeu/cabs/turkey.html
[s] Turkish Maritime Pilots' Association. http://www.turkishpilots.org/
[t] "Russia Becoming an Oil Ally", New York Times, October 19, 2001
[u] http://www.eia.doe.gov/emeu/cabs/caspoile.html
[v] http://www.eia.doe.gov/emeu/cabs/turkey.html
[w] http://www.eia.doe.gov/emeu/cabs/caspoile.html
[x] "Baku-Tbilisi-Ceyhan becoming a reality", BP Press Release, 20th June 2001
[y] Russia Becoming an Oil Ally", New York Times, October 19, 2001
[z] Azerbaijan, Georgia agree on tariffs for gas pipeline to Turkey, Oil and Gas Journal OnLine, October 1, 2001
[aa] http://www.eia.doe.gov/emeu/cabs/turkey.html
[ab] "TCGP's woes multiply with threat of competing Caspian gas export line.,"Oil and Gas Journal OnLine, June 5, 2000.

5. Emerging Issues

This chapter of *Performance Profiles* analyzes new developments and emerging directions of the larger energy industry. FRS data are combined with additional information from company annual reports, press releases, and other energy company public disclosures so as to expand the scope of energy industry financial analyses presented in this report. Specifically, this chapter presents three analyses ("Special Topics") that discuss:

- The role of mergers and acquisitions in the changing composition of the U.S. major energy companies
- The growing importance over the last decade of coal bed methane production by the U.S. majors, and the role that Section 29 tax credits played in spurring that growth
- The many ways to measure the recent changes in U.S. gasoline marketing

SPECIAL TOPIC: *The Changing Cast of Major Energy Companies -- The Role of Mergers, Acquisitions, and Divestitures*

What is a Major Energy Company?

The Energy Information Administration's (EIA's) Financial Reporting System (FRS) is responsible for reporting on the financial performance, broadly construed, of U.S. major energy companies. To do so, the EIA developed criteria for identifying certain U.S. energy companies, designating them as U.S. major energy companies, and selecting them as respondents to the FRS. Specifically, for EIA purposes, a major energy company is a U.S.-based corporation that accounts for 1 percent or more of U.S. production or reserves of oil or natural gas or 1 percent or more of U.S. petroleum refining capacity or refined product sales volume. Prior to 1998, a company also had to be among the top 50 U.S.-based oil producers.

When initially applied in the 1977 reporting year, these criteria resulted in the selection of 26 companies: 24 vertically integrated petroleum companies and 2 non-integrated oil and gas producers (Figure 32). A vertically integrated company includes all stages from exploration and production of oil and gas, transport, refining, and marketing: from drill bit to gas tank (or burner tip in the case of natural gas) and all stages in between.

Although the criteria were applied annually to select FRS respondents, there was little change in the reporting group through the 1980's. The reduction in the number of vertically integrated companies

Figure 32. Companies in the Financial Reporting System, 1980, 1990, and 2000

1980

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

2000

Vertically Integrated

- Exxon Mobil
- BP Amoco
- Chevron
- Texaco
- Shell Oil
- USX (Marathon)
- Conoco
- Phillips Petroleum
- Amerada Hess
- Fina

Non-integrated Producers

- Occidental Petroleum
- Anadarko Petroleum
- Unocal
- Burlington Resources
- Kerr-McGee
- Apache Petroleum
- Devon Energy

Non-integrated Refiners

- Equilon Enterprises
- Motiva Enterprises
- Tosco
- Ultramar Diamond Shamrock
- CITGO Petroleum
- Sunoco
- Valero Energy
- Lyondell-CITGO Refining
- Premcor
- Tesoro Petroleum

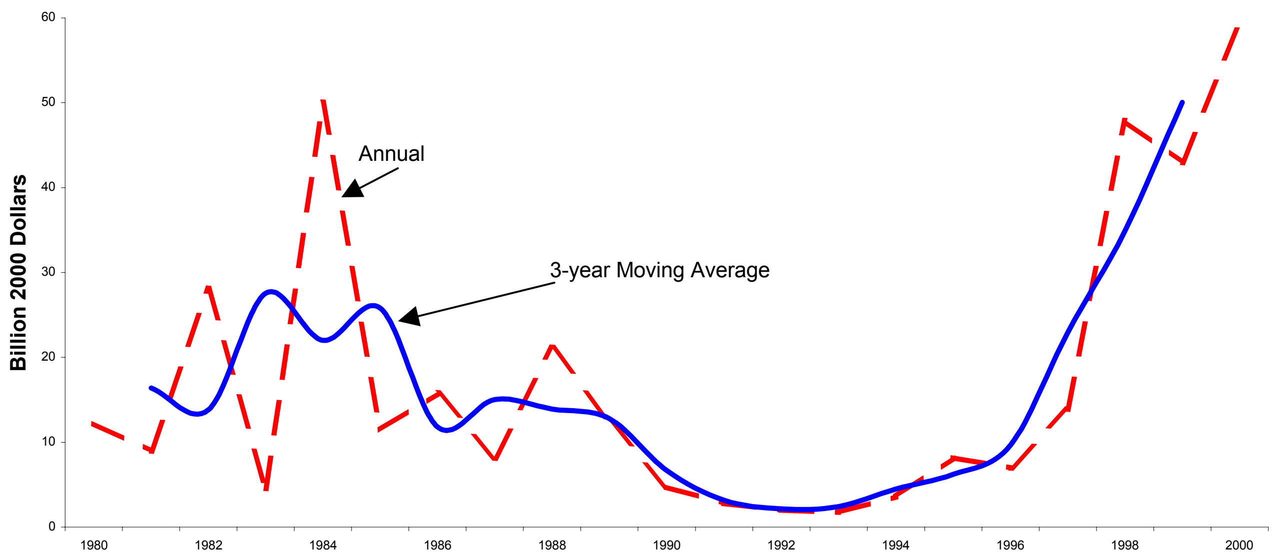
Energy Services

- Enron
- Williams Companies
- Dominion Resources
- El Paso Energy

from 24 to 19 by 1990 (Figure 32) was the result of intragroup mergers and divestitures. In 1982, Occidental Petroleum acquired Cities Service, and, in 1984, Chevron acquired Gulf Oil, Texaco acquired Getty Oil, and Mobil acquired Superior Oil. Also, DuPont and USX became U.S. major energy companies through acquisitions of then FRS companies Conoco and Marathon, respectively, in 1982. During the 1980's, the largest divestiture among the FRS companies was Tenneco's sale of their petroleum and natural gas assets in 1988 for $7.9 billion ($10.5 billion in 2000 dollars). Tenneco's petroleum assets largely remained in the FRS group, as other FRS companies acquired about 85 percent (by dollar value) of Tenneco's assets. Other divestitures included sales of refining and marketing operations by Occidental Petroleum and Union Pacific and Sunoco's spinoff of its U.S. oil and gas production operations in the form of Oryx Corporation. Also, Total Petroleum (North America) had a short tenure as an FRS respondent.

Mergers, acquisitions, and divestitures were instrumental in consolidating and reallocating assets among the FRS companies in the 1980's. Indeed, the value of these transactions (adjusted for inflation) was at a level in the 1982 through 1984 period that was not matched until recent years (Figure 33). Nevertheless, the vertically integrated form of organization remained as the key characteristic of a U.S. major. For instance, in 1980 the 24 vertically integrated companies accounted for 98 percent of the value of FRS total assets, while in 1990, the 19 vertically integrated companies accounted for 90 percent.

Figure 33. The FRS Companies' Capital Expenditures for Mergers and Acquisitions, 1980-2000



Note: Includes effects of BP-Amoco (1998) and Exxon-Mobil (1999) mergers. However, in the FRS database these had no effect on capital expenditures since they were poolings of interest between FRS companies.

The Cast of Major Energy Companies Changes in Recent Years

By 2000, the cast and character of major energy companies were considerably different than in 1990. The number of vertically integrated companies was down from 19 in 1990 to 10 in 2000 (Figure 32). In terms of share of FRS companies' total assets, the vertically integrated companies' share fell from 90 percent in 1990 to 59 percent in 2000.

Non-integrated oil and gas producers in the ranks of the majors increased from 4 to 7 over the same period.

Growth of non-integrated downstream companies in the 1990's expanded the categories of companies that could be deemed major energy companies. A non-integrated downstream company refines petroleum and generally markets petroleum products, but does not produce oil and gas. Although there were many specialized U.S. refiners in the 1980's, none of them were large enough to pass the criteria for inclusion in the FRS group. In the 1990's, the non-integrated downstream form of organization became more prominent to the point that 10 such companies were among the major energy companies in the FRS in 2000.

Yet another type of company made an appearance among the ranks of the major energy companies in the 1990's: the energy services company. Operations of an energy services company (also termed power and gas companies in some publications) can include (but are not limited to) production and distribution of electric power, transport and distribution of natural gas, wholesale trading and retail marketing of electric power and natural gas, and provision of associated services to customers, such as risk management. Energy services companies in the FRS usually produce natural gas, but this line of activity tends to be relatively small in the context of the energy services companies' overall asset base.

The growth of the energy services company as a form of corporate organization was largely a response to regulatory and technological developments. Deregulation of U.S. natural gas markets in the early 1990's meant that natural gas marketing and distribution were unbundled from interstate pipeline transport, opening the way for new entrants. Potential synergies from provision of both natural gas and electric power from the same enterprise encouraged the melding of downstream natural gas assets and electric power assets. Changes in Federal regulations, some going back to the late 1970's and early 1980's, encouraged the growth of electricity generation by enterprises apart from regulated utilities. This growth was often accomplished through building natural gas combined cycle generating facilities, thanks to the development of highly fuel-efficient turbines originally in the context of aircraft design. The prospect of state-level deregulation of electricity generation and marketing encouraged the combination of electricity assets across geographically distinct markets. Also, the introduction and development of futures markets, together with the rapidity of trading in these markets, both future and spot, stemming from innovations such as the Internet, have encouraged the growth of virtual providers of actual energy commodities and risk-related trading activity.

The number of energy services companies in the FRS went from none in 1990 to four in 2000. The energy services companies' share of FRS total assets went from 0 in 1990 to 24 percent in 2000. This growth does not completely reveal the attraction of this area for other FRS companies. Chapter 2 of this report notes that growth in the energy services business came not only from the selection of these four companies, but also from growth in this area by vertically integrated FRS companies.

Mergers, Acquisitions, and Divestitures

The steep upswing in the majors' spending for mergers and acquisitions, beginning in 1995 (Figure 33), was in part related to the changes in the cast of majors, which also mostly began in the mid-1990's. Also related to these changes were a number of large divestitures by vertically integrated companies.

Vertically Integrated Companies. In recent years, intragroup mergers and acquisitions reduced the number of vertically integrated companies among the FRS companies by four. In 1998, British Petroleum plc, of the United Kingdom, merged with Amoco, through an exchange of stock valued at $55 billion. The resulting company, BP Amoco plc, is the third largest energy company in the world. For FRS purposes, Amoco's operations were combined with FRS respondent BP America, BP Amoco's U.S.-based subsidiary. In 1999, FRS respondents Exxon and Mobil merged through an exchange of Exxon shares for Mobil shares valued at $79 billion, the largest acquisition of energy assets ever. The surviving company, Exxon Mobil, is the world's largest publicly-traded energy company. In 2000, BP Amoco acquired FRS respondent Atlantic Richfield (ARCO) in an all-stock deal valued at $27 billion. Also in 2000, but not officially consummated until January 29, 2001, was FRS respondent El Paso's merger with FRS respondent Coastal in an exchange of stock transaction valued at $24 billion. For financial reporting purposes, El Paso included Coastal for the 2000 reporting year.

The number of vertically integrated majors was reduced by an additional four through divestitures in the mid-1990's. Kerr-McGee sold their refining and marketing assets in 1995, thereby transforming the company primarily into an oil and gas producer, and, in 1997, Unocal also became a non-integrated upstream company by selling its refining and marketing assets. In 1996, Sunoco sold the last of its oil and gas producing properties. Ashland departed the FRS group after exchanging its refining assets for a minority interest in Marathon Ashland Petroleum (62 percent owned by FRS respondent USX).

Non-integrated Oil and Gas Producers. The FRS companies began the 1990's with four non-integrated upstream companies: Burlington Resources, Occidental Petroleum, Oryx (a spinoff of Sunoco in 1987), and Union Pacific, who later separated its railroad operations from the purview of the FRS when it spun off its energy operations in the form of Union Pacific Resources Group in 1996. As noted above, Kerr-McGee and Unocal transformed themselves into non-integrated oil and gas producers through divestitures of downstream assets in 1995 and 1997, respectively.

Four non-integrated producers were added to the FRS after 1990 as a result of their growth in U.S. natural gas production and reserves. Anadarko Petroleum and Enron, who later spun off their oil and gas operations in the form of EOG Resources (an FRS company beginning in 2000), were added in 1992. In 2000, Apache and Devon Energy were added. These four companies made numerous acquisitions of oil and gas assets and other oil and gas producers in the 1990's.

A summary measure of the importance of acquisitions in the growth of these companies is the share of additions to their oil and gas reserves that came through acquisitions rather than through exploration and development efforts. Over the 1992 through 2000 period, the share of total worldwide oil and gas reserve additions gained through acquisitions of already discovered reserves for these four companies overall was 49 percent, ranging from 19 percent for Enron/EOG Resources to 73 percent for Devon Energy.

During the 1990's there were two intra-FRS transactions among the non-integrated producers: Kerr-McGee acquired Oryx in 1998 and Anadarko Petroleum acquired Union Pacific Resources Group in 2000.

Non-integrated Refiners. Most of the increased prominence of non-integrated refiners in the 1990's came through acquisitions of downstream assets divested by vertically integrated FRS companies. In 1990, vertically integrated companies accounted for all refining activity within the FRS group of companies. No publicly-traded U.S. refining company apart from the vertically integrated companies owned more than the requisite 1 percent of capacity to be in the FRS group then. However, in 1993, a wave of consolidations of U.S. refining/marketing operations by vertically integrated companies began. The consolidations were of two types: reorganization of refining/marketing assets into joint ventures and sales of assets to non-integrated refiners.

Reorganization of downstream assets by some FRS companies actually began in the 1980's. Texaco formed Star Enterprise, a 50-50 joint venture with Saudi Aramco, in 1988, which was built around three of Texaco's refineries (610 thousand barrels per day of total distillation capacity). In 1989, ARCO made an initial public offering of stock in Lyondell Petrochemical, a subsidiary consisting of a refinery in Houston and a petrochemical complex in Texas. In 1997, ARCO divested its holdings in Lyondell, making the former subsidiary an independent company. In 1998, the refining arm of Lyondell,

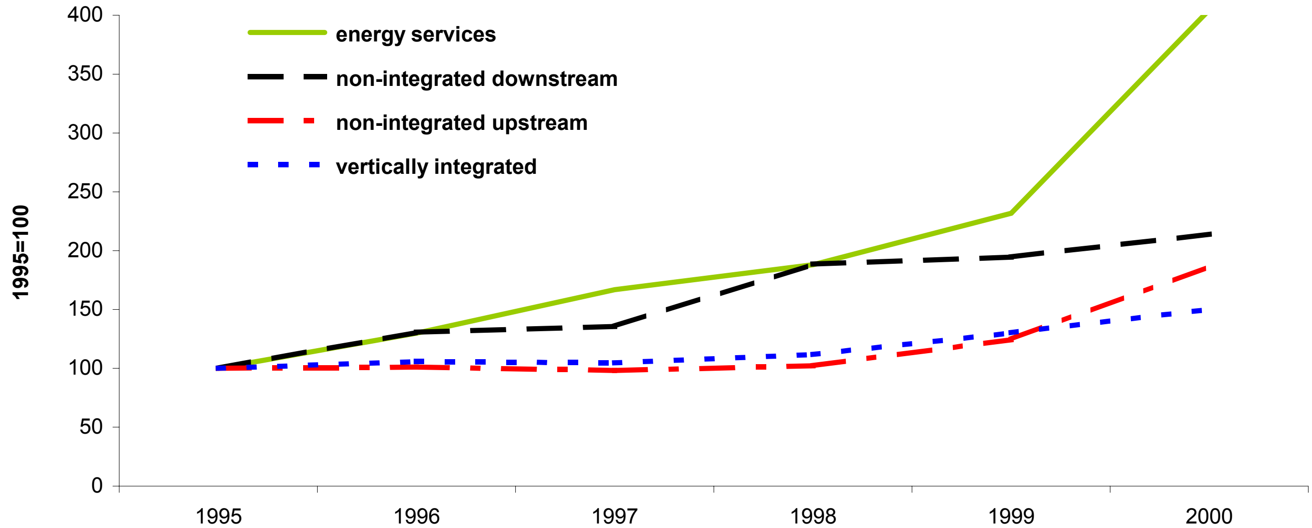
Lyondell-CITGO Refining, became an FRS respondent. More recently, FRS respondents Texaco and Shell Oil formed the Equilon Enterprises joint venture in 1998, consisting of the companies' refineries and marketing facilities in the west, southwest, and Midwest. Also in 1998, Shell Oil and Star Enterprise, the joint venture of Texaco and Saudi Aramco, formed Motiva Enterprises, with refining and marketing operations on the East Coast and Gulf Coast. Equilon and Motiva became FRS respondents in 1998. Thus, three non-integrated refining companies that joined the ranks of major energy companies in 1998 plus Sunoco, an original FRS respondent that divested their upstream operations, were composed of assets that had been directly operated and controlled by vertically integrated companies.

Six refiners that were not tied to FRS company ownership were also added to the FRS group in 1998: CITGO Petroleum, Premcor (formerly known as Clark Refining and Marketing), Tesoro Petroleum, Tosco, Ultramar Diamond Shamrock, and Valero Energy. Between 1990 and 1998, these companies more than tripled their ownership of U.S. refining capacity, primarily through acquisitions of assets divested by vertically integrated FRS companies. Of the 2.2 million barrels per day of added refinery capacity, 67 percent consisted of divestitures by FRS companies, 24 percent reflected acquisitions of other refineries, and 9 percent came through internal expansion. After 1998, intra-FRS transactions continued as Tosco acquired retail gasoline outlets from BP Amoco (1999), BP Amoco's Alliance, LA refinery (2000), and Equilon's Wood River, IL refinery (2000), and 1,740 retail gasoline outlets in the northeast from Exxon Mobil (2000). Ultramar Diamond Shamrock acquired Tosco's Avon, CA refinery (2000) and Valero Energy acquired Exxon Mobil's Benecia, CA refinery (2000).

Energy Services Companies. The FRS companies in the energy services group grew the most rapidly in recent years, as measured by total assets (Figure 34). On average, the energy services companies quadrupled in size between 1995 and 2000. In contrast, the vertically integrated majors of 2000 grew by a considerably slower 50-percent rate over the same period.

The energy services companies' growth, in part, came through the merger and acquisition route. Several of the acquisitions exceeded $1 billion in value. Dominion Resources acquired Consolidated Natural Gas and its natural gas reserves and pipelines in a $6.4-billion transaction in 2000. El Paso added greatly to their natural gas pipelines and natural gas reserves through acquisitions of Tenneco Energy Resources for $3.9 billion in 1997 and FRS respondent Sonat for $6.0 billion in 1999. El Paso merged with FRS respondent Coastal in a $24.0-billion transaction that became official in early 2001. Enron added to their electric power assets in acquisitions of Cajun Electric Power (1997) and Portland General Electric (1998) valued at $1.0 billion and $3.2 billion, respectively. Williams Companies gained downstream natural gas assets in its acquisition of Transco Energy in 1995 for $2.7 billion and added pipelines, refineries, and extensive natural gas liquids facilities to its asset base in its acquisition of MAPCO in 1999 for $3.1 billion.

Figure 34. Index of Total Assets of FRS Companies Grouped by Company Categories, 1995-2000 (1995=100)



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

SPECIAL TOPIC: *Coalbed Methane and Section 29 Tax Credits*

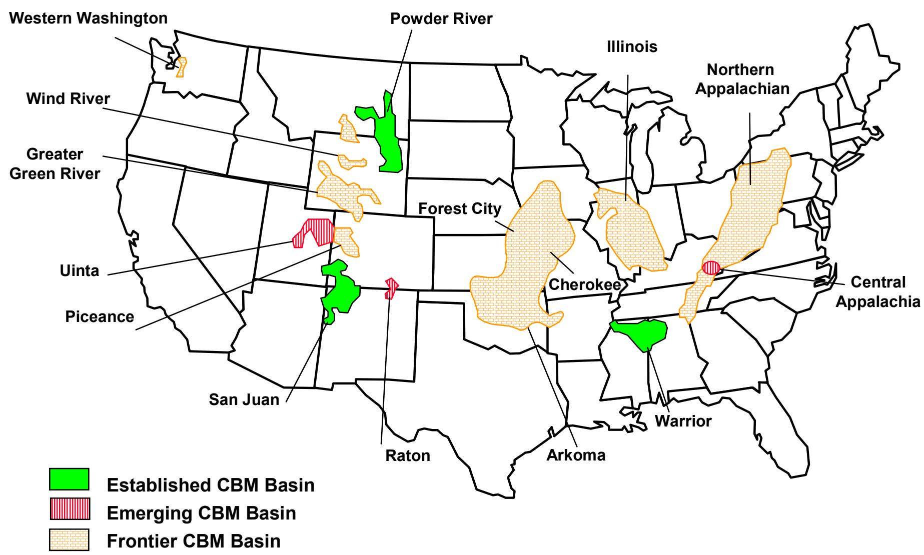
A recent EIA report, *The Majors' Shift to Natural Gas* (http://www.eia.doe.gov/emeu/finance/sptopics/majors/index.html), analyzed the role of credits from Section 29 of the Windfall Profit Tax Act in the growth of the FRS companies' U.S. natural gas production. Natural gas from coal seams (generally termed, coalbed methane, or CBM) has been a major source of growth in U.S. natural gas production in the 1990's. Between 1990 and 2000, growth in CBM production equaled 60 percent of the overall growth in U.S. natural gas production.[a]

CBM is methane extracted from coal beds. In a conventional oil or gas reservoir, production is from oil or gas located above a water contact. By contrast, since water completely permeates coal beds, to produce CBM the water must be drawn off first, lowering the pressure so that the methane will desorb from the coal and then flow to the well bore.

In 2000, 1.4 trillion cubic feet (Tcf) of CBM was produced, representing 7.2 percent of the 19.2 Tcf of U.S. natural gas production. There were 15.7 Tcf of CBM reserves in 2000, representing 8.9 percent of the 177.4 Tcf of natural gas proved reserves.[b] New Mexico, Colorado, and Alabama hold 75 percent of proved coalbed reserves. Emerging CBM areas are located in Appalachia and the Rocky Mountain region (Figure 35).

The availability of tax credits for non-conventional fuels production under Section 29 appears responsible for much of the growth of the majors' U.S. natural gas production. The Section 29 credit applies to CBM (as well as other qualified alternative fuels) from wells drilled between 1980 and 1992 inclusive, for sales of fuel between 1980 and 2002 inclusive. The value of the Section 29 credit is determined by a formula that varies with the price of oil and inflation.[c] The full value of the credit has ranged from $0.90 per thousand cubic feet of natural gas to $1.08 per thousand feet of natural gas during the 1990's. The credit averaged $1.02 per thousand cubic feet for the decade and added 53 percent to the effective price received for eligible production based on the U.S. wellhead price.

Figure 35. U.S. Lower 48 Coalbed Methane Basins



Most of the FRS companies that generated Section 29 credits did so by producing CBM. Based on an analysis of FRS companies' public information, all but two of the companies that reported receiving Section 29 credits were involved in CBM production. The two other companies received Section 29 credits for production from tight natural gas formations.

FRS companies have been prominent in the growth of CBM production, accounting for about two-thirds of U.S. CBM production in the 1990's (Figure 36). However, only a minority of the FRS companies have been involved in CBM production.

What led some majors to pursue this non-conventional source of natural gas production while other majors focused on more familiar sources? Most of the CBM in the United States is extracted from deposits in Rocky Mountain states. A characteristic common to all of the FRS companies involved in CBM production was significant ownership of coal reserves in the western United States in the first half of the 1980's. A company that is familiar with the geology of coal deposits in this area and owns mineral rights to these deposits would likely have a cost advantage in the development of CBM. However, ownership of western coal reserves was not sufficient to make CBM development attractive to every major: six surviving majors that owned western coal reserves in the 1980's never ventured into CBM production.

The incentives provided by Section 29 credits played a key role in the majors' shift to natural gas in the 1990's. Figure 37 shows that the FRS companies receiving Section 29 tax credits ("Section 29 companies") were responsible for the growth in the majors' U.S. natural gas production in the 1990's (prior to 1990, CBM production was negligible). Between 1990 and 1999, the Section 29 companies increased their U.S. natural gas production by 26 percent, while other majors reduced their production by 14 percent.

The contrast in natural gas-related resource development activity between the companies was even more

Figure 36. U.S. Coalbed Methane Production for FRS Companies, 1991- 2000

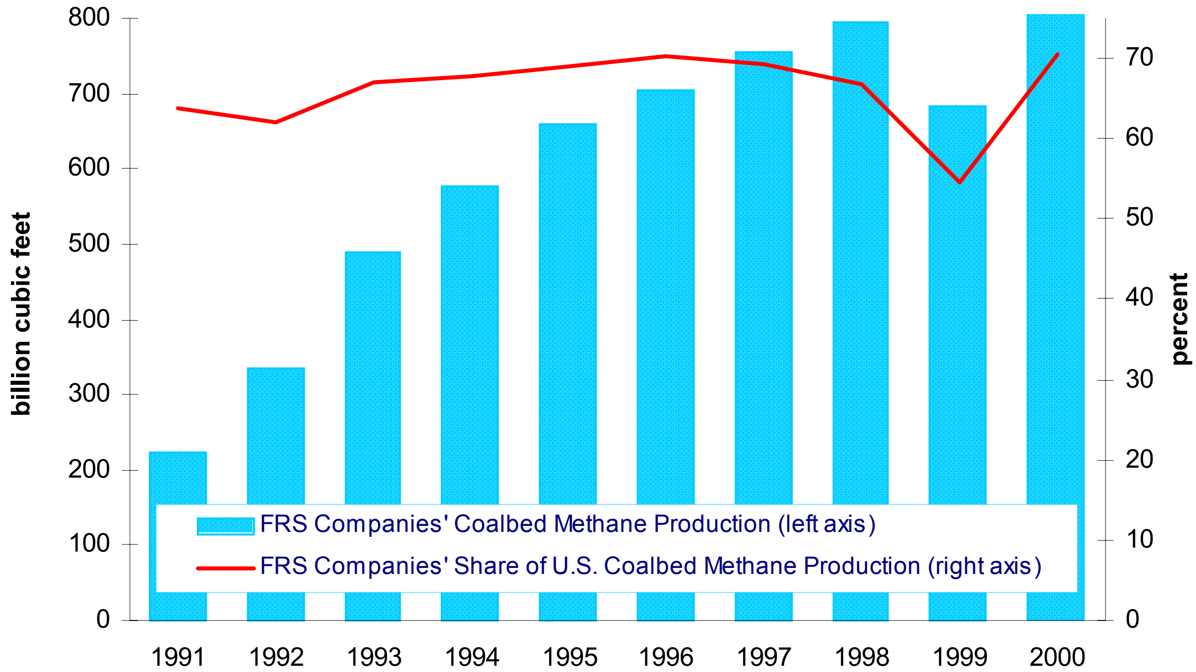
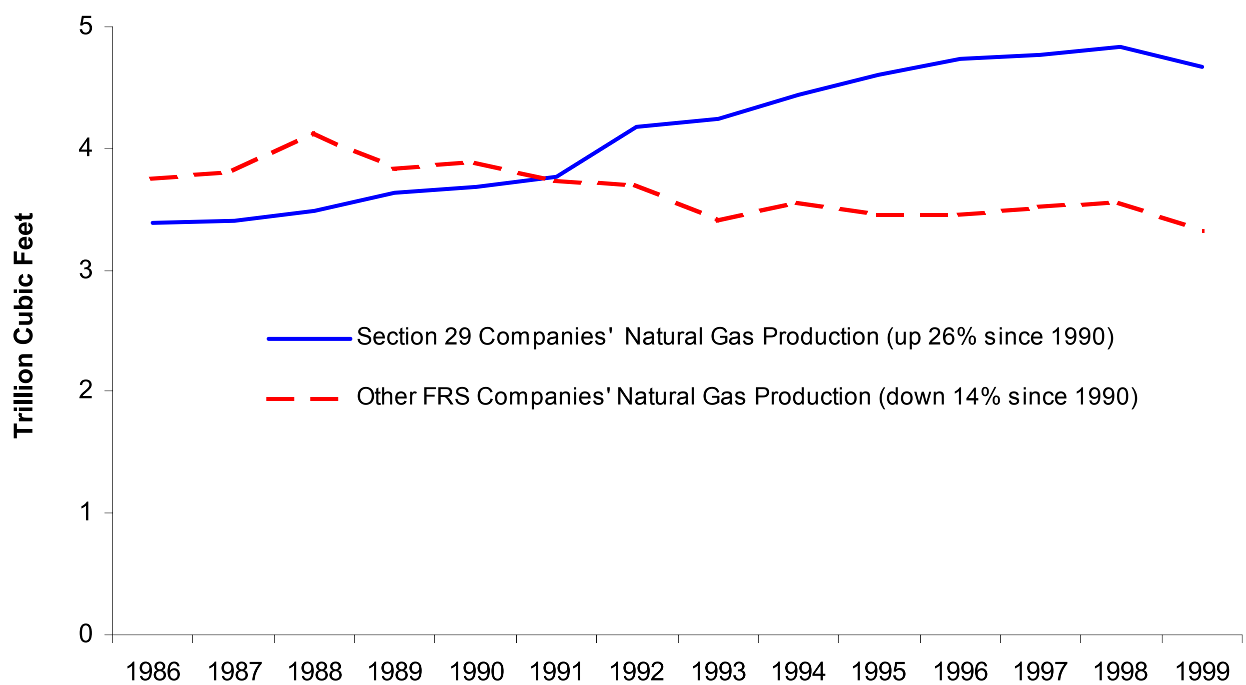
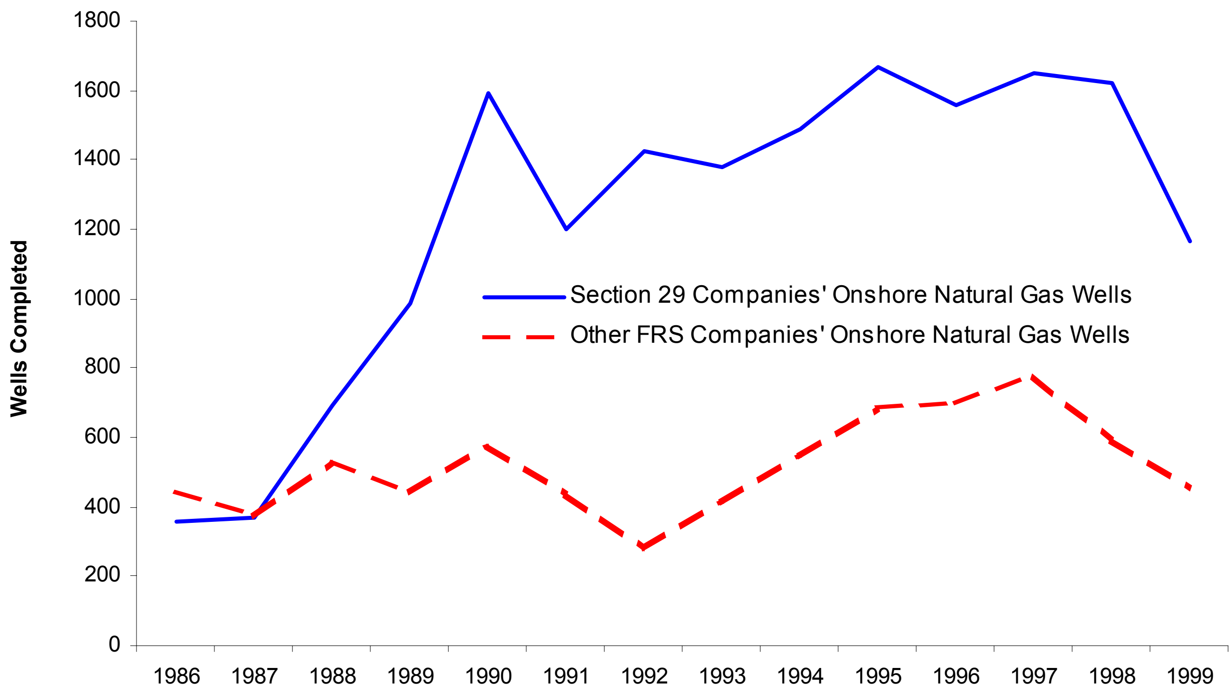


Figure 37. U.S. Gas Production for FRS Companies, 1986-1999



dramatic than production growth. The FRS companies that reported receiving Section 29 tax credits, overall, quadrupled their rate of onshore natural gas drilling between 1986 and 1990, from slightly under 400 natural gas well completions per year to about 1,600 (Figure 38).

Figure 38. U.S. Onshore Gas Wells Completed by FRS Companies, 1986-1999



This surge in drilling activity undoubtedly was related to the originally legislated deadline of December 31, 1990, when production from wells initiated after that date would not qualify for Section 29 credits. (Note that Congress then extended the deadline to December 31, 1992.) In contrast, other FRS natural gas producers increased their onshore natural gas drilling activity by less than 200 well completions over the same period.

After 1990, the natural gas drilling activity of the two groups of companies exhibited a roughly parallel pattern, with the Section 29 companies averaging over 900 more completions per year than the other majors. The persistently higher rate of onshore drilling largely reflects the costs and geologic characteristics of CBM development. CBM development requires many more, but much shallower, wells to achieve a given rate of production than do most other onshore natural gas fields, as these wells have much lower rates of production per well.

During the latter part of the 1990's and continuing through the present, some majors have sought to increase their CBM reserves and exploratory acreage in potential CBM regions through acquisitions of companies.

- Texaco acquired EnerVest San Juan for $121 million in a January 2001 deal retroactive to November 2000. The acquired assets are CBM properties in the San Juan Basin of Colorado and New Mexico.[d] Texaco has also been active in China, gaining an interest in eight of ten CBM license blocks awarded by China United Coalbed Methane Corporation through November

2000.[e] In prior years, Texaco Inc., ARCO, and Phillips Petroleum Co. had also signed production service contracts for the cooperative exploitation of CBM in China.[f]

- In September 2000, Phillips Petroleum, one of the most active of the integrated companies in CBM, acquired CBM properties in Alabama and the Powder River Basin for $123 million.[g]
- USX's Marathon Oil Company had pending at year end a $500-million acquisition of Pennaco Energy, Inc., a company entirely focused on the production of CBM in the Powder River Basin. The deal was closed in March 2001.[h]
- In February 2000, Shell signed a $40-million production loan facility with Mannix Oil Co. Inc. to develop its CBM methane play in the Arkoma Basin of East Central Oklahoma.[i]
- Anadarko gained 72 CBM wells in the Rocky Mountains as a result of its $4.4 billion merger with Union Pacific Resources Group Inc. in July 2001.[j]
- Devon Energy, a new FRS survey entrant in 2000, has CBM interests in the San Juan basin of New Mexico; the Raton basin, which straddles the Colorado-New Mexico border; and the Green River and Powder River basins of Wyoming.[k]
- Dominion Energy Inc., another new FRS survey entrant in 2000, owns interest in CBM in Alabama's Black Warrior Basin.[l]

Ongoing CBM projects and recent acquisitions indicate a continuing interest in CBM by the majors even if eligibility for Section 29 credits expires. The majors' continued interest in CBM production, which accounted for a major share of their growth in U.S. natural gas production in the 1990's, should increase their share of total U.S. production.

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[a] Based on data from *Advance Summary U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 2000 Annual Report* at http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/advanced_summary_2000/adsum2000.pdf, Tables 1 and 9.
[b] ibid.
[c] For the latest value of the credit, see Internal Revenue Bulletin 2001-17 Weekly (available at http://www.irs.ustreas.gov/bus_info/bullet.html) p. 1093.
[d] Texaco, Inc., Press Release (January 9, 2001).
[e] Texaco, Inc., Press Release (November 8, 2000).
[f] *Oil and Gas Journal*, June 5, 2000.
[g] Phillips Petroleum Company, Press Release (September 25, 2000).
[h] Marathon Oil Company, Press Release (March 27, 2001).
[i] Shell Capital Inc, Press Release (February 28, 2000).
[j] *Oil and Gas Journal*, November 6, 2000.
[k] ibid.
[l] *Business Wire*, New York, July 2, 1999.

Special Topic —*Operations of U.S. Motor Gasoline Marketing Industry Coalesce*

Number of Outlets Declines, But Offset by Greater Outlet Productivity

The U.S. motor gasoline marketing industry has consolidated over the past decade as the number of retail outlets declined from 210,120 in 1990 to 175,941 in 2000 (Figure 39). However, the country's population increased over a comparable period, rising from 249.5 million in 1990 to 272.7 million in 1999.[a] The number of outlets per capita declined by 23 percent between 1990 and 1999. Nonetheless, at the same time, motor gasoline sales increased by 7 percent. The increased sales were achieved through using the remaining outlets more intensely, as indicated by a 21-percent increase in the average monthly sales volume during the 1990's (Figure 40).

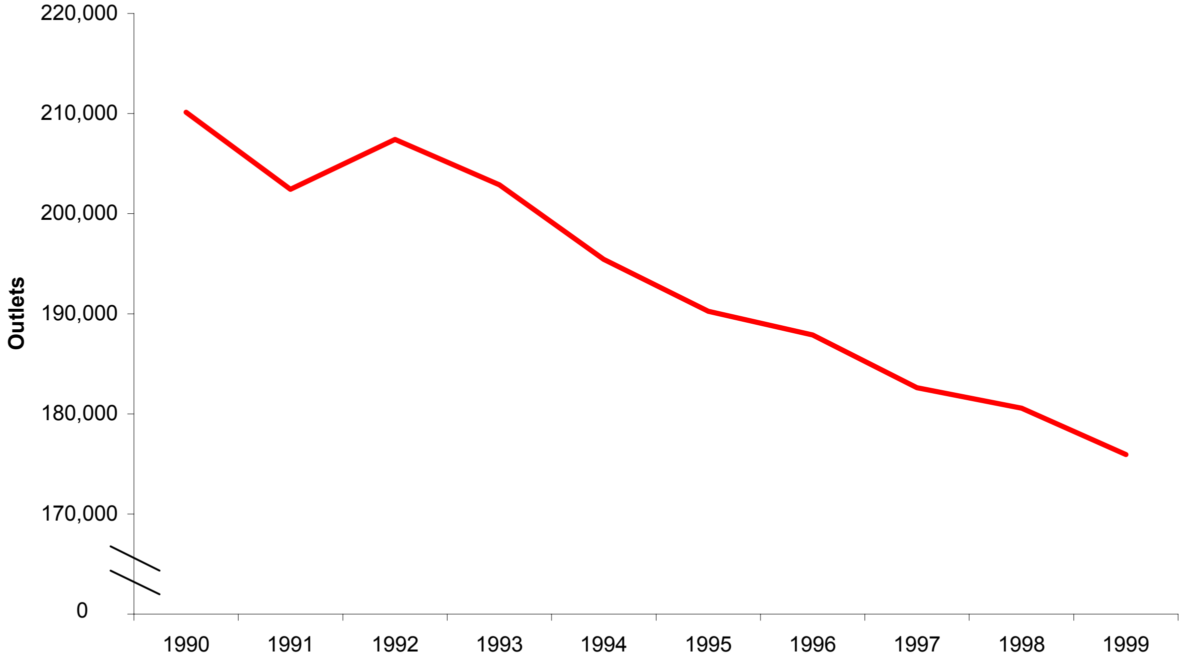
Among the factors that would motivate all these changes, especially more intensive use of motor gasoline outlets, are the introduction of Phase I diesel and motor gasoline in the early 1990's (required by the 1990 Clean Air Act Amendments) and underground storage tank requirements that generally became effective at the end of 1998.[b] These factors raised costs and tended to squeeze marginal operators, some of whom probably exited the industry. Increases in some motor gasoline retailing costs elicited efforts by retailers to reduce other costs, including using the fixed assets (e.g., the retail outlet and its location) more intensively by shoehorning more goods and services into the outlet and expanding operating hours.

Convenience Store Replaces Service Station As Primary Outlet Format

The transition from the traditional service station to the convenience store format began during the early 1970's with the rise in the availability of self-serve motor gasoline.[c] The traditional service station of the 1940's, 1950's, and 1960's had one or more mechanics on-duty working in one to three service bays and pumping motor gasoline from 2 or 3 islands, each with 3 pumps and 1 or 2 nozzles on each pump.[d] The availability of self-serve motor gasoline increased during the 1970's in response to upward pressure on motor gasoline prices due to the Arab oil embargo and subsequent instability associated with the war between Iraq and Iran. Self-serve motor gasoline allowed retailers to use fewer attendants (who were employed to fuel vehicles), passing along some of the savings to consumers. The increased dependability and complexity of motor vehicles, especially passenger cars, contributed to the decline in the ability of service stations to sell automobile repair and maintenance services.[e] In turn, this led to the need to replace the revenue streams these activities supplied. Convenience items supply revenue to augment the motor gasoline and lubricants revenue streams retained by the outlets (although some outlets opted just to go out of business).

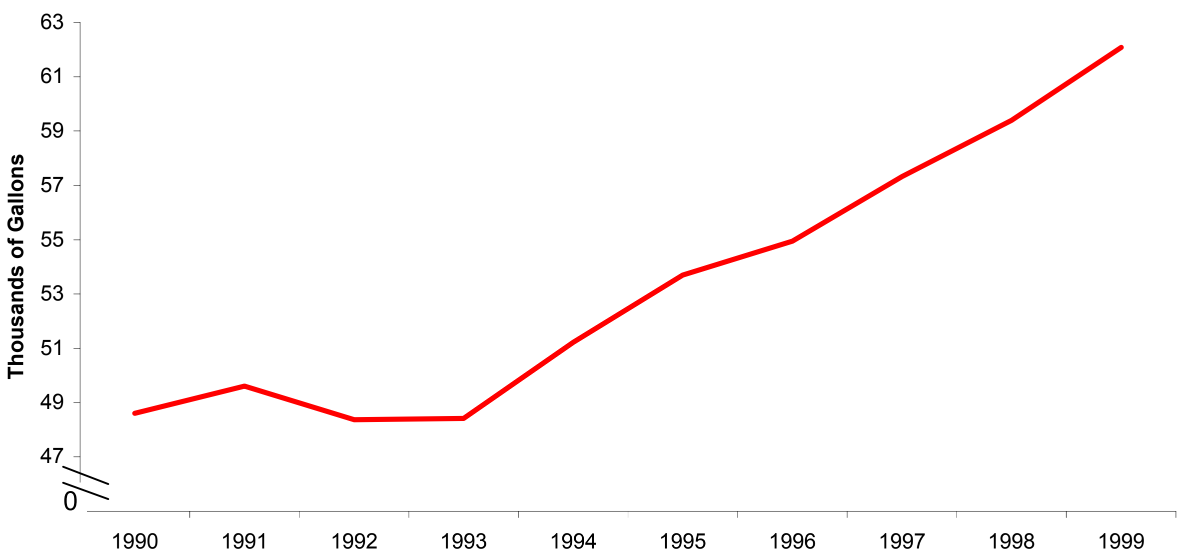
Replacing the traditional station was the convenience store (c-store) format (and lately hypermarkets[f]) in which items such as soft drinks, coffee, and cigarettes are sold inside a store that is surrounded by many gasoline pump islands. The c-store has evolved further in recent years as branded fast food stores have been combined with the c-store. This combination has expanded the offerings of the outlet by adding nationally- (or regionally-) branded fast food, and automatic teller machines. This is referred to as co-branding or multiple formatting -- i.e., combining a branded motor gasoline outlet with a branded fast

Figure 39. U.S. Motor Gasoline Outlets, 1990 - 1999



Source: National Petroleum News, Market Facts '96 (mid-July 1996), p. 120 and Market Facts 2000 (mid-July 2000), p. 120.

Figure 40. Average Monthly Motor Gasoline Sales Volume per Retail Outlet, 1990-1999



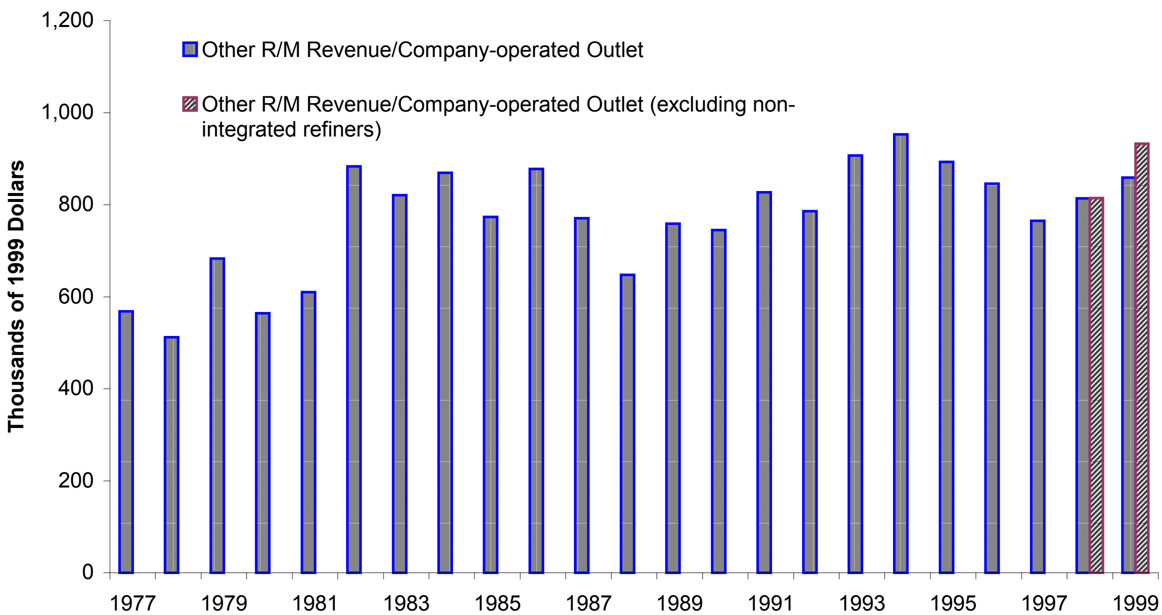
Note: Between 1990 and 1999, average monthly motor gasoline sales volume per retail outlet increased by 48.6 thousands of gallons to 62.1, a 28-percent increase. Because of the differences in the time periods during which the National Petroleum News (NPN) collects retail outlet data and the Energy Information Administration (EIA) collects sales volume data, the NPN data are associated with EIA data for the previous year. For example, NPN outlet numbers for 1991 are associated with EIA 1990 volume data and all are assigned to 1990.

Sources: Retail outlets: NPN, Market Facts '96 (mid-July 1996), p. 120 and Market Facts 2000 (mid-July 2000), p. 120. Sales volume: EIA, Petroleum Marketing Annual, DOE/EIA-0487 (Washington, DC, 1990-1999), Table 48.

food chain outlet. Co-branded/multiple-format outlets were introduced as early as 1987, but were widely embraced by the FRS companies during the 1990's.[g] Subsequently, most of the FRS companies indicated that they, too, had made similar changes in their marketing operations. These changes were intended to broaden the client base and reduce the operational costs of the affected outlets.

The degree to which convenience store operations have grown in importance to the FRS companies can be approximated, albeit imperfectly, through use of the FRS data. In the FRS data series the data item termed "other refining/marketing revenue"[h] per company-operated outlet[i] can be used as a proxy for the FRS companies' convenience store sales. During the 1990's the significance of the FRS companies' convenience item sales grew (between 1990 and 1994), declined (1994 to 1997), and grew again (1997 through 1999), ending the decade at $859,000, 14-percent higher than the 1990 value of $745,000 per company-operated outlet (Figure 41).[j]

Figure 41. FRS Companies' Gross Other Refining/Marketing Revenue Per Company-Operated Branded Retail Outlet, 1977-1999



Note: Because of the relatively large differences in the organization of the non-integrated refiners and the rest of the FRS companies, two measures are given for the two years that the non-integrated refiners have been FRS companies; one without the non-integrated refiners (grey) and one with the non-integrated refiners (black).
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Two features of this measure of c-store sales per outlet should be noted. First, since about 1982, there has been no upward trend in sales (adjusted for inflation) per outlet. C-store sales (inflation-adjusted) per outlet were about the same in 2000 as in 1982. This finding could be indicative of regulatory limits, such as zoning restrictions, that hold down the scale of c-store/gasoline outlet establishments. The finding might also be evidence of diminishing returns. Beyond some point, additional c-store capacity changes the character of the outlet and dilutes the synergies between c-store revenues and motor gasoline sales. Second, the time series shown in Figure 41 fluctuates rather than being a flat trend. It turns out that this series is inversely related to refining/marketing profitability. That is, when refining/marketing profitability is declining, c-store sales per outlet are increasing and c-store sales per outlet decrease when refining/marketing profitability is increasing. Over the past 20, or so, years the correlation between refining/marketing profitability and c-store sales per outlet is –0.6 (-1.0 would be perfect inverse correlation). This finding suggests that the FRS companies add c-store capacity to their outlets as one way of offsetting declining profitability. When refining/marketing profitability rises, the pressure to generate more revenues from existing outlets tends to ease.

Employment, Salaries, and the Value of Outlets All Grow

Convenience items and self-serve motor gasoline grew in importance as repair and maintenance services and full-serve motor gasoline sales diminished in importance.[k] Consequently, cashiers and attendants, which tend to be lower skill positions with lower wages, supplanted more skilled and higher paid mechanics. The average number of employees per outlet increased nationally during the 1990's, from 6.7 employees in 1990 to 7.6 in 1998, a 15-percent increase (Figure 42). Such a change may be consistent with several hypotheses, including an increase in the number of hours of operation.[l] Convenience stores may tend toward longer operating hours than service stations and the employment data do not contradict that conclusion.[m]

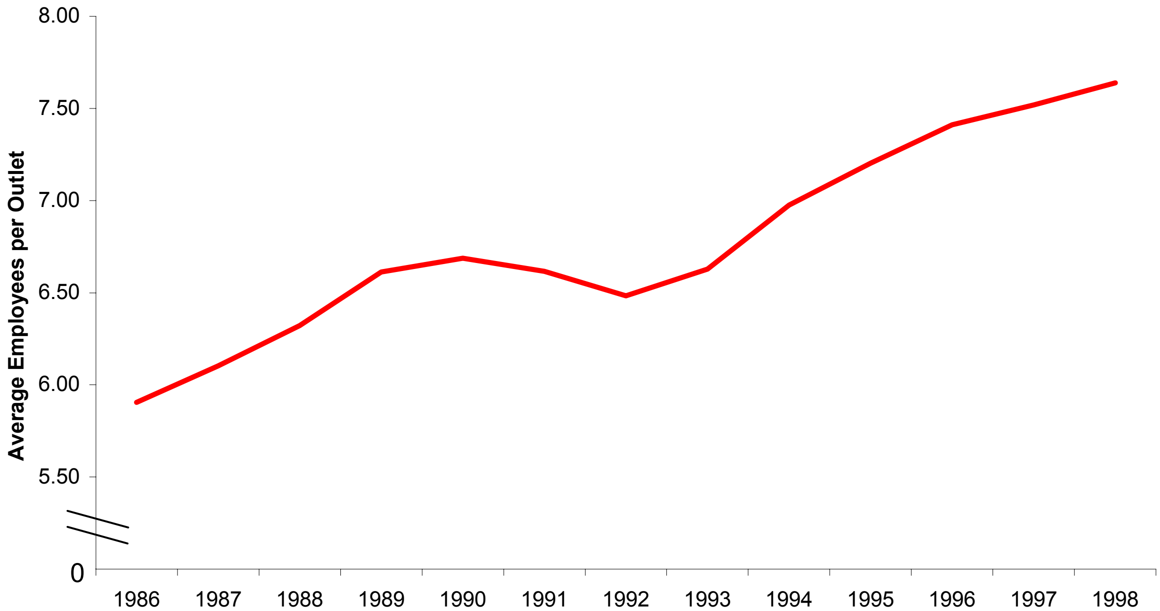
The associated salary data also do not appear to contradict the idea that the increased number of employees is due to longer hours of operation instead of increased use of part-time employees (over approximately the same number of hours of operation).[n] The average annual salary received by employees of motor gasoline outlets increased from $12,976 in 1990 to $13,222 in 1998 (both expressed in 1999 dollars). However, indexing the motor gasoline retail average annual salary (i.e., dividing it by the more general retail average annual salary) tells a slightly different story. The indexed motor gasoline outlet average annual salary declined slightly from 88 percent of the average annual retail salary in 1990 to 86 percent in 1997.[o]

Thus, while motor gasoline retail employment increased, salaries seem to have remained relatively unchanged during the 1990's. However, labor costs may be a target of future cost-cutting efforts in motor gasoline retailing. Perhaps reducing labor costs will become a target soon. A recent article in *National Petroleum News* discussed the limited introduction of an in-store scanner that allows customers to scan their purchases and then pay a cashier. A sidebar in the same article discussed the introduction of gasoline clubs that use unattended retail sites. Both of these innovations allow businesses to substitute capital assets for labor, potentially lowering overall costs.[p]

The capital intensity of retail outlets affords a second approach to quantify the changes in motor gasoline outlets over the past decade. The capital intensity of the FRS companies' retail outlets can be measured by the per-outlet value of net investment in place, which increased from $500,000 per outlet in 1990 to $771,000 in 1999 (Figure 43). The 54-percent increase of the capital intensity of the FRS companies' retail outlets may be instructive of underlying industry-wide changes. The FRS companies shed 13 percent of their lessee and company-operated outlets between 1990 and 1999, which fell from 31,553 to 27,612.[q] The average per outlet net investment in place may have increased partially through the divestiture of marginal outlets, which probably tended to be among the smallest outlets (in terms of monthly motor gasoline sales volume, and probably also in terms of capital investment). However the FRS companies made considerable capital investment in their retailing outlets over the period 1990 to 1999, fluctuating between a low of $71,538 per outlet in 1993 and a high of $108,481 per outlet in 1990 and totaled about $22 billion over the period.

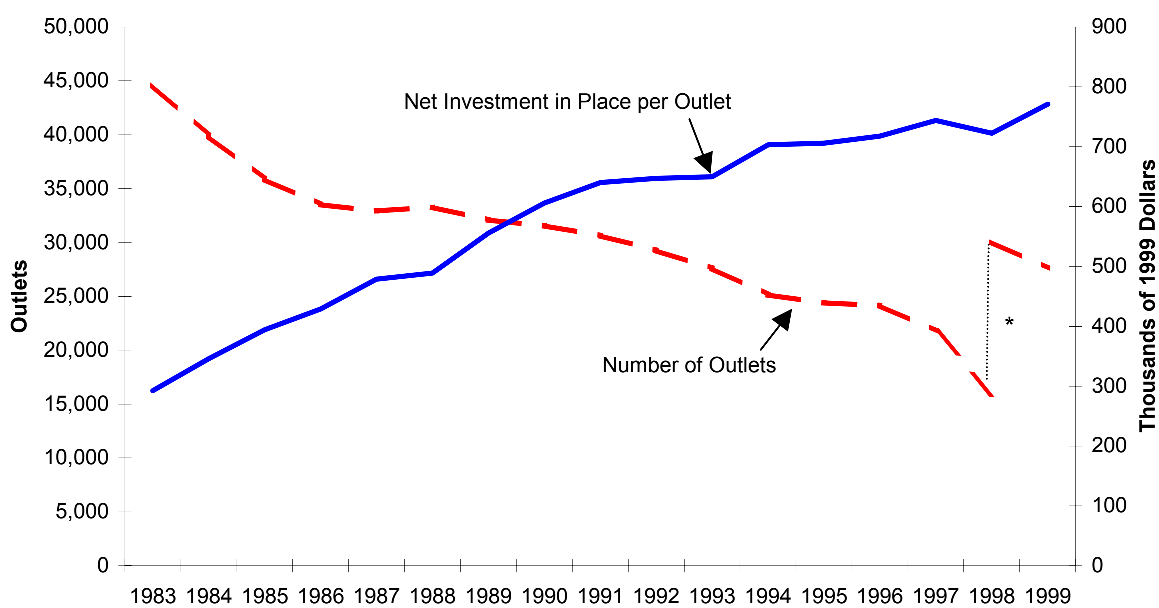
The increased marketing investment by the FRS companies accomplished at least two goals during the decade of the 1990's. First, this investment enabled the integrated refiners to meet the underground storage tank requirements of the U.S. Environmental Protection Agency.[r] Second, the investment

Figure 42. U.S. Average Number of Employees per Outlet (Week of March 12), 1986-1998



Source: U.S. Department of Commerce, U.S. Census Bureau, County Business Patterns (1986-1998).

Figure 43. Net Investment in Place per FRS Company-Operated and Lessee Dealer Outlet and Number of Outlets, 1983-1999



*: Eleven companies were added to the FRS group in 1998, which is the largest single-year change in the history of the FRS.

Note: Net investment in place is the sum of net property, plant, and equipment and the year-end balance of investments and advances to unconsolidated affiliates.

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

allowed the FRS companies to use their existing assets more intensively as demonstrated by their increased sales volume achieved over the decade. The FRS companies' average motor gasoline sales, which were 31,000 gallons per month in 1981, were 76,000 gallons per month in 1990, but had increased to 100,000 gallons per month by 1999.

Although the domestic motor gasoline marketing industry, measured in terms of outlets, was much smaller by the close of 1999 than it had been at the end of 1989, the industry, particularly the FRS companies, had made numerous changes in order to reduce costs and increase profitability. As has been shown elsewhere in *Performance Profiles of Major Energy Producers 2000*, those efforts have begun to bear fruit. (For a more comprehensive discussion of U.S. motor gasoline marketing developments over the past decade, see *Restructuring: The Changing Face of Motor Gasoline Marketing* at http://www.eia.doe.gov/emeu/finance/sptopics/downstrm00/index.html.)

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[a]U.S. Census Bureau, *State Population Estimates*, Population Estimates Program (ST-99-3, December 1999).
[b]McGraw-Hill Companies and the U.S. Department of Commerce, International Trade Administration, *U.S. Industry and Trade Outlook 2000*, p.4-4.
[c]This trend began more than a decade earlier as indicated by Thomas Hogarty's *The Decline of Motor Gasoline Service Stations and Motorists' Access to Car Maintenance Services*, Discussion Paper #058 (American Petroleum Institute, March 1989), Table 1; and Temple, Barker, and Sloane, Inc., *Gasoline Marketing in the 1980s: Structure, Practices, and Public Policy*, (Lexington, Massachusetts, May 1988), p. 23.
[d]See Energy Information Administration, *The Motor Gasoline Industry: Past, Present, and Future*, DOE/EIA-0539 (Washington, DC, January 1991), pp. 21-27; and *Gasoline Marketing in the United States Today*, Publication Number 1593 (American Petroleum Institute, September 1986), p. 8.
[e]Energy Information Administration, *The Motor Gasoline Industry: Past, Present, and Future*, DOE/EIA-0539 (Washington, DC, January 1991), pp. 5-8; and Temple, Barker, and Sloane, Inc., *Gasoline Marketing in the 1980s: Structure, Practices, and Public Policy*, (Lexington, Massachusetts, May 1988), pp. 23-38.
[f]A substantial group of articles related to hypermarkets is accumulating. Briefly, a hypermarket is a supermarket (especially in the United Kingdom), other traditional retail store, or discounter (such as Wal-Mart or Costco in the United States) with a motor gasoline outlet in the parking lot. See, for example, "New hypermart entrants to challenge existing U.S. gasoline marketers ," *Oil and Gas Journal*, Volume 99, Number 20 (May 14 , 2001), p. 56; and "New Hypermarkets," *Oil and Gas Journal*, Volume 99, Number 23 (June 4 , 2001); “Hypermarket fears echoed in the canyon at SIGMA,” *National Petroleum News*, Volume 93, Number 7 (July 2001), p. 17; and “Report: Hypermarkets grabbing Texas market share,” *National Petroleum News*, Volume 93, Number 9 (August 2001), p. 10.
[g]For example ARCO, Ashland, Chevron, Exxon, Phillips, Sun, Texaco, Unocal, and USX/Marathon all introduced such outlets during 1995 and 1996. See Energy Information Administration, *Performance Profiles of Major Energy Producers 1995*, DOE/EIA-0206(95) (Washington, DC, February 1997), p. 44. Note that subsequent mergers have transformed ARCO into BP Amoco, Ashland's downstream operations into Marathon Ashland Petroleum, and Exxon into Exxon Mobil. Also the pending merger of Chevron and Texaco, will replace them with Chevron Texaco, if the merger is approved. Finally, Sun has changed its name to Sunoco.
[h]Non-gasoline convenience store revenues are not directly collected from the FRS companies, but revenue from non-gasoline sales is collected. The category "other refining and marketing revenue" was originally intended to measure revenue from sales of tires, batteries, and accessories at traditional gasoline stations. It now tends to capture convenience store non-gasoline sales revenue with an occasional unusual item (e.g., a favorable legal judgement) included. Although not all company-operated retail outlets have convenience store formats, many do.
[i]The FRS companies’ branded motor gasoline retail outlets are divided into three categories: company-operated outlets, lessee dealer outlets, and open dealer outlets. Company-operated outlets are owned and operated by the FRS company. Lessee dealer outlets are those in which the owner leases assets from and is supplied motor gasoline by the FRS company. Open dealer outlets are those in which the owner is supplied motor gasoline by the FRS company.
[j]This attempt to quantify the importance of convenience item sales to motor gasoline marketing illustrates the difficulty of separating petroleum refining from motor gasoline marketing. Other studies encountered similar problems, e.g., Energy Information Administration, *The Motor Gasoline Industry: Past, Present, and Future*, DOE/EIA-0539 (Washington, DC, January 1991).
[k]See *Gasoline Marketing in the United States Today*, Publication Number 1593 (American Petroleum Institute, September 1986), p. 8.

[l]Alternatively, an increase in the average number of employees could indicate a movement of repair work back to retail outlets, which seems unlikely.

[m]However, a general movement toward more part-time employees is indicated by, "On the decline in average weekly hours worked," a recent Department of Labor study by Katie Kirkland in the *Monthly Labor Review* (July 2000, pp. 26-31). More part-time employment may increase the average number of employees with no change in hours of operation. Thus, these data may be made more informative by indexing them by a more general category of labor. Indexing will tend to remove the effect of more general changes occurring in the labor force, and more starkly present changes in motor gasoline outlet employment.

[n]This presumes that part-time employees tend to be paid less than are full-time employees over a period of time.

[o] Beginning in 1998, the Census Bureau switched from the Standard Industrial Classification (SIC) system to the North American Industrial Classification System (NAICS) with the result that a vertical displacement occurred in the data series. Between 1997 and 1999, the NAICS motor gasoline outlet average annual salary fell from 73 percent to 71 percent of the average annual salary for retail outlets in general.

[p]See, "Removing the Cashier," *National Petroleum News*, Volume 93, Number 7 (July 2001), pp. 18-20.

[q] This change is somewhat misleading because of the addition of 11 companies beginning with the 1998 reporting year. Ignoring these 11 companies, the FRS company-operated and lessee outlets would have declined to 16,022 in 1999, a 49-percent decline since 1990.

[r]The McGraw-Hill Companies and U.S. Department of Commerce, International Trade Administration, *U.S. Industry and Trade Outlook 2000*, (New York, 2000), p. 4-4.

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, 1994-2000

Operating Statistics	1994	1995	1996	1997	1998	1999	2000
Petroleum and Natural Gas							
Net Production							
Crude Oil and Natural Gas Liquids (million barrels)							
FRS Companies	1,593.8	1,570.6	1,532.4	1,458.8	1,388.8	1,305.7	1,268.1
U.S. Industry[1]	3,059.0	3,004.0	3,023.0	3,002.0	2,824.0	2,848.0	2,801.0
FRS as a Percent of U.S. Industry	52.1	52.3	50.7	48.6	49.2	45.8	45.3
Natural Gas (billion cubic feet)							
FRS Companies	7,998.4	8,055.3	8,191.6	8,299.1	8,395.9	7,994.1	8,354.0
U.S. Industry[1]	18,322.0	17,966.0	18,861.0	19,211.0	18,720.0	18,928.0	19,219.0
FRS as a Percent of U.S. Industry	43.7	44.8	43.4	43.2	44.8	42.2	43.5
Net Imports							
Crude Oil and Natural Gas Liquids (million barrels)							
FRS Companies	754.1	612.1	565.7	571.1	634.7	474.9	324.1
U.S. Industry[1]	2,788.7	2,810.0	2,946.6	3,191.0	3,358.5	3,366.4	3,527.0
FRS as a Percent of U.S. Industry	27.0	21.8	19.2	17.9	18.9	14.1	9.2
Refinery Capacity (thousand barrels per day)							
FRS Companies	10,642.0	10,427.0	10,477.0	9,410.0	14,277.0	14,158.0	14,393.0
U.S. Industry[1]	16,069.3	15,981.0	16,031.8	16,128.7	16,567.0	16,787.0	17,177.4
FRS as a Percent of U.S. Industry	66.2	65.2	65.4	58.3	86.2	84.3	83.8
Refinery Output[2] (thousand barrels per day)							
FRS Companies	10,812.0	10,652.0	10,954.0	10,030.0	14,929.0	14,639.0	14,499.0
U.S. Industry[1]	16,341.1	16,534.7	16,800.7	17,234.3	17,499.6	17,493.1	17,763.2
FRS as a Percent of U.S. Industry	66.2	64.4	65.2	58.2	85.3	83.7	81.6
Coal Production							
(million tons)							
FRS Companies	179.7	165.4	169.4	163.3	73.9	44.0	35.5
U.S. Industry[1]	1,028.9	1,028.3	1,059.1	1,085.3	1,112.9	1,095.7	1,069.0
FRS as a Percent of U.S. Industry	17.5	16.1	16.0	15.0	6.6	4.0	3.3

[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 2000 Annual Report December 2001). 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 2,968 million barrels in 2000 and 2,959 million barrels in 1999. (See Energy Information Administration, Petroleum Supply Annual 2000, Volume I (June 2001), p. 2.) For dry natural gas production, the official Energy Information Administration U.S. totals are 19,103 billion cubic feet in 2000 and 18,623 billion cubic feet in 1999. (See Energy Information Administration, Natural Gas Monthly, September 2001, Table 1.)

Sources: Industry data - Petroleum net production: Energy Information Administration, Form EIA-23; see U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 2000 Annual Report (December 2001). 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, 1999 and 2000. Coal production: 1994-2000--EIA, *Coal Industry Annual*, annual reports. FRS companies' data - Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B2. Selected Financial Items for the FRS Companies and the S&P Industrials, 1999-2000
(Billion Dollars)

Selected Financial Items	FRS Companies		S&P Industrials	
	1999	2000	1999	2000
Income Statement				
Operating Revenues	578.2	910.6	4,231.2	4,743.9
Operating Expenses	-546.0	-826.8	-3,747.2	-4,180.7
Operating Income	32.2	83.8	484.0	563.2
Interest Expense	-8.7	-10.6	-81.4	-98.0
Other Income[1]	10.2	15.0	34.1	30.0
Income Taxes	-10.8	-35.0	-153.7	-186.3
Net Income	22.9	53.2	283.1	308.9
Cash Flows from Operations[2]				
Net Income	22.9	53.2	283.1	308.9
Other Items, Net[3]	31.9	35.5	244.2	257.2
Net Cash Flow from Operations	54.8	88.7	527.3	566.1
Cash Flows from Investing Activities[2]				
Additions to Property, Plant & Equipment	-50.7	-102.2	-310.2	-357.4
Other Investment Activities, Net[4]	9.9	28.2	-170.8	-204.3
Net Cash Flow from Investing Activities	-40.8	-73.9	-481.1	-561.8
Cash Flows from Financing Activities[2]				
Proceeds from Long-Term Debt	29.9	33.3	408.4	436.5
Proceeds from Equity Security Offerings	3.6	30.6	58.4	69.6
Dividends to Shareholders	-16.1	-19.0	-88.9	-95.8
Reductions in Long-Term Debt	-25.0	-29.3	-288.7	-308.6
Stock Repurchases	-0.4	-5.4	-120.8	-122.3
Other Financing Activities, Net	-3.4	-17.2	35.3	30.9
Net Cash Flow from Financing Activities	-11.5	-7.0	3.7	10.3
Effect of Exchange Rate Changes on Cash	0.0	-0.1	-2.4	-3.9
Increase (Decrease) in Cash and Cash Equivalents	2.5	7.6	47.6	10.7

[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: Depreciation, Depletion & Amortization, deferred taxes, dry hole expense, minority interest, recognized undistributed earnings/(losses) of unconsolidated affiliates, (gain)/loss on disposition of Property, Plant & Equipment, 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, 1999-2000

	FRS Companies		S&P Industrials	
	1999	2000	1999	2000
Balance Sheet	(billion dollars)			
Assets				
Current Assets	121.0	196.5	1,249.8	1,431.3
Noncurrent Assets				
Property, Plant, and Equipment (PP&E)				
Gross	708.0	757.2	2,751.6	2,994.1
Accumulated Depreciation, Depletion, and Amortization (DD&A)	-355.5	-351.6	-1,259.7	-1,342.4
Net	352.5	405.5	1,491.8	1,651.8
Investments and Advances	58.2	61.9	194.0	193.0
Other Noncurrent Assets	39.6	87.4	2,111.0	2,558.4
Subtotal Noncurrent Assets	450.3	554.8	2,441.0	3,073.2
Total Assets	571.3	751.2	5,046.6	5,834.4
Liabilities and Stockholders Equity				
Liabilities				
Current Liabilities	131.3	198.8	996.6	1,147.8
Long-Term Debt	104.0	120.0	978.9	1,146.0
Other Long-Term Items	114.5	143.6	1,401.4	1,446.8
Minority Interest	15.2	17.1	45.6	78.5
Subtotal Liabilities and Other Items	364.9	479.5	3,422.5	3,819.1
Stockholders' Equity				
Retained Earnings	170.6	199.2	1,152.7	1,249.5
Other Equity	35.7	72.5	471.5	765.8
Subtotal Stockholders' Equity	206.3	271.8	1,624.1	2,015.3
Total Liabilities and Stockholders' Equity	571.3	751.2	5,046.6	5,834.4
Financial Ratios	(percent)			
Net Income/Stockholders' Equity	11.1	19.6	17.4	15.3
Net Income plus Interest/Total Invested Capital	10.2	16.3	14.0	12.9
Dividends/Net Cash Flow from Operations	29.3	21.4	16.9	16.9
Long-term Debt/Stockholders' Equity	50.4	44.2	60.3	56.9

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, 1994-2000
(Billion Dollars)

Balance Sheet Items	1994	1995	1996	1997	1998	1999	2000
Assets							
Current Assets							
Cash & Marketable Securities	13.2	12.2	13.4	12.2	8.1	12.2	18.7
Trade Accounts & Notes Receivable	45.8	48.8	56.2	51.2	47.8	68.1	98.6
Inventories							
Raw Materials & Products	22.9	22.6	22.7	21.4	21.6	23.3	25.6
Materials & Supplies	4.4	4.1	3.8	3.7	3.8	3.9	4.4
Other Current Assets	10.2	10.9	12.1	12.4	12.9	13.4	49.1
Total Current Assets	96.6	98.6	108.2	100.9	94.2	121.0	196.5
Non-current Assets							
Property, Plant & Equipment							
Gross	624.1	640.2	635.0	636.9	671.0	708.0	757.2
Accumulated DD&A	315.4	329.8	331.6	333.3	334.5	355.5	351.6
Net	308.7	310.5	303.4	303.6	336.5	352.5	405.5
Investments & Advances to Unconsolidated Affiliates	25.9	29.0	32.3	44.2	53.9	58.2	61.9
Other Non-current Assets	26.2	26.5	26.8	35.2	35.8	39.6	87.4
Total Non-current Assets	360.8	366.0	362.4	382.9	426.3	450.3	554.8
Total Assets	457.4	464.6	470.6	483.8	520.4	571.3	751.2
Liabilities & Stockholders' Equity							
Liabilities							
Current Liabilities							
Trade Accounts & Notes Payable	51.5	53.1	61.4	57.7	62.8	79.4	102.4
Other Current Liabilities	45.8	50.8	48.8	49.2	51.1	51.9	96.4
Long-Term Debt	88.1	84.6	70.9	73.4	94.6	104.0	120.0
Deferred Income Tax Credits	45.0	45.5	45.5	46.3	49.0	53.1	68.2
Other Deferred Credits	16.8	17.3	19.2	18.8	18.4	18.8	34.1
Other Long-Term Items	39.3	40.7	40.6	41.6	39.7	42.6	41.2
Minority Interest in Consolidated Affiliates	5.1	5.8	6.6	8.2	10.4	15.2	17.1
Total Liabilities	291.7	297.9	292.9	295.1	326.0	364.9	479.5
Stockholders' Equity	145.0	151.4	156.3	160.8	165.8	170.6	199.2
Retained Earnings	20.7	15.3	21.4	27.9	28.7	35.7	72.5
Other Equity							
Total Stockholders' Equity	165.7	166.7	177.8	188.7	194.4	206.3	271.8
Total Liabilities & Stockholders' Equity	457.4	464.6	470.6	483.8	520.4	571.3	751.2
Memo:							
Foreign Currency Translation Adjustment Cumulative at Year End	0.7	1.5	1.2	-2.7	-2.3	-2.7	-3.0
Foreign Currency Translation Adjustment for the Current Year	1.9	0.7	-0.4	-3.9	0.0	-0.3	-2.1

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

Table B5. Consolidating Statement of Income for FRS Companies, 2000
(Million Dollars)

Income Statement Items	Consolidated	Eliminations & Nontraceables	Petroleum	Coal	Other Energy	Nonenergy
Operating Revenues	910,577	-16,634	769,139	1,724	84,987	71,361
Operating Expenses						
General Operating Expenses	770,865	-12,944	644,443	1,519	78,871	58,976
DD&A	37,619	626	32,674	220	1,211	2,888
General & Administrative	18,318	2,483	10,283	31	1,867	3,654
Total Operating Expenses	826,802	-9,835	687,400	1,770	81,949	65,518
Operating Income	83,775	-6,799	81,739	-46	3,038	5,843
Other Revenue & (Expense)						
Earnings of Unconsolidated Affiliates	7,932	-305	7,694	33	755	-245
Other Dividend & Interest Income	3,940	3,940	-	-	-	-
Gain/Loss on Disposition of PP&E	2,065	2,437	-186	47	66	-299
Interest Expenses & Financial	-10,565	-10,565	-	-	-	-
Minority Interest in Income	-1,912	-1,912	-	-	-	-
Foreign Currency Translation Effects	-168	-168	-	-	-	-
Other Revenue & (Expense)	1,635	1,635	-	-	-	-
Total Other Revenue & (Expense)	2,927	-4,938	7,508	80	821	-544
Pretax Income	86,702	-11,737	89,247	34	3,859	5,299
Income Tax Expense	35,024	-3,236	35,526	7	1,116	1,611
Discontinued Operations	-227	48	W	0	0	W
Extraordinary Items and Cumulative Effect of Accounting Changes	1,741	1,834	W	0	0	W
Net Income	53,192	-6,619	53,548	27	2,743	3,493

- = 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, 2000
(Million Dollars)

Income Statement Items	U.S. Petroleum				Foreign Petroleum			
	Consolidated	Production	Refining/ Marketing	Pipelines	Consolidated	Production	Refining/ Marketing	Int'l Marine
Operating Revenues								
Raw Material Sales	196,385	79,250	180,384	4,237	106,664	67,987	84,813	0
Refined Products Sales	306,779	W	310,661	155	147,306	W	147,597	0
Transportation Revenues	11,161	1,149	2,761	9,203	2,045	358	342	2,388
Management and Processing Fees	3,462	W	3,040	311	1,689	W	1,848	W
Other	14,826	2,140	11,435	1,375	3,195	633	2,564	W
Total Operating Revenues	532,613	83,849	508,281	15,281	260,899	71,086	237,164	2,623
Operating Expenses								
General Operating Expenses	458,552	37,590	486,977	8,783	210,264	27,982	229,762	2,494
DD&A	19,883	13,119	4,712	2,052	12,791	10,795	1,942	W
General & Administrative	8,222	1,308	5,832	1,082	2,061	992	1,065	W
Total Operating Expenses	486,657	52,017	497,521	11,917	225,116	39,769	232,769	2,552
Operating Income	45,956	31,832	10,760	3,364	35,783	31,317	4,395	71
Other Revenue & (Expense)								
Earnings of Unconsolidated Affiliates	3,813	2,011	1,253	549	3,881	3,749	104	W
Gain(Loss) on Disposition of PP&E	-404	-533	93	36	218	306	-72	W
Total Other Revenue & (Expense)	3,409	1,478	1,346	585	4,099	4,055	32	12
Pretax Income	49,365	33,310	12,106	3,949	39,882	35,372	4,427	83
Income Tax Expense	16,644	10,698	4,360	1,586	18,882	17,321	1,527	34
Discontinued Operations	W	W	W	W	W	W	W	W
Extraordinary Items and Cumulative Effect of Accounting Changes	W	W	W	W	W	W	W	W
Contribution To Net Income	32,570	22,609	7,659	2,302	20,978	18,029	2,900	49

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, 2000
(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	118,919	4,425	45,095	-317	13,119
Refining/Marketing					
Refining	42,530	8,305	7,553	617	2,788
Marketing	20,138	2,132	3,281	120	1,533
Refining/Marketing Transport					
Pipelines	3,245	1,078	454	57	164
Marine	584	W	186	W	84
Other	1,354	W	152	W	143
Total U.S. Refining/Marketing	67,851	11,579	11,626	403	4,712
Rate Regulated Pipelines					
Refined Products	5,950	548	1,105	W	156
Natural Gas	23,974	3,202	2,640	49	1,710
Crude Oil and Liquids	4,451	642	209	W	186
Total Rate Regulated Pipelines	34,375	4,392	3,954	48	2,052
Total U.S. Petroleum	221,145	20,396	60,675	134	19,883
Foreign					
Production	94,883	12,880	26,913	2,592	10,795
Refining/Marketing	24,732	8,398	1,722	W	W
International Marine	660	101	12	W	W
Total Foreign Petroleum	120,275	21,379	28,647	3,269	12,791
Total Petroleum	341,420	41,775	89,322	3,403	32,674
Coal					
Foreign	W	W	W	W	W
United States	W	W	W	W	W
Total Coal	1,488	61	150	20	220
Other Energy					
Foreign	3,646	4,136	1,595	1,192	222
United States	15,575	1,577	2,071	582	989
Total Other Energy	19,221	5,713	3,666	1,774	1,211
Nonenergy					
Foreign Chemicals	7,157	3,203	1,016	855	422
U.S. Chemicals	16,280	6,023	1,664	126	1,452
Foreign Other Nonenergy	1,260	318	102	39	89
U.S. Other Nonenergy	10,954	3,633	5,003	1,350	925
Total Nonenergy	35,651	13,177	7,785	2,370	2,888
Nontraceable	7,759	1,137	1,269	-411	628
Consolidated	405,539	61,863	102,192	7,156	37,621

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, 1999-2000
(Percent)

Line of Business	All FRS		Top Four		Five through Twelve		All Other	
	1999	2000	1999	2000	1999	2000	1999	2000
Petroleum	7.2	14.0	7.6	16.1	7.8	10.6	5.9	12.1
U.S. Petroleum	7.0	13.5	8.4	16.7	6.8	9.6	5.9	12.6
Oil and Gas Production	7.6	18.3	7.6	20.4	8.9	18.5	5.9	12.9
Refining/Marketing	6.5	9.6	9.6	11.1	4.6	-5.5	5.7	13.4
Pipelines	6.4	5.9	9.3	7.9	5.8	5.3	7.5	6.9
Foreign Petroleum	7.6	14.8	7.0	15.6	11.6	14.5	5.9	10.4
Oil and Gas Production	8.5	16.7	8.9	18.7	10.1	14.7	6.1	10.3
Refining/Marketing	5.1	8.8	3.7	8.2	20.3	12.6	3.7	12.0
International Marine	0.8	6.4	2.7	4.1	(1)	450.0	(1)	0.0
Coal	9.5	1.7	5.7	12.1	W	-5.3	24.4	-12.3
Other Energy	7.6	11.0	12.4	18.2	5.7	10.0	6.1	9.3
Nonenergy	5.8	7.2	8.2	8.2	4.6	6.1	4.5	6.5

[1]Not meaningful.
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, 1994-2000
(Million Dollars)

	1994	1995	1996	1997	1998	1999	2000
Sources of R&D Funds							
Federal Government	15	W	W	W	W	27	W
Internal Company	2,985	2,817	2,675	2,841	1,668	1,377	1,316
Other Sources	50	W	W	W	W	20	W
Total Sources	3,050	2,861	2,717	2,885	1,707	1,424	1,326
Breakdown of R&D Expenditures							
Oil & Gas Recovery	572	494	482	585	606	430	453
Other Petroleum	531	461	432	380	365	345	327
Coal Gasification/Liquefaction	W	W	W	W	W	W	W
Other Coal	W	W	W	W	W	W	W
Nuclear and Other Energy	116	50	51	54	28	34	W
Nonenergy	1,741	1,744	1,617	1,738	616	538	452
Unassigned	71	100	127	120	85	W	W
Total Expenditures	3,050	2,861	2,717	2,885	1,707	1,424	1,326

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, 2000
(Percent)

Line of Business	Top Four	Five through Twelve	All Other	All FRS
Petroleum	49.7	24.2	28.2	100.0
United States	36.7	30.9	35.0	100.0
Production	44.7	28.3	32.1	100.0
Refining/Marketing	36.5	16.0	47.5	100.0
Refining	34.9	17.8	47.3	100.0
Marketing	44.5	8.5	47.0	100.0
Rate Regulated Pipelines	11.9	69.5	18.5	100.0
Foreign	71.8	12.7	16.7	100.0
Production	67.0	14.4	20.1	100.0
Refining/Marketing	86.8	7.4	5.7	100.0
International Marine	99.3	0.5	0.1	100.0
Coal	64.3	1.2	35.7	100.0
Other Energy	12.5	82.2	5.3	100.0
Nonenergy	47.5	32.1	20.4	100.0
Chemicals	64.4	15.7	19.8	100.0
Other Nonenergy	13.2	65.3	21.5	100.0
Consolidated	48.2	27.7	25.8	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, 1994-2000
(Million Dollars)

Cash Flows [1]	1994	1995	1996	1997	1998	1999	2000
Cash Flows From Operations							
Net Income	16,547	21,131	32,029	32,082	12,519	22,866	53,192
Minority Interest in Income	513	731	845	896	764	1,161	1,912
Noncash Items:							
DD&A	30,667	36,698	29,331	29,569	35,445	32,452	37,621
Dry Hole Expense, This Year	1,805	1,510	1,812	2,069	2,518	1,808	1,328
Deferred Income Taxes	509	-327	2,863	2,301	-1,123	-25	5,611
Recognized Undistributed (Earnings)/Losses of Unconsolidated Affiliates	-372	-845	-226	-374	2,987	136	-3,319
(Gain)/Loss on Disposition of PP&E	-570	-2,445	-1,940	-2,716	-2,658	-1,922	-2,065
Changes in Operating Assets and Liabilities and Other Noncash Items	-1,884	-763	-365	298	-3,792	-2,259	-6,226
Other Cash Items, Net	1,084	2,808	-165	1,197	1,502	581	629
Net Cash Flow From Operations	48,299	58,498	64,184	65,322	48,162	54,798	88,683
Cash Flows From Investing Activities							
Additions to PP&E:							
Due to Mergers and Acquisitions	-2,271	-4,137	-2,281	-5,579	-18,868	-5,961	-49,722
Other	-35,217	-40,356	-41,872	-48,666	-51,046	-44,775	-52,470
Total Additions to PP&E	-37,488	-44,493	-44,153	-54,245	-69,914	-50,736	-102,192
Additions to Investments and Advances	-1,588	-3,208	-5,799	-7,685	-5,223	-6,874	-7,156
Proceeds From Disposals of PP&E	6,447	9,063	10,942	9,320	16,243	13,267	26,663
Other Investment Activities, Net	-2,363	4,086	1,608	6,587	4,235	3,523	8,742
Cash Flow From Investing Activities	-34,992	-34,552	-37,402	-46,023	-54,659	-40,820	-73,943
Cash Flows From Financing Activities							
Proceeds From Long-Term Debt	12,500	19,929	10,708	17,901	27,072	29,862	33,292
Proceeds From Equity Security Offerings	2,614	3,471	1,171	1,507	9,112	3,557	30,606
Reductions in Long-Term Debt	-13,760	-18,657	-18,883	-19,774	-18,019	-24,988	-29,323
Purchase of Treasury Stock	-1,010	-10,035	-1,299	-7,910	-5,776	-424	-5,362
Dividends to Shareholders	-14,906	-15,238	-15,585	-16,941	-17,169	-16,081	-18,981
Other Financing Activities, Including Net Change in Short-Term Debt	-1,091	-2,350	-578	5,537	6,859	-3,377	-17,205
Cash Flow From Financing Activities	-15,653	-22,880	-24,466	-19,680	2,079	-11,451	-6,973
Effect of Exchange Rate on Cash	131	14	3	-255	-13	-24	-119
Net Increase/(Decrease) in Cash and Cash Equivalents	-2,215	1,080	2,319	-636	-4,431	2,503	7,648

[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, 1994-2000
(Million Dollars)

	1994	1995	1996	1997	1998	1999	2000
Income Taxes (as per Financial Statements)							
Current Paid or Accrued:							
U.S. Federal, before Investment Tax Credit & Alternative Minimum Tax	1,907	4,486	6,141	5,656	603	1,375	11,705
U.S. Federal Investment Tax Credit	0	-162	-146	-93	-85	-90	-129
Effect of Alternative Minimum Tax	30	151	-325	-400	-16	445	-1,222
U.S. State & Local Income Taxes	528	649	745	794	443	371	1,338
Foreign Income Taxes							
Canada	705	634	745	932	456	597	1,765
Europe and Former Soviet Union [1]	2,300	2,752	3,862	2,927	1,798	3,110	7,002
Africa	1,127	1,204	1,956	1,926	449	1,607	3,617
Middle East	835	1,024	1,326	802	745	1,286	2,380
Other Eastern Hemisphere	2,085	1,882	2,195	1,901	992	1,679	2,214
Other Western Hemisphere	464	514	729	1,739	428	346	900
Total Foreign	7,516	8,010	10,813	10,227	4,868	8,625	17,878
Total Current	9,981	13,134	17,228	16,184	5,813	10,726	29,570
Deferred							
U.S. Federal, before Investment Tax Credit	691	-793	1,410	1,477	-373	1,480	3,168
U.S. Federal Investment Tax Credit	26	61	69	-2	-28	-14	-78
Effect of Alternative Minimum Tax	-51	-158	312	400	-16	-415	1,233
U.S. State & Local Income Taxes	-56	-30	56	54	104	136	221
Foreign	43	537	930	519	-791	-1,075	910
Total Deferred	653	-383	2,777	2,448	-1,104	112	5,454
Total Income Tax Expense	10,634	12,751	20,005	18,632	4,709	10,838	35,024
Reconciliation of Accrued U.S. Federal Income Tax Expense To Statutory Rate							
Consolidated Pretax Income/(Loss)	29,592	34,233	52,808	51,453	16,017	33,837	86,702
Less: Foreign Source Income not Subject to U.S.	3,575	4,038	6,230	5,827	251	2,160	13,355
Equals: Income Subject to U.S. Tax	26,017	30,195	46,578	45,626	15,766	31,677	73,347
Less: U.S. State & Local Income Taxes	438	440	782	785	570	486	1,497
Less: Applicable Foreign Income Taxes Deducted	327	377	554	312	32	107	353
Equals: Pretax Income Subject to U.S. Tax	25,252	29,378	45,242	44,529	15,164	31,084	71,497
Tax Provision Based on Previous Line	8,842	10,281	15,834	15,621	5,332	10,902	25,032
Increase/(Decrease) in Taxes Due To:							
Foreign Tax Credits Recognized	-4,831	-5,661	-6,926	-6,982	-3,563	-5,963	-9,787
U.S. Federal Investment Tax Credit Recognized	-34	-97	-123	-137	-124	-98	-129
Statutory Depletion	-52	-70	-54	-63	-30	-8	-3
Effect of Alternative Minimum Tax	-14	0	1	0	-16	23	11
Other	-1,314	-868	-1,273	-1,399	-1,485	-2,068	-447
Actual U.S. Federal Tax Provision (Refund)	2,597	3,585	7,459	7,040	114	2,788	14,677

[1] OECD Europe combined with the former Soviet Union and Eastern Europe to avoid disclosure.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B13. U.S. Taxes Other Than Income Taxes for FRS Companies, 1994-2000
(Million Dollars)

	1994	1995	1996	1997	1998	1999	2000
Production Taxes							
Oil and Gas Production	1,719	1,693	2,098	1,965	1,176	1,674	2,604
Coal	126	157	139	172	47	43	30
Other [1]	5	11	1	1	0	0	25
Total Production Taxes	1,850	1,861	2,238	2,138	1,223	1,717	2,659
Superfund	291	293	14	W	W	W	W
Import Duties	122	104	260	W	W	W	W
Sales, Use, and Property	3,089	2,886	2,516	2,407	2,648	2,268	2,356
Payroll	1,986	1,844	1,531	1,406	1,357	1,289	1,259
Other Taxes	630	566	514	559	360	467	789
Total Taxes Paid (Other Than Income Taxes)	7,968	7,554	7,073	6,601	5,660	5,825	7,186
Excise Taxes Collected	30,092	30,813	32,426	30,984	39,918	46,293	47,084

[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, 1994-2000
(Million Dollars)

	1994	1995	1996	1997	1998	1999	2000
United States							
Exploration							
Acquisition of Unproved Acreage	477	595	997	2,653	3,912	633	4,010
Geological and Geophysical	405	486	625	750	916	621	849
Drilling and Equipping [1]	1,887	1,833	2,338	2,905	2,964	1,921	2,550
Other	619	596	693	690	954	659	610
Total Exploration	3,388	3,510	4,653	6,998	8,746	3,834	8,019
Development							
Acquisition of Proved Acreage	1,576	980	922	2,928	3,568	1,144	27,939
Lease Equipment	1,386	1,425	1,613	1,823	2,688	2,431	1,907
Drilling and Equipping [1]	4,524	5,433	6,154	8,540	7,769	5,022	8,788
Other [2]	1,714	1,086	1,290	1,557	1,657	1,056	1,391
Total Development	9,200	8,924	9,979	14,848	15,682	9,653	40,025
Total U.S. Exploration and Development	12,588	12,434	14,632	21,846	24,428	13,487	48,044
Foreign							
Exploration							
Acquisition of Unproved Acreage	343	214	745	565	2,159	2,252	4,105
Geological and Geophysical	932	843	869	897	1,065	885	875
Drilling and Equipping [1]	1,595	2,114	2,277	2,684	2,650	1,579	1,824
Other	960	989	919	1,128	1,299	903	1,087
Total Exploration	3,830	4,160	4,810	5,274	7,173	5,619	7,891
Development							
Acquisition of Proved Acreage	737	371	1,932	1,641	7,121	2,083	11,644
Lease Equipment	1,329	1,537	2,064	2,207	2,505	2,142	1,842
Drilling and Equipping [1]	4,085	4,535	5,278	6,426	6,206	5,143	5,057
Other [2]	1,928	2,568	2,534	2,383	3,388	2,531	2,364
Total Development	8,079	9,011	11,808	12,657	19,220	11,899	20,907
Total Foreign Exploration and Development	11,909	13,171	16,618	17,931	26,393	17,518	28,798

[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, 2000
(Million Dollars)

	Worldwide	United States			Foreign
		Total	Onshore	Offshore	
Exploration and Development Expenditures					
Exploration Expenditures					
Unproved Acreage	8,115	4,010	3,044	966	4,105
Drilling and Equipping:					
Completed Well Costs	-	1,739	429	1,310	-
Work-in-progress Adjustment	-	811	117	694	-
Total Drilling and Equipping	4,374	2,550	546	2,004	1,824
Geological and Geophysical	1,724	849	276	573	875
Other, Including Direct Overhead	1,697	610	270	340	1,087
Total Exploration Expenditures	15,910	8,019	4,136	3,883	7,891
Development Expenditures					
Proved Acreage (Including Mergers and Acquisitions)	39,583	27,939	15,765	12,174	11,644
Drilling and Equipping:					
Completed Well Costs	-	6,388	3,981	2,407	-
Work-in-progress Adjustment	-	2,400	1,077	1,323	-
Total Drilling and Equipping	13,845	8,788	5,058	3,730	5,057
Lease Equipment	3,749	1,907	1,070	837	1,842
Other Development					
Support Equipment	518	221	163	58	297
Other, Including Direct Overhead	3,237	1,170	897	273	2,067
Total Development Expenditures	60,932	40,025	22,953	17,072	20,907
Total Exploration and Development Expenditures	76,842	48,044	27,089	20,955	28,798

- = Not available.

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

Table B16. Exploration and Development Expenditures by Region, 1994-2000
(Million Dollars)

	1994	1995	1996	1997	1998	1999	2000
Exploration Expenditures							
U.S. Onshore	1,491	1,644	1,826	3,396	3,941	1,174	4,136
U.S. Offshore	1,897	1,866	2,827	3,602	4,805	2,660	3,883
Total United States	3,388	3,510	4,653	6,998	8,746	3,834	8,019
Canada	573	493	355	310	638	420	1,184
OECD Europe	1,063	1,242	1,345	1,684	1,916	767	869
Former Soviet Union and E. Europe	204	181	194	285	630	354	317
Africa	678	707	779	807	1,092	1,268	910
Middle East	104	90	45	53	141	96	56
Other Eastern Hemisphere	888	1,016	1,462	1,341	1,563	1,192	1,675
Other Western Hemisphere	320	431	630	794	1,193	1,522	2,880
Total Foreign	3,830	4,160	4,810	5,274	7,173	5,619	7,891
Worldwide Exploration Expenditures	7,218	7,670	9,463	12,272	15,919	9,453	15,910
Development Expenditures							
U.S. Onshore	6,324	6,051	6,087	9,624	9,519	5,396	22,953
U.S. Offshore	2,876	2,873	3,892	5,224	6,163	4,257	17,072
Total United States	9,200	8,924	9,979	14,848	15,682	9,653	40,025
Canada	1,262	1,406	1,210	1,688	4,168	1,636	3,697
OECD Europe	3,376	3,962	4,222	5,368	6,670	3,370	6,651
Former Soviet Union and E. Europe	93	178	267	343	637	252	576
Africa	714	1,336	2,014	2,171	2,042	1,826	1,809
Middle East	341	271	418	590	801	297	494
Other Eastern Hemisphere	1,870	1,414	2,670	1,643	2,386	2,250	5,112
Other Western Hemisphere	423	444	1,007	854	2,516	2,268	2,568
Total Foreign	8,079	9,011	11,808	12,657	19,220	11,899	20,907
Worldwide Development Expenditures	17,279	17,935	21,787	27,505	34,902	21,552	60,932
Total Exploration and Development Expenditures							
U.S. Onshore	7,815	7,695	7,913	13,020	13,460	6,570	27,089
U.S. Offshore	4,773	4,739	6,719	8,826	10,968	6,917	20,955
Total United States	12,588	12,434	14,632	21,846	24,428	13,487	48,044
Canada	1,835	1,899	1,565	1,998	4,806	2,056	4,881
OECD Europe	4,439	5,204	5,567	7,052	8,586	4,137	7,520
Former Soviet Union and E. Europe	297	359	461	628	1,267	606	893
Africa	1,392	2,043	2,793	2,978	3,134	3,094	2,719
Middle East	445	361	463	643	942	393	550
Other Eastern Hemisphere	2,758	2,430	4,132	2,984	3,949	3,442	6,787
Other Western Hemisphere	743	875	1,637	1,648	3,709	3,790	5,448
Total Foreign	11,909	13,171	16,618	17,931	26,393	17,518	28,798
Worldwide Exploration and Development Expenditures	24,497	25,605	31,250	39,777	50,821	31,005	76,842

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

Table B17. Production (Lifting) Costs by Region for FRS Companies, 1994-2000
(Million Dollars)

	1994	1995	1996	1997	1998	1999	2000
United States							
Taxes Other Than Income Taxes	1,719	1,693	2,098	1,965	1,176	1,674	2,604
Other Costs	11,107	10,429	10,221	10,147	9,787	9,494	8,417
Total Production Costs	12,826	12,122	12,319	12,112	10,963	11,168	11,021
U.S. Onshore	10,342	9,769	9,855	9,604	8,198	8,039	8,254
U.S. Offshore	2,484	2,353	2,464	2,508	2,765	3,129	2,767
Canada							
Royalty Expenses	W	W	W	W	W	W	W
Taxes Other Than Income Taxes	W	W	W	W	W	W	W
Other Costs	1,141	1,082	993	961	1,037	1,120	1,379
Total Production Costs	1,234	1,174	1,082	1,049	1,129	1,252	1,496
OECD Europe							
Royalty Expenses	206	235	251	217	251	62	W
Taxes Other Than Income Taxes	274	311	400	360	269	330	W
Other Costs	4,128	4,116	3,996	3,950	3,980	3,666	3,485
Total Production Costs	4,608	4,662	4,647	4,527	4,500	4,058	4,025
Former Soviet Union and E. Europe							
Royalty Expenses	0	0	0	0	0	0	0
Taxes Other Than Income Taxes	W	W	W	W	W	W	W
Other Costs	W	W	W	W	W	W	W
Total Production Costs	65	128	134	192	208	148	196
Africa							
Royalty Expenses	W	W	W	W	W	66	96
Taxes Other Than Income Taxes	W	W	W	W	W	49	480
Other Costs	740	607	812	861	1,194	1,153	1,208
Total Production Costs	1,011	916	1,259	1,310	1,490	1,268	1,784
Middle East							
Royalty Expenses	W	W	W	W	W	W	137
Taxes Other Than Income Taxes	W	W	W	W	W	W	75
Other Costs	340	258	296	280	250	235	175
Total Production Costs	435	403	483	491	429	424	387
Other Eastern Hemisphere							
Royalty Expenses and							
Taxes Other Than Income Taxes	433	400	542	456	240	507	618
Other Costs	1,132	1,110	1,161	1,144	1,074	1,097	1,392
Total Production Costs	1,565	1,510	1,703	1,600	1,314	1,604	2,010
Other Western Hemisphere							
Royalty Expenses and							
Taxes Other Than Income Taxes	83	129	180	156	87	184	304
Other Costs	346	428	389	470	552	443	533
Total Production Costs	429	557	569	626	639	627	837
Total Foreign							
Royalty Expenses	613	680	901	891	740	384	437
Taxes Other Than Income Taxes	843	942	1,196	1,050	675	1,172	1,947
Other Costs	7,891	7,728	7,780	7,854	8,294	7,825	8,351
Total Production Costs	9,347	9,350	9,877	9,795	9,709	9,381	10,735

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, 1994-2000
(Thousand Acres)

	1994	1995	1996	1997	1998	1999	2000
Net Acreage							
U.S. Onshore							
Developed	28,744	27,429	26,733	25,474	26,396	25,895	31,760
Undeveloped	35,698	38,792	31,659	31,154	30,598	25,880	37,657
U.S. Offshore							
Developed	4,818	6,154	5,470	5,343	4,634	4,988	5,383
Undeveloped	13,925	14,334	16,880	22,983	23,168	24,940	21,483
Foreign							
Developed	20,505	18,063	22,574	21,984	24,887	26,337	32,535
Undeveloped	444,427	449,255	445,176	472,106	514,511	416,209	416,941
Gross Acreage							
U.S. Onshore							
Developed	51,846	50,016	46,887	45,249	49,097	45,978	57,626
Undeveloped	57,865	61,651	53,775	55,530	51,364	42,325	59,295
U.S. Offshore							
Developed	10,112	11,291	9,668	10,665	8,861	9,534	10,588
Undeveloped	19,128	18,595	21,786	30,845	32,439	35,689	31,609
Foreign							
Developed	57,885	49,946	59,926	58,198	64,358	59,247	71,330
Undeveloped	855,790	892,178	857,130	924,839	1,083,355	835,615	882,761

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

Table B19. U.S. Net Wells Completed for FRS Companies and U.S. Industry, 1994-2000

	1994	1995	1996	1997	1998	1999	2000
Number of Net Wells Completed During Year for FRS Companies							
Onshore							
Net Exploratory Wells							
Dry Holes	175	232	274	163	159	93	86
Oil Wells	101	104	91	90	55	26	19
Gas Wells	167	201	207	170	142	105	217
Total Exploratory Wells	443	538	572	424	356	225	321
Net Development Wells							
Dry Holes	203	262	319	301	256	162	228
Oil Wells	1,980	1,908	2,095	3,016	2,510	1,130	1,775
Gas Wells	1,865	2,156	2,049	2,261	2,074	1,519	2,927
Total Development Wells	4,048	4,326	4,463	5,577	4,841	2,812	4,929
Offshore							
Net Exploratory Wells							
Dry Holes	78	72	84	98	91	59	73
Oil Wells	13	32	36	31	22	28	28
Gas Wells	47	53	87	73	63	61	59
Total Exploratory Wells	138	157	206	202	176	148	159
Net Development Wells							
Dry Holes	17	18	23	46	32	26	30
Oil Wells	150	151	158	181	115	145	128
Gas Wells	120	95	153	168	133	153	157
Total Development Wells	287	265	334	396	280	324	315
Total United States							
Net Exploratory Wells							
Dry Holes	253	304	358	261	249	153	158
Oil Wells	114	137	127	121	77	54	47
Gas Wells	214	255	293	243	205	166	275
Total Exploratory Wells	581	695	778	626	531	372	480
Net Development Wells							
Dry Holes	220	280	342	347	288	188	258
Oil Wells	2,130	2,059	2,253	3,197	2,625	1,275	1,903
Gas Wells	1,985	2,252	2,202	2,429	2,208	1,672	3,084
Total Development Wells	4,335	4,591	4,797	5,973	5,121	3,136	5,244
Number of Net Wells Completed During Year for Total U.S. Industry							
Net Exploratory Wells							
Dry Holes	2,479	2,302	2,154	2,145	1,843	1,368	2,000
Oil Wells	836	866	484	434	306	156	192
Gas Wells	994	992	575	542	589	552	728
Total Exploratory Wells	4,309	4,160	3,213	3,121	2,739	2,076	2,927
Net Development Wells							
Dry Holes	2,862	2,778	3,184	3,659	3,138	2,244	3,149
Oil Wells	5,905	6,788	7,911	9,889	6,566	4,021	4,539
Gas Wells	8,517	7,284	8,729	10,592	11,494	10,350	14,522
Total Development Wells	17,284	16,849	19,824	24,140	21,198	16,615	22,211
Number of Net In-Progress Wells At Year End for FRS Companies							
Onshore							
Exploratory Wells	90	135	133	135	51	40	70
Development Wells	524	541	675	929	392	464	716
Total In-Progress Wells	614	676	808	1,064	444	504	786
Offshore							
Exploratory Wells	46	46	45	92	52	68	50
Development Wells	91	57	93	128	73	87	110
Total In-Progress Wells	137	103	138	220	124	155	160
Total United States							
Exploratory Wells	136	181	178	226	103	108	120
Development Wells	615	598	768	1,058	465	551	826
Total In-Progress Wells	751	779	946	1,284	568	659	946

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 2001, p. 83. 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, 1994-2000
(Thousand Feet)

	1994	1995	1996	1997	1998	1999	2000
FRS Companies							
Onshore							
Exploratory Well Footage							
Dry Hole Footage	1,699	1,799	2,052	1,700	1,714	921	955
Oil Well Footage	796	836	732	1,027	406	312	199
Gas Well Footage	1,464	1,456	1,860	1,521	1,548	1,150	1,399
Total Exploratory Footage	3,959	4,091	4,644	4,248	3,668	2,383	2,553
Development Well Footage							
Dry Hole Footage	1,177	1,550	2,224	1,926	1,939	1,252	1,597
Oil Well Footage	10,269	10,053	10,956	14,534	12,513	4,449	9,374
Gas Well Footage	12,955	14,468	14,304	16,751	16,521	12,291	20,516
Total Development Footage	24,401	26,071	27,484	33,211	30,973	17,992	31,487
Offshore							
Exploratory Well Footage							
Dry Hole Footage	911	891	1,091	1,362	1,345	848	1,151
Oil Well Footage	132	408	408	397	443	434	364
Gas Well Footage	568	702	1,824	981	1,285	1,002	1,141
Total Exploratory Footage	1,611	2,001	3,323	2,740	3,073	2,284	2,656
Development Well Footage							
Dry Hole Footage	124	155	244	459	344	199	411
Oil Well Footage	1,597	1,588	1,704	1,736	1,428	1,280	1,505
Gas Well Footage	1,025	1,011	1,538	1,584	1,398	1,295	1,899
Total Development Footage	2,746	2,754	3,486	3,779	3,170	2,774	3,815
Total United States							
Exploratory Well Footage							
Dry Hole Footage	2,610	2,690	3,143	3,062	3,059	1,769	2,107
Oil Well Footage	928	1,244	1,140	1,424	849	746	563
Gas Well Footage	2,032	2,158	3,684	2,502	2,833	2,152	2,540
Total Exploratory Footage	5,570	6,092	7,967	6,988	6,741	4,667	5,209
Development Well Footage							
Dry Hole Footage	1,301	1,705	2,468	2,385	2,283	1,451	2,008
Oil Well Footage	11,866	11,641	12,660	16,270	13,941	5,729	10,879
Gas Well Footage	13,980	15,479	15,842	18,335	17,919	13,586	22,415
Total Development Footage	27,147	28,825	30,970	36,990	34,143	20,766	35,303
Total United States Industry							
Exploratory Well Footage							
Dry Hole Footage	14,570	13,562	13,199	13,861	12,398	8,785	13,175
Oil Well Footage	5,277	5,502	3,504	3,432	2,505	1,058	1,399
Gas Well Footage	5,934	6,398	3,782	3,955	4,196	3,449	5,477
Total Exploratory Footage	25,781	25,462	20,485	21,248	19,098	13,293	20,050
Development Well Footage							
Dry Hole Footage	14,807	14,353	16,656	19,666	18,005	12,432	16,659
Oil Well Footage	30,824	32,776	36,988	47,773	32,125	17,711	20,817
Gas Well Footage	54,066	45,098	54,376	65,860	70,746	53,943	77,046
Total Development Footage	99,696	92,227	108,020	133,298	120,875	84,087	114,522
Number of Net Producing Wells for FRS Companies							
Onshore							
Oil Wells	105,679	94,867	87,461	75,493	69,401	58,987	68,274
Gas Wells	49,237	50,388	48,779	48,779	49,429	44,880	64,696
Total Producing Wells	154,916	145,256	136,240	124,272	118,830	103,867	132,970
Offshore							
Oil Wells	4,179	4,180	3,552	3,760	3,421	2,855	3,536
Gas Wells	2,895	3,042	2,556	2,898	2,737	2,707	3,111
Total Producing Wells	7,074	7,221	6,108	6,658	6,158	5,562	6,647
Total United States							
Oil Wells	109,858	99,047	91,013	79,253	72,822	61,842	71,810
Gas Wells	52,132	53,430	51,335	51,677	52,166	47,587	67,807
Total Producing Wells	161,990	152,477	142,348	130,930	124,987	109,429	139,617

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 2001, p. 83. 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, 1994-2000

	1994	1995	1996	1997	1998	1999	2000
Canada							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	111.2	107.5	86.2	22.8	54.8	36.4	126.3
Oil Wells	42.0	66.6	46.0	10.7	10.0	25.8	23.3
Gas Wells	105.1	74.0	96.1	49.2	66.3	127.5	194.2
Total Exploratory Wells	258.3	248.1	228.3	82.7	131.1	189.7	343.8
Development Wells							
Dry Holes	59.6	42.7	48.1	59.6	58.8	58.3	138.2
Oil Wells	174.2	569.5	559.4	778.6	198.9	352.1	373.3
Gas Wells	416.6	189.6	233.7	275.1	422.4	758.7	891.5
Total Development Wells	650.4	801.8	841.2	1,113.3	680.1	1,169.1	1,403.0
Net In-Progress Wells at Year End	57.6	43.1	17.2	30.6	24.3	76.3	116.8
Net Producing Wells							
Oil Wells	11,268.5	9,793.9	8,719.5	9,364.7	10,532.3	10,155.9	12,094.8
Gas Wells	5,953.3	5,998.6	5,784.8	6,199.5	8,872.7	10,038.7	15,242.7
Total Producing Wells	17,221.8	15,792.5	14,504.3	15,564.2	19,405.0	20,194.6	27,337.5
Europe and Former Soviet Union [1]							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	33.7	42.1	49.4	56.6	36.3	15.4	15.7
Oil Wells	13.3	21.4	14.5	19.2	11.8	9.2	5.2
Gas Wells	11.2	10.6	11.4	8.9	12.0	4.0	6.4
Total Exploratory Wells	58.2	74.1	75.3	84.7	60.1	28.6	27.3
Development Wells							
Dry Holes	1.5	2.2	5.3	3.2	7.8	2.6	10.3
Oil Wells	60.4	72.4	77.6	80.7	118.5	75.4	67.7
Gas Wells	24.5	29.0	31.0	25.1	60.5	30.4	30.4
Total Development Wells	86.4	103.6	113.9	109.0	186.8	108.4	108.3
Net In-Progress Wells at Year End	74.5	73.0	68.7	62.7	54.5	31.6	63.7
Net Producing Wells							
Oil Wells	1,430.2	1,359.4	1,445.5	1,328.0	1,294.4	1,218.8	1,431.3
Gas Wells	720.7	741.9	765.2	766.8	805.3	626.6	737.7
Total Producing Wells	2,150.9	2,101.3	2,210.7	2,094.8	2,099.7	1,845.4	2,169.0
Africa and Middle East							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	32.0	28.4	19.8	25.3	33.1	14.9	37.2
Oil Wells	W	W	W	W	W	9.9	W
Gas Wells	W	W	W	W	W	10.0	W
Total Exploratory Wells	47.9	42.8	44.0	46.1	65.0	34.8	50.7
Development Wells							
Dry Holes	W	W	W	W	W	5.8	W
Oil Wells	105.7	109.7	133.0	151.6	218.4	206.3	239.3
Gas Wells	W	W	W	1.2	3.1	8.6	W
Total Development Wells	117.7	119.2	144.0	157.8	225.6	220.7	252.0
Net In-Progress Wells at Year End	45.1	41.9	36.9	29.0	18.0	36.8	35.2
Net Producing Wells							
Oil Wells	1,442.2	1,509.0	1,688.9	1,644.6	1,924.2	1,969.8	1,954.1
Gas Wells	34.4	41.9	49.9	59.5	62.7	83.2	79.0
Total Producing Wells	1,476.6	1,550.9	1,738.8	1,704.1	1,986.9	2,053.0	2,033.1

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, 1994-2000 (Continued)

	1994	1995	1996	1997	1998	1999	2000
Other Eastern Hemisphere							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	47.4	47.4	42.6	39.8	47.1	35.4	40.7
Oil Wells	11.6	13.1	21.6	16.1	36.6	41.6	31.3
Gas Wells	14.5	44.4	46.3	15.8	13.8	16.0	20.7
Total Exploratory Wells	73.5	104.9	110.5	71.7	97.5	93.0	92.7
Development Wells							
Dry Holes	5.2	1.5	3.7	4.7	11.5	1.9	4.4
Oil Wells	115.7	92.7	103.1	162.6	149.5	82.4	140.6
Gas Wells	45.9	32.4	91.7	116.5	101.2	104.5	113.5
Total Development Wells	166.8	126.6	198.5	283.8	262.2	188.8	258.5
Net In-Progress Wells at Year End	71.9	92.5	72.4	61.4	64.5	56.2	80.5
Net Producing Wells							
Oil Wells	1,714.9	1,476.2	1,622.0	1,767.0	1,707.2	1,654.2	1,950.2
Gas Wells	437.9	401.4	561.2	633.8	862.2	882.2	927.4
Total Producing Wells	2,152.8	1,877.6	2,183.2	2,400.8	2,569.4	2,536.4	2,877.6
Other Western Hemisphere							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	7.5	9.2	12.4	5.7	14.6	7.9	14.5
Oil Wells	8.0	4.7	9.0	4.7	10.4	3.2	W
Gas Wells	0.0	0.0	2.0	0.0	4.5	3.8	W
Total Exploratory Wells	15.5	13.9	23.4	10.4	29.5	14.9	23.4
Development Wells							
Dry Holes	W	W	W	W	W	W	W
Oil Wells	85.6	120.5	123.3	141.4	212.8	81.4	205.8
Gas Wells	W	W	W	W	W	W	W
Total Development Wells	94.3	133.1	129.8	148.3	224.5	91.7	245.0
Net In-Progress Wells at Year End	14.8	20.2	16.1	24.4	28.9	27.2	31.3
Net Producing Wells							
Oil Wells	2,939.6	2,980.6	2,478.9	605.0	2,045.6	2,426.5	2,597.2
Gas Wells	48.7	57.6	77.3	72.2	190.9	161.4	253.1
Total Producing Wells	2,988.3	3,038.2	2,556.2	677.2	2,236.5	2,587.9	2,850.3
Total Foreign							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	231.8	234.6	210.4	150.2	185.9	110.0	234.4
Oil Wells	88.5	119.7	110.9	71.0	97.6	89.7	74.1
Gas Wells	133.1	129.5	160.2	74.4	99.7	161.3	229.4
Total Exploratory Wells	453.4	483.8	481.5	295.6	383.2	361.0	537.9
Development Wells							
Dry Holes	77.2	51.9	67.9	75.5	83.7	70.1	156.7
Oil Wells	541.6	964.8	996.4	1,314.9	898.1	797.6	1,026.7
Gas Wells	496.8	267.6	363.1	421.8	597.4	911.0	1,083.5
Total Development Wells	1,115.6	1,284.3	1,427.4	1,812.2	1,579.2	1,778.7	2,266.8
Net In-Progress Wells at Year End	263.9	270.7	211.3	208.1	190.2	228.1	327.5
Net Producing Wells							
Oil Wells	18,795.4	17,119.1	15,954.8	14,709.3	17,503.7	17,425.2	20,027.6
Gas Wells	7,195.0	7,241.4	7,238.4	7,731.8	10,793.8	11,792.1	17,239.9
Total Producing Wells	25,990.4	24,360.5	23,193.2	22,441.1	28,297.5	29,217.3	37,267.5

[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		
	1999	2000	Percent Change	1999	2000	Percent Change	1999	2000	Percent Change
Exploration									
Oil Wells									
Wells Completed	54.1	46.5	-14.0	26.1	18.9	-27.6	28.0	27.6	-1.4
Average Depth (thousand feet)	13.8	12.1	-12.2	12.0	10.5	-11.9	15.5	13.2	-14.9
Gas Wells									
Wells Completed	165.7	275.1	66.0	105.2	216.5	105.8	60.5	58.6	-3.1
Average Depth (thousand feet)	13.0	9.2	-28.9	10.9	6.5	-40.9	16.6	19.5	17.5
Dry Holes									
Wells Completed	152.5	158.4	3.9	93.3	85.8	-8.0	59.2	72.6	22.6
Average Depth (thousand feet)	11.6	13.3	14.6	9.9	11.1	12.8	14.3	15.9	10.7
Development									
Oil Wells									
Wells Completed	1,275.4	1,902.8	49.2	1,130.1	1,774.5	57.0	145.3	128.3	-11.7
Average Depth (thousand feet)	4.5	5.7	27.3	3.9	5.3	34.2	8.8	11.7	33.2
Gas Wells									
Wells Completed	1,672.0	3,083.8	84.4	1,519.4	2,926.5	92.6	152.6	157.3	3.1
Average Depth (thousand feet)	8.1	7.3	-10.5	8.1	7.0	-13.3	8.5	12.1	42.3
Dry Holes									
Wells Completed	188.4	257.7	36.8	162.1	228.2	40.8	26.3	29.5	12.2
Average Depth (thousand feet)	7.7	7.8	1.2	7.7	7.0	-9.4	7.6	13.9	83.9

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

Table B23. Oil and Gas Reserves for FRS Companies and U.S. Industry, 2000

	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	25,032.0	2,281.0	-31.0	2,105.0	25,177.0	108.4
FRS Companies	11,859.5	1,369.6	-431.2	827.0	11,970.9	165.6
All Other	13,172.5	911.4	400.2	1,278.0	13,206.1	71.3
U.S. Offshore						
Total U.S. Industry	4,639.0	1,364.0	-94.0	696.0	5,213.0	196.0
FRS Companies	3,224.0	599.5	158.8	441.2	3,541.1	135.9
All Other	1,415.0	764.5	-252.8	254.8	1,671.9	300.0
U.S. Total						
Total U.S. Industry	29,671.0	3,395.0	-125.0	2,801.0	30,390.0	121.2
FRS Companies	15,083.5	1,969.1	-272.5	1,268.1	15,512.0	155.3
All Other	14,587.5	1,425.9	147.5	1,532.9	14,878.0	93.0
FRS Companies' Foreign Oil Reserves						
Canada	2,012.1	100.2	100.4	167.1	2,045.6	60.0
Europe	4,364.0	474.1	275.0	601.8	4,511.3	78.8
FSU and Eastern Europe	676.1	68.7	18.8	32.7	730.9	210.2
Africa	4,335.5	868.5	164.4	350.3	5,018.0	247.9
Middle East	848.6	95.9	-6.7	120.2	817.5	79.7
Other Eastern Hemisphere	1,889.1	238.4	64.5	223.6	1,968.4	106.6
Other Western Hemisphere	1,753.5	48.1	-87.1	100.6	1,614.0	47.9
Total Foreign	15,879.0	1,894.0	529.2	1,596.3	16,705.9	118.7
Worldwide Total for FRS Companies	30,962.5	3,863.1	256.7	2,864.4	32,217.9	134.9
Dry Natural Gas	(billion cubic feet)					
U.S. Onshore						
Total U.S. Industry	140,297.0	19,727.0	3,675.0	14,205.0	149,494.0	138.9
FRS Companies	55,554.4	7,725.8	3,260.8	5,364.1	61,176.9	144.0
All Other	84,742.6	12,001.2	414.2	8,840.9	88,317.1	135.7
U.S. Offshore						
Total U.S. Industry	27,109.0	5,482.0	356.0	5,014.0	27,933.0	109.3
FRS Companies	18,947.4	2,683.1	834.7	2,989.9	19,475.2	89.7
All Other	8,161.6	2,798.9	-478.7	2,024.1	8,457.8	138.3
U.S. Total						
Total U.S. Industry	167,406.0	25,209.0	4,031.0	19,219.0	177,427.0	131.2
FRS Companies	74,501.7	10,408.9	4,095.5	8,354.0	80,652.1	124.6
All Other	92,904.3	14,800.1	-64.5	10,865.0	96,774.9	136.2
FRS Companies' Foreign Gas Reserves						
Canada	10,980.7	656.5	957.2	1,220.6	11,373.7	53.8
Europe	22,518.5	1,292.4	415.6	2,385.3	21,841.3	54.2
FSU and Eastern Europe	1,043.1	108.5	0.0	30.3	1,121.3	358.4
Africa	2,710.2	1,188.1	11.8	115.5	3,794.5	1,028.3
Middle East	593.7	22.9	0.0	97.9	518.7	23.4
Other Eastern Hemisphere	24,729.7	247.1	83.2	1,568.1	23,491.9	15.8
Other Western Hemisphere	13,971.5	1,470.9	115.7	548.3	15,010.0	83.6
Total Foreign	76,547.5	4,986.4	1,583.5	5,965.9	77,151.5	83.6
Worldwide Total for FRS Companies	151,049.2	15,395.3	5,679.0	14,319.9	157,803.6	107.5

[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.

- = Not available.

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*, 1999 and 2000 (November 2000 and December 2001). FRS companies' data - Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B24. Oil and Gas Reserve Balances by Region for FRS Companies, 2000

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	30,963	15,084	11,860	3,224	15,879
Revisions of Previous Estimates	1,332	940	798	142	392
Improved Recovery	544	317	303	14	227
Purchases of Minerals-in-Place	5,197	3,562	3,091	471	1,635
Extensions & Discoveries	1,986	712	268	444	1,275
Production	-2,864	-1,268	-827	-441	-1,596
Sales of Minerals-in-Place	-4,940	-3,834	-3,522	-312	-1,105
End of period	32,218	15,512	11,971	3,541	16,706
Proportionate Interest in Investee Reserves and Foreign Access Reserves	--	--	--	--	6,590
Natural Gas Reserves	(billion cubic feet)				
Beginning of Period	151,049	74,502	55,554	18,947	76,547
Revisions of Previous Estimates	2,116	1,537	1,819	-281	579
Improved Recovery	1,380	1,084	996	88	295
Purchases of Minerals-in-Place	18,848	12,023	9,856	2,168	6,825
Extensions & Discoveries	11,899	7,787	4,911	2,876	4,112
Production	-14,320	-8,354	-5,364	-2,990	-5,966
Sales of Minerals-in-Place	-13,169	-7,928	-6,595	-1,333	-5,242
End of Period	157,804	80,652	61,177	19,475	77,151
Proportionate Interest in Investee Reserves and Foreign Access Reserves	--	--	--	--	23,859

See footnotes at end of table.

Table B24. Oil and Gas Reserve Balances by Region for FRS Companies,2000 (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	15,879	2,012	5,040	5,184	1,889	1,754
Revisions of Previous Estimates	392	-18	229	123	62	-4
Improved Recovery	227	40	97	W	W	25
Purchases of Minerals-in-Place	1,635	127	593	W	W	424
Extensions & Discoveries	1,275	78	217	778	174	27
Production	-1,596	-167	-634	-471	-224	-101
Sales of Minerals-in-Place	-1,105	-26	-300	W	W	-511
End of period	16,706	2,046	5,242	5,836	1,968	1,614
Proportionate Interest in Investee Reserves and Foreign Access Reserves	6,590	W	2,196	W	1,087	1,964
Natural Gas Reserves			(billion cubic feet)			
Beginning of Period	76,547	10,981	23,562	3,304	24,730	13,972
Revisions of Previous Estimates	579	-786	992	729	-770	413
Improved Recovery	295	119	127	0	W	W
Purchases of Minerals-in-Place	6,825	1,311	1,729	W	W	W
Extensions & Discoveries	4,112	1,324	282	482	992	1,033
Production	-5,966	-1,221	-2,416	-213	-1,568	-548
Sales of Minerals-in-Place	-5,242	-354	-1,313	W	W	W
End of Period	77,151	11,374	22,963	4,313	23,492	15,010
Proportionate Interest in Investee Reserves and Foreign Access Reserves	23,859	W	18,549	W	560	2,202

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

-- = 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, 2000 and Percent Change from 1999

	United States			Foreign Total
	Total	Onshore	Offshore	
Exploration and Development Expenditures (million dollars)				
FRS Companies	48,044.0	27,089.0	20,955.0	28,798.0
Percent Change	256.2	312.3	202.9	64.4
Wells Completed				
FRS Companies	5,724.3	5,250.4	473.9	2,804.7
Percent Change	63.2	72.9	0.4	31.1
Industry[1]	25,138.0	24,456.0	682.0	24,069.0
Percent Change	34.5	34.8	23.3	42.4
Success Rate[2]				
FRS Companies	92.7	94.0	78.5	86.1
Industry[1]	79.5	80.4	47.7	88.0
Crude Oil and NGL Production[3] (million barrels)				
FRS Companies	1,268.1	827.0	441.2	1,630.7
Percent Change	-2.9	-7.3	6.7	1.6
Industry [1]	2,801.0	2,105.0	696.0	23,248.3
Percent Change	-1.7	-3.4	3.9	4.5
Crude Oil and NGL Reserve Interests[4] (million barrels)				
FRS Companies	15,512.0	11,970.9	3,541.1	23,295.8
Percent Change	5.9	4.0	13.1	20.3
Natural Gas Production (billion cubic feet)				
FRS Companies	8,354.0	5,364.1	2,989.9	6,267.9
Percent Change	4.5	4.0	5.4	1.6
Industry[1]	19,219.0	14,205.0	5,014.0	66,429.0
Percent Change	1.5	2.8	-2.0	5.4
Natural Gas Reserve Interests (billion cubic feet)				
FRS Companies	80,652.1	61,176.9	19,475.2	101,010.5
Percent Change	13.7	15.8	7.6	6.4

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, 2000 and Percent Change from 1999 (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	28,798.0	4,881.0	8,413.0	2,719.0	550.0	6,787.0	5,448.0
Percent Change	64.4	137.4	77.4	-12.1	39.9	97.2	43.7
Wells Completed							
FRS Companies	2,804.7	1,746.8	135.7	141.0	161.7	351.2	268.4
Percent Change	31.1	28.6	-1.0	61.3	-3.8	24.6	151.8
Foreign Industry[1]	24,069.0	16,927.0	936.0	644.0	768.0	1,831.0	2,963.0
Percent Change	42.4	52.5	-3.3	13.4	16.7	0.2	66.3
Success Rate[2] (percent)							
FRS Companies	86.1	84.9	80.8	76.4	96.5	87.2	93.8
Foreign Industry[1]	88.0	87.3	82.8	82.1	97.0	88.3	91.9
Crude Oil and NGL Production[3] (million barrels)							
FRS Companies	1,630.7	167.1	634.4	350.3	154.7	223.6	100.6
Percent Change	1.6	-3.1	5.4	2.6	-0.6	-1.9	-5.3
Foreign Industry[1]	23,248.3	991.9	5,486.3	2,862.1	8,414.3	1,729.4	3,764.3
Percent Change	4.5	4.7	3.4	5.3	5.3	6.7	2.8
Crude Oil and NGL Reserve Interests[4] (million barrels)							
FRS Companies	23,295.8	2,045.6	7,438.2	5,018.0	2,159.8	3,055.7	3,578.5
Percent Change	20.3	1.9	28.8	17.9	-6.8	31.3	33.3
Natural Gas Production (billion cubic feet)							
FRS Companies	6,267.9	1,220.6	2,415.5	115.5	97.9	1,568.1	850.3
Percent Change	1.6	11.4	2.6	162.0	-3.7	-3.6	-10.2
Foreign Industry[1]	66,429.0	5,929.2	35,611.8	4,538.4	7,320.0	8,381.4	4,648.2
Percent Change	5.4	3.5	5.5	13.0	10.8	2.5	-1.3
Natural Gas Reserve Interests (billion cubic feet)							
FRS Companies	101,010.5	11,373.7	41,511.9	3,794.5	3,066.8	24,051.8	17,211.7
Percent Change	6.4	12.1	3.9	58.0	-14.9	-0.5	17.6

[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 (71.7 percent of total foreign) and "Other Access" reserves (28.3 percent of total foreign). "Other Access" reserves include proportional interest in investee reserves and foreign access reserves.

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

- = Not available.

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*, 1999, and 2000 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 2001, p. 83. Reserve Additions, Foreign - *British Petroleum Statistical Review of World Energy 2000 and 2001.* Wells Completed, Foreign - *World Oil*, August 2000 and 2001. FRS

Table B26. U.S. and Foreign Refining/Marketing Sources and Dispositions of Crude Oil and Natural Gas Liquids for FRS Companies,1994-2000
(million barrels)

	1994	1995	1996	1997	1998	1999	2000
U.S. Refining/Marketing							
Sources							
Acquisitions from U.S. Production Segment	2,014	1,658	1,599	1,542	1,484	1,516	1,238
Purchases from Other U.S. Segments and Unconsolidated Affiliates	385	432	459	468	1,935	2,181	2,184
Purchases from Third Parties	3,937	4,100	4,488	4,444	4,968	5,205	5,340
Net Transfers from Foreign Refining/Marketing Segment	754	612	566	571	635	475	324
Total Sources	7,090	6,802	7,112	7,025	9,021	9,377	9,086
Dispositions							
Net Change in Inventories	48	23	21	14	31	-1	-4
Input to Refineries	3,636	3,565	3,563	3,259	4,883	4,872	4,690
Sales to:							
Unaffiliated Third Parties	3,235	2,961	3,291	3,424	3,730	4,147	4,316
Other Segments Excluding Foreign Refining/Marketing	172	252	237	328	377	359	84
Total Dispositions	7,090	6,802	7,112	7,025	9,021	9,377	9,086
Foreign Refining/Marketing							
Sources							
Acquisitions from Foreign Production	1,335	1,249	1,371	1,391	1,380	1,462	1,585
Purchases							
Other Foreign Segments	95	93	88	W	W	W	W
Unconsolidated Affiliates	63	89	89	W	W	W	W
Unaffiliated Third Parties							
Foreign Access	120	107	145	228	209	W	W
Foreign Governments (Open Market)	726	621	844	851	679	W	W
Other Unaffiliated Third Parties	2,147	2,063	1,819	1,785	2,000	2,244	2,165
Net Transfers to U.S. Refining/Marketing	-754	-612	-566	-571	-635	-475	-324
Total Sources	3,731	3,610	3,790	3,699	4,021	4,307	4,067
Dispositions							
Net Change in Inventories	0	1	38	18	155	-19	10
Input to Refineries	1,535	1,520	1,605	1,435	1,419	1,641	1,673
Sales	2,195	2,090	2,147	2,246	2,446	2,685	2,384
Total Dispositions	3,731	3,610	3,790	3,699	4,021	4,307	4,067

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, 1994-2000

	1994	1995	1996	1997	1998	1999	2000
Purchases	Values (million dollars)						
U.S. Refining/Marketing Segment							
Raw Materials							
Crude Oil and NGL	104,471	111,556	138,397	126,535	106,128	152,880	253,751
Natural Gas	12,360	9,747	15,651	18,657	15,177	20,387	58,401
Other Raw Materials	3,498	3,892	2,697	3,159	5,348	5,705	8,395
Total Raw Materials	120,329	125,195	156,745	148,351	126,653	178,972	320,547
Refined Products							
Motor Gasoline	12,430	14,131	18,078	18,613	24,249	36,095	65,488
Distillate Fuels	6,626	6,773	9,634	9,565	10,574	17,433	35,116
Other Refined Products	8,389	10,114	10,246	9,141	8,786	9,963	17,036
Total Refined Products	27,445	31,018	37,958	37,319	43,609	63,491	117,640
U.S. Production Segment							
Crude Oil and NGL	2,660	3,353	5,163	5,399	4,694	5,695	4,794
Natural Gas	5,950	6,981	10,715	11,220	8,922	8,608	12,029
Total Raw Materials	8,610	10,334	15,878	16,619	13,616	14,303	16,823
Sales							
U.S. Refining/Marketing Segment							
Raw Materials							
Crude Oil and NGL	49,752	53,544	69,485	70,437	50,702	72,955	121,777
Natural Gas	12,432	9,295	15,790	18,252	15,270	20,023	56,204
Other Raw Materials	2,201	2,325	1,276	1,499	2,172	1,576	2,403
Total Raw Materials	64,385	65,164	86,551	90,188	68,144	94,554	180,384
Refined Products							
Motor Gasoline	61,032	65,701	75,330	71,185	84,968	109,301	176,394
Distillate Fuels	30,568	30,420	41,618	36,962	39,513	51,810	91,998
Other Refined Products	23,190	24,577	24,577	20,964	23,283	28,506	42,269
Total Refined Products	114,790	120,698	141,525	129,111	147,764	189,617	310,661
U.S. Production Segment							
Crude Oil and NGL	23,468	26,303	32,948	30,604	19,688	25,186	38,405
Natural Gas	19,757	18,696	26,840	29,459	23,649	23,178	40,845
Total Raw Materials	43,225	44,999	59,788	60,063	43,337	48,364	79,250
Purchases	Volumes						
U.S. Refining/Marketing Segment							
Raw Materials							
Crude Oil and NGL (million barrels)	7,090	6,802	7,112	7,025	9,021	9,377	9,086
Natural Gas (billion cubic feet)	7,479	6,543	7,506	7,573	7,425	9,285	13,262
Refined Products (million barrels)							
Motor Gasoline	563	588	677	689	1,272	1,533	1,708
Distillate Fuels	322	321	380	397	625	837	943
Other Refined Products	345	422	363	329	464	446	535
Total Refined Products	1,230	1,330	1,420	1,415	2,361	2,815	3,185
U.S. Production Segment							
Crude Oil and NGL (million barrels)	201	237	300	308	394	367	200
Natural Gas (billion cubic feet)	3,276	4,395	4,723	4,551	4,295	3,835	3,223
Sales							
U.S. Refining/Marketing Segment							
Raw Materials							
Crude Oil and NGL (million barrels)	3,406	3,213	3,528	3,752	4,107	4,506	4,400
Natural Gas (billion cubic feet)	6,960	6,089	7,195	7,242	6,764	8,834	13,230
Refined Products (million barrels)							
Motor Gasoline	2,347	2,422	2,488	2,371	3,789	4,070	4,286
Distillate Fuels	1,392	1,374	1,562	1,473	2,146	2,344	2,444
Other Refined Products	1,172	1,183	1,069	1,008	1,342	1,407	1,390
Total Refined Products	4,911	4,979	5,119	4,852	7,277	7,820	8,119
U.S. Production Segment							
Crude Oil and NGL (million barrels)	1,889	1,875	1,933	1,860	1,805	1,667	1,484
Natural Gas (billion cubic feet)	10,810	12,108	12,281	12,421	11,765	10,952	11,367

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

Table B28. U.S. and Foreign Petroleum Refining Statistics for FRS Companies, 1994-2000

	1994	1995	1996	1997	1998	1999	2000
U.S. Refining	(thousand barrels per calendar day)						
Runs to Stills							
At Own Refineries	9,809	9,669	9,777	9,060	13,699	13,476	13,361
By Refineries of Others	5	5	5	5	0	82	86
Total Runs to Stills	9,814	9,674	9,782	9,065	13,699	13,558	13,447
Refinery Output at Own Refineries and Refineries of Others							
Reformulated Motor Gasoline	0	0	1,302	768	1,552	1,792	2,129
Oxygenated Motor Gasoline	0	0	165	749	1,018	609	412
Other Motor Gasoline	0	0	3,410	2,980	4,665	4,588	4,207
Total Motor Gasoline	4,936	4,849	4,877	4,497	7,235	6,989	6,748
Distillate Fuels	3,030	2,901	3,323	2,921	4,278	4,167	4,376
Other Refined Products	2,846	2,902	2,754	2,612	3,416	3,483	3,375
Total Refinery Output	10,812	10,652	10,954	10,030	14,929	14,639	14,499
Refinery Capacity at End of Year	10,642	10,427	10,477	9,410	14,277	14,158	14,393
	(number of refineries)						
Number of Wholly-Owned Refineries	74	69	69	60	95	94	90
	(thousand barrels per calendar day)						
Foreign Refining							
Runs to Stills							
At Own Refineries	3,829	3,962	3,936	3,961	4,043	4,407	4,513
By Refineries of Others	304	323	506	340	292	397	403
Total Runs to Stills	4,133	4,285	4,442	4,301	4,335	4,804	4,916
Refinery Output at Own Refineries							
Motor Gasoline	1,122	1,175	1,172	1,041	1,135	1,247	1,331
Distillate Fuels	1,674	1,662	1,690	1,648	1,787	1,901	1,738
Other Refined Products	1,102	1,183	1,280	1,283	1,213	1,315	1,681
Total Refinery Output at Own Refineries	3,898	4,020	4,142	3,972	4,135	4,463	4,750
Refinery Output at Refineries of Others							
Motor Gasoline	85	70	107	75	83	122	123
Distillate Fuels	140	140	234	154	121	135	171
Other Refined Products	82	113	165	110	87	146	80
Total Refinery Output at Refineries of	307	323	506	339	291	403	374
Total Refinery Output	4,205	4,343	4,648	4,311	4,426	4,866	5,124
Refinery Capacity at End of Year	4,766	4,450	4,346	4,270	4,508	4,930	5,134
	(number of refineries)						
Number of Wholly-Owned Refineries	26	24	20	20	20	19	18
Number of Partially-Owned Refineries	14	13	12	15	15	18	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, 2000
(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]	14,499	5,070	1,436	7,993	17,763	81.6
Percent Gasoline						
d	17.5	16.3	5.4	20.5	15.5	92.2
Other	29.0	28.4	35.9	28.2	30.4	77.8
Percent Distillate	30.2	29.2	32.7	30.4	30.5	80.9
Percent Other	23.3	26.2	26.0	20.9	23.6	80.6
Refinery Capacity						
Years Change (Net)	235	1,005	-1,762	992	390	(5)
At Year End	14,393	4,449	1,703	8,241	17,177	83.8
Utilization Rate[4]	93.6	110.1	60.7	96.1	91.8	(5)
Foreign						
Refinery Output Volume[3]	5,124	4,353	0	771	-	-
Percent Gasoline	28.4	27.6	0.0	32.6	-	(5)
Percent Distillate	37.3	36.1	0.0	43.7	-	(5)
Percent Other	34.4	36.3	0.0	23.7	-	(5)
Refinery Capacity						
Years Change (Net)	204	89	0	115	230	(5)
At Year End	5,134	4,329	0	805	59,955	8.6
Utilization Rate[3]	89.7	88.7	0.0	95.3	-	(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,* 1999 and 2000. Industry data, Foreign - Refinery Capacity: *British Petroleum Statistical Review of World Energy*, 2000 and 2001. 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, 1994-2000

U.S. Dispositions	1994	1995	1996	1997	1998	1999	2000
	Values (million dollars)						
Motor Gasoline							
Intersegment Sales	268	365	400	581	966	1,521	1,802
U.S. Third-Party Sales							
Wholesale-Resellers	24,923	27,386	32,500	31,895	38,659	51,908	83,203
Company Operated Automotive Outlets	9,694	10,088	11,293	11,855	15,497	17,334	24,870
Company Lessee and Open Automotive	20,948	20,494	21,725	20,517	23,966	29,434	48,693
Other (Industrial, Commercial and Other	5,199	7,368	9,412	6,337	5,880	9,104	17,826
Total Third-Party Sales	60,764	65,336	74,930	70,604	84,002	107,780	174,592
Total Motor Gasoline Sales	61,032	65,701	75,330	71,185	84,968	109,301	176,394
Distillate Fuels							
Intersegment Sales	211	219	291	191	682	708	444
Third-Party Sales	30,357	30,201	41,327	36,771	38,831	51,102	91,554
Total Distillate Fuels Sales	30,568	30,420	41,618	36,962	39,513	51,810	91,998
Other Refined Products							
Intersegment Sales	3,824	3,952	4,124	3,322	2,059	2,779	6,078
Third-Party Sales	19,366	20,625	20,453	17,642	21,224	25,727	36,191
Total Other Refined Products Sales	23,190	24,577	24,577	20,964	23,283	28,506	42,269
Total U.S. Refined Products							
Intersegment Sales	4,303	4,536	4,815	4,094	3,707	5,008	8,324
Third-Party Sales	110,487	116,162	136,710	125,017	144,057	184,609	302,337
Total U.S. Refined Products Sales	114,790	120,698	141,525	129,111	147,764	189,617	310,661
	Volumes (million barrels)						
Motor Gasoline							
Intersegment Sales	9	11	12	18	50	66	47
U.S. Third-Party Sales							
Wholesale-Resellers	1,064	1,117	1,154	1,150	1,901	2,059	2,126
Company Operated Automotive Outlets	308	309	319	335	558	540	543
Company Lessee and Open Automotive	736	680	653	615	965	1,006	1,105
Other (Industrial, Commercial and Other	229	304	350	253	316	399	465
Total Third-Party Sales	2,338	2,411	2,476	2,353	3,739	4,004	4,239
Total Motor Gasoline Sales	2,347	2,422	2,488	2,371	3,789	4,070	4,286
Distillate Fuels							
Intersegment Sales	11	11	12	8	38	33	13
Third-Party Sales	1,381	1,363	1,550	1,464	2,109	2,310	2,430
Total Distillate Fuels Sales	1,392	1,374	1,562	1,473	2,146	2,344	2,444
Other Refined Products							
Intersegment Sales	226	222	209	254	141	153	213
Third-Party Sales	946	961	860	755	1,201	1,254	1,176
Total Other Refined Products Sales	1,172	1,183	1,069	1,008	1,342	1,407	1,390
Total U.S. Refined Products							
Intersegment Sales	246	245	232	280	229	252	274
Third-Party Sales	4,665	4,734	4,886	4,572	7,048	7,568	7,845
Total U.S. Refined Products Sales	4,911	4,979	5,119	4,852	7,277	7,820	8,119
Number of Active Automobile Outlets at Year End	Number of Automotive Outlets						
Company Operated	8,755	8,549	8,927	8,942	13,645	12,018	12,583
Lessee Dealers	16,385	15,861	15,247	12,852	16,396	17,847	16,953
Open Dealers	15,320	13,950	14,151	11,959	28,859	26,805	25,707
Total Outlets	40,460	38,360	38,325	33,753	58,900	56,670	55,243

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, 1999-2000
(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								
2000	47.4	38.01	47.3	38.01	W	W	W	W
1999	65.6	23.17	35.2	24.26	W	W	W	W
Percent Change	-27.8	64.0	34.1	56.7	W	W	W	W
Wholesale/Resellers								
2000	2,125.9	39.14	661.7	39.69	201.6	41.91	1,262.6	38.41
1999	2,059.0	25.21	467.5	25.65	397.5	25.52	1,194.0	24.94
Percent Change	3.2	55.2	41.5	54.7	-49.3	64.2	5.7	54.0
Dealer-Operated Outlets								
2000	1,104.6	44.08	565.3	45.51	0.0	0.00	539.3	42.58
1999	1,006.2	29.25	351.4	30.33	153.3	27.85	501.5	28.92
Percent Change	9.8	50.7	60.9	50.1	-100.0	0.0	7.5	47.2
Company-Operated Outlets								
2000	543.3	45.77	165.4	48.35	39.8	43.64	338.2	44.76
1999	540.4	32.08	131.0	33.44	151.3	30.64	258.1	32.23
Percent Change	0.5	42.7	26.2	44.6	-73.7	42.4	31.0	38.9
Other [1]								
2000	464.9	38.34	112.8	40.40	98.6	39.09	253.5	37.14
1999	398.6	22.84	18.6	19.81	145.8	23.29	234.2	22.80
Percent Change	16.6	67.9	505.3	104.0	-32.4	67.8	8.3	62.9
Total Gasoline								
2000	4,286.2	41.15	1,552.4	42.73	340.2	41.29	2,393.6	40.11
1999	4,069.9	26.86	1,003.7	28.15	878.4	26.31	2,187.8	26.48
Percent Change	5.3	53.2	54.7	51.8	-61.3	56.9	9.4	51.5
Distillate								
2000	2,443.7	37.65	847.6	38.06	230.6	37.30	1,365.5	37.45
1999	2,343.7	22.11	613.9	21.97	500.4	22.42	1,229.5	22.04
Percent Change	4.3	70.3	38.1	73.3	-53.9	66.3	11.1	69.9
All Other Products								
2000	1,389.6	30.42	478.1	31.29	134.9	27.75	776.6	30.34
1999	1,406.6	20.27	371.2	23.24	244.2	18.52	791.2	19.41
Percent Change	-1.2	50.1	28.8	34.7	-44.8	49.9	-1.8	56.3
Total Refined Products								
2000	8,119.5	38.26	2,878.1	39.46	705.7	37.40	4,535.7	37.64
1999	7,820.2	24.25	1,988.8	25.32	1,623.0	23.94	4,208.4	23.86
Percent Change	3.8	57.8	44.7	55.8	-56.5	56.2	7.8	57.8

[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, 1994-2000
(Million Dollars)

Revenues and Costs	1994	1995	1996	1997	1998	1999	2000
Refined Product Revenues	114,790	120,698	141,525	129,111	147,764	189,617	310,661
Refined Product Costs							
Raw Materials Processed [1]	58,025	62,142	70,339	58,888	60,094	83,348	135,624
Refinery Energy Expense	4,702	4,101	5,480	5,005	5,349	6,427	10,838
Other Refinery Expense	8,854	8,854	9,882	8,436	12,219	11,734	10,635
Product Purchases	27,445	31,018	37,958	37,319	43,609	63,491	117,640
Other Product Supply Expense	3,432	3,432	4,072	3,777	5,160	4,915	6,655
Marketing Expense [2]	8,822	8,709	9,318	8,538	10,308	11,100	11,128
Total Refined Product Costs	111,280	118,256	137,049	121,963	136,739	181,015	292,520
Refined Product Margin	3,510	2,442	4,476	7,148	11,025	8,602	18,141
Refined Products Sold (million barrels)	4,911.0	4,978.8	5,118.6	4,852.2	7,276.9	7,820.2	8,119.5
Dollars per Barrel Margin [3]	0.71	0.49	0.87	1.47	1.52	1.10	2.23
Other Refining/Marketing Revenues [4]	10,586	10,449	10,731	9,693	15,997	14,282	14,196
Other Refining/Marketing Expenses							
DD&A	3,780	4,732	3,847	3,674	4,700	5,273	4,712
Other [5]	7,454	7,166	7,873	8,419	15,547	12,546	16,865
Total Other Expenses	11,234	11,898	11,720	12,093	20,247	17,819	21,577
Refining/Marketing Operating Income	2,862	993	3,487	4,748	6,775	5,065	10,760
Miscellaneous Revenue & Expense [6]	289	-107	-101	204	1,315	1,367	1,265
Less Income Taxes	1,306	371	1,135	1,876	2,142	1,714	4,360
Refining/Marketing Net Income	1,845	508	2,251	3,106	5,932	4,883	7,659

[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 nonfuel 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.

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

Table B33. U.S. Petroleum Refining/Marketing General Operating Expenses for FRS Companies, 1994-2000
(Million Dollars)

General Operating Expenses	1994	1995	1996	1997	1998	1999	2000
Raw Material Supply							
Raw Material Purchases	120,329	125,195	156,745	148,351	126,653	178,972	320,547
Other Raw Material Supply Expense	5,014	4,699	4,067	4,523	5,183	3,184	2,371
Total Raw Material Supply Expense	125,343	129,894	160,812	152,874	131,836	182,156	322,918
Less: Cost of Raw Materials Input To Refining	59,336	64,086	75,892	64,132	62,955	85,270	139,931
Net Raw Material Supply	66,007	65,808	84,920	88,742	68,881	96,886	182,987
Refining							
Raw Materials Input to Refining	59,336	64,086	75,892	64,132	62,955	85,270	139,931
Less: Raw Material Used as Refinery Fuel	2,933	2,588	3,922	3,798	3,598	4,254	6,910
Refinery Process Energy Expense	4,702	4,101	5,480	5,005	5,349	6,427	10,838
Other Refining Operating Expenses	9,658	9,551	10,631	9,173	12,984	12,928	13,675
Refined Product Purchases	27,445	31,018	37,958	37,319	43,609	63,491	117,640
Other Refined Product Supply Expenses	3,432	3,432	4,072	3,777	5,160	4,915	6,655
Total Refining	101,640	109,600	130,111	115,608	126,459	168,777	281,829
Marketing							
Cost of Other Products Sold	4,074	4,389	5,449	6,255	6,844	5,305	7,342
Other Marketing Expenses	8,822	8,709	9,318	8,538	10,308	11,100	11,128
Subtotal	12,896	13,098	14,767	14,793	17,152	16,405	18,470
Expense of Transport Services for Others	1,125	627	507	376	4,297	4,191	3,691
Total Marketing	14,021	13,725	15,274	15,169	21,449	20,596	22,161
Total U.S. Refining/Marketing Segment General Operating Expenses	181,668	189,133	230,305	219,519	216,789	286,259	486,977

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

Table B34. U.S. Coal Reserves Balance for FRS Companies, 1994-2000
(Million Tons)

Reserves and Production Statistics	1994	1995	1996	1997	1998	1999	2000
Changes to U.S. Coal Reserves							
Beginning of Period	16,142	13,395	10,493	9,410	7,502	5,334	4,410
Changes due to:							
Leases/Purchases of Minerals-in-Place	W	W	W	W	W	W	W
Corporate Mergers and Acquisitions	W	W	W	W	W	W	W
Other Reserve Changes	-61	-699	8	-127	-17	-25	-58
Production	-180	-165	-169	-163	-74	-44	-36
Dispositions of Minerals-in-Place	-2,591	-2,128	-1,150	-774	-2,113	-802	-1,799
End of Period Reserves	13,381	10,493	9,542	8,498	5,334	4,507	2,530
Weighted Average Annual Production Capacity	201	184	192	215	65	55	51
Reserves and Production:							
Total United States							
FRS Companies' Reserves	13,381	10,493	9,542	8,498	5,334	4,507	2,530
FRS Companies' Production	180	165	169	163	74	44	36
U.S. Industry Production	1,029	1,028	1,059	1,085	1,113	1,096	1,069
Region							
East							
FRS Companies' Reserves	2,833	2,763	2,675	2,477	1,774	1,676	1,034
FRS Companies' Production	46	46	44	43	24	21	20
U.S. Industry Production	441	430	447	463	455	421	416
Midwest							
FRS Companies' Reserves	3,212	3,206	2,467	2,080	1,372	1,055	1,051
FRS Companies' Production	16	17	18	17	12	W	W
U.S. Industry Production	121	109	112	112	110	104	87
West							
FRS Companies' Reserves	7,336	4,524	4,400	3,940	2,188	1,776	446
FRS Companies' Production	118	103	107	104	38	W	W
U.S. Industry Production	467	489	500	511	548	571	566
Mining Method							
Underground							
FRS Companies' Reserves	5,479	5,337	4,571	3,880	2,352	1,853	1,752
FRS Companies' Production	59	62	59	51	28	21	21
U.S. Industry Production	399	396	409	420	417	391	373
Surface							
FRS Companies' Reserves	7,902	5,156	4,970	4,618	2,982	2,654	779
FRS Companies' Production	121	103	110	112	46	23	15
U.S. Industry Production	630	633	650	665	696	704	696

W = Data withheld to avoid disclosure.
Sources: Energy Information Administration, Form EIA-28 (Financial Reporting System). Coal production: 1994-2000--EIA, *Coal Industry Annual*, annual reports.