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Performance Profiles of Major Energy Producers 2002

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Energy Information Administration
Office of Energy Markets and End Use
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Contacts

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 Greg Filas (202) 586-1347. The following authors contributed to this report: Mary Northup, 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 2002, 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 1977-2002 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.

For further information on the Financial Reporting System data, please contact Greg Filas at (202) 586-1347, FAX (202) 586-9753, or by email: greg.filas@eia.doe.gov.

Dedication

This issue of *Performance Profiles* is dedicated to the memory of Jon Rasmussen, who passed away on December 19, 2003. Jon served as the Senior Economist for the Financial Reporting System for 24 years. He was respected as one of the foremost analysts in energy economics. His intellectual leadership, his dedication, and his professionalism served as a guiding light and inspiration to all who worked with him. Jon will be sorely missed by his many friends and colleagues at the Energy Information Administration, and by all those in both the public and private sectors who came to him for his insights on the energy industry. We are truly grateful for the time we had with him.

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 2002" 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 annual report, *Foreign Direct Investment in U.S. Energy* 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 2002. Although the focus is on 2002 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

The year 2002 began with the world oil market in a state of excess supply. Reflecting this market condition, the earnings of the U.S.-based major energy companies in 2002 declined 45 percent compared to their net income in 2001, after having already dropped 29 percent from the year 2000. Key developments in 2002 included:

- Global petroleum inventories began the year well above normal levels.
- In the United States, petroleum stocks (crude oil plus finished petroleum products) at the beginning of 2002 were over nine percent higher than at the beginning of 2001.
- Natural gas in working storage opened the year at its highest level since 1990.
- The crude oil price (as represented by the U.S. composite refiner acquisition price) climbed over the year, beginning the year at $17.38 per barrel and ending the year close to $27 per barrel, as excess supplies were reduced.
- Also as excess supplies were reduced, estimated natural gas prices at the U.S. wellhead rose from $2.35 per thousand cubic feet in January to $3.84 in December, an increase of over 63 percent.

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 2002" 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.

Major Energy Companies' Profits Decline In 2002 As Income From Both Upstream And Downstream Operations Falls

Net income of the FRS companies totaled $20.6 billion in 2002, a 45-percent decrease from the $37.7-billion result achieved in 2001. (Excluding the effects of unusual items (such as asset writedowns), the decline in 2002 was 36.6 percent.) In addition to the 2002 result being the majors' second net income decline in two years, on a constant-dollar basis, it represented the lowest level of net income achieved since 1998 and the eighth-lowest level over the 1974 through 2002 period of FRS data collection.

Further, 2002 was an unusual year for the FRS companies in that both upstream and downstream earnings were negatively affected relative to prior-year levels. Net income from oil and gas operations was down by over $4 billion, a 21-percent decrease, largely due to a glut of natural gas in the United States in the first half of 2002, which resulted in lower natural gas prices. However, financial results of the FRS companies' refining/marketing operations were significantly worse with overall refining/marketing net income declining in 2002 by $16.8 billion, or 111 percent.

With recession in much of the global economy, the impacts of September 11, 2001, a relatively warm 2001-2002 winter, and world oil supply outpacing demand until mid-2002, domestic refiner margins for the U.S. energy industry were squeezed, as petroleum product prices declined while crude oil prices increased. Although net income from the foreign refining/marketing operations of the FRS companies managed to remain positive, both foreign and domestic operations registered a steep decline, with domestic refining/marketing net income falling to a loss of $0.3 billion, an all-time low for U.S. refining/marketing profitability over the 1977 to 2002 period of FRS line-of-business data collection. Further, these historic losses for domestic refining/marketing are all the more troubling as 2001 was the second-most profitable year for U.S refining/marketing, reflecting this industry's continuing efforts at cost-cutting.

The demise of energy trading activities across the energy industry, driven by the collapse of the Enron Corporation in late 2001, also negatively affected many of the overall financial results in 2002 for the FRS companies. Although only a small minority of FRS companies were significantly involved in energy trading, the drop in cash flow for those FRS companies involved in energy trading exceeded that of all other FRS companies combined. Further, net income from the FRS companies' "other energy" line of business (now largely consisting of electric power and energy trading activities) plunged from a positive $2.0 billion in 2001 to a loss of $1.5 billion in 2002, a $3.5-billion decline.

Despite Lower Profits, Capital Expenditures Remain High Due to Acquisitions

Capital expenditures of the FRS companies (as measured by additions to investment in place) totaled $98 billion in 2002, 11 percent below the all-time high of $110 billion reached in 2001. Among the geographic regions, the U.S. Onshore region continued to be the most popular upstream target of investment, even with an exploration and development cutback of 17 percent. Additionally, while most FRS companies reduced their spending in the U.S. Offshore region, several projects in the Gulf of Mexico moved ahead in 2002, and total U.S. Offshore spending held steady, declining by only one percent between 2001 and 2002. The largest cutback was for projects in the Canadian region, which were down by 37 percent and were concentrated among those majors having made significant acquisitions in recent years. Political turmoil in Venezuela may have affected exploration and development spending in South America (in the Other Western Hemisphere region) as it declined a relatively steep 43 percent. However, spending for Asian Pacific projects (in the Other Eastern Hemisphere region) was up 22 percent in 2002, and spending for European projects (in the OECD Europe region, and mostly in the North Sea) increased by $0.9 billion, or 19 percent, over 2001 levels.

With the exception of the Devon Energy acquisition of Mitchell Energy and the completion of the ConocoPhillips merger, the upstream mergers by the FRS companies that were a prominent feature of the 1998 to 2001 period fell off. Some of the companies previously involved in significant upstream merger activity (other than Devon and ConocoPhillips) may have ceased their merger activity in order to address debt level or stock value problems on their balance sheets. In contrast, the bulk of capital expenditures in 2002 (as in 2001) reported by the FRS companies for U.S. refining and marketing operations involved transactions between FRS companies. Excluding the effects of mergers and acquisitions, the FRS companies' capital expenditures increased by only 5 percent between 2001 and 2002.

1. Market Developments and FRS Companies in 2002

The 28 major U.S. energy companies[1] reporting to the Energy Information Administration's (EIA) Financial Reporting System (FRS) derive the bulk of their revenues and income from petroleum operations, including natural gas production. A majority of these companies are multinational, with 39 percent of the majors' net investment located abroad. Worldwide petroleum and natural gas market developments are of primary importance to the companies' financial performance. (These companies are listed below)

The FRS Companies in 2002

Amerada Hess Corporation	LYONDELL-CITGO Refining, L.P.
Anadarko Petroleum Corporation	Marathon Oil Corporation
Apache Corporation	Motiva Enterprises, L.L.C.
BP America, Inc.[2]	Occidental Petroleum Corporation
Burlington Resources, Inc.	Phillips Petroleum Company
ChevronTexaco Corporation	Premcor, Inc.
CITGO Petroleum Corporation	Shell Oil Company
Conoco, Inc.	Sunoco, Inc.
Devon Energy Corporation	Tesoro Petroleum Corporation
Dominion Resources, Inc.	Total Fina Elf Holdings USA, Inc.
El Paso Energy Corporation	Unocal Corporation
EOG Resources, Inc.	Valero Energy Corporation
Exxon Mobil Corporation	The Williams Companies, Inc.
Kerr-McGee Corporation	XTO Energy, Inc.

Overall, petroleum and natural gas market developments led to deterioration in the majors' financial performance in 2002 compared to results for 2001. Developments in the capital markets in 2002 also had particularly adverse consequences for a number of the major energy companies.

Petroleum and Natural Gas Markets in 2002

Gauged by financial performance, the year 2002 was unusual for the major energy companies in that earnings from both upstream operations (oil and gas exploration, development, and production) and downstream petroleum operations (refining, marketing, and transport) were down considerably from prior-year levels. As in 1998, these conditions reflected market imbalances in which excess supplies put downward pressure on oil and natural gas prices and squeezed refiners' profit margins.

The world oil market began 2002 in a state of excess supply. This situation had been building for some time. World oil supplies had been generally outpacing demand since early 2000 and continued to do so until the second quarter of 2002. The imbalance was especially exacerbated in the second half of 2001 by economic downturns in much of the world, a relatively mild onset of winter weather in the United States, and the impacts of the terrorist attacks in the United States on September 11, 2001 (hereafter referred to as 9/11).

These higher-than-normal inventories indicated an excess of supplies in the marketplace. Beginning-of-year petroleum inventories in 2002 (excluding government stockpiles) among the industrialized nations of the Organization for Economic Cooperation and Development (OECD) were near a 5-year maximum. In the United States, stocks of motor gasoline, distillate fuel, and crude oil were at the top of their ranges. Natural gas in working storage in the United States opened the year at the highest level since 1990.

Oil and natural gas prices and refiners' margins (the difference between product prices received and crude oil prices paid by refiners) began the year 2002 at sharply reduced levels compared to 2001. In January 2002, the price of crude oil, as measured by the composite U.S. refiner acquisition cost of crude oil, was $17 per barrel compared with $25 per barrel in January 2001. The U.S. refiner margin plunged from an all-time peak of $18 per barrel in May of 2001 to $7 per barrel in January 2002. Natural gas prices at the U.S. wellhead averaged $2.35 per thousand cubic feet (mcf) in January 2002, down from $6.82 per Mcf in the prior January, a record high.

The elimination of excess supplies and recovery of prices and margins characterized much of petroleum and natural gas markets for 2002.

Turning first to petroleum markets, on the demand side, growth in worldwide petroleum demand, which was near zero for 2001, grew steadily in 2002 compared to the prior year. The growth in petroleum demand mainly reflected the improvements in world economic activity. As measured by real gross domestic product (GDP), world economic growth began to recover in 2002 from recession and the impacts of 9/11. Year-over-year global real GDP growth steadily improved, from near zero in the fourth quarter of 2001 to an annual rate of 2.5 percent in the fourth quarter of 2002. For all of 2002, world oil demand was up almost 1 percent over demand in 2001. Growth in petroleum demand came largely from Asia (apart from Japan) and Russia. Petroleum demand in the United States was up 1 percent.

Domestically, the modest growth in U.S. petroleum demand was led by a 2.8-percent increase in gasoline demand. The increase in gasoline demand in part reflected higher economic growth, but also continued reluctance by businesses and consumers to return to pre-9/11 levels of airline travel. This latter development was evident in the demand for jet fuel, which dropped 2 percent in 2002 following a 4-percent drop in 2001.

On the supply side, the nations of the Organization of Petroleum Exporting Countries (OPEC), including Iraq, managed to cut production by 1.9 million barrels per day (mmb/d) in 2002 compared to the prior year. Notable increases in oil production by Angola, Brazil, Canada, and Russia were only minor offsets to the OPEC cuts. For the year, world oil production was 1.2 mmb/d lower in 2002 than in 2001. Adjustments by OPEC and a recovery in petroleum demand eliminated most of the excess of petroleum supplies by the second half of 2002. In the United States, petroleum stocks (excluding the Strategic Petroleum Reserve) at the beginning of 2002 were 6 percent above normal levels. As world oil production was cut and petroleum demand recovered, U.S. refiners drew down inventories. By the end of 2002, petroleum stocks were below the average level of recent years.

As oil markets came into balance during 2002, oil prices rose. In December 2001, the refiner acquisition cost of imported crude oil was $16 per barrel. By December 2002, it was $27 per barrel. Most petroleum product prices in the United States, with the exception of jet fuel, rose slightly faster than crude oil input prices, providing a boost to refiners' margins. However, despite this latter improvement, refiners' margins throughout 2002 were well below the levels of 2001. On an annual basis, the refiners' margin was down to an average $8 per barrel in 2002 from just under $12 per barrel in 2001. The sharp drop in the margin had a devastating effect on U.S. refiners' financial results for 2002.

In refining operations abroad, margins also tended to rise during 2002 in the key European and Asia Pacific regions. For the year as a whole, though, margins tended to be lower in 2002 than in 2001.

Natural gas market developments had the most severe impacts on upstream financial results in 2002. The year 2002 opened with the highest level of natural gas in working storage in the United States since 1990 (using previous year-end levels to approximate beginning year levels of the current year). The buildup of natural gas inventories was in part due to mild winter weather at the outset of 2002 (U.S. heating degree days in the fourth quarter of 2001 were 27 percent below the previous fourth quarter) and in part due to the falloff in economic activity in the second half of 2001. Mild winter weather continued into early 2002, putting further downward pressure on U.S. natural gas prices. The U.S. wellhead price in February 2002 was slightly over $2 per mcf, down from over $5 per mcf in the previous February.

Natural gas suppliers drew down inventories during 2002, aided by higher economic growth and a colder-than-normal start to winter weather in the fourth quarter of 2002. As excess gas inventories declined, estimated natural gas prices rose. However for the year, estimated U.S. wellhead natural gas prices averaged $2.95 per Mcf in 2002, a 27-percent drop from $4.02 per Mcf in 2001. Lower natural gas prices were the main cause of reduced U.S. upstream earnings for the majors in 2002 compared to 2001.

Outside the United States, the majors were also hit by lower natural gas prices. The FRS companies' reported foreign natural gas prices averaged $2.54 per Mcf in 2002, down from an average of $2.82 per Mcf in 2001.

Demise of Energy Trading Impacts Financial Results

Many of the overall financial results of the FRS companies were affected by the demise of the energy trading business in 2002.

Late in 2001, the Enron Corporation made revelations of improper financial disclosures going back four years. The abuses of financial reporting standards included deliberate inflation of revenues, misclassification of liabilities to hide debt financing, and manipulation of reported earnings to meet earlier forecasts. Many of the abuses were related to Enron's energy trading business, Enron being the largest energy trader at the time.

Enron's energy trading customers withdrew their business on a massive scale, having lost confidence in Enron's ability to guarantee future contracted trades at stated terms. Following the accounting revelations that began with its report of third quarter earnings on October 16, 2001, investors lost confidence in Enron and its ability to generate future earnings. Consequently, Enron's share prices plunged in value to less than $1 a share on November 28, 2001, from a peak value of $84.87 a share on December 28, 2000.[3] The demise of Enron's trading business, its rapidly declining net worth, and its growing debt repayments led the company to file for Chapter 11 bankruptcy in November 2001.

The loss in investor confidence in energy trading activities rapidly spread beyond Enron to other energy companies engaged in these activities. Customers who had utilized energy traders to contract for future deliveries of energy commodities and manage the prices of future deliveries also lost confidence. The financial impacts of the Enron aftermath were severe for companies that depended on energy trading as a core source of revenues and earnings.

As customers cut back on their use of energy trading services, an important source of revenue shrank, reducing the net income of energy trading companies. Prior to the Enron collapse, revenue from energy trading was the main source of reported revenue growth for companies with significant trading operations.

Energy traders gained profit by tailoring future deliveries and purchases of energy commodities at contracted prices to their customers' particular needs. A key component of these transactions was the trader's assurance to the customer that the stated future conditions would be fulfilled. The energy trading customer was essentially purchasing assurances of future deliveries and sales at specified prices or within price ranges.

In order to assure that future transactions could be completed, the energy trader had to take positions in contracts (i.e., the buying and selling of multiple contracts, such as in the futures, commodities, and other markets), both financial and physical. The energy trader's position often entailed borrowing funds in order to provide ready cash to expeditiously settle contracts. As long as the cash flow from the trading business was growing, or at least steady and predictable, payback of borrowed funds was done in the normal course of business. However, should the trading business go into a rapid decline and associated cash flow diminish, the energy trader could be in a situation in which the cash needed to pay back prior borrowings exceeds the cash currently coming in from the trading business. In this situation, the trader must borrow more or sell assets to pay back its borrowings.

Following the Enron debacle, energy-trading customers lost confidence in the process, concerned that future contracts might not be wholly fulfilled. The loss of business had a double-edged effect. The first effect is simply that loss of customers means loss of revenue and lower bottom-line results. The other, more adverse effect stemmed from paybacks of borrowed funds and associated interest expense that exceeded current cash flow from the trading business. To make paybacks in excess of cash flow, energy traders borrowed more, moving the trader into a riskier position. With higher risk comes a higher cost of capital for additional funds. Increased borrowing at higher interest rates further eroded the financial results of energy trading companies.

Selling assets is another way of raising cash. Energy-trading companies priced some of their assets for quick sale to raise cash, often at prices below the assets' balance sheet value. In corporate financial reporting, when a fixed asset (e.g., a pipeline) is sold for a price below its book value, the loss reduces net income, resulting in lower reported profits. Traders sold other assets because they were profitable with many ready buyers. In this situation, the energy trader was reducing its profits in order to raise cash. Again, the need to raise cash reduced reported profits as well as the company's stock of productive assets.

Thus, massive defection of trading customers, increased borrowing costs, and negative bottom-line impacts of hurried asset sales reduced the net income and cash flow of companies engaged in energy trading in 2002. Although only a small minority of FRS companies were significantly involved in energy trading, the demise of the energy trading business appeared to have effects on overall financial results for 2002. For example, as discussed in the next chapter, the drop in cash flow from company operations in 2002 of the handful of energy traders in the FRS group exceeded that of all other FRS companies combined.

Changes in the FRS Group in 2002

New Survey Entrant

XTO Energy, Inc. (formerly Cross Timbers Oil Company) was added to the FRS respondent group for 2002 due to its oil and gas reserves and production levels. XTO's growth over the last few years was largely due to asset acquisitions and resulted in its addition to the FRS respondent group.

Mergers and Acquisitions

Two FRS companies merged with other FRS companies during 2002. On March 3, 2002, Equilon was fully consolidated into Shell Oil Company following Shell's acquisition of Texaco's 44-percent ownership of Equilon on February 18, 2002, and consolidated retroactively as of January 1, 2002.[4] On August 30, 2002, Conoco and Phillips completed their merger, a transaction valued at $15.2 billion when originally reported in November 2001. ConocoPhillips Company is the name of the resulting company, but both Conoco and ConocoPhillips reported to the FRS survey as stand-alone companies for 2002.

Two other companies, Tosco and Ultramar Diamond Shamrock, were stand-alone respondents to the FRS for 2001 despite being acquired by other FRS companies (Phillips and Valero, respectively) before the end of 2001. These companies have now been fully consolidated into Phillips and Valero and, as of 2002, are no longer reported to the FRS survey on a stand-alone basis.

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

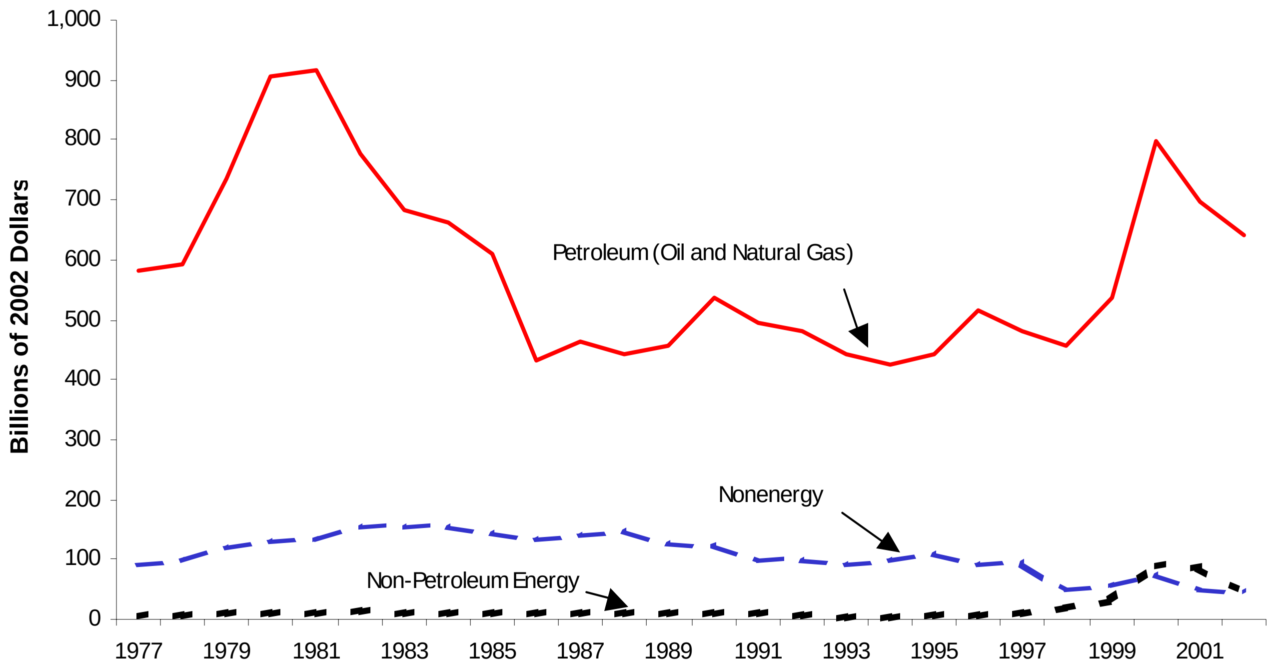
For the reporting year 2002, 28 major energy companies reported their financial and operating data to the EIA on Form EIA-28.[5] These companies (referred to as the FRS companies in this report) occupy a significant position in the U.S.[6] economy. In 2002, operating revenues of the FRS companies totaled $699 billion, which is equal to 10 percent of the $7.0 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 88 percent, or $642 billion, of allocated operating revenues[8] were derived from energy sales. Nearly all of these revenues were derived from the companies' core petroleum operations (which includes natural gas) (Figure 1). (For the purposes of this report, the petroleum line of business includes natural gas.[9])

In 2002, the FRS companies accounted for 49percent of total U.S. oil, which includes crude oil and natural gas liquids (NGL) production,[10] 45 percent of natural gas production, and 84 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.

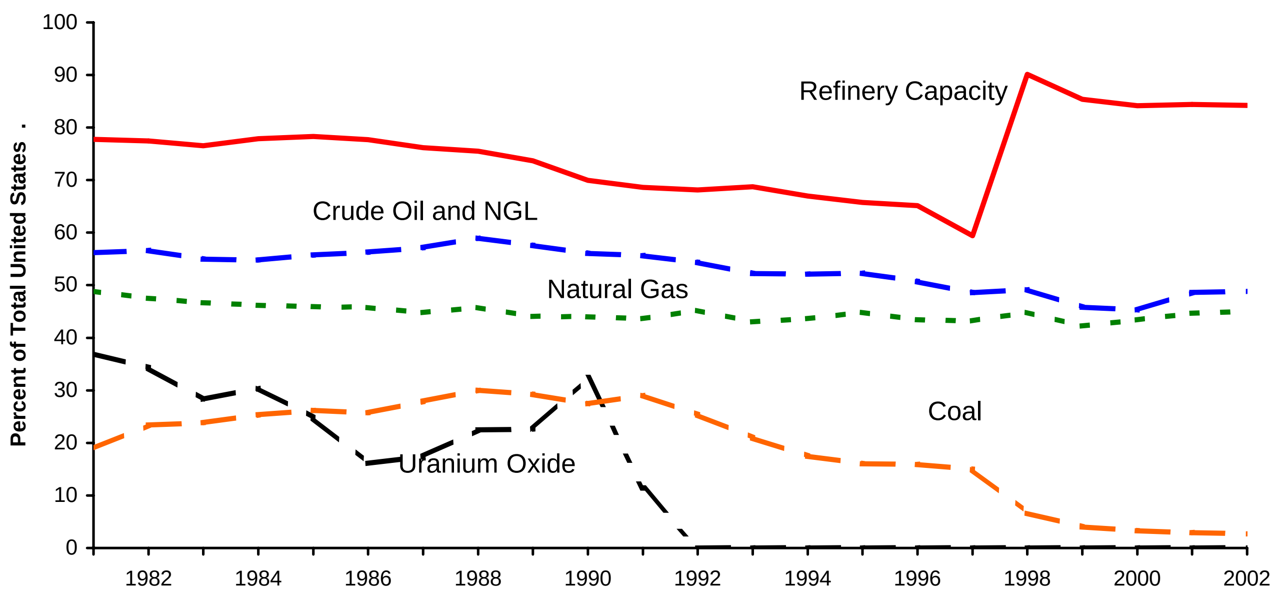
Energy production other than oil and natural gas has been a relatively small, but growing, part of the FRS companies' operations since 1994. During 2002, the combined operating revenues of the coal and

Figure 1. Operating Revenues by Line of Business for FRS Companies, 1977-2002



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

Figure 2. Shares of U.S. Energy Production and Refinery Capacity for FRS Companies, 1981-2002



Note: The FRS companies last produced uranium 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).

other energy operations of the FRS companies totaled $44 billion, or 6 percent of allocated revenues. Increased activity in electricity more than offset the continued decline in coal activity by the FRS companies beginning in 1994 and continuing through 2001, but declined in 2002. In particular, the FRS companies accounted for 29 percent of U.S. coal production in 1991, 15 percent in 1997, 7 percent in 1998, and 3 percent in 2002, with these declines largely being due to the relative lack of profitability attributable to this line of business. Meanwhile, FRS other energy (exclusive of coal), which is chiefly composed of electricity operations, increased from 0.3 percent of allocated revenues in 1994 to 10.2 percent in 2001, but fell to 6 percent in 2002.

During the 1980's, the FRS companies were major producers of domestic uranium. However, no FRS company has produced uranium oxide since 1991. Nonenergy businesses, mainly chemicals, accounted for slightly more than 6 percent, or $46 billion, of the FRS companies' allocated revenues in 2002.

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. 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 2002 are listed in Appendix A, Table A1. Three of the FRS companies are owned by foreign companies: BP America—owned by BP plc; TotalFinaElf Holdings USA—owned by TotalFinaElf; and Shell Oil—owned by Royal Dutch/Shell.
[2]BP America, the U.S. subsidiary of BP plc of the United Kingdom, is the FRS respondent.
[3] *Houston Chronicle*, "History of Enron Corp." (November 29, 2001).
[4]Details of the transaction were largely undisclosed, but the value of the overall transaction was $3.8 billion. The transaction had several aspects. Shell acquired Texaco's 44-percent ownership of Equilon, Shell acquired about 48 percent of Texaco's 32.8-percent share of Motiva, and Saudi Refining acquired about 52 percent of Texaco's 32.8-percent share of Motiva. The results of the transaction are that Texaco (now ChevronTexaco) has no ownership in Equilon or Motiva, Shell fully owns Equilon (and subsequently consolidated it), Shell and Saudi Refining are now 50/50 joint venture partners in Motiva.
[5]Aggregate time series data from Form EIA-28 for 1977 through 2001 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/fortune/fortune500).
[8] Note that "allocated operating revenues" exceeds corporate operating revenue because of double –counting that is eliminated when calculating corporate operating revenues.
[9]Generally accepted accounting principles (GAAP) for the United States do not require that energy companies separately account for costs of oil production and natural gas production in company financial records. Various exploration and development costs cannot easily or separately be assigned to either oil production or natural gas production.
[10]Note that U.S. totals include royalty production while the FRS production levels do not. Thus, the FRS share of crude oil and natural gas liquids production and natural gas production are somewhat understated by these calculations.

2. Financial Developments in 2002

Net income of the FRS companies[10] declined 45 percent, from $37.7 billion in 2001 to $20.6 billion in 2002 (Table 1). This was the second lowest level of net income in the past eight years and well below the FRS companies' peak earnings of $53.2 billion in 2000. Profitability (at 7 percent, as measured by return on equity[11]), was also at the second lowest level in the past ten years (Figure 3). Profitability of other large U.S. industrial corporations, as represented by the Standard and Poor's (S&P) Industrials,[12] rebounded from poor results in 2001 and was well above the profitability of the FRS companies in 2002.

Table 1. Consolidated Income Statement for FRS Companies and the S&P Industrials, 2001-2002
(Billion Dollars)

Income Statement Items	FRS Companies 2001	FRS Companies 2002	FRS Companies Percent Change 2001-2002	S&P Industrials[1] 2001	S&P Industrials[1] 2002	S&P Industrials[1] Percent Change 2001-2002
Operating Revenues	803.7	698.9	-13.0	4,527.1	4,608.7	1.8
Operating Expenses	-735.6	-659.7	-10.3	-4,068.9	-4,124.7	1.4
Operating Income	68.1	39.2	-42.4	458.1	484.0	5.6
Interest Expense	-9.1	-10.7	18.7	-105.6	-94.5	-10.5
Other Revenue (Expense)	6.3	6.7	5.8	-124.3	-147.4	18.6
Income Tax Expense	-27.7	-14.6	-47.3	-108.6	-124.7	14.8
Net Income	37.7	20.6	-45.4	119.7	117.3	-1.9
Net Income Excluding Unusual Items	51.2	32.5	-36.6	NA	NA	

[1]Time Warner and Qwest Communications data have been excluded from S&P Industrials data due to anomalies in the data for both companies in 2002, which, when included, greatly distorted the numbers for the group as a whole.

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

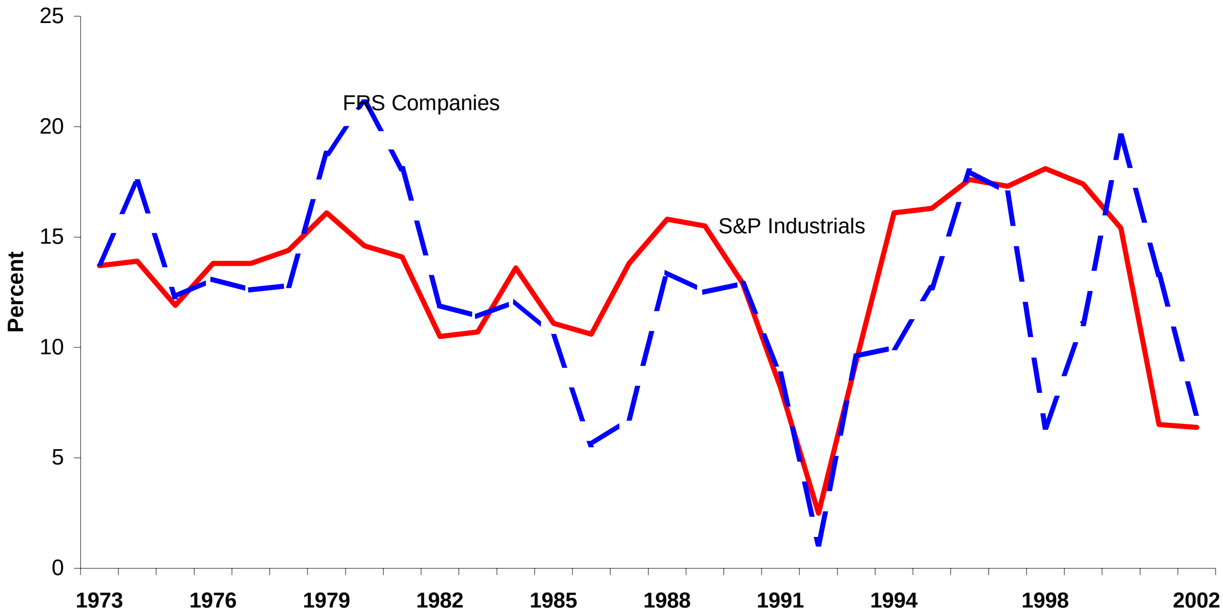
NA= not available.

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.

The primary explanation for the steep decline in net income was the excess supply of petroleum (crude oil and refined products) at the beginning of 2002 that squeezed refining margins (the spread between refined product prices and crude oil input prices) for most of 2002. Lower natural gas prices, due to a glut of natural gas in the United States in the first half of 2002, also reduced the net income of the FRS companies.

Another development in 2002 that had an adverse impact on income and cash flow was the collapse of the energy trading business following the demise of the Enron Corporation in late 2001.[13] Although only a minority of FRS companies were significantly involved in energy trading, these companies appeared to do much worse in terms of financial results than did other FRS companies. For example, the companies that were most affected by energy trading activity (El Paso, Williams Companies, and ChevronTexaco through its Dynegy subsidiary) registered a drop in net income of 138 percent, compared to a 38-percent decline for other FRS companies, and accounted for over one-half of the FRS companies' decline in cash flow from their operations.

Figure 3. Return on Equity for FRS Companies and the S&P Industrials, 1973-2002



Note: Time Warner and Qwest Communications data have been excluded from S&P Industrials data in 2001 and 2002 due to anomalies in the data for both companies in 2002, which, when included, greatly distorted the numbers for the group as a whole.
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.

Unusual items, which are charges against and additions to net income of a non-recurring nature, had a sizeable effect in 2002 as they did in 2001. Of the $11.9 billion (net) charges against income in 2002, $7.9 billion was for asset writedowns. Most of the writedowns stemmed from lower projected cash flows from oil and gas projects, but nearly $3 billion in asset writedowns appeared to be related to energy trading activities. Restructuring changes, which usually accompany downsizing and planned divestitures, totaled $1.5 billion, and discontinued operations reduced net income by $1.0 billion.

Excluding the effects of unusual items, net income of the FRS companies was down 37 percent between 2001 and 2002, from $51.2 billion to $32.5 billion (Table 1). Nearly all lines of business registered income declines in 2002. The worst financial performance, by far, was in petroleum refining and marketing.

Income and Cash Flow

Downstream Petroleum Performance Hit A New Low in 2002

Net income[14] from the FRS companies' U.S. refining/marketing line of business, excluding unusual items, fell from $12.8 billion in 2001 to a loss of $0.3 billion in 2002 (Table 2). The loss in 2002 was an all-time low for the FRS companies' U.S. refining/marketing operations during the 1977 to 2002 period of FRS data collection. The profitability of these operations, as measured by return on investment,[15] was

Table 2. Contributions to Net Income by Line of Business for FRS Companies, 2001-2002
(Million Dollars)

Line of Business	Net Income 2001	Net Income 2002	Net Income Percent Change 2001-2002	Net Income Excluding Unusual Items 2001	Net Income Excluding Unusual Items 2002	Net Income Excluding Unusual Items Percent Change 2001-2002
Petroleum[a]						
U.S. Petroleum						
Production	17,646	15,030	-14.8	20,635	16,232	-21.3
Refining/Marketing	11,951	-2,164	-118.1	12,829	-284	-102.2
Pipelines	3,345	1,694	-49.4	3,754	2,141	-43.0
Total U.S. Petroleum	32,942	14,560	-55.8	37,218	18,089	-51.4
Foreign Petroleum[a]						
Production	14,558	12,918	-11.3	16,101	15,744	-2.2
Refining/Marketing	3,115	452	-85.5	3,239	526	-83.8
International Marine	176	-38	-121.6	176	-38	-121.6
Total Foreign Petroleum	17,849	13,332	-25.3	19,516	16,232	-16.8
Total Petroleum	50,791	27,892	-45.1	56,734	34,321	-39.5
Coal	134	-46	-134.3	136	-350	-357.4
Other Energy	1,993	-1,460	-173.3	2,000	2,118	5.9
Nonenergy	-2,726	1,842	--	320	2,088	552.5
Total Allocated	50,192	28,228	-43.8	59,190	38,177	-35.5
Nontraceables and Eliminations	-12,457	-7,636	--	-7,975	-5,716	--
Consolidated Net Income[b]	37,735	20,592	-45.4	51,215	32,461	-36.6

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

[b]The total amount of unusual items was -$2,286 million and -$13,480 million in 2000 and 2001, respectively.

-- = Not meaningful.

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

also at an all-time low. Over two-thirds of the $17.1-billion decline in the FRS companies' total net income can be attributed to the plunge in U.S. refining/marketing financial results.

The dramatic reversal in performance was caused by a confluence of events and market developments (discussed in detail in Chapter 1), including:

- world oil supply that outpaced demand until mid-2002,
- recession in much of the global economy,
- the impacts of the attacks of 9/11,
- a relatively warm 2001-to-2002 winter, and
- low natural gas prices that encouraged substitution away from petroleum products.

These developments resulted in glut of crude oil and petroleum products at the beginning of 2002. Excess petroleum supplies, which had been building for several months prior to 2002, put downward pressure on petroleum prices. Refiners' margins were squeezed. For example, the average margin for U.S. refiners plunged from an all-time peak of $18 per barrel in May of 2001 to $7 per barrel in January 2002.

The workings of the market, aided by oil production cutbacks by the Organization of Petroleum Exporting Countries (OPEC) averaging nearly 2 million barrels per day, eventually eliminated excess petroleum supplies by the second half of 2002. Refiner margins rose throughout the year, but not by enough to offset the earlier damage. On an annual basis, U.S. refiner margins were $8 per barrel in 2002, down from nearly $12 per barrel in 2001. Also, among the FRS refiners, operating costs (the costs of running refineries and refined product supply networks) were up by $2 per barrel between 2001 and 2002, continuing an upward trend evident since 1999. This trend is, at least in part, the result of the recent rapid pace of merger and acquisition activity and the difficulties of integrating acquired companies and assets into complex and geographically dispersed manufacturing and distribution networks. However, recent data do not indicate that environmental requirements were the prime culprit in increased operating costs (see the Highlight entitled "Environmental Compliance Partially Eclipses Recent Gains in Profitability" in Chapter 3 for a more detailed description).

The FRS companies' downstream petroleum operations outside the United States also registered poor financial results in 2002. Net income from the foreign refining/marketing line of business, excluding unusual items, fell by 84 percent in 2002 compared to net income in 2001. However, the decline in income was not as steep as the 102-percent decline in U.S. refining/marketing net income. Available data indicate that refiner margins in the regions of Europe and Asia-Pacific, the main areas of the FRS companies' foreign downstream operations, did not decline as much as U.S. margins (see Chapter 3 for additional details). The growing weakness of the U.S. dollar during 2002 contributed to this result.

FRS Companies' Pipeline Earnings

Net income from the FRS companies' pipeline operations, excluding unusual items, was down 43 percent between 2001 and 2002. This is an unusual result since pipelines, both interstate and intrastate, tend to be subject to economic regulation. A characteristic of economically regulated industries is stability of rates of return and earnings.

The volatility of the FRS companies' pipeline profits comes from the commingling of regulated and unregulated activities in this line of business. Due to limitations in the current design of Form EIA-28, companies have to report downstream natural gas operations in the pipeline line of business section of the Form. Downstream natural gas includes gas gathering (the collection of gas from field production locations) and processing, transmission (the transport of natural gas from producing areas to consuming areas), distribution (the local delivery of gas to residences and commercial establishments), marketing, and trading. (Note that, beginning with the 2003 reporting year, Form EIA-28 will have a separate downstream natural gas line of business.)

The inclusion in pipeline operations of natural gas trading, which declined sharply in 2002 (as did all energy trading), caused the large decline in net income from the pipeline line of business. The impact of reduced trading activity can be gauged by the change in non-transport revenues. For companies whose pipeline operations were wholly or primarily in natural gas, non-transport revenues fell by $3.5 billion, or 92 percent. Net income from pipelines for this group, excluding unusual items, fell from $2.7 billion in 2001 to $1.2 billion in 2002. In contrast, the balance of net income, which is primarily from liquids pipelines, was $1.1 billion in 2001 and $0.9 billion in 2002, a 15-percent decline (unrounded data).

Low Natural Gas Prices Hurt Upstream Profits

Net income from U.S. oil and gas production, excluding unusual items, was down 21 percent (or by over $4 billion) in 2002 from net income in 2001 (Table 2). The decline was largely attributable to lower estimated natural gas prices. In January 2002, the price of natural gas was $2.35 per thousand cubic feet (Mcf) -- 66 percent below the wellhead price of the prior January.[16] The year began with a high level of natural gas in storage, a result of mild winter weather and a fall off in demand stemming from reduced economic activity in the second half of 2001. Natural gas suppliers drew down inventories throughout the year, aided by a recovery in economic growth and a colder-than-normal start to winter in late 2002. By December 2002, the wellhead price was $3.84, a 12-percent rise from the price of $3.44 of the previous December. On an annual basis, however, the U.S. wellhead natural gas price averaged $2.95 per Mcf in 2002, a 27-percent drop from $4.02 per Mcf in 2001.

On an annual basis, U.S. oil prices at the wellhead averaged $22.50 per barrel in 2002, up 3 percent from 2001. Oil prices were up because of cutbacks in oil production of 1.9 million barrels per day by OPEC and a modest recovery in world economic growth and petroleum demand. However, the effect of higher oil prices could not fully offset the adverse impact of lower natural gas prices. Also, the FRS companies' U.S. oil production and natural gas production were both 1 percent lower in 2002 compared to 2001, which further contributed to lower revenues and income.

Foreign upstream operations fared somewhat better than U.S. upstream operations. Net income, excluding unusual items, was nearly flat, down only 2 percent between 2001 and 2002 (Table 2). Foreign upstream production is tilted more toward oil than is U.S. production (58 percent oil abroad vs. 46 percent in U.S. operations), so that foreign operations benefited more from higher oil prices and were hurt less by lower gas prices. Also, natural gas prices abroad realized by the FRS companies (see Chapter 3) did not fall as much as U.S. prices. An increase in foreign natural gas production of 12 percent and an increase in foreign oil production of 1 percent by the FRS companies both mitigated the decline in foreign upstream net income.

Other Energy Plagued by Energy Trading Collapse

Although the "other energy" line of business was originally intended for reporting on nonconventional energy (synthetic fuels and renewable energy), it now largely consists of electric power activities and energy trading. The shift in composition of the other energy line of business occurred over the past 10 years and reflects two developments. First, in recent years, several companies that satisfy the FRS survey respondent selection criteria have significant electric power operations. These companies have acquired natural gas production operations large enough to account for at least one percent of U.S. total natural gas production and/or reserves and thereby qualify as FRS respondents. Second, several long-time FRS respondents have become involved in various aspects of electric power, both in the United States and abroad, including generation, distribution, marketing, and trading. Due to the limitations of Form EIA-28, electric power financial information is reported in the other energy line of business. (Note that, beginning with the 2003 reporting year, Form EIA-28 will have a separate electric power line of business.)

Net income from the other energy line of business plunged from a positive $2.0 billion in 2001 to a loss of $1.5 billion in 2002, a $3.5-billion downturn. The decline is attributable to the large amount, $3.6 billion, in unusual items in 2002. The unusual items were the balance sheet consequences of actions taken to repair the damage from the collapse of the energy trading business following the demise of the Enron Corporation in late 2001. Since these actions tended to reduce the value of a company's stockholders' equity, the impacts on required stockholders' equity are to be included in the income statement.

The energy trading activities of ChevronTexaco and El Paso accounted for most of the unusual items. ChevronTexaco reported an after-tax writedown of $1.6 billion due to the decline in the value of its ownership of Dynegy. Dynegy is an unconsolidated subsidiary of ChevronTexaco, which (until 2002) was one of the largest energy traders in the United States. ChevronTexaco also took an after-tax charge of $0.7 billion for its share of Dynegy's asset writedowns, revaluations, and loss on asset sales.[17] El Paso reported after-tax charges against income totaling $1.1 billion from its energy trading and related businesses. The charges were largely for reductions in the fair market value of energy trading contracts, reductions in the value of its investments in energy-trading subsidiaries, litigation directed at its energy trading business, and changes in accounting principles related to reporting the value of energy trading contracts.[18]

Excluding unusual items, net income from the other energy line of business was up 6 percent to $2.1 billion in 2002. This result suggests that the core of ongoing other energy operations -- production/generation, transmission, distribution, and marketing of electricity -- continued to yield positive returns even while the energy trading business was collapsing.

Chemical Operations Yield Rare Gains in Earnings

Net income from the FRS companies' nonenergy line of business, excluding unusual items, totaled $2.1 billion in 2002, a nearly seven-fold increase over results for 2001. The increase in income was due to increased earnings from chemical manufacturing and decreased losses from the remaining businesses beyond energy.

Operating income from the FRS companies' chemical businesses[19], excluding unusual items, was $1.9 billion in 2002, more than double the amount in 2001 (Table 3). Increased earnings were widespread with all but 2 of the 11 companies with chemical operations reporting an earnings improvement in 2002. The improvement reflected increased sales volumes compared to 2001. However, chemical margins, the difference in product prices and new material input prices, may not have improved much overall in 2002. For example, Exxon Mobil noted, "chemicals earnings… were $123 million higher than 2001…[benefiting] from record…product sales volumes,"[20] but elsewhere said, "Earnings for 2002 … were higher than 2001, after excluding special items … as strong volume growth more than offset lower margins."[21] However, despite the sharp upswing in income in 2002, the profitability of the FRS companies' chemical operations remained low in an historical context (Figure 4).

The balance of the FRS companies' activities outside energy is reported in the "other nonenergy" line of business. Other nonenergy has been a long-running target of retrenchment. As discussed in detail in the previous edition of this report,[22] the FRS companies' other nonenergy assets as a share of their total assets steadily declined from a peak of 13 percent in 1983 to 1.3 percent in 2001. The share declined again in 2002, to 1.0 percent, as Exxon Mobil sold its Chilean copper operations for $1.3 billion.[23] Most of the FRS companies' other nonenergy activity in 2002 was in technology development. Real estate, financial services, and remnants of telecommunications ventures were also included by some of the companies. The other nonenergy line of business, however, contributed positively to bottom-line results, as the FRS companies were able to reduce their operating losses in this area in 2002 by more than $0.2 billion (Table 3).

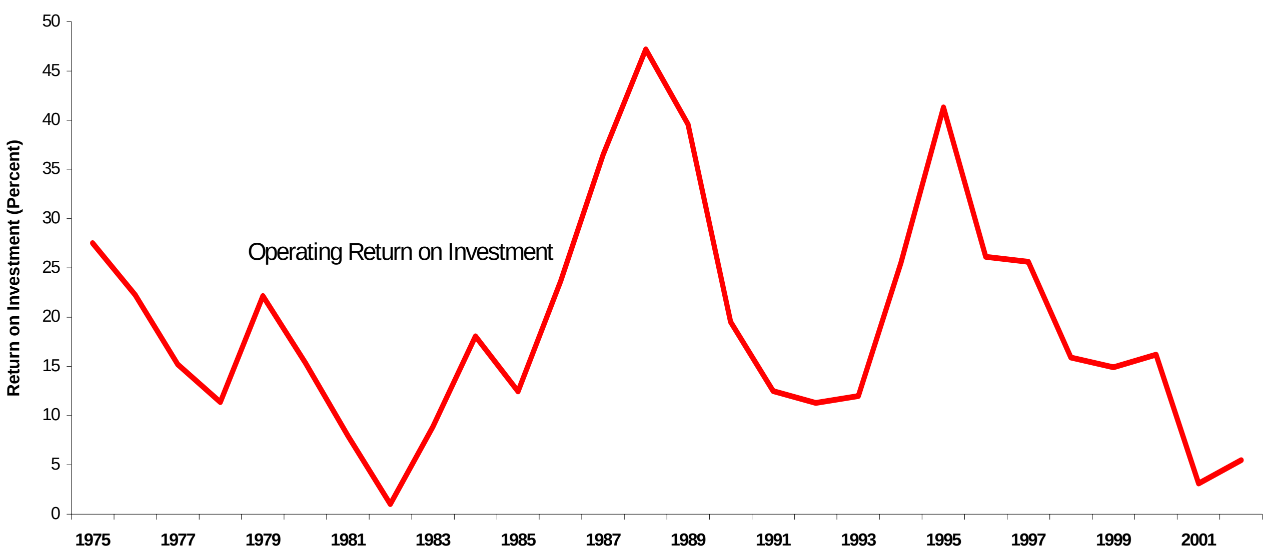
Table 3. Operating Income in Chemicals and Other Nonenergy Segments for FRS Companies, 2001-2002
(Million Dollars)

Segment	2001	2002	Percent Change 2001-2002
Operating Income, Excluding Unusual Items			
Chemicals	906	1,921	112.0
Other Nonenergy	-1,176	-907	--

-- = not meaningful

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

Figure 4. Operating Return on Investment in Chemicals for FRS Companies, 1975-2002



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.

Record Cash Flow in 2001 Followed by Mediocre Cash Flow in 2002

Cash flow is the cash realized from a company's ongoing operations. Cash includes currency, demand deposits, and interest-bearing assets of less than 30 days maturity. Cash flow from operations is usually computed by adding to (subtracting from) net income those cost (revenue) items that did not actually involve an outlay (receipt) of cash.[24] For energy companies, the largest non-cash item generally is depreciation, depletion, and amortization (DD&A), which is an allowance for the decline in value of property, plant, and equipment recorded as a charge against income.

In 2002, the FRS companies' cash flow from operations was down $15 billion from the record of $90 billion realized in 2001 (Table 4). Although this was a substantial drop, the FRS companies' cash flow performance in 2002 was still somewhat better than in recent years. Cash flow of $75 billion realized in 2002 was slightly above the average of $70 billion for the prior five years, from the 1997 to 2001.

Due to limitations of Form EIA-28, cash flow by lines of business can be computed only on a pretax basis. The decline in overall pretax cash flow of $30 billion (Table 4) was in line with the $32-billion decline in pretax income (Table B12). Among the lines of business, downstream petroleum operations, with a drop in cash flow of $25 billion, were largely responsible for the decline in cash flow in 2002.

Table 4. Line-of-Business Contributions to Pretax Cash Flow for FRS Companies, 2001-2002
(Billion Dollars)

Contribution to Pretax Cash Flow [a]	2001	2002	Percent Change 2001-2002
Petroleum[b]			
Oil and Gas Production	85.0	76.2	-10.3
Refining, Marketing, and Transport	34.8	10.3	-70.3
Coal and Other Energy	3.3	0.4	-88.6
Chemicals	0.9	1.5	61.6
Other Nonenergy	0.2	1.2	649.7
Nontraceable	-7.3	-2.9	--
Total Contribution to Pretax Cash Flow[a]	116.8	86.7	-25.8
Current Income Taxes	-24.0	-14.5	-39.5
Other (Net)	-3.2	2.8	--
Cash Flow from Operations	89.6	75.0	-16.4

[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

FRS Companies Increase Upstream Focus on OECD Europe, North Sea

Capital expenditures of the FRS companies (as measured by additions to investment in place[25]) in 2002, at $98 billion, were 11 percent below the 2001 all-time high of $110 billion (Table 5). Oil and gas production accounted for nearly two-thirds of the FRS companies' capital expenditures in 2002. The FRS collects oil and gas exploration and development expenditures by region and by function. Exploration and development expenditures include exploration expenses as well as capital expenditures.

Reviewing patterns of exploration and development expenditures yields a picture of targets of upstream investment across regions.

Regions that were targets of increased exploration and development in 2002 were in the Eastern Hemisphere while cutbacks were in the Western Hemisphere. Overall exploration and development expenditures for the Eastern Hemisphere were up $3.0 billion, or 20 percent, while exploration and development expenditures in total for the Western Hemisphere were down $5.0 billion, or 16 percent.

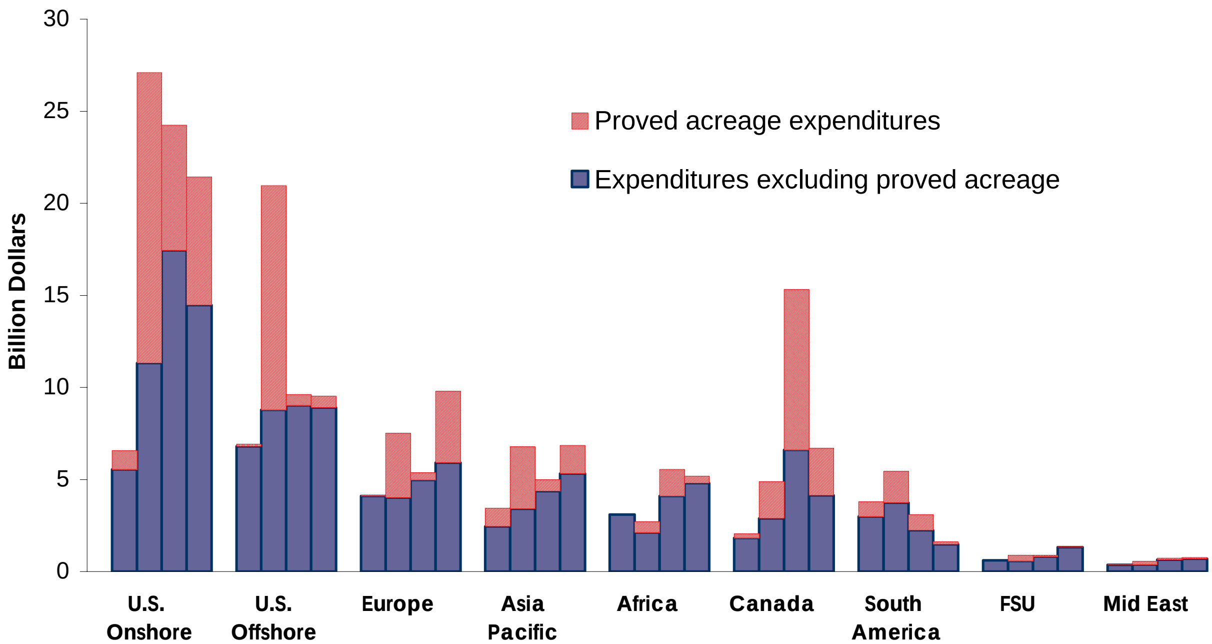
Table 5. Additions to Investment in Place by Line of Business for FRS Companies, 2001-2002
(Billion Dollars)

Lines of Business	2001	2002	Percent Change 2001-2002	Percent Change Excluding Mergers and Acquisitions 2001-2002
Petroleum [a]				
U.S. Petroleum				
Production	33.0	30.1	-8.9	3.9
Refining/Marketing				
Refining	12.1	15.1	25.1	111.4
Marketing	5.6	1.9	-66.3	-35.6
Transport	1.6	1.9	19.5	19.5
Total Refining/Marketing	19.2	18.9	-1.9	39.7
Pipelines	3.8	2.7	-28.1	-13.7
Total U.S. Petroleum	56.0	51.7	-7.8	11.1
Foreign Petroleum [a]				
Production	35.9	33.7	-6.1	18.1
Refining/Marketing	4.6	5.0	9.7	-0.8
International Marine	0.0	0.0	--	--
Total Foreign Petroleum	40.5	38.7	-4.3	14.8
Total Petroleum [a]	96.5	90.4	-6.3	12.6
Coal	0.1	0.0	-80.0	-80.0
Other Energy	5.0	3.7	-26.6	19.5
Nonenergy				
Chemicals	3.8	2.3	-38.8	-28.5
Other Nonenergy	3.4	0.4	-87.9	-86.9
Total Nonenergy	7.2	2.7	-62.1	-58.2
Nontraceables	1.5	1.2	-22.7	-23.0
Additions to Investment in Place [b]	110.4	98.0	-11.2	5.0
Additions Due to Mergers and Acquisitions	45.8	30.2	-34.1	
Total Additions Excluding Mergers and Acquisitions	64.6	67.8	5.0	

[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.

Among the geographic regions, the U.S. onshore continued to be the most popular upstream target (Figure 5), though spending for exploration and development was down 17 percent. Cutbacks were widespread, with 16 companies reducing exploration and development expenditures. A clear exception to this development was Devon. More than 95 percent of Devon's total oil and natural gas production comes from the western United States, the Gulf of Mexico, and western Canada, with about two-thirds of the production being natural gas.[26] Devon completed its acquisition of Mitchell Energy in early 2002,[27] giving the company total proved oil and natural gas reserves of approximately two billion barrels of oil equivalent.

Figure 5. Exploration and Development Expenditures by Region for FRS Companies, 1999-2002



Note: In each quadruple of bars, the first bar depicts 1999, the second 2000, the third 2001, and the fourth 2002. Regions are in order of exploration and development expenditures, excluding proved acreage, in 2002. FSU = Former Soviet Union and Eastern Bloc countries.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Offshore spending held steady, declining by only one percent between 2001 and 2002. However, companies reducing offshore spending outnumbered other offshore producers by two to one. Two of the largest participants in the Gulf of Mexico forged ahead with projects in 2002. Shell's increased Gulf production levels in 2002 were driven by the expansion of production capacity at the Brutus platform.[28] BP, the largest acreage holder in the deepwater Gulf, announced that it expects to spend at least $15 billion over the next ten years on exploration, production, and development in the Gulf of Mexico, focusing primarily on drilling wells and developing already-discovered fields.[29]

The largest absolute regional cutback in expenditures excluding proved acreage was for Canadian upstream projects, which were down by $2.5 billion, or 37 percent. The cutbacks were concentrated among majors making significant acquisitions in recent years. ConocoPhillips announced a shift away from short-life, high-decline fields to longer-life, low-decline fields in Canada, with plans to reduce operating costs and sell more than $300 million worth of nonstrategic conventional properties.[30] Devon acquired Anderson Exploration Ltd. in early 2002, which increased the relative importance of its Canadian operations: at year-end 2002, 36 percent of Devon's proved reserves were in Canada.[31]

However, Devon recorded writedowns to its Canadian oil and gas properties in 2002 based on lower oil and natural gas prices.[32] Anadarko began its operations in Canada in 2000 with the merger of Union Pacific Resources Group, Inc. (later named the RME Holding Company), and further expanded in 2001 with the purchase of Berkley Petroleum Corporation. During 2002, however, Anadarko sold its heavy oil assets in eastern Alberta for about $160 million.[33] In 2002, Apache made two acquisitions in Alberta, one from Burlington Resources for $26 million, and one from Canadian affiliates of ConocoPhillips for $60 million.[34] However, the company also sold marginal properties for $7 million. To some extent, these companies were sorting out the assets that belong in their North American core before undertaking significant new projects.

South America also registered a relatively steep 34-percent decline in exploration and development expenditures (excluding proved acreage). The political turmoil in Venezuela in the 2001 to 2002 period was probably key to this development. BP, however, was noticeable by its increased spending in South America. BP has been operating in Trinidad and Tobago since 1961 and has been spending there to expand production.[35] For example, the company expects its natural gas production to increase from 1.2 billion cubic feet (bcf) per day in 2002 to 2.0 bcf per day in 2003 to supply Atlantic LNG's (in which BP has an interest) new liquefied natural gas production train, which was approved in 2003.[36] BP has also been developing Trinidad's Kapok Field, which is expected to deliver natural gas by 2003.

Asian-Pacific projects drew the largest step up in spending in 2002 -- up $1.0 billion, or 22 percent, with two-thirds of the companies reporting higher spending (exclusive of purchases of proved acreage). Deepwater prospects oriented toward gas appeared to be favored targets. Companies noting projects in the region included ConocoPhillips, Exxon Mobil, Unocal, and ChevronTexaco.

Exploration and development expenditures directed to Europe, almost entirely for the North Sea, were up $0.9 billion over the prior year. An increased commitment to North Sea projects may be surprising since some FRS companies have announced plans to reduce their North Sea holdings. The rationale given is that the North Sea is a mature oil and gas province with few large frontier properties. Nevertheless, on an overall basis, the FRS companies increased their spending on European prospects by 19 percent in 2002. For example, ConocoPhillips (along with its partners) has developed and in 2002 began natural gas production from the Hawksley field in the North Sea.[37] ChevronTexaco, operator of the Alba Field in the North Sea, developed and in 2002 began production from the southern region of the field.[38] Exxon Mobil has continued developing oil and natural gas resources in the North Sea, leading to the start of production in February 2003 from the Ringhorne platform, part of a $1.1-billion development located in the North Sea's Norwegian sector.[39] Exxon Mobil is the operator and sole owner of the project. Exxon Mobil is also developing two other projects in offshore Norway, which will produce both oil and natural gas.

Africa continued to attract investment from the majors in 2002. Exploration and development expenditures were up 17 percent, or by $0.7 billion, in 2002. The bulk of the spending is for deepwater prospects off the coast of West Africa. Countries accounting for most of the active deepwater projects include Angola, Equatorial Guinea, and Nigeria. Notable projects in the region in 2002 include those of Exxon Mobil, Marathon, ChevronTexaco, and Amerada Hess. Exploration and development efforts in Africa also include projects in North Africa, mainly projects by Anadarko in Algeria and by Apache in Egypt.

Expenditures in the countries of the Former Soviet Union region registered the steepest percentage increase, 60 percent, of all the regions shown in Figure 5. Most of the majors' activity involves prospects in the Caspian Sea area, including those of ChevronTexaco, ConocoPhillips, and Unocal. Exxon Mobil has been developing oil reserves in the Sakhalin Island area, which is located north of Japan.

The upstream mergers that were a prominent feature of the 1998 to 2001 period fell off in 2002, with two exceptions: in 2002, Devon Energy continued their acquisition spree of recent years by acquiring Mitchell Energy; and Phillips Petroleum and Conoco, Inc. (now ConocoPhillips) completed their merger, which had been announced in 2001. For a further exposition of the upstream mergers over this period, see the Highlight entitled “Upstream Merger Wave Ebbs” and Figure 6.)

Upstream Merger Wave Ebbs

Several mergers among the FRS survey respondents and acquisitions by FRS oil and gas producers (both non-vertically integrated and vertically integrated ones) occurred over the 1998 to 2002 period (see Figure 6 for a diagram of the upstream merger transactions during this period). Devon Energy emerged as the apparent leader in this series of mergers based on sheer number of major transactions they undertook. The recent wave of upstream mergers and acquisitions, however, may have ended in 2001, as there were only three merger completions after that – Devon Energy’s acquisition of Mitchell Energy in January 2002[40], the completion of the ConocoPhillips’ merger in August 2002[41], and Devon Energy’s acquisition of Ocean Energy in February 2003[42].

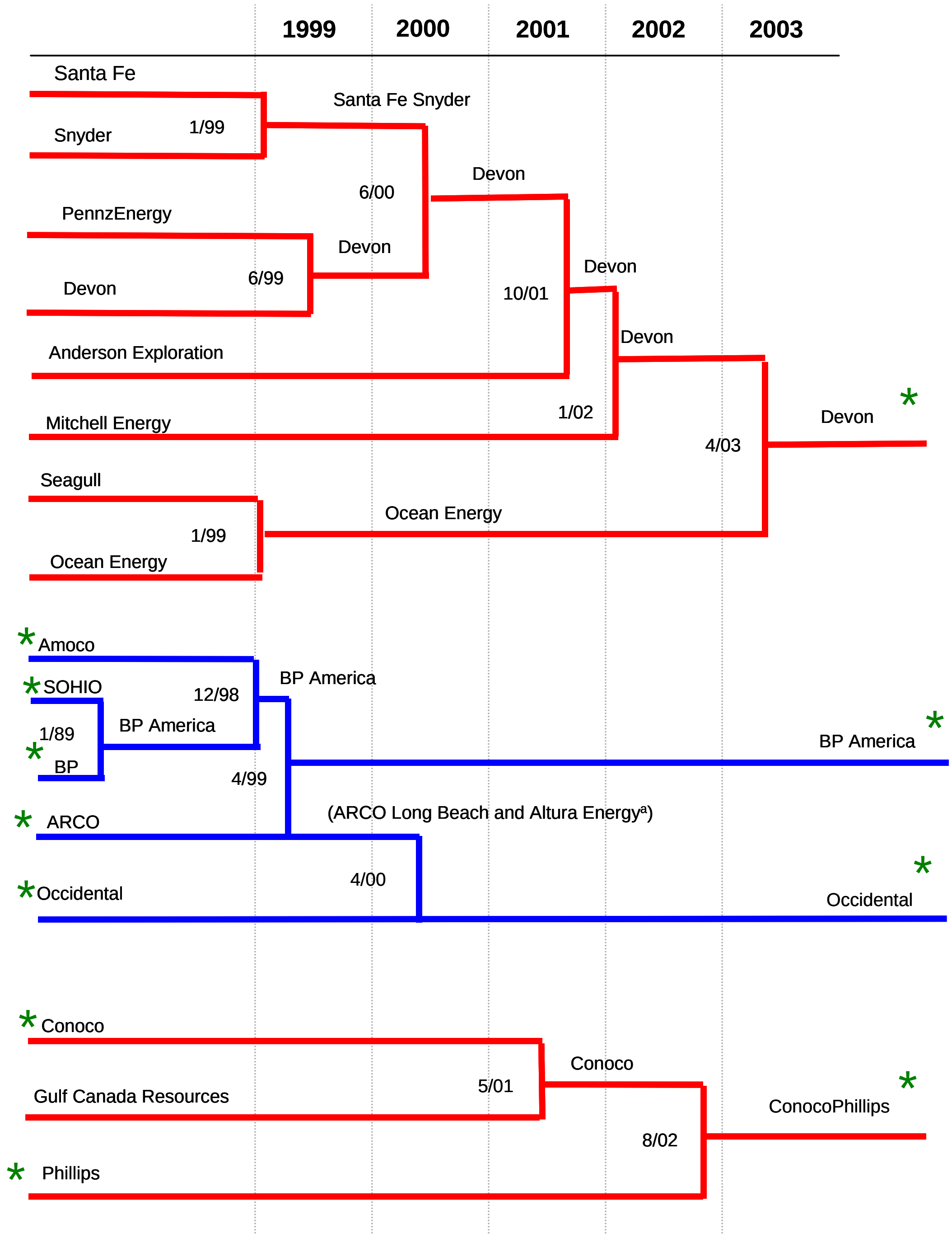
Some of the companies previously involved in significant upstream merger activity (other than ConocoPhillips and Devon) may have ceased their merger activity in order to address problems on their balance sheets. For example, some companies may have not wanted to further increase their level of debt or further dilute the value of a single share of their stock, depending on the degree to which they had used debt or equity financing in their previous merger transactions. As in other industries, other energy companies may merely be waiting for confirmation that economic activity has recovered from the events of 9/11, the aftermath, and subsequent economy-wide changes.

Nonetheless, whatever the reasons, the wave of upstream merger and acquisition activity that characterized the FRS oil and gas producers in the late 1990’s appears to have paused in 2002, and continued to do so in 2003.

Mergers Drive Increase in Refining/Marketing Capital Expenditures

In contrast, in 2002, the bulk of capital expenditures reported by the FRS companies for U.S. refinery and marketing operations in 2001 and 2002 were for intra-FRS mergers and acquisitions. In 2001, Phillips Petroleum acquired Tosco while Valero acquired Ultramar Diamond Shamrock, two of BP’s Rocky Mountain refineries, and El Paso’s Corpus Christi refinery. In 2002, Phillips Petroleum acquired Conoco to form ConocoPhillips (Table 6). This acquisition included four refineries (566 million barrels per day (mmb/d) of crude distillation capacity) along with some related pipelines, terminals, and retail gasoline outlets.

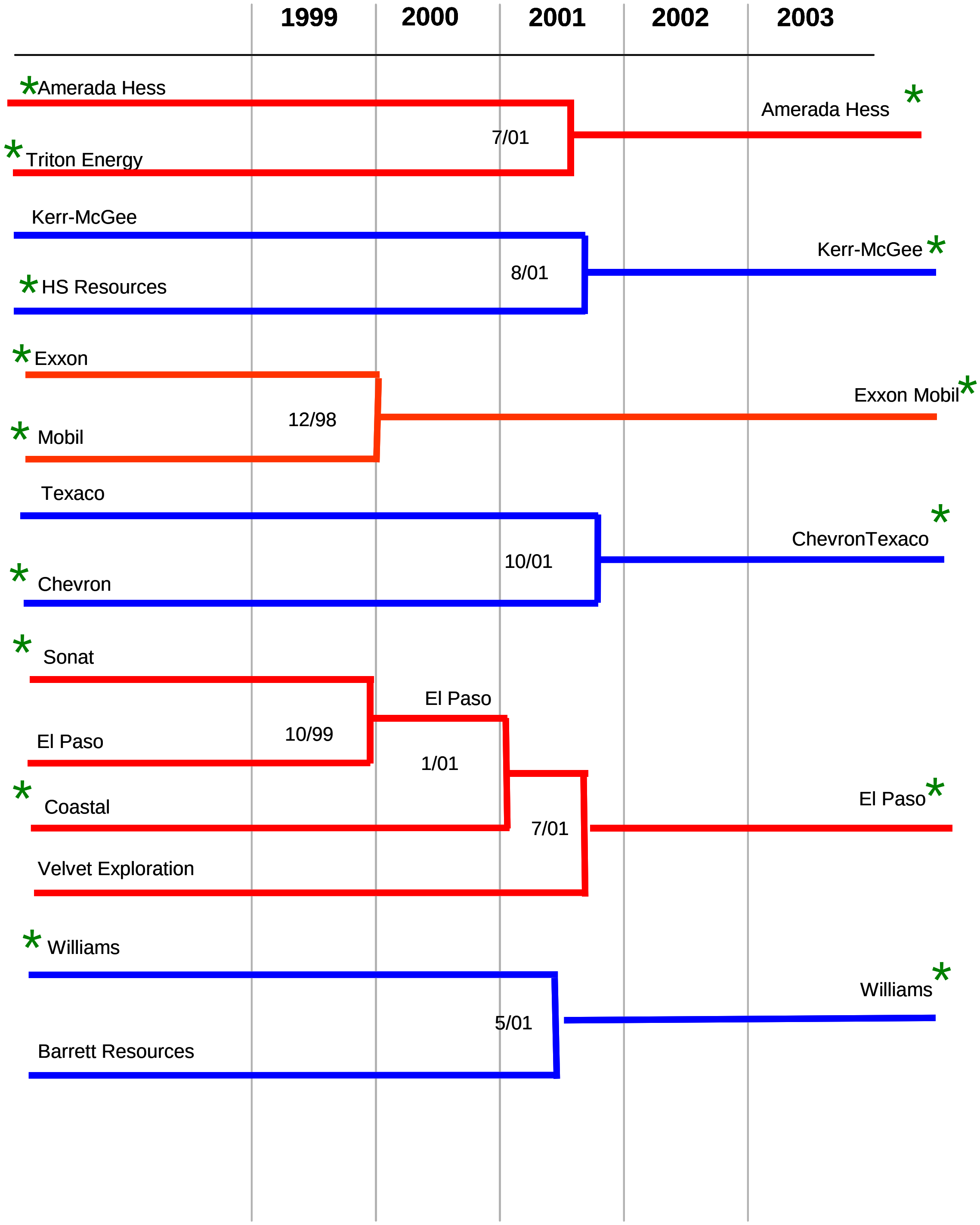
Figure 6. Recent Mergers Affecting FRS Oil and Gas Producers



*Indicates company was an FRS respondent in the nearest year; i.e., a star to the left of a company name indicates that company was an FRS company in 1998 (in the case of SOHIO, this company was a respondent in 1989 when it was acquired by BP). Alternatively, if the star is to the right of the company, then it was an FRS respondent in 2002.

Footnote and source notes are at the bottom of the third page of the genealogy figures.

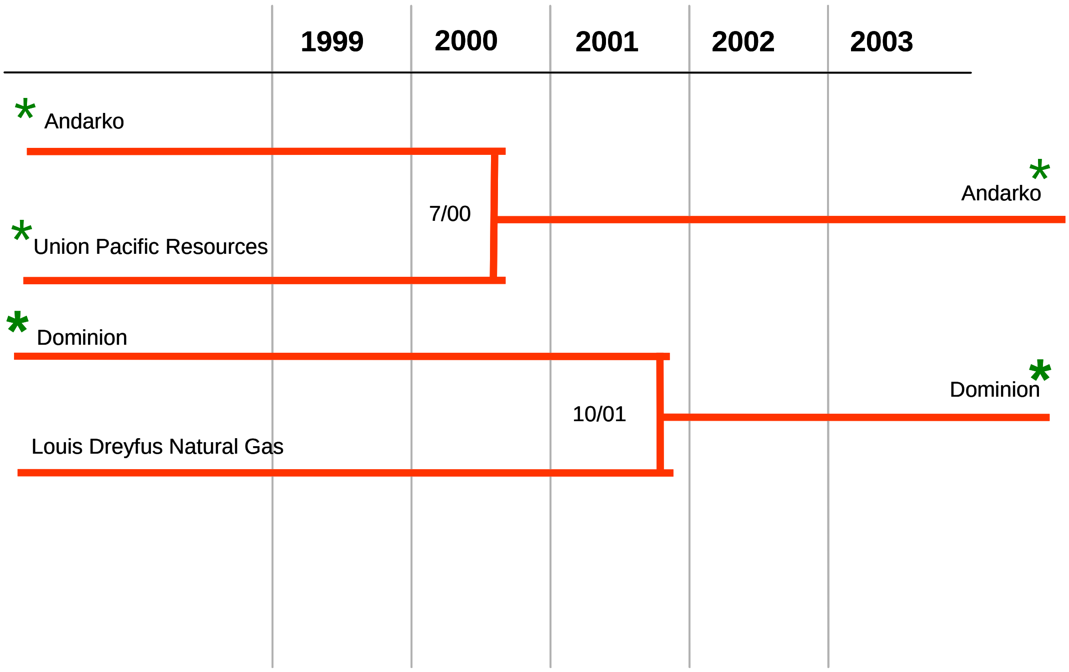
Figure 6. Recent Mergers Affecting FRS Oil and Gas Producers (continued)



*Indicates company was an FRS respondent in the nearest year; i.e., a star to the left of a company name indicates that company was an FRS company in 1998. Alternatively, if the star is to the right of the company, then it was an FRS respondent in 2002.

Footnotes and source notes are at the bottom of the third and fourth pages of the genealogy figures.

Figure 6. Recent Mergers Affecting FRS Oil and Gas Producers (continued)



*Indicates company was an FRS respondent in the nearest year; i.e., a star to the left of a company name indicates that company was an FRS company in 1998. Alternatively, if the star is to the right of the company, then it was an FRS respondent in 2002.

[a]Occidental acquired control of Altura Energy, a limited partnership owned by BP Amoco and Royal Dutch/Shell (through Shell Oil) at approximately the same time as it acquired ARCO Long Beach. Altura Energy was the largest oil producer in the state of Texas at the time of the transaction. See Energy Information Administration, "Aspects of Occidental Petroleum's Purchase of Altura Energy and ARCO Long Beach" (April 18, 2000). This is available on the Internet at http://www.eia.doe.gov/emeu/finance/mergers/oxyindex.html (as of November 28, 2003).

Sources: Company news releases and other public disclosures.

The other large intra-FRS deal in 2002 was a consequence of Chevron's merger with Texaco in 2001, which was also an intra-FRS transaction. Among other requirements for approval of the merger, the Federal Trade Commission (FTC) required the sale of Texaco's ownership interest in Equilon Enterprises and Motiva Enterprises. Equilon was formed in January 1998 as a 56/44 percent joint venture of Shell Oil and Texaco, which combined the companies' downstream petroleum assets in the western United States. Motiva began operation in July 1998 as a joint venture of Shell Oil (35 percent), Texaco (32.5 percent), and Saudi Aramco (32.5 percent). This joint venture combined the companies' downstream petroleum assets in the Midwestern and eastern United States. In February 2002, the FTC approved Shell Oil's acquisition of Texaco's ownership share of Equilon and about 48 percent of Texaco's ownership interest in Motiva with Saudi Aramco acquiring the remainder. Subsequent to these transactions, Equilon became a part of Shell Oil's consolidated operations and no longer exists as a separate entity. This means that Equilon's operations continue to be included in the FRS aggregate data but as part of Shell Oil. Motiva continues as a separate enterprise reporting to the FRS.

The increase in refining/marketing capital expenditures is larger than it would have been had several FRS companies not merged. This is because before a merger occurs, assets are carried on a company's books at their purchase prices (less the DD&A reductions that were taken over a number of years). However, since mergers involve the selling of assets from an acquired company to the newly merged entity, these same assets, after a merger, are carried on the newly merged entity's books at new purchase prices, before the DD&A process begins anew on the books of the newly merged entity.

Table 6. Value of Mergers, Acquisitions, and Related Transactions by FRS Companies, 2002 (Million Dollars)

Line of Business and Acquiring Company	Merger or Acquisition	Reported Value of Acquisition
Mergers and Acquisitions between FRS Companies		
ConocoPhillips	Merger of Phillips and Conoco	16,000
Shell Oil	Acquisition of remaining 50% interest in Equilon and 13.5% interest in Motiva	3,100
Tesoro	Valero's Golden Eagle Refinery (California)	923
Other Acquisitions by FRS Companies		
Foreign Oil and Natural Gas Production		
Marathon	Interests in Equatorial Guinea from CMS Energy	993
Burlington Resources	Canadian assets from ATCO	349
Conoco	Remaining 28 percent of Gulf Indonesia	327
Marathon	Globex Energy (Equatorial Guinea)	155
Occidental Petroleum	Pakistan properties	72
U.S. Oil and Natural Gas Production		
Devon	Mitchell Energy & Development	4,816
Unocal	Remaining 35% interest in Pure Oil	410
XTO	Rocky Mountain properties	354
Anadarko	Howell Corporation	311
Apache	Lousiana properties from Cartex Energy	259
El Paso	Tension leg platform, Gulf of Mexico	190
Burlington Resources	Producing properties in Texas	141
Refining, Marketing, and Transport		
Shell Oil	Pennzoil Quaker State	2,900
Dominion Resources	Cove Point LNG Partnership	225
Other Energy		
Dominion Resources	Mirant State Line Ventures, Inc.	185

Sources: Company annual reports to shareholders and press releases.

Although most of the capital expenditures for U.S. refining came from companies involved in mergers and acquisitions, other FRS refiners showed an increased commitment to these operations in 2002. This latter group of companies increased their capital expenditures for U.S. refining from $2.9 billon in 2001 to $4.8 billion in 2002. The increased spending was apparently for refinery upgrades and enhancements rather than expansion, in that the group's crude distribution capacity fell one percent from the prior year. The FRS asset base in refining increased, part of which was due to an accounting change regarding Citgo's Lemont, Illinois refinery.[43]

Projects noted by those FRS refiners not involved in mergers and acquisitions in 2002 include Exxon Mobil and ChevronTexaco. Exxon Mobil reported a $2.45-billion (6 percent) increase over 2001 in downstream capital expenditures to meet low-sulfur fuel requirements, in addition to cogeneration projects underway at several refineries.[44] ChevronTexaco finished upgrades at its El Segundo, California refinery to produce gasoline meeting environmental requirements without the use of the oxygenated blending component methyl tertiary butyl ether (MTBE), and continued construction on a project at the Pascagoula, Louisiana refinery to produce lower-sulfur motor gasoline and diesel.[45]

The FRS companies trimmed their capital expenditures for U.S. petroleum marketing operations sharply in 2002, from $5.6 billion in 2001 to $1.9 billion. In large part, this decline was due to fewer marketing assets in the mergers and acquisitions of 2002 compared to 2001. Even excluding mergers and acquisitions, the FRS companies' capital expenditures for petroleum marketing were down by $1.0 billion, a decline of over 30 percent.

The FRS companies' reduced financial commitment was reflected in their ownership of major gasoline outlets as direct-supplied branded motor gasoline outlets fell from 54,085 in 2001 to 46,561 in 2002. Nevertheless, some companies reported positive activity in gasoline marketing in 2002**.** For example, Amerada Hess added 25 "Hess Express" convenience stores and Exxon Mobil added 180 new "On the Run" convenience stores.[46]

Abroad, FRS companies' interest in downstream petroleum operations appeared to increase in 2002. The companies' consolidated refining capacity outside the United States was 5,642 thousand barrels per day (mb/d), up from 5,572 mb/d in 2001 (Table B28). Further, their capital expenditures for foreign refining/marketing operations increased by 400 million dollars between 2001 and 2002 (Table 5). However, these two developments present an overly positive view of the FRS companies' commitment to downstream petroleum operations abroad.

The increase in refining capacity was largely the result of a reorganization by BP plc, the British parent of the FRS respondent BP America, rather than investment in new capacity. Beginning in 2002, BP America's consolidated operations include Australian refineries in Bulwer Island (69.8 mb/d of capacity)[47] and Kwinana (158.5 mb/d of capacity)[48]. Excluding these two refineries, the FRS companies' foreign refinery capacity is 5,414 mb/d.

The big jump in capital expenditures is attributable to Phillips Petroleum's acquisition of Conoco in 2002. This transaction added over $3 billion in foreign downstream petroleum assets to the balance sheet of ConocoPhillips, the merged entity. However, the transaction simply shifted assets within the FRS group but resulted in no expansion of capacity. The effect on foreign refining/marketing capital expenditures reported in Table 5 is less than $3 billion since plant and equipment are just parts of total assets but still large. Excluding the effects of mergers and acquisitions, the FRS companies' capital expenditures for foreign refining/marketing operations was down one percent between 2001 and 2002.

Despite the drop in expenditures, upgrading of foreign downstream capacity was evident in 2002. For example, in 2002 Exxon Mobil completed the integration of its refineries in Port Jerome-Gravenchon (France) and the integration of its refinery/chemical complexes in Singapore.[49] Likewise, ChevronTexaco upgraded its refineries in Pembroke (UK) and Nerefco (Netherlands) to produce fuel meeting the new sulfur specifications.[50]

Other Energy No Longer a Source of Corporate Growth

Until 2002, the other energy line of business was a source of corporate growth for a minority of the FRS companies. However, in 2002, other energy capital expenditures fell 27 percent relative to 2001, reaching a level of $3.7 billion (Table 5). Even though the other energy line of business, excluding unusual items, still contributed positively to net income, this line of business suffered from the post-Enron flight from energy trading in electricity. (For additional details on the post-Enron collapse, see the section entitled "The Demise of Energy Trading Impacts Financial Results" in Chapter 1.)

More specifically, electricity generation projects seemed to be the primary focus of 2002 capital expenditures by FRS companies. For example, Exxon Mobil was expanding its generation capacity at the Black Point Power Station in Hong Kong.[51] Dominion Resources purchased a 515-megawatt plant in Indiana and completed construction on three power generation units in Pennsylvania, Ohio, and West Virginia.[52] BP America is constructing a 570-megawatt cogeneration plant at its Texas City refinery.[53]

Sources and Uses of Cash

In 2002, the FRS companies faced a number of problems in their deployment of capital (Table 7). Cash flow generated by company operations was $15 billion lower than the year before, largely stemming from poor financial results in downstream petroleum. Energy companies' balance sheets were being scrutinized more intensively by investors due to the collapse in energy trading and revelations of accounting irregularities following the demise of the Enron Corporation in late 2001. The general responses of the FRS companies were to cut back on outlays and reduce their amount of debt financing.

Table 7. Sources and Uses of Cash for FRS Companies, 2001-2002
(Billion Dollars)

Sources and Uses of Cash	2001	2002	Percent Change 2001-2002
Main Sources of Cash			
Cash Flow from Operations	89.6	75.0	-16.4
Proceeds from Long-Term Debt	55.0	34.1	-38.0
Proceeds from Disposals of Assets	7.7	14.3	86.3
Proceeds from Equity Security Offerings	6.3	4.9	-22.2
Main Uses of Cash			
Additions to Investment in Place	110.4	98.0	-11.2
Reductions in Long-Term Debt	34.3	27.9	-18.7
Dividends to Shareholders	17.1	17.7	3.6
Purchase of Treasury Stock	7.5	4.7	-37.4
Other Investment and Financing Activities, Net	11.9	23.1	93.2
Net Change in Cash and Cash Equivalents	1.3	3.0	136.6

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).

The largest outlay is for capital expenditures (measured as additions to investment in place). The FRS companies reduced their capital expenditures by $12 billion to $98 billion in 2002. The reduction was accomplished through a respite from mergers and acquisitions, which had been at record levels in 2000 and 2001, and cutbacks in expenditures for projects outside oil and gas production. Total capital expenditures in 2002 for lines of business outside oil and gas production, excluding mergers and acquisitions, were 27 percent below expenditures in 2001.

The cutbacks were widespread and reductions in capital expenditures in excess of $1 billion were common among companies with recent mergers and acquisitions. Two of the companies involved in energy trading, El Paso and Williams Companies, reduced their capital expenditures by nearly 50 percent. The only companies that increased their capital expenditures by more than $1 billion between 2001 and 2002 were ConocoPhillips, with the purchase of Conoco by Phillips for $16 billion, Shell Oil, with its acquisition of Pennzoil Quaker State and interests in Equilon and Motiva, and Exxon Mobil.

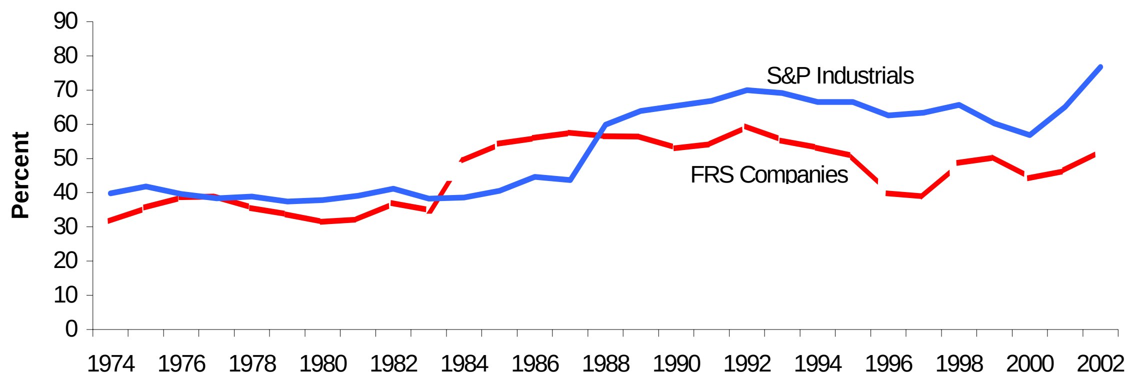
Other outlays subject to cuts were expenditures to reduce long-term debt, down 19 percent between 2001 and 2002, and purchases of treasury stock, down 37 percent. The only outlay that was not cut was cash dividends to shareholders. Dividend payouts typically show modest year-to-year increases. Also, the anticipation of favorable tax treatment of dividends made companies reluctant to reduce dividends in 2002.

The greater attention by investors to energy company balance sheets discouraged the use of debt financing. The FRS companies issued $34 billion in long-term debt in 2002, a 38-percent reduction from the $55 billion raised in the prior year. Even if the fallout from energy trading and accounting irregularities had not occurred, the FRS companies still would have shown a reduction in debt financing due to the reduced level of merger and acquisition activity in 2002.

Despite the emphasis on reducing the role of debt in companies' balance sheets, the FRS companies' ratio of long-term debt to stockholders' equity (a summary measure of the importance of long-term debt in a company's balance sheet) rose in 2002 (Figure 7). The apparent rise in long-term debt was the result of several companies reclassifying short-term debt as long-term debt and Shell Oil's assumption of debt in its acquisition of Pennzoil Quaker State and its remaining interests in Equilon.

Cash raised through the sale of assets by the FRS companies increased from $8 billion in 2001 to $14 billion in 2002. Asset sales by the companies most involved in energy trading increased from $1 billion to $3 billion. However, companies with recent mergers and acquisitions accounted for most of the asset sales as they sorted out acquired assets that they determined were not integral to their core businesses.

Figure 7. Long-Term Debt/Equity Ratio for FRS Companies and the S&P Industrials, 1974-2002



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.

Endnotes

[10]For a list of the FRS companies in 2002, see the box entitled, "The FRS Companies in 2002," in Chapter 1.
[11]Return on equity, a frequently used measure of corporate profitability, is measured by the ratio of net income to stockholders' equity.
[12]The Standard and Poor's (S&P) 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.
[13]Energy Information Administration, *Performance Profiles of Major Energy Producers 2001*, DOE/EIA-0206(01) (Washington, DC, January 2002), p. 53.
[14]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).
[15]Return on investment is net income divided by net investment in place, which is net property, plant, and equipment plus year-end balance for investments and advances to unconsolidated affiliates.
[16]Energy Information Administration, *Monthly Energy Review*, (DOE/EIA-0035 (2003/11)) (Washington, DC, November 2003), Table 9-11.
[17]ChevronTexaco Corporation 2002 *Annual Report*, pp. 36-37.
[18]El Paso Coporation 2002 Securities and Exchange Commission Form 10-K, pp. 61-65.
[19]For FRS purposes, separate reporting of income for chemical and other nonenergy segments was discontinued beginning with the 1987 reporting year. However, the disclosures of chemical segment revenues and operating income made by the FRS companies in their annual reports to shareholders closely track, in the aggregate, comparable disclosures in the Form EIA-28 from 1974 through 1986, when income statement items were collected for chemical businesses by the FRS. Thus, the public disclosures of chemical segment revenue and operating income were utilized for 1987 through 2002. 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.
[20]Exxon Mobil Corporation 2002 Securities and Exchange Commission Form 10-K, p. 29.
[21]Exxon Mobil Corporation, 2002 *Financial and Operating Review*, p. 77.
[22]Energy Information Administration, *Performance Profiles of Major Energy Producers 2001*, DOE/EIA-0206(2001) (Washington, DC, January 2003), p. 81.
[23]Exxon Mobil Corporation, press release (November 13, 2002).
[24]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.
[25]To the extent possible, capital expenditures are measured by *additions to investment in place*, which is defined as additions to property, plant, and equipment (PP&E) plus additions to investments and advances. In 2002, additions to PP&E accounted for 92 percent of capital expenditures so measured.
[26]Devon Energy Corporation 2002 *Annual Report*, p. 14.
[27]Devon Energy Corporation, press release (January 24, 2002).
[28]Royal Dutch/Shell, press release (October 31, 2002).
[29]BP, press release (August 2, 2002).
[30]ConocoPhillips 2002 *Annual Report*, pp. 13-15.
[31]Devon Energy Corporation 2002 Securities and Exchange Commission Form 10-K, p.19.
[32]Devon Energy Corporation 2002 Securities and Exchange Commission Form 10-K, p.47.
[33]Anadarko Petroleum Corporation 2002 Securities and Exchange Commission Form 10-K, p.14.
[34]Apache Corporation 2002 Securities and Exchange Commission Form 10-K, p. 4, F16.
[35]BP November 2003 discussion on: Upstream Build Projects." Web address: http://www.eia.doe.gov/perfpro/ref_pi/fig5.gif.
[36] Two other trains that were approved earlier have yet to begin full operations, although one began deliveries in August 2002. Atlantic LNG, Company Website (at Hhttp://www.atlanticlng.comH) train2_3.php3 (as of 1/14/2004).

[37]ConocoPhillips, press release (September 23, 2002).
[38]ChevronTexaco Corporation, press release (October 1, 2002).
[39]Exxon Mobil Corporation, press release (February 11, 2003).
[40]Devon Energy Corporation, press release (January 24, 2002).
[41]ConocoPhillips Company, press release (August 30, 2002).
[42]Devon Energy Corporation, press release (April 25, 2003).
[43]CITGO Petroleum Corporation 2002 Securities and Exchange Commission Form 10-K, p. 2.
[44]Exxon Mobil Corporation, *2002 Financial and Operating Review*, pp. 63, 66.
[45]ChevronTexaco Corporation, *2002 Supplement to the Annual Report*, p. 40.
[46]Exxon Mobil Corporation, 2002 *Annual Report*, p. 17.
[47]*The Oil and Gas Journal*, Volume 100, Number 52 (December 23, 2002), p.72.
[48]*The Oil and Gas Journal*, Volume 100, Number 52 (December 23, 2002), p.72.
[49]Exxon Mobil Corporation, *2002 Financial and Operating Review*, p. 65.
[50]ChevronTexaco Corporation, *2002 Supplement to the Annual Report*, p. 40.
[51]Exxon Mobil Corporation, *2002 Financial and Operating Review*, pp. 31 and 40.
[52]Dominion Resources, Inc., *2002 Annual Report*, pp. 13 and 63.
[53]BP plc, *Annual Report on Form 20-F 2002*, p. 43.

3. Behind the Bottom Line

Upstream Income

The oil and gas production operations of the FRS companies in the United States fared worse in financial performance in 2002 than did the companies' foreign operations. Net income from U.S. oil and gas production, excluding unusual items, totaled $16.2 billion in 2002, a 21-percent decline from prior-year results (Table 8). Foreign upstream operations registered a much smaller 2-percent decline. The difference in financial results is largely traceable to changes in revenues in 2002.

Revenues from U.S. upstream operations declined almost $8 billion, largely due to lower natural gas revenues (Table 8). The realized natural gas prices of the FRS companies averaged $3.07 per thousand cubic feet (Mcf) in 2002, a decline of 90 cents, or 23 percent, from the average price realized in 2001 (Table 9). This decline was less than the drop in the overall U.S. wellhead price of $1.07 per Mcf. A contributing factor may be due to the FRS companies having some success in hedging their natural gas prices, or it may be that the FRS companies sold more of their natural gas when prices were higher. (EIA's average U.S. wellhead price excludes the effects of price hedges.) Nevertheless, the lower natural gas price more than offset the 10-percent increase in the FRS companies' U.S. upstream natural gas sales volumes.

Domestic oil revenues declined slightly between 2001 and 2002, as a 2-percent increase in FRS companies' average U.S. wellhead price (domestic production average sales price) was more than offset a by a 4-percent drop in sales volumes (Table 9). Foreign oil production was up one percent as increased production from Canada, Africa, and South America more that offset lower North Sea and Former Soviet Union and Eastern Europe production.

The decline in domestic natural gas revenues was partially offset by lower operating expenses in 2002 (Table 8). Operating expenses were lower, in part, because the FRS companies' U.S. crude oil and natural gas production levels were each down 1 percent (Table 9). More important was the nearly $2-billion decline in depreciation, depletion, and amortization (DD&A) between 2001 and 2002. DD&A was unusually high in 2001, up by $7 billion from the prior year, because of writedowns of oil and gas assets. As noted in the previous edition of this report (*Performance Profiles of Major Energy Producers 2001*, January 2003):

> "In 2001, the FRS companies charged $5.3 billion against pre-tax income for asset writedowns in U.S. oil and gas production operations and $2.7 billion in foreign upstream operations. Asset writedowns are usually included in depreciation, depletion, and amortization (DD&A). Higher expenses for DD&A were the main sources of increased operating costs in the FRS companies' upstream operations between 2000 and 2001."[54]

Foreign upstream revenues of the FRS companies were less affected by lower natural gas prices in 2002. Natural gas is a smaller share of foreign oil and gas production than domestically, 42 percent vs. 54 percent, respectively, on an energy-equivalent basis. Accordingly, the impact of lower gas prices on foreign upstream revenues is less than on domestic upstream revenues. Also, the fall in domestic natural gas prices was much steeper than the fall in foreign prices in 2002 (Table 9). This decline more than offset higher oil and gas production and higher crude oil prices. Natural gas production from foreign

Table 8. Income Components and Financial Ratios in Oil and Natural Gas Production for FRS Companies, 2001-2002 (Billion Dollars)

Components of Income and Financial Ratios	Worldwide		United States		Foreign	
	2001	2002	2001	2002	2001	2002
Oil and Natural Gas Revenues						
Oil	NA	NA	31.6	30.9	NA	NA
Natural Gas	NA	NA	47.4	40.2	NA	NA
Total Revenues	141.7	132.5	79.0	71.1	62.7	61.4
Expenses						
Depreciation, Depletion, and Amortization	32.2	32.8	20.0	18.3	12.1	14.6
Lifting Costs	24.7	25.1	12.9	12.5	11.8	12.6
Exploration Expenses	5.2	4.7	3.0	3.1	2.2	1.5
General and Administrative Expenses	2.7	2.6	1.9	1.7	0.8	0.9
Raw Material Purchases	21.9	15.8	16.1	12.5	5.8	3.3
Other Costs (Revenues)	4.9	10.6	-0.2	3.8	5.1	6.8
Total Operating Expenses	91.2	91.1	53.3	51.4	37.9	39.7
Operating Income	50.5	41.5	25.7	19.7	24.8	21.7
Other Income (Expense)[a]	4.8	4.8	1.6	1.6	3.2	3.2
Income Tax Expense	23.1	18.3	9.6	6.3	13.4	12.0
Net Income	32.2	27.9	17.6	15.0	14.6	12.9
Less Unusual Items	-4.5	-4.0	-3.0	-1.2	-1.5	-2.8
Net Income, Excluding Unusual Items	36.7	32.0	20.6	16.2	16.1	15.7
Unit Values (Dollars Per Barrel of Production COE)[b]						
Direct Lifting Costs (Excluding Taxes)	3.49	3.58	3.53	3.56	3.45	3.60
Production Taxes	0.78	0.67	0.85	0.75	0.70	0.59
Ratios (Percent)						
Return on Investment[c]	12.2	9.9	13.1	10.5	11.2	9.2
Effective Tax Rate[d]	41.7	39.9	35.3	29.7	48.0	48.6

[a]Earnings of unconsolidated affiliates and gain (loss) on disposition of assets.
[b]COE = Crude oil equivalent. Dry natural gas was converted at 0.178 barrels of oil per thousand cubic feet.
[c]Net Income divided by net investment in place (Net investment in place = net property, plant, and equipment plus investments and advances).
[d]Income tax expense divided by pretax income.
NA = Not available.
Note: Sum of components may not equal total due to independent rounding.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

fields was up 11 percent between 2001 and 2002 vs. a 1-percent decline in the United States (Figures 8a and 8b**).**

The bulk of the increased foreign natural gas production was from Canada and Asia-Pacific locales. Canadian natural gas production increased 24 percent, with some of the companies that made acquisitions of Canadian producers in recent years (Devon Energy and Burlington Resources) accounting for most of the increase. The 17-percent increase in the FRS companies' Asia-Pacific natural gas production largely came from Exxon Mobil and, to a lesser extent, from ChevronTexaco. Exxon Mobil's 2002 production in Indonesia rebounded from a low in 2001 that had resulted from a shutdown in onshore operations "due to civil unrest,"[55] while ChevronTexaco's production in the Philippines grew because 2002 was its first full year of operation there.[56] Other regions registering notable increases in natural gas production were South America and Africa, as well as companies active in deepwater production off the west coast of Africa. South American natural gas production was up 16 percent, largely due to increased production from BP's Amherstia field in Trinidad-Tobago in order to supply a second liquefied natural gas train there.[57] African natural gas production was also up, by 37 percent, largely due to BP's increased production from the Temsah field in Egypt,[58] and Marathon Oil's initiation of production in Equatorial Guinea.[59]

Table 9. Average Prices, Sales, and Production in Oil and Natural Gas for FRS Companies, 2001-2002

Prices, Sales, and Production	2001	2002	Percent Change 2001-2002
Worldwide Oil and Gas Production[a]			
Crude Oil and NGL (Million Barrels)	3,087	3,093	0.2
Dry Natural Gas (Billion Cubic Feet)	15,148	15,747	4.0
Total (Million Barrels COE)[b]	5,784	5,896	1.9
Domestic Oil and Gas Production[a]			
Crude Oil and NGL (Million Barrels)	1,363	1,346	-1.2
Dry Natural Gas (Billion Cubic Feet)	8,838	8,713	-1.4
Total (Million Barrels COE)[b]	2,936	2,897	-1.3
Domestic Oil and Gas Sales Volumes			
Crude Oil and NGL (Million Barrels)	1,498	1,433	-4.3
Dry Natural Gas (Billion Cubic Feet)	11,957	13,109	9.6
Total (Million Barrels COE)[b]	3,626	3,766	3.9
Domestic Production Average Sales Prices			
Crude Oil and NGL (Dollars Per Barrel)	21.11	21.59	2.3
Dry Natural Gas (Dollars Per Thousand Cubic Feet)	3.96	3.07	-22.6
Composite (Dollars Per Barrel COE)[b]	21.79	18.89	-13.3
Foreign Oil and Gas Production[a]			
Crude Oil and NGL (Million Barrels)	1,724	1,747	1.3
Dry Natural Gas (Billion Cubic Feet)	6,310	7,034	11.5
Total (Million Barrels COE)[b]	2,847	2,999	5.3
Foreign Production Average Sales Prices			
Crude Oil and NGL (Dollars Per Barrel)	22.04	23.05	4.6
Dry Natural Gas (Dollars Per Thousand Cubic Feet)	2.91	2.54	-12.8
Canada	3.63	2.68	-26.1
OECD Europe	3.18	2.93	-8.0
Other Foreign	2.25	2.33	3.6
Composite (Dollars Per Barrel COE)[b]	19.97	19.38	-2.9

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

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

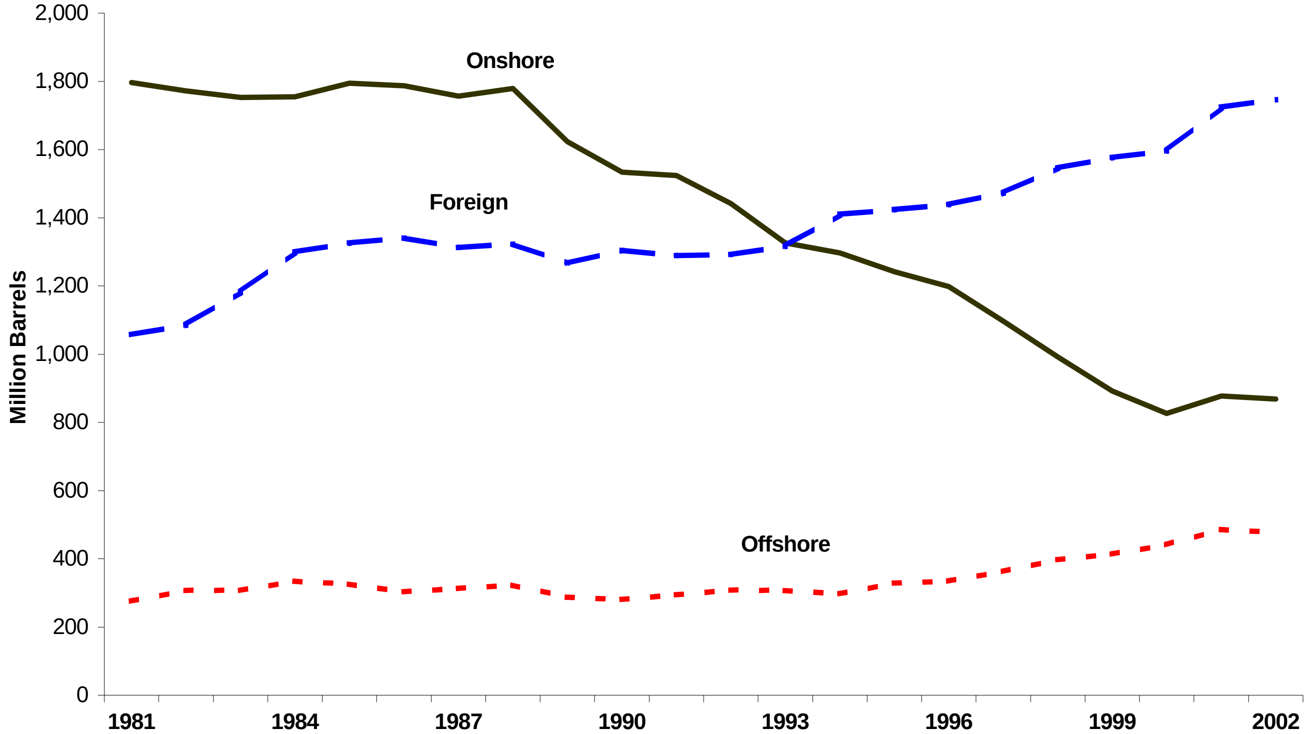
Sources: Energy Information Administration, Form EIA-28 (Financial Reporting System). Foreign production segment per unit sales values were compiled from information in FRS companies' filings of Securities and Exchange Commission Form 10-K, annual reports to shareholders, and supplements to annual reports.

Lifting costs decreased $0.4 billion in the United States but increased $0.8 billion abroad (Table 8). The decrease in the United States occurred because oil and gas production (Table 9) and production taxes per barrel fell, while the increase abroad resulted from increased oil and gas production and increased lifting costs per barrel, excluding production taxes. The next section of this chapter reviews lifting costs in more detail.

Lifting Costs Little Changed -- Production Taxes Decline

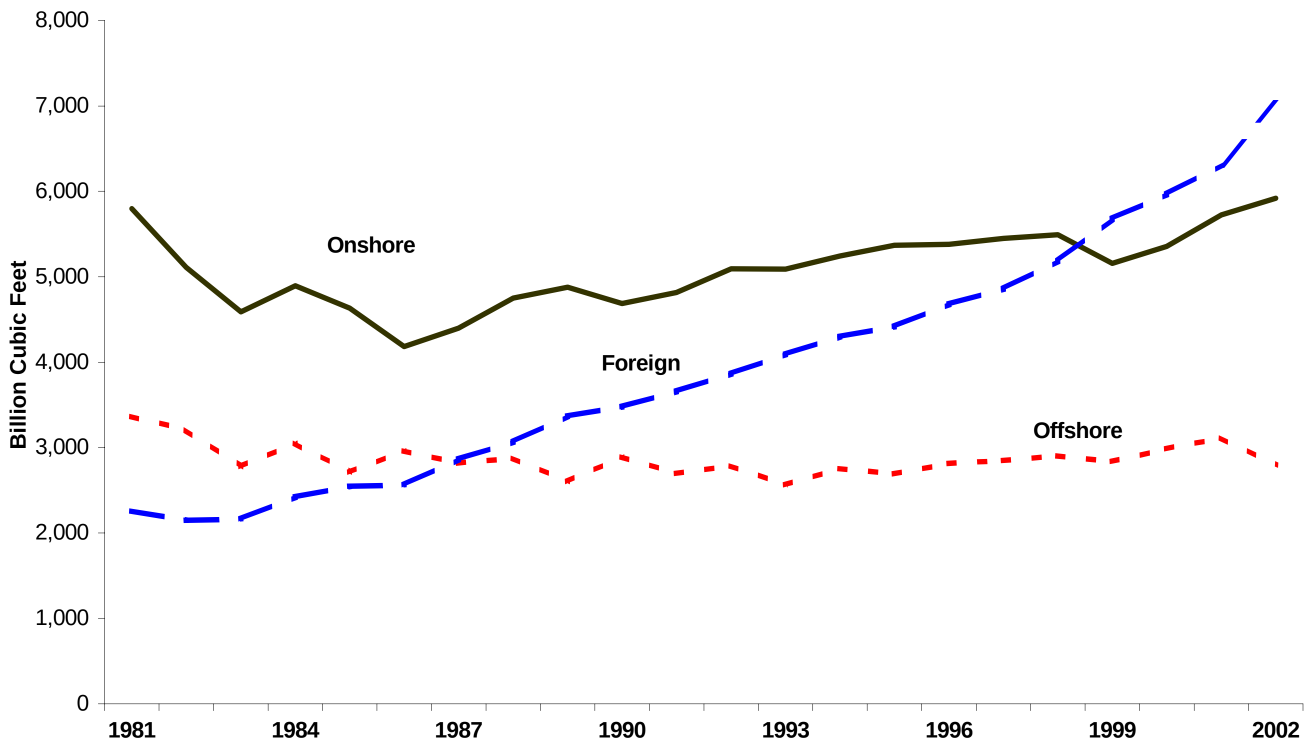
Worldwide lifting costs (including taxes) changed little in 2002, with a small decline in the United States offsetting a small increase in foreign regions (Table 10). Over the long term, lifting costs declined very slightly between 1994 and 2002, after declining faster in the early years of the 1990's (Figure 9). [Lifting costs (also called production costs) are the per barrel costs of producing oil and

Figure 8a. Oil Production for FRS Companies, 1981-2002



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

Figure 8b. Natural Gas Production for FRS Companies, 1981-2002



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

natural gas (measured on a barrel-of-oil equivalent basis). They include the costs to operate and maintain wells and related equipment and facilities after hydrocarbons (both crude oil and natural gas) have been found and/or acquired, and developed for production.] These per barrel costs include depreciation costs for capital equipment and facilities used in production. Total lifting costs are direct lifting costs plus production taxes.

Table 10. Lifting Costs by Region for FRS Companies, 2001-2002
(Dollars Per Barrel of Crude Oil Equivalent)

	Direct Lifting Costs			Production Taxes			Total		
Region	2001	2002	Percent Change	2001	2002	Percent Change	2001	2002	Percent Change
United States									
Onshore	--	--	--	--	--	--	5.19	5.02	-3.3
Offshore	--	--	--	--	--	--	2.93	2.93	0.0
Total United States	3.53	3.56	0.7	0.85	0.75	-11.5	4.39	4.32	-1.6
Foreign									
Canada	3.92	4.07	3.8	0.22	0.19	-13.8	4.14	4.26	2.9
OECD Europe	3.51	3.54	1.1	0.66	0.52	-20.3	4.16	4.07	-2.3
Former Soviet Union and Eastern Europe	3.85	3.21	-16.6	0.89	0.00	-100.0	4.74	3.21	-32.3
Africa	3.58	4.23	18.3	1.20	0.92	-22.9	4.77	5.15	8.0
Middle East	3.05	3.78	24.1	0.41	0.35	-15.9	3.46	4.12	19.3
Other Eastern Hemisphere	3.21	3.27	1.8	0.88	0.72	-17.4	4.09	4.00	-2.3
Other Western Hemisphere	2.75	2.57	-6.7	0.66	1.12	70.7	3.41	3.69	8.2
Total Foreign	3.45	3.60	4.6	0.70	0.59	-14.8	4.14	4.20	1.3
Worldwide Total	3.49	3.58	2.6	0.78	0.67	-13.3	4.27	4.26	-0.3

-- = Data not available.

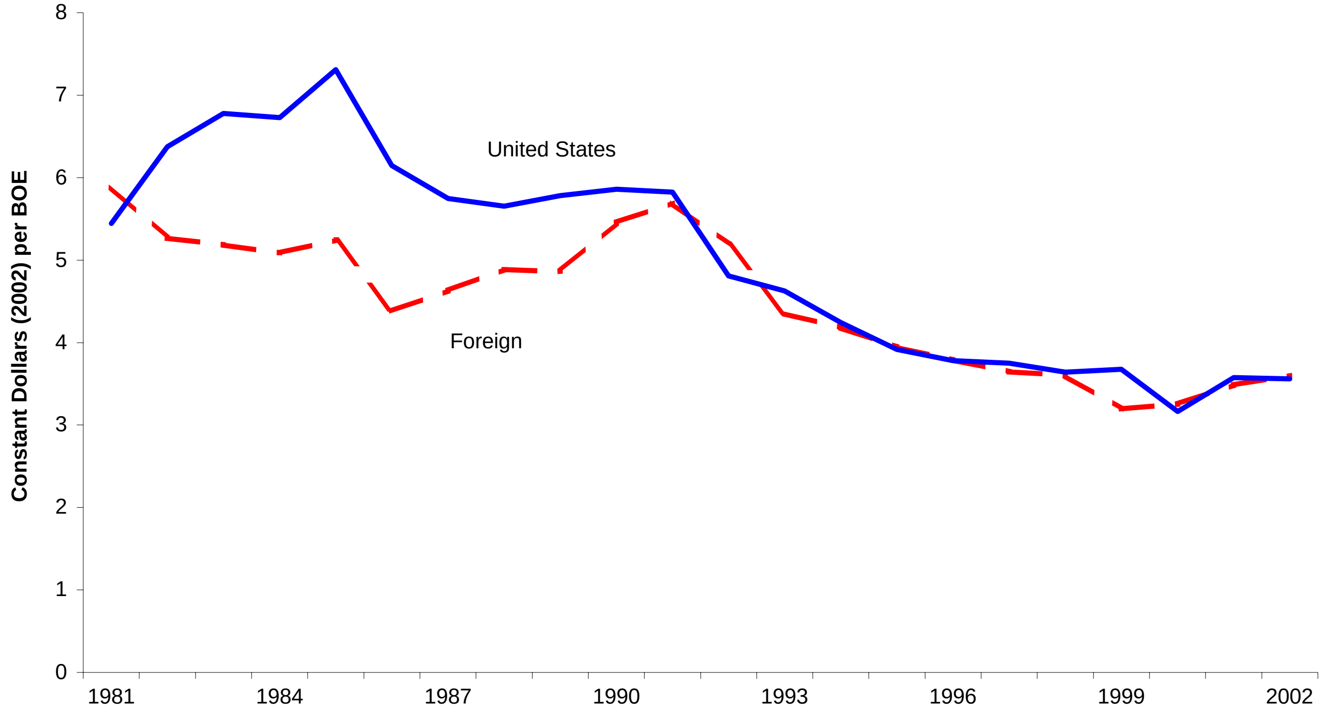
Note: Sum of components may not add to total due to independent rounding.

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

One of the most notable changes in lifting costs in 2002 was the decline in both domestic and foreign production taxes (Table 10).[60] Production taxes increased only in the Other Western Hemisphere region (primarily Latin America), which experienced a fairly large increase.[61] In the United States, production taxes (also called severance taxes) are largely levied by State governments, largely against production in the U.S. Onshore and usually in the form of a percent of the value of the oil and gas produced.[62] In the first half of the 1980's, domestic production taxes per barrel-of-oil equivalent (boe) for the FRS companies fell sharply from their 1981 high of $10 per boe (in real 2002 dollars), reflecting in large part a substantial decline in crude oil prices and, to a lesser extent, natural gas prices over that period (Figure 10). However, in 2000 and 2001, when crude oil and natural gas prices reached highs not seen since the mid-1980's, domestic production taxes remained below $1 per boe.

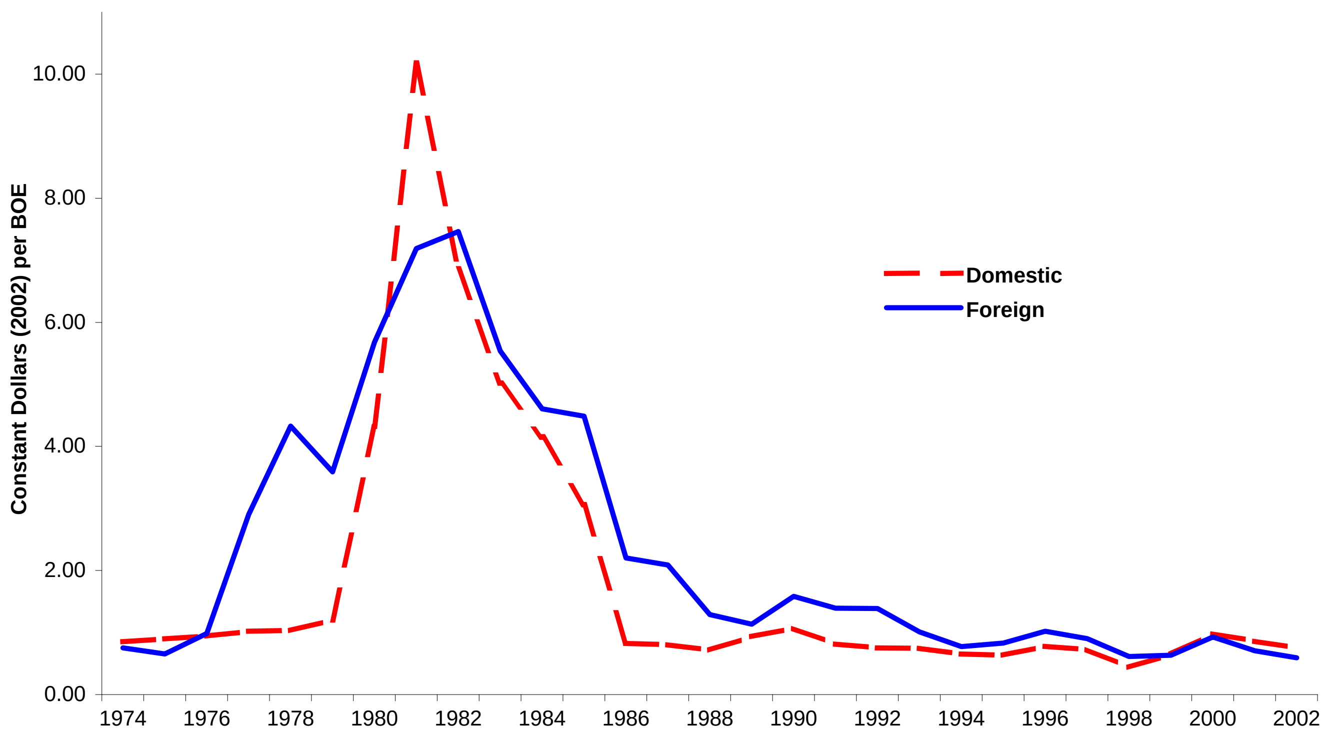
One reason that domestic production taxes for the FRS companies did not respond more dramatically to increased prices in 2000 and 2001 is the movement of domestic production from onshore to offshore. In 1985, 31 percent of the FRS companies' domestic oil and gas production (on a boe basis) came from the Offshore region. By 2002, production from the Offshore reached 51 percent of the domestic total. Since production from Federal Offshore areas is not subject to State severance taxes, the share of production exposed to severance taxes for the FRS companies has been falling. Inexplicably, production taxes paid by the FRS companies on foreign production, which is subject to multiple tax schemes, have historically moved in tandem with domestic production taxes (Figure 10).[63]

Figure 9. Direct Oil and Gas Lifting Costs for FRS Companies, 1981-2002



Note: Direct lifting costs are the costs of extracting oil and gas, excluding production taxes.
BOE = Barrels of crude oil equivalent.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Figure 10. Production Taxes for FRS Companies, 1974-2002



Note: Foreign production taxes include royalty payments while domestic production taxes do not.
BOE = Barrels of crude oil equivalent.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

The small decline in worldwide production taxes was offset by an increase in per barrel direct lifting costs in 2002 (Table 10). Africa was the largest contributor to the increase in worldwide direct lifting costs. This is because production by the FRS companies in Africa increased only 6 percent, while total expenditures on production (excluding production taxes) increased 25 percent, which resulted in an 18-percent increase in direct lifting costs. Worldwide direct lifting costs of the FRS companies also were notably influenced by increases in Canada and the Middle East, but because of relatively less production there, were not as significant as those of Africa.[64]

One cause of higher direct lifting costs can be a decline in oil and gas production, with fixed costs spread over less production. Another possible cause of higher lifting costs is related to the launching of new projects, such as bringing new production online or initiating enhanced recovery programs, which often have higher costs initially.

With an increase of 15 percent, Canada led all regions for increased production in 2002 (Table B25). Production in Africa also increased, by 3 percent, while production in the Middle East declined slightly. In contrast, the Other Western Hemisphere was the only region making a substantial contribution to lower worldwide direct lifting costs; oil and gas production there grew twice as fast as direct production spending.

While 2002 worldwide total lifting costs (i.e., direct lifting costs plus production taxes) were virtually unchanged, although the Middle East region and the Former Soviet Union and East Europe region had relatively large changes in total lifting costs in 2002. In the Middle East, production taxes declined, and an increase in direct lifting costs was the only cause of the increase in total lifting costs. In contrast, the Former Soviet Union and East Europe was the only region to exhibit a decline in both direct lifting costs and production taxes, which resulted in a large relative decline in total lifting costs for the region. The FRS companies have just begun substantial production in the Former Soviet Union and East Europe, with production there much less than in any other region. Increased production at established projects also may lead to falling lifting costs because fixed costs are spread over more production.

U.S. Refining and Marketing

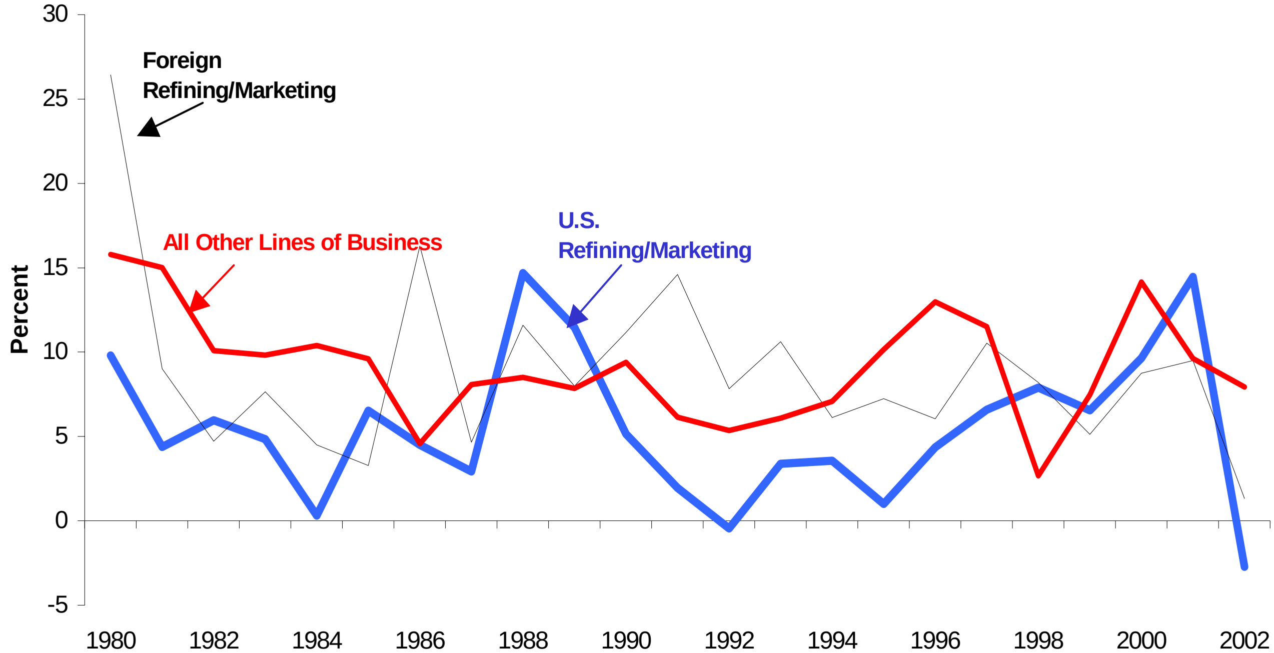
Profitability of U.S. Refining/Marketing Operations Lowest in Survey History

The results of 2002 established a new record as the most unprofitable year for the FRS companies' refining/marketing operations in the 26-year history of the FRS. These disappointing results came after a 6-year period of almost continuously increasing profitability, which had resulted in returns from the FRS domestic refining/marketing operations becoming competitive with all other lines of business (Figure 11) and was referred to just a year ago as a "sort of 'golden age' of U.S. refining and marketing."[65]

In addition, perhaps one of the most unsettling aspects of the historical losses reported in 2002 is that they came on the heels of the second-most profitable year in the history of the FRS. Thus, in view of the apparently tenuous nature of profitability gains in this line of business, it appears that the urgency of the ongoing cost-cutting efforts that characterized the domestic refining/marketing operations of the FRS companies throughout the 1990's will continue unabated through this decade.

The change in the profitability of U.S. refining/marketing operations can easily be explored by examining the net refined product margin (net margin), which is highly correlated with profitability.[66] The net margin is the gross margin (refined product revenues minus purchases of raw materials input to refining and refined product purchases) minus out-of-pocket operating costs per barrel of refined product sold. The net margin measures before-tax cash earnings from the production and sale of refined products.[67] The $0.19 per barrel net margin of 2002 was the lowest since 1984 (when the net margin, after adjusting for inflation, was $0.01 per barrel) and the second lowest in the history of the FRS (Figure 12), barely surpassing the $0.21 per barrel (also adjusted for inflation) achieved in 1987.

Figure 11. Return on Investment in U.S. and Foreign Refining/Marketing, and All Other Lines of Business for FRS Companies, 1980-2002



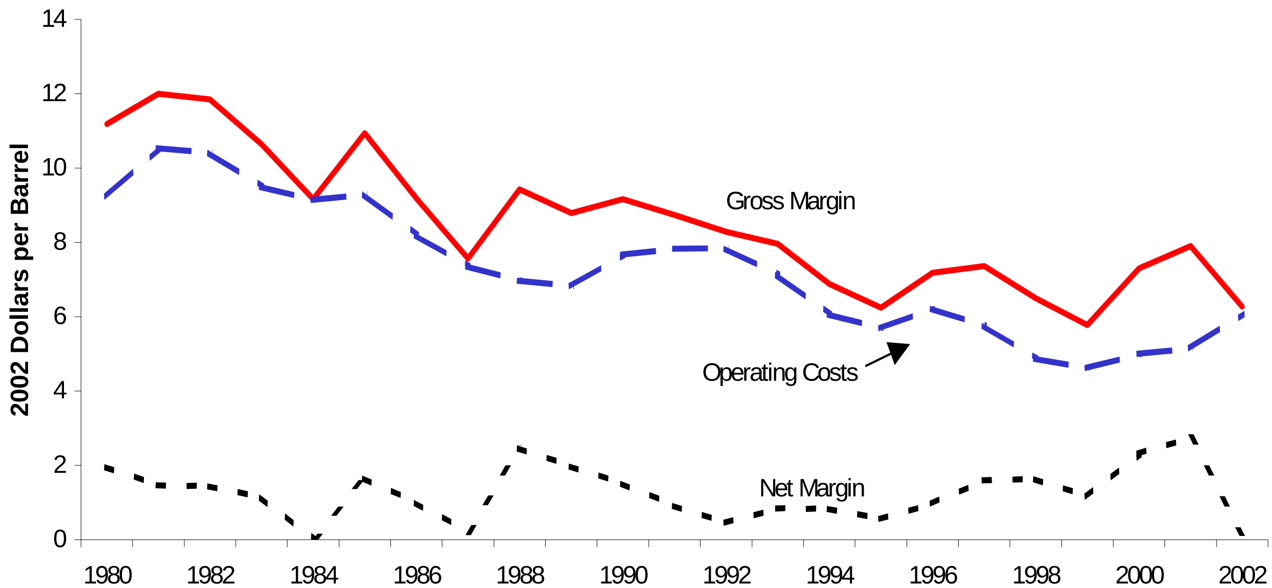
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Lower Product Prices Reduce Product Sales Revenue

The 7-percent decline in petroleum product sales revenues (Table 11) was partially due to lower prices received, which fell 4 percent in 2002 compared to 2001 (Table 12). Declines in the average price received for motor gasoline (falling 6 percent) and distillate (falling 8 percent) were somewhat offset by small gains (6 percent) in the average price for other petroleum products. Revenue from other sources (e.g., non-petroleum sales at convenience stores) also fell while operating cost increased slightly. The combination was disastrous and resulted in an operating loss of $1.5 billion and a net loss of $2.2 billion ($1.0 billion excluding unusual items).

Economic growth (2.4 percent), cooler winter weather (2.2 percent more heating degree-days), and warmer summer weather (11 percent more cooling degree-days) in 2002 compared to 2001[68] ameliorated the downward trend in prices. However, these factors were insufficient to overwhelm the dampening effect of unusually high end-of-2001 product stock levels (and continuing through the first part of 2002) brought on by events in 2001, including the worldwide economic downturn and the impacts of the terrorist attacks of 9/11.

Figure 12. U.S. Refined Product Margins and Costs per Barrel of Petroleum Product Sold for FRS Companies, 1980-2002



Note: The gross margin is refined product revenues less raw material cost and product purchases divided by refined product sales volume.

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

Table 11. U.S. and Foreign Refining/Marketing Financial Items for FRS Companies, 2001-2002
(Million Dollars)

	2001	2002	Percent Change 2001 - 2002
Domestic Refining/Marketing Operations			
Refined Product Sales Revenue	291,609	272,190	-6.7
Other Revenue[a]	19,301	16,600	-14.0
Operating Expense[a, b]	294,536	290,282	-1.4
Operating Income[b]	16,374	-1,492	-109.1
Net Income, excluding unusual Items	12,829	-1,011	-107.9
Unusual Items	-878	-1,153	--
Net Income	11,951	-2,164	-118.1
Foreign Refining/Marketing Operations			
Refined Product Sales Revenue	142,949	142,227	-0.5
Other Revenue[a]	14,249	6,300	-55.8
Operating Expense[a, b]	152,420	147,298	-3.4
Operating Income[b]	4,778	1,229	-74.3
Net Income, excluding unusual Items	3,239	564	-82.6
Unusual Items	-124	-112	--
Net Income	3,115	452	-85.5

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

Table 12. Sales, Prices, Costs, and Margins in U.S. Refining/Marketing for FRS Companies, 2001-2002

	2001	2002	Percent Change 2001-2002
Refined Product Sales (Million Barrels per Day)	23.6	23.0	-2.5
	(Nominal Dollars per Barrel)		
Gasoline Average Price	36.96	34.87	-5.6
Distillate Average Price	32.96	30.49	-7.5
Other Products Average Price	26.30	27.81	5.8
All Refined Products Average Price	33.88	32.43	-4.3
Less: Raw Materials Costs and Product Purchases	26.07	26.16	0.3
Equals: Gross Refining Margin	7.81	6.27	-19.7
Less: Direct Operating Costs	5.09	6.08	19.5
Equals: Net Refining Margin[a]	2.72	0.19	-93.0
Reseller/wholesaler spread (dealer price - wholesale price)	3.05	2.32	-24.1
Retailer spread (company-operated price - dealer price)	3.16	4.27	35.1

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

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

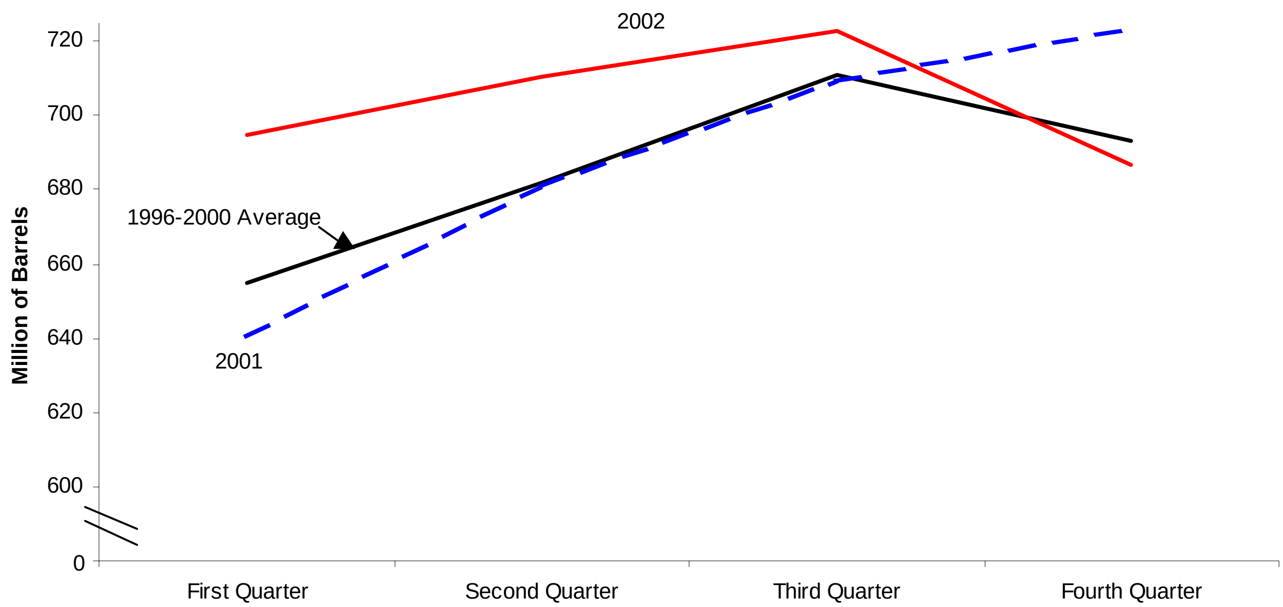
Industry-wide petroleum product stocks were 9 percent higher in 2002 than in 2001 over the first quarter, falling to 4 percent over the second quarter and 2 percent over the third quarter (Figure 13), which exerted substantial (and declining) downward pressure on petroleum product prices compared to a year earlier.[69] Industry-wide stocks of motor gasoline also were higher during the first part of 2002 compared to 2001, but were much more similar to the average over the period of 1996 through 2000 (Figure 14) than was the case for petroleum products in general. The accompanying decline in motor gasoline prices received by the FRS companies also was somewhat smaller at 6 percent.

Lower Product Sales Magnify Downward Pressure on Revenue

The downward pressure on revenues created by lower product prices was magnified by lower product sales in 2002 relative to 2001. Sales fell a relatively slight 0.6 million barrels per day against the 2001 level of almost 24 million barrels for a 3-percent decline in 2002 relative to 2001 (Table 12), largely due to a 12-percent decline in the sales of the amorphous category of "other products" (i.e., petroleum products other than motor gasoline and distillate) (Table 13). Motor gasoline sales were essentially flat while distillate sales fell a slight 2 percent. Thus, sales of the more highly valued products did little to offset the effects of the product price declines.

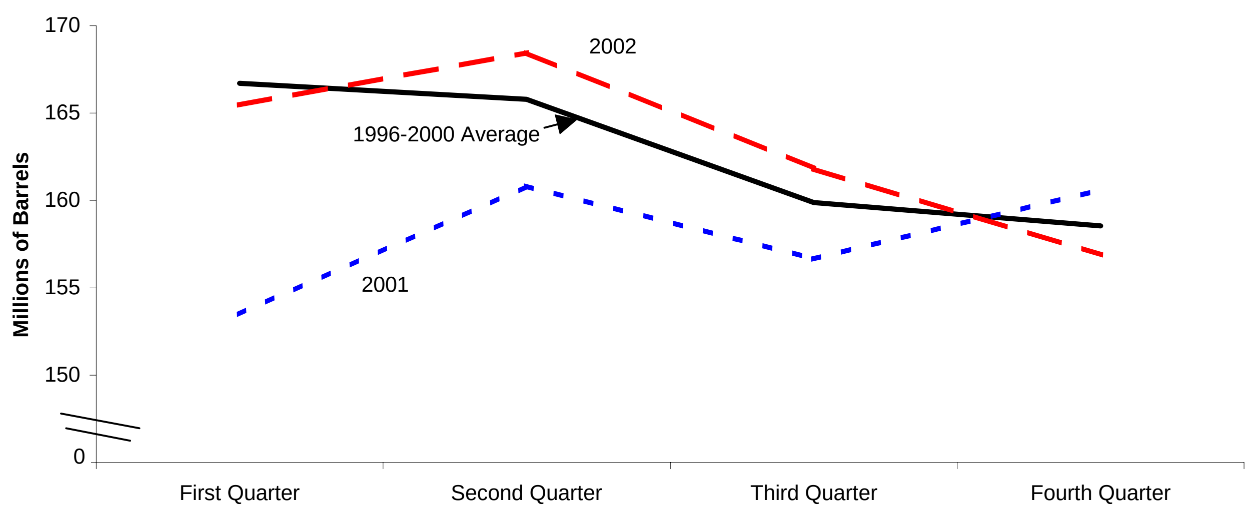
Meanwhile, refinery capacity reported by the FRS companies fell slightly (less than 1 percent)[70] (Table 14) as small expansions in the capacity of many refineries largely offset Precor's closing of its Hartford, Illinois refinery in October 2002[71] and BP's sale of its Yorktown, Virginia refinery to Giant Industries.[72] A few intra-FRS transactions (all of which occurred during 2002) shifted assets around among the FRS companies. For example, Tesoro acquired Valero's Golden Eagle refinery,[73] Shell purchased Texaco's share of Equilon and subsequently consolidated the Equilon assets,[74] and Phillips acquired Conoco via merger.[75] Additionally, all of these transactions contributed to the 25-percent increase in net investment in place between 2002 and 2001. This is because an asset is carried on a company's books at its purchase price less the depreciation, depletion, and amortization (DD&A) reductions taken over a number of years, but then, when sold, this same asset is carried on the new owner's books at the new purchase price, before the DD&A process begins anew with the purchasing company. Further, upgrading of refineries continued to occur during 2002[76] and also contributed to the increase.

Figure 13. Quarterly U.S. Commercial Petroleum Product Stocks, 1996-2000 Average, 2001, and 2002



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

Figure 14. Quarterly U.S. Motor Gasoline Stocks, 1996-2000 Average, 2001, and 2002



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

Table 13. U.S. Refined Product Margins and Costs per Barrel Sold and Product Sales Volume for FRS Companies, 2001-2002

	2001	2002	Percent Change 2001 - 2002
	(Dollars per Barrel)		
Gross Margin	7.81	6.27	-19.7
- Marketing Costs	1.59	1.57	-1.1
- Energy Costs	1.32	1.21	-8.4
- Other Operating Costs	2.19	3.31	51.2
= Net Margin	2.72	0.19	-93.0
Product Sales Volume	(Million Barrels)		
Motor Gasoline	12,435	12,469	0.3
Distillate	6,958	6,822	-2.0
Other Products	4,185	3,701	-11.6
Total	23,579	22,991	-2.5

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

Table 14. U.S. and Foreign Refining Investment and Operating Items for FRS Companies, 2001-2002

	2001	2002	Percent Change 2001-2002
	(Billion Dollars)		
U.S. Refining Additions to Investment in Place	12.1	15.1	25.1
U.S. Marketing Additions to Investment in Place	7.2	3.8	-47.4
Foreign Refining/Marketing Additions to Investment in Place	4.6	5.0	9.7
	(Thousand Barrels per Day)		
U.S. Refining Capacity	14,682	14,557	-0.9
U.S. Refinery Output	14,936	14,676	-1.7
Foreign Refining Capacity	5,572	5,642	1.3
Foreign Refinery Output	4,766	4,873	2.2
	(Percent)		
U.S. Refinery Utilization Rate[1]	95.2	91.0	(2)
Foreign Refinery Utilization Rate[1]	83.9	85.2	(2)

[1]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.

[2]Not meaningful.

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

Gross Margin Squeezed As Product Prices Fall

Industry-wide gross refining margins in 2002 were consistently lower than in 2001 for almost the entire year and fluctuated around the average level for the 1996 to 2000 period (Figure 15) throughout the year. Only over the last quarter of 2002 (when the gross margin collapsed) was the gross refining margin similar to 2001. Higher motor gasoline stocks than a year ago (Figure 14) and higher petroleum product stocks in general (Figure 13) put downward pressure on the industry-wide gross margins. Meanwhile, U.S. crude oil stock levels were at historically high levels during the first half of 2002 before consistently falling over the latter half of the year (Figure 16), resulting in an increase in the price of crude oil[77] and putting downward pressure on the gross margin. The overall effect of these (and other) effects was that the industry-wide gross refining margin of 2002 averaged $8.05 per barrel, a 31–percent decline relative to the 2001 average of $11.59 per barrel.

Meanwhile, the gross refining margin received by the FRS companies fell a lesser 20 percent compared to 2001 (Table 13). The average price received for petroleum products declined $1.45 per barrel (4 percent) while raw materials and purchased product costs rose $0.09 per barrel (less than 1 percent), which resulted in a $1.54 per barrel decline in the gross refining margin.[78]

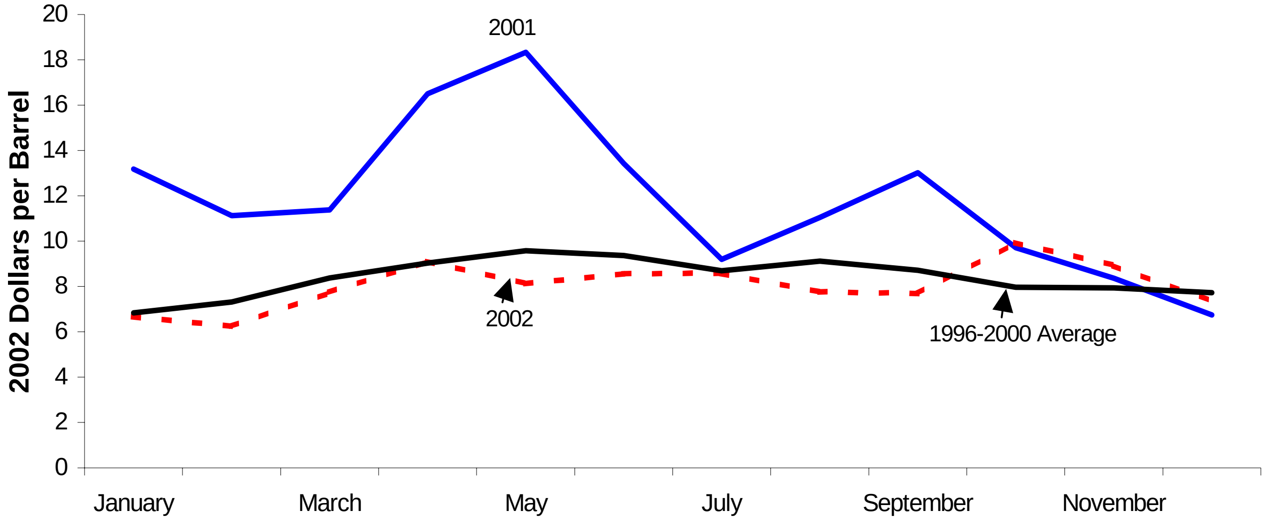
Successful efforts to increase the complexity of the FRS refineries over the last several years[79] allow the FRS companies to refine a wide range of crude oils, which has enabled them to use relatively low-cost heavy crude oils and transform them into relatively more higher-priced, light products. However, during 2002 the price of heavy crude relative to light crude increased (Figure 17), which put less downward pressure on the price of crude oil paid by the FRS companies and contributed to the slight increase in the raw materials and purchased product costs of the FRS companies. Similarly, the price of light products (represented by the price of motor gasoline) fell relative to the price of heavy products (represented by the price of residual fuel oil), which tended to increase the downward pressure on the prices of refined products of the FRS companies (Figure 18). Thus, the revenue side of the net margin was substantially lower in 2002 than in 2001. We will next examine the cost side of the net margin.

Operating Costs Rise Despite Lower Energy and Marketing Costs

A closer look at the operating costs that distinguish the gross margin from the net margin indicates that these costs increased 20 percent, but hardly at a uniform rate across the different types of costs (Table 13). Efforts over the last few years by the FRS companies to reduce their energy costs appeared to bear fruit in 2002 as energy costs fell $0.11 per barrel, an 8-percent reduction from their 2001 level. Cogeneration projects are one of the major approaches that these companies have taken to reducing their energy costs over the last few years.[80]

However, continued retrenchment of marketing operations through both selective investment in outlets in profitable areas and sales of marginal outlets and of outlets in marginal areas[81] was less successful in 2002 as marketing costs fell $0.02 per barrel, a 1-percent decline. The decline in marketing costs occurred despite extensive cost increases due to several companies re-branding their marketing outlets.[82] However, branded marketing outlets directly-supplied by the FRS companies continued to decline in 2002 (Figure 19), falling to 46,561 (14 percent less than the 54,085 reported in 2001 (Table 15)) and indicative of the FRS companies' efforts to increase the profitability of this line of business by shifting to wholesale and direct sales.[83] Company-operated outlets were reduced by slightly more than 14 percent while dealer outlets were reduced by slightly less than 14 percent. These efforts to eliminate marginal outlets resulted in increased productivity as the average monthly volume through all direct-supplied FRS branded outlets increased 7 percent between 2001 and 2002, with all of the increase achieved through dealer outlets.

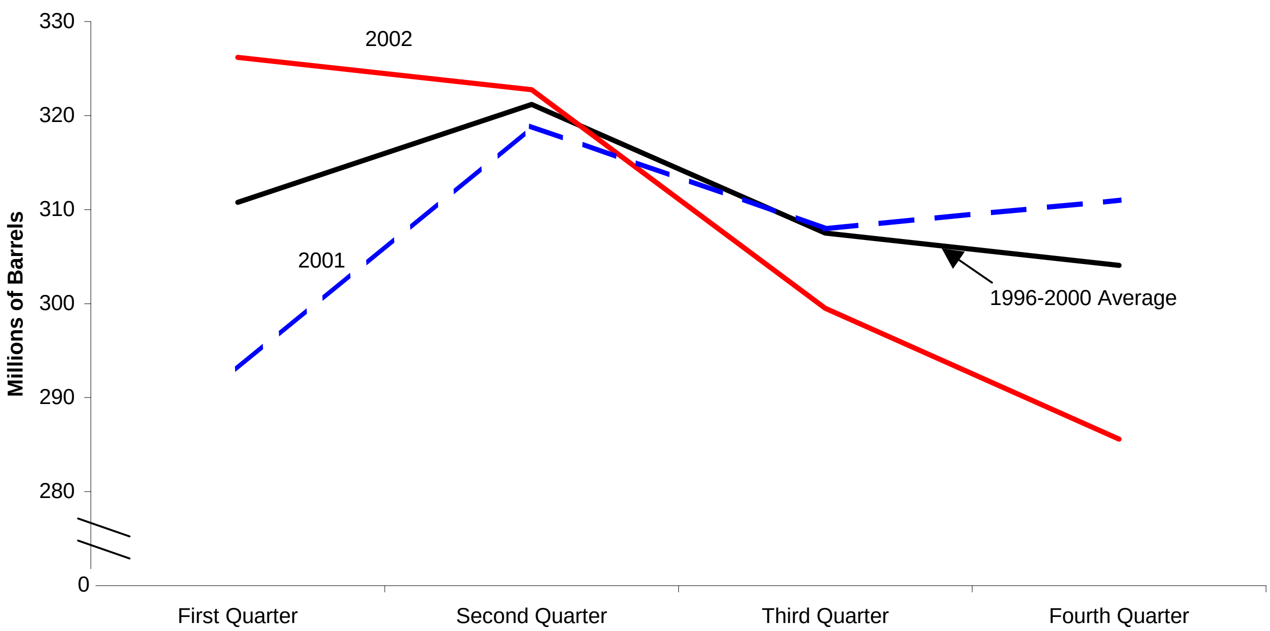
Figure 15. Monthly Gross Refined Product Margin for United States, 1996-2000 Average, 2001, and 2002



Note: The U.S. gross refined product margin is the difference between the composite wholesale product price and the composite refiner acquisition cost of crude oil.

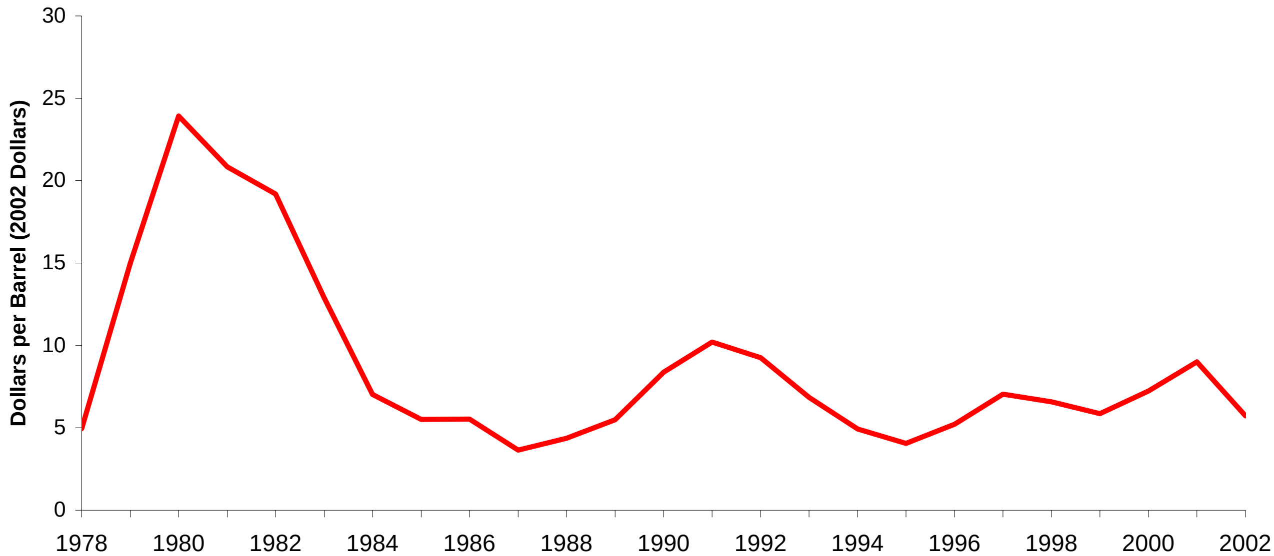
Sources: Energy Information Administration, *Petroleum Marketing Monthly* , DOE/EIA-0380 (April 1996 - March 2003), Table 1, Table 4, and Table 5; and Energy Information Administration, *Monthly Energy Review* , DOE/EIA-0380 (February 1996 - January 2003), Table 3-2b.

Figure 16. Quarterly U.S. Crude Oil Stocks, 1996-2000 Average, 2001, and 2002



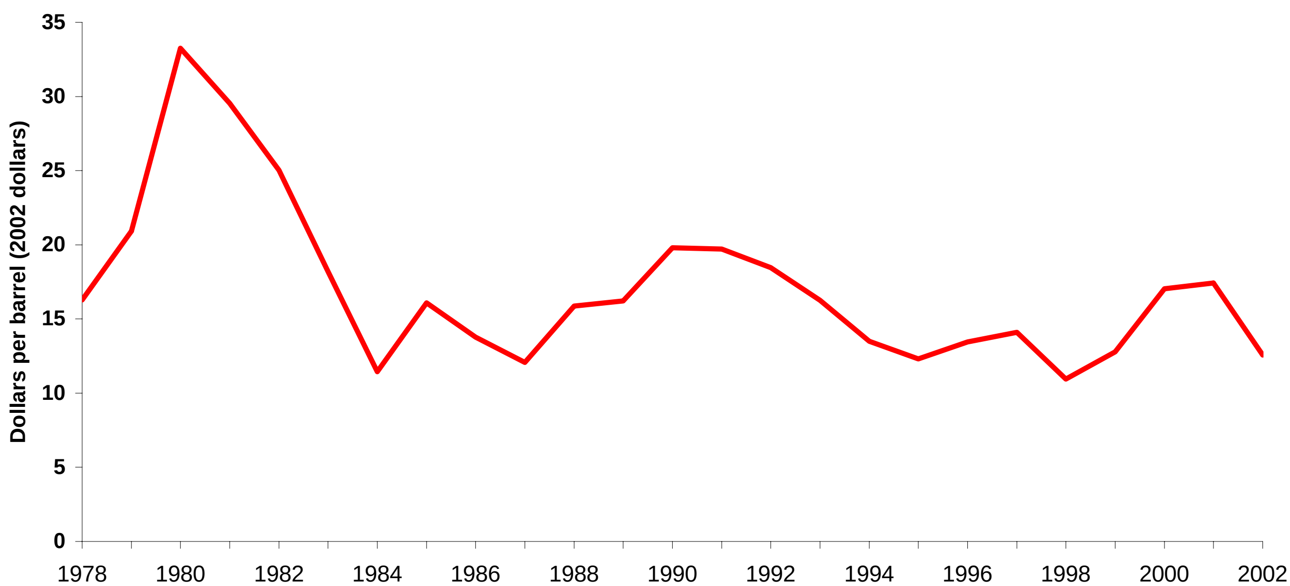
Source: Energy Information Administration, *Petroleum Supply Monthly* , DOE/EIA-0109 (Various issues, Washington, DC), Table 51.

Figure 17. Real Price Difference Between Light Crude Oil and Heavy Crude Oil, 1978-2002



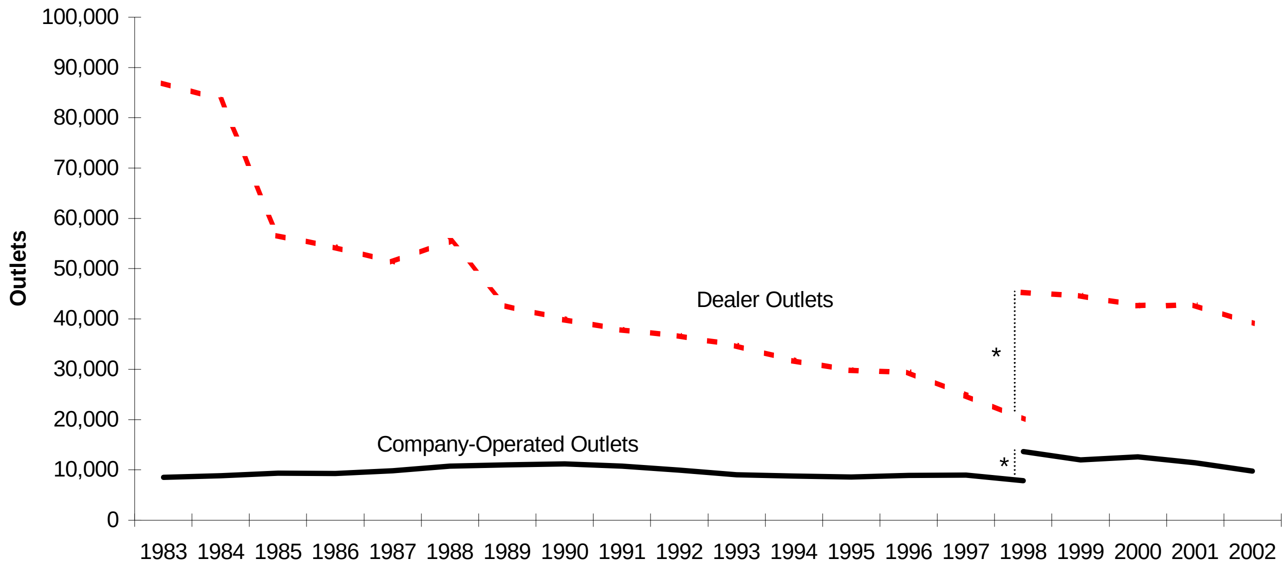
Note: Light crude oil tends to sell for a higher price per barrel than does heavy crude oil. Thus, the vertical distance of the line in the figure from the horizontal axis indicates the premium paid for light crude oil relative to heavy crude oil. The more expensive light crude oil is defined here as having an API gravity of 40.1 or greater and heavy crude oil is defined as having an API gravity of 20 or less.
Source: Energy Information Administration, *Petroleum Marketing Monthly* , DOE/EIA-0380, Tables 27 and 28.

Figure 18. Real Resale Price Difference Between Motor Gasoline and Residual Fuel Oil, 1978-2002



Note: Motor gasoline tends to sell for a higher price per barrel than does residual fuel oil. Thus, the vertical distance of the line in the figure from the horizontal axis indicates the premium paid for motor gasolinel relative to residual fuel oil.
Source: Energy Information Administration, *Petroleum Marketing Monthly* , DOE/EIA-0380, Table 4.

Figure 19. Company-Operated and Dealer Outlets for FRS Companies, 1984-2002



*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 15. Motor Gasoline Distribution and Number of Direct-Supplied Branded Outlets for FRS Companies, 2001-2002

	2001	2002	Percent Change 2001-2002
	(Million Barrels)		
Third-Party Volume			
Wholesale	1,955.8	2,032.4	3.9
Retail			
Dealer	1,182.1	1,133.4	-4.1
Company-Operated	545.1	464.3	-14.8
Total Retail	1,727.3	1,597.6	-7.5
Direct	777.0	819.8	5.5
Total Third-Party Volume	4,460.1	4,449.8	-0.2
Intersegment Volume	78.8	101.4	28.7
	(Number of Direct-Supplied Branded Outlets)		
Dealer Outlets	42,705	36,816	-13.8
Company-Operated Outlets	11,380	9,745	-14.4
Total Retail Outlets	54,085	46,561	-13.9
Average Monthly Outlet Volume	(Thousand Gallons per Month)		
Dealers	96.9	107.7	11.2
Company-Operated	167.7	166.7	-0.6
All Direct-Supplied Outlets	111.8	120.1	7.4

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

Productivity increases, though, were offset by a substantial increase during 2002 in other operating costs related to refining, which rose by $1.12 per barrel (51 percent) relative to 2001. However, the change was largely due to data reported by one of the respondents. Removal of that company from this particular calculation would eliminate more than half of the apparent FRS change in refining-related operating costs between 2001 and 2002. Additionally, the FRS companies involved in recent mergers have somewhat elevated the cost structure of the FRS companies as the surviving companies merge their operations and corporate cultures. Further, environmental spending to comply with the Clean Air Act Amendments of 1990 continues, accounting for some increase in other operating costs. (Although we have no estimate of the significance of the environmental spending within 2002 other operating costs, a recent study examined these for the 1995 to 2001 period and is summarized in the Highlight entitled, "*Environmental Compliance Partially Eclipses Recent Gains in Profitability*.")

In summary, despite the profits of recent years, the year 2002 saw the lowest level of profits for refiner/marketers in the history of the FRS. The net margin was reduced in 2002 by a falling gross margin (and revenues), a circumstance that was worsened by higher operating costs, which played a large role in the losses experienced in 2002. Nonetheless, reduced energy and marketing costs in 2002 relative to 2001 may give hope for the future domestic refining/marketing results of the FRS companies because cost-cutting efforts by these companies over the last several years suggest that they have reorganized (and continue to fine tune) their operations to better withstand the vicissitudes of their industry.

Environmental Compliance Partially Eclipses Recent Gains in Profitability

The effect of environmental legislation on profitability over the 1995 to 2001 period is explored through two avenues in a recent EIA study (*The Impact of Environmental Compliance Costs on U.S. Refining Profitability, 1995 – 2001*[a]): operating costs, and capital expenditures and depreciation charges. This study updates earlier work that examined the apparent effects of environmental compliance on refining/marketing operations' operating costs and capital expenditures (including depreciation charges) over the 1988 to 1995 period.[b]

The profitability[c] of the FRS companies' U.S. refining/marketing operations increased from approximately zero in 1995 to more than 14 percent in 2001 (Figure 11). An investigation of the reasons for increased profitability are complicated by tax and other considerations that affect net income and the investment base. However, a more straightforward approach for an examination of profitability changes is available.

The net margin is also closely related to refining/marketing profitability. Figure 20 shows that when cash earnings per barrel sold (net refined product margin adjusted for price changes) are low, so is refining/marketing profitability (return on investment). The correlation between profitability (measured by return on net investment in place) and the net margin is 0.93,[d] which is highly significant by the usual statistical conventions.

The net refining margin (net margin) is refined product revenue minus purchases of raw material inputs to refining and refined product purchases (gross margin) less out-of-pocket operating costs per barrel of refined products sold. The net margin represents the before-tax cash earnings from production and sale of refined products and excludes ancillary activities such as non-fuel sales from convenience stores. The net margin is an important determinant of short-term decisions in refining operations. Basically, for a given scale and configuration of a refinery, output will tend to be expanded as long as the added output contributes to cash earnings.

The increase in the net margin over the 1995 to 2001 period was due to both an increase in the gross margin and a reduction in operating costs. The gross margin increased over the 1995 to 2001 period (Figure 12) as low product stocks (especially in 2000 and 2001) led to higher product prices and the increasing sophistication of the FRS companies' refineries[e] allowed the companies to take advantage of price differences between light and heavy crude oil (Figure 17), lowering their raw materials costs.

Meanwhile, operating costs generally declined. The FRS companies routinely noted various cost-cutting efforts in their public disclosures for the 1995 to 2001 period (i.e., annual reports and Securities and Exchange Commission Form 10-K filings). Although energy costs actually increased over the period, reductions in other costs more than offset these increases (Table 16). Among these were environmental operating costs, which declined $0.15 per barrel (30 percent) due to increased familiarity with the production of reformulated fuels and the increased scale of production. Marketing costs were even more significant to the increased net margin as they fell $0.36 per barrel (19 percent) due to the increased use of lower-cost motor gasoline distribution channels (i.e., wholesale and direct sales) and the decreased use of higher-cost motor gasoline distribution channels (i.e., directly supplied company-operated and dealer-operated outlet sales). Lastly, and most important, was the reduction in other refining costs, which fell $0.44 per barrel (19 percent) due to cost-cutting efforts such as holding lower stock levels, as cited by numerous FRS companies. Thus, one of the reasons for the growth in profitability of U.S. refining/marketing was lower environmental operating costs, but it was hardly the major reason as it was surpassed by marketing costs and other operating costs in terms of the nominal change.[f]

The asset base used to generate the cash earnings discussed above must also be examined. Capital expenditures and depreciation charges attributable to environmental requirements are also part of the profitability calculation. Capital spending by the FRS companies, which had steadily declined between 1995 and 1997, surged in 1998 as 11 non-vertically integrated refiners were added to the FRS group. Capital spending continued to increase following 1998 largely due to mergers and acquisitions (Figure 21). (Excluding mergers and acquisitions, FRS capital spending has been essentially flat at $3.6 billion annually between 1998 and 2001.) Capital spending for environmental compliance fluctuated through the 1990's and early 2000's ahead of deadlines established by the Clean Air Act Amendments of 1990 (CAAA90). The amount of capital investment by the FRS companies was considerably less after 1995 than earlier. The effects of this change were twofold: depreciation for environmentally-related assets declined from $745 million (in 2001 dollars) in 1995 to $673 million in 2001; and the share of fixed assets accounted for by environmental investments declined (Figure 22) from 38 percent in 1995 (having peaked at 47 percent a year earlier) to 9 percent in 2001. Thus, the asset base on which the income was earned grew more due to economic reasons and less due to environmental reasons during the 1995 to 2001 period than had been the case during the 1991 to 1995 period.

In summary, the financial effects (i.e., operating costs, depreciation charges, and investment) attributable to environmental compliance all diminished between 1995 and 2001, but have they returned to pre-CAAA90 levels? To address this issue, actual profitability was compared with profitability adjusted to remove the financial effects attributable to environmental compliance in order to determine the effect of environmental compliance over the 1996 to 2001 period. The ratio of income (omitting environmentally related operating costs and depreciation) to net fixed assets (omitting the part of the investment base attributable to environmental requirements) is an accounting measure of profitability that excludes the financial effects of environmental requirements.[g] Operating income is used as the measure of income for both measures of profitability for simplicity.[h] The average profitability over the 1996 to 2001 period was lower (Figure 23) (by 42 percent) than it would have been in the absence of environmental requirements, but it still exceeds the 32-percent reduction in profitability associated with environmental compliance over the pre-CAAA90 1988 to 1990 period.

[a]T See Energy Information Administration, The Impact of Environmental Compliance Costs on U.S. Refining Profitability, 1995 – 2001 (Washington, DC, May 2003). This report can be found on the Internet at http://www.eia.doe.gov/emeu/perfpro/ref-pi2/index.html .

[b] See Energy Information Administration, *The Impact of Environmental Compliance Costs on U.S. Refining Profitability* (October 1997). This report can be found on the Internet at http://www.eia.doe.gov/emeu/perfpro/ref-pi/contents.html .

[c] Profitability of lines of business of the FRS companies is computed by dividing the net income contributed by the line of business by the net investment in place associated with the line of business. More explicitly, net investment in place is the sum of year-end net property, plant, and equipment and year-end investments and advances to unconsolidated affiliates.

[d] The results from the regression of the return on net investment in place (ROI) for domestic refining/marketing on the net margin (in 2001 dollars) for all FRS refiners (i.e., those FRS companies having non-zero values for beginning and/or ending refining capacity) for the years 1977 through 2001 are as follows: Multiple R = 0.934; R square = 0.872; adjusted R square = 0.867; standard error of the regression = 1.440; and observations = 25. The estimated equation is: Domestic refining/marketing ROI = -1.156 [0.651] + 5.514 [0.440] * net margin, where the standard errors of the estimated coefficients are in brackets.

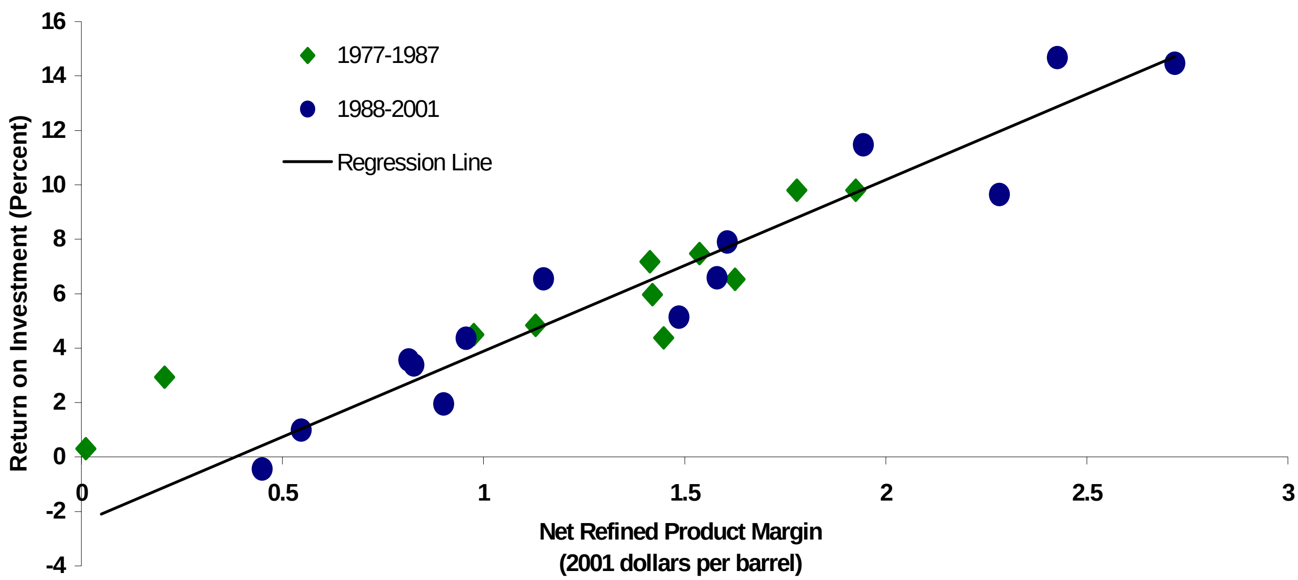
[e] See, Energy Information Administration, Update of Tables and Figures from U.S. Petroleum Refining and Gasoline Marketing Industry (Washington, DC, June 2002), Table 6. This is an Internet-only product and is located at http://www.eia.doe.gov/emeu/finance/usi&to/downstream/update/index.html.

[f] Percentage changes may be misleading because a large percentage can occur due of a large nominal change relative to a large base, or because of a small nominal change relative to a small base. Consequently, nominal changes are also presented and may take precedence over percentage changes when ascribing significance to factors.

[g] However, this measure of profitability does not include any estimates of the impacts on energy market dynamics (including 9/11) that might have occurred in the absence of environmental requirements on the U.S. refining industry.

[h] Were net income, the more traditional measure of income in profitability calculations, used instead of operating income, then the effects of environmental compliance on affiliate income, income taxes, and gains/losses from asset sales would all have to be estimated. These additional estimates are avoided by using operating income. Further, return on investment calculated with net income is highly correlated with return on investment calculated with operating income. Consequently, the returns on investment that are compared use operating income in the calculation.

Figure 20. U.S. Refining/Marketing Return on Investment and Net Refined Product Margin for FRS Companies, 1977-2001



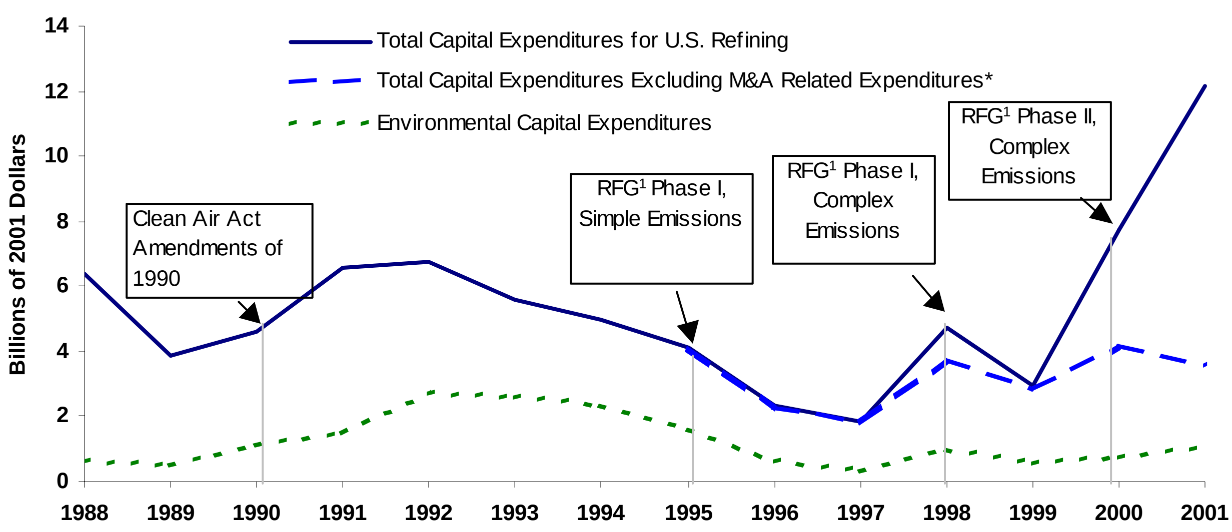
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table 16. Components of the Gross Refining Margin and Average Refined Product Revenues for FRS Companies, 1988, 1995, and 2001
(2001 dollars per barrel of refined product sold)

	1988	1995	2001	Percent Change 1995-2001
Average Refined Product Revenues	29.36	27.04	33.88	25.3
Raw material Acquisition Costs and Refined Product Purchases	20.05	20.87	26.04	24.8
Gross Margin	9.31	6.17	7.85	27.2
Energy Costs	1.45	0.92	1.37	49.3
Marketing Costs	2.14	1.95	1.59	-18.6
Environmental Operating Costs	0.36	0.49	0.34	-29.8
Other Refining Costs	2.94	2.26	1.82	-19.4
Net Refining Margin	2.43	0.55	2.72	397.0
Average Refined Product Revenues				
Motor Gasoline	33.59	30.26	36.96	22.1
Distillate	27.59	24.70	32.96	33.4
Other Products	23.20	23.17	26.30	13.5
All Refined Products	29.36	27.04	33.88	25.3

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

Figure 21. U.S. Refining Capital Expenditures for FRS Companies, 1988-2001

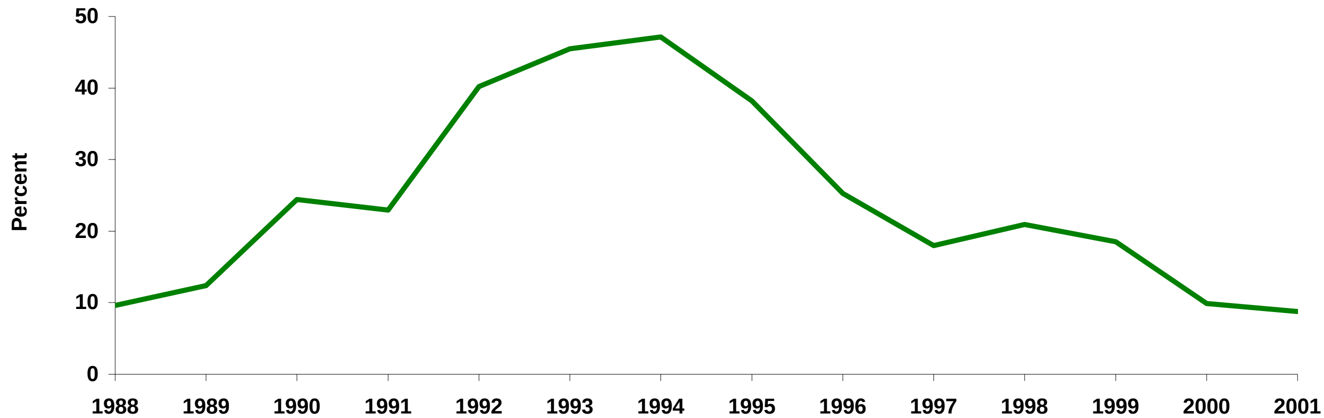


[1]Reformulated motor gasoline.

* Note that total capital expenditures excluding merger & acquisition related expenditures only cover the period 1995 through 2001.

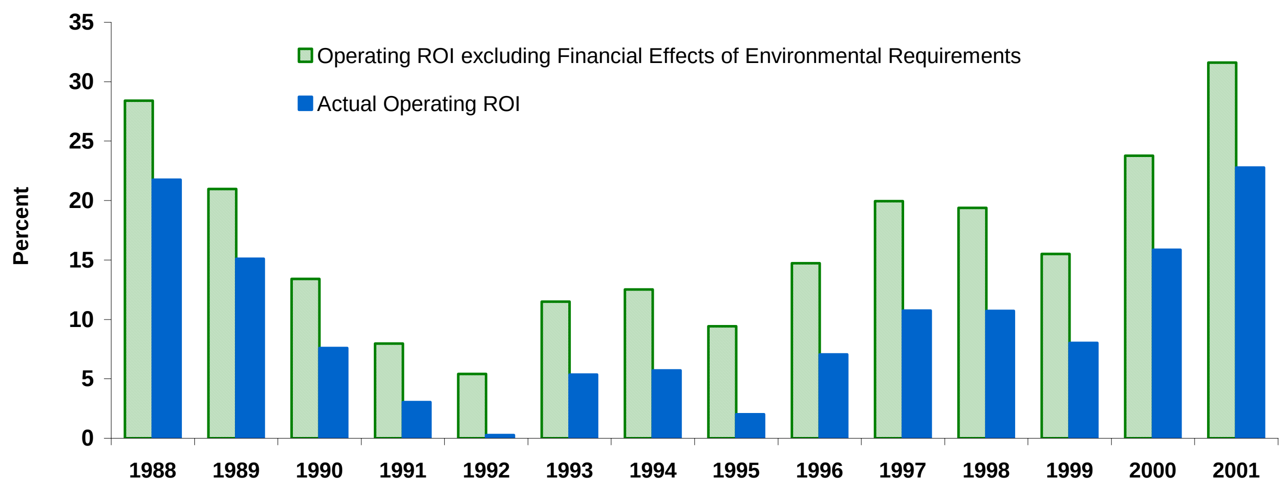
Sources: U.S. refining capital expenditures - Energy Information Administration, Form EIA-28 (Financial Reporting System) Environmental capital expenditures - **1990-1996:** American Petroleum Institute, *Petroleum Industry Environmental Performance* (Washington, DC, May 1997), pp. 47-48. **1997-2001:** American Petroleum Institute, *U.S. Oil and Natural Gas Industry's Environmental Expenditures* (Washington, DC, February 2003), p. 9. FRS environmental capital expenditures are prorated by share of U.S. crude distillation capacity.

Figure 22. Environmental Capital Expenditures as a Share of U.S. Refining Capital Expenditures for FRS Companies, 1988-2001



Sources: U.S.refining capital expenditures - Energy Information Administration, Form EIA-28 (Financial Reporting System) Environmental capital expenditures - **1988-1989**: American Petroleum Institute, *Petroleum Industry Environmental Performance* (Washington, DC, May 1997), pp. 47-48 and U.S. Department of Commerce, Bureau of the Census, *Pollution Abatement Costs and Expenditures* (various issues) (Washington, D.C.). (Estimates of expenditures were made by applying the ratio of the American Petroleum Institute series to the corresponding Census series for the 1990-1994 overlap period to the Census values for 1988 and 1989.) **1990-1996**: American Petroleum Institute, Petroleum Industry Environmental Performance (Washington, DC, May 1997), pp. 47-48. **1997-2001**: American Petroleum Institute, U.S. Oil and Natural Gas Industry's Environmental Expenditures (Washington, DC, February 2003), p. 9. FRS environmental capital expenditures are prorated by share of U.S. crude distillation capacity.

Figure 23. Operating Return on Investment in U.S. Refining/Marketing for FRS Companies, 1988-2001



Note: Operating Return on Investment (Actual Operating ROI) = operating income as a percent of net property, plant, and equipment (PP&E). Operating ROI excluding financial effects of environmental requirements = operating income less environmental operating costs less environmental depreciation expenses as a percent of net PP&E less environmental net PP&E.

Sources: Energy Information Administration, Form EIA-28 (Financial Reporting System); American Petroleum Institute, *Petroleum Industry Environmental Performance* (Washington, DC, May 1997); American Petroleum Institute, *U.S. Oil and Natural Gas Industry's Environmental Expenditures* (Washington, DC, February 2003).

Foreign Refining and Marketing

Profitability of Foreign Refining/Marketing Operations At An All-Time Low

In 2002, foreign refining/marketing return on net investment in place achieved an all-time low in the 26-year history of the FRS at 1.3 percent, breaking the previous low of 3.3 percent in 1985 (Figure 11). A small reduction in refined product revenue relative to 2001 coupled with a 56-percent decline in other revenue and a 3-percent decline in operating expense resulted in a 86-percent decline in net income (83-percent decline in net income exclusive of unusual items).

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 (a joint venture, for example is usually an unconsolidated affiliate from the perspective of at least one of the partners[84]). 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 financial information about a fully consolidated affiliate (such as revenues) is reported in the public financial disclosures of the parent corporation.

Consolidated Operations Contribute to Net Income

Historically, the operations of the FRS companies' unconsolidated foreign refining/marketing affiliates have been mainly in the Asia-Pacific region. ChevronTexaco owns much of the FRS Asia-Pacific refinery capacity, most of which is unconsolidated. In fact, about 69 percent of FRS unconsolidated foreign refinery capacity was in the Asia-Pacific region in both 2001 and 2002 (Table 17).

Consolidated FRS foreign refinery capacity is mostly located in Europe, falling from 51 percent in 2001 to 50 percent in 2002. The primary reason for the slight decline was BP's re-assignment of two Australian refineries to its U.S. affiliate (an FRS respondent) in 2002,[85] which increased the share of consolidated capacity in Asia and diminished it elsewhere, including Europe.

The contribution to net income from the FRS companies' unconsolidated foreign refining/marketing operations has been small for the last several years (since 1997) (Figure 24). However, in 2002, it reached an all-time low with a loss of $331 million (after a loss of $4 million in 2001). Alternatively, consolidated operations have consistently contributed more to the FRS companies' foreign refining/marketing earnings than have unconsolidated operations over the last several years, particularly since 1996. More to the point, between 1990 and 1996, earnings from unconsolidated operations averaged 44 percent of the contribution from consolidated operations, peaking at 102 percent in 1996. Since then (over the 1997 to 2002 time period), unconsolidated operations' earnings have averaged 9 percent of consolidated operations' earnings, reaching a nadir in 2002 by generating a loss, while consolidated operations generated income.

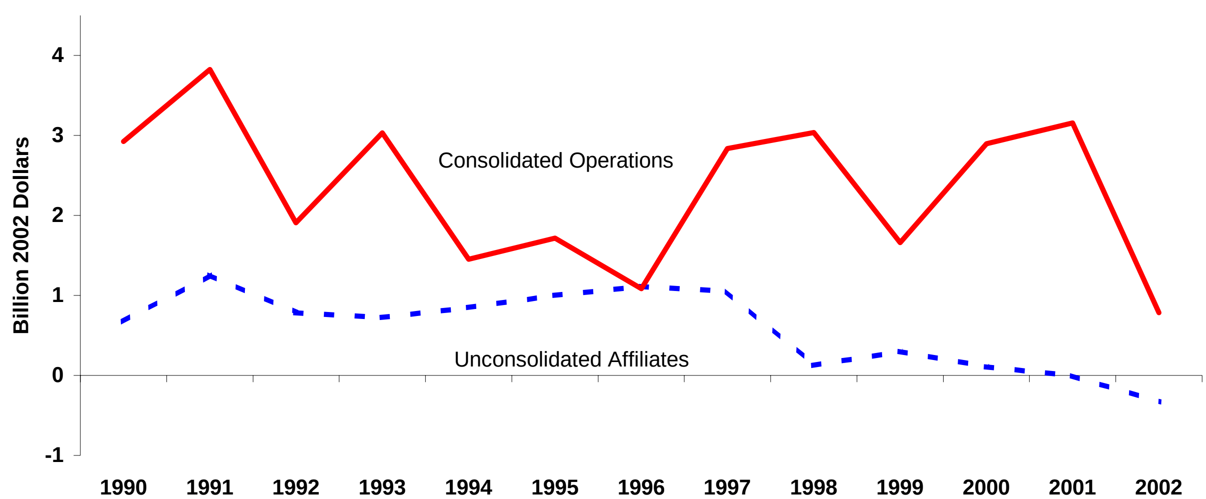
The FRS companies gave several reasons for the disappointing performance of foreign refining/marketing. These included low margins due to excess refinery capacity and weak demand, lower refinery runs in response to low margins and due to refinery outages (which were due to a fire (El Paso)[86] and an electrical outage (ConocoPhillips)[87]), and foreign exchange losses.

Table 17. Regional Distribution of Foreign Refinery Capacity for FRS Companies, 2001-2002
(Percent)

	Consolidated Operations		Unconsolidated Affiliates	
	2001	2002	2001	2002
Europe	51.0	50.0	18.0	17.9
Asia	25.0	29.0	68.6	68.7
Latin America	11.6	9.2	0.7	0.7
Canada	9.7	9.2	0.0	0.0
Other	2.7	2.6	12.7	12.7
Grand Total	100.0	100.0	100.0	100.0

Note: The region denoted as "Other" includes Africa and the Middle East.
Sources: Company Annual Reports and filings of U.S. Securities and Exchange Commission Form 10-K.

Figure 24. Foreign Refining/Marketing Net Income from Consolidated Operations and Unconsolidated Affiliates of FRS Companies, 1990-2002



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

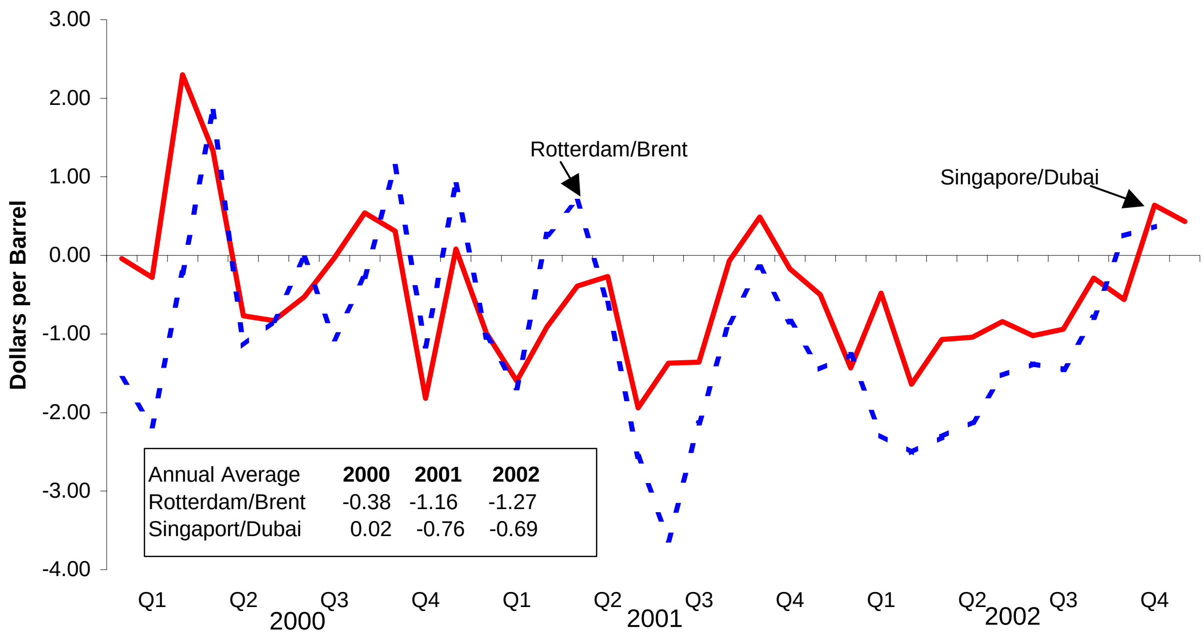
Asian-Pacific Markets Continue Poor Performance

During 2002, the FRS companies' unconsolidated affiliates generated a loss of $331 million, which was a reduction of net income of $327 million relative to a $4-million loss in 2001. The Asian-Pacific refining margins of 2002 (represented by the Singapore/Dubai gross refining margin) were much lower than those of 2001 over the first half of 2002, but by the end of the year this circumstance had reversed with the fourth quarter refining margin of 2002 exceeding that of 2001 (Figure 25) by $3 per barrel.

Due to the late rally, the gross refining margin in the Asian-Pacific region in 2002 averaged $0.07 per barrel more than in 2001.

Consumption of petroleum products in the Asia-Pacific region (combining Asian Developing Countries with Australasia and Japan) increased 2 percent between 2001 and 2002. However, the increased consumption was insufficient to prevent the FRS companies from reporting lower returns from their unconsolidated foreign refining/marketing operations, which are located in this region. Excess refining capacity and the recent relatively small growth of Asia-Pacific petroleum product consumption[88] are reasons given in company public disclosures for the losses generated by the Asia-Pacific operations of the FRS companies.

Figure 25. Foreign Refining Margins, 2000-2002



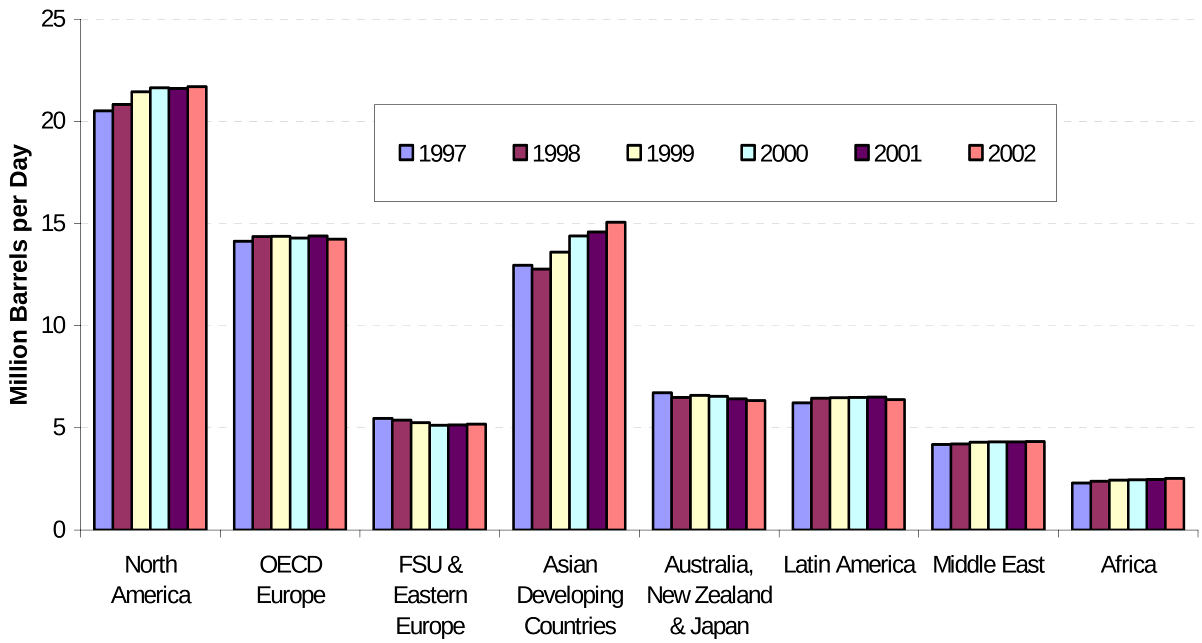
Sources: Energy Intelligence Group, *Oil Market Intelligence* **2000**: January 2001 and July 2000, p. 12; **2001**: January 2002 and July 2001, p. 12; and **2002**: January 2003 and July 2002, p. 12.

European Markets Continue to Bolster Foreign Refining/Marketing Results

The FRS companies' consolidated operations (bottom line net income from foreign refining/marketing less income from unconsolidated affiliates) provided $783 million of net income, which was 75-percent lower than the $3.12 billion result achieved in 2001. Lower earnings were consistent with the decline in Europe's consumption of petroleum products (Figure 26), which fell 1 percent between 2002 and 2001 (and increased a scant 0.8 percent between 1997 and 2002).

European refining margins (represented by the Rotterdam/Brent gross refining margin) were $1 to $2 dollars per barrel lower during the first half of 2002 than during the first half of 2001 (Figure 25). However, they rallied in the second half of the year (much as they did in the Asia-Pacific region) and surpassed the 2001 margin in both the third and the fourth quarters of 2002. Despite the late rally, the average margin for 2002 was $0.11 per barrel lower than the average margin for 2001. Thus, the industry-wide story of lower petroleum product consumption and a negligible decrease in the refining margin provided a background for an equally dismal story for the FRS companies. Among the reasons cited in public disclosures for the FRS companies' decline in earnings from their European operations were an electrical outage (and resulting diminished product sales), lower refining margins, lingering effects of the 9/11 events on product demand, and currency (foreign exchange) losses.

Figure 26. Petroleum Consumption by Region, 1997-2002



Source: BP plc, *BP Statistical Review of World Energy* (June 2003). p. 9.

Other Energy

The FRS "other energy" line of business consists of energy operations other than the production of oil, natural gas, or coal. This includes nonconventional energy operations such as synfuels and renewables, as well as assorted other activities including electric power production and supply, transportation of power, energy trading operations, and energy management services. Measured by asset growth, the other energy line of business has grown much faster in recent years than all other lines of business of the FRS companies (See Figure 27). This is equally true if revenues are used as a measure instead of assets.

Revenue and Income Drop Due to Energy Trading Decline

The story for the FRS companies' other energy line of business since the mid-1990's has been one of tremendous growth, followed by a dramatic reversal of that growth in 2001 and 2002. Much of the growth has been due to increased electric power generation and trading in both electricity and natural gas by the FRS companies. However, a decline in revenues and actual losses in earnings over the last two years has occurred largely due to the downturn in the energy trading business following the Enron financial scandal.

From 1995 until 2000, the FRS companies' revenues in other energy grew at a brisk annual rate (Figure 27) of 127 percent. In 2001, revenues dropped 1.4 percent, as Enron ceased reporting to the FRS. By 2002, the energy trading crash had spread across the energy industry, leading to a collapse in other energy revenues of 48 percent from the 2001 level (Table 18). The demise of El Paso's trading business[89] was the biggest cause of this.

The income story is similar to the revenue story. Other energy income grew at a 74- percent annual rate over 1995 through 2000. In 2001, income dropped 27 percent over the 2000 level. In 2002, however, income collapsed 173 percent as earnings went negative, with much of the decline due to losses of El Paso and ChevronTexaco's affiliate Dynegy Inc., which had also been active in energy trading.[90]

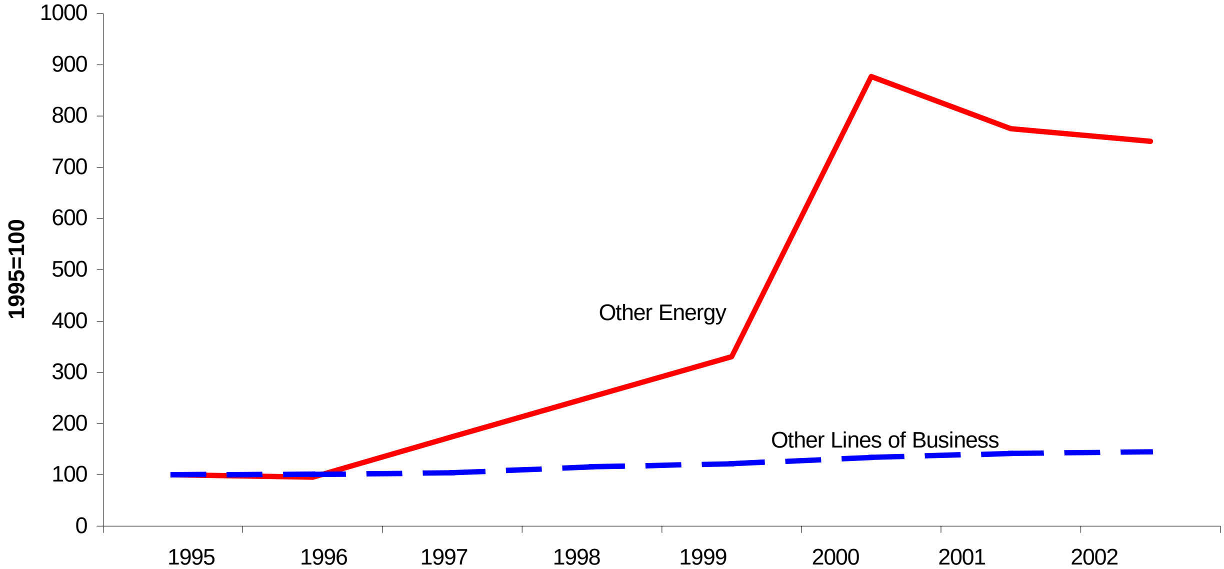
Nonconventional Energy: Tar Sands and Geothermal Stand Out

Originally, the FRS "other energy" line of business was primarily intended to cover nonconventional energy, which includes renewable resources (such as wind, solar, and geothermal energy) and hydrocarbons from tar sands, oil shale, coal gasification and liquefaction, among other sources. Although nonconventional energy was the lion's share of other energy until the mid-1990's, the FRS companies' forays into nonconventional energy were generally unprofitable, and most FRS companies started to scale back their investments in nonconventional energy during the 1980's.

Nonetheless, two nonconventional energy projects stand out: Exxon Mobil's Canadian tar sands and the Unocal Corporation's geothermal energy in Southeast Asia. Exxon Mobil significantly relies on production from tar sands, and has been extracting oil from Canadian tar sands since the 1970's. The company reports a year-end 2002 total of 800 million barrels of Canadian tar sand reserves, representing 6.3 percent of its worldwide crude oil and natural gas liquids reserves.[91] Gross synthetic crude oil produced from those tar sands was 84 million barrels in 2002, up from 80 million barrels in 2001.[92]

Unocal has over 35 years experience in geothermal energy. It operates major geothermal fields producing steam for electricity at Tiwi and Mak-Ban in the Philippines, and Gunung Salak and Wayang Windu in Indonesia. These four projects supply steam for a total of 1,120 megawatts of generating capacity.[93] Unocal's total 2002 geothermal energy production averaged 13 million kilowatt-hours, the equivalent of 20,000 barrels of oil per day, down from 22,000 barrels per day in 2001. Its net proved geothermal reserves at year-end 2002 were the equivalent of 232 million barrels of oil, compared to 162 million barrels in 2000.

Figure 27. Net Investment in Place in Other Energy and All Other Businesses for FRS Companies, 1995-2002



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

Table 18. Income Components for Other Energy for FRS Companies, 2000-2002

Income Components	2000	2001	2002	Percent Change 2001- 2002
	(Million Dollars)			
Operating Revenue	84,987	83,811	43,243	-48.4
Operating Expenses	81,948	81,678	43,886	-46.3
Operating Income	3,039	2,133	-643	-130.1
Equity Income	753	902	-563	-162.4
Net Income	2,741	1,993	-1,460	-173.3
unusual items	0	8	-133	--
Net Income excluding unusual items	2,741	1,985	-1,327	-166.9

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

End Notes

[54] Energy Information Administration, *Performance Profiles of Major Energy Producers 2001*, DOE/EIA-0206(01) (Washington, DC, January 2003), p. 34.
[55] Exxon Mobil, *2002 Financial & Operating Review*, p, 55 and *2001 Financial and Operating Review*, p, 54.
[56] ChevronTexaco, *2002 Supplement to the Annual Report*, p. 35 and *2001 Supplement to the Annual Report,* p. 24.
[57] BP, *Report to the Securities and Exchange Commission on Form 20-F, 2002,* pp. 27 and 80.
[58] BP, *Report to the Securities and Exchange Commission on Form 20-F, 2002,* pp. 27 and 35.
[59] Marathon Oil, *Report to the Securities and Exchange Commission on Form 20-F, 2002,* p. F-44.
[60] The levels of domestic and foreign production taxes are not comparable, because the latter includes royalty expenses while the former does not.
[61] It is not clear why the Other Western Hemisphere region experienced a large increase in production taxes in 2002. However, the fact that this region produces heavy oils that may not bring as high a price as lighter oils may be a contributing factor, and some South American governments may have increased their production taxes to levels higher than in other regions.
[62] See Energy Information Administration, *State Energy Severance Taxes, 1989-1993,* DOE/EIA-TR/0599 (Washington, DC, September 1995).
[63] While the same causality may be driving both domestic and foreign production tax patterns, none is obvious.
[64] Both an individual region's change in lifting costs and its amount of production have an effect on aggregate lifting costs because the cost changes in individual regions are weighted by the production in the region to obtain the aggregates.
[65]Energy Information Administration, *Performance Profiles of Major Energy Producers 2001*, DOE-EIA-0206(2001) (Washington, DC, January 2003), p. 37. This publication is available on the Internet at http://tonto.eia.doe.gov/FTPROOT/financial/020601.pdf (as of November 12, 2003).
[66]As has been mentioned numerous times over the last few years, the net margin is highly correlated with return on investment. The correlation was re-estimated during the spring of 2003 with additional data (now covering the period 1977 through 2001) and the correlation coefficient was found to be 0.93. See Energy Information Administration, *The Impact of Environmental Compliance Costs on U.S. Refining Profitability, 1995-2001* (May 2003), page 4. This publication is available on the Internet at http://www.eia.doe.gov/emeu/perfpro/ref_pi2/index.html (as of November 12, 2003).
[67]The net margin excludes peripheral activities such as non-petroleum product sales at convenience stores.
[68]Energy Information Administration, *Short-Term Energy Outlook* (Washington, DC, November 6, 2003), Table A1. This publication is available on the Internet at http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/nov03.pdf (as November 12, 2003).
[69]Comparing the stock levels of 2002 with the average for the period of 1996 through 2000 tells a similar story with a slightly smaller difference in the first quarter and similar differences in the subsequent quarters.
[70]Note that the apparent decline in the number of FRS wholly owned U.S. refineries was mostly due to double counting among merging companies. The actual decline was two refineries, BP sold its Yorktown, Virginia refinery to Giant Industries (a non-FRS company) and Precor shutdown its Hartford, Illinois rather than make upgrading investments. All other changes are purely due to double counting.
[71]See Premcor Inc., "Premcor to Close Hartford, Ill. Refinery in October" (February 28, 2002).
[72]See BP plc, "Giant Industries, Inc. Announces Acquisition of Yorktown, Virginia Refinery from BP" (February 12, 2002).
[73]Tesoro Petroleum Corporation, "Tesoro Petroleum Corporation Announces Revised Terms for Golden Eagle Acquisition" (May 6, 2002).
[74]Shell Oil Company, press release (February 12, 2002).
[75]*Houston Chronicle*, "Merger finally a done deal, ConocoPhillips now country's largest refiner" (August 31, 2002).
[76]Several FRS companies mentioned upgrading projects in their public financial disclosures. These included: ChevronTexaco (ChevronTexaco, *2002 Supplement to the Annual Report*, p. 40), ConocoPhillips (ConocoPhillips Petroleum Company, *2002 Annual Report*, pp. 18 and 19), ExxonMobil (Exxon Mobil Corporation, *2002 Annual Report*, p. 15 and *2002 Financial and Operating Review*, p. 63), Amerada Hess (Amerada Hess Corporation, *2002 Annual Report*, p. 2), Lyondell-CITGO Refinery LLP (Lyondell Chemical Corporation, 2002 U.S. Securities and Exchange Commission Form 10-K Filing, p. 54), Marathon Corporation (Marathon Corporation, *2002 Annual Report*, p. 23 and 2002 U.S. Securities and Exchange Commission Form 10-K Filing, p. 47), Premcor Inc., (Premcor Inc., 2002 U.S. Securities and Exchange Commission Form 10-K Filing, p. 50), Tesoro Petroleum Corporation (Tesoro Petroleum Corporation, 2002 U.S. Securities and Exchange Commission Form 10-K Filing, p. 46), and Valero Corporation (Valero Corporation, 2002 U.S. Securities and Exchange Commission Form 10-K Filing, p. 41).
[77]Energy Information Administration, *Annual Energy Review 2002*, DOE/EIA-0384(2002) (Washington, DC, October 24, 2003), Table 5-19. This publication is available on the Internet at http://www.eia.doe.gov/emeu/aer/petro.html (as of November 12, 2003).

[78]A $1.50-per-barrel decline seems less significant when compared to a base of almost $34 per barrel than when it is compared to a base of slightly less than $8 per barrel.
[79]See Energy Information Administration, "Update of Tables and Figures from *U.S. Petroleum Refining and Gasoline Marketing Industry*," Table 6. This is an Internet-only product that is available at http://www.eia.doe.gov/emeu/finance/usi&to/downstream/update/index.html (as of November 12, 2003).
[80]See for example, Energy Information Administration, *Performance Profiles of Major Energy Producers 2001*, DOE/EIA-0206(2001) (Washington, DC, January 2003), p.43 (This publication is available on the Internet from a link at http://www.eia.doe.gov/emeu/finance/histlib.html (as of November 12, 2003).) and ExxonMobil Corporation, *2002 Financial and Operating Review*, p. 66.
[81]Amerada Hess added 25 Hess Express convenience stores during 2002 (Amerada Hess Corporation, *2002 Annual Report*, p. 12). ConocoPhillips recorded charges for the impairment of assets associated with retail outlets that will be sold during 2003 (ConocoPhillips, *2002 Annual Report*, p. 72). ExxonMobil identified four key areas for its focus: "cost reductions, nonpetroleum income growth, selective and disciplined new investments, and high-grading service stations (ExxonMobil Corporation, *2002 Annual Report*, p. 17)." Marathon consolidated Speedway SuperAmerica operations by exiting southeastern States in which it has a minimum market presence, refocusing on its Midwest operations. (Marathon Oil Company, *2002 Annual Report*, p. 23). Valero invested in "top-performing stores" and closed marginal ones (Valero Corporation, *2002 Annual Report*, p. 15).
[82]For example, BP is transforming many Amoco outlets into BP outlets, but continuing to offer Amoco-branded motor gasoline (see BP plc, "BP Unveils Chicago's Gas Station of the Future" (May 14, 2002) at http://www.bpamoco.com/centres/press/p_r_detail_p.asp?id=895 (as of November 12, 2003)). Also, Shell is transforming many Texaco outlets that were formerly part of Equilon into Shell-branded outlets (see Shell Oil Company, "Shell Brand Poised for Major Expansion in U.S." (February 8, 2002) at http://www.piersystem.com/external/final_View.cfm?pressID=5527&CID=69 (as of November 12, 2003)). Additionally, BP has installed photovoltaic panels at many of its outlets, which are asserted to supply about "20 percent of the site's overall energy needs" (see BP plc, "Commited to Cleaner Environment, BP Begins Selling Ultra Low Sulfur Diesel in California; Converts ARCO Sites to Solar" (June 14, 2002) at http://www.bpamoco.com/centres/press/p_r_detail_p.asp?id=903 (as of November 12, 2003)).
[83]This continues a recent trend discussed elsewhere, particularly two Energy Information Administration publications: *Performance Profiles of Major Energy Producers 2000*, DOE/EIA-0206(2000) (Washington, DC, January 2002), p. 44 (available on the Internet at http://tonto.eia.doe.gov/FTPROOT/financial/020600.pdf (as of November 13, 2003)) and *Restructuring: The Changing Face of Motor Gasoline Marketing* (October 2001), an Internet-only product at http://www.eia.doe.gov/emeu/finance/sptopics/downstrm00/index.html (as of November 13, 2003).
[84]The Caltex joint venture was an unconsolidated affiliate for both of its parents, Chevron and Texaco.
[85]The refineries are the 69,800 barrels per day Bulwar Island refinery and the 158,500 barrels per day Kwinana refinery.
[86]El Paso Corporation, 2002 U.S. Securities and Exchange Commission Form 10-K filing, p. 60.
[87]ConocoPhillips Company, *2002 Annual Report*, p. 43.
[88]Between 1992 and 1997 Asia-Pacific (computed by combining Asian Developing Countries and Australia, New Zealand, and Japan) petroleum product consumption increased 28 percent. However, between 1997 and 2002 Asia-Pacific petroleum product consumption increased 9 percent. Thus, the growth over the last few years has failed to match the pace over the earlier period, which seems to be the major reason that companies speak of excess refinery capacity in this region.
[89]El Paso Corporation, press release (November 8, 2002).
[90]Dynegy Inc., 2002 Securities and Exchange Commission Form 10-K, pp. F-73, F-74.
[91]Exxon Mobil Corporation, *2002 Financial and Operating Review*, p.57.
[92]Exxon Mobil Corporation, *2001 Financial and Operating Review*, p.35.
[93]Unocal Corporation, 2002 Securities and Exchange Commission Form 10-K, pp. 18-19.

4. Resource Development Trends

This chapter of *Performance Profiles* addresses the costs of finding oil and natural gas and other resource development issues. While the costs of adding oil and gas reserves (finding costs) do not directly affect 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 four analyses ("Special Topics") that discuss:

- Variations in regional finding costs
- Development in the Gulf of Mexico
- Natural gas production in the United States
- The Mackenzie pipeline and implications for the U.S. natural gas market

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***SPECIAL TOPIC*: Finding Costs Increased in Most Regions**

Average finding costs rose worldwide, boosted by increases in six of the nine FRS regions for the 2000 to 2002 period, with Canada again experiencing the highest costs as it had for the 1999 to 2001 period (Table 19). Compared to the second-most-costly region, Canada’s costs increased from $3 per barrel of oil equivalent for the 1999 to 2001 to $5.51 for the 2000 to 2002 period and had the largest absolute increase for the 2000 to 2002 finding costs for any FRS region.

Finding costs are the costs of adding oil, including crude oil and natural gas liquids, and 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). Ideally, finding costs would include 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 (excluding 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.

Other prominent changes in regional finding costs for the FRS companies for the 2000 to 2002 period include the largest proportional increase in finding costs in OECD Europe and a notable increase in the U.S. Onshore (Table 19). The large increase in OECD Europe (predominantly the North Sea) raised that region to the second-highest region for finding costs, while the increase in the U.S. Onshore pushed it into virtual tie with the U.S. Offshore (predominantly the Gulf of Mexico) for the third highest-cost region. The large decrease in finding costs for the FRS companies in the Middle East for the 2000 to 2002 period is of little significance because, with the unfavorable investment climate in the Middle East, this region is usually the one with the smallest amount of reserve additions through the drill bit for the FRS companies.

Table 19. Finding Costs by Region for FRS Companies, 1999-2001 and 2000-2002
(Dollars per Barrel of Oil Equivalent)

Region	1999-2001	2000-2002	Percent Change
United States			
Onshore	6.01	7.62	26.7
Offshore	6.99	7.59	8.6
Total United States	6.39	7.61	19.1
Foreign			
Canada	10.70	14.83	38.6
OECD Europe	5.51	9.32	69.3
Former Soviet Union and Eastern Europe	3.26	3.10	-4.9
Africa	3.68	3.68	0.0
Middle East	7.66	5.94	-22.5
Other Eastern Hemisphere	4.07	4.63	13.7
Other Western Hemisphere	6.22	5.14	-17.5
Total Foreign	5.25	5.92	12.6
Worldwide	5.78	6.70	16.0

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).

In order to understand the basis for finding cost increases or decreases, one must look at its two components -- finding rates and expenditures per well. Finding rates are the average amount of proved reserves added by the drill bit (through extensions and discoveries, improved recovery, and revisions to previous reserves estimates) per well drilled.

Ideally, reserve additions per well are measured as the average of the reserves added by each well during its lifetime (no matter the date that the well was completed or the reserves added). In practice, additions to reserves per well are actually measured as the ratio of total proven reserve additions (excluding net purchases) to the number of wells completed (including dry holes) during a specified period of time, with no attempt to link reserve increases to individual wells.[c]

Similarly, expenditures per well are ideally measured as the average of the exploration, development, and unproved acreage expenditures associated with each well during its lifetime. In practice, expenditures per well are the total expenditures on exploration, development, and unproved acreage divided by the number of wells completed during a particular time period, with no attempt to link expenditures to individual wells.

These two ratios are generally measured in *Performance Profiles* as a weighted average over a period of three years (in part, to compensate for the imperfect way they are measured), and, if several years of data are presented, expenditures are usually reported in constant dollars (to facilitate comparisons over time). Finding costs are then the expenditures (to find additional reserves) per well completed divided by the finding rate (proven reserve additions per well completed).

Worldwide finding rates and expenditures per well for the FRS companies both fell for the 2000 to 2002 period (Table 20). However, the increase in worldwide finding costs, as shown in Table 19, resulted from finding rates falling faster than expenditures per well.[d] In other words, the relatively larger decline in the worldwide finding rate was the sole reason that finding costs rose. In Canada, the region with the largest absolute increase in finding costs for the 2000 to 2002 period, a 13-percent decline in the expenditures per well was more than offset by a 37-percent decline in the finding rate. Finding costs in OECD Europe rose so much because the finding rate there fell while expenditures per well rose (both of which resulted in increased finding costs). For the U.S. Onshore, expenditures per well changed little while the finding rate fell. In each of these instances, the fall in finding rates was the more prominent contributor to increased finding costs.

Table 20. Finding Rates and Expenditures per Well by Region for FRS Companies, 1999-2001 and 2000-2002

Region	Finding Rates (Thousand Barrel of Oil Equivalent per Well)			Expenditures Per Well (Thousand Dollars per Well)		
	1999-2001	2000-2002	Percent Change	1999-2001	2000-2002	Percent Change
United States						
Onshore	354	293	-17.2	2,128	2,232	4.9
Offshore	2,258	2,293	1.5	15,782	17,391	10.2
Total United States	522	437	-16.3	3,332	3,322	-0.3
Foreign						
Canada	162	102	-37.4	1,738	1,508	-13.2
OECD Europe	6,087	4,185	-31.2	33,519	39,024	16.4
Former Soviet Union and Eastern Europe	10,067	13,913	38.2	32,776	43,068	31.4
Africa	6,715	6,057	-9.8	24,687	22,263	-9.8
Middle East	438	831	89.7	3,358	4,940	47.1
Other Eastern Hemisphere	1,728	1,338	-22.6	7,034	6,193	-12.0
Other Western Hemisphere	2,127	1,721	-19.1	13,240	8,836	-33.3
Total Foreign	1,084	817	-24.6	5,696	4,836	-15.1
Worldwide	723	582	-19.6	4,180	3,900	-6.7

Notes: The above finding rates are 3-year weighted averages of reserve additions, excluding net purchases of reserves, divided by number of wells completed, and the above expenditures per well are 3-year weighted averages of exploration and development

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

Finding Costs for Many Regions Show Consistent Patterns Since Early 1990's

Regional finding costs vary substantially across the FRS regions in any particular period and in any particular region from period-to-period (Table 19). From the 1990's until 2002, the highest and lowest regional finding costs year have differed from each other by $3.60 per barrel of oil equivalent (boe) to $11.90 per boe in constant 2002 dollars (Figure 28). The relatively high variance in regional finding costs is indicated by the extent that the range between the maximum and minimum finding costs has exceeded the lowest finding cost in every year except one. In addition, the gap between maximum and minimum finding costs has been widening in recent years, largely because the maximum finding cost has increased much more than the minimum one.

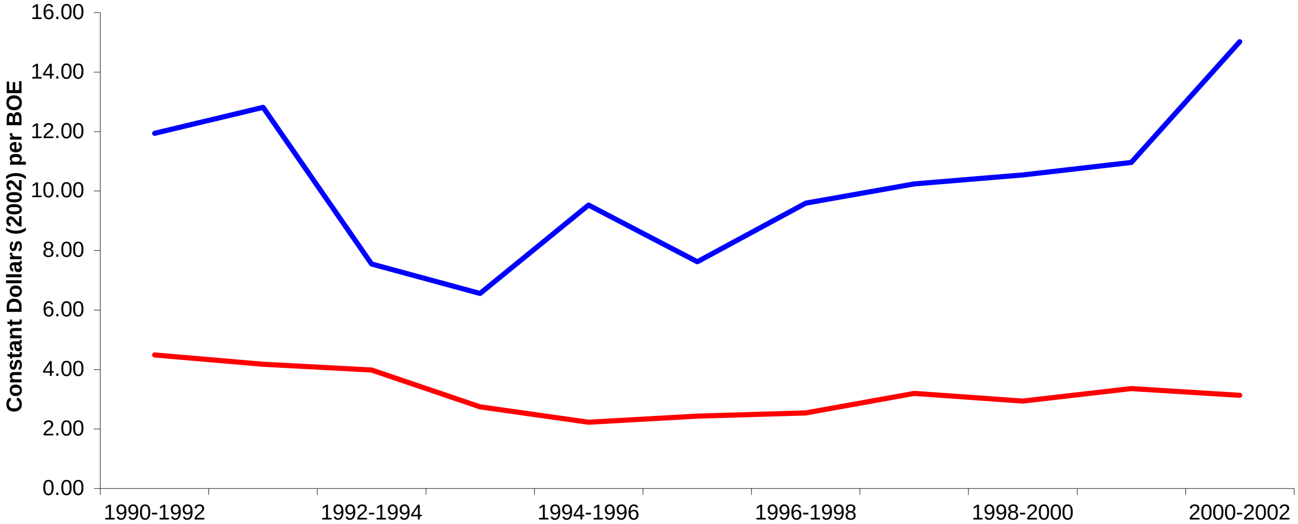
Nonetheless, when examining regional finding costs over a long period of time, many of the regions have had relatively consistent finding cost levels. (In this discussion of regional finding cost trends, five-year periods are being used to dampen extreme values and facilitate comparisons.) The regions can, somewhat arbitrarily, be separated into groups with high costs, low costs, and varying costs for the years 1990 through 2002 (Figure 29).

The regions that have had high finding costs are Canada, the U.S. Offshore (largely the Gulf of Mexico), and OECD Europe (largely the North Sea). Moreover, some of the largest finding cost increases in recent years have been incurred in these regions. With one of the lowest expenditures per well of any region, Canada might be expected to have low finding costs. However, most of Canada's oil and gas reserves tend to be in smaller pockets somewhat near to the surface, resulting in a majority of the wells in Canada being relatively shallow wells that are less costly to drill but also account for smaller reserve additions. Therefore, the low reserve additions per well results in Canada having one of the highest regional finding costs for the FRS companies. OECD Europe reserves are mostly offshore. Offshore exploration and development tends to be relatively more expensive, with larger fields found and lower lifting costs. This is part of the reason that the U.S. Offshore and OECD Europe are among the regions with the highest expenditures per well.

The low-cost regions from 1990 through 2002 are Africa, the Other Western Hemisphere, and the Other Eastern Hemisphere (Figure 29). All three regions fall in the middle range of the amount of exploration and development activity, both in spending and reserves added over the period. These regions differ from the other FRS regions because they are not as well developed as the U.S. Onshore and Offshore, Canada, and OECD Europe regions and generally have not restricted investment by U.S. companies as much as the two regions of the Middle East and the Former Soviet Union and Eastern Europe. The three low-cost regions also have had some of the most stable finding cost levels of any of the FRS regions.

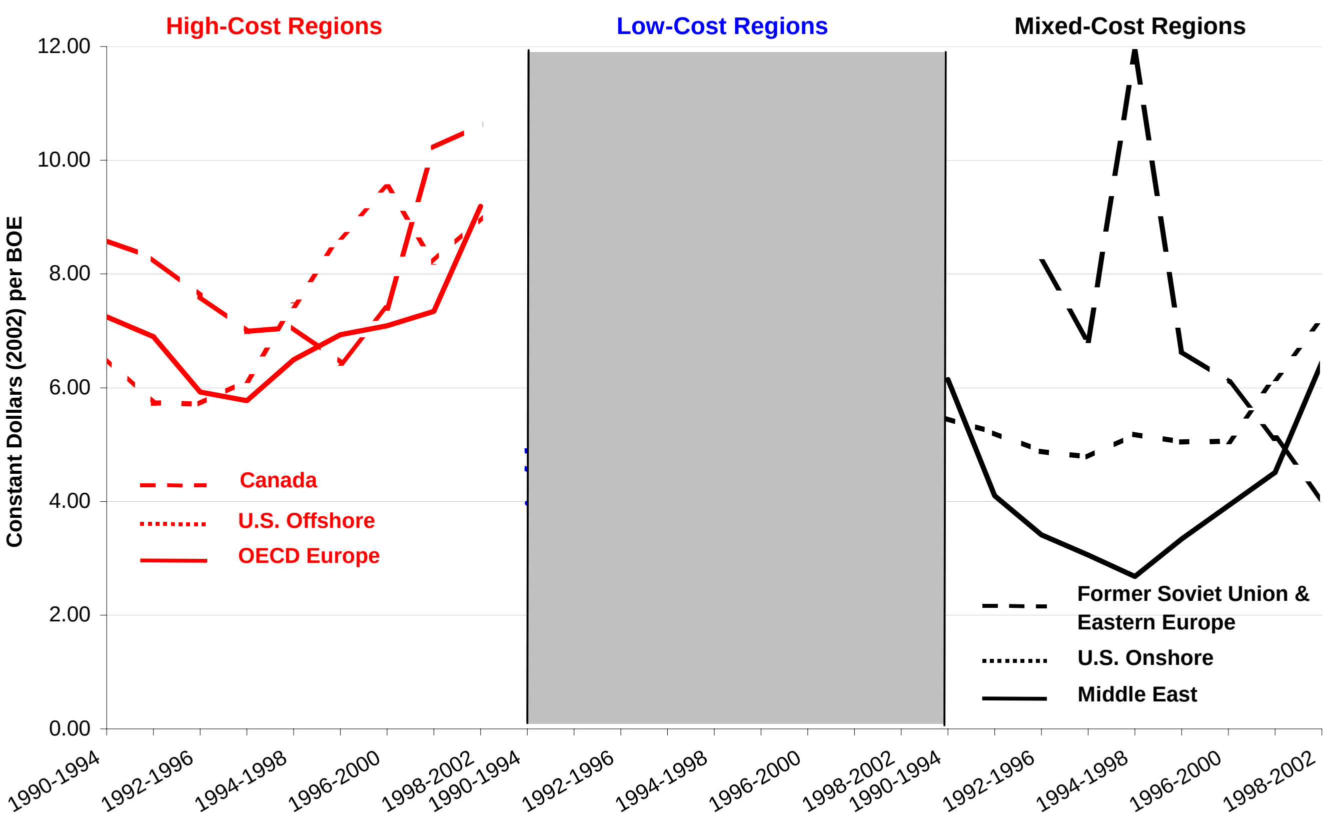
The remaining regions, the U.S. Onshore, the Middle East, and the Former Soviet Union and Eastern Europe, exhibit cost patterns that are not as consistent as the other FRS regions (Figure 29). Finding costs for the U.S. Onshore had remained rather stable and low, but they have increased substantially in both of the last two five-year periods, indicating the possibility that this region may become one of the high-cost ones.[e] Finding costs for the FRS companies in the Middle East have followed a "U-shaped" pattern, from high to low to high again, with increases in the last four five-year periods (a total timeframe of eight years). The cost estimates for this region are probably the most uncertain, because, as previously explained, the Middle East has had less exploration and development spending by the FRS companies than any other region by a large margin. The region of the Former Soviet Union and Eastern Europe had high finding costs in the middle of the period, but has experienced dramatic declines in eight-year period comprised by the last four five-year periods, as exploration and development activities has ramped up from very low levels in the early and mid-1990's.[f]

Figure 28. Maximum and Minimum Three-Year Weighted Average Regional Finding Costs for FRS Companies, 1990-1992 to 2000-2002



Note: Finding costs are weighted averages of the annual finding costs for the three years specified. The labels used on the horizontal axis reflect that the values plotted on the figure are 3-year averages.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Figure 29. Five-Year Weighted Average Regional Finding Costs for FRS Companies, 1990-1994 to 1998-2002



Note: Finding costs are weighted averages of the annual finding costs for the five years specified. The labels used on the horizontal axis reflect that the values plotted are 5-year averages. Finding costs for the Former Soviet Union and Eastern Europe are not available before 1992-1996 due to confidentially requirements.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Finding Costs Are Rising, But So Are Prices

Overall, finding costs have been rising above their lows of the mid-1990's, both domestically and abroad (Figure 30). However, U.S. Offshore finding costs, which had surged beginning in the three years of 1994 to 1996, have fallen back to meet the rising U.S. Onshore costs, while foreign costs have stayed lower than costs in the United States for the two most recent three-year periods.

However, trends in finding costs must be considered, among other things, in the context of oil and gas prices. Finding costs are expected to move in concert with crude oil and natural gas prices.[g] Higher crude oil and natural gas prices mean that crude oil and natural gas are worth more than they had been, so profit-seeking companies should be spending more to find them.

The prices of crude oil and natural gas declined through most of the 1980's, followed by a level period for natural gas and a slight decline for crude oil (Figure 31).[h] However, both have been rising in recent years. The trend in worldwide finding costs for the FRS companies has exhibited a similar pattern. Worldwide finding costs declined in the 1980's through mid-1990's, but then began rising. They have increased 42 percent since their low in the 1994 to 1996 period; over the same period, domestic crude oil prices rose by 39 percent and natural gas prices by 72 percent.

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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 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 over a long time period), 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]As with finding costs, measurements of reserve additions per well are limited because the reserves added and the wells completed during a particular interval of time do not necessarily correspond exactly with each other. (For further discussion, see previous note.)

[d]If finding rates and expenditures either rise or fall by the same percentage, then finding costs will not change. (See Former Soviet Union and Eastern Europe Tables 19 and 20.)

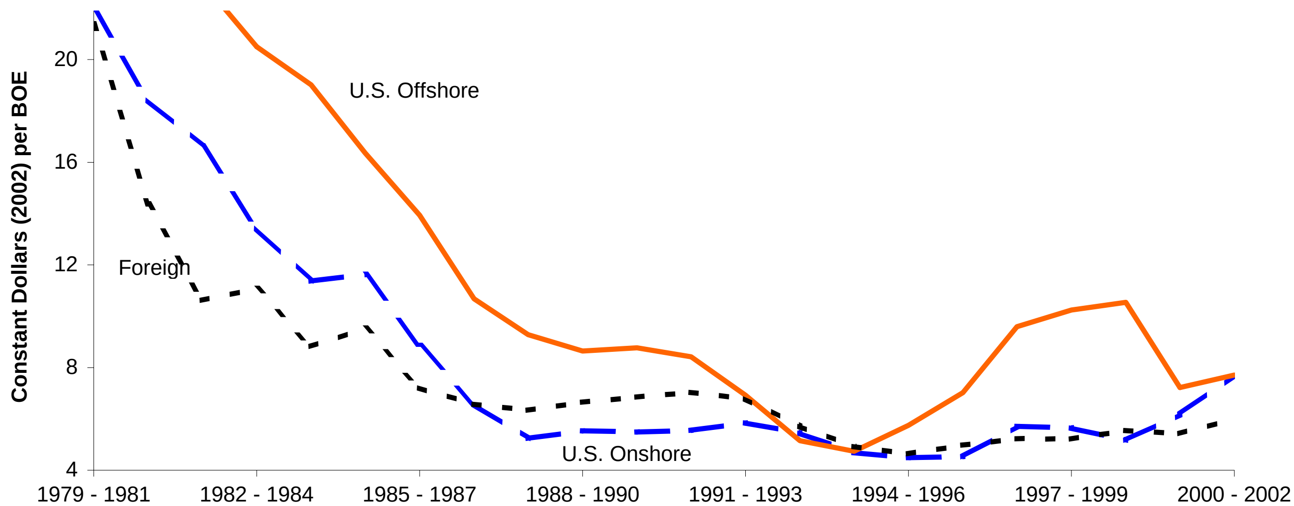
[e]Every year, one year is added and one year is dropped from this calculation. The above result regarding finding costs for the U.S. Onshore region means that annual U.S. Onshore finding costs were higher in 2001 that in 1996, and higher in 2002 than in 1997.

[f]Five-year finding costs for the regions of the Former Soviet Union and Eastern Europe before the 1992 to 1996 period cannot be disclosed because of data confidentiality requirements.

[g]Technological change is another factor in determining finding costs; it is not considered in this discussion.

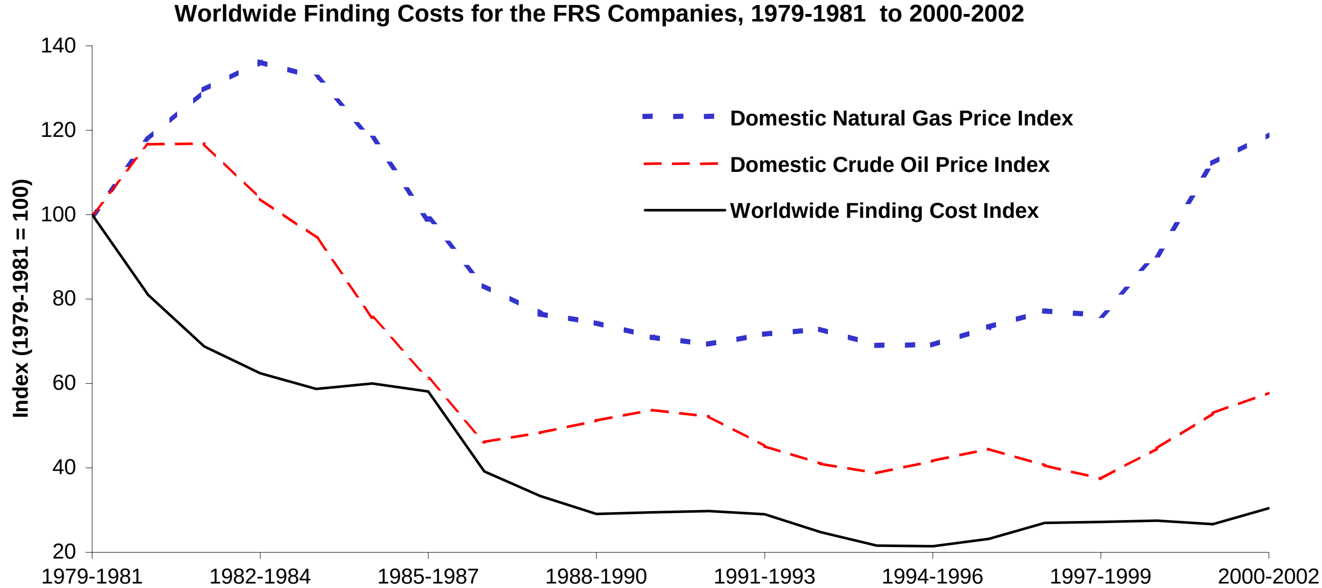
[h]The prices used to construct these indices are domestic prices. While the domestic price of crude oil is similar to the world price, the domestic price of natural gas is not. However, worldwide natural gas prices have moved in similar directions since the mid-1990's. See *BP Statistical Review of World Energy,* (London, United Kingdom, June 2003), p. 29.

Figure 30. U.S. Onshore, U.S. Offshore, and Foreign Three-Year Weighted Average Finding Costs for FRS Companies, 1979-1981 to 2000-2002



Note: Finding costs are weighted averages of the annual finding costs for the three years specified. The labels used on the horizontal axis reflect that the values plotted on the figure are 3-year averages.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Figure 31. Indices of Three-Year Average Domestic Real Prices of Crude Oil and Natural Gas and Worldwide Finding Costs for the FRS Companies, 1979-1981 to 2000-2002



Notes: Averages are unweighted. Real prices are in constant 2002 dollars. Crude oil price is the crude oil domestic first purchase price, and natural gas price is the domestic wellhead natural gas price. The labels used on the horizontal axis reflect that the values plotted on the figure are 3-year averages.
Source: Domestic natural gas price index and domestic crude oil price index: Energy Information Administration, *Monthly Energy Review October 2003,* DOE/EIA-0035(2003/10) (Washington, DC, October 2003), Tables 9.1 and 9.11. Worldwide finding cost index: Energy Information Administration, Form EIA-28 (Financial Reporting System).

SPECIAL TOPIC: The Gulf of Mexico – Do Technology and Recent Economics Favor Oil Reserves Over Natural Gas?

Exploration and development in the Gulf of Mexico commenced over fifty years ago when the Kerr-McGee corporation discovered Ship Shoal 32, about 10 miles off the Louisiana coast in 18 feet of water. By the mid-1980's, almost 1,000 fields had been discovered and many industry analysts were convinced that the Gulf was in decline.[a] Some even referred to the Gulf as the "Dead Sea."[b] Starting with Shell Oil's discovery of the 220-million-barrel deepwater Auger field in 1987, this view has been replaced with the recognition that the Gulf still has tremendous potential. What has been especially striking about the deepwater fields are the high productivity rates of the wells. For example, a typical shallow-water oil well flows at just over 100 barrels of oil per day, whereas oil wells at the deepwater Ursa field each produce about 30,000 barrels of oil per day.[c] Similarly, a single well at the deepwater Mensa field produces about 100 million cubic feet of gas per day, which is about fifty times the flow rate for a typical shallow-water gas well.[d]

In the shallow-water portion of the Gulf, i.e. that portion of Gulf where the water depth is less than 200 meters, the industry over the period of 1993 through 2002 replaced approximately 80 percent of the roughly 7.4 billion of crude oil equivalent that was produced over the period.[e] As a result, crude oil equivalent reserves in the shallow Gulf were approximately 33 percent lower at the end of 2002 than in 1993. Fortunately, this has been more than offset by the deepwater where reserve additions over the 1993 through 2002 period were more than 2.5 times the level of production.

For the Gulf as a whole, over 12 billion barrels of crude oil equivalent were produced over the period 1993 through 2002 while reserves at the end of 2002 were approximately 2.5 billion barrels of oil equivalent higher than at the beginning of the period.[f] With respect to remaining undiscovered resources, the 2000 resource assessment performed by the U.S. Department of Interior's Minerals Management Service (MMS) indicates that there are approximately 71 billion barrels of oil equivalent yet to be added to reserves.[g] Not surprisingly, the vast proportion of the remaining undiscovered resources are in the deepwater. MMS estimated that the split between oil versus natural gas resources is approximately fifty-fifty.[h]

Some of the more notable deepwater discoveries include:

Thunder Horse. This field (previously known as Crazy Horse) is believed to contain between one and three billion barrels of recoverable crude oil equivalent, which makes it the largest field ever discovered in the Gulf of Mexico.[i] This field gives new meaning to the notion of a deep field in that it lies over 25,000 feet below the ocean floor which in turn is 6,000 feet below the surface of the Gulf. The field also typifies the long lead-time associated with offshore exploration and development. Lead times can be long because production requires pipeline infrastructure that may only be economic when there are a number of fields to be brought onstream.

For example, in the case of Thunder Horse, the field was leased in 1988 but the first discovery well was not drilled until 1999. Initial production is expected to commence in 2005, 17 years after the lease was acquired.[j] It is expected to be worth the wait given that the field will be produced using a 250,000-barrels-of-oil-equivalent-per-day floating production facility. Partners in the field are BP (with a 75-percent ownership share) and Exxon Mobil (with a 25-percent ownership share). The field also typifies the oil-prone nature of the deepwater discoveries to date based on the planned production facilities, approximately 87 percent of the production (on an oil equivalent basis) is expected to be accounted for by crude oil as compared to natural gas.[k]

Mad Dog. Discovered in 1998, the Mad Dog oil field development is planned to have 14 wells tied back to a spar. The facility is designed to process 87,000 barrels of oil equivalent per day.[l] Approximately 92 percent of the production is expected to be oil.[m] The first production of oil is expected by early 2005. Partners in the project are BP (with a 60.5-percent ownership share), BHP Billiton (with a 23.9-percent ownership share), and Unocal (with a 15.6-percent ownership share).

Na Kika. This project is located 140 miles southeast of New Orleans. It consists of five distinct fields with water depths of 5,800 to 7,000 feet.[n] In part because of a lack of pipeline infrastructure, the fields (while discovered in the 1980s) are only now being developed. The fields will be produced using 10 wells tied back to a centrally located floating production platform. The platform is a semi-submersible unit equipped with drilling and production equipment. It is anchored in place or can be dynamically positioned using thrusters. The facility is designed to process 190,000 barrels of oil equivalent per day with approximately 57 percent of the production being accounted for by oil.[o] Production is expected to commence in early 2004. Partners in the project are BP and Shell Oil. The partners have equal ownership interests in four of the five fields. BP has a majority stake in the fifth field.

Atlantis. This field is located 125 miles south of New Orleans in 4,400 to 7,100 feet of water.[p] The field will be developed with a moored semi-submersible production facility with a design capacity of around 180,000 barrels of oil equivalent per day. Less than 20 percent of the output is expected to be natural gas. BP is the operator and has a 56-percent ownership interest. BHP Billiton accounts for the remaining 44-percent ownership share.

All of the above projects will make use of the $1-billion Mardi Gras transportation system which upon completion will consist of five pipelines stretching more the 450 miles across the Gulf. This system will have the capability of transporting over 1 million barrels per day and 1.5 billion cubic feet day of crude oil and natural gas, respectively.[q]

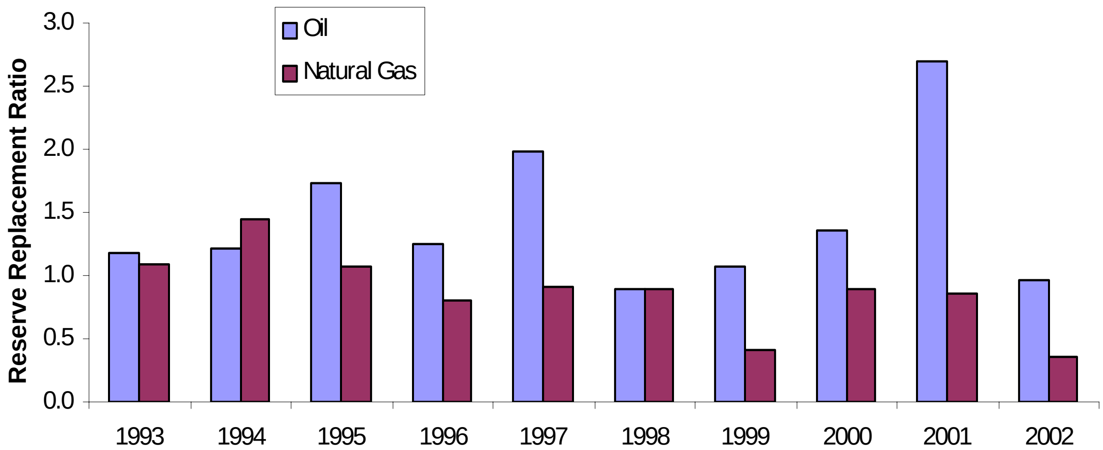
Other recent significant discoveries includes Vortex (Kerr-McGee, BHP Billiton, and Ocean Energy), Tahiti (ChevronTexaco, PanCanadian Energy, and Enterprise), Deimos (Shell Oil and BP), and Great White (Shell Oil, BP, and ChevronTexaco). Only Vortex is known to be prone to natural gas.[r]

The oil-prone nature of these recent discoveries does not appear to be consistent with what one would expect based on MMS's fifty-fifty oil to natural gas resource assessment in 2000. It is also not consistent with the most recent 2003 MMS resource assessment which (according to *The Wall Street Journal*) significantly raised their estimate of the amount of undiscovered natural gas resources left in the Gulf.[s]

It may be the oil-prone nature of the projects currently being developed in the Gulf is a legacy of the industry's previous focus on finding and developing oil resources. Alternatively, this outcome could be attributed to the fact that many of the undiscovered gas prospects have a vertical drilling depth greater than 15,000 feet where the seismic imaging is poor relative to shallower drilling depths.

In any event, the relatively more oil versus natural gas being developed in the Gulf has major implications for domestic crude oil and natural gas supplies. Buoyed by these and other discoveries, the FRS companies have replaced over 100 percent of their offshore oil production in eight out of the past ten years (Figure 32). For the period as a whole, the companies have replaced 145 percent of their offshore crude oil production. In contrast, the natural gas reserve replacement rate has exceeded 100 percent in only three of the past ten years. For the period as a whole, the natural gas reserve replacement rate was a disappointing 87 percent.[t] Additionally, this situation has deteriorated further in recent years. Over the 1998 through 2002 period, natural gas reserve additions were only about 70 percent of the amount of natural gas that was produced. Fortunately, continued improvement in seismic technology (in conjunction with the current price environment) should eventually yield the discovery of additional natural gas.

Figure 32. Reserve Replacement Ratios for the FRS Companies in the U.S. Offshore, 1993-2002



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

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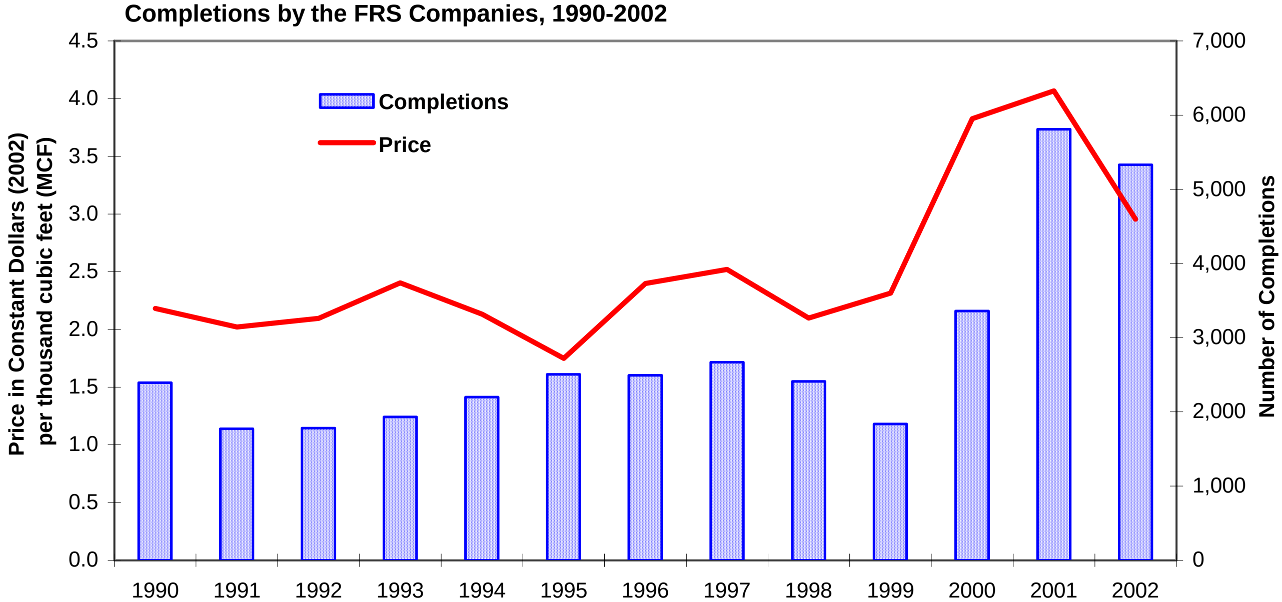
[a]Kallaur, Carolita, "The Deepwater Gulf of Mexico—Lessons Learned," Institute of Petroleum's International Conference on Deepwater Exploration and Production in Association with OGP, February 22, 2001 London, UK. Located on the Internet at http://www.gomr.mms.gov/homepg/offshore/deepwatr/lessons_learned.html (as of December 15, 2003).
[b]Ibid.
[c]Ibid.
[d]Ibid.
[e]Energy Information Administration, "Advanced Summary U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserve 2002 Annual Report," DOE/EIA-0216(2002) Advance Summary, October 2003.
[f]Minerals Management Service, "Outer Continental Shelf Petroleum Assessment 2000," September 2003. Located on the Internet at http://www.mms.gov/revaldiv/RedNatAssessment.htm (as of December 15, 2003).
[g]Ibid.
[h] Ibid.
[i] BP plc, "Upstream Build Projects," January 2003. Located on the Internet at http://www.bp.com/liveassets/bp_internet/globalbp/STAGING/global_assets/downloads/U/Upstream_build_projects.pdf (as of December 15, 2003).
[j]Ibid.
[k]Ibid. Based on the reported design capacities and the conversion factor of 0.178 mcf of natural gas per barrel of crude oil.
[l] Ibid.
[m]Ibid. Based on the reported design capacities and the conversion factor of 0.178 mcf of natural gas per barrel of crude oil.
[n] Ibid.
[o]Ibid. Based on the reported design capacities and the conversion factor of 0.178 mcf of natural gas per barrel of crude oil.
[p] Ibid.
[q]Ibid.
[r]"BHP Billiton Discovers Natural Gas with Vortex-1 Well in Deepwater Gulf of Mexico," Oil & Gas Journal Online, (December 13, 2002). Located on the Internet at http://ogj.pennnet.com/articles/web_article_display.cfm?Section=Archives&Article_Category=ExplD&ARTICLE_ID=163772&KEYWORD=vortex (as of December 15, 2003)
[s]Gold, Russell, " Gulf of Mexico May Hold More Natural-Gas Supply," *The Wall Street Journal* (November 19, 2003).
[t]Energy Information Administration, Form EIA-28 (Financial Reporting System).

SPECIAL TOPIC: Natural Gas Supply -- A New Paradigm?

Throughout most of the 1990's, many natural gas analysts were of the view that technological progress would enable the North American natural gas supply industry to meet growing demand at moderate to low prices. According to the Energy Information Administration, the natural gas price in 1999[a] was $2.19 per thousand cubic feet while the natural gas price for 2003[b] was projected (in December 2003) to be $4.97 per thousand cubic feet, a 127-percent increase over the period. However, despite these higher prices, natural gas production in 2003 was projected (in December 2003) to be only about 3.6 percent higher than in 1999.[c] This seemingly inelastic response of production with respect to price has led some to question whether technology advances will in fact be robust enough to keep natural gas prices at moderate to low levels. In other words, is a new natural gas supply paradigm – one of higher prices being needed to meet projected demand – emerging? For instance, the National Petroleum Council (NPC) has recently concluded that current North American producing areas and those under development will be unable to meet projected demand over the next 20 years.[d]

At first glance, the NPC's concerns appear to be misplaced. Producers such as the FRS companies have responded to the increase in the price of natural gas by substantially increasing their level of drilling for natural gas (Figure 33). Domestic gas well completions by the FRS companies attained an all-time high in 2001. While completions were off in 2002, they were nevertheless almost three times their level in 1999.

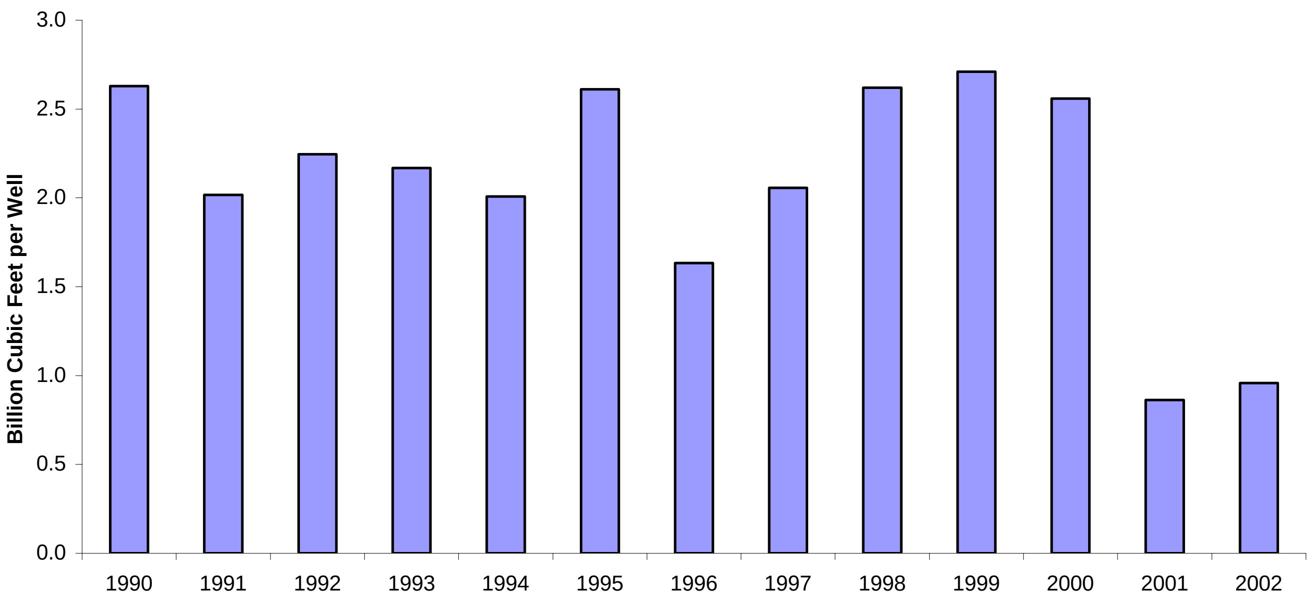
Figure 33. The Domestic Wellhead Price of Natural Gas and the Number of Domestic Gas Well Completions by the FRS Companies, 1990-2002



Sources: Energy Information Administration, Form EIA-28 (Financial Reporting System) and Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0130(2003/10) (Washington, DC, October 2003).

The possibility of a paradigm shift becomes more apparent if one examines the volume of gas added to reserves by the average successful gas well. Over the period of 1990 through 2000, the FRS companies drilled 23,367 gas wells in the onshore United States. This drilling yielded approximately 54,903 billion cubic feet of reserve additions (extensions and discoveries plus reserve additions associated with improved recovery plus reserve revisions), which means that the average onshore gas well added approximately 2.3 billion cubic feet of natural gas to proved reserves.[e] In sharp contrast, reserve additions per well in 2001 and 2002 were about 1 billion cubic feet (Figure 34). A portion of the decline can be attributed to a change in the type of wells drilled. Approximately 90 percent of the onshore gas wells that the FRS companies drilled over the period of 1990 through 2000 were developmental wells.[f] Relative to exploratory wells, developmental wells do not add much to reserves but instead extract gas out of already proved reserves. In the 2000 through 2001 time period, the share of wells classified as developmental was over 95 percent. Whether this shift in the mix of drilling explains the entire decline in reserves added per well is the fundamental natural gas supply question.

Figure 34. Natural Gas Reserve Additions per Well for FRS Companies in U.S. Onshore, 1990-2002

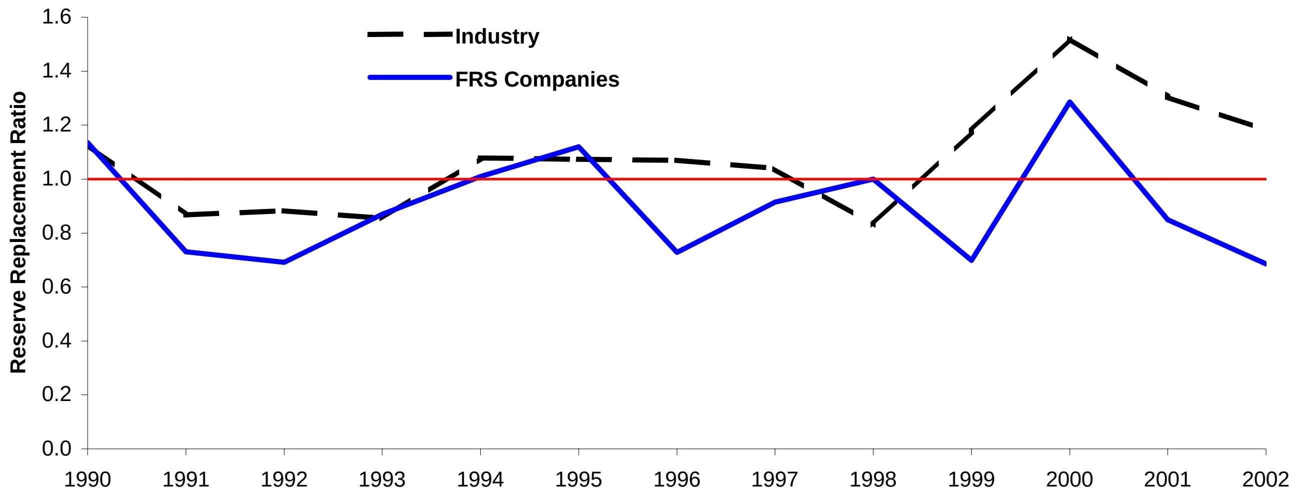


Notes: The numerator of reserves additions per well includes revisions, improved recovery, and extensions and discoveries. The denominator includes both exploratory and developmental successful gas wells.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Nonetheless, the NPC's concern about the adequacy of the natural gas supply becomes almost impossible to dismiss if one examines the reserve replacement rate. This statistic is the ratio of reserve additions to production. (A ratio greater than one indicates that exploration and development efforts are adding more to reserves than the firms are withdrawing from reserves.[g] A ratio less than one indicates that the exploration and development efforts are adding less to reserves than the amounts that the firms are producing from reserves.[h]) The domestic natural gas reserve replacement rate for the FRS companies over the period of 1990 through 2002 was less than 1.0 in 9 out of the 13 years (Figure 35). For the entire period, the companies replaced only about 90 percent of production. For the industry as a whole, the situation is less grim. The domestic natural gas reserve replacement rate for the industry over the period of 1990 through 2002 was greater than 1 in 9 out of the previous 13 years.[i] For the period of 1990 through 2002 as a whole, the industry has replaced 108 percent of production. While this latter statistic does provide some grounds for natural gas supply optimism, it should be understood within the context of a declining extraction rate.

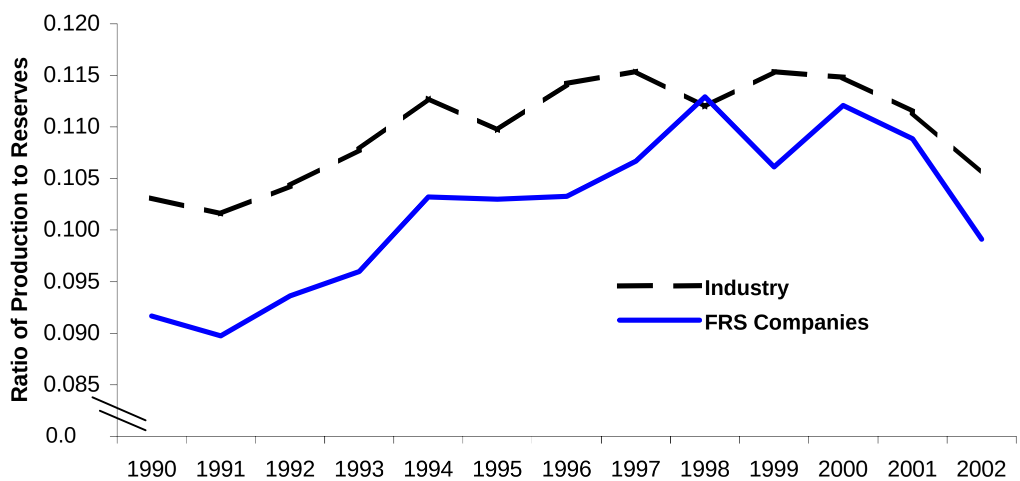
The extraction rate, which is the ratio of production to reserves, increased over the early part of the 1990's for both the FRS companies and the industry as a whole (Figure 36). Over the past few years, however, the ratio has declined for both groups. Indicative of the significance of the decline, the domestic natural gas production of the FRS companies in 2002 would have been 616 billion cubic feet higher had the production to reserves ratio in 2002 been equal to its 1999 value. For the industry as a whole, production would have been 1.8 trillion cubic feet higher.

Figure 35. The Domestic Natural Gas Reserve Replacement Ratio for the FRS Companies and the Domestic Natural Gas Supply Industry as a Whole, 1990-2002



Sources: Energy Information Administration, Form EIA-28 (Financial Reporting System) and Energy Information Administration, *Advanced Summary U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserve 2002 Annual Report* , DOE/EIA-0216(2002) Advance Summary (Washington, DC, October 2003).

Figure 36. The Ratio of Natural Gas Production to Proved Natural Gas Reserves for the FRS Companies and the Domestic Natural Gas Supply Industry, 1990-2002.



Source: Sources: Energy Information Administration, Form EIA-28 (Financial Reporting System) and Energy Information Administration, *Advanced Summary U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserve 2002 Annual Report* , DOE/EIA-0216(2002) Advance Summary (Washington, DC, October 2003).

The recent decline in the production to reserves ratio can be partly attributed to an increase in non-producing reserves as firms commence drilling in areas where there may be a lack of pipeline infrastructure (such as in frontier areas of the Rocky Mountains). Another factor contributing to the decline is the increased emphasis on unconventional gas sources such as coalbed methane, tight sands, and gas shales.[j] As recently as 1996, less than 40 percent of onshore reserve additions were accounted for by unconventional sources; the comparable figure for 2000, the latest year for which reliable data are available, is 67 percent.[k] As compared to conventional natural gas wells, unconventional wells typically have lower daily production rates, which translate into a smaller amount of production for a given reserve base. For example, in 2000, the extraction rate for tight gas was almost 25 lower per unit of reserves as compared to conventional gas.[l] Given that unconventional gas is expected to become an even larger component of gas supply in the future,[m] the lower extraction rate that both the FRS companies and the industry as whole have experienced over the past few years may become a permanent fixture in the gas supply paradigm.

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[a]Energy Information Administration, *Natural Gas Annual 1999*, DOE/EIA-0131(99) (Washington DC, October 2000).
[b]Energy Information Administration, *Short-Term Energy Outlook*, December 2003, http://www.eia.doe.gov/emeu/steo/pub/contents.html (as of December 16, 2003).
[c]Ibid.
[d]The NPC report is available at http://npc.org
[e]Energy Information Administration, Form EIA-28 (Financial Reporting System).
[f]Ibid.
[g]Remaining reserves rise as a result, which enables production to also rise (for a given extraction rate).
[h]Remaining reserves decline as a result, which allows production to also decline (for a given extraction rate).
[i]Energy Information Administration, *Advanced Summary U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserve 2002 Annual Report*, DOE/EIA-0216(2002) Advance Summary, October 2003.
[j]For additional information on the production of natural gas as coalbed methane, see Energy Information Administration, *Performance Profiles of Major Energy Producers 2000*, DOE/EIA-0206(2000) (January 2002, Washington, DC), pp. 79-83. Available on the Internet at http://tonto.eia.doe.gov/FTPROOT/financial/020600.pdf (as of December 16, 2003).
[k]Special compilation by the Energy Information Administration, Office of Integrated Analysis and Forecasting.
[l]Ibid.
[m]Energy Information Administration, *Annual Energy Outlook 2004*, DOE/EIA-0383(2004) (Washington DC, January 2004).

***SPECIAL TOPIC*: Canada's Mackenzie Delta -- One Part of Future Natural Gas Supply?**

Natural gas prices are now over twice what they were in the late 1990's[a]. Some, such as Federal Reserve Chairman Alan Greenspan, see imported liquefied natural gas (LNG) as the solution to this problem.[b] While not dismissing the importance of LNG, others point out that North America has a substantial quantity of stranded gas reserves -- gas that could be marketed if there were a low-cost mechanism of transporting the gas to market. For instance, the Mackenzie Delta in Canada's Northwest Territories contains over 10 trillion cubic (tcf) feet of known recoverable natural gas.[c] This is the volume of gas that had been booked as reserves during the 1970's; however, like the natural gas on Alaska's North Slope, this gas was never produced because of a lack of pipeline infrastructure that could move the gas to market. In 1994, the Mackenzie Delta gas reserves were written off the books (by those companies owning the gas) when the price of gas in Canada sold for an equivalent of approximately $1.50 (U.S.) per thousand cubic feet (Mcf).[d] A year earlier, over 14 tcf of gas located in Canada's Artic Islands (located northeast of the Mackenzie Delta) was also written off given its remote location.[e]

Recently, Imperial Oil (Canada's largest oil company, 69.6-percent owned by the FRS company Exxon Mobil), ConocoPhillips, Exxon Mobil, and Shell Canada (a wholly owned subsidiary of the British Royal Dutch Shell) have formed the Mackenzie Gas Producers Group with the aim of developing the natural gas fields and constructing a pipeline system along the Mackenzie Valley. This system would deliver the gas to Northwestern Alberta where existing pipelines could then move the gas to other parts of Canada as well as to the United States.[f] The goal is to have the natural gas moving through the pipeline by 2010. The pipeline is planned to have a 1.2-billion-cubic-feet-per-day (bcf/d) initial capacity that could be expanded to 1.9 bcf/d by adding additional compression stations. The overall cost of the project including the construction costs of the pipeline, the gathering system, and required field development is estimated at $4 to 5 billion (in Canadian dollars), which is approximately $3 to 3.8 billion (in U.S. dollars).

A large portion of the gas for the pipeline is expected to come from three major fields:

Taglu. This field has estimated recoverable natural gas resources of 3 tcf. Imperial Oil Limited has a 100-percent interest in the field. Imperial will also have an interest in the gathering lines as well as in the pipeline system.

Parsons Lake. This field has estimated recoverable natural gas resources of 1.8 tcf. Partners in this field are the FRS companies ConocoPhillips (with a 75-percent ownership share) and Exxon Mobil (with a 25-percent ownership share).

Nglintgak. This field was discovered in 1973 and has estimated recoverable natural gas resources of approximately 1 tcf. The field is owned by Shell Canada. Because of the high productivity of the wells in terms of output per day, it is believed that the field can be developed using only about 6 to 10 wells.

In addition to the Producers Group, the Aboriginal Pipeline Group (APG) will also have an interest in the pipeline portion of the project. The APG was formed in 2000 to represent the interests of the aboriginal people of the Northwest Territories in the project. The APG has signed a "Memorandum of Understanding" with the Mackenzie Gas Producers Group that gives APG the right, depending on the throughput of the pipeline, to own up to one-third of it. Also, as part of the Memorandum, TransCanada (a Canadian pipeline company) will lend approximately $80 million (in Canadian dollars), which is approximately $60 million in U.S. dollars to the APG to finance APG's share of the project planning costs. The APG expects to finance the vast proportion of its share of the pipeline construction costs by borrowing against its share of future pipeline revenues. However, it is far from clear that these loans will be sufficient to fund the entire amount of APG's commitment.

Other companies active in the Mackenzie Delta include Devon Energy and Petro-Canada (a major Canadian integrated oil and gas company), which together hold leases on more than 1 million acres of land. Over the last two winters, the two firms drilled three unsuccessful exploratory wells -- Kurk M-15, Tuk B-02, and Kugpik L-46. While hydrocarbons were encountered at Tuk B-02, the well was subsequently determined to be uneconomic. More recently, the partners have announced that a fourth exploratory well, Tuk M-18, has yielded significant gas flows. The well is estimated to have a reserve potential of 200 to 300 bcf with a sustained deliverability of 60 to 80 mcf/d.[h]

While it is increasingly likely that the Mackenzie Delta project will become a reality, it is far from clear how much of the gas will ultimately reach U.S. markets. It may be that much of the gas will be used by Canada's expanding oil sands (synthetic crude) industry. The in situ oil sands projects in Canada use natural gas to create steam that enables the bitumen hydrocarbons to flow to the surface. According to

Canada's National Energy Board, one of the most promising in situ technologies, Steam Assisted Gravity Drainage (SAGD), requires 1 mcf of gas for every barrel of bitumen that is produced.[i] Given these gas requirements, it is not surprising that one study has recently concluded that the incremental gas demand from the oil sands projects could equal or even exceed the initial planned capacity of the MacKenzie Delta pipeline.

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[a]Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0130(2003/10) (October 2003, Washington, DC).
[b]"Natural Gas Outlook Worries Greenspan," *New York Times*, (June 11, 2003), p. C4.
[c]Canadian Association of Petroleum Producers, *Statistical Handbook for Canada's Upstream Petroleum Industry, 2002*, Table 2-13A.
[d] Ibid..Table 5-06A.
[e]Ibid. Table 2-13A.
[f]Canadian Association of Petroleum Producers, "Canadian Natural Gas Overview," April 2003.
This document is available in the Internet at
http://www.capp.ca/Pandell_Docs_File_Streamer/IndependantFileRelayDirectFromDocs.asp?XXX=1&doctype=NTV&docnumber=56189 (as of December 15, 2003).
[g]This information is based on the project's preliminary information package which is available on the Internet at http://www.mackenziegasproject.com/theProject/regulatoryProcess/pipSubmission/Documents/Volume%202%20PIP.pdf (as of December 15, 2003).
[h]"Exploration and Development: Canada," *Oil & Gas Journal Online*, January 24, 2003. Available on the Internet at http://ogj.pennnet.com/articles/web_article_display.cfm?Section=Archives&Article_Category=ExplD&ARTICLE_ID=166830&KEYWORD=Tuk%20M%2D18 (as of December 15, 2003).
[i]"No Relief from Mackenzie gas: Lehman Brothers report says Delta Gas will likely all go to Oil Sands," *Petroleum News*, September 14, 2003.

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 level of activity of the U.S. major energy companies in energy production from renewable energy sources
- The level of success of mergers and acquisitions by the U.S. majors as a strategy in replacing their oil and natural gas reserves
- The role of the U.S. majors in the developing liquefied natural gas market in the United States

SPECIAL TOPIC: FRS Company Production From Renewables

Even though renewable energy sources constitute a small part of the U.S. energy mix, some of the large U.S. major energy companies reporting to EIA's Financial Reporting System (FRS) have become involved in renewables energy production. Specifically, in referring to the term "renewables," we are confining our discussion to geothermal, solar, and wind energy sources. Biomass is not significant in any FRS company's energy production. In addition, hydroelectric power has more than a hundred-year history in the United States and is beyond the scope of what can be addressed here.

Despite strong governmental and public interest in renewables, of the three renewables being discussed here only wind energy production has grown in the 1998 to 2002 period, by 242 percent from 0.031 quadrillion Btus to 0.106 quadrillion Btus.[a] Production from geothermal and solar has essentially remained steady over that period. Together, these three energy sources comprised just under one-half of one percent of total U.S. energy consumption in 2002.

Geothermal Energy

Geothermal energy chiefly is electric power that is derived from heat within the earth.[b] More specifically, geothermal energy comes from precipitation that over the eons has seeped deep into the ground and has been warmed by the natural heat of the earth. These heated geothermal fluids occur where magma has pushed close enough to the surface through fractures in the earth's crust. These heated fluids have been found and developed in reservoirs up to 9,800 feet deep. Wells are drilled to recover these fluids to the surface. There the fluids are converted into steam, and if necessary scrubbed to remove impurities, with excess fluids being returned to the reservoir. The scrubbed steam is then delivered by pipeline to a power plant. The power plant uses the steam to drive turbines to generate electric power.

Geothermal energy's environmental properties are considered benign: geothermal emissions consist mostly of water, and geothermal energy production requires no cooling water from the surrounding area.

The geological conditions necessary for harnessing geothermal energy have been found mainly in the Pacific Rim, particularly in the Philippines and Indonesia.

The Unocal Corporation is the only FRS company active in geothermal energy. It has been producing geothermal energy for over 30 years. Unocal's geothermal operations are in the Philippines, at Tiwi (330 megawatts of generating capacity) and Mak-Ban (426 megawatts of generating capacity),[c] and in Indonesia, at Gunung Salak (330 megawatts of generating capacity) and Wayang Windu (110 megawatts of generating capacity).[d] The two Philippines plants have been operating over thirty years and provide 15 percent of the electricity required by Luzon, the Philippines' largest island. Unocal began geothermal operations in Indonesia in 1982.

Together, these four projects supply steam for almost 1,200 megawatts of generating capacity. Unocal's total 2002 geothermal energy production averaged 13 million kilowatthours, the equivalent of 20,000 barrels of oil per day, down from 22,000 barrels per day in 2001.[e] Its net proved geothermal reserves at year-end 2002 were the equivalent of 232 million barrels of oil, compared to 162 million barrels in 2001.

Wind Energy

Wind energy is the harnessing of the wind to generate power. By turning like a pinwheel in the wind, wind turbines convert the energy in the wind into mechanical power. This mechanical power can be used directly for such things as grinding grain or pumping water or can be converted into electricity.

Environmentally, wind energy is considered a very clean source of power. The primary environmental concerns with wind are noise from the rotors, the visual aesthetics of wind farms, and potential harm to wildlife. Objections have been raised to proposed wind energy installation both inland and offshore.

Europe has the largest base of installed wind power capacity, at over 20,000 megawatts, particularly in Germany, Spain, and Denmark. The United States follows at 4,685 megawatts at year-end 2002.[f] Regions in the United States with an average annual wind speed of at least 13 miles per hour, a speed considered the threshold for undertaking a wind power project, are found along the East Coast, the Appalachian Mountains, the Great Plains, the Pacific Northwest, and California.[g]

A former FRS company, Enron, was active in wind power, but has divested its wind generating assets due to Enron's bankruptcy. Enron was active both in manufacturing wind power equipment and in developing wind farms. Both General Electric Co. and American Electric Power have purchased Enron wind assets.

Another FRS company, Shell Oil, has a parent (Royal Dutch/Shell) that has a modest wind energy program. Royal Dutch/Shell subsidiary Shell WindEnergy Inc. is building its largest wind farm to date near Lubbock, Texas, in a 50/50 percent joint venture with Padoma Wind Power.[h] This 160-megawatt project was scheduled be completed by year-end 2003. Shell Wind Energy first entered the U.S. wind power market with its purchase of a 50-megawatt facility in Wyoming in 2001. The company also develops and operates wind parks in Europe.

One other FRS company, BP America, has a parent company (BP plc of the United Kingdom) with one wind project.[i] This is its jointly owned Nerefco oil refinery near Rotterdam, where it has nine wind turbines, with the power sold through the national power grid.

Although wind power represents a small part of the U.S. electric power generation mix, this renewable energy source has recently been growing faster, beginning in 1999. This is in part due to technological innovations improving performance and cost and also to a Federal tax credit of 1.5 cents per kilowatthour for electricity generated by wind turbines. This credit expired at year-end 2003. Although there had been two retroactive renewals of the tax credit in the past, it was not renewed a third time.

Despite the recent growth in generation from wind, there is not as yet a big presence by FRS companies in this renewable power source. Non-FRS companies are the market leaders in wind power in the United States. FPL Energy is the nation's largest generator of wind power, with 24 wind farms. American Electric Power is another big presence in wind power. Also, the Federal government's Bonneville Power Administration has increased its presence as a supplier of electric power from wind energy.

Solar Energy

Solar energy refers to the harnessing of the power of the sun. Passive solar is a means of reducing energy consumption. As for actual energy production, there are primarily two types of solar energy: photovoltaic, which uses the sun's rays to generate electricity, and thermal, in which the sun's heat is concentrated and used directly for such applications as heating water or other liquids. Worldwide, most solar energy production is from the use of photovoltaics.

Solar energy is considered environmentally benign, with essentially no harmful emissions, and it also can be used for power generation. There seem to be fewer objections about solar's visual aesthetics than wind's, perhaps since solar collection facilities tend to be located remotely and not on high ground. However, solar power still represents a small part of the U.S. energy mix.

Two FRS companies, Shell Oil and BP America, have parent companies (Royal Dutch/Shell and BP plc) active in the solar energy business. They are primarily active in the solar equipment and facilities manufacturing end of the business, not in solar power production itself. This may be in part because solar has been used mainly in smaller, decentralized applications and much less in central station electric power generation.

Shell Solar is active in the photovoltaic but not the thermal portion of the solar manufacturing business, manufacturing solar components as well as complete solar systems. The company reports a total yearly manufacturing capacity of 60 megawatts of solar panels, with facilities in the United States and Europe.[j] Shell Solar acquired Siemens Solar in 2002[k] and reports a global market share of 13 percent.[l]

BP is active in solar equipment manufacturing, with nearly 30 years of experience in the United States and elsewhere.[m] BP reports being the largest user of solar energy in the world, employing solar power at BP service stations, plants, and offices.[n] BP Solar, headquartered in Maryland, does own and operate one small solar field in Paulsboro, New Jersey, for supplying electric power to the grid, a 350,000-kilowatthour per year field, enough for 50 homes.[o]

ChevronTexaco, with a fledgling solar program, has also begun operating a solar facility outside Bakersfield, California.[p]

Conclusion

Interest in renewable energy resources has increased over time, due to both environmental and energy security considerations. Renewables are considered more environmentally benign than other fuels, with little to no air emissions or local water use. They are also viewed as enhancing energy security both by diversifying the portfolio of energy we use and by relying on resources that are domestically abundant.

The FRS companies producing renewable energy may be involved in these energy sources in part to keep up with potential advances in energy production technologies and perhaps also to enhance their environmental image.[q] However, there is no indication that renewable energy will constitute a substantial portion of the energy produced by FRS companies in the near future.

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[a]Energy Information Administration, *Renewable Energy Annual 2001*, DOE/EIA-0603(2001) (Washington, DC, November 21, 2002), Table 1. Web address: http://www.eia.doe.gov/cneaf/solar.renewables/page/rea2002.pdf
[b]Other types of geothermal energy include geothermal heat pump and enhanced geothermal recovery (hot dry rock), which is a potential technology.
[c]Unocal Corporation, March 2002 discussion on "Philippine Geothermal." Web address: http://www.unocal.com/geopower/pgi.htm
[d]Unocal Corporation, July 2003 discussion on "Unocal Geothermal Indonesia." Web address: http://www.unocal.com/geopower/ugi.htm.
[e]Unocal Corporation, 2002 Securities and Exchange Commission Form 10-K, p.18.
[f]United States Department of Energy, discussion on Wind Energy. Web address: http://www.eere.energy.gov/windpoweringamerica/pdfs/wpa/wpa_update.pdf
[g]U.S. Department of Energy, discussion on Wind Energy. Web address: http://www.eere.energy.gov/windpoweringamerica.
[h]Royal Dutch Shell, press release (July 23, 2003)
[i]BP plc, discussion on "Renewable Energy." Web address: http://www.bp.com/environ_social/environment/renewable.asp
[j]Royal Dutch Shell, September 2003 discussion on "Shell Renewables." Web address: http://www.shell.com/home/Framework?siteId=shellsolar&FC1=&FC2=%2FLeftHandNav%3FLeftNavState%3D1%2C0&FC3=%2Fshellsolar%2Fhtml%2Fiwgen%2Fabout_shell%2Ffact_fig_new_01291129.html&FC4=&FC5=
[k]Royal Dutch Shell, press release (January 23, 2002).
[l]Royal Dutch Shell, press release (September 11, 2003).
[m]BP plc, September 2003 discussion on "Renewable Energy." Web address: http://www.bp.com/environ_social/environment/renewable.asp
[n]BP plc, September 2003 discussion on "BP Gas, Power & Renewables." Web address: http://www.bp.com/bp_businesses/transition_page.asp?id=39
[o]BP plc, press release (April 22, 2003).
[p]ChevronTexaco Corporation, press release (June 5, 2003).
[q]Newsweek Magazine, September 22, 2003, advertisement by Shell Oil after page 10: "One of our goals is to make solar energy cheaper ... It's part of our commitment to sustainable development, balancing economic progress with environmental care and social responsibility."

SPECIAL TOPIC: Recent Upstream Mergers: A Tradeoff Between Growth and Profitability?

In order to survive, oil and natural gas companies need to replenish their oil and natural gas resources as they are produced, even if demand for those fuels is stable. But with the demand for natural gas and petroleum forecast to grow sharply over the coming decade, continuing the trend of recent years, the question arises all the more prominently: what strategies do companies employ to obtain the natural gas and petroleum they intend to supply?

To shed light on this question, two choices companies face were examined: to find and develop the reserves themselves in areas they have mineral rights to, or to acquire reserves already discovered by others through mergers and acquisitions. This was termed the “make-or-buy” choice. Reasonable hypotheses were then developed to explain why companies choose one strategy or the other.

The universe of companies examined to test these hypotheses was the set of companies responding to EIA’s FRS that held oil or natural gas reserves in the United States during the 1997 to 2002 period.

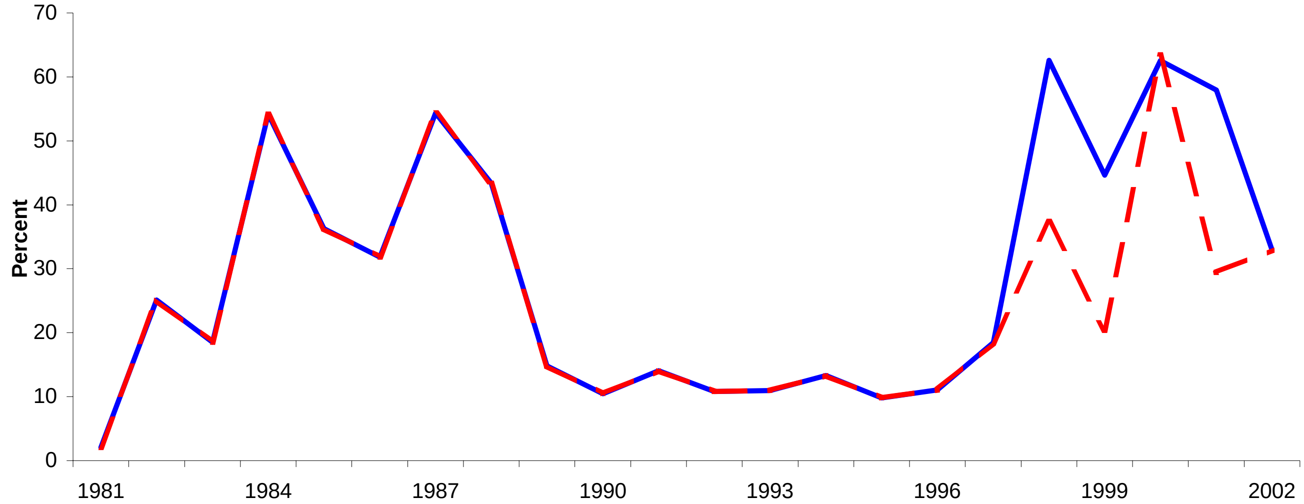
More particularly, these companies are: TotalFinaElf USA, Shell Oil Company, Burlington Resources Inc., ConocoPhillips Company, Inc., Marathon Oil, Corp., Exxon Mobil Corporation, Amerada Hess Corporation, Anadarko Petroleum, Inc., Unocal Corporation, Apache Corporation, EOG Resources, Inc., Devon Energy Corporation, Kerr-McGee Corporation, BP America, Inc., Williams Companies, Inc., Occidental Petroleum Corporation, ChevronTexaco Corporation, Dominion Resources, Inc., El Paso Corporation, and XTO Energy, Inc.

The 1997 to 2002 period of study was chosen because, while there were relatively few mergers among the FRS companies in the first part of the 1990’s, around 1997 a wave of mergers began, continuing through 2002 (Figure 37).

What goes into a company’s decision on how to obtain the natural gas and petroleum it intends to supply? Since it is costly to find oil and natural gas resources that will yield successfully producing wells and since the FRS companies are profit seekers, it is natural to examine oil and gas finding costs as an explanatory factor. A company’s finding cost is its average cost of finding a unit of reserves. Other things being equal, one would expect that companies which faced higher finding costs for oil and gas resources would tend to be buyers of reserves, whereas companies with lower finding costs would tend to be “makers” of reserves (that is, develop their own reserves in areas where they had mineral rights). To test these explanations, the FRS data was examined.

In fact, the data revealed a tendency for companies with higher finding costs to buy their reserves rather than “make” them. As expected, for companies with higher finding costs, buying reserves is the strategy that entails relatively lower cost (Table 21). However, the statistical significance of these results was below the threshold of significance. Consequently, the data hint at the tendency just described, but are not strong enough to warrant a definite conclusion on this score.

Figure 37. Share of FRS Companies' Domestic Oil and Natural Gas Reserve Additions due to Mergers and Acquisitions, 1981-2002



Note: Solid line includes U.S. reserves added in BP-Amoco (1998), Exxon-Mobil (1999), BP Amoco-ARCO (2000), Chevron-Texaco (2001), and El Paso-Coastal (2001) mergers as purchases in addition to all other transactions. These mergers were accounted for using the "pooling of interests" method, which does not record reserves acquired in a business combination as purchased reserves. For mergers initiated after June 30, 2001, the Financial Accounting Standards Board (FASB) no longer allows the use of this method of accounting in business combinations. Dashed line excludes the effects of accounting for "mergers as purchases."

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

Table 21. Average Finding Cost and Return on Investment for FRS Companies, 1997-2002

Company Type	1997-2002	
	U.S. Finding Cost (Dollars Per Barrel of Oil Equivalent)	**Return on Investment** (Percent)
Makers	6.83	12.71
Buyers	7.88	10.25

Notes: Included are those 20 companies that were FRS respondents in 2002 and had oil or natural gas reserves (this, for example, excluded FRS respondents who are only refiner/marketer companies). Return on investment is net income as a percent of net property, plant, and equipment.

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

An interesting finding was that companies having a higher "purchase ratio", that is, the ratio of reserve additions that were purchased to reserve additions that were developed by the company, tended to have higher growth in reserves. One possible explanation for this might be that these companies adopted a strategy of fast growth, and the way for them to achieve that was to buy reserves rather than the slower process of developing their own.

The rate of return on investment was also examined for both the "make" companies and the "buy" companies (Table 21). It turns out that "makers" tended to have a higher return on investment than "buyers." Furthermore, unlike the result for finding costs, this result was statistically significant. One possible explanation for this outcome is that "makers" may have been focusing on maximizing profits while "buyers" were focusing on growing fast.

Another possibility is that the initial endowments of these two types of companies, their starting positions, were different. This may have led to different strategies and consequently different outcomes in profitability. Specifically, companies tending toward the strategy of "making" their own reserves, relative to companies electing to buy reserves, may have been endowed with more lucrative assets: namely, a base of reserves tending to be relatively rich and productive. Whether having a relatively fortunate initial position stems from good fortune or shrewd decision-making in the past is an open question. Thus, although the level of finding costs that an FRS company experiences is one of the factors that a company would examine, it evidently does not, by itself, determine the choice of reserve acquisition and replacement strategy.

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[a]Energy Information Administration, *Financial Aspects of the U.S. Oil and Gas Industry in the 1980's,* DOE/EIA-0524 (Washington, DC, May 1989).

***SPECIAL TOPIC*: LNG -- A Future for the FRS Companies?**

There appears to be steadily increasing interest in LNG as an energy source in the United States, as alternative sources are being sought to satisfy the anticipated growth in demand for natural gas. The FRS companies play a major role in the United States' LNG market: they own two of the four LNG import facilities and the sole export facility in the United States.[a]

While FRS company investment in LNG is clearly an important part of supplying U.S. energy needs, the discussion below indicates that FRS company activity in LNG was mixed in 2002: some FRS companies expanded their LNG activities while others contracted in that area.

Domestic Facilities: Cove Point, Elba Island, and Alaska's Kenai Peninsula.

In September 2002, Dominion Resources bought the Cove Point LNG facility in Lusby, Maryland, for $225 million from The Williams Companies (another FRS company).[b] The purchased assets include an LNG import facility, an LNG storage facility, and an approximately 85-mile natural gas pipeline feeding into an established natural gas market in the mid-Atlantic region. Dominion reports that capacity at the Cove Point facility is fully booked.[c] The El Paso Corporation also held rights to capacity at the Cove Point LNG regasification facility. However, in the fourth quarter of 2002, El Paso sold that capacity (along with its position in the LNG purchase and sale agreement at Cove Point) to Norway's Statoil for $210 million.

Serving the natural gas market in the southeastern United States is a facility which El Paso still owns, the LNG terminal and regasification facility at Elba Island, Georgia. This facility began receiving deliveries in December 2001.[d] In August 2002, Marathon acquired capacity rights for 22 years for delivering LNG to the Elba Island facility.[e] This would provide a potential outlet for Marathon-owned natural gas resources located near the company's proposed LNG plant in Equatorial Guinea, where the natural gas would be liquefied and shipped to Elba Island for regasification and subsequent distribution to the U.S. southeastern natural gas market.[f]

There is only one LNG export facility in the United States, located on the Kenai Peninsula in southern Alaska. At present, it is entirely devoted to serving the Pacific Rim natural gas market.[g] Phillips built this 230-million-cubic-feet-per-day export facility in a joint venture with Marathon.[h] ConocoPhillips, the result of the recent merger of Conoco and Phillips, owns a 70-percent share and is the operator of the facility, while Marathon owns the other 30 percent. Export began in 1969, under a 15-year contract to supply LNG to Tokyo Electric and Tokyo Gas. Shipping to those two utilities has continued uninterrupted since then. As with the investment in the Kenai Peninsula LNG export facility, much of FRS companies' investments in LNG projects abroad is intended for the Pacific Rim market, with some also aimed at portions of the European market.

Investments in LNG Facilities Abroad: Qatar and Australia

The Exxon Mobil Corporation has been involved with LNG for more than thirty years, and, through its subsidiaries, has had a presence in Qatar since 1935,[i] where Exxon Mobil owns interest in two LNG projects:[j]

- Qatargas, in which Exxon Mobil has a 10-percent interest, with most of the LNG going to Japan and Spain.
- RasGas LNG facilities, in which Exxon Mobil has a 25-percent interest, with most of the LNG going to Korea. Exxon Mobil also has a 28.5-percent interest in the two additional RasGas LNG trains currently under construction, each with a planned capacity of 4.7 million metric tons per year, intending to supply India and Europe.

The ChevronTexaco Corporation holds a one-sixth interest in the North West Shelf Venture in Australia.[k] About 60 percent of the natural gas from this venture is sold in the form of LNG to Japanese utilities, with the remaining natural gas being sold in the Australian domestic market.[l] A project to increase this LNG capacity by about 50 percent is currently under construction, and a conditional 25-year agreement was signed with China in October 2002 to supply the proposed Guangdong LNG Terminal Project.[m]

ConocoPhillips also has ownership in major natural gas production ventures in the Bayu-Undan field in the Timor Sea off Australia, and is in development phase of a planned liquefaction facility near Darwin, Australia.[n] To market this LNG, in March 2002 ConocoPhillips signed an agreement with the same two utilities it has been supplying, Tokyo Electric and Tokyo Gas, for the sale of LNG for 17 years.[o]

Financial Distress Causes Retrenching in LNG: El Paso

During 2002, El Paso felt the effects of the downturn of the energy trading and merchant services businesses that began with the demise of Enron in 2001.[p] Contributing to its financial pressures, El Paso suffered from a $67-million decline in the fair value of its LNG supply contract derivatives in 2002 compared to a $86-million increase in the fair value of those contracts in 2001.[q] El Paso stated that the significant capital and credit requirements associated with the LNG business were in excess of its current financial capacity.[r]

El Paso responded to these developments by initiating a series of actions to wind down its involvement in non-core businesses including energy trading and petroleum markets, as well as the capital-intensive business of LNG operations.[s] In particular, in February 2003 El Paso extricated itself from obligations to charter four LNG tankers, in exchange for payments by El Paso totaling $24 million.[t]

What Next?

There are many proposals by FRS and other companies to build LNG facilities, with varying degrees of promise. Some proposals may be intended as strategic moves by a company considering investing in a particular LNG market, designed to discourage other companies from entering that market. However, actual investment in LNG facilities, particularly in liquefaction, requires large commitments of capital. Not all companies are currently in a strong enough financial position to risk undertaking such projects. Nonetheless, given the ever-increasing demand for natural gas, involvement by the FRS companies in the LNG market warrants continued watching.

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[a] The two domestic import LNG facilities in which the FRS companies have no ownership are in Lake Charles, Louisiana and Everett, Massachusetts.
[b] Dominion Resources, Inc., 2002 Securities and Exchange Commission Form 10K, p. 3.
[c] Dominion Resources, Inc., *2002 Annual Report*, p. 12.
[d] El Paso Corporation, 2002 Securities and Exchange Commission Form 10K, p. 5.
[e] Marathon Oil Corporation, 2002 Securities and Exchange Commission Form 10K, p. 19.
[f] Marathon Oil Corporation, *2002 Annual Report*, p. 3.
[g] Phillips Petroleum Company, Press Release (September 14, 2000).
[h] Marathon Oil Corporation, Press Release (February 28, 2002).
[i] Exxon Mobil Corporation, Press Release (April 4, 2001).
[j] Exxon Mobil Corporation, *2002 Financial & Operating Review, p.48*
[k] ChevronTexaco Corporation, *2002 Annual Report*, p. 1.
[l] ChevronTexaco Corporation, *2002 Annual Report*, p. 23.
[m] ChevronTexaco Corporation, *2002 Annual Report*, p. 23.
[n] ConocoPhillips, *2002 Annual Report*, p. 17.
[o] ConocoPhillips, *2002 Annual Report*, p. 14.
[p] El Paso Corporation, 2002 Securities and Exchange Commission Form 10K, pp. 1-2.
[q] El Paso Corporation, 2002 Securities and Exchange Commission Form 10K, p. 60.
[r] El Paso Corporation, 2002 Securities and Exchange Commission Form 10K, p. 22.
[s] El Paso Corporation, 2002 Securities and Exchange Commission Form 10K, p. 2.
[t] El Paso Corporation, 2002 Securities and Exchange Commission Form 10K, p. 23.

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 Energy Information Administration (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 EIA 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, 1996-2002

Operating Statistics	1996	1997	1998	1999	2000	2001	2002
Petroleum and Natural Gas							
Net Production							
Crude Oil and Natural Gas Liquids (million barrels)							
FRS Companies	1,532.4	1,458.8	1,388.8	1,305.7	1,267.9	1,363.2	1,346.4
U.S. Industry[1]	3,023.0	3,002.0	2,824.0	2,848.0	2,801.0	2,805.0	2,759.0
FRS as a Percent of U.S. Industry	50.7	48.6	49.2	45.8	45.3	48.6	48.8
Natural Gas (billion cubic feet)							
FRS Companies	8,191.6	8,299.1	8,395.9	7,994.1	8,340.1	8,838.0	8,712.5
U.S. Industry[1]	18,861.0	19,211.0	18,720.0	18,928.0	19,219.0	19,779.0	19,353.0
FRS as a Percent of U.S. Industry	43.4	43.2	44.8	42.2	43.4	44.7	45.0
Net Imports							
Crude Oil and Natural Gas Liquids (million barrels)							
FRS Companies	565.7	571.1	634.7	474.9	324.1	716.1	630.5
U.S. Industry[1]	2,946.6	3,191.0	3,358.5	3,366.4	3,527.0	3,620.1	3,523.2
FRS as a Percent of U.S. Industry	19.2	17.9	18.9	14.1	9.2	19.8	17.9
Refinery Capacity (thousand barrels per day)							
FRS Companies	10,477.0	9,410.0	14,277.0	14,158.0	14,424.0	14,682.0	14,557.0
U.S. Industry[1]	16,031.8	16,128.7	16,567.0	16,787.0	17,177.4	17,367.4	17,338.9
FRS as a Percent of U.S. Industry	65.4	58.3	86.2	84.3	84.0	84.5	84.0
Refinery Output[2] (thousand barrels per day)							
FRS Companies	10,954.0	10,030.0	14,929.0	14,639.0	14,499.0	15,022.0	14,761.0
U.S. Industry[1]	16,800.7	17,234.3	17,499.6	17,493.1	17,763.2	17,688.9	17,654.5
FRS as a Percent of U.S. Industry	65.2	58.2	85.3	83.7	81.6	84.9	83.6
Coal Production							
(million tons)							
FRS Companies	169.4	163.3	73.9	44.0	35.5	33.0	29.3
U.S. Industry[1]	1,063.9	1,089.9	1,117.5	1,100.4	1,073.6	1,127.7	1,093.3
FRS as a Percent of U.S. Industry	15.9	15.0	6.6	4.0	3.3	2.9	2.7

[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.

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 2002 Annual Report November 2003). 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 2,936 million barrels in 2002 and 2,940 million barrels in 2001. (See Energy Information Administration, Petroleum Supply Annual 2002, Volume I (June 2003), p. 2.) For dry natural gas production, the official Energy Information Administration U.S. totals are 19,047 billion cubic feet in 2002 and 19,676 billion cubic feet in 2001. (See Energy Information Administration, Natural Gas Monthly, September 2003, 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, 2002 Annual Report (November 2003). 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, 2001 and 2002. Coal production: 1996-2000--EIA, *Coal Industry Annual* , annual reports; 2001-2002 - EIA, *Annual Coal Report, 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, 2001-2002 (Billion Dollars)

Selected Financial Items	FRS Companies		S&P Industrials	
	2001	2002	2001	2002
Income Statement				
Operating Revenues	803.7	698.9	4,841.0	4,703.8
Operating Expenses	-735.6	-659.7	-4,380.5	-4,206.2
Operating Income	68.1	39.2	460.5	497.6
Interest Expense	-9.1	-10.7	-114.0	-98.2
Other Income[1]	6.3	6.7	-148.5	-246.1
Income Taxes	-27.7	-14.6	-111.7	-127.1
Net Income	37.7	20.6	86.4	26.2
Cash Flows from Operations[2]				
Net Income	37.7	20.6	86.4	26.2
Other Items, Net[3]	51.9	54.4	502.1	556.3
Net Cash Flow from Operations	89.6	75.0	588.5	582.5
Cash Flows from Investing Activities[2]				
Additions to Property, Plant & Equipment	-100.3	-90.5	-360.8	-290.3
Other Investment Activities, Net[4]	6.0	36.4	-128.3	-103.7
Net Cash Flow from Investing Activities	-94.3	-54.1	-489.2	-394.0
Cash Flows from Financing Activities[2]				
Proceeds from Long-Term Debt	55.0	34.1	539.7	460.1
Proceeds from Equity Security Offerings	6.3	4.9	72.5	33.8
Dividends to Shareholders	-17.1	-17.7	-98.7	-95.4
Reductions in Long-Term Debt	-34.3	-27.9	-370.1	-336.4
Stock Repurchases	-7.5	-4.7	-110.9	-108.9
Other Financing Activities, Net	3.8	-7.1	-60.1	-85.2
Net Cash Flow from Financing Activities	6.2	-18.4	-27.5	-132.0
Effect of Exchange Rate Changes on Cash	-0.3	0.6	-2.8	4.9
Increase (Decrease) in Cash and Cash Equivalents	1.3	3.0	69.0	61.4

[1] "Other Income" includes other revenue and expense (excluding interest expense), discontinued operations, extraordinary items, and accounting changes.

[2] Items that add to cash are positive, and items that use cash are shown as negative values.

[3] "Other Items, Net" includes: 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 are extracted from the S&P 500 Index, excluding the Financial, Utilities, and Transportation, sectors - Compustat PC Plus, a service of Standard & Poor's.
FRS companies' data - Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B3. Balance Sheet Items and Financial Ratios for FRS Companies and S&P Industrials, 2001-2002

	FRS Companies		S&P Industrials	
	2001	2002	2001	2002
Balance Sheet	(billion dollars)			
Assets				
Current Assets	147.5	156.3	1,441.2	1,510.2
Noncurrent Assets				
Property, Plant, and Equipment (PP&E)				
Gross	806.0	826.3	3,222.8	3,178.6
Accumulated Depreciation, Depletion, and Amortization (DD&A)	-373.6	-379.6	-1,457.0	-1,479.9
Net PP&E	432.4	446.6	1,765.8	1,698.7
Investments and Advances	57.3	53.9	155.3	135.3
Other Noncurrent Assets	97.9	115.7	2,933.4	2,910.4
Subtotal Noncurrent Assets	587.5	616.2	3,308.3	3,136.1
Total Assets	735.0	772.5	6,295.6	6,254.5
Liabilities and Stockholders Equity				
Liabilities				
Current Liabilities	159.8	156.7	1,098.3	1,087.4
Long-Term Debt	132.0	154.0	1,397.2	1,493.7
Other Long-Term Items	144.0	156.1	1,568.7	1,653.1
Minority Interest	15.5	11.0	82.9	75.5
Subtotal Liabilities and Other Items	451.3	477.8	4,147.1	4,309.8
Stockholders' Equity				
Retained Earnings	209.7	206.1	1,150.9	962.0
Other Equity	74.0	88.7	997.6	982.7
Subtotal Stockholders' Equity	283.7	294.7	2,148.5	1,944.7
Total Liabilities and Stockholders' Equity	735.0	772.5	6,295.6	6,254.5
Financial Ratios	(percent)			
Net Income/Stockholders' Equity	13.3	7.0	4.0	1.3
Net Income plus Interest/Total Invested Capital	11.3	7.0	5.7	3.6
Dividends/Net Cash Flow from Operations	19.1	23.7	16.8	16.4
Long-term Debt/Stockholders' Equity	46.5	52.3	65.0	76.8

Sources:
Standard & Poor's (S&P) Industrials data are extracted from the S&P 500 Index, excluding the Financial, Utilities, and Transportation, sectors - Compustat PC Plus, a service of Standard & Poor's.
FRS companies' data - Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B4. Consolidated Balance Sheet for FRS Companies, 1996-2002
(Billion Dollars)

Balance Sheet Items	1996	1997	1998	1999	2000	2001	2002
Assets							
Current Assets							
Cash & Marketable Securities	13.4	12.2	8.1	12.2	18.7	18.6	19.5
Trade Accounts & Notes Receivable	56.2	51.2	47.8	68.1	98.6	71.4	78.7
Inventories							
Raw Materials & Products	22.7	21.4	21.6	23.3	25.6	23.4	23.2
Materials & Supplies	3.8	3.7	3.8	3.9	4.4	7.3	7.6
Other Current Assets	12.1	12.4	12.9	13.4	49.1	26.7	27.4
Total Current Assets	108.2	100.9	94.2	121.0	196.5	147.5	156.3
Non-current Assets							
Property, Plant & Equipment (PP&E)							
Gross PP&E	635.0	636.9	671.0	708.0	757.2	806.0	826.3
Accumulated Depcreciation, Depletion, and Amortization	-331.6	-333.3	-334.5	-355.5	-351.6	-373.6	-379.6
Net PP&E	303.4	303.6	336.5	352.5	405.5	432.4	446.6
Investments & Advances to Unconsolidated Affiliates	32.3	44.2	53.9	58.2	62.3	57.3	53.9
Other Non-current Assets	26.8	35.2	35.8	39.6	86.9	97.9	115.7
Total Non-current Assets	362.4	382.9	426.3	450.3	554.8	587.5	616.2
Total Assets	470.6	483.8	520.4	571.3	751.2	735.0	772.5
Liabilities & Stockholders' Equity							
Liabilities							
Current Liabilities							
Trade Accounts & Notes Payable	61.4	57.7	62.8	79.4	102.4	90.6	91.8
Other Current Liabilities	48.8	49.2	51.1	51.9	96.4	69.2	64.9
Long-Term Debt	70.9	73.4	94.6	104.0	120.0	132.0	154.0
Deferred Income Tax Credits	45.5	46.3	49.0	53.1	68.2	77.0	76.1
Other Deferred Credits	19.2	18.8	18.4	18.8	34.1	23.3	27.9
Other Long-Term Items	40.6	41.6	39.7	42.6	41.2	43.7	52.1
Minority Interest in Consolidated Affiliates	6.6	8.2	10.4	15.2	17.1	15.5	11.0
Total Liabilities	292.9	295.1	326.0	364.9	479.5	451.3	477.8
Stockholders' Equity	156.3	160.8	165.8	170.6	199.2	209.7	206.1
Retained Earnings	21.4	27.9	28.7	35.7	72.5	74.0	88.7
Other Equity							
Total Stockholders' Equity	177.8	188.7	194.4	206.3	271.8	283.7	294.7
Total Liabilities & Stockholders' Equity	470.6	483.8	520.4	571.3	751.2	735.0	772.5
Memo:							
Foreign Currency Translation Adjustment Cumulative at Year End	1.2	-2.7	-2.3	-2.7	-3.0	-5.1	-2.0
Foreign Currency Translation Adjustment for the Current Year	-0.4	-3.9	0.0	-0.3	-2.1	-1.0	3.1

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

Table B5. Consolidating Statement of Income for FRS Companies, 2002
(Million Dollars)

Income Statement Items	Consolidated	Eliminations & Nontraceables	Petroleum	Coal	Other Energy	Non-energy
Operating Revenues	698,884	-33,320	642,126	737	43,243	46,098
Operating Expenses						
General Operating Expenses	598,972	-32,595	547,481	572	41,706	41,808
Depreciation, Depletion, & Allowance	45,529	780	41,561	W	878	2,239
General & Administrative	15,161	2,202	10,021	W	1,302	1,617
Total Operating Expenses	659,662	-29,613	599,063	662	43,886	45,664
Operating Income	39,222	-3,707	43,063	75	-643	434
Other Revenue & (Expense)						
Earnings of Unconsolidated Affiliates	4,103	-294	4,714	W	-563	244
Other Dividend & Interest Income	2,614	2,614	-	-	-	-
Gain/Loss on Disposition of Property, Plant, & Equipment	1,374	-295	1,024	W	W	646
Interest Expenses & Financial Charges	-10,748	-10,748	-	-	-	-
Minority Interest in Income	-1,068	-1,068	-	-	-	-
Foreign Currency Translation Effects	197	197	-	-	-	-
Other Revenue & (Expense)	477	477	-	-	-	-
Total Other Revenue & (Expense)	-3,051	-9,117	5,738	W	-565	890
Pretax Income	36,171	-12,824	48,801	78	-1,208	1,324
Income Tax Expense	14,566	-5,381	20,023	21	15	-112
Discontinued Operations	-828	-81	-968	W	W	W
Extraordinary Items and Cumulative Effect of Accounting Changes	-185	-112	82	W	W	W
Net Income	20,592	-7,636	27,892	-46	-1,460	1,842

- = 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, 2002
(Million Dollars)

Income Statement Items	U.S. Petroleum				Foreign Petroleum			
	Consoli-dated	Production	Refining/ Marketing	Pipe-lines	Consoli-dated	Production	Refining/ Marketing	Int'l Marine
Operating Revenues								
Raw Material Sales	126,771	71,138	109,067	1,625	87,424	61,405	63,582	0
Refined Products Sales	267,974	W	272,190	W	141,742	W	142,227	0
Transportation Revenues	11,115	1,085	2,562	9,561	1,698	376	W	2,643
Management and Processing Fees	1,491	W	1,257	W	1,968	W	W	W
Other	14,161	968	12,781	416	4,598	529	4,051	W
Total Operating Revenues	421,512	73,974	397,857	11,810	237,430	63,932	212,109	2,681
Operating Expenses								
General Operating Expenses	368,645	34,304	390,037	6,433	195,652	26,694	207,559	2,691
Depreciation, Depletion, & Allowance	24,935	18,268	5,617	1,050	16,626	14,579	2,011	W
General & Administrative	7,760	1,653	3,695	2,412	2,261	945	1,310	W
Total Operating Expenses	401,340	54,225	399,349	9,895	214,539	42,218	210,880	2,733
Operating Income	20,172	19,749	-1,492	1,915	22,891	21,714	1,229	-52
Other Revenue & (Expense)								
Earnings of Unconsolidated Affiliates	1,944	1,041	613	290	2,770	3,082	-331	W
Gain(Loss) on Disposition of Property, Plant, & Equipment	996	312	367	317	28	-7	37	W
Total Other Revenue & (Expense)	2,940	1,353	980	607	2,798	3,075	-294	17
Pretax Income	23,112	21,102	-512	2,522	25,689	24,789	935	-35
Income Tax Expense	7,481	6,274	346	861	12,542	12,038	501	3
Discontinued Operations	-1,139	W	W	W	W	W	W	0
Extraordinary Items and Cumulative Effect of Accounting Changes	68	W	W	W	W	W	W	0
Contribution To Net Income	14,560	15,030	-2,164	1,694	13,332	12,918	452	-38

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, 2002
(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	137,933	4,773	29,191	863	18,268
Refining/Marketing					
Refining	53,109	4,439	14,644	451	3,710
Marketing	15,124	959	1,452	430	1,171
Refining/Marketing Transport					
Pipelines	2,410	774	740	68	250
Marine	1,265	W	530	W	296
Other	1,113	W	239	W	190
Total U.S. Refining/Marketing	73,021	6,545	17,605	1,259	5,617
Rate Regulated Pipelines					
Refined Products	1,965	632	92	151	45
Natural Gas	21,767	3,604	2,049	-103	817
Crude Oil and Liquids	4,335	553	352	195	188
Total Rate Regulated Pipelines	28,067	4,789	2,493	243	1,050
Total U.S. Petroleum	239,021	16,107	49,289	2,365	24,935
Foreign					
Production	124,225	15,738	30,138	3,554	14,579
Refining/Marketing	27,998	W	4,055	W	2,011
International Marine	529	W	10	W	36
Total Foreign Petroleum	152,752	22,038	34,203	4,527	16,626
Total Petroleum	391,773	38,145	83,492	6,892	41,561
Coal					
Foreign	0	0	W	0	0
United States	522	W	W	0	71
Total Coal	522	W	23	0	71
Other Energy					
Foreign	2,640	2,858	1,154	304	74
United States	14,038	1,800	1,759	477	804
Total Other Energy	16,678	4,658	2,913	781	878
Nonenergy					
Foreign Chemicals	7,057	2,650	544	336	578
U.S. Chemicals	19,485	4,723	1,608	-166	1,531
Foreign Other Nonenergy	W	2,138	W	-393	W
U.S. Other Nonenergy	W	763	W	183	W
Total Nonenergy	28,799	10,274	2,776	-40	2,239
Nontraceable	8,877	774	1,265	-104	780
Consolidated	446,649	53,873	90,469	7,529	45,529

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, 2001-2002 (Percent)

Line of Business	All FRS		Top Four		Five through Twelve		All Other	
	2001	2002	2001	2002	2001	2002	2001	2002
Petroleum	12.2	6.5	12.5	8.0	11.8	6.3	12.2	2.7
U.S. Petroleum	13.1	5.7	12.7	7.3	12.7	5.7	14.5	2.6
Oil and Gas Production	13.1	10.5	12.3	12.8	14.0	10.4	13.3	6.1
Refining/Marketing	14.5	-2.7	16.7	-3.3	10.9	-2.8	15.1	-2.0
Pipelines	9.7	5.2	8.2	5.7	11.0	3.0	25.7	13.6
Foreign Petroleum	10.9	7.6	12.3	8.6	9.0	8.0	7.7	2.9
Oil and Gas Production	11.2	9.2	13.0	11.4	9.3	8.3	7.9	2.9
Refining/Marketing	9.5	1.3	10.0	1.1	5.7	3.3	5.7	3.2
International Marine	25.9	-6.2	24.9	-5.6	W	0.0	0.0	0.0
Coal	9.0	-8.5	5.1	-33.6	34.4	W	W	W
Other Energy	9.0	-6.8	15.2	-31.9	5.7	6.5	2.8	10.5
Nonenergy	-6.6	4.7	2.9	4.6	-33.9	0.8	-1.3	13.1

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, 1996-2002
(Million Dollars)

	1996	1997	1998	1999	2000	2001	2002
Sources of R&D Funds							
Federal Government	W	W	W	27	W	W	W
Internal Company	2,675	2,841	1,668	1,377	1,316	1,542	1,742
Other Sources	W	W	W	20	W	W	W
Total Sources	2,717	2,885	1,707	1,424	1,326	1,570	1,753
Breakdown of R&D Expenditures							
Oil & Gas Recovery	482	585	606	430	453	592	464
Other Petroleum	432	380	365	345	327	376	656
Coal Gasification/Liquefaction	W	W	W	W	W	0	0
Other Coal	W	W	W	W	W	0	W
Nuclear and Other Energy	51	54	W	W	W	W	59
Nonenergy	1,617	1,738	616	538	452	526	517
Unassigned	127	120	85	W	W	W	W
Total Expenditures	2,717	2,885	1,707	1,424	1,326	1,570	1,753

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, 2002
(Percent)

Line of Business	Top Four	Five through Twelve	All Other	All FRS
Petroleum	51.5	29.4	19.1	100.0
United States	41.9	36.5	21.6	100.0
Production	41.8	38.6	19.6	100.0
Refining/Marketing	34.1	33.8	32.1	100.0
Refining	28.7	36.1	35.2	100.0
Marketing	56.0	15.3	28.8	100.0
Rate Regulated Pipelines	61.1	34.1	4.9	100.0
Foreign	65.6	19.0	15.4	100.0
Production	59.9	22.2	17.8	100.0
Refining/Marketing	88.2	6.2	5.5	100.0
International Marine	100.0	0.0	0.0	100.0
Coal	53.1	3.9	43.0	100.0
Other Energy	35.0	63.4	1.7	100.0
Nonenergy	63.2	24.5	12.3	100.0
Chemicals	60.0	26.6	13.4	100.0
Other Nonenergy	84.6	10.5	4.9	100.0
Consolidated	52.1	30.2	17.6	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, 1996-2002
(Million Dollars)

Cash Flows [1]	1996	1997	1998	1999	2000	2001	2002
Cash Flows From Operations							
Net Income	32,029	32,082	12,519	22,866	53,192	37,735	20,592
Minority Interest in Income	845	896	764	1,161	1,912	2,172	1,068
Noncash Items:							
Depreciation, Depletion, & Allowance	29,331	29,569	35,445	32,452	37,621	46,377	45,529
Dry Hole Expense, This Year	1,812	2,069	2,518	1,808	1,328	2,344	1,925
Deferred Income Taxes	2,863	2,301	-1,123	-25	5,611	3,145	-143
Recognized Undistributed (Earnings)/Losses of Unconsolidated Affiliates	-226	-374	2,987	136	-3,319	-318	1,144
(Gain)/Loss on Disposition of Property, Plant, & Equipment (PP&E)	-1,940	-2,716	-2,658	-1,922	-2,065	-1,176	-1,374
Changes in Operating Assets and Liabilities and Other Noncash Items	-365	298	-3,792	-2,259	-6,269	2,848	-636
Other Cash Items, Net	-165	1,197	1,502	581	629	-3,490	6,847
Net Cash Flow From Operations	64,184	65,322	48,162	54,798	88,640	89,637	74,952
Cash Flows From Investing Activities							
Additions to PP&E:							
Due to Mergers and Acquisitions	-2,281	-5,579	-18,868	-5,961	-49,722	-40,971	-33,147
Other	-41,872	-48,666	-51,046	-44,775	-52,470	-59,313	-57,322
Total Additions to PP&E	-44,153	-54,245	-69,914	-50,736	-102,192	-100,284	-90,469
Additions to Investments and Advances	-5,799	-7,685	-5,223	-6,874	-7,156	-10,086	-7,529
Proceeds From Disposals of PP&E	10,942	9,320	16,243	13,267	26,663	7,683	14,310
Other Investment Activities, Net	1,608	6,587	4,235	3,523	8,742	8,406	29,572
Cash Flow From Investing Activities	-37,402	-46,023	-54,659	-40,820	-73,943	-94,281	-54,116
Cash Flows From Financing Activities							
Proceeds From Long-Term Debt	10,708	17,901	27,072	29,862	33,292	54,987	34,094
Proceeds From Equity Security Offerings	1,171	1,507	9,112	3,557	30,606	6,267	4,878
Reductions in Long-Term Debt	-18,883	-19,774	-18,019	-24,988	-29,323	-34,264	-27,863
Purchase of Treasury Stock	-1,299	-7,910	-5,776	-424	-5,362	-7,474	-4,680
Dividends to Shareholders	-15,585	-16,941	-17,169	-16,081	-18,981	-17,132	-17,744
Other Financing Activities, Including Net Change in Short-Term Debt	-578	5,537	6,859	-3,377	-17,205	3,848	-7,063
Cash Flow From Financing Activities	-24,466	-19,680	2,079	-11,451	-6,973	6,232	-18,378
Effect of Exchange Rate on Cash	3	-255	-13	-24	-119	-308	571
Net Increase/(Decrease) in Cash and Cash Equivalents	2,319	-636	-4,431	2,503	7,605	1,280	3,029

[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, 1996-2002
(Million Dollars)

	1996	1997	1998	1999	2000	2001	2002
Income Taxes (as per Financial Statements)							
Current Paid or Accrued:							
U.S. Federal, before Investment Tax Credit &							
Alternative Minimum Tax	6,141	5,656	603	1,375	11,705	8,812	390
U.S. Federal Investment Tax Credit	-146	-93	-85	-90	-129	-246	-245
Effect of Alternative Minimum Tax	-325	-400	-16	445	-1,222	-632	69
U.S. State & Local Income Taxes	745	794	443	371	1,338	1,067	478
Foreign Income Taxes							
Canada	745	932	456	597	1,765	1,139	1,236
Europe and Former Soviet Union [1]	3,862	2,927	1,798	3,110	7,002	6,515	5,619
Africa	1,956	1,926	449	1,607	3,617	3,057	2,884
Middle East	1,326	802	745	1,286	2,380	1,937	1,753
Other Eastern Hemisphere	2,195	1,901	992	1,679	2,214	1,676	1,674
Other Western Hemisphere	729	1,739	428	346	900	695	669
Total Foreign	10,813	10,227	4,868	8,625	17,878	15,019	13,835
Total Current	17,228	16,184	5,813	10,726	29,570	24,020	14,527
Deferred							
U.S. Federal, before Investment Tax Credit	1,410	1,477	-373	1,480	3,168	2,403	241
U.S. Federal Investment Tax Credit	69	-2	-28	-14	-78	-10	-18
Effect of Alternative Minimum Tax	312	400	-16	-415	1,233	650	-69
U.S. State & Local Income Taxes	56	54	104	136	221	26	76
Foreign	930	519	-791	-1,075	910	567	-191
Total Deferred	2,777	2,448	-1,104	112	5,454	3,636	39
Total Income Tax Expense	20,005	18,632	4,709	10,838	35,024	27,656	14,566
Reconciliation of Accrued U.S. Federal Income Tax Expense To Statutory Rate							
Consolidated Pretax Income/(Loss)	52,808	51,453	16,017	33,837	86,702	68,246	36,171
Less: Foreign Source Income not Subject to U.S.	6,230	5,827	251	2,160	13,355	8,918	8,816
Equals: Income Subject to U.S. Tax	46,578	45,626	15,766	31,677	73,347	59,328	27,355
Less: U.S. State & Local Income Taxes	782	785	570	486	1,497	895	345
Less: Applicable Foreign Income Taxes Deducted	554	312	32	107	353	82	252
Equals: Pretax Income Subject to U.S. Tax	45,242	44,529	15,164	31,084	71,497	58,351	26,758
Tax Provision Based on Previous Line	15,834	15,621	5,332	10,902	25,032	20,438	9,363
Increase/(Decrease) in Taxes Due To:							
Foreign Tax Credits Recognized	-6,926	-6,982	-3,563	-5,963	-9,787	-8,513	-7,283
U.S. Federal Investment Tax Credit Recognized	-123	-137	-124	-98	-129	-486	-245
Statutory Depletion	-54	-63	-30	-8	-3	-1	-3
Effect of Alternative Minimum Tax	1	0	-16	23	11	16	0
Other	-1,273	-1,399	-1,485	-2,068	-447	-582	-1,462
Actual U.S. Federal Tax Provision (Refund)	7,459	7,040	114	2,788	14,677	10,872	370

[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, 1996-2002
(Million Dollars)

	1996	1997	1998	1999	2000	2001	2002
Production Taxes							
Oil and Gas Production	2,098	1,965	1,176	1,674	2,604	2,506	2,187
Coal	139	172	47	43	30	35	33
Other [1]	1	1	0	0	25	1	2
Total Production Taxes	2,238	2,138	1,223	1,717	2,659	2,542	2,222
Superfund	14	W	W	W	W	W	W
Import Duties	260	W	W	W	W	W	W
Sales, Use, and Property	2,516	2,407	2,648	2,268	2,356	2,373	2,360
Payroll	1,531	1,406	1,357	1,289	1,259	1,193	1,121
Other Taxes	514	559	360	467	789	546	378
Total Taxes Paid (Other Than Income Taxes)	7,073	6,601	5,660	5,825	7,186	6,740	6,156
Excise Taxes Collected	32,426	30,984	39,918	46,293	47,084	44,310	43,464

[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, 1996-2002

(Million Dollars)

	1996	1997	1998	1999	2000	2001	2002
United States							
Exploration							
Acquisition of Unproved Acreage	997	2,653	3,912	633	4,010	3,527	2,281
Geological and Geophysical	625	750	916	621	849	758	821
Drilling and Equipping [1]	2,338	2,905	2,964	1,921	2,550	3,276	2,555
Other	693	690	954	659	610	770	832
Total Exploration	4,653	6,998	8,746	3,834	8,019	8,331	6,489
Development							
Acquisition of Proved Acreage	922	2,928	3,568	1,144	27,939	7,383	7,572
Lease Equipment	1,613	1,823	2,688	2,431	1,907	3,818	3,325
Drilling and Equipping [1]	6,154	8,540	7,769	5,022	8,788	11,671	10,711
Other [2]	1,290	1,557	1,657	1,056	1,391	2,655	3,715
Total Development	9,979	14,848	15,682	9,653	40,025	25,527	25,323
Total U.S. Exploration and Development	14,632	21,846	24,428	13,487	48,044	33,858	31,812
Foreign							
Exploration							
Acquisition of Unproved Acreage	745	565	2,159	2,252	4,105	4,696	2,588
Geological and Geophysical	869	897	1,065	885	875	1,028	939
Drilling and Equipping [1]	2,277	2,684	2,650	1,579	1,824	2,677	2,108
Other	919	1,128	1,299	903	1,087	1,146	864
Total Exploration	4,810	5,274	7,173	5,619	7,891	9,547	6,499
Development							
Acquisition of Proved Acreage	1,932	1,641	7,121	2,083	11,644	12,186	8,600
Lease Equipment	2,064	2,207	2,505	2,142	1,842	3,186	2,538
Drilling and Equipping [1]	5,278	6,426	6,206	5,143	5,057	7,060	8,040
Other [2]	2,534	2,383	3,388	2,531	2,364	3,965	5,695
Total Development	11,808	12,657	19,220	11,899	20,907	26,397	24,873
Total Foreign Exploration and Development	16,618	17,931	26,393	17,518	28,798	35,944	31,372

[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, 2002
(Million Dollars)

	Worldwide	United States			Foreign
		Total	Onshore	Offshore	
Exploration and Development Expenditures					
Exploration Expenditures					
Unproved Acreage	4,869	2,281	1,483	798	2,588
Drilling and Equipping:					
Completed Well Costs	-	2,065	609	1,456	-
Work-in-progress Adjustment	-	490	165		-
Total Drilling and Equipping	4,663	2,555	774	1,781	2,108
Geological and Geophysical	1,760	821	355	466	939
Other, Including Direct Overhead	1,696	832	411	421	864
Total Exploration Expenditures	12,988	6,489	3,023	3,466	6,499
Development Expenditures					
Proved Acreage (Including Mergers and Acquisitions)	16,172	7,572	6,951	621	8,600
Drilling and Equipping:					
Completed Well Costs	-	8,665	5,929	2,736	-
Work-in-progress Adjustment	-	2,046	882	1,164	-
Total Drilling and Equipping	18,751	10,711	6,811	3,900	8,040
Lease Equipment	5,863	3,325	2,276	1,049	2,538
Other Development					
Support Equipment	1,561	1,366	1,340	26	195
Other, Including Direct Overhead	7,849	2,349	1,929	420	5,500
Total Development Expenditures	50,196	25,323	19,307	6,016	24,873
Total Exploration and Development Expenditures	63,184	31,812	22,330	9,482	31,372

- = Not available.

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

Table B16. Exploration and Development Expenditures by Region, for FRS Companies, 1996-2002
(Million Dollars)

	1996	1997	1998	1999	2000	2001	2002
Exploration Expenditures							
U.S. Onshore	1,826	3,396	3,941	1,174	4,136	4,779	3,023
U.S. Offshore	2,827	3,602	4,805	2,660	3,883	3,552	3,466
Total United States	4,653	6,998	8,746	3,834	8,019	8,331	6,489
Canada	355	310	638	420	1,184	3,899	1,694
OECD Europe	1,345	1,684	1,916	767	869	756	1,223
Former Soviet Union and E. Europe	194	285	630	354	317	374	470
Africa	779	807	1,092	1,268	910	1,579	1,292
Middle East	45	53	141	96	56	197	121
Other Eastern Hemisphere	1,462	1,341	1,563	1,192	1,675	1,478	1,121
Other Western Hemisphere	630	794	1,193	1,522	2,880	1,264	578
Total Foreign	4,810	5,274	7,173	5,619	7,891	9,547	6,499
Worldwide Exploration Expenditures	9,463	12,272	15,919	9,453	15,910	17,878	12,988
Development Expenditures							
U.S. Onshore	6,087	9,624	9,519	5,396	22,953	19,465	19,307
U.S. Offshore	3,892	5,224	6,163	4,257	17,072	6,062	6,016
Total United States	9,979	14,848	15,682	9,653	40,025	25,527	25,323
Canada	1,210	1,688	4,168	1,636	3,697	11,425	4,993
OECD Europe	4,222	5,368	6,670	3,370	6,651	4,617	8,571
Former Soviet Union and E. Europe	267	343	637	252	576	507	803
Africa	2,014	2,171	2,042	1,826	1,809	3,968	3,799
Middle East	418	590	801	297	494	542	653
Other Eastern Hemisphere	2,670	1,643	2,386	2,250	5,112	3,513	5,074
Other Western Hemisphere	1,007	854	2,516	2,268	2,568	1,826	980
Total Foreign	11,808	12,657	19,220	11,899	20,907	26,397	24,873
Worldwide Development Expenditures	21,787	27,505	34,902	21,552	60,932	51,924	50,196
Total Exploration and Development Expenditures							
U.S. Onshore	7,913	13,020	13,460	6,570	27,089	24,244	22,330
U.S. Offshore	6,719	8,826	10,968	6,917	20,955	9,614	9,482
Total United States	14,632	21,846	24,428	13,487	48,044	33,858	31,812
Canada	1,565	1,998	4,806	2,056	4,881	15,324	6,687
OECD Europe	5,567	7,052	8,586	4,137	7,520	5,373	9,794
Former Soviet Union and E. Europe	461	628	1,267	606	893	881	1,273
Africa	2,793	2,978	3,134	3,094	2,719	5,547	5,091
Middle East	463	643	942	393	550	739	774
Other Eastern Hemisphere	4,132	2,984	3,949	3,442	6,787	4,991	6,195
Other Western Hemisphere	1,637	1,648	3,709	3,790	5,448	3,090	1,558
Total Foreign	16,618	17,931	26,393	17,518	28,798	35,944	31,372
Worldwide Exploration and Development Expenditures	31,250	39,777	50,821	31,005	76,842	69,802	63,184

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

Table B17. Production (Lifting) Costs by Region for FRS Companies, 1996-2002
(Million Dollars)

	1996	1997	1998	1999	2000	2001	2002
United States							
Taxes Other Than Income Taxes	2,098	1,965	1,176	1,674	2,604	2,506	2,187
Other Costs	10,221	10,147	9,787	9,494	8,417	10,377	10,315
Total Production Costs	12,319	12,112	10,963	11,168	11,021	12,883	12,502
U.S. Onshore	9,855	9,604	8,198	8,039	8,254	9,838	9,650
U.S. Offshore	2,464	2,508	2,765	3,129	2,767	3,045	2,852
Canada							
Royalty Expenses	W	W	W	W	W	0	0
Taxes Other Than Income Taxes	W	W	W	W	W	105	109
Other Costs	993	961	1,037	1,120	1,379	1,842	2,303
Total Production Costs	1,082	1,049	1,129	1,252	1,496	1,947	2,412
OECD Europe							
Royalty Expenses	251	217	251	62	W	W	49
Taxes Other Than Income Taxes	400	360	269	330	W	W	456
Other Costs	3,996	3,950	3,980	3,666	3,485	3,496	3,416
Total Production Costs	4,647	4,527	4,500	4,058	4,025	4,151	3,921
Former Soviet Union and E. Europe							
Royalty Expenses	W	W	W	W	W	W	0
Taxes Other Than Income Taxes	W	W	W	W	W	W	0
Other Costs	133	188	207	111	179	155	111
Total Production Costs	134	192	208	148	196	191	111
Africa							
Royalty Expenses	W	W	W	W	W	W	0
Taxes Other Than Income Taxes	W	W	W	W	W	W	377
Other Costs	812	861	1,194	1,153	1,208	1,384	1,730
Total Production Costs	1,259	1,310	1,490	1,268	1,784	1,847	2,107
Middle East							
Royalty Expenses	W	W	W	W	137	0	0
Taxes Other Than Income Taxes	W	W	W	W	75	55	46
Other Costs	296	280	250	235	175	407	502
Total Production Costs	483	491	429	424	387	462	548
Other Eastern Hemisphere							
Royalty Expenses and Taxes Other Than Income Taxes	542	456	240	507	618	527	468
Other Costs	1,161	1,144	1,074	1,097	1,392	1,931	2,114
Total Production Costs	1,703	1,600	1,314	1,604	2,010	2,458	2,582
Other Western Hemisphere							
Royalty Expenses and Taxes Other Than Income Taxes	180	156	87	184	304	143	276
Other Costs	389	470	552	443	533	600	633
Total Production Costs	569	626	639	627	837	743	909
Total Foreign							
Royalty Expenses	901	891	740	384	437	153	150
Taxes Other Than Income Taxes	1,196	1,050	675	1,172	1,947	1,831	1,631
Other Costs	7,780	7,854	8,294	7,825	8,351	9,815	10,809
Total Production Costs	9,877	9,795	9,709	9,381	10,735	11,799	12,590

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

Table B18. Oil and Gas Acreage for FRS Companies, 1996-2002
(Thousand Acres)

	1996	1997	1998	1999	2000	2001	2002
Net Acreage							
U.S. Onshore							
Developed	26,733	25,474	26,396	25,895	31,760	34,332	37,103
Undeveloped	31,659	31,154	30,598	25,880	37,657	43,293	40,280
U.S. Offshore							
Developed	5,470	5,343	4,634	4,988	5,383	5,881	5,281
Undeveloped	16,880	22,983	23,168	24,940	21,483	20,933	21,929
Foreign							
Developed	22,574	21,984	24,887	26,337	32,535	32,903	37,603
Undeveloped	445,176	472,106	514,511	416,209	416,941	424,465	429,394
Gross Acreage							
U.S. Onshore							
Developed	46,887	45,249	49,097	45,978	57,626	63,721	69,641
Undeveloped	53,775	55,530	51,364	42,325	59,295	69,790	64,841
U.S. Offshore							
Developed	9,668	10,665	8,861	9,534	10,588	11,317	9,802
Undeveloped	21,786	30,845	32,439	35,689	31,609	30,523	32,384
Foreign							
Developed	59,926	58,198	64,358	59,247	71,330	70,112	81,171
Undeveloped	857,130	924,839	1,083,355	835,615	882,761	834,500	799,007

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

Table B19. U.S. Net Wells Completed for FRS Companies and U.S. Industry, 1996-2002

	1996	1997	1998	1999	2000	2001	2002
Number of Net Wells Completed During Year for FRS Companies							
Onshore							
Net Exploratory Wells							
Dry Holes	274	163	159	93	86	122	119
Oil Wells	91	90	55	26	19	59	21
Gas Wells	207	170	142	105	217	351	164
Total Exploratory Wells	572	424	356	225	321	533	304
Net Development Wells							
Dry Holes	319	301	256	162	229	266	220
Oil Wells	2,095	3,016	2,510	1,130	1,775	1,815	1,187
Gas Wells	2,049	2,261	2,074	1,519	2,927	5,226	4,982
Total Development Wells	4,463	5,577	4,841	2,812	4,930	7,307	6,389
Offshore							
Net Exploratory Wells							
Dry Holes	84	98	91	59	73	63	52
Oil Wells	36	31	22	28	28	39	35
Gas Wells	87	73	63	61	59	63	53
Total Exploratory Wells	206	202	176	148	159	165	140
Net Development Wells							
Dry Holes	23	46	32	26	29	38	38
Oil Wells	158	181	115	145	128	240	135
Gas Wells	153	168	133	153	157	170	134
Total Development Wells	334	396	280	324	315	448	307
Total United States							
Net Exploratory Wells							
Dry Holes	358	261	249	153	158	185	171
Oil Wells	127	121	77	54	47	98	56
Gas Wells	293	243	205	166	275	415	217
Total Exploratory Wells	778	626	531	372	480	698	443
Net Development Wells							
Dry Holes	342	347	288	188	258	305	259
Oil Wells	2,253	3,197	2,625	1,275	1,903	2,054	1,321
Gas Wells	2,202	2,429	2,208	1,672	3,084	5,396	5,116
Total Development Wells	4,797	5,973	5,121	3,136	5,245	7,755	6,696
Number of Net Wells Completed During Year for Total U.S. Industry							
Net Exploratory Wells							
Dry Holes	2,154	2,145	1,843	1,157	1,331	1,576	1,130
Oil Wells	484	434	306	153	267	327	223
Gas Wells	575	542	589	520	613	963	666
Total Exploratory Wells	3,213	3,121	2,739	1,830	2,210	2,866	2,018
Net Development Wells							
Dry Holes	3,184	3,659	3,138	2,273	2,636	2,742	2,394
Oil Wells	7,911	9,889	6,566	4,119	7,240	7,876	5,934
Gas Wells	8,729	10,592	11,494	10,530	15,852	20,740	16,097
Total Development Wells	19,824	24,140	21,198	16,921	25,728	31,358	24,424
Number of Net In-Progress Wells At Year End for FRS Companies							
Onshore							
Exploratory Wells	133	135	51	40	70	85	66
Development Wells	675	929	392	464	716	1,052	1,315
Total In-Progress Wells	808	1,064	444	504	786	1,138	1,381
Offshore							
Exploratory Wells	45	92	52	68	50	56	55
Development Wells	93	128	73	87	110	63	47
Total In-Progress Wells	138	220	124	155	160	118	102
Total United States							
Exploratory Wells	178	226	103	108	120	141	120
Development Wells	768	1,058	465	551	826	1,115	1,362
Total In-Progress Wells	946	1,284	568	659	946	1,256	1,482

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, October 2003, p. 84. 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, 1996-2002

	1996	1997	1998	1999	2000	2001	2002
FRS Companies							
Onshore				(thousand feet)			
Exploratory Well Footage							
Dry Hole Footage	2,052	1,700	1,714	921	955	1,085	1,000
Oil Well Footage	732	1,027	406	312	199	397	141
Gas Well Footage	1,860	1,521	1,548	1,150	1,399	2,016	1,284
Total Exploratory Footage	4,644	4,248	3,668	2,383	2,553	3,498	2,425
Development Well Footage							
Dry Hole Footage	2,224	1,926	1,939	1,252	1,597	2,029	1,716
Oil Well Footage	10,956	14,534	12,513	4,449	9,374	9,435	6,928
Gas Well Footage	14,304	16,751	16,521	12,291	20,516	26,653	32,078
Total Development Footage	27,484	33,211	30,973	17,992	31,487	38,117	40,722
Offshore							
Exploratory Well Footage							
Dry Hole Footage	1,091	1,362	1,345	848	1,151	1,004	652
Oil Well Footage	408	397	443	434	364	551	589
Gas Well Footage	1,824	981	1,285	1,002	1,141	759	697
Total Exploratory Footage	3,323	2,740	3,073	2,284	2,656	2,314	1,938
Development Well Footage							
Dry Hole Footage	244	459	344	199	411	353	369
Oil Well Footage	1,704	1,736	1,428	1,280	1,505	2,260	1,362
Gas Well Footage	1,538	1,584	1,398	1,295	1,899	1,917	1,370
Total Development Footage	3,486	3,779	3,170	2,774	3,815	4,530	3,101
Total United States							
Exploratory Well Footage							
Dry Hole Footage	3,143	3,062	3,059	1,769	2,107	2,089	1,652
Oil Well Footage	1,140	1,424	849	746	563	948	730
Gas Well Footage	3,684	2,502	2,833	2,152	2,540	2,775	1,981
Total Exploratory Footage	7,967	6,988	6,741	4,667	5,209	5,812	4,363
Development Well Footage							
Dry Hole Footage	2,468	2,385	2,283	1,451	2,008	2,382	2,085
Oil Well Footage	12,660	16,270	13,941	5,729	10,879	11,695	8,290
Gas Well Footage	15,842	18,335	17,919	13,586	22,415	28,570	33,448
Total Development Footage	30,970	36,990	34,143	20,766	35,303	42,647	43,823
Total United States Industry							
Exploratory Well Footage							
Dry Hole Footage	13,199	13,861	12,398	7,646	8,863	10,100	7,479
Oil Well Footage	3,504	3,432	2,505	1,045	1,918	2,433	1,548
Gas Well Footage	3,782	3,955	4,196	3,315	4,538	6,938	5,016
Total Exploratory Footage	20,485	21,248	19,098	12,006	15,319	19,472	14,044
Development Well Footage							
Dry Hole Footage	16,656	19,666	18,005	12,508	13,981	14,573	12,688
Oil Well Footage	36,988	47,773	32,125	17,705	31,782	36,470	26,589
Gas Well Footage	54,376	65,860	70,746	52,204	76,309	103,547	88,903
Total Development Footage	108,020	133,298	120,875	82,417	122,073	154,590	128,179
Number of Net Producing Wells for FRS Companies				(number of wells)			
Onshore							
Oil Wells	87,461	75,493	69,401	58,987	68,274	66,667	69,021
Gas Wells	48,779	48,779	49,429	44,880	64,696	82,083	89,102
Total Producing Wells	136,240	124,272	118,830	103,867	132,970	148,750	158,123
Offshore							
Oil Wells	3,552	3,760	3,421	2,855	3,536	4,738	4,384
Gas Wells	2,556	2,898	2,737	2,707	3,111	3,606	3,011
Total Producing Wells	6,108	6,658	6,158	5,562	6,647	8,344	7,395
Total United States							
Oil Wells	91,013	79,253	72,822	61,842	71,810	71,405	73,405
Gas Wells	51,335	51,677	52,166	47,587	67,807	85,689	92,113
Total Producing Wells	142,348	130,930	124,987	109,429	139,617	157,094	165,518

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* , October 2003, p. 84.

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, 1996-2002

	1996	1997	1998	1999	2000	2001	2002
Canada							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	86.2	22.8	54.8	36.4	126.3	106.4	156.6
Oil Wells	46.0	10.7	10.0	25.8	23.3	63.1	74.0
Gas Wells	96.1	49.2	66.3	127.5	194.2	165.9	329.4
Total Exploratory Wells	228.3	82.7	131.1	189.7	343.8	335.4	560.0
Development Wells							
Dry Holes	48.1	59.6	58.8	58.3	138.2	228.8	151.2
Oil Wells	559.4	778.6	198.9	352.1	373.3	818.1	794.1
Gas Wells	233.7	275.1	422.4	758.7	891.5	2,025.1	2,381.1
Total Development Wells	841.2	1,113.3	680.1	1,169.1	1,403.0	3,072.1	3,326.4
Net In-Progress Wells at Year End	17.2	30.6	24.3	76.3	116.8	307.2	190.0
Net Producing Wells							
Oil Wells	8,719.5	9,364.7	10,532.3	10,155.9	12,094.8	17,640.5	14,203.0
Gas Wells	5,784.8	6,199.5	8,872.7	10,038.7	15,242.7	25,230.5	26,434.9
Total Producing Wells	14,504.3	15,564.2	19,405.0	20,194.6	27,337.5	42,870.9	40,637.9
Europe and Former Soviet Union [1]							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	49.4	56.6	36.3	15.4	15.7	15.6	11.2
Oil Wells	14.5	19.2	11.8	9.2	5.2	25.9	5.3
Gas Wells	11.4	8.9	12.0	4.0	6.4	8.6	3.1
Total Exploratory Wells	75.3	84.7	60.1	28.6	27.3	50.1	19.6
Development Wells							
Dry Holes	5.3	3.2	7.8	2.6	10.3	5.4	4.6
Oil Wells	77.6	80.7	118.5	75.4	67.7	91.8	63.0
Gas Wells	31.0	25.1	60.5	30.4	30.4	31.8	41.2
Total Development Wells	113.9	109.0	186.8	108.4	108.4	129.0	108.8
Net In-Progress Wells at Year End	68.7	62.7	54.5	31.6	63.7	69.3	38.7
Net Producing Wells							
Oil Wells	1,445.5	1,328.0	1,294.4	1,218.8	1,431.3	1,478.2	1,225.7
Gas Wells	765.2	766.8	805.3	626.6	737.7	717.2	788.7
Total Producing Wells	2,210.7	2,094.8	2,099.7	1,845.4	2,169.0	2,195.4	2,014.4
Africa and Middle East							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	19.8	25.3	33.1	14.9	37.2	21.9	26.8
Oil Wells	W	W	W	9.9	W	W	W
Gas Wells	W	W	W	10.0	W	W	W
Total Exploratory Wells	44.0	46.1	65.0	34.8	50.7	50.9	67.5
Development Wells							
Dry Holes	W	W	W	5.8	W	W	11.3
Oil Wells	133.0	151.6	218.4	206.3	239.3	159.8	209.4
Gas Wells	W	W	W	8.6	W	W	13.5
Total Development Wells	144.0	157.8	225.6	220.7	252.0	186.9	234.2
Net In-Progress Wells at Year End	36.9	29.0	18.0	36.8	35.2	35.4	57.0
Net Producing Wells							
Oil Wells	1,688.9	1,644.6	1,924.2	1,969.8	1,954.1	2,063.8	2,209.2
Gas Wells	49.9	59.5	62.7	83.2	79.0	121.2	140.2
Total Producing Wells	1,738.8	1,704.1	1,986.9	2,053.0	2,033.1	2,185.0	2,349.4

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, 1996-2002 (Continued)

	1996	1997	1998	1999	2000	2001	2002
Other Eastern Hemisphere							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	42.6	39.8	47.1	35.4	40.7	39.1	36.8
Oil Wells	21.6	16.1	36.6	41.6	31.3	19.9	11.0
Gas Wells	46.3	15.8	13.8	16.0	20.7	42.3	26.6
Total Exploratory Wells	110.5	71.7	97.5	93.0	92.7	101.3	74.4
Development Wells							
Dry Holes	3.7	4.7	11.5	1.9	4.4	7.1	3.0
Oil Wells	103.1	162.6	149.5	82.4	140.6	595.3	554.8
Gas Wells	91.7	116.5	101.2	104.5	113.5	117.0	201.7
Total Development Wells	198.5	283.8	262.2	188.8	258.5	719.4	759.5
Net In-Progress Wells at Year End	72.4	61.4	64.5	56.2	80.5	67.1	30.9
Net Producing Wells							
Oil Wells	1,622.0	1,767.0	1,707.2	1,654.2	1,950.2	7,852.9	7,458.6
Gas Wells	561.2	633.8	862.2	882.2	927.4	1,090.3	1,288.8
Total Producing Wells	2,183.2	2,400.8	2,569.4	2,536.4	2,877.6	8,943.2	8,747.4
Other Western Hemisphere							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	12.4	5.7	14.6	7.9	14.5	31.9	13.2
Oil Wells	9.0	4.7	10.4	3.2	W	W	W
Gas Wells	2.0	0.0	4.5	3.8	W	W	W
Total Exploratory Wells	23.4	10.4	29.5	14.9	23.4	40.0	21.3
Development Wells							
Dry Holes	W	W	W	W	W	W	W
Oil Wells	123.3	141.4	212.8	81.4	205.8	240.5	217.0
Gas Wells	W	W	W	W	W	W	W
Total Development Wells	129.8	148.3	224.5	91.7	245.0	262.9	245.1
Net In-Progress Wells at Year End	16.1	24.4	28.9	27.2	31.3	47.4	31.6
Net Producing Wells							
Oil Wells	2,478.9	605.0	2,045.6	2,426.5	2,597.2	2,580.2	2,439.6
Gas Wells	77.3	72.2	190.9	161.4	253.1	262.7	274.0
Total Producing Wells	2,556.2	677.2	2,236.5	2,587.9	2,850.3	2,842.9	2,713.6
Total Foreign							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	210.4	150.2	185.9	110.0	234.4	214.9	244.6
Oil Wells	110.9	71.0	97.6	89.7	74.1	136.0	134.3
Gas Wells	160.2	74.4	99.7	161.3	229.4	226.8	363.9
Total Exploratory Wells	481.5	295.6	383.2	361.0	537.9	577.7	742.8
Development Wells							
Dry Holes	67.9	75.5	83.7	70.1	156.7	252.5	171.2
Oil Wells	996.4	1,314.9	898.1	797.6	1,026.7	1,905.5	1,838.3
Gas Wells	363.1	421.8	597.4	911.0	1,083.5	2,212.2	2,664.5
Total Development Wells	1,427.4	1,812.2	1,579.2	1,778.7	2,266.9	4,370.3	4,674.0
Net In-Progress Wells at Year End	211.3	208.1	190.2	228.1	327.5	526.4	348.2
Net Producing Wells							
Oil Wells	15,954.8	14,709.3	17,503.7	17,425.2	20,027.6	31,615.6	27,536.1
Gas Wells	7,238.4	7,731.8	10,793.8	11,792.1	17,239.9	27,421.9	28,926.6
Total Producing Wells	23,193.2	22,441.1	28,297.5	29,217.3	37,267.5	59,037.4	56,462.7

[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. Number of Net Wells Completed, and Average Depth, Onshore and Offshore, for FRS Companies, 2001 and 2002

Drilling and Equipping Measures	Total United States			U.S. Onshore			U.S. Offshore		
	2001	2002	Percent Change	2001	2002	Percent Change	2001	2002	Percent Change
Exploration									
Oil Wells									
Wells Completed	97.9	55.5	-43.3	58.8	21.0	-64.3	39.1	34.5	-11.8
Average Depth (thousand feet)	9.7	13.2	35.8	6.8	6.7	-0.6	14.1	17.1	21.1
Gas Wells									
Wells Completed	414.7	216.7	-47.7	351.4	164.0	-53.3	63.3	52.7	-16.7
Average Depth (thousand feet)	6.7	9.1	36.6	5.7	7.8	36.5	12.0	13.2	10.3
Dry Holes									
Wells Completed	185.2	171.2	-7.5	122.4	118.8	-2.9	62.8	52.4	-16.5
Average Depth (thousand feet)	11.3	9.6	-14.5	8.9	8.4	-5.0	16.0	12.4	-22.2
Development									
Oil Wells									
Wells Completed	2,054.3	1,321.3	-35.7	1,814.6	1,186.6	-34.6	239.7	134.7	-43.8
Average Depth (thousand feet)	5.7	6.3	10.2	5.2	5.8	12.3	9.4	10.1	7.3
Gas Wells									
Wells Completed	5,396.3	5,115.7	-5.2	5,226.1	4,982.0	-4.7	170.2	133.7	-21.4
Average Depth (thousand feet)	5.3	6.5	23.5	5.1	6.4	26.3	11.3	10.2	-9.0
Dry Holes									
Wells Completed	304.7	258.7	-15.1	266.3	220.4	-17.2	38.4	38.3	-0.3
Average Depth (thousand feet)	7.8	8.1	3.1	7.6	7.8	2.2	9.2	9.6	4.8

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

Table B23. Oil and Gas Reserves for FRS Companies and U.S. Industry, 2002

	Beginning Reserves	Plus Reserve Additions[1]	Plus Net Purchases	Less Production	Equals Ending Reserves	Replacement Rate (percent)
Crude Oil and Natural Gas Liquids	(million barrels)					
U.S. Onshore						
Total U.S. Industry	24,242.0	2,149.0	0.0	2,048.0	24,342.0	104.9
FRS Companies	11,652.2	585.4	14.6	868.9	11,383.4	67.4
All Other	12,589.8	1,563.6	-14.6	1,179.1	12,958.6	132.6
U.S. Offshore						
Total U.S. Industry	6,197.0	842.0	0.0	711.0	6,329.0	118.4
FRS Companies	4,479.7	459.9	4.3	477.5	4,466.4	96.3
All Other	1,717.3	382.1	-4.3	233.5	1,862.6	163.6
U.S. Total						
Total U.S. Industry	30,439.0	2,991.0	0.0	2,759.0	30,671.0	108.4
FRS Companies	16,131.9	1,045.3	19.0	1,346.4	15,849.8	77.6
All Other	14,307.1	1,945.7	-19.0	1,412.6	14,821.2	137.7
FRS Companies' Foreign Oil Reserves						
Canada	2,583.5	228.8	-389.2	234.7	2,188.4	97.5
Europe	4,448.6	-28.9	-34.1	559.7	3,825.8	-5.2
FSU and Eastern Europe	948.9	393.2	-5.0	28.9	1,308.2	1,360.2
Africa	5,257.8	999.3	104.1	370.9	5,990.3	269.4
Middle East	857.4	38.7	6.8	116.8	786.1	33.2
Other Eastern Hemisphere	3,048.5	14.3	-81.1	316.7	2,664.9	4.5
Other Western Hemisphere	1,599.7	14.5	-38.3	119.2	1,456.7	12.1
Total Foreign	18,744.4	1,659.9	-436.9	1,746.9	18,220.5	95.0
Worldwide Total for FRS Companies	34,876.3	2,705.2	-417.9	3,093.3	34,070.3	87.5
Dry Natural Gas	(billion cubic feet)					
U.S. Onshore						
Total U.S. Industry	155,127.0	20,283.0	0.0	14,688.0	160,722.0	138.1
FRS Companies	68,514.6	4,930.9	610.5	5,920.7	68,135.3	83.3
All Other	86,612.4	15,352.1	-610.5	8,767.3	92,586.7	175.1
U.S. Offshore						
Total U.S. Industry	28,333.0	2,556.0	0.0	4,665.0	26,224.0	54.8
FRS Companies	19,485.1	1,048.2	-26.5	2,791.8	17,715.1	37.5
All Other	8,847.9	1,507.8	26.5	1,873.2	8,508.9	80.5
U.S. Total						
Total U.S. Industry	183,460.0	22,839.0	0.0	19,353.0	186,946.0	118.0
FRS Companies	87,999.7	5,979.2	583.9	8,712.5	85,850.3	68.6
All Other	95,460.3	16,859.8	-583.9	10,640.5	101,095.7	158.4
FRS Companies' Foreign Gas Reserves						
Canada	15,937.3	970.2	76.8	1,863.3	15,121.0	52.1
Europe	21,348.4	639.8	-213.5	2,270.4	19,504.3	28.2
FSU and Eastern Europe	1,020.2	373.7	0.0	31.7	1,362.2	1,177.7
Africa	5,267.6	1,031.4	563.9	214.3	6,648.6	481.4
Middle East	610.9	115.2	52.6	90.4	688.3	127.5
Other Eastern Hemisphere	24,186.2	2,322.0	-696.1	1,849.1	23,963.0	125.6
Other Western Hemisphere	16,336.5	4,294.8	-262.1	715.1	19,654.1	138.6
Total Foreign	84,707.1	9,747.1	-478.4	7,034.3	86,941.5	138.6
Worldwide Total for FRS Companies	172,706.8	15,726.3	105.5	15,746.8	172,791.9	99.9

[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.

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* , 2001 and 2002 (November 2002 and November 2003).
FRS companies' data - Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B24. Oil and Gas Reserve Balances by Region for FRS Companies, 2002

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	34,876	16,132	11,652	4,480	18,744
Revisions of Previous Estimates	29	105	109	-4	-76
Improved Recovery	685	346	247	99	338
Purchases of Minerals-in-Place	1,497	473	430	44	1,024
Extensions & Discoveries	1,991	594	229	365	1,397
Production	-3,093	-1,346	-869	-477	-1,747
Sales of Minerals-in-Place	-1,915	-454	-415	-40	-1,461
End of period	34,070	15,850	11,383	4,466	18,221
Proportionate Interest in Investee Reserves and Foreign Access Reserves	--	--	--	--	7,383
Natural Gas Reserves	(billion cubic feet)				
Beginning of Period	172,707	88,000	68,515	19,485	84,707
Revisions of Previous Estimates	694	-1,111	-558	-553	1,805
Improved Recovery	2,327	821	780	41	1,506
Purchases of Minerals-in-Place	12,649	5,562	5,297	265	7,087
Extensions & Discoveries	12,705	6,269	4,709	1,560	6,436
Production	-15,747	-8,713	-5,921	-2,792	-7,034
Sales of Minerals-in-Place	-12,544	-4,978	-4,687	-292	-7,566
End of Period	172,792	85,850	68,135	17,715	86,942
Proportionate Interest in Investee Reserves and Foreign Access Reserves	--	--	--	--	29,512

See footnotes at end of table.

Table B24. Oil and Gas Reserve Balances by Region for FRS Companies, 2002 (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	18,744	2,584	5,397	6,115	3,049	1,600
Revisions of Previous Estimates	-76	78	-116	182	-113	-106
Improved Recovery	338	9	22	237	W	W
Purchases of Minerals-in-Place	1,024	150	475	196	W	W
Extensions & Discoveries	1,397	141	458	619	100	79
Production	-1,747	-235	-589	-488	-317	-119
Sales of Minerals-in-Place	-1,461	-540	-515	-85	-234	-87
End of period	18,221	2,188	5,134	6,776	2,665	1,457
Proportionate Interest in Investee Reserves and Foreign Access Reserves	7,383	W	3,235	W	W	2,709
Natural Gas Reserves	(billion cubic feet)					
Beginning of Period	84,707	15,937	22,369	5,878	24,186	16,337
Revisions of Previous Estimates	1,805	-508	354	272	1,554	133
Improved Recovery	1,506	11	W	W	51	W
Purchases of Minerals-in-Place	7,087	1,711	2,798	668	1,909	0
Extensions & Discoveries	6,436	1,467	622	726	717	2,905
Production	-7,034	-1,863	-2,302	-305	-1,849	-715
Sales of Minerals-in-Place	-7,566	-1,634	W	W	-2,605	W
End of Period	86,942	15,121	20,866	7,337	23,963	19,654
Proportionate Interest in Investee Reserves and Foreign Access Reserves	29,512	42	19,980	W	W	2,368

[1] OECD Europe combined with the former Soviet Union and Eastern Europe to avoid disclosure. Prior to 1993, only OECD Europe is included in this region.
-- = 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, 2002 and Percent Change from 2001

	United States			Foreign Total
	Total	Onshore	Offshore	
Exploration and Development Expenditures (million dollars)				
FRS Companies	31,812.0	22,330.0	9,482.0	31,372.0
Percent Change	-6.0	-7.9	-1.4	-12.7
Wells Completed				
FRS Companies	7,139.1	6,692.8	446.3	5,416.8
Percent Change	-15.5	-14.6	-27.2	9.5
Industry[1]	26,442.0	25,927.0	515.0	21,493.0
Percent Change	-25.9	-27.0	208.4	-16.3
Success Rate[2]				
FRS Companies	94.0	94.9	79.7	92.3
Industry[1]	86.7	87.2	58.3	93.2
Crude Oil and NGL Production[3] (million barrels)				
FRS Companies	1,346.4	868.9	477.5	1,778.3
Percent Change	-1.2	-0.9	-1.8	1.2
Industry [1]	2,759.0	2,048.0	711.0	22,765.3
Percent Change	-1.6	-1.3	-2.6	-1.7
Crude Oil and NGL Reserve Interests[4] (million barrels)				
FRS Companies	15,849.8	11,383.4	4,466.4	25,603.8
Percent Change	-1.3	-2.6	2.2	3.2
Natural Gas Production (billion cubic feet)				
FRS Companies	8,712.5	5,920.7	2,791.8	7,034.3
Percent Change	-1.4	3.5	-10.4	11.5
Industry[1]	19,353.0	14,688.0	4,665.0	68,347.9
Percent Change	-2.2	0.7	-10.1	3.1
Natural Gas Reserve Interests (billion cubic feet)				
FRS Companies	85,850.3	68,135.3	17,715.1	116,454.0
Percent Change	0.1	2.2	-7.1	4.0

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, 2002 and Percent Change from 2001 (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	31,372.0	6,687.0	11,067.0	5,091.0	774.0	6,195.0	1,558.0
Percent Change	-12.7	-56.4	77.0	-8.2	4.7	24.1	-49.6
Wells Completed							
FRS Companies	5,416.8	3,886.4	128.4	201.7	100.0	833.9	266.4
Percent Change	9.5	14.1	-28.3	35.0	13.3	1.6	-12.1
Foreign Industry[1]	21,493.0	14,237.0	687.0	854.0	1,050.0	1,649.0	3,016.0
Percent Change	-16.3	-19.6	-11.4	33.0	38.5	-20.1	-19.3
Success Rate[2] (percent)							
FRS Companies	92.3	92.1	87.7	83.3	95.5	95.2	94.6
Foreign Industry[1]	93.2	94.0	100.9	85.7	97.2	88.9	92.9
Crude Oil and NGL Production[3] (million barrels)							
FRS Companies	1,778.3	234.7	588.6	370.9	148.2	316.7	119.2
Percent Change	1.2	15.1	-4.1	3.2	-2.2	-1.1	9.7
Foreign Industry[1]	22,765.3	1,051.2	5,745.9	2,897.0	7,655.0	1,679.0	3,737.2
Percent Change	-1.7	4.2	1.8	1.6	-5.7	-0.8	-3.1
Crude Oil and NGL Reserve Interests[4] (million barrels)							
FRS Companies	25,603.8	2,262.0	8,369.2	5,990.3	2,119.0	2,697.2	4,166.0
Percent Change	3.2	-13.7	5.7	13.9	-3.6	-12.8	12.2
Natural Gas Production (billion cubic feet)							
FRS Companies	7,034.3	1,863.3	2,302.1	214.3	90.4	1,849.1	715.1
Percent Change	11.5	24.5	-3.2	37.1	1.9	17.3	16.4
Foreign Industry[1]	68,347.9	6,477.6	34,408.1	4,702.0	8,316.7	9,499.2	4,864.3
Percent Change	3.1	6.7	0.5	7.4	3.3	7.8	2.2
Natural Gas Reserve Interests (billion cubic feet)							
FRS Companies	116,454.0	15,162.6	40,846.3	6,648.6	6,380.1	25,394.6	22,021.8
Percent Change	4.0	-5.0	-0.9	26.2	31.6	-1.0	15.7

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

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

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

[4]Foreign includes net ownership interest reserves (71.2 percent of total foreign) and "Other Access" reserves (28.8 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.

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* , 2001, and 2002 Annual Reports. Wells completed, U.S. - special compilation provided by the Energy Information Administration's Office of Oil and Gas. Totals are based on data which appeared in the Energy Information Administration's *Monthly Energy Review* , October 2003, p. 84. Reserve Additions, Foreign - *British Petroleum Statistical Review of World Energy 2002 and 2003.* Wells Completed, Foreign - *World Oil* , August 2002 and 2003.

FRS companies' data - Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B26. U.S. and Foreign Refining/Marketing Sources and Dispositions of Crude Oil and Natural Gas Liquids for FRS Companies,1996-2002
(million barrels)

	1996	1997	1998	1999	2000	2001	2002
U.S. Refining/Marketing							
Sources							
Acquisitions from U.S. Production Segment	1,599	1,542	1,484	1,516	1,238	1,358	1,368
Purchases from Other U.S. Segments and Unconsolidated Affiliates	459	468	1,935	2,181	2,149	2,629	1,709
Purchases from Third Parties	4,488	4,444	4,968	5,205	5,340	3,679	4,219
Net Transfers from Foreign Refining/Marketing Segment	566	571	635	475	324	716	631
Total Sources	7,112	7,025	9,021	9,377	9,050	8,383	7,926
Dispositions							
Net Change in Inventories	21	14	31	-1	-4	-1	-28
Input to Refineries	3,563	3,259	4,883	4,872	4,690	4,668	4,711
Sales to:							
Unaffiliated Third Parties	3,291	3,424	3,730	4,147	4,281	3,391	3,060
Other Segments Excluding Foreign Refining/Marketing	237	328	377	359	84	325	183
Total Dispositions	7,112	7,025	9,021	9,377	9,050	8,383	7,926
Foreign Refining/Marketing							
Sources							
Acquisitions from Foreign Production Segment	1,371	1,391	1,380	1,462	1,585	1,661	1,590
Purchases							
Other Foreign Segments	88	W	W	W	W	W	W
Unconsolidated Affiliates	89	W	W	W	W	W	W
Unaffiliated Third Parties							
Foreign Access	145	228	209	W	W	W	W
Foreign Governments (Open Market)	844	851	679	W	W	W	W
Other Unaffiliated Third Parties	1,819	1,785	2,000	2,244	2,165	2,459	1,626
Net Transfers to U.S. Refining/Marketing	-566	-571	-635	-475	-324	-716	-631
Total Sources	3,790	3,699	4,021	4,307	4,067	4,200	3,287
Dispositions							
Net Change in Inventories	38	18	155	-19	10	-2	0
Input to Refineries	1,605	1,435	1,419	1,641	1,673	1,682	1,639
Sales	2,147	2,246	2,446	2,685	2,384	2,520	1,647
Total Dispositions	3,790	3,699	4,021	4,307	4,067	4,200	3,287

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, 1996-2002

	1996	1997	1998	1999	2000	2001	2002
Purchases	Values (million dollars)						
U.S. Refining/Marketing Segment							
Raw Materials							
Crude Oil and NGL	138,397	126,535	106,128	152,880	253,092	192,228	186,084
Natural Gas	15,651	18,657	15,177	20,387	58,679	38,947	33,744
Other Raw Materials	2,697	3,159	5,348	5,705	8,395	7,852	7,950
Total Raw Materials	156,745	148,351	126,653	178,972	320,166	239,027	227,778
Refined Products							
Motor Gasoline	18,078	18,613	24,249	36,095	65,488	64,609	59,357
Distillate Fuels	9,634	9,565	10,574	17,433	35,116	31,323	27,031
Other Refined Products	10,246	9,141	8,786	9,963	17,036	18,895	16,868
Total Refined Products	37,958	37,319	43,609	63,491	117,640	114,827	103,256
U.S. Production Segment							
Crude Oil and NGL	5,163	5,399	4,694	5,695	4,794	1,979	721
Natural Gas	10,715	11,220	8,922	8,608	12,208	14,113	11,785
Total Raw Materials	15,878	16,619	13,616	14,303	17,002	16,092	12,506
Sales							
U.S. Refining/Marketing Segment							
Raw Materials							
Crude Oil and NGL	69,485	70,437	50,702	72,955	121,118	86,675	75,241
Natural Gas	15,790	18,252	15,270	20,023	56,482	37,648	32,882
Other Raw Materials	1,276	1,499	2,172	1,576	2,403	2,203	944
Total Raw Materials	86,551	90,188	68,144	94,554	180,003	126,526	109,067
Refined Products							
Motor Gasoline	75,330	71,185	84,968	109,301	176,394	167,735	158,691
Distillate Fuels	41,618	36,962	39,513	51,810	91,998	83,702	75,929
Other Refined Products	24,577	20,964	23,283	28,506	42,269	40,172	37,570
Total Refined Products	141,525	129,111	147,764	189,617	310,661	291,609	272,190
U.S. Production Segment							
Crude Oil and NGL	32,948	30,604	19,688	25,186	38,314	31,613	30,930
Natural Gas	26,840	29,459	23,649	23,178	40,719	47,390	40,208
Total Raw Materials	59,788	60,063	43,337	48,364	79,033	79,003	71,138
Purchases	Volumes						
U.S. Refining/Marketing Segment							
Raw Materials							
Crude Oil and NGL (million barrels)	7,112	7,025	9,021	9,377	9,050	8,383	7,926
Natural Gas (billion cubic feet)	7,506	7,573	7,425	9,285	13,323	9,147	10,458
Refined Products (million barrels)							
Motor Gasoline	677	689	1,272	1,533	1,708	1,892	1,840
Distillate Fuels	380	397	625	837	943	987	944
Other Refined Products	363	329	464	446	535	625	633
Total Refined Products	1,420	1,415	2,361	2,815	3,186	3,504	3,417
U.S. Production Segment							
Crude Oil and NGL (million barrels)	300	308	394	367	200	88	37
Natural Gas (billion cubic feet)	4,723	4,551	4,295	3,835	3,276	3,461	3,956
Sales							
U.S. Refining/Marketing Segment							
Raw Materials							
Crude Oil and NGL (million barrels)	3,528	3,752	4,107	4,506	4,365	3,716	3,243
Natural Gas (billion cubic feet)	7,195	7,242	6,764	8,834	13,001	8,460	9,783
Refined Products (million barrels)							
Motor Gasoline	2,488	2,371	3,789	4,070	4,286	4,539	4,551
Distillate Fuels	1,562	1,473	2,146	2,344	2,444	2,540	2,490
Other Refined Products	1,069	1,008	1,342	1,407	1,405	1,528	1,351
Total Refined Products	5,119	4,852	7,277	7,820	8,135	8,606	8,392
U.S. Production Segment							
Crude Oil and NGL (million barrels)	1,933	1,860	1,805	1,667	1,484	1,498	1,433
Natural Gas (billion cubic feet)	12,281	12,421	11,765	10,952	11,348	11,957	13,109

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

Table B28. U.S. and Foreign Petroleum Refining Statistics for FRS Companies, 1996-2002

	1996	1997	1998	1999	2000	2001	2002
U.S. Refining	(thousand barrels per calendar day)						
Runs to Stills							
At Own Refineries	9,777	9,060	13,699	13,476	13,361	13,875	13,307
By Refineries of Others	5	5	0	82	86	105	80
Total Runs to Stills	9,782	9,065	13,699	13,558	13,447	13,980	13,387
Refinery Output at Own Refineries and Refineries of Others							
Reformulated Motor Gasoline	1,302	768	1,552	1,792	2,129	2,061	1,991
Oxygenated Motor Gasoline	165	749	1,018	609	412	588	552
Other Motor Gasoline	3,410	2,980	4,665	4,588	4,207	4,373	4,456
Total Motor Gasoline	4,877	4,497	7,235	6,989	6,748	7,022	6,999
Distillate Fuels	3,323	2,921	4,278	4,167	4,376	4,331	4,167
Other Refined Products	2,754	2,612	3,416	3,483	3,375	3,669	3,595
Total Refinery Output	10,954	10,030	14,929	14,639	14,499	15,022	14,761
Refinery Capacity at End of Year	10,477	9,410	14,277	14,158	14,424	14,682	14,557
	(number of refineries)						
Number of Wholly-Owned Refineries	69	60	95	94	90	99	84
	(thousand barrels per calendar day)						
Foreign Refining							
Runs to Stills							
At Own Refineries	3,936	3,961	4,043	4,407	4,513	4,620	4,778
By Refineries of Others	506	340	292	397	403	339	325
Total Runs to Stills	4,442	4,301	4,335	4,804	4,916	4,959	5,103
Refinery Output at Own Refineries							
Motor Gasoline	1,172	1,041	1,135	1,247	1,295	1,293	1,427
Distillate Fuels	1,690	1,648	1,787	1,901	1,738	1,744	2,041
Other Refined Products	1,280	1,283	1,213	1,315	1,717	1,729	1,405
Total Refinery Output at Own Refineries	4,142	3,972	4,135	4,463	4,750	4,766	4,873
Refinery Output at Refineries of Others							
Motor Gasoline	107	75	83	122	123	120	117
Distillate Fuels	234	154	121	135	171	155	175
Other Refined Products	165	110	87	146	80	84	70
Total Refinery Output at Refineries of	506	339	291	403	374	359	362
Total Refinery Output	4,648	4,311	4,426	4,866	5,124	5,125	5,235
Refinery Capacity at End of Year	4,346	4,270	4,508	4,930	5,134	5,572	5,642
	(number of refineries)						
Number of Wholly-Owned Refineries	20	20	20	19	18	23	22
Number of Partially-Owned Refineries	12	15	15	18	18	18	19

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, 2002
(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]	14,761	5,089	4,354	5,318	17,655	83.6
Percent Gasoline						
Reformulated/Oxygenated	17.2	17.0	16.9	17.7	17.2	83.8
Other	30.2	28.7	30.7	31.2	30.1	84.0
Percent Distillate	28.2	28.3	27.5	28.8	30.0	78.6
Percent Other	24.4	26.0	24.9	22.3	22.7	89.6
Refinery Capacity						
Years Change (Net)	-125	-51	553	-627	-29	(5)
At Year End	14,557	4,544	4,542	5,471	17,339	84.0
Utilization Rate[4]	91.0	96.8	92.0	85.8	88.4	(5)
Foreign						
Refinery Output Volume[3]	5,235	4,583	0	652	-	(5)
Percent Gasoline	29.5	29.1	0.0	32.4	-	(5)
Percent Distillate	42.3	42.0	0.0	44.9	-	(5)
Percent Other	28.2	29.0	0.0	22.7	-	(5)
Refinery Capacity						
Years Change (Net)	70	197	0	-127	0	(5)
At Year End	5,642	5,121	0	521	0	0.0
Utilization Rate[3]	85.2	82.3	0.0	110.4	0.0	(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.

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,* 2001 and 2002. Industry data, Foreign - Refinery Capacity: *British Petroleum Statistical Review of World Energy* , 2002 and 2003.
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, 1996-2002

U.S. Dispositions	1996	1997	1998	1999	2000	2001	2002
	Values (million dollars)						
Motor Gasoline							
Intersegment Sales	400	581	966	1,521	1,802	2,521	3,500
U.S. Third-Party Sales							
Wholesale-Resellers	32,500	31,895	38,659	51,908	83,203	69,799	68,311
Company Operated Automotive Outlets	11,293	11,855	15,497	17,334	24,870	22,843	18,662
Company Lessee and Open Automotive Outlets	21,725	20,517	23,966	29,434	48,693	45,798	40,720
Other (Industrial, Commercial and Other Retail)	9,412	6,337	5,880	9,104	17,826	26,774	27,498
Total Third-Party Sales	74,930	70,604	84,002	107,780	174,592	165,214	155,191
Total Motor Gasoline Sales	75,330	71,185	84,968	109,301	176,394	167,735	158,691
Distillate Fuels							
Intersegment Sales	291	191	682	708	444	535	2,387
Third-Party Sales	41,327	36,771	38,831	51,102	91,554	83,167	73,542
Total Distillate Fuels Sales	41,618	36,962	39,513	51,810	91,998	83,702	75,929
Other Refined Products							
Intersegment Sales	4,124	3,322	2,059	2,779	6,078	7,386	4,474
Third-Party Sales	20,453	17,642	21,224	25,727	36,191	32,786	33,096
Total Other Refined Products Sales	24,577	20,964	23,283	28,506	42,269	40,172	37,570
Total U.S. Refined Products							
Intersegment Sales	4,815	4,094	3,707	5,008	8,324	10,442	10,361
Third-Party Sales	136,710	125,017	144,057	184,609	302,337	281,167	261,829
Total U.S. Refined Products Sales	141,525	129,111	147,764	189,617	310,661	291,609	272,190
	Volumes (million barrels)						
Motor Gasoline							
Intersegment Sales	12	18	50	66	47	79	101
U.S. Third-Party Sales							
Wholesale-Resellers	1,154	1,150	1,901	2,059	2,126	1,956	2,032
Company Operated Automotive Outlets	319	335	558	540	543	545	464
Company Lessee and Open Automotive Outlets	653	615	965	1,006	1,105	1,182	1,133
Other (Industrial, Commercial and Other Retail)	350	253	316	399	465	777	820
Total Third-Party Sales	2,476	2,353	3,739	4,004	4,239	4,460	4,450
Total Motor Gasoline Sales	2,488	2,371	3,789	4,070	4,286	4,539	4,551
Distillate Fuels							
Intersegment Sales	12	8	38	33	13	17	85
Third-Party Sales	1,550	1,464	2,109	2,310	2,430	2,522	2,405
Total Distillate Fuels Sales	1,562	1,473	2,146	2,344	2,444	2,540	2,490
Other Refined Products							
Intersegment Sales	209	254	141	153	213	258	162
Third-Party Sales	860	755	1,201	1,254	1,191	1,269	1,188
Total Other Refined Products Sales	1,069	1,008	1,342	1,407	1,405	1,528	1,351
Total U.S. Refined Products							
Intersegment Sales	232	280	229	252	274	354	348
Third-Party Sales	4,886	4,572	7,048	7,568	7,861	8,252	8,043
Total U.S. Refined Products Sales	5,119	4,852	7,277	7,820	8,135	8,606	8,392
Number of Active Automotive Outlets at Year End	Number of Automotive Outlets						
Company Operated	8,927	8,942	13,645	12,018	12,583	11,380	9,745
Lessee Dealers	15,247	12,852	16,396	17,847	16,953	11,474	9,371
Open Dealers	14,151	11,959	28,859	26,805	25,707	31,231	26,277
Total Outlets	38,325	33,753	58,900	56,670	55,243	54,085	45,393

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, 2001-2002
(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								
2002	101.4	34.51	101.4	34.51	W	W	0.0	0.00
2001	78.8	31.99	77.8	31.95	W	W	0.0	0.00
Percent Change	28.7	7.9	30.3	8.0	W	W	0.0	0.0
Wholesale/Resellers								
2002	2,032.4	33.61	695.3	34.60	371.3	34.95	965.8	32.38
2001	1,955.8	35.69	676.6	36.06	324.4	36.80	954.9	35.05
Percent Change	3.9	-5.8	2.8	-4.0	14.5	-5.0	1.1	-7.6
Dealer-Operated Outlets								
2002	1,133.4	35.93	653.4	36.23	148.8	36.68	331.2	34.99
2001	1,182.1	38.74	634.5	38.22	76.7	37.59	471.0	39.63
Percent Change	-4.1	-7.3	3.0	-5.2	94.0	-2.4	-29.7	-11.7
Company-Operated Outlets								
2002	464.3	40.20	189.0	37.56	135.2	40.50	140.1	43.46
2001	545.1	41.90	149.4	40.35	118.7	43.65	277.0	41.99
Percent Change	-14.8	-4.1	26.5	-6.9	13.8	-7.2	-49.4	3.5
Other [1]								
2002	819.8	33.54	211.7	33.69	504.6	33.65	103.6	32.71
2001	777.0	34.46	257.4	35.72	198.3	32.90	321.2	34.41
Percent Change	5.5	-2.7	-17.8	-5.7	154.4	2.3	-67.8	-5.0
Total Gasoline								
2002	4,551.2	34.87	1,850.7	35.37	1,159.8	35.25	1,540.8	33.97
2001	4,538.9	36.96	1,795.7	36.95	719.1	36.94	2,024.1	36.96
Percent Change	0.3	-5.6	3.1	-4.3	61.3	-4.6	-23.9	-8.1
Distillate								
2002	2,489.9	30.49	1,008.4	31.27	658.1	30.09	823.3	29.87
2001	2,539.8	32.96	988.6	33.55	415.6	33.55	1,135.6	32.22
Percent Change	-2.0	-7.5	2.0	-6.8	58.4	-10.3	-27.5	-7.3
All Other Products								
2002	1,350.7	27.81	535.5	28.15	345.1	29.67	470.2	26.07
2001	1,527.6	26.30	641.4	26.66	286.0	25.03	600.2	26.51
Percent Change	-11.6	5.8	-16.5	5.6	20.7	18.5	-21.7	-1.6
Total Refined Products								
2002	8,391.9	32.43	3,394.6	33.01	2,163.0	32.79	2,834.3	31.47
2001	8,606.3	33.88	3,425.7	34.04	1,420.7	33.55	3,759.9	33.86
Percent Change	-2.5	-4.3	-0.9	-3.0	52.3	-2.3	-24.6	-7.1

[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, 1996-2002
(Million Dollars)

Revenues and Costs	1996	1997	1998	1999	2000	2001	2002
Refined Product Revenues	141,525	129,111	147,764	189,617	310,661	291,609	272,190
Refined Product Costs							
Raw Materials Processed [1]	70,339	58,888	60,094	83,348	135,624	109,565	116,277
Refinery Energy Expense	5,480	5,005	5,349	6,427	10,838	11,321	10,114
Other Refinery Expense	9,882	8,436	12,219	11,734	10,635	12,274	15,202
Product Purchases	37,958	37,319	43,609	63,491	117,640	114,827	103,256
Other Product Supply Expense	4,072	3,777	5,160	4,915	6,655	6,552	12,562
Marketing Expense [2]	9,318	8,538	10,308	11,100	11,128	13,672	13,186
Total Refined Product Costs	137,049	121,963	136,739	181,015	292,520	268,211	270,597
Refined Product Margin	4,476	7,148	11,025	8,602	18,141	23,398	1,593
Refined Products Sold (million barrels)	5,118.6	4,852.2	7,276.9	7,820.2	8,134.7	8,606.3	8,391.9
Dollars per Barrel Margin [3]	0.87	1.47	1.52	1.10	2.23	2.72	0.19
Other Refining/Marketing Revenues [4]	10,731	9,693	15,997	14,282	14,196	16,918	15,343
Other Refining/Marketing Expenses							
Depreciation, Depletion, & Allowance	3,847	3,674	4,700	5,273	4,712	5,259	5,617
Other [5]	7,873	8,419	15,547	12,546	16,865	18,683	12,811
Total Other Expenses	11,720	12,093	20,247	17,819	21,577	23,942	18,428
Refining/Marketing Operating Income	3,487	4,748	6,775	5,065	10,760	16,374	-1,492
Miscellaneous Revenue & Expense [6]	-101	204	1,315	1,367	1,265	1,866	1,002
Less Income Taxes	1,135	1,876	2,142	1,714	4,360	6,271	346
Refining/Marketing Net Income	2,251	3,106	5,932	4,883	7,659	11,951	-2,164

[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, 1996-2002
(Million Dollars)

General Operating Expenses	1996	1997	1998	1999	2000	2001	2002
Raw Material Supply							
Raw Material Purchases	156,745	148,351	126,653	178,972	320,166	239,027	227,778
Other Raw Material Supply Expense	4,067	4,523	5,183	3,184	2,371	4,196	4,520
Total Raw Material Supply Expense	160,812	152,874	131,836	182,156	322,537	243,223	232,298
Less: Cost of Raw Materials Input To Refining	75,892	64,132	62,955	85,270	139,931	114,400	121,192
Net Raw Material Supply	84,920	88,742	68,881	96,886	182,606	128,823	111,106
Refining							
Raw Materials Input to Refining	75,892	64,132	62,955	85,270	139,931	114,400	121,192
Less: Raw Material Used as Refinery Fuel	3,922	3,798	3,598	4,254	6,910	7,132	6,954
Refinery Process Energy Expense	5,480	5,005	5,349	6,427	10,838	11,321	10,114
Other Refining Operating Expenses	10,631	9,173	12,984	12,928	13,675	14,657	16,459
Refined Product Purchases	37,958	37,319	43,609	63,491	117,640	114,827	103,256
Other Refined Product Supply Expenses	4,072	3,777	5,160	4,915	6,655	6,552	12,562
Total Refining	130,111	115,608	126,459	168,777	281,829	254,625	256,629
Marketing							
Cost of Other Products Sold	5,449	6,255	6,844	5,305	7,342	9,797	8,677
Other Marketing Expenses	9,318	8,538	10,308	11,100	11,128	13,672	13,186
Subtotal	14,767	14,793	17,152	16,405	18,470	23,469	21,863
Expense of Transport Services for Others	507	376	4,297	4,191	3,691	4,002	439
Total Marketing	15,274	15,169	21,449	20,596	22,161	27,471	22,302
Total U.S. Refining/Marketing Segment General Operating Expenses	230,305	219,519	216,789	286,259	486,596	410,919	390,037

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

Table B34. U.S. Coal Reserves Balance for FRS Companies, 1996-2002
(Million Tons)

Reserves and Production Statistics	1996	1997	1998	1999	2000	2001	2002
Changes to U.S. Coal Reserves							
Beginning of Period	10,493	9,410	7,502	5,334	4,410	2,530	1,320
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	8	-127	-17	-25	-58	-354	27
Production	-169	-163	-74	-44	-36	-33	-29
Dispositions of Minerals-in-Place	-1,150	-774	-2,113	-802	-1,799	W	W
End of Period Reserves	9,542	8,498	5,334	4,507	2,530	1,320	856
Weighted Average Annual Production Capacity	192	215	65	55	51	40	40
Reserves and Production:							
Total United States							
FRS Companies' Reserves	9,542	8,498	5,334	4,507	2,530	1,320	856
FRS Companies' Production	169	163	74	44	36	33	29
U.S. Industry Production	1,064	1,090	1,118	1,100	1,074	1,128	1,093
Region							
East							
FRS Companies' Reserves	2,675	2,477	1,774	1,676	1,034	557	227
FRS Companies' Production	44	43	24	21	20	16	14
U.S. Industry Production	452	468	460	426	420	433	399
Midwest							
FRS Companies' Reserves	2,467	2,080	1,372	1,055	1,051	394	W
FRS Companies' Production	18	17	12	W	W	W	W
U.S. Industry Production	112	112	110	104	87	95	93
West							
FRS Companies' Reserves	4,400	3,940	2,188	1,776	446	370	W
FRS Companies' Production	107	104	38	W	W	W	W
U.S. Industry Production	500	511	548	571	566	597	601
Mining Method							
Underground							
FRS Companies' Reserves	4,571	3,880	2,352	1,853	1,752	886	620
FRS Companies' Production	59	51	28	21	21	18	16
U.S. Industry Production	410	421	418	392	374	381	357
Surface							
FRS Companies' Reserves	4,970	4,618	2,982	2,654	779	434	236
FRS Companies' Production	110	112	46	23	15	15	13
U.S. Industry Production	654	669	700	709	700	747	736

W = Data withheld to avoid disclosure.
Sources: Coal production: 1996-2000--Energy Information Administration, *Coal Industry Annual* , annual reports; 2001-2002 - EIA, *Annual Coal Report, annual reports.*
FRS Companies' data - Energy Information Administration, Form EIA-28 (Financial Reporting System).