DOE/EIA-0206(05)
Distribution Category UC-950

Performance Profiles of Major Energy Producers 2003

March 2005

Energy Information Administration
Office of Energy Markets and End Use
U.S. Department of Energy
Washington, DC 20585

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 Margot Anderson, Director of the Office of Energy Markets and End Use. The project was directed by Mark Rodekohr, Director of the Energy Markets and Contingency Information Division, available at (202) 586-1130; and Bruce Bawks, Team Leader of the Financial Analysis Team, available at (202) 586-6579. Specific technical information concerning the associated data survey (Form EIA-28) may be obtained from Greg Filas, available at (202) 586-1347. The following authors contributed to this report: Bruce Bawks, Neal Davis, Bob Schmitt, and Larry Spancake. In addition, Kevin Forbes of SAIC provided essential research in the oil and gas production area.

Data File Information

Historical Financial Reporting System (FRS) data are available from EIA's File Transfer Protocol (FTP) site. These data cover the years 1977 through 2003 and are published in EIA's annual editions of *Performance Profiles of Major Energy Producers.* There are two sets of data: (1) aggregate data from the FRS survey form; and (2) multiyear tables from Appendix B of *Performance Profiles of Major Energy Producers.*

FRS 1977–2003 data files can be downloaded from the EIA 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 by phone at (202) 586-8800, by fax at (202) 586-0727, by TTY at (202) 586-1181, or by e-mail at infoctr@eia.doe.gov.

For further information on FRS data, please contact Greg Filas by phone at (202) 586-1347, by fax at (202) 586-9753, or by e-mail at greg.filas@eia.doe.gov.

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. 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 from publicly available data as respondents to the FRS. Currently, the Administrator uses the following selection criteria: U.S.-based publicly-owned companies or U.S.-based subsidiaries of publicly-owned foreign companies that had at least one percent of either production or reserves of oil (crude oil and natural gas liquids) or natural gas in the United States, or one percent of either refining capacity or petroleum product sales in the United States. The information is collected in accordance with the confidential information protection provisions of Title 5, Subtitle A, Public Law 107-347 and other applicable Federal laws, and is used for statistical purposes only. The survey responses are kept confidential and are not disclosed in identifiable form to anyone other than employees or agents without consent of the company. The names of the companies selected, though, are based on publicly available information, are not confidential and are publicly released. The companies that reported to the FRS for the years 1974 through 2003 are listed in Appendix A, Table A1. Three of the FRS companies are owned by foreign companies: BP America—owned by BP plc; Total Holdings USA—owned by TotalFinaElf; and Shell Oil—owned by Royal Dutch/Shell.

The 28 major U.S. energy companies 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 (see the box entitled "The FRS Companies in 2003" in the Executive Summary of this report). A majority of these companies are multinational, with 42 percent of the majors' net investment located abroad. Worldwide petroleum and natural gas market developments are of primary importance to these companies' financial performance.

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 trends and transactions in U.S. energy resources, assets, and companies was previously included as a separate chapter in the report. However, EIA now publishes this report, *Foreign Direct Investment in U.S. Energy,* separately on the Internet (see http://www.eia. doe.gov/emeu/finance/fdi/index. html). 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…."

Performance Profiles focuses on annual 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. It highlights significant organizational decisions of the majors (such as those involving corporate mergers or joint ventures) and discusses new strategic directions (such as concentration on core businesses or competencies, movements into new lines of business, or changes in global investment patterns). *Performance Profiles* also explores 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.

This edition of *Performance Profiles* reviews financial and operating data for the calendar year 2003. Although the focus is on 2003 activities and results, important trends prior to that time and emerging issues relevant to U.S. energy company operations are also discussed.

Chapter 1 provides more details on key financial and operational developments in 2003.

In addition to a summary of market activities, Chapter 2 also presents information about the FRS group of companies and their shares of energy production and refining capacity.

Chapter 3 gives more in-depth coverage of financial and operational trends in oil and gas production and refining and marketing. The oil and gas production section includes a review of revenues, production, production costs, and finding costs. The refining and marketing section covers sales, profitability, margins, and costs in domestic and foreign refining and marketing.

Chapter 4 contains several special topics:

- "Are the FRS Companies Finding Enough Oil and Gas to Keep Up with Demand?" This article provides an overview of how well FRS and other companies are doing at replacing production with reserve additions.
- "The Gulf of Mexico—Is Deep-Shelf Gas the Solution to the Gulf's Declining Natural Gas Reserve Replacement Ratio?" This article surveys the interest in exploring for natural gas prospects in the deep shelf, defined as deposits at greater than 15,000 feet or greater in water depths up to 200 feet.
- "Are Investment Climates Affecting the Supply of Oil and Gas?" This article explores the investment climate in several countries and its impact on investment expenditures in those countries.
- "Are Refining Margins Predictors of Profitability?" This article analyzes the relationship between refining profits and various refining margins, including net margins, gross margins, and what is referred to as the 3-2-1 crack spread.

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

Because 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. 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 alternative energy, downstream natural gas, and electric power) 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 FRS, which are 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 analysis reports 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 FRS. For a glossary of terms and definitions used in this report, see http://www.eia.doe.gov/emeu/perfpro/glossary.html.

Table of Contents

Tables

Tables (continued)

Figures

Figures (continued)

Executive Summary

Performance Profiles of Major Energy Producers 2003 is produced from information provided to the Energy Information Administration (EIA) on Form EIA-28, the Financial Reporting System (FRS). U.S. major energy companies (see the box entitled "The FRS Companies in 2003") report financial and operating information annually to the FRS. The report examines the companies' operations on a consolidated corporate level, by individual lines of business, by major functions within each line of business, and by various geographic regions.

The FRS Companies in 2003	
Amerada Hess Corporation	Kerr-McGee Corporation
Anadarko Petroleum Corporation	LYONDELL-CITGO Refining, L.P.
Apache Corporation	Marathon Oil Corporation
BP America, Inc.	Motiva Enterprises, L.L.C.
Burlington Resources, Inc.	Occidental Petroleum Corporation
Chesapeake Energy Corporation	Premcor, Inc.
ChevronTexaco Corporation	Shell Oil Company
CITGO Petroleum Corporation	Sunoco, Inc.
ConocoPhillips Company	Tesoro Petroleum Corporation
Devon Energy Corporation	Total Holdings USA, Inc.
Dominion Resources	Unocal Corporation
EOG Resources, Inc.	The Williams Companies, Inc.
Equitable Resources, Inc.	Valero Energy Corp.
Exxon Mobil Corporation	XTO Energy, Inc.

Note: BP America, Inc., the U.S. subsidiary of BP plc of the United Kingdom, is the FRS respondent.

FRS companies earned $57.4 billion in 2003, nearly triple the earnings of 2002 and the highest net income (in constant dollars) since 1980. Excluding the effect of unusual items (unusual items include accounting changes, asset dispositions and write-downs, tax adjustments, etc.), net income rose 78 percent from 2002, due primarily to higher crude oil, natural gas, and petroleum product prices. This was a significant reversal from 2002, when profits and profitability were down, and put 2003 back in line with 2000 and 2001 as very strong years financially. With 2002 as the exception, the 2000 to 2003 period has been similar to 1979 to 1981 in terms of earnings and profitability. The companies earned an 18.1-percent return on stockholders' equity (ROE) in 2003, 4.5 percentage points higher than the ROE of the Standard and Poor (S&P) Industrial companies. ROE for the FRS companies averaged 4 percentage points higher than the S&P Industrial companies from 2000 to 2003, after averaging 3 percentage points less from 1985 to 1999.

These financial results were driven for the most part by higher prices in oil and natural gas markets. In the United States in 2003, crude oil prices rose 17 percent, natural gas wellhead prices jumped 69 percent, and gross margins (the difference between petroleum product prices and crude oil costs) increased 23 percent. Highlights of petroleum and natural gas market activity in 2003:

- World oil consumption increased by the largest amount since 1999.
- Colder weather contributed to higher oil and natural gas demand in the first quarter of 2003, drawing down inventories and pushing up oil and natural gas prices.
- Oil supply concerns, primarily as a result of strikes by oil workers in Venezuela and Nigeria, exacerbated the price increases in the early part of 2003.
- Petroleum product inventories remained below the levels of the previous year throughout 2003, keeping prices firm.
- Natural gas consumption declined in the United States in 2003, as higher prices resulted in fuel switching to distillate and residual fuel in the electric power and industrial sectors.

The higher crude oil and natural gas wellhead prices made oil and gas production the most profitable line of business for the FRS companies, providing $44 billion in net income in 2003 and a return on net investment in place (ROI) of 15.3 percent. Contributions to net income from production averaged $37.1 billion per year from 2000 to 2003 (in constant 2003 dollars), up from an annual average of $14.7 billion in the 1990-to-1999 period.

Changes to the FRS Lines of Business in 2003

The FRS collects financial and operational data for consolidated corporate entities as well as for lines of business within entities. The lines of business changed with the 2003 data collection. The separation of downstream natural gas operations has affected to some extent oil and gas production, refining and marketing, and pipeline operations. This has been noted in several places in the text and tables, and downstream natural gas has been included with the petroleum line of business in several tables to maintain consistency. Electric power was part of Other Energy in previous years and is included in the total for Other Energy in several tables for consistency. In many cases, the trends are still clear, but these changes do limit the ability to provide precise comparisons with prior years for several of the lines of business.

The lines of business in 2003 consist of petroleum, downstream natural gas (including natural gas pipelines), electric power, other energy (including coal, nuclear, renewable fuels, and nonconventional energy), and nonenergy. The petroleum line of business is further segmented into production, refining and marketing, crude and petroleum product pipelines (for domestic petroleum), and international marine transport (for foreign petroleum). Prior to 2003, the lines of business consisted of petroleum, coal, other energy, and nonenergy. Natural gas operations were included in the petroleum line of business, and electric power was part of other energy.

Higher petroleum product prices made 2003 one of the more profitable years for the refining and marketing line of business, a substantial turnaround from 2002, which was the least profitable year for refining and marketing in the history of the FRS survey. Refining and marketing ROI reached 8.9 percent in 2003, lower than that of 2000 and 2001 but much improved from the average ROI of 5.8 percent from 1990 to 1999. Refining and marketing costs declined in 2003 after rising for the last 3 years. This contributed to higher net margins (gross margins less refining and marketing costs), which increased to $2.05 per barrel in 2003, only the fourth time in the survey that net margins have surpassed $2 per barrel (in 2003 dollars).

Nonenergy (which consists of chemicals and other industries) was the only line of business showing a decline in net income in 2003. Two new lines of business were broken out in the FRS survey in 2003, downstream natural gas and electric power. Downstream natural gas contributed $3.6 billion in net income and electric power $1.0 billion.

Higher oil and natural gas prices brought an increase in cash flow from operating activities. Cash flow from operations reached $105.1 billion in 2003, the highest level reported in the 18 years that the FRS survey has collected this information. Over the past 4 years, coinciding with higher crude oil, petroleum product, and natural gas prices, cash flow from operations has been sharply higher, averaging $28.1 billion per year more (in constant 2003 dollars) than the average from 1986 to 1999.

The largest use of cash was for capital expenditures (measured as additions to investment in place). Despite the increased cash flow, capital expenditures fell $20.7 billion in 2003 (in constant 2003 dollars) although the $80 billion in 2003 was higher than all but four of the 18 years of survey data. The high level of expenditures for mergers and acquisitions of the past few years slowed significantly in 2003, falling to $11.4 billion in 2003 from $34.8 billion in the previous year.

FRS companies put more of the increase in cash flow in 2003 into reducing debt, repurchasing stock, and paying dividends than into capital expenditures and other investments. The FRS companies' long-term debt-to-equity ratio in 2003 fell more than 5 percentage points, nearly back to the level of 2001 and more than 22 percentage points below the level of the S&P Industrial companies. In addition, FRS companies enlarged their cash and cash equivalents positions by $8.8 billion in 2003, the largest increase ever reported for net additions to cash.

The biggest change in the use of cash from the previous year occurred in dividends to shareholders, which more than doubled to $42.8 billion. With higher incomes in 2003, most respondents did report increased dividends, but the main reason for the $25.1 billion increase (in nominal dollars) in dividends was the result of a very large increase by one company.

Expenditures for oil and gas exploration (excluding acquisition of unproved acreage cost) by FRS companies fell for the second year in a row, down 21 percent from the 2001 level (in constant dollars) but still 14 percent higher than the low point of 1993. Although expenditures for finding reserves declined in 2002 and 2003, FRS companies substantially increased funds for developing reserves (excluding acquisition of proved acreage cost) from 2000 to 2003. Development expenditures by FRS companies rose 5.1 percent in 2003, reaching the highest level since 1982. Higher prices have encouraged companies to develop their known reserves into producing properties, but exploration expenditures have been slower to respond. Lack of access to some producing regions and inhospitable investment climates have also been mentioned as reasons for lower exploration expenditures.

FRS companies targeted the U.S. offshore region for the most exploration expenditures in 2003, as they have each year since 1992. Despite its maturity as an oil and natural gas producing region, the U.S. onshore still received more exploration expenditures than any of the FRS foreign regions. Outside the United States, FRS companies spent the most for exploration over the past 5 years in Canada and Africa.

Development expenditures outside the United States have doubled since 2000 (in constant dollars), while domestic spending has fallen in the past 2 years. Over the past 5 years, more development funds have been spent domestically than abroad, but the difference has decreased, with the largest growth recently in Africa and the former Soviet Union. Development expenditures onshore in the United States fell sharply in 2003, but the region still receives more development expenditures than any other region. Outside the United States, Organization for Economic Cooperation and Development (OECD) Europe had received the most development expenditures by FRS companies until 2003, when spending in Africa jumped 74 percent (in 2003 dollars) to surpass Europe.

Capital expenditures for worldwide refining and marketing dropped in 2003 as mergers and acquisitions between FRS companies declined from the previous 2 years. Many of the capital expenditures in refining and marketing in 2003 appeared to be related to upgrades for producing cleaner fuels, in particular low-sulfur gasoline and diesel fuel, as fuel standards tighten for these products.

FRS companies added more oil and natural gas reserves[1] in 2003 than they extracted through production. The reserve replacement ratio was 104 percent, up from 96 percent in 2002 but still considerably below the high replacement levels of 2000 and 2001. Extensions and discoveries were by far the primary means for adding reserves, but reserve additions from improved recovery methods yielded more reserves in 2003 than in any previous year of the survey. Reserve revisions in 2002 and 2003, however, were the smallest in the FRS data series history. Higher reserves and slightly lower production raised the FRS companies' reserves-to-production ratio to 11.4 for natural gas and 11.3 for oil. (The reserves-to-production ratio is the number of years that proved reserves would last at current production rates.)

The worldwide average per-unit cost for the FRS companies of finding oil and natural gas increased by 8.7 percent to $7.48 per barrel of oil equivalent (in constant 2003 dollars) in the 2001 to 2003 period, continuing the upward trend that started in the mid-1990s. U.S. offshore costs increased 32.3 percent in the latest period to $10.42 per barrel, while U.S. onshore finding costs jumped to the highest level since the 1984 to 1986 period. Foreign finding costs, in contrast, grew by just 0.6 percent from the previous period. Finding costs fell in Canada, the former Soviet Union, the Asia-Pacific region, and South America. A jump of 63.1 percent in costs in Africa led the increases (although Africa still remains below the average finding cost for foreign regions), with smaller rises in OECD Europe and the Middle East.

Oil and natural gas production costs, also known as lifting costs, increased by 12.3 percent to $4.87 per barrel in 2003, the highest amount since 1994 (in constant 2003 dollars). Production taxes led the increase, increasing by $0.30 per barrel to $1.00 per barrel. Direct lifting costs (excluding production taxes) rose 6.5 percent to $3.87 per barrel in 2003. The biggest increases in direct lifting costs occurred in Canada, the former Soviet Union, and OECD Europe, balanced by declines in Africa, Asia-Pacific, and South America.

[1]Reserve additions include net revisions, extensions, discoveries, and additions through improved recovery, but do not include purchases.

1. Financial and Operational Developments in 2003

Net income and profitability improved substantially in 2003 for companies reporting to the Financial Reporting System (FRS).[2] The petroleum line of business continued to be the most profitable, led by the oil and natural gas production segment. The domestic refining and marketing segment also had a good year financially, a complete reversal from 2002, when this segment had its worst year since the FRS collection began. Refining and marketing costs declined for the first time in 4 years. Combined with higher gross margins as a result of rising prices, net margins jumped to one of the highest levels yet.

Strong increases in cash flow provided funds for capital expenditures and improving long-term debt positions. Despite the greater availability of cash, merger and acquisition activity dropped off significantly from that of the past few years. The higher cash flow did not result in an increase in expenditures for exploration, but spending for the development of oil and natural gas reserves was at the highest level yet in the history of the survey. Even so, FRS companies still managed to find more reserves than they produced, although the replacement ratio was considerably lower than the peak replacement ratio reported in 2001. Net reserve revisions remained at a low level, only slightly higher than 2002, while reserves found through improved recovery methods reached the highest level reported in the survey. The cost per barrel of oil equivalent of finding and developing oil and natural gas reserves increased in 2003, continuing the upward trend that started in the mid-1990s. The unit cost of producing a barrel of oil also rose in 2003.

Net Income and Profitability

Net income for the FRS companies reached $57.4 billion in 2003 (**Table 1**), nearly triple the $20.6 billion (in nominal dollars) in 2002 and the highest level (in constant dollars) since 1980 (**Figure 1**).[3] Excluding the effect of unusual items,[4] net income rose 78 percent in 2003. Operating revenues jumped 27 percent in 2003 as a result of sharply higher crude oil, natural gas, and petroleum product prices. (Chapter 2 provides an overview of oil and natural gas market trends in 2003.) Operating costs also increased, but by less than the rise in revenues, resulting in a more than doubling of operating income.

Table 1. Consolidated Income Statement for FRS Companies and the S&P Industrials, 2002-2003 (Billion Dollars)

Income Statement Items	FRS Companies			S&P Industrials[a]		
	2002	2003	Percent Change 2002-2003	2002	2003	Percent Change 2002-2003
Operating Revenues	698.9	888.5	27.1	4,680.1	5,094.0	8.8
Operating Expenses	-659.7	-806.9	22.3	-4,194.1	-4,542.5	8.3
Operating Income (Revenues minus Expenses)	39.2	81.6	107.9	486.0	551.5	13.5
Interest Expense	-10.7	-8.8	-18.5	-97.4	-97.2	-0.2
Other Revenue (Expense)	6.7	16.9	153.2	-147.8	-12.6	-91.4
Income Tax Expense	-14.6	-32.3	121.7	-124.0	-143.7	15.9
Net Income	20.6	57.4	178.9	116.8	297.9	155.2
Net Income Excluding Unusual Items	32.5	57.6	77.6	NA	NA	

[a]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.

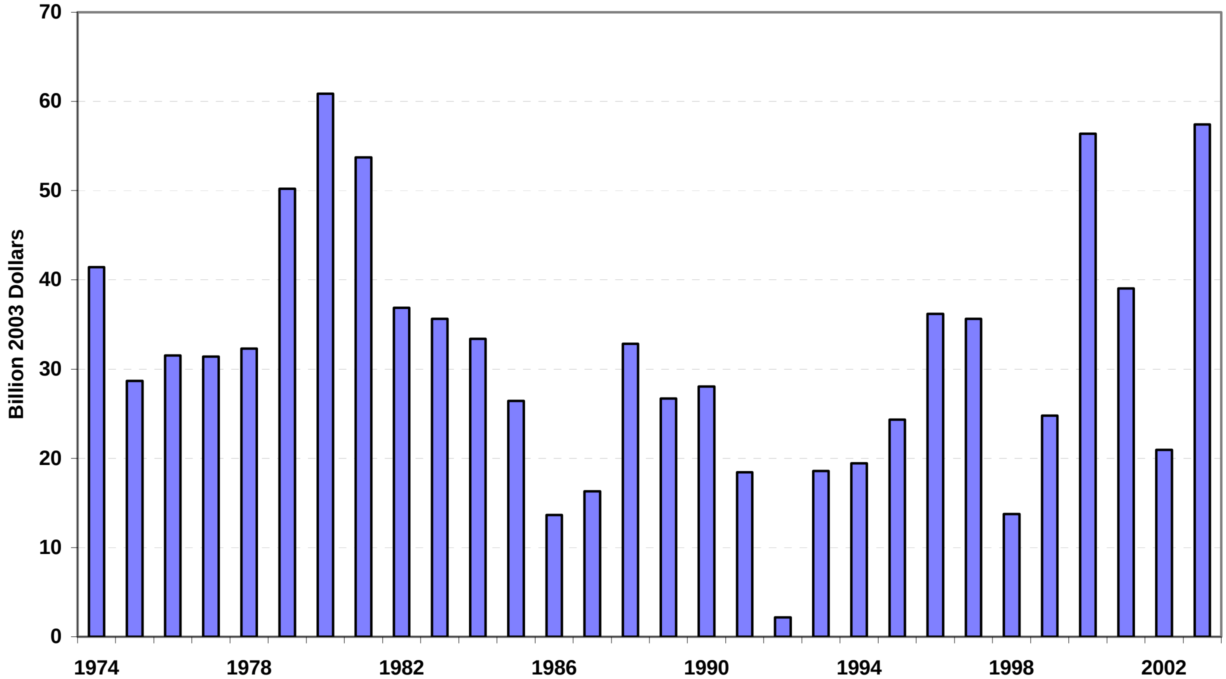
NA= not available.

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.

Profitability, which is a measure of a company's net income relative to the equity (or capital) provided by its investors, also increased substantially. The 18.1 percent return on stockholders' equity (ROE) (**Table B3**) in 2003 represents the second highest return since 1981 (**Figure 2**). This further solidifies the trend in the first few years of the 2000s of the FRS companies outpacing the Standard & Poor's (S&P) Industrial companies in profitability (**Figure 3**). ROE for the FRS companies averaged 4 percentage points more than the S&P Industrial companies from 2000 to

2003, after averaging 3 percentage points less from 1985 to 1999. Over the past 4 years, average prices for crude oil, natural gas, and petroleum products have all risen to higher levels, providing FRS companies with greater profits and profitability.

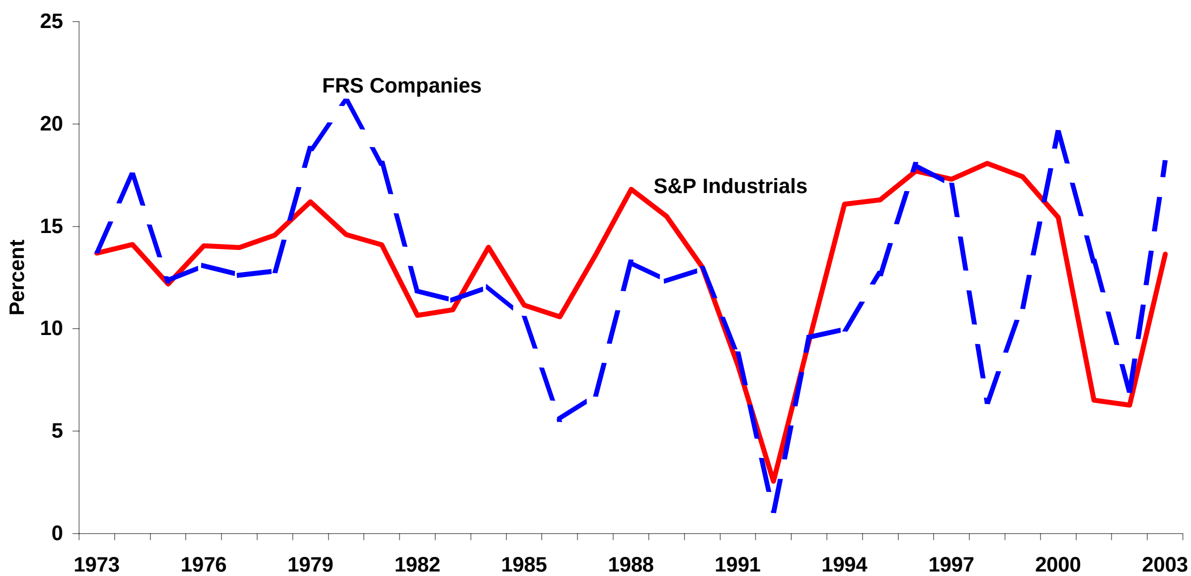
Figure 1. FRS Net Income, 1974-2003



Note: The FRS group of companies has changed incrementally over the years. See endnote 2.

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

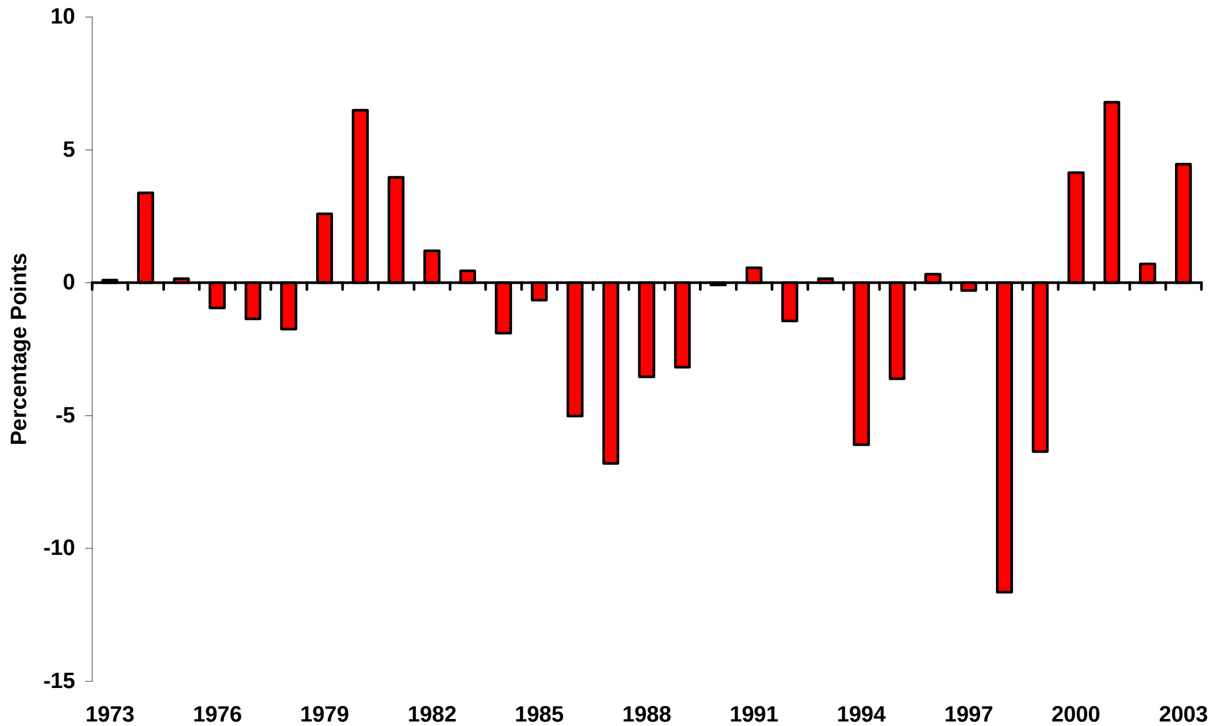
Figure 2. Return on Stockholders' Equity for FRS Companies and the S&P Industrials, 1973-2003



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.

Figure 3. Difference Between FRS and S&P Return on Stockholders' Equity, 1973-2003



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.

Among the FRS companies' lines of business and business segments,[5] oil and natural gas production and refining/marketing business segments both reported significantly higher net income in 2003 (**Table 2**). Net income for the nonenergy line of business fell by 49 percent, the only line of business showing a reduction in net income. Of the new lines of business in 2003, downstream natural gas provided $3.6 billion in net income and electric power $1.0 billion.

Oil and natural gas production remained the leading contributor to net income among the lines of business and business segments. Crude oil production has been profitable for major energy companies for a long time, but much higher natural gas wellhead prices and higher crude oil prices since 2000 have helped considerably to improve income and profitability for the oil and gas production line of business. Contributions to net income from production averaged $37.1 billion per year from 2000 to 2003 (in constant 2003 dollars), up from an annual average of $14.7 billion in the 1990 to 1999 period. In 2003, the production segment provided $44.0 billion of net income for the FRS companies, with domestic production providing about 51 percent of that amount.

The production segment's return on net investment in place (ROI) [6] rose to 15.3 percent, the second highest return since 1981. With the lower-price years (for both crude oil and natural gas) of 1998 and 1999 as the only exceptions, production ROI has equaled or exceeded 10 percent in 6 of the past 8 years. This coincides with the rise in natural gas wellhead prices over the past 8 years. From 1986 to 1995, however, the ROI for production reached 10 percent only once, in 1990, when crude oil prices increased after the Iraqi invasion of Kuwait. Since 1996, domestic production ROI has been on par with that of foreign production (**Figure 4**). Prior to 1996, FRS companies had always received a higher return for their foreign production net investment in place than for domestic production.

Domestic refining and marketing has become a more prominent contributor to net income over the past 4 years but has also demonstrated how volatile this segment of the industry can be. In 2000, 2001, and 2003, domestic refining and marketing had 3 of the 4 best years in terms of net income in the history of the FRS survey, while 2002 had the biggest loss at $1.4 billion (in nominal dollars). Foreign refining and marketing net income for FRS companies was also at its lowest point in 2002, but bounced back to $2.9 billion in 2003.[7] The 2003 level, however, was only slightly higher than the average net income for foreign refining and marketing in the 10 years prior to 2002.

Table 2. Contributions to Net Income by Line of Business for FRS Companies, 2002-2003
(Million Dollars)

Line of Business	Net Income			Net Income Excluding Unusual Items		
	2002	2003	Percent Change 2002-2003	2002	2003	Percent Change 2002-2003
Petroleum[a]						
U.S. Petroleum						
Production	15,030	22,630	50.6	16,232	23,085	42.2
Refining/Marketing	-1,350	7,434	--	530	7,832	--
Pipelines	1,694	827	-51.2	2,141	838	-60.9
Downstream Natural Gas[b]	NA	1,694	NA	NA	1,997	NA
Total U.S. Petroleum	15,374	32,585	111.9	18,903	31,755	68.0
Foreign Petroleum						
Production	12,918	21,334	65.1	15,744	21,606	37.2
Refining/Marketing[c]	-400	2,916	--	-288	2,893	--
Downstream Natural Gas[b]	NA	1,909	NA	NA	522	NA
Total Foreign Petroleum	12,518	26,159	109.0	15,418	24,645	59.8
Total Petroleum	27,892	58,744	110.6	34,321	58,919	71.7
Electric Power[b]	NA	959	NA	NA	1,686	NA
Total Other Energy[d]	-1,506	1,074	--	1,768	1,800	1.8
Nonenergy	1,842	934	-49.3	2,088	2,198	5.3
Total Allocated	28,228	60,752	115.2	38,177	62,917	64.8
Nontraceables and Eliminations	-7,636	-3,325	--	-5,716	-5,268	--
Consolidated Net Income[e]	20,592	57,427	178.9	32,461	57,649	77.6

[a]In 2002, natural gas operations were part of the Petroleum line of business. In 2003, downstream natural gas operations were separated into their own line of business but are included in Petroleum in this table for consistency.

[b]The downstream natural gas and electric power lines of business started in 2003.

[c]International Marine is included in Refining/Marketing.

[d]The Other Energy line of business includes electric power as well as coal, nuclear, and non-conventional energy.

[e]The total amount of unusual items was -$11,869 million and -$222 million in 2002 and 2003, respectively.

-- = Not meaningful.

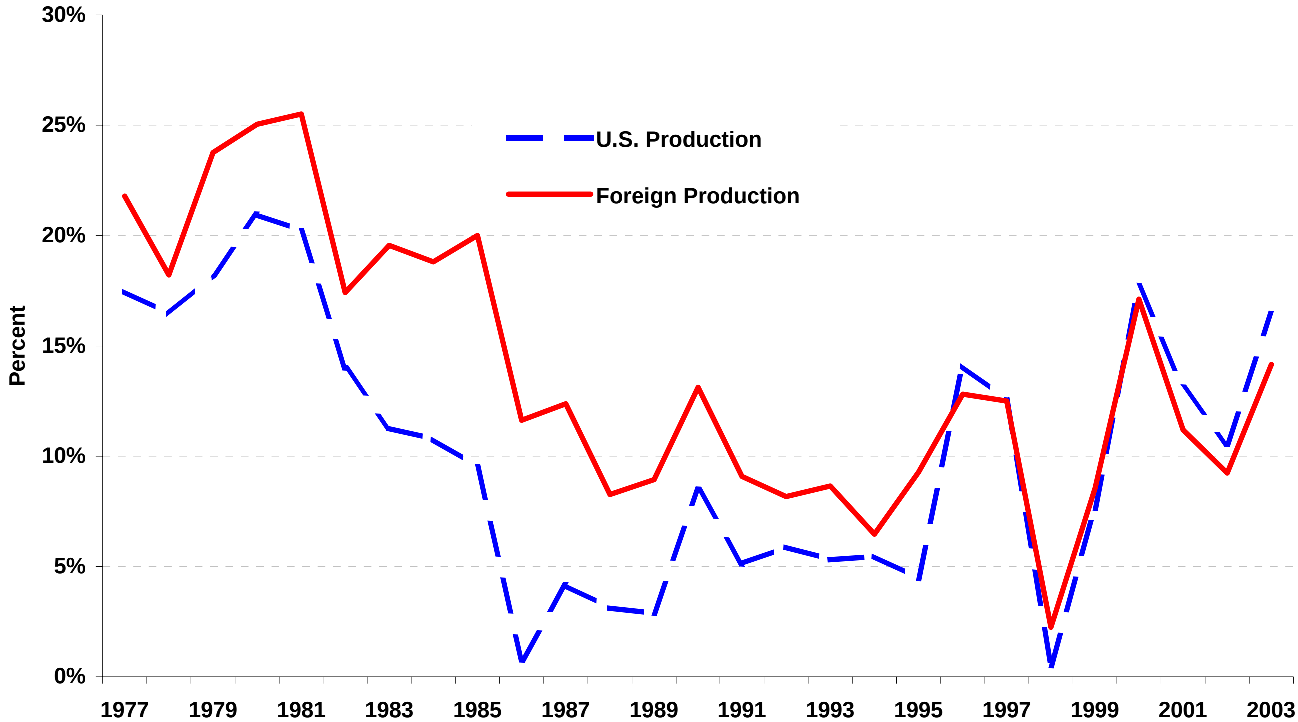
NA = Not available.

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

Domestic refining and marketing earnings increased in 2003, primarily due to strong petroleum product markets in which prices rose more than crude oil. Motor gasoline prices hit a nominal (unadjusted for inflation) high in August 2003 as a result of tight supplies, heavy demand, and a series of local supply disruptions.[8] Number 2 distillate prices also rose sharply early in 2003 as cold weather depleted inventories and fuel switching from natural gas pushed up demand.[9] As a result of higher product prices, gross margins (the difference between product prices and crude oil costs)[10] for the FRS companies jumped to $7.84 per barrel in 2003, the second highest level in the last 10 years (**Figure 5**). After rising for the last 3 years, refining and marketing costs declined in 2003, which further contributed to higher net margins (gross margins less refining and marketing costs).[11] Refining and marketing net margins rebounded strongly from the second lowest level ever recorded by FRS companies of $0.19 per barrel (constant 2003 dollars) in 2002 to $2.05 per barrel in 2003, only the fourth time in the survey that net margins have surpassed $2 per barrel.

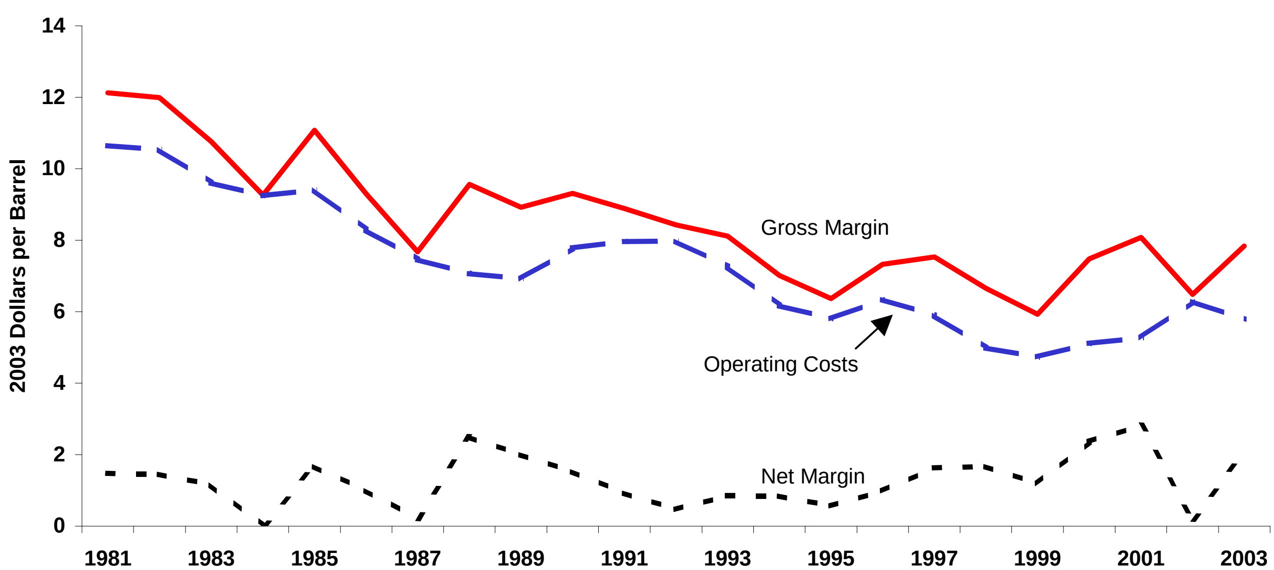
Tighter product markets and higher prices and margins made domestic refining and marketing a more profitable segment in 2003 (**Figure 6**).[12] Domestic refining and marketing ROI rose to 9.3 percent in 2003 (**Table B8**). In 3 of the past 4 years, domestic refining and marketing ROI has exceeded 9 percent compared to a 4.9-percent average return from 1990 to 1999. In 4 of the past 5 years, domestic refining and marketing ROI has exceeded that of foreign refining and marketing for FRS companies, whereas this occurred in just 5 of the 22 years of FRS data prior to 1999.

Figure 4. Return on Net Investment in Place for U.S. and Foreign Oil and Gas Production, 1977-2003



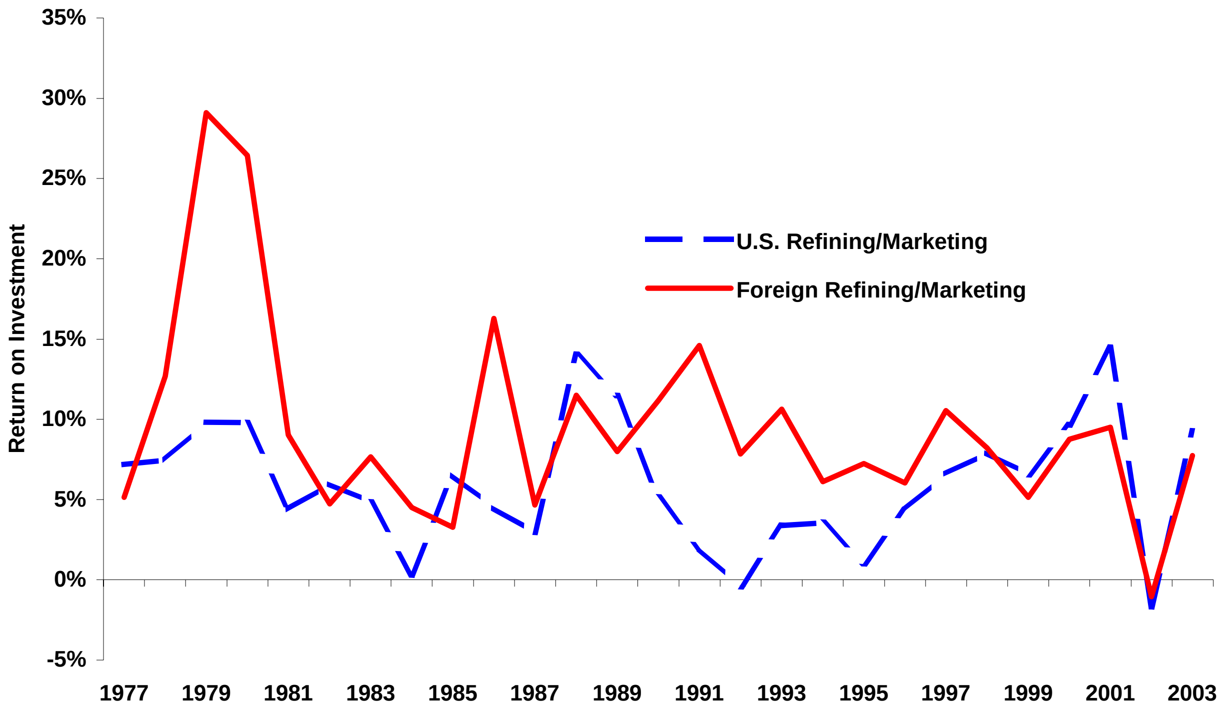
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Figure 5. U.S. Refined Product Margins and Costs per Barrel of Petroleum Product Sold for FRS Companies, 1981-2003



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).

Figure 6. Return on Net Investment in Place for U.S. and Foreign Refining/Marketing, 1977-2003



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

Sources and Uses of Cash

Cash flow analysis provides insight into where companies' funds are coming from and how those funds are being used. The cash flow statement shows the sources and uses of cash grouped into three main categories: operations, investing activities, and financing activities. Operating activities typically provide cash, while investing and financing are usually net users of cash.

The largest source of cash by far in 2003 was cash flow from operations[13] (**Table 3**). Higher oil and natural gas prices brought a surge in cash from operating activities, reflected by the increase in net income. Cash flow from operations reached $105.1 billion in 2003, the highest level reported since the FRS survey began collecting cash flow information in 1986. Non-cash items changed little in 2003 from the 2002 level. Over the past 4 years, coinciding with higher crude oil, petroleum product, and natural gas prices, cash flow from operations averaged $92.0 billion per year (in constant 2003 dollars), $28.1 billion per year higher than the 1986 to 1999 average.

Cash flow by lines of business can be computed only on a pretax basis (**Table 4**). The rise in pretax cash flow of $40 billion reflects the increase of nearly $12 billion in current income taxes paid in 2003 as a result of higher earnings. Half of the increase in pretax cash flow came from oil and natural gas production. Cash flow from downstream petroleum (refining, marketing, and transportation of products) more than doubled from 2002, but remained below the levels of 2000 and 2001. The two new lines of business, downstream natural gas and electric power, contributed a total of $8 billion in cash flow in 2003.[14]

The largest use of cash was for capital expenditures (measured as additions to investment in place). Despite the increased cash flow, capital expenditures fell $20.7 billion in 2003 (in constant 2003 dollars), although the $80 billion in 2003 was higher than all but 4 of the 18 years of survey data (**Figure 7**). The high level of expenditures for mergers and acquisitions of the past few years slowed significantly in 2003, falling to $11.4 billion in 2003 from $34.2 billion (constant 2003 dollars) in the previous year. FRS companies put more of the increase in cash flow in 2003 into reducing debt, repurchasing stock, and paying dividends than into capital expenditures and other investments. Lack of access to some exploration areas, such as in the Middle East, has also been indicated as a reason for lower investment expenditures,[15] as well as inhospitable fiscal regimes (see the special topic "Are Investment Climates Affecting the Supply of Oil and Gas?" in Chapter 4). The next section of Chapter 1 provides more information on capital expenditures by line of business and geographic area.

Table 3. Sources and Uses of Cash for FRS Companies, 2002-2003 (Billion Dollars)

Sources and Uses of Cash	2002	2003	Percent Change 2002-2003
Main Sources of Cash			
Cash Flow from Operations	75.0	105.1	40.2
Proceeds from Long-Term Debt	34.1	26.4	-22.7
Proceeds from Disposals of Assets	15.2	16.1	6.1
Proceeds from Equity Security Offerings	4.9	8.4	72.1
Main Uses of Cash			
Additions to Investment in Place	98.9	80.0	-19.1
Reductions in Long-Term Debt	27.9	26.2	-5.9
Dividends to Shareholders	17.7	42.8	141.3
Purchase of Treasury Stock	4.7	6.1	29.5
Other Investment and Financing Activities, Net	23.1	7.9	-65.8
Net Change in Cash and Cash Equivalents	3.0	8.8	190.7

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).

Table 4. Line-of-Business Contributions to Pretax Cash Flow, Income Taxes, and Cash Flow for FRS Companies, 2002-2003 (Billion Dollars)

Contribution to Pretax Cash Flow [a]	2002	2003	Absolute Change 2002-2003	Percent Change 2002-2003
Petroleum[b]				
Oil and Gas Production	76.2	96.6	20.3	26.7
Refining, Marketing, and Transport	10.3	23.7	13.4	130.2
Downstream Natural Gas[c]	NA	5.4	NA	NA
Other Energy[d]	0.4	3.2	2.9	752.8
Electric Power[c]	NA	2.6	NA	NA
Chemicals	1.5	1.5	0.0	1.9
Other Nonenergy	1.2	1.6	0.4	33.5
Nontraceable	-2.9	-5.0	-2.1	70.7
Total Contribution to Pretax Cash Flow[a]	86.7	127.1	40.4	46.6
Current Income Taxes	-14.5	-26.3	-11.8	81.2
Other (Net)	2.8	4.4	1.6	55.4
Cash Flow from Operations	75.0	105.1	30.2	40.2

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

[b]The Petroleum line of business included natural gas operations in 2002. Downstream natural gas operations were separated into their own line of business in 2003 but are included in Petroleum in this table for consistency.

[c]New lines of business in 2003.

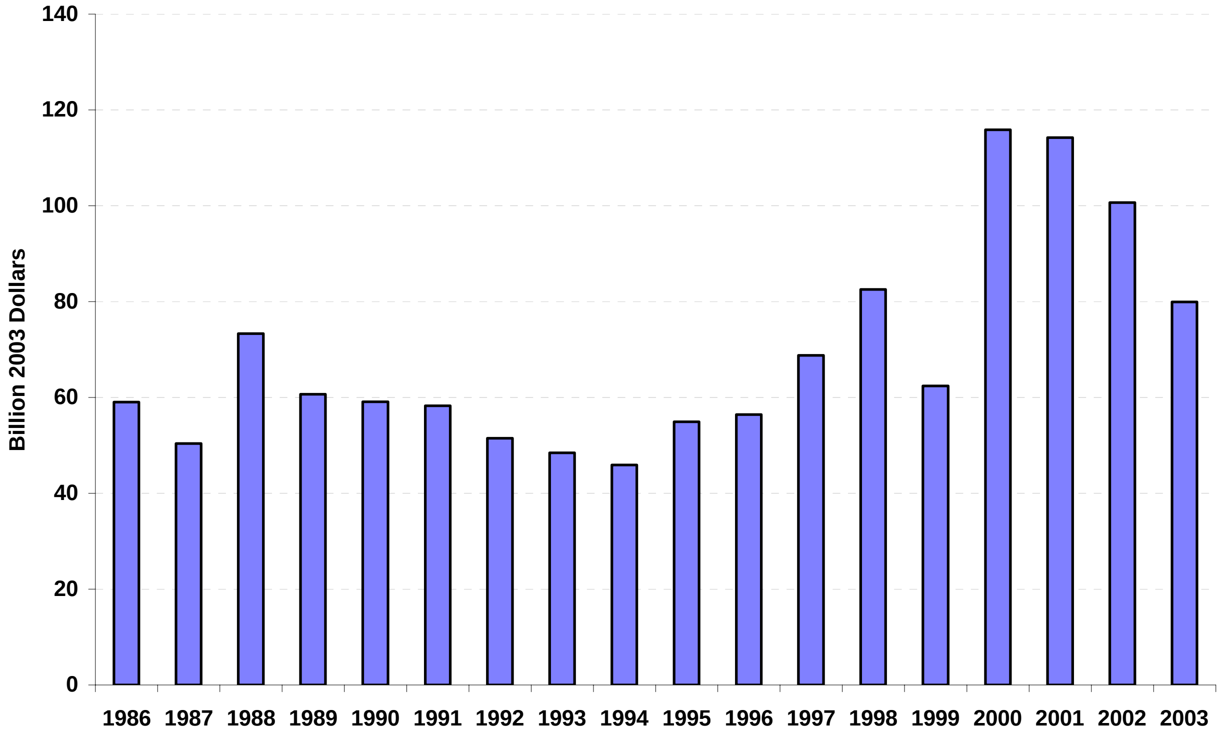
[d]The Other Energy line of business includes electric power as well as coal, nuclear, and non-conventional energy.

-- = Not meaningful.

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

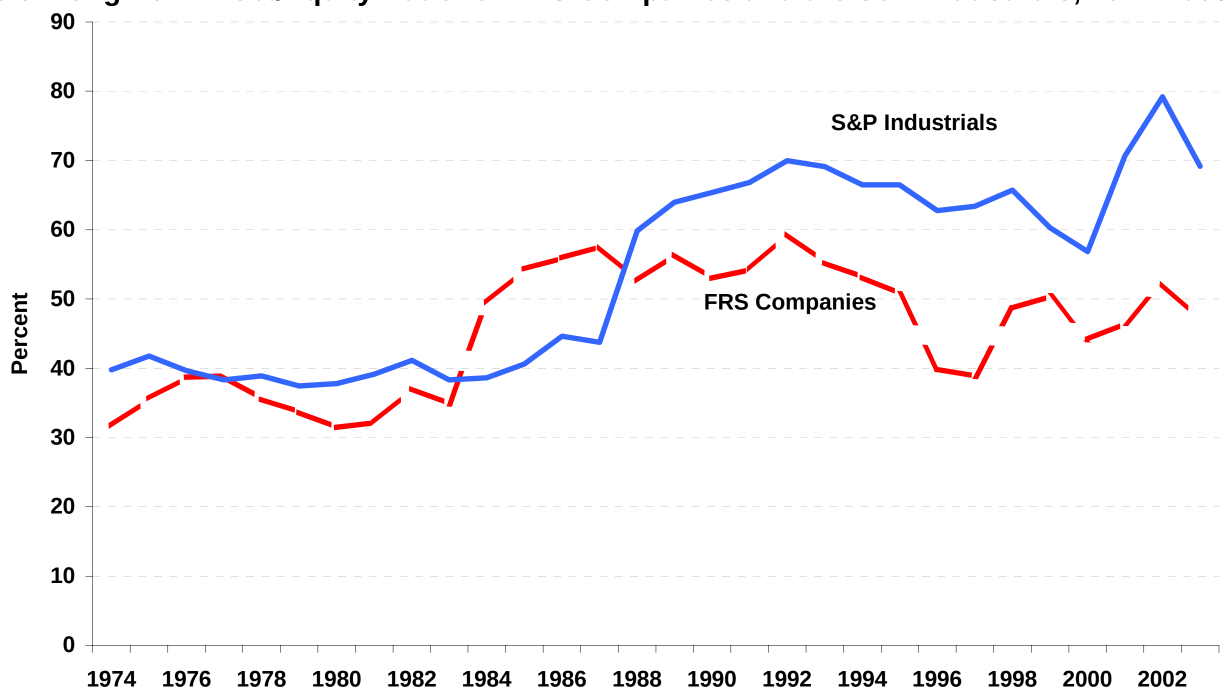
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Figure 7. FRS Capital Expenditures, 1986-2003



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

Figure 8. Long-Term Debt/Equity Ratio for FRS Companies and the S&P Industrials, 1974-2003



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 biggest change in the use of cash from the previous year occurred in dividends to shareholders, which more than doubled to $42.8 billion (**Table 3**). With higher incomes in 2003, most respondents did report increased dividends, but the main reason for the $25.1 billion increase (in nominal dollars) in dividends was the result of a very large increase by one company.[16]

Other sources and uses of cash indicated that companies used the improved financial conditions in 2003 to strengthen their balance sheets. FRS companies increased proceeds from equity offerings by 72 percent in 2003 and reduced proceeds from issuing long-term debt by 23 percent (**Table 3**). Funds used to reduce long-term debt were down slightly in 2003, while purchases of stock increased. The overall effect was lower long-term debt and higher equity. The FRS companies' long-term debt-to-equity ratio in 2003 fell more than 5 percentage points (**Table B3**), nearly back to the level of 2001 and more than 22 percentage points below the level of the S&P Industrial companies (**Figure 8**).

Table 5 presents a summary of uses of cash by investing, financing, and other categories. It shows that FRS companies put more of the increase in cash flow in 2003 into financing activities—reducing debt, repurchasing stock, and paying out dividends—than into capital expenditures and other investments. FRS companies also enlarged their cash and cash equivalents positions by $8.8 billion in 2003, the largest increase ever reported for net additions to cash.

Table 5. Net Uses of Cash for Investing and Financing Activities, 1999-2003
(Billion 2003 Dollars)

Cash Flow Statement Items	1999	2000	2001	2002	2003	Average 1999-2002
Net Investing Activities	44.2	78.4	97.6	55.1	59.3	68.8
Net Financing Activities	12.4	7.4	-6.5	18.7	37.8	8.0
Other Net Uses[1]	2.7	8.2	1.6	2.5	8.0	3.8
Total[2]	59.4	94.0	92.8	76.3	105.1	80.6

[1]Includes changes in cash and cash equivalents and effect of exchange rate changes on cash.

[2]Equals net cash flow from operations

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

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

Capital Expenditures

Capital expenditures of FRS companies (measured as additions to investment in place)[17] declined 19 percent (in nominal dollars) to $80 billion in 2003 (**Table 6**). Oil and natural gas production accounted for 65 percent of capital expenditures while total petroleum accounted for 90 percent.

FRS companies report oil and natural gas production expenditures in the categories of exploration, development, and production. Regional breakdowns of the information are also provided.[18] Current expenditures as well as capital expenditures are included in the data, but capital expenditures predominate. Reviewing exploration and development expenditures provides insight into the regional targets of upstream investment by FRS companies.

Worldwide, exploration expenditures fell for the second year in a row to $7.9 billion in 2003 (**Figure 9**). While this was 14 percent higher than the low point reached in 1993 (in constant 2003 dollars), it was down 21 percent from the 2001 level. Expenditures for exploration, which typically follow but lag crude oil price changes, rose from 1994 through 1998, fell sharply in 1999, then rose again in 2000 and 2001. Higher crude oil prices in 2002 and 2003, however, have not yet resulted in higher expenditures for exploration. From 2000 to 2003, FRS companies substantially increased funds for developing reserves, but expenditures for finding reserves declined. Development expenditures by FRS companies rose 5.1 percent in 2003, reaching the highest level since 1982. Higher prices have encouraged companies to develop their known reserves into producing properties, but exploration expenditures have been slower to respond.

Regionally, the U.S. offshore has received more exploration expenditures over the past 10 years than any other FRS region (**Figure 10**). With advancing technologies allowing companies to drill in deeper water, companies have moved farther offshore to explore for oil and natural gas reserves. In 2003, however, U.S. offshore exploration expenditures declined even though more than half of the FRS respondents reported increases. Devon expanded its presence in the deepwater Gulf of Mexico by acquiring Ocean Energy in 2003 (**Table 7**), which provided interests in two producing properties to go along with its interests in deepwater discoveries at Cascade and St. Malo. Devon also indicated that recent advances in seismic technology and Federal royalty incentives have stimulated interest in drilling deeper in the shallow waters of the Gulf of Mexico. (See the special topic "The Gulf of Mexico—Is Deep-Shelf Gas the Solution to the Gulf's Declining Natural Gas Reserve Replacement Ratio?" in Chapter 4.) Devon made its first deep-shelf discovery in early 2004.[19] ChevronTexaco operates the second largest number of blocks in the deepwater Gulf of Mexico and reported four discoveries and four successful appraisal wells in 2003, including the deepest well ever drilled at 31,824 feet (9,700 meters).[20]

Despite its maturity as an oil and natural gas producing region, companies have maintained interest in the U.S. onshore. While exploration expenditures declined nearly 18 percent in 2003 from the previous year, the 2003 spending level was still greater than that of any of the FRS foreign regions. However, the level of exploration expenditures in the U.S. onshore in 2003 was only a fraction of what was spent annually in the early 1980s. About 56 percent of Anadarko's proved reserves are located onshore in the lower-48 States.[21] Anadarko indicated that they are targeting unconventional resources such as tight gas and coalbed methane, as well as drilling into deeper oil and natural gas zones, which points out the mature nature of the onshore oil and natural gas basins.[22]

Outside the United States, OECD Europe (consisting mainly of the North Sea) was the foreign region receiving the most exploration funds until 1998. From 1999 to 2003, however, expenditures dropped to less than half of the

Table 6. Additions to Investment in Place by Line of Business for FRS Companies, 2002-2003 (Billion Dollars)

Lines of Business	2002	2003	Percent Change 2002-2003	Percent Change Excluding Mergers and Acquisitions 2002-2003
Petroleum [a]				
U.S. Petroleum				
Production	30.1	25.6	-14.7	-10.9
Refining/Marketing				
Refining	16.0	7.1	-55.3	-22.5
Marketing	1.9	1.7	-11.0	-18.6
Transport	1.9	1.2	-37.6	-37.6
Total Refining/Marketing	19.7	10.0	-49.4	-24.2
Pipelines	2.7	0.5	-81.1	-80.7
Downstream Natural Gas[b]	NA	5.3	NA	NA
Total U.S. Petroleum	52.5	41.4	-21.1	-6.0
Foreign Petroleum				
Production	33.7	26.3	-21.9	8.5
Refining/Marketing[c]	5.0	2.8	-45.4	-23.6
Downstream Natural Gas[b]	NA	1.5	NA	NA
Total Foreign Petroleum	38.7	30.6	-21.0	10.0
Total Petroleum[a]	91.3	72.0	-21.1	0.5
Electric Power[b]	NA	2.3	NA	NA
Total Other Energy[d]	3.7	3.1	-17.9	1.1
Total Nonenergy	2.7	3.5	26.4	31.9
Nontraceables	1.2	0.1	-92.7	-92.6
Additions to Investment in Place[e]	98.9	80.0	-19.1	2.0
Additions Due to Mergers and Acquisitions	30.2	9.8	-67.4	
Total Additions Excluding Mergers and Acquisitions	68.7	70.1	2.1	

[a]The Petroleum line of business includes natural gas operations. In 2003, downstream natural gas operations were separated into their own line of business but are included in Petroleum in this table for consistency.

[b]New line of business in 2003.

[c]International Marine is included in Refining/Marketing.

[d]The Other Energy line of business includes electric power as well as coal, nuclear, and non-conventional energy.

[e]Additions to investment in place = additions to property, plant, and equipment, plus additions to investments and advances.

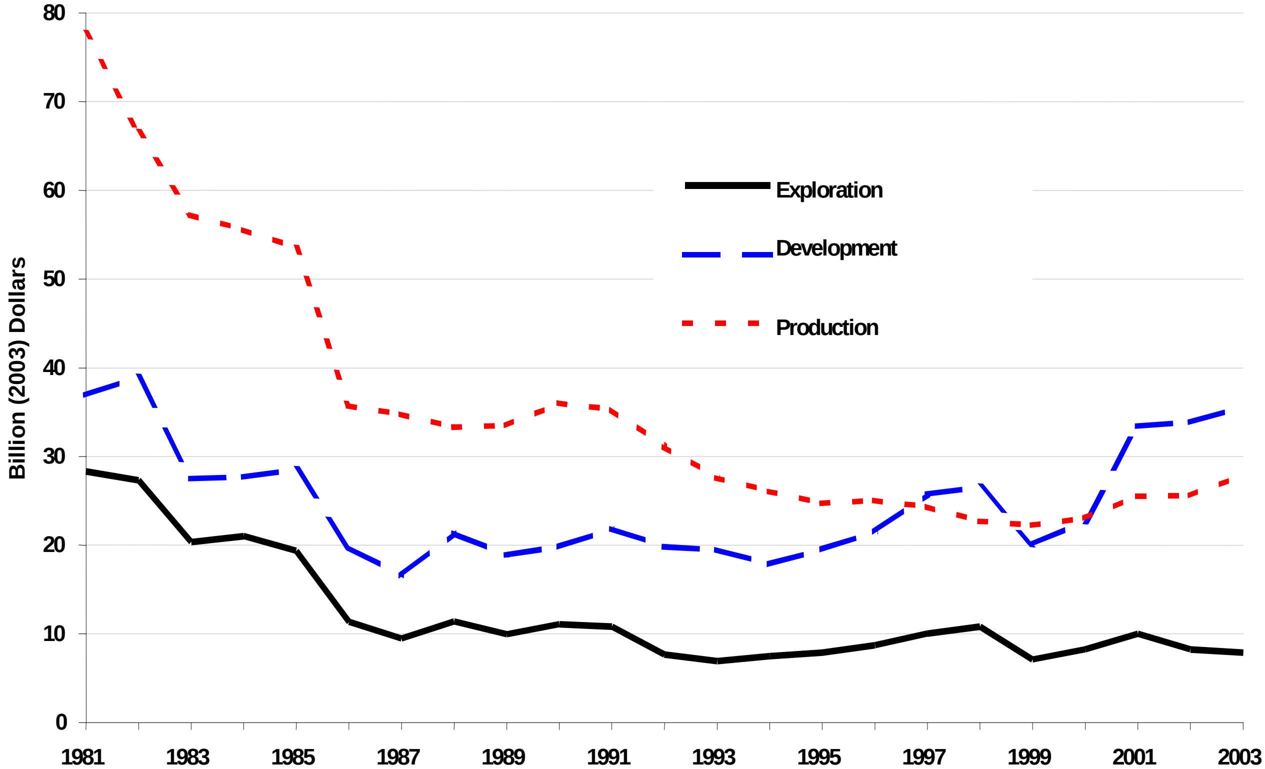
-- = Not meaningful.

NA = Not available.

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

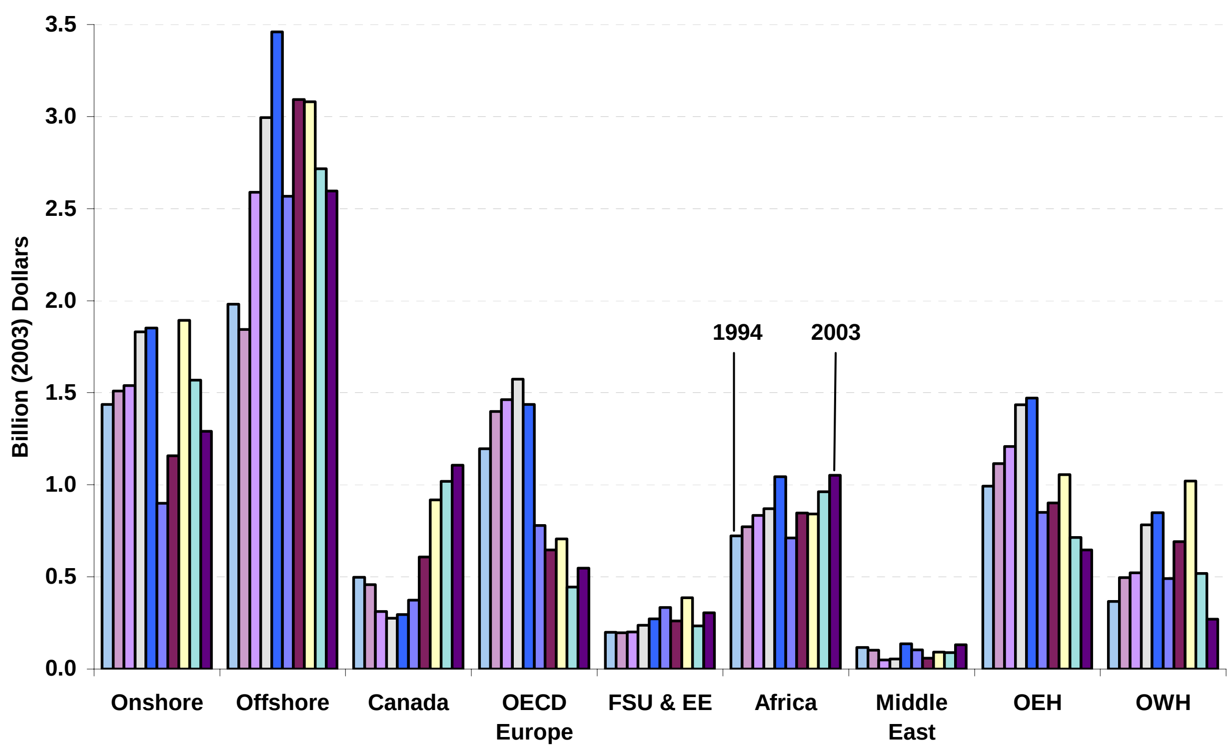
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Figure 9. FRS Worldwide Expenditures for Exploration, Development, and Production, 1981-2003



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

Figure 1-10. FRS Expenditures for Oil and Natural Gas Exploration by Region, 1994-2003



Note: OEH is Other Eastern Hemisphere, which is primarily the Asia-Pacific region. OWH is Other Western Hemisphere, which is primarily Central and South America and the Caribbean.

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

Table 7. Value of Mergers, Acquisitions, and Related Transactions by FRS Companies, 2003 (Million Dollars)

Line of Business and Acquiring Company	Merger or Acquisition	Reported Value of Acquisition
Mergers and Acquisitions between FRS Companies		
Apache	Properties from BP	1,158
XTO	Colorado properties from Williams	381
Premcor	Williams' Memphis refinery	310
Anadarko	Gulf of Mexico properties from Amerada Hess	255
Occidental	Permian Basin properties from BP	234
Apache	Gulf of Mexico properties from Shell	200
Marathon	Williams' retail travel center operations	189
Shell	Kerr-McGee's assets in Kazakhstan	165
Sunoco	193 Speedway Service Stations from Marathon	162
Burlington	Marathon's 50% interest in Clam Petroleum	100
Other Acquisitions by FRS Companies		
Foreign Oil and Natural Gas Production		
EOG Resources	Canadian natural gas properties from Husky	320
Marathon	Acquired Khanty Mansiysk Oil Company	285
U.S. Oil and Natural Gas Production		
Devon	Merger with Ocean Energy	7,219
Chesapeake	Properties from El Paso	510
Chesapeake	Properties from ONEOK, Inc.	296
Chesapeake	South Texas natural gas properties	200
Chesapeake	Oxley Petroleum properties	155
Apache	Various property acquisitions	126
XTO	Properties in Texas, Arkansas, New Mexico, Colorado	100
Refining, Marketing, and Transport		
Valero	Orion Refining's Louisiana refinery	510
Power Generation		
Dominion	Kewaunne Power Plant (Wisconsin)	220
Nonenergy		
Sunoco	Equistar's polypropylene facility in Texas	198

Sources: Company annual reports to shareholders and press releases

level of the previous 5-year period, reflecting the increasing maturity of this region for oil and natural gas exploration. In the past 5 years, FRS companies spent the most for exploration (outside the United States) in Canada and Africa.

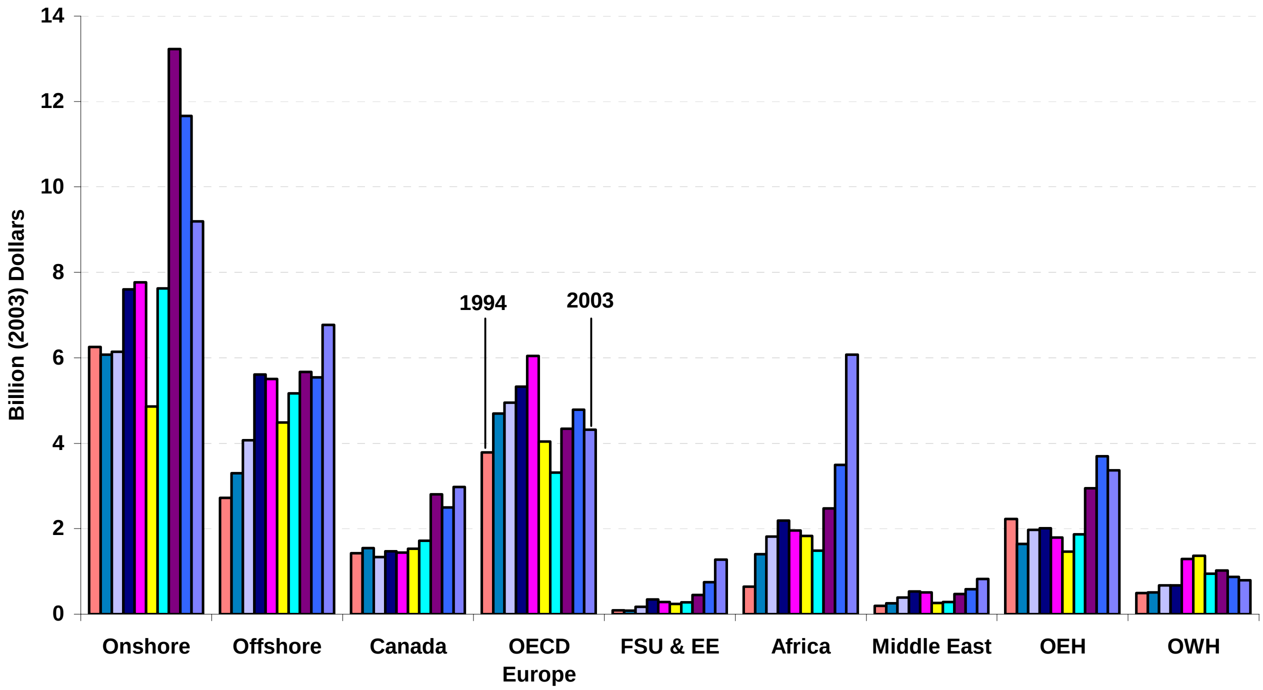
Devon sees growth opportunities in its large holding of undeveloped acreage in Canada and is planning to devote $250 million for Canadian exploration in 2004, which would be about 10 percent of their entire estimated exploration and development expenditures.[23] About 16 percent of Anadarko's total production volumes came from Canada in 2003, and they reported exploration operations in several provinces in Western Canada, including a significant natural gas discovery in the Saddle Hills area of Alberta.[24]

Nigeria and Angola, along with the U.S. Gulf of Mexico, were listed as the principal areas of exploration for ChevronTexaco. ChevronTexaco is the largest holder of deepwater acreage in Nigeria and reported deepwater drilling successes at Aparo, Nsiko, and Usan in 2003.[25] Exxon Mobil is also very active in West Africa and reported 11 discoveries in 2003 in Angola and Nigeria.[26]

Development expenditures outside the United States have doubled since 2000, while domestic spending has fallen in the past 2 years (**Figure 11**). Over the past 5 years, more development funds have been spent domestically than abroad, but the difference has decreased with the largest growth recently in Africa and the former Soviet Union. Development expenditures in the U.S. onshore fell sharply in 2003, but the region still receives more development expenditures than any other region. Outside the United States, OECD Europe had received the most development expenditures by FRS companies until 2003, when spending in Africa jumped 74 percent to surpass Europe.

In the United States, ConocoPhillips has a major expansion project underway to increase oil production from the Alpine field in the Western North Slope of Alaska, expected to add 26,000 barrels of oil equivalent per day by 2005, and is also pursuing development opportunities for significant natural gas resources in Alaska.[27] BP continued development of several fields in the Gulf of Mexico, reporting that the Na Kika field started production in 2003 and that the Holstein field is expected to begin production in late 2004. Several other fields are on track to come into production in the next few years.[28]

Figure 11. FRS Expenditures for Oil and Natural Gas Development by Region, 1994-2003



Note: OEH is Other Eastern Hemisphere, which is primarily the Asia-Pacific region. OWH is Other Western Hemisphere, which is primarily Central and South America and the Caribbean.

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

Europe still provides 31 percent of Exxon Mobil's worldwide production. Exxon Mobil announced seven major offshore developments starting in 2003, with total daily production from these fields expected to be about 220,000 oil-equivalent barrels.[29] ConocoPhillips reported that it is drilling 25 new wells and modifying several existing facilities to expand production in the Greater Ekofisk Area, starting production at the Grane field in the Norwegian North Sea, and expecting to start production in 2004 in the Clair field offshore of the Shetland Islands. Both Grane and Clair are expected to produce 14,000 barrels per day in 2005.[30]

Africa represents one of Exxon Mobil's primary near-term growth regions. Exxon Mobil reported several development projects in Angola, Nigeria, and Chad, including the 1-billion-barrel Chad Doba project, which consists of a 233-well development and a 650-mile pipeline through Cameroon.[31] Royal Dutch/Shell reported continuing investment and progress in Nigeria's first deepwater development, the Bonga field.[32] In Angola, ChevronTexaco is proceeding with the installation of an integrated drilling and production platform and the development of the Benguela and Belize fields in Deepwater Block 14. When the second phase is completed (estimated 2007), maximum daily production is estimated at more than 200,000 barrels of crude oil per day.[33]

FRS companies have also targeted the former Soviet Union for oil and gas development. BP noted that construction of the Baku-Tbilisi-Ceyhan pipeline began in May 2003, which will provide another outlet for crude oil from the Caspian area when completed. Construction also began on the platform to develop the Shah Deniz field in Azerbaijan, which is expected to produce its first gas in 2006.[34] Exxon Mobil reported progress toward a 220,000-barrel-per-day expansion in the Tengiz field in Kazakhstan, expected to start up in 2006. Drilling continued toward the first production at the giant offshore Kashagan field in the Caspian Sea. Expansion activities are also underway to increase capacity in the Azeri-Chirag-Gunashli development in Azerbaijan by more than 400,000 barrels per day, anticipated to start in 2005.[35]

Capital expenditures for refining and marketing dropped in 2003[36] (**Table 6**) as mergers and acquisitions between FRS companies declined from the previous 2 years.[37] Some purchases did occur: ConocoPhillips' Wood River refinery acquired some refining assets from the adjacent Hartford refinery owned by Premcor,[38] and Premcor purchased Williams' Memphis refinery[39] (**Table 7**). In addition, Valero purchased a refinery in Louisiana from Orion Refining Corporation.[40]

Many of the capital expenditures in refining and marketing in 2003 appeared to be related to upgrades for producing cleaner fuels. Several companies reported upgrades and new processing units designed to reduce sulfur in gasoline and diesel fuel. Starting in 2005, refiners must produce, on average, gasoline with sulfur levels no greater than 30 parts per million (ppm) as part of the Tier 2 motor gasoline requirements.[41] In 2006, sulfur in diesel fuel at retail levels must be reduced to 15 ppm, requiring that refiners produce fuel with even lower sulfur content.[42] Citgo constructed a unit at its Lemont, Illinois, refinery that removes sulfur without reducing the octane level of the gasoline.[43] Valero estimates that $1.5 billion will be needed through 2006 to meet the Tier 2 standards, of which $500 million had been expended at the end of 2003.[44] Marathon completed a $440 million multiyear project at its Catlettsburg, Kentucky, refinery that will allow the refinery to begin producing low-sulfur (Tier 2) gasoline.[45] Premcor noted that compliance with Tier 2 gasoline specifications would cost an estimated $315 million through 2005, of which $194 million had been incurred at the end of 2003.[46]

Refiners on the West Coast also had to prepare for the elimination of methyl tertiary butyl ether (MTBE) in gasoline (the phaseout started on December 31, 2003)[47] and for the California Air Resources Board (CARB) III gasoline requirements. ConocoPhillips expanded the alkylation unit at its Ferndale, Washington, refinery by 50 percent, which not only increased the average clean product yields by more than 6 percent but will also allow for excess alkylate to be shipped to other West Coast refineries to help make California-grade gasoline.[48] Tesoro completed a project at its California refinery that will allow it to produce at least 90,000 barrels per day of CARB gasoline components.[49]

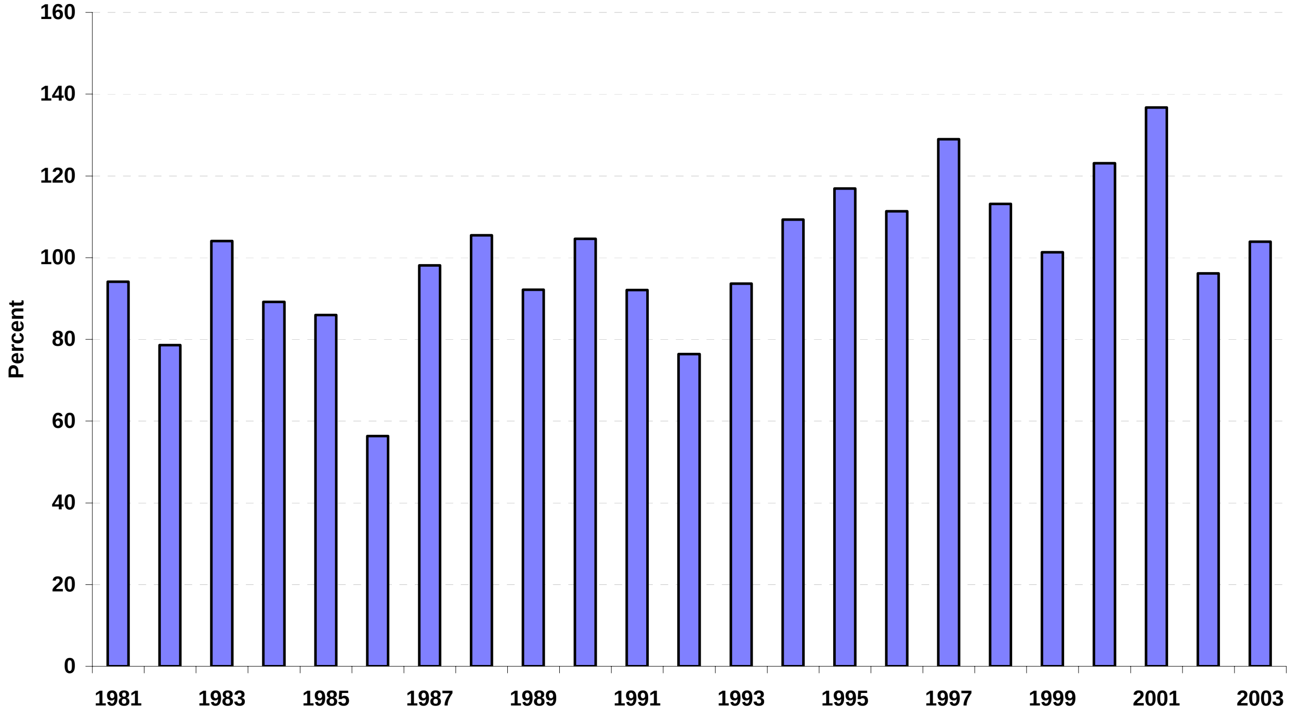
The European Union has plans to restrict the sulfur content of gasoline to 30 ppm in 2005 and diesel fuel to 50 ppm by 2006. The diesel fuel standard falls further to 10 ppm by 2009.[50] ChevronTexaco noted facility upgrades at refineries in the United Kingdom and the Netherlands to enable the manufacture of diesel and motor gasoline to a 10-ppm sulfur specification.[51] Exxon Mobil reported a $200 million enhanced conversion project at the Port Jerome-Gravenchon, France, refinery designed to increase yields of chemical feedstock and gasoline as well as to provide the capability to meet low-sulfur motor fuel specifications.[52]

Reserve Additions

FRS companies added more oil and natural gas reserves by drilling (purchases of reserves are not included) in 2003 than they extracted through production. The reserve replacement ratio was 104 percent, up from 96 percent in 2002 but still considerably below the high replacement levels of 2000 and 2001, which were 123 and 137 percent, respectively (**Figure 12**). (See also the special topic "Are the FRS Companies Finding Enough Oil and Gas to Keep Up with Demand?" in Chapter 4.) FRS companies report reserve additions in three categories: revisions, improved recovery, and extensions and discoveries.[53] Extensions and discoveries are by far the primary means for adding reserves (**Figure 13**). Improved recovery methods yielded more reserves in 2003 than in any previous year of the survey, indicating an increasing use of advanced production techniques.[54] Reserve revisions can be positive or negative, but for the FRS group as a whole have always been positive. Reserve revisions in 2002 and 2003, however, were the smallest in the FRS data series history, due primarily to large negative revisions in the U.S. offshore region (**Figure 14**).

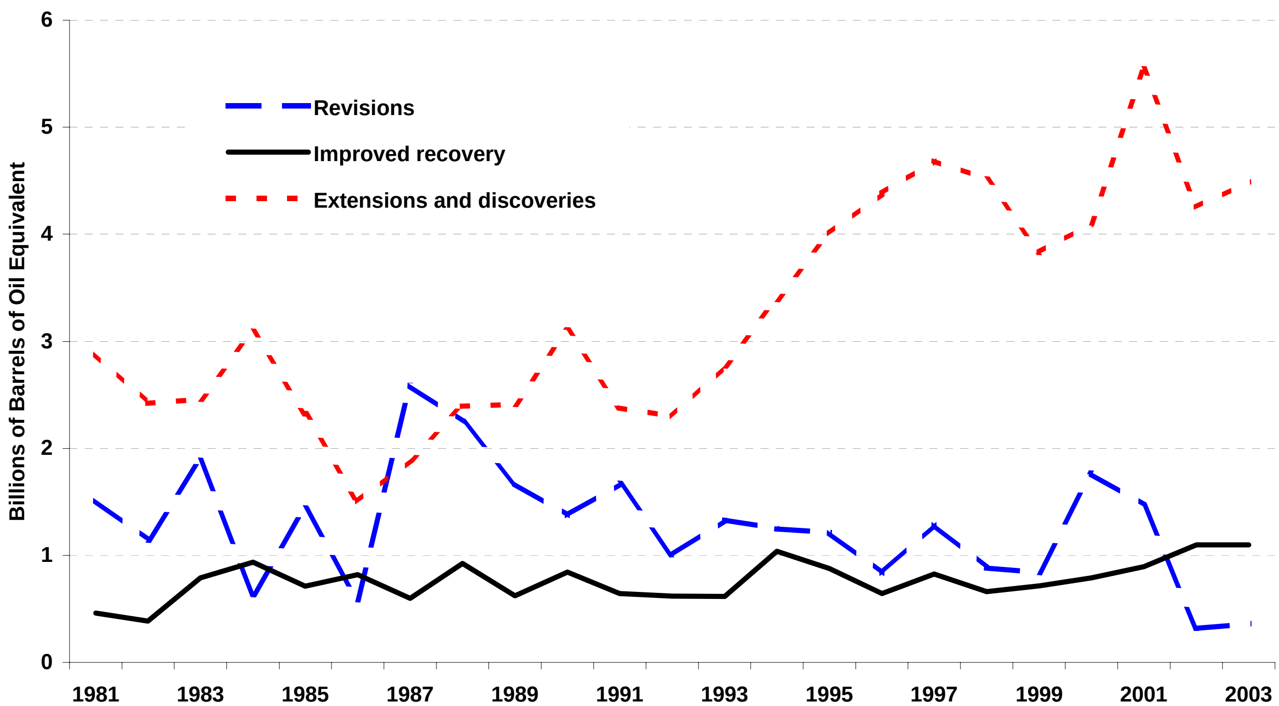
Higher reserves and slightly lower production raised the FRS companies' reserves-to-production ratio (**Figure 15**) to 11.4 for natural gas and 11.3 for oil. (The reserves-to-production ratio is the number of years that proved reserves would last at current production rates.) Higher prices for crude oil and natural gas in recent years have encouraged exploration and development of resources, which has tended to increase the reserves-to-production ratio. For oil, the reserves-to-production ratio in 2003 was the highest in the history of the FRS survey, although it was only slightly higher than the 2001 level. Natural gas reserve life has been showing an upward trend since 1997 as reserve growth has outpaced production increases. In 2003, reserves continued to increase while production fell, pushing the reserves-to-production ratio to the highest level since 1992. Because reserves are a type of inventory that companies maintain for future production and because finding and holding reserves entails cost, it is not expected that companies would attempt to significantly increase the reserves-to-production ratio. It does show, however, that companies have maintained a cushion of reserves even as some of their key producing regions have matured.

Figure 12. FRS Reserve Replacement Ratio, 1981-2003



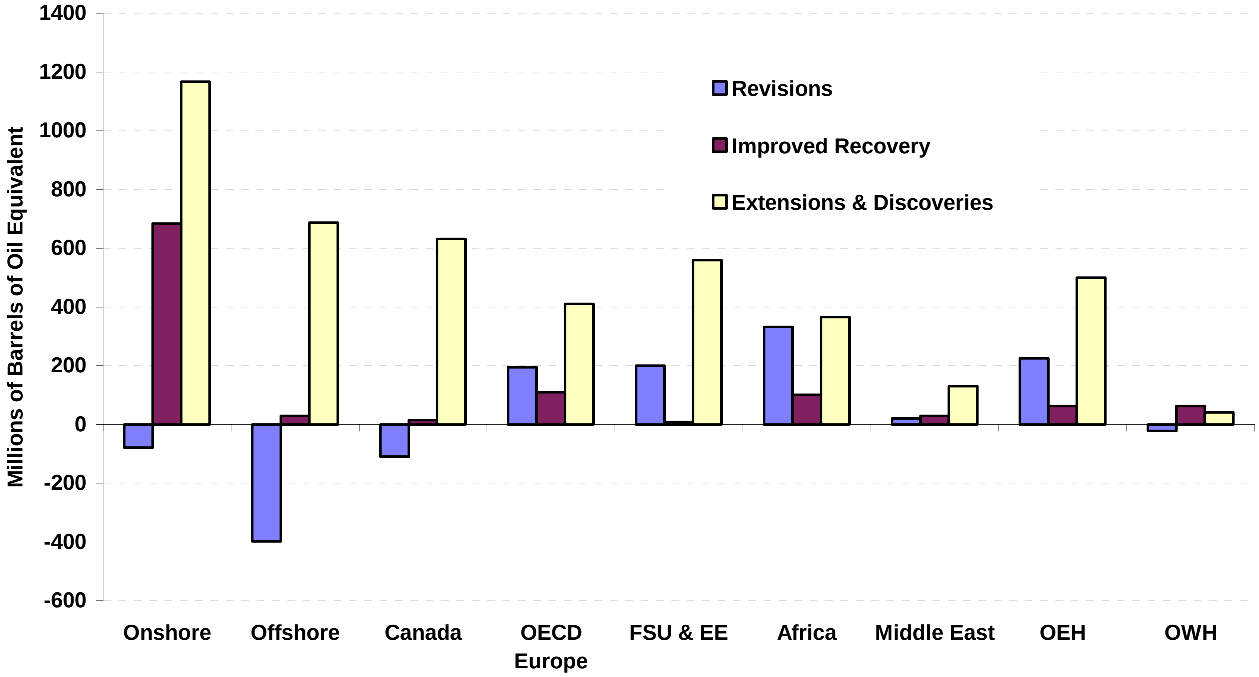
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Figure 13. FRS Reserve Additions by Type, 1981-2003



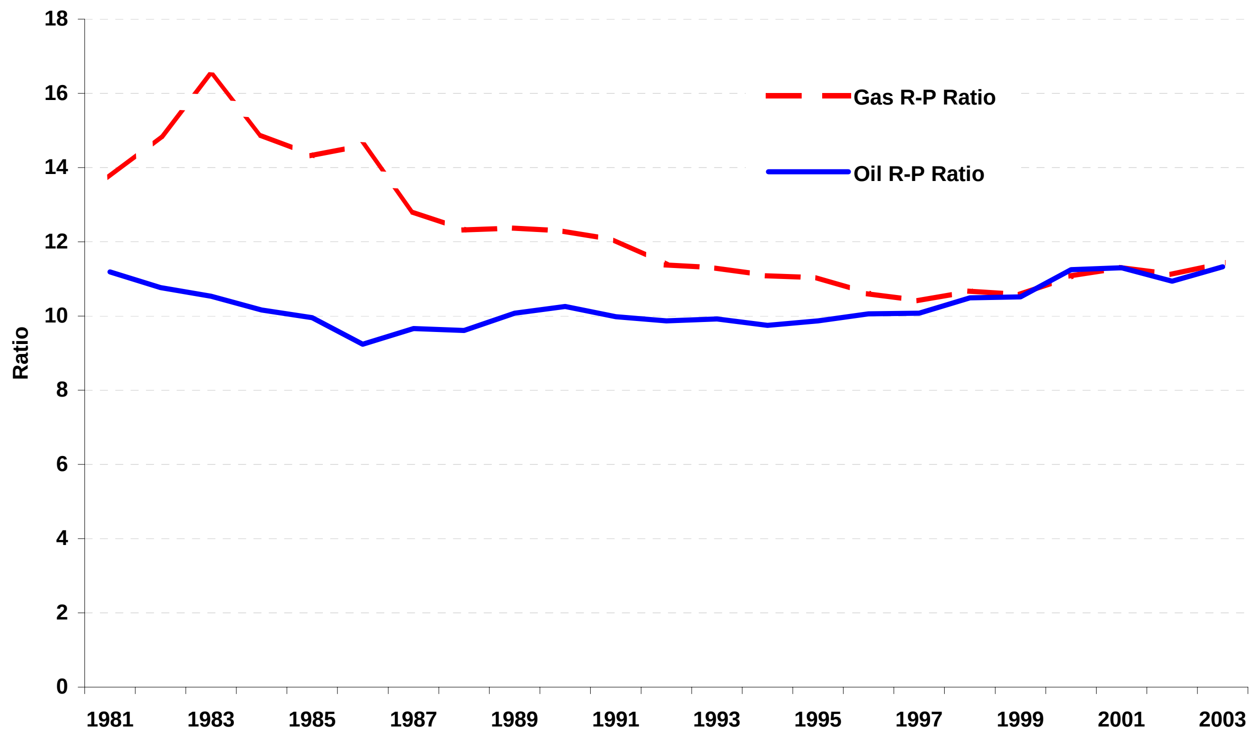
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Figure 14. FRS Reserve Additions by Type and by Region, 2003



Note: OEH is Other Eastern Hemisphere, which is primarily the Asia-Pacific region. OWH is Other Western Hemisphere, which is primarily Central and South America and the Caribbean.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Figure 15. FRS Reserve to Production (R-P) Ratio, Oil and Natural Gas, 1981-2003

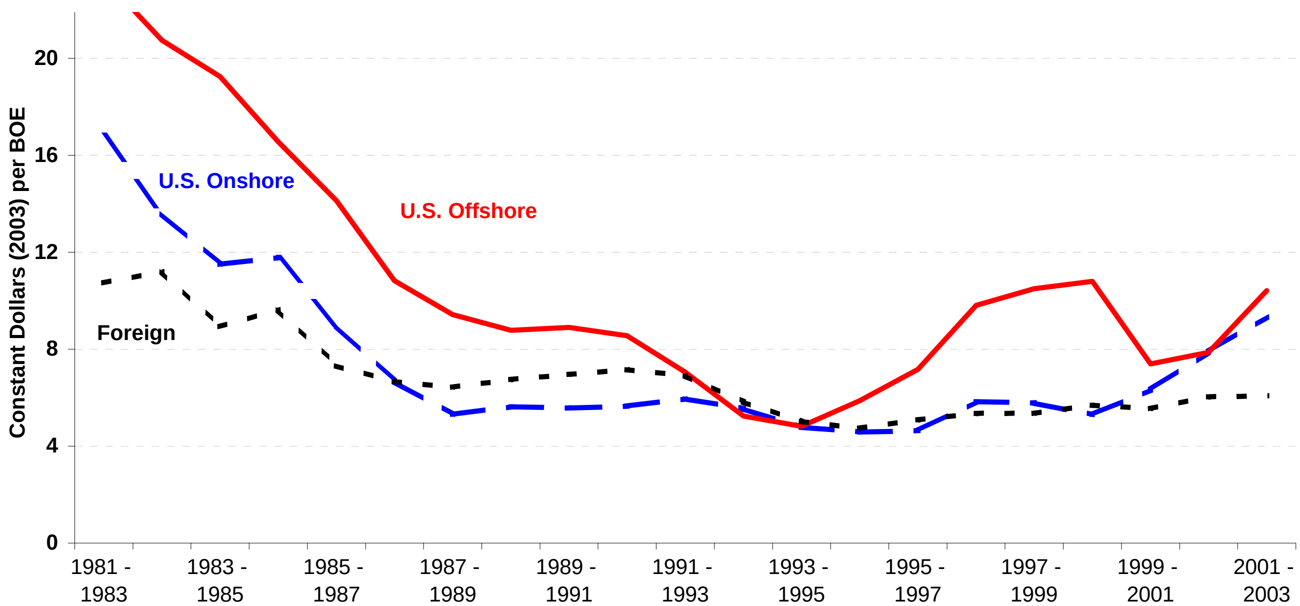


Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Finding and Production (Lifting) Costs

The average per-unit cost for the FRS companies of finding[55] oil and natural gas increased by 8.7 percent to $7.48 per barrel of oil equivalent (in constant 2003 dollars) in the 2001 to 2003 period, continuing the upward trend that started in the mid-1990s (**Figure 16**). Increases in U.S. onshore and offshore costs were primarily responsible for the increase, with offshore costs rising by 32.3 percent in the latest period to $10.42 per barrel. U.S. onshore finding costs jumped to the highest level since 1984 to 1986. Foreign finding costs grew by just 0.6 percent from the previous period. The difference between foreign and domestic finding costs widened to $3.67 per barrel, which is the widest gap since the mid-1980s. Finding costs fell in Canada, the former Soviet Union, Other Eastern Hemisphere, and Other Western Hemisphere. A jump of 63.1 percent in Africa led the increases (although Africa still remains below the average finding cost for foreign regions), with smaller rises in OECD Europe and the Middle East. See Chapter 3 for a more detailed presentation of trends in finding costs.

Figure 16. U.S. Onshore, U.S. Offshore, and Foreign Three-Year Weighted-Average Finding Costs for FRS Companies, 1981-1983 to 2001-2003



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).

Oil and natural gas production costs,[56] also known as lifting costs, increased by 12.3 percent to $4.87 per barrel in 2003, the highest amount since 1994 (in constant 2003 dollars). Production taxes led the increase, rising $0.30 per barrel to $1.00 per barrel. Production taxes are often based on the prices of oil and natural gas, so higher prices consequently raise production taxes. Domestic production taxes jumped to the highest level since 1985. All regions except the Middle East reported increases in production taxes. Direct lifting costs (excluding production taxes) rose 6.5 percent to $3.87 per barrel in 2003. The biggest increases in direct lifting costs occurred in Canada, the former Soviet Union, and OECD Europe, balanced by declines in Africa, Other Eastern Hemisphere, and Other Western Hemisphere. See Chapter 3 for additional discussion of lifting costs.

[2] The U.S.-based energy companies that respond to the FRS Form EIA-28 are considered to be U.S. majors by the Energy Information Administration (EIA) (see Public Law [P.L.] 95-91, Sec. 205 (h)). More information about the FRS companies can be found in Chapter 2, in the preface of this report, in Appendix A, and at http://www.eia.doe.gov/emeu/finance/page1a.html.

[3] The composition of the group of FRS companies has changed over time, but the changes are usually incremental. Companies are added to the survey when, through growth or acquisition, they meet the criteria classifying them as a major energy company. Typically no more than one or two companies are added to the survey in any given year. The new companies are usually relatively small compared to the existing FRS group, so the effect on the aggregate totals is marginal. The only year that was an exception was 1998 when, because of a change in the FRS criteria, 11 companies were added to the FRS group. Companies rarely exit unless through merger, in which case the assets of the exiting company are absorbed into the surviving company. Thus, despite occasional year-to-year changes in the FRS group composition, comparisons are still meaningful and informative.

[4] Unusual items include accounting changes, asset dispositions and write-downs, tax adjustments, etc.

[5] The FRS collects financial and operational information for combined corporate entities as well as by lines of business within entities. The lines of business changed with the 2003 data collection and now consist of petroleum, downstream natural gas (including natural gas pipelines), electric power, nonenergy, and other energy (including coal, nuclear, renewable fuels, and unconventional fuels). The petroleum line of business is further segmented into production, refining and marketing, crude and petroleum product pipelines (for domestic petroleum), and international marine transport (for foreign petroleum). Prior to 2003, the lines of business consisted of petroleum, coal, nonenergy, and other energy. This change limits the ability to provide comparison with prior years for several of the lines of business. See the box in the Executive Summary for more information.

[6] Profitability for the consolidated FRS companies can be measured by ROE, calculated by net income as a percentage of stockholder's equity. Because stockholder's equity is a corporate concept, the lines of business within the company use ROI as a measure of profitability. ROI is defined as net income divided by net investment in place for that segment. Net investment in place consists of the value of property, plant, and equipment net of depreciation plus investments and advances to unconsolidated affiliates.

[7] International marine is included in foreign refining/marketing net income.

[8] Energy Information Administration, *Short-Term Energy Outlook* (September 2003), page 1.

[9] Energy Information Administration, *Short-Term Energy Outlook* (March 2003), page 4.

[10] The FRS gross margin calculation also accounts for product purchases.

[11] See Chapter 3 for a more detailed presentation of refining/marketing revenue and cost trends.

[12] See "Are Refining Margins Predictors of Profitability" in Chapter 4 for a discussion of the relationship between margins and profitability.

[13] Cash flow from operations consists of net income plus expenses that do not require an outlay of cash minus earnings that do not provide a receipt of cash. For energy companies, the largest noncash item is generally depreciation, depletion, and amortization (DD&A), which is an allowance for the decline in value of property, plant, and equipment (PP&E), based on accounting principles, recorded as a charge against income.

[14] Because of the changes in the FRS lines of business for 2003, some cash flow that was attributed to the production and refining/marketing lines of business in 2002 (and earlier) is now in the downstream natural gas segment. Thus the increases in cash flow for production and refining/marketing would be even larger in 2003 than what is shown. For consistency, downstream natural gas is presented with the petroleum line of business for 2003.

[15] See, for example, "Study Finds Upstream Spending Shifts to Development from Exploration," *Oil Daily* (October 14, 2004), page 5.

[16] It is presently unclear if this large dividend payment was a one-time event or is the beginning of a trend.

[17] Additions to investment in place are defined as additions to property, plant, and equipment (PP&E), plus additions to investments and advances to unconsolidated affiliates.

[18] The regions for which separate FRS data are collected include U.S. onshore, U.S. offshore, Canada, OECD Europe, Former Soviet Union and Eastern Europe, Africa, Middle East, Other Eastern Hemisphere (primarily Asia-Pacific), and Other Western Hemisphere (primarily South America).

[19] Devon Energy Corporation, *2003 Annual Report*, pages 10, 18–19.

[20] ChevronTexaco Corporation, *2003 Supplement to the Annual Report*, pages 13–14.

[21] Anadarko Petroleum Corporation, 2003 U.S. Securities and Exchange Commission Form 10-K filing, pages 7–8.

[22] Anadarko Petroleum Corporation, *2003 Annual Report*, pages 7–8.

[23] Devon Energy Corporation, *2003 Annual Report*, pages 12 and 22.

[24] Anadarko Petroleum Corporation, 2003 U.S. Securities and Exchange Commission Form 10-K filing, page 16.

[25] ChevronTexaco Corporation, *2003 Annual Report*, pages 7 and 22.

[26] Exxon Mobil Corporation, *2003 Summary Annual Report*, pages 9–10.

[27] ConocoPhillips, *2003 Annual Report*, page 14.

[28] BP plc, *Annual Review 2003*, page 26.

[29] Exxon Mobil Corporation, *2003 Summary Annual Report*, pages 8–9.

[30] ConocoPhillips, *2003 Annual Report*, page 15.

[31] Exxon Mobil Corporation, *2003 Summary Annual Report*, pages 9–10.

[32] Royal Dutch/Shell Group of Companies, *Annual Report and Accounts 2003*, page 19.

[33] ChevronTexaco Corporation, *2003 Supplement to the Annual Report*, page 19.

[34] BP plc, *Annual Review 2003*, page 26.

[35] Exxon Mobil Corporation, *2003 Summary Annual Report*, page 12.

[36] Some of the decrease for refining and marketing in Table 1–6 was the result of breaking out downstream natural gas as a separate line of business in 2003. However, even if all of downstream natural gas were added into refining and marketing, it would still show a decrease in capital expenditures in 2003.

[37] See Energy Information Administration, *Performance Profiles of Major Energy Producers 2002*, DOE/EIA-0206(04) (Washington, DC, February 2004), page 24.

[38] ConocoPhillips Company, *2003 Annual Report*, page 18.

[39] Premcor, Inc., "Premcor Completes Purchase of Williams' Memphis Refinery" (March 4, 2003).

[40] Valero Energy Corporation, 2003 U.S. Securities and Exchange Commission Form 10-K filing, page 5.

[41] Energy Information Administration, *Timing of Startups of the Low-Sulfur and RFS Programs* (September 2002), page 3.

[42] Energy Information Administration, *The Transition to Ultra-Low-Sulfur Diesel Fuel: Effects on Prices and Supply* (May 2001), page ix.

[43] CITGO, "Successful Start-Up of ISAL Unit at Citgo's Lemont Refinery" (November 18, 2003).

[44] Valero, 2003 U.S. Securities and Exchange Commission Form 10-K filing, page 16.

[45] Marathon, 2003 U.S. Securities and Exchange Commission Form 10-K filing, page 15.

[46] Premcor, 2003 U.S. Securities and Exchange Commission Form 10-K filing, page 18.

[47] According to *Final Regulation Order: Amendments to the California Phase 3 Gasoline (CaRFG3) Regulations to Refine the Prohibitions of MTBE and Other Oxygenates in California Gasoline*, adopted March 14, 2003, and filed with the Office of Administrative Law of the State of California on March 20, 2003, page 4: "No person shall sell, offer for sale, supply or offer for supply California gasoline which contains MTBE in concentrations greater than: 0.60 volume percent starting December 31, 2003, 0.30 volume percent starting July 1, 2004, 0.15 volume percent starting December 31, 2005, and 0.05 volume percent starting July 1, 2007." Available on the Internet at http://www.arb.ca.gov/regact/mtberesid/finreg.pdf (as of November 16, 2004).

[48] ConocoPhillips, *2003 Annual Report*, page 19.

[49] Tesoro, 2003 U.S. Securities and Exchange Commission Form 10-K filing, page 12.

[50] International Council on Clean Transportation, *Clean Gasoline and Diesel—The Foundation for Modern Vehicles and Clean Air*, page 2, http://www.cleantransportcouncil.org/docs/Sulfur_policymaker_brief.pdf (as of December 6, 2004).

[51] ChevronTexaco, *2003 Supplement to the Annual Report*, page 39.

[52] Exxon Mobil, *Financial and Operating Review*, page 65.

[53] Companies also report reserve additions through purchases, but the focus here is on additions by drilling. Extensions and discoveries are those reserves added by extending the proved acreage of previously discovered reservoirs or by discovery of new fields or reservoirs. Improved recovery refers to reserves resulting from the application of improved recovery techniques. Reserve revisions are changes (upward or downward) in previous estimates resulting from new information obtained from development drilling and production history or a change in economic factors.

[54] See, for example, "US market for well-stimulation materials to reach $1.4 billion by 2005," *Oil & Gas Journal Online*, http://ogj.pennnet.com/articles/web_article_display.cfm?Section=OnlineArticles&Article_Category=DriPr&ARTICLE_ID=215087&KEYWORD=well%20stimulation&x=y (as of December 1, 2004).

[55] Finding costs represent the cost of discovering a barrel of oil equivalent and preparing it for production. In the FRS data, they include exploration and development costs and the cost of acquiring unproved acreage. The costs are averaged over 3-year periods as an attempt to mitigate the problem of expenditures to find oil and gas occurring in a different time period than the recognition of the reserves as proved.

[56] Production costs include the costs to operate and maintain producing wells and related equipment and facilities.

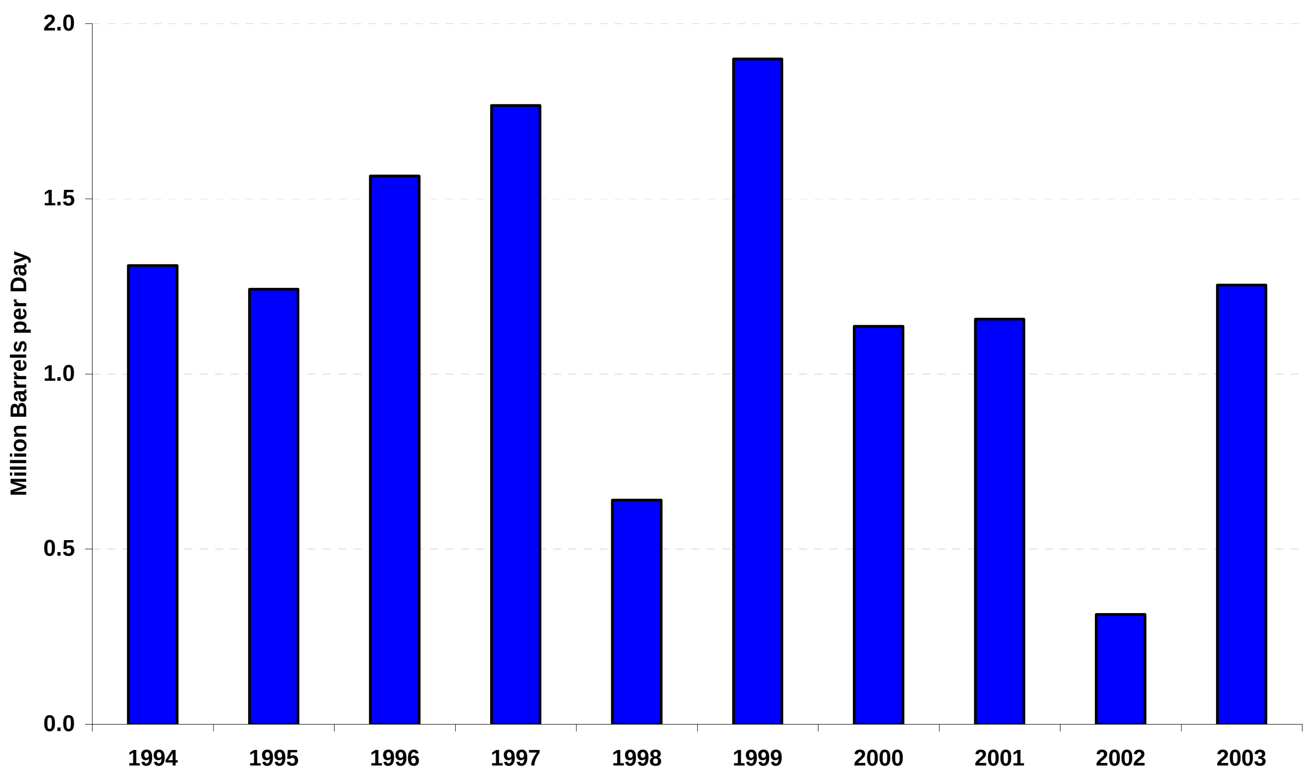
2. Market Developments and Financial Reporting System (FRS) Companies in 2003

Petroleum and Natural Gas Markets in 2003

For world oil markets, 2003 was a year of high prices driven by strong demand and supply concerns in several key supply regions. Companies saw increased demand for petroleum products at considerably higher prices than in previous years. Natural gas prices also were significantly higher, which contributed to lower demand for natural gas in the United States. Financially, 2003 was a sharp turnaround from 2002, when the net income and profitability of major energy companies were near low points. The higher prices for crude oil, natural gas, and petroleum products, along with the higher demand for petroleum products, provided a strong financial boost to energy companies.

World oil consumption increased by 1.3 million barrels per day in 2003, much larger than the 314,000 barrels-per-day rise in 2002 and the largest increase since 1999 (**Figure 17**). China continued to show strong economic growth and contributed 30 percent of the increase in world oil consumption.[57] Oil demand in Japan increased for the first time in 4 years, in large part due to its increased use of oil for power generation after 17 nuclear power plants were shut down for safety inspections.[58]

Figure 17. World Oil Consumption, Change from Previous Year, 1994-2003



Source: Energy Information Administration, *Monthly Energy Review*, DOE-EIA-0034 (2004/10) (Washington, DC, October 2004), Table 11.2.

In 2003, world oil supplies more closely kept pace with demand in contrast to 2002, when demand significantly outpaced supply (**Table 8**). After a substantial decline in 2002, the Organization of the Petroleum Exporting Countries (OPEC) supply increased by 1.6 million barrels per day, returning nearly to the level of 2001. Non-OPEC supply rose by 0.9 million barrels per day, slightly less than the average increase of the past 3 years.[59]

In 2003, annual average oil consumption in the United States surpassed 20 million barrels per day for the first time (**Table 9**). The 273,000 barrels-per-day rise from the 2002 average was the largest annual increase in oil consumption since 1999, although it remained less than the average annual increases of the late 1990s. The increase in U.S. oil consumption was primarily driven by the 3-percent rise in gross domestic product (GDP) in 2003 from 2002. GDP growth continued to recover from the sharp slowdown in 2001. As a result of high natural gas prices, the substitution of oil for natural gas in electric power generation and in some industrial uses also contributed to the growth in oil consumption.[60] This growth was evident in the increase in distillate and residual fuel oil consumption (**Figure 18**). Gasoline consumption also went up but by a lower amount than that of the last 2 years. Demand for jet fuel fell for the third year in a row.

Table 8. World Petroleum Balance, 2002–2003

(Million Barrels per Day)

	Quarterly 2003				Annual	
	Q1	Q2	Q3	Q4	2002	2003
Demand	80.3	77.1	79.3	82.0	78.4	79.7
Supply	78.6	78.2	79.1	81.6	76.9	79.4
Supply from Inventories	1.6	-1.1	0.1	0.5	1.6	0.3

Note: Supply from Inventories includes statistical discrepancy.
Source: Energy Information Administration, *International Petroleum Monthly* (October 2004), Table 2.1.

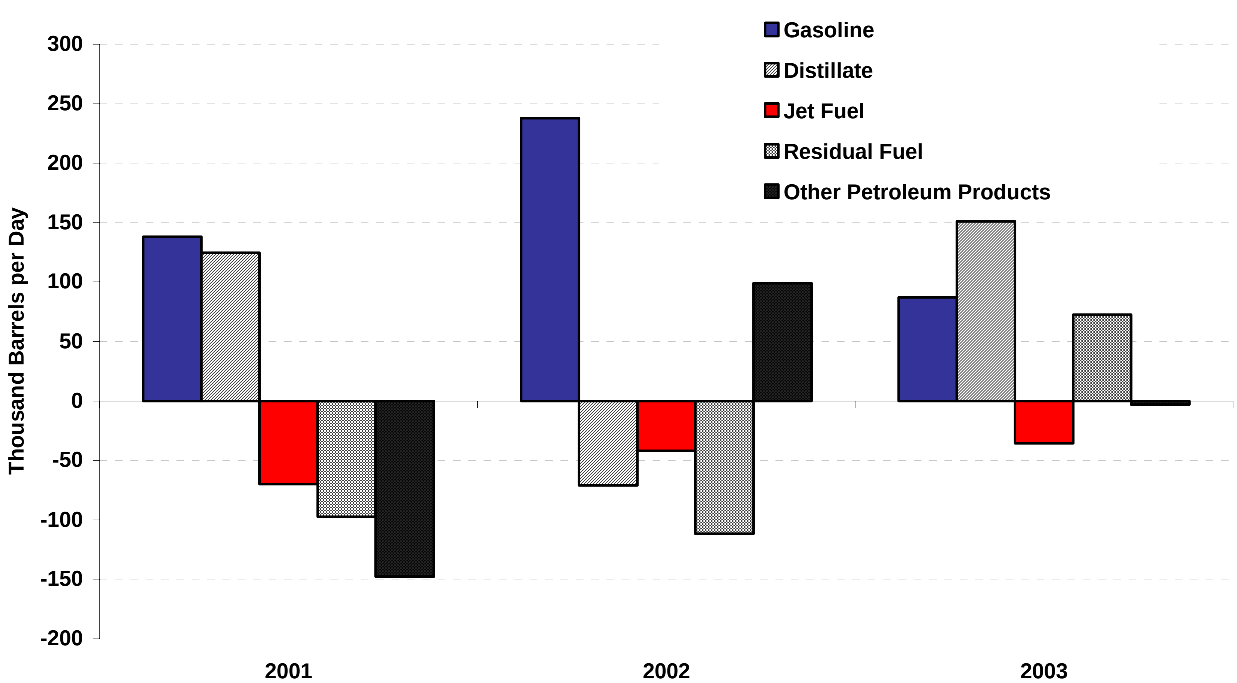
Table 9. U.S. Petroleum Balance, 2002–2003

(Million Barrels per Day)

	Quarterly 2003				Annual	
	Q1	Q2	Q3	Q4	2002	2003
Demand	20.0	19.7	20.2	20.2	19.8	20.0
Domestic Supply	8.9	8.8	8.8	8.8	9.1	8.9
Net Imports	10.3	11.8	11.8	11.1	10.5	11.2
Supply from Inventories	0.8	-0.9	-0.4	0.3	0.1	-0.1

Note: Domestic supply includes crude, natural gas liquids (NGL), and other liquids production and refinery processing gain.
Source: Energy Information Administration, *Monthly Energy Review* (October 2004), Tables 3.1a and 3.1b.

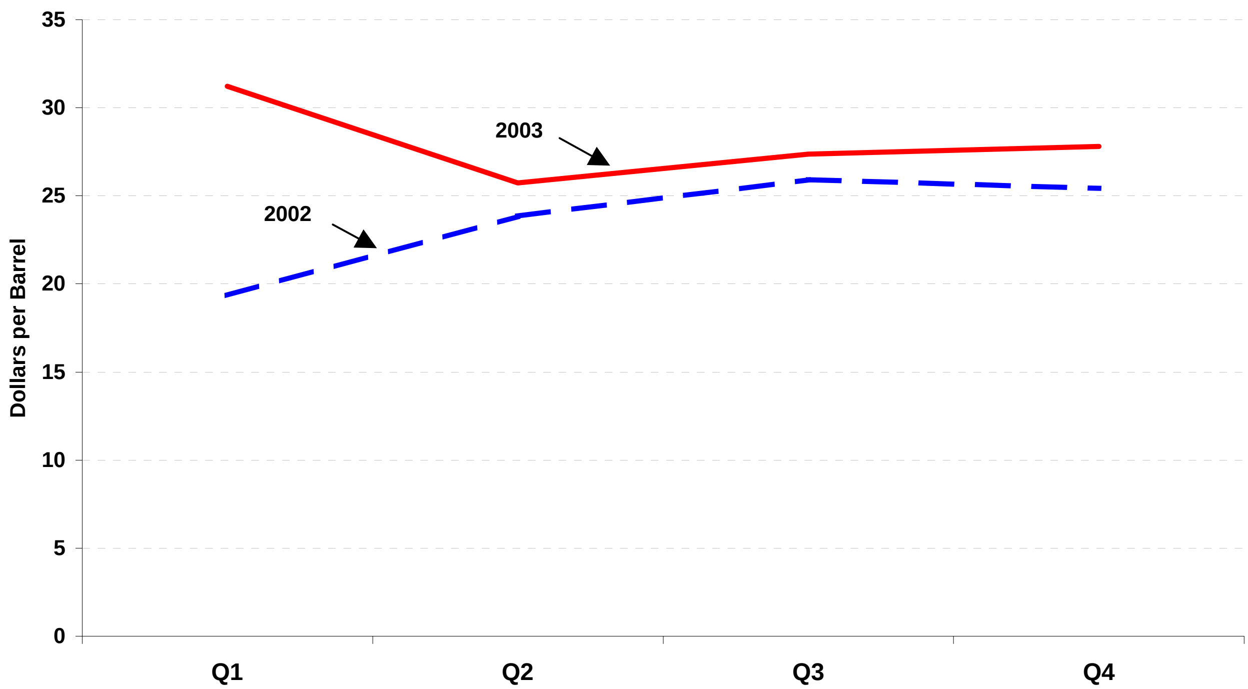
Figure 18. U. S. Petroleum Product Consumption, Change from Previous Year, 2001-2003



Sources: 2001-2002: Energy Information Administration, *Annual Energy Review*, DOE/EIA-0384 (2003) (Washington, DC, September 2004), Table 5.11; 2003: Energy Information Administration, *Petroleum Supply Annual*, DOE/EIA-0340 (2003/1) (Washington, DC, July 2004), Table 3.

Crude oil prices (as measured by the U.S. imported refiner acquisition cost for crude oil) increased $4 per barrel in 2003 to $27.71 per barrel (**Figure 19**). Crude oil prices averaged $32.23 in February, the highest monthly level of the year. In the first quarter of 2003, world oil demand exceeded supply by 1.6 million barrels per day, putting significant upward pressure on oil prices. U.S. petroleum product inventories fell by an average of 1.4 million barrels per day in January and February 2003.[61] Weather that was 4 percent colder than normal and 20 colder than the previous year for the December 2002 to February 2003 period contributed to higher demand levels. At the same time, strikes by oil workers in Venezuela and Nigeria reduced available supplies.

Figure 19. Quarterly U.S. Refiner Acquisition Cost of Imported Crude Oil, 2002 and 2003



Source: Energy Information Administration, *Short-Term Energy Outlook* (May 8, August 6, and December 8, 2003; and March 9, 2004), Table 4.

Prices eased in the second quarter as demand dropped and supply exceeded demand by 1.1 million barrels per day. With the increase in demand during the second half of the year outpacing supply, however, prices remained firm and averaged higher than 2002 during each month except September.

Higher demand kept petroleum product stocks, in particular motor gasoline stocks, well below the level of the previous year (See Chapter 3, “Domestic Refining/Marketing”). U.S. petroleum product prices rose even more than crude prices and were especially strong during the first quarter of 2003. Gasoline gross margins (the difference between product prices and crude oil prices) increased by $3.31 per barrel in 2003 from the 2002 level, and number 2 distillate fuel (an average of number 2 heating oil and number 2 diesel fuel) margins went up $2.89 per barrel.[62]

U.S. refinery output, at 17.5 million barrels per day, reached its highest level ever, surpassing the previous peak in 2000. Reflective of the shift in consumption, the output shares of gasoline and jet fuel were slightly lower than in 2002, while distillate and residual fuel shares rose slightly.[63]

In 2003, world natural gas consumption rose 2 percent over 2002. Increases in Europe, Russia, and the Asia-Pacific region offset consumption declines in the United States. Production went up 3.4 percent with the largest increases occurring in Russia, Asia-Pacific, and Central and South America. Canadian natural gas production, however, fell by 3.9 percent.[64] Because the United States imports significant quantities of Canadian natural gas, this provided support for higher natural gas prices in the United States.

For 2003 as a whole, natural gas consumption in the United States declined 4.6 percent from 2002 (**Table 10**). Large declines in the electric power and industrial sectors were offset only partially by increases in residential and commercial sector consumption. As mentioned previously, high natural gas prices in the United States resulted in switching from natural gas to distillate and residual fuel in electric power generation and in some industrial processes. On the supply side, U.S. natural gas production increased by 0.5 percent in 2003 (although total domestic supply declined slightly) while net imports fell. With consumption down from the previous year, inventories increased in 2003, reversing the net withdrawal situation that occurred in 2002.

Table 10. U.S. Natural Gas Balance, 2002–2003
(Trillion Cubic Feet)

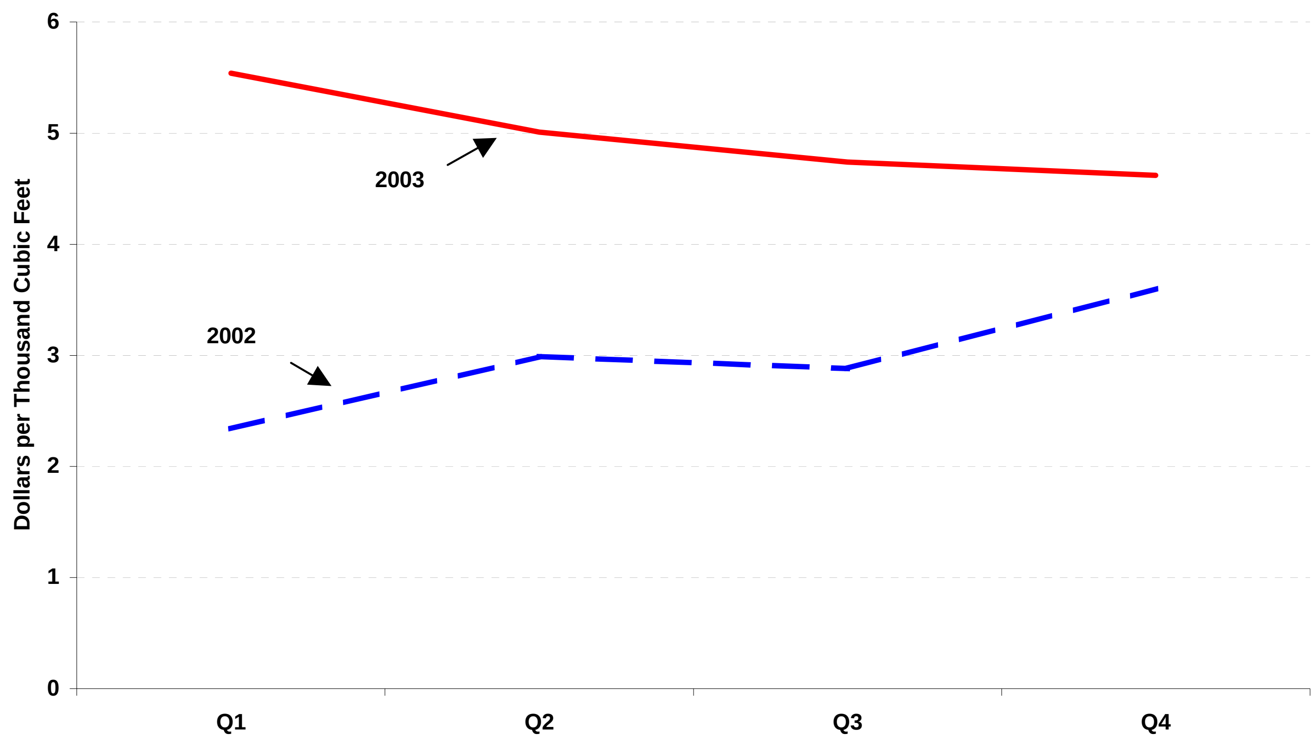
	Quarterly 2003				Annual	
	Q1	Q2	Q3	Q4	2002	2003
Demand	7.3	4.5	4.6	5.5	23.0	22.0
Domestic Supply	4.9	4.8	4.8	4.4	19.1	18.9
Net Imports	0.8	0.8	0.9	0.8	3.5	3.3
Supply from Inventories	1.7	-1.0	-1.1	0.3	0.5	-0.2

Note: Domestic supply includes dry gas production, supplemental gaseous fuels, and the balancing item.

Source: Energy Information Administration, *Monthly Energy Review* (October 2004), Table 4.1.

Natural gas prices began rising in the second half of 2002, driven by higher demand (**Figure 20**). Colder weather in the first quarter of 2003 caused a 5-percent increase in consumption over the first quarter of 2002, driving stock levels well below the average of the previous 5 years (**Figure 21**) and continuing the strong upward pressure on prices. The higher prices induced fuel switching, which brought about a drop in demand of nearly 10 percent in the second and third quarters compared to the previous year. Inventories increased through the second and third quarters and prices moderated. By the beginning of the fourth quarter, stocks had returned to the 1997-2001 average. But stocks remained below the 2002 level through September 2003, and wellhead prices stayed well above 2002 levels throughout the year. Wellhead prices averaged $4.98 per thousand cubic feet in 2003, 69 percent higher than the previous year.

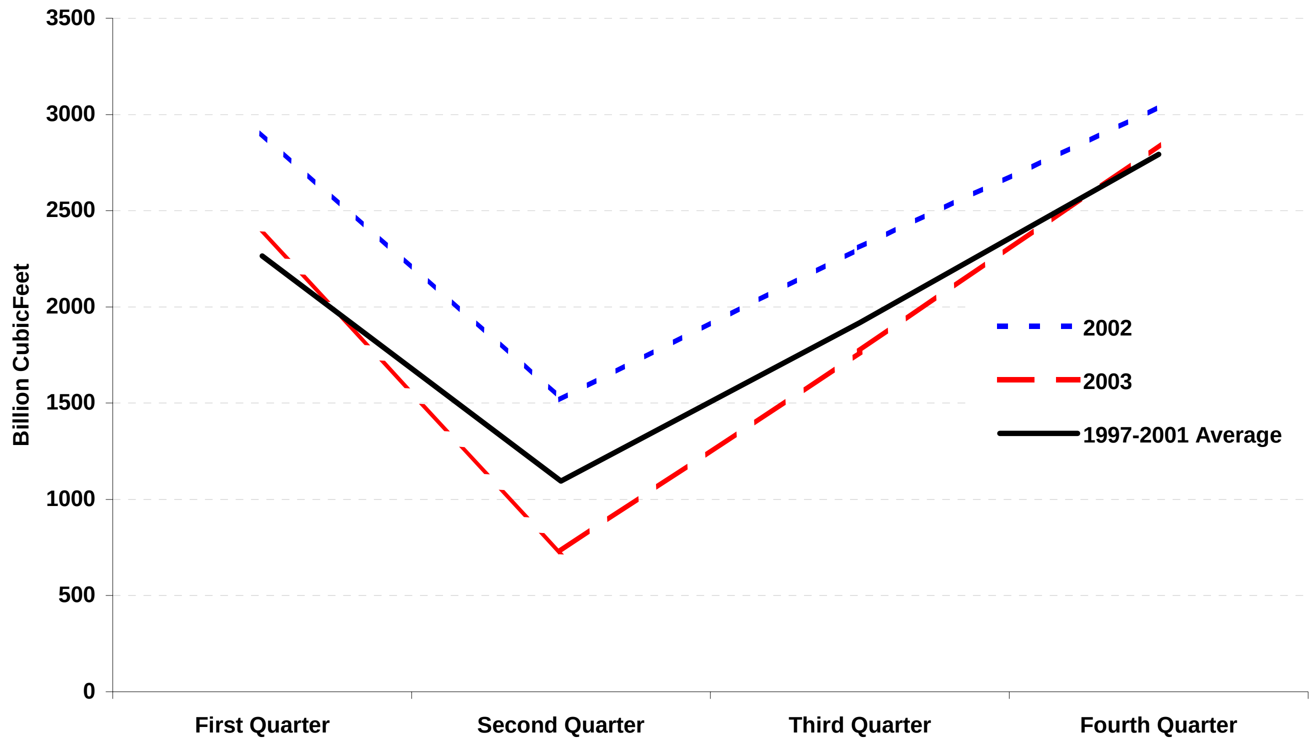
Figure 20. Quarterly U.S. Natural Gas Wellhead Price, 2002 and 2003



Source: Energy Information Administration, *Short-Term Energy Outlook* (May 8, August 6, and December 8, 2003; and March 9, 2004), Table 4.

In summary, world oil demand in 2003 increased by the largest amount in 4 years. At the same time, strikes by oil workers and other supply concerns in various parts of the world also contributed to a strong boost to oil prices. Average crude oil prices for 2003 reached the highest level since 2000 (in constant dollars). Natural gas prices also increased sharply as a result of strong demand at the end of 2002 and beginning of 2003 and lower natural gas imports. Fuel switching brought about lower natural gas consumption in the United States for 2003 overall. But the higher oil and natural gas prices and stronger demand for petroleum products made 2003 an exceptional year financially for energy companies.

Figure 21. Quarterly U.S. Opening Level of Working Gas in Storage, 1997-2001 Average, 2002, and 2003



Source: Energy Information Administration, *Monthly Energy Review*, DOE-EIA-0034 (2004/10) (Washington, DC, October 2004), Table 4.5.

New Entrants in the FRS Group in 2003

Chesapeake Energy Corporation[65] is one of the largest U.S. non-vertically integrated producers of natural gas. Chesapeake's U.S. reserves and its production of crude oil, natural gas, and natural gas liquids (NGLs) have steadily grown during the past 5 years,[66] with much of its growth due to asset acquisitions.[67] As a result of Chesapeake's growth, it was added the FRS respondent group for the 2003 reporting year.

Equitable Resources, Inc.[68] is an integrated energy company that primarily engages in natural gas production, transmission, and distribution and energy management services.[69] Equitable's proven and developed U.S. natural gas reserves have been largely the same for the past 3 years, while its production has increased steadily.[70] Consequently, Equitable was added to the FRS respondent group for the 2003 reporting year.

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

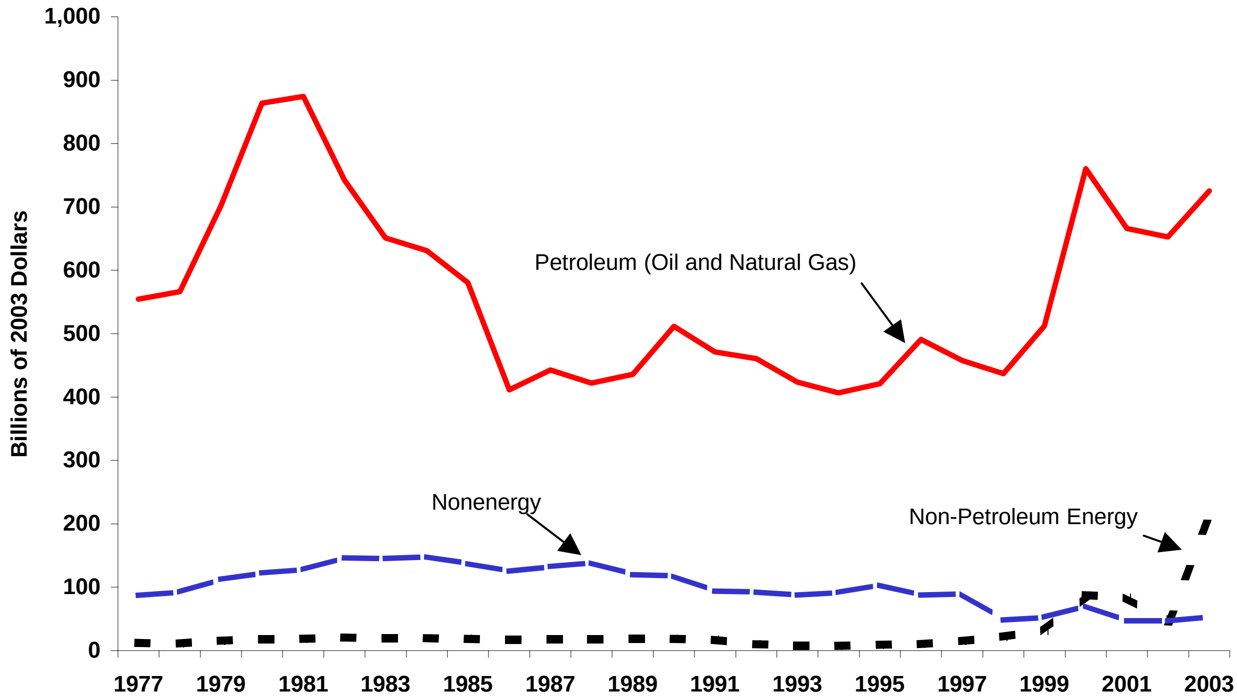
For the 2003 reporting year, 28 major energy companies reported their financial and operating data to the EIA FRS on Form EIA-28.[71] These companies (referred to as the FRS companies in this report) occupy a significant position in the U.S.[72] economy. In 2003, operating revenues of the FRS companies totaled $889 billion, which is equal to 12 percent of the $7.5 trillion in revenues of the Fortune 500 largest U.S. corporations.[73]

The reporting companies engage in a wide range of business activities, but their most important activities are in the energy sector. About 95 percent, or $933 billion, of allocated operating revenues[74] were derived from energy lines of business. Nearly all of these revenues were derived from the companies' core petroleum operations (**Figure 22**). (For the purposes of this report, the petroleum line of business includes natural gas exploration, development, and production, but not downstream natural gas, which is a separate FRS line of business beginning with the 2003 reporting year, as is electric power.[75])

In 2003, the FRS companies accounted for 48 percent of total U.S. crude oil and NGL production,[76] 43 percent of natural gas production, 85 percent of U.S. refining capacity, 3 percent of U.S. electricity generation, and 2 percent of

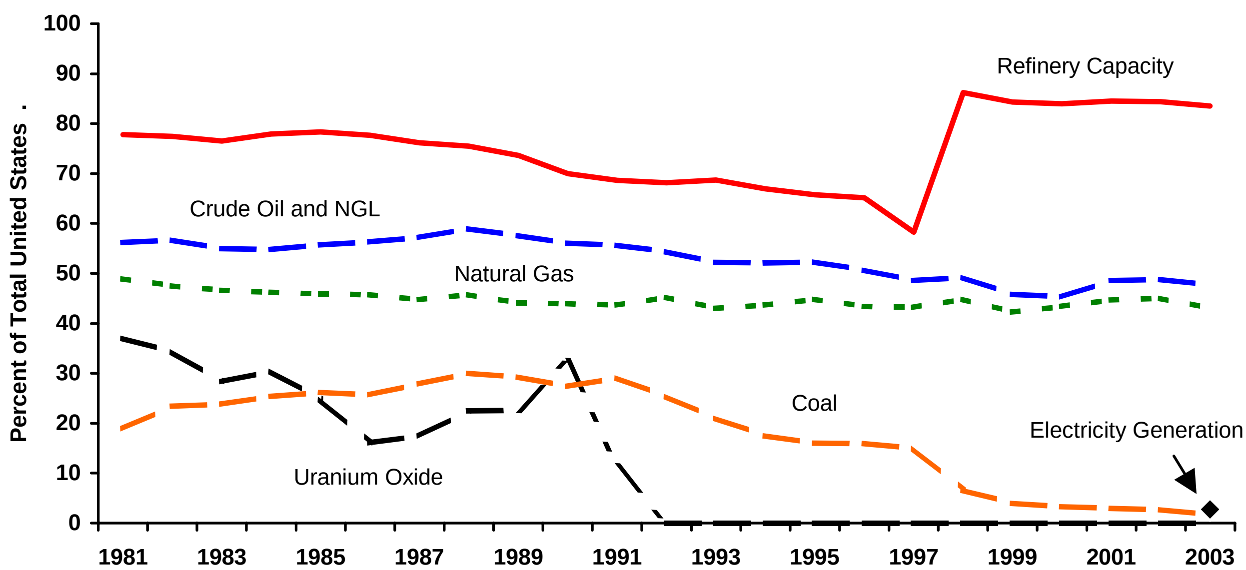
U.S. coal production (**Figure 23**). More than 85 percent of the FRS companies' assets and new investments during 2003 were devoted to sustaining various aspects of petroleum production, processing, transportation, and marketing.

Figure 22. Operating Revenues by Line of Business for FRS Companies, 1977-2003



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

Figure 23. Shares of U.S. Energy Production[a] and Refinery Capacity for FRS Companies, 1981-2003



[a]Oil and gas production for the FRS companies includes only the production that is owned by the FRS companies; it does not include any interests not owned by the FRS companies (e.g., royalty interests owned by others). Total production for the United States includes the interests of all owners.

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).

Energy production other than oil and natural gas has been a relatively small, but growing, part of the FRS companies' operations since 1994. During 2003, the combined operating revenues of the downstream natural gas, electricity, and other energy operations[77] of the FRS companies totaled $207 billion, or 21 percent of allocated revenues. Increased activity in downstream natural gas and electricity more than offset the continued decline in coal activity by the FRS companies, which began in 1994 and continues to the present.[78] The growing importance of downstream natural gas and electric power operations to the FRS companies has resulted in the addition of each of these as a separate line of business for the 2003 reporting year.

Nonenergy businesses, mainly chemicals, accounted for 5 percent, or $54 billion, of the FRS companies' allocated revenues in 2003. During the 1980s, the FRS companies were major producers of domestic uranium. However, no FRS company has produced uranium oxide domestically since 1991.

---

[57] Energy Information Administration, *International Petroleum Monthly* (October 2004), Table 2.1.

[58] Energy Information Administration, *International Energy Outlook 2004* (April 2004), page 122.

[59] Energy Information Administration, *International Petroleum Monthly* (October 2004), Table 2.1.

[60] Energy Information Administration, *Short-Term Energy Outlook* (January 2004), page 2.

[61] Energy Information Administration, *Monthly Energy Review* (October 2004), Table 3.1a.

[62] Energy Information Administration, *Monthly Energy Review* (October 2004), Tables 9.1 and 9.6.

[63] Energy Information Administration, *Petroleum Supply Annual 2003, Volume 1* (July 2004), Table 3.

[64] BP plc, *BP Statistical Review of World Energy* (June 2004), pages 22 and 25.

[65] For more information about Chesapeake Energy Corporation, see its Web site at http://www.chesapeake-energy.com/.

[66] Chesapeake Energy Corporation, *2003 Annual Report*, p. 2.

[67] For example, in June 2003, Chesapeake announced that it had acquired Oxley Petroleum for $220 million (Chesapeake Energy Corporation, "Chesapeake Energy Corporation Announces $220 Million of Mid-Continent Natural Gas Acquisitions, Increased 2003 Production Forecast, Initial 2004 Production Forecast and Additions to Hedging Positions" (June 24, 2003)). In March 2003, Chesapeake announced that it had acquired natural gas assets from El Paso Corporation for $500 million (Chesapeake Energy Corporation, "Chesapeake Energy Corporation Announces Completion of Acquisition of $500 Million of Mid-Continent Gas Reserves from El Paso Corporation" (March 13, 2003)). In February 2003, Chesapeake announced that it had acquired $300 million of natural gas assets from ONEOK (Chesapeake Energy Corporation, "Chesapeake Energy Corporation Announces Completion of Its Acquisition of $300 Million of Mid-Continent Gas Reserves From ONEOK, Inc." February 3, 2003). And in June 2002, Chesapeake announced that it had acquired Canaan Energy Corporation (Chesapeake Energy Corporation, "Chesapeake Energy Corporation Completes Acquisition of Canaan Energy Corporation and Declares Quarterly Cash Dividend" (June 28, 2002)) for $120 million.

[68] For more information about Equitable Resources, Inc. see its Web site at http://www.eqt.com/.

[69] Equitable Resources, Inc., 2003 U.S. Securities and Exchange Commission Form 10-K filing, pp. 4-11.

[70] Equitable Resources, Inc., 2003 U.S. Securities and Exchange Commission Form 10-K filing, p. 103.

[71] Aggregate time series data from Form EIA-28 for 1977 through 2003 and previous editions of this report can be obtained from the EIA (see http://www.eia.doe.gov/emeu/finance/page2.html).

[72] 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.

[73] 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).

[74] The sum of allocated operating revenue ($986 billion) exceeds corporate operating revenue ($889 billion) because allocated revenues include revenues from sales within the company and between different lines of business, in addition to the revenue from sales by the company to third parties (i.e., those outside the company). However, the revenue from inter-segment sales are eliminated in calculating corporate operating revenue, which only includes sales by the company to third parties.

[75] 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.

[76] Note that U.S. totals include royalty production, while the FRS companies' production levels do not. Thus, the FRS companies' share of crude oil and NGL production and natural gas production are somewhat understated by these calculations.

[77] Beginning with the 2003-reporting year, "Other energy" operations include coal operations. Prior to 2003, coal was a separate line of business. Financial information for coal operations has been merged with that of the alternate energy operations, although the operating information related to coal continues to be collected.

[78] In particular the FRS companies accounted for 29 percent of U.S. coal production in 1991, 15 percent in 1997, 7 percent in 1998, 3 percent in 2001, and 2 percent in 2003. These declines were due largely to the lack of profitability attributable to the coal operations of the FRS companies compared to other FRS operations, averaging a 4-percent annual return over the period 1977–2002.

3. Behind the Bottom Line

Upstream Income

In 2003, the oil and gas production operations of the Financial Reporting System (FRS) companies yielded worldwide net income (including unusual items) of $44 billion (**Table 11**). Net income from U.S. oil and gas production (including unusual items), at $23 billion, slightly exceeded that from foreign upstream operations, while net income from foreign production increased more than that from domestic production. Both domestic and foreign upstream operations achieved these results by taking advantage of higher oil and gas prices and by decreasing operating expenses. The effects of theses two factors, however, were muted by a change in reporting requirements for the FRS companies.[79]

Table 11. Income Components and Financial Ratios in Oil and Natural Gas Production for FRS Companies, 2002-2003

(Billion Dollars)

Components of Income and Financial Ratios	Worldwide		United States		Foreign	
	2002	2003	2002	2003	2002	2003
Oil and Natural Gas Revenues						
Oil	NA	NA	30.9	35.0	NA	NA
Natural Gas	NA	NA	40.2	39.4	NA	NA
Total Revenues	132.5	141.9	71.1	74.5	61.4	67.4
Expenses						
Depreciation, Depletion, and Amortization	32.8	29.0	18.3	16.0	14.6	13.0
Production Costs	25.1	27.9	12.5	13.6	12.6	14.4
Exploration Expenses	4.7	5.2	3.1	1.5	1.5	3.7
General and Administrative Expenses	2.6	2.0	1.7	1.2	0.9	0.9
Raw Material Purchases[a]	NA	NA	12.5	4.0	NA	NA
Other Costs (Revenues)[b]	26.4	8.3	3.8	6.6	10.1	1.6
Total Operating Expenses	91.1	76.1	51.4	42.5	39.7	33.6
Operating Income	41.5	65.9	19.7	32.0	21.7	33.9
Other Income (Expense)[c]	4.8	6.5	1.6	2.6	3.2	3.9
Income Tax Expense	18.3	28.4	6.3	12.0	12.0	16.4
Net Income	27.9	44.0	15.0	22.6	12.9	21.3
Less Unusual Items	-3.9	-0.7	-1.1	-0.5	-2.8	-0.3
Net Income, Excluding Unusual Items	31.8	44.7	16.1	23.1	15.7	21.6
Unit Values (Dollars Per Barrel of Production BOE)[d] Direct Lifting Costs (Excluding Taxes)	3.57	3.87	3.57	3.77	3.57	3.96
Production Taxes	0.69	1.00	0.75	1.13	0.63	0.88
Ratios (Percent)						
Return on Investment[e]	9.9	15.3	10.5	16.5	9.2	14.2
Effective Tax Rate[f]	39.9	39.4	29.7	34.7	48.6	43.8

[a]Production was prohibited from purchasing natural gas and NGLs for resale to third parties and unconsolidated affiliates beginning in 2003.

[b]For Foreign and Worldwide, Other Costs (Revenues) include Raw Material Purchases.

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

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

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

[f]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).

One of the major factors affecting the income statement of the FRS companies in 2003 was a substantial revision to the Form EIA-28, which collects data from the FRS companies.[80] For the years 2002 and before, the production (and refining and marketing) segment of the petroleum line of business could report the purchase of both dry natural gas (natural gas) and natural gas liquids (NGLs) for resale to third parties and unconsolidated affiliates. With the introduction of a downstream natural gas line of business in 2003, FRS rules stipulate that only the downstream natural gas line of business may report the sale of natural gas and NGLs to third parties and unconsolidated affiliates or purchase natural gas and NGLs from third parties and unconsolidated affiliates. The production (and refining/marketing) segment may only report purchased natural gas and NGLs from the downstream natural gas line of business, and only for use in their own production (and refining/marketing).[81]

The prohibition on reselling natural gas by the production segment was the primary reason for the 1.9-percent decline in revenues from the sale of natural gas by domestic production in 2003 (**Table 11**).[82] Had the volume of natural gas sales by domestic production remained constant that year, the revenue from the sale of natural gas by the FRS companies would have increased by 52 percent, the same as average domestic natural gas prices (**Table 12**). However, the volume of sales of natural gas by the domestic production segment declined 35 percent in 2003, including a 4.2-percent decline in natural gas production.

Table 12. Average Prices, Sales, and Production in Oil and Natural Gas for FRS Companies, 2002-2003

Prices, Sales, and Production	2002	2003	Percent Change 2002-2003
Worldwide Oil and Gas Production[a]			
Crude Oil and NGL (Million Barrels)	3,093	2,991	-3.3
Dry Natural Gas (Billion Cubic Feet)	15,747	15,391	-2.3
Total (Million BOE)[b]	5,896	5,731	-2.8
Domestic Oil and Gas Production[a]			
Crude Oil and NGL (Million Barrels)	1,346	1,278	-5.1
Dry Natural Gas (Billion Cubic Feet)	8,713	8,344	-4.2
Total (Million BOE)[b]	2,897	2,763	-4.6
Domestic Oil and Gas Sales Volumes			
Crude Oil and NGL (Million Barrels)[c]	1,433	1,336	-6.7
Dry Natural Gas (Billion Cubic Feet)	13,109	8,466	NM
Total (Million BOE)[b]	3,766	2,843	NM
Domestic Production Average Sales Prices			
Crude Oil and NGL (Dollars Per Barrel)	21.59	26.20	21.4
Dry Natural Gas (Dollars Per Thousand Cubic Feet)	3.07	4.66	51.9
Composite (Dollars Per BOE)[b]	18.89	26.19	38.6
Foreign Oil and Gas Production[a]			
Crude Oil and NGL (Million Barrels)	1,747	1,714	-1.9
Dry Natural Gas (Billion Cubic Feet)	7,034	7,047	0.2
Total (Million BOE)[b]	2,999	2,968	-1.0
Foreign Production Average Sales Prices			
Crude Oil and NGL (Dollars Per Barrel)	23.05	26.81	16.3
Dry Natural Gas (Dollars Per Thousand Cubic Feet)	2.54	3.36	32.3
Canada	2.68	4.73	76.5
Europe	2.93	3.62	23.5
Asia-Pacific	NA	2.97	-
Other Foreign	2.33	2.46	5.6
Composite (Dollars Per BOE)[b]	19.38	23.46	21.0

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

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

[c]Production was prohibited from selling natural gas and NGLs to third parties and unconsolidated affiliates beginning in 2003.

NA = Not available; NM = Not meaningful.

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.

The effect of the prohibition on reselling NGLs by the domestic production segment was less noticeable than it was for natural gas, in part because NGLs are combined with crude oil in production segment statistics for the FRS.[83] The volume of oil[84] sales by domestic production was down only 6.7 percent in 2003, including a 5.1-percent decline in production (**Table 12**). However, the increase in domestic oil prices in 2003 more than made up for the decline in domestic sales of oil, leading to a substantial increase in domestic oil revenues for the FRS companies in 2003 (**Table 11**).

The prohibition on reselling natural gas and NGLs by the production segment also affected domestic operating expenses in 2003. Raw material purchases by the domestic production segment fell 68 percent largely for this reason

(**Table 11**).[85] Beginning in 2003, raw material purchases by the production segment include only natural gas and NGLs used in its own production process. Also, general and administrative expenses declined slightly, in part because of decreased oil and gas production.

Diminished oil and gas production had a dampening effect on oil and gas revenue increases and, in addition, contributed to the decline in depreciation, depletion, and amortization (DD&A) charges for the production segment in 2003 (**Table 11**). In addition to the 5.1-percent decline in domestic oil production and 4.2-percent decline in domestic gas production, foreign oil production fell by 1.9 percent (**Table 12**).[86] Accounting rules usually depreciate the cost of a capital asset based on some estimate of its useful service life. For oil and gas production, the capital assets are largely either proven oil and gas reserves and wells or related equipment and facilities that are associated with those reserves. The useful service life for oil and gas assets depends on how much reserves are left and how fast they are being depleted. Consequently, the accounting rules require that DD&A be calculated based on the shares of oil and gas reserves that were produced.[87] For example, if 10 percent of reserves were produced, then 10 percent of the costs for reserves and wells would be included in DD&A. Thus a decline in production usually results in a decline in DD&A.[88]

Lifting Costs

Lifting costs (also called production costs) are the out-of-pocket costs per barrel of oil and natural gas produced (measured on a barrel-of-oil equivalent basis) to operate and maintain wells and related equipment and facilities after hydrocarbons have been found, acquired, and developed for production. Total lifting costs are direct lifting costs plus production taxes.

Both domestic and foreign total production expenses rose in 2003, despite the decline in the volume of oil and gas produced (**Table 11**). This combination results in noticeably increased lifting costs. In 2003, total lifting costs had their largest increase since 1990, rising by 14.4 percent worldwide (**Table 13**). Total lifting costs increased in all of the FRS regions except the Other Western Hemisphere,[89] with five of the nine regions undergoing double-digit increases. The four largest producing regions for the FRS companies, on a barrel of oil equivalent (boe) basis, are among those five.[90] Nonetheless, U.S. Offshore (primarily the Gulf of Mexico) remained the region with the lowest total lifting costs.

Table 13. Lifting Costs by Region for FRS Companies, 2002-2003
(Dollars Per Barrel of Oil Equivalent)

Region	Direct Lifting Costs			Production Taxes			Total		
	2002	2003	Percent Change	2002	2003	Percent Change	2002	2003	Percent Change
United States									
Onshore	--	--	--	--	--	--	5.02	5.66	12.7
Offshore	--	--	--	--	--	--	2.96	3.34	12.9
Total United States	3.57	3.77	5.7	0.75	1.13	49.9	4.33	4.90	13.4
Foreign									
Canada	4.07	5.34	31.2	0.19	0.23	17.1	4.26	5.56	30.6
OECD Europe	3.54	4.39	23.8	0.52	0.84	60.6	4.07	5.23	28.5
Former Soviet Union and Eastern Europe	3.21	4.43	38.0	0.00	0.75	-	3.21	5.18	61.4
Africa	4.23	3.89	-8.1	0.92	1.32	42.8	5.15	5.20	1.0
Middle East	3.78	3.99	5.5	0.35	0.15	-55.4	4.12	4.14	0.4
Other Eastern Hemisphere	3.10	2.97	-4.2	0.90	1.09	21.6	4.00	4.06	1.6
Other Western Hemisphere	2.57	2.14	-16.7	1.12	1.45	29.6	3.69	3.59	-2.6
Total Foreign	3.57	3.96	11.1	0.63	0.88	39.4	4.20	4.84	15.4
Worldwide Total	3.57	3.87	8.5	0.69	1.00	44.7	4.26	4.87	14.4

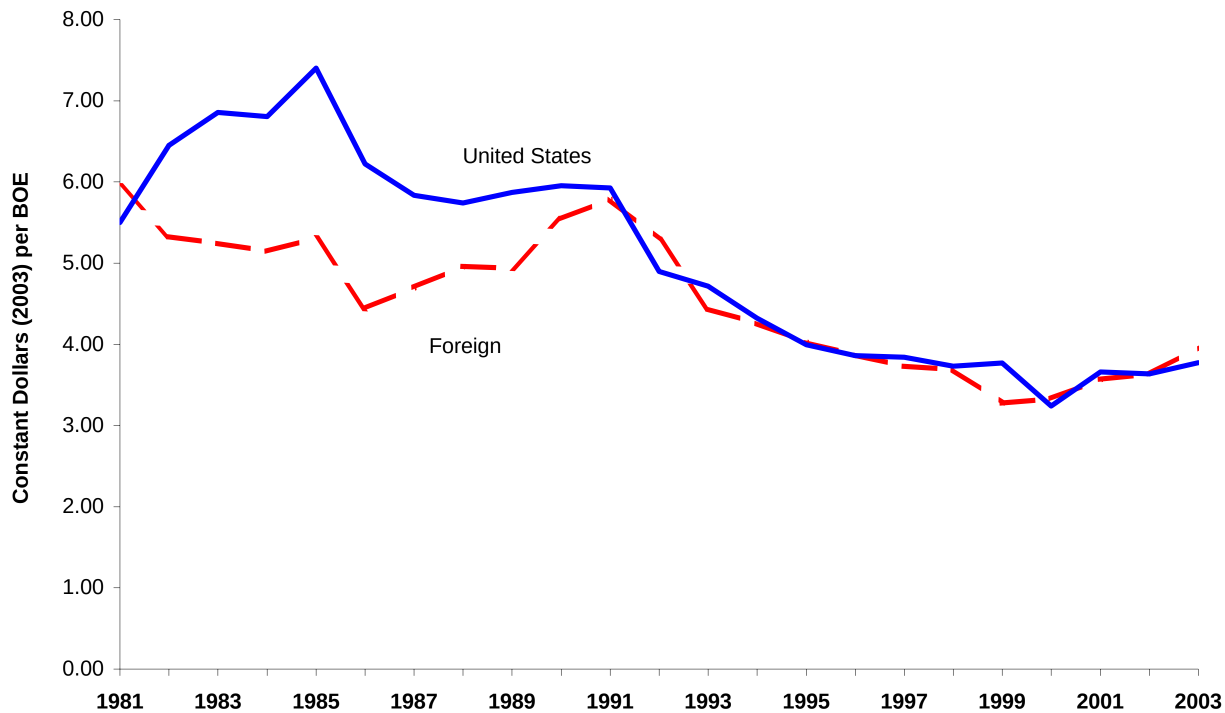
-- = Data not available.
Note: Sum of components may not add to total due to independent rounding.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

The increase in total lifting costs in 2003 was driven by production tax increases (**Table 13**). By increasing more than their 2002 decline, worldwide production taxes increased 31 cents per boe from 2002 to 2003.[91] Production tax amounts are often based on the price of the hydrocarbon taxed, and prices for both oil and gas increased substantially in 2003. However, U.S. Offshore production taxes are minimal, because most production taxes in the United States are levied by State and local governments, while most offshore production occurs in Federal waters.[92] Thus most of the rise in offshore total lifting costs probably can be attributed to increased direct lifting costs instead of increased production taxes.

While direct lifting costs (production costs without production taxes) also increased, their rise was a more moderate 8.5 percent. One cause of higher direct lifting costs can be a decline in oil and gas production (which occurred in 2003), because fixed costs are spread over less production. Another possible cause of higher lifting costs is the launching of new projects, such as bringing new production online or initiating enhanced recovery programs, which often have higher costs initially.

In the longer term, domestic and foreign direct lifting costs have been similar to each other since 1991 (**Figure 24**). Direct lifting costs began increasing in 1999–2000, after declining during the 1990s. This increase is not surprising, given the high costs of oil and gas in recent years. Producers are willing to spend more to produce oil and gas when their prices increase.

Figure 24. Direct Oil and Gas Lifting Costs for FRS Companies, 1981-2003



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).

Finding Costs

Finding costs are the costs of adding proven reserves of oil and gas via exploration and development activities and the purchase of properties that might contain reserves.[93] They are measured for oil and gas combined in units of dollars per 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 (except the expenditures on proved acreage) to proven reserve additions (excluding net purchases of proven reserves) during a specified period of time.[94] Finding costs are generally measured in this report as a weighted average over a period of 3 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).

Average worldwide finding costs for the FRS companies rose 10.6 percent during the 2001 to 2003 period (**Table 14**). Canada again ranked on top of the list of FRS regions, even though its finding costs fell for the period.

The U.S. Offshore rose to second place with a 35-percent gain. Along with the U.S. Onshore and OECD Europe, these four regions have substantially higher finding costs for the FRS companies than the other regions.

In general, finding costs have been rising since the 1993-to-1997 period (in 2003 dollars) (**Figure 16**). This is especially true in the United States, where both onshore and offshore finding costs have risen for the last 2 years. Offshore finding costs, after falling sharply in the 1999-to-2001 period, have risen to levels that, before 1997-to-1999, were not seen since the 1986-to-1988 period. To find comparable onshore finding costs, one has to go back to 1984-to-1986. The rise in foreign finding costs has been much more moderate, although Canada and OECD Europe have finding costs comparable to or above U.S. levels. The other foreign regions, Other Eastern Hemisphere, Africa, Other Western Hemisphere, Middle East, and Former Soviet Union and Eastern Europe, have increasingly restrained the growth of foreign and worldwide finding costs as their share of worldwide reserve additions by the FRS companies (on a boe basis) has risen from 27 percent in the 1993 to 1995 period to 47 percent in 2001 to 2003. To keep costs low, one would expect the FRS companies to continue to focus on these lower-cost regions. Of course, the high oil and gas prices seen recently encourage production, even in high cost areas.[95]

Table 14. Finding Costs by Region for FRS Companies, 2000-2002 and 2001-2003
(Dollars per Barrel of Oil Equivalent)

Region	2000-2002	2001-2003	Percent Change
United States			
Onshore	7.62	9.16	20.1
Offshore	7.59	10.24	35.0
Total United States	7.61	9.56	25.6
Foreign			
Canada	14.83	12.26	-17.3
OECD Europe	9.32	9.86	5.7
Former Soviet Union and Eastern Europe	3.10	2.63	-15.2
Africa	3.48	5.79	66.1
Middle East	5.94	6.22	4.7
Other Eastern Hemisphere	4.61	4.05	-12.1
Other Western Hemisphere	5.18	3.98	-23.1
Total Foreign	5.83	5.97	2.4
Worldwide	6.65	7.35	10.6

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).

U.S. Refining and Marketing

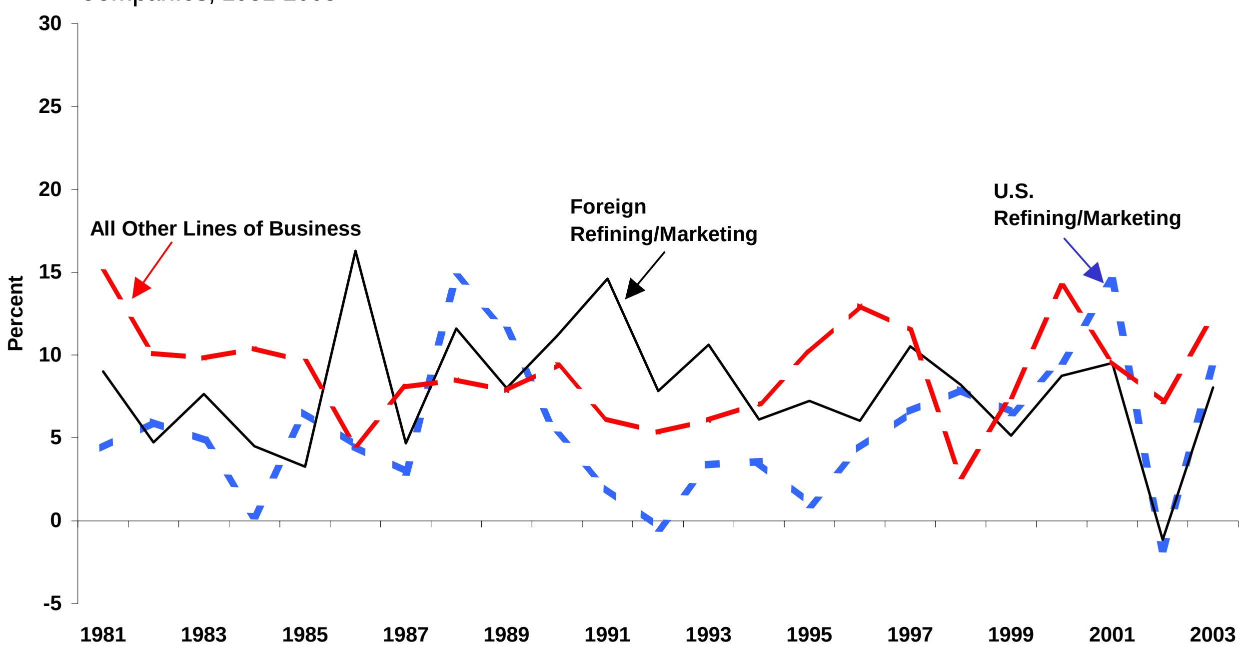
The profitability of the U.S. refining/marketing operations of the FRS companies increased to 9 percent in 2003, more than 11 percentage points higher than the loss of 2 percent in 2002.[96] The last 3 years have been extremely volatile for the U.S. refining/marketing industry. In 2001, U.S. refining/marketing had its second best year, in terms of profitability, in the history of the FRS (dating back to 1977), which was followed by the worst year ever in 2002 (**Figure 25**). The industry bounced back in 2003 to have one of its better years, the seventh most profitable year out of the 27 years of FRS data. The ongoing cost-cutting efforts that have characterized the domestic refining/marketing operations of the FRS companies since the 1990s still appear important in view of the variability of profitability in this business segment.

The change in the profitability of U.S. refining/marketing operations can be explored by examining the net refined product margin (net margin), which is highly correlated with profitability.[97] 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.[98] The $2.05-per-barrel net margin of 2003 was not only the third highest in the past 4 years (in terms of 2003 dollars), but also was higher than any net margin between 1989 and 1999, inclusive, and was the fourth-highest in the 28-year history of the FRS (**Figure 15**).

The 16-percent increase in domestic petroleum product sales revenues (**Table 15**) was due entirely to higher prices received, which increased 21 percent relative to 2002 (**Table 16**). Petroleum product sales declined 4 percent between 2002 and 2003, which prevented product sales revenue from increasing even more than it did. Revenue from other sources fell substantially, but operating costs increased slightly more than half as much as did sales revenues (on a percentage basis) (**Table 15**). This combination of increases in revenues and costs generated operating income of $10.2 billion and net income of $7.4 billion, which was almost $9 billion greater than the loss of a year ago.

Cooler summer weather (7 percent fewer cooling degree-days) in 2003 compared to 2002[99] put downward pressure on petroleum prices. However, economic growth of 3 percent and cooler winter weather (4 percent more heating degree-days) in 2003 relative to 2002[100] put upward pressure on petroleum prices. Furthermore, unusually low product stock levels (especially during the first part of 2003) (**Figure 26**) brought on by various events[101] put even more upward pressure on product prices. In particular, industry-wide petroleum product stocks were 13 percent lower in the first quarter of 2003 than in the first quarter of 2002, but the gap between 2003 and 2002 stock levels narrowed throughout the year, exerting substantial (but declining) upward pressure on petroleum product prices compared to a year earlier.[102] Industrywide stocks of motor gasoline also were lower throughout 2003 compared to 2002 (**Figure 27**), varying between 8 and 10 percent lower.[103]

Figure 25. Return on Investment in U.S. and Foreign Refining/Marketing, and All Other Lines of Business for FRS Companies, 1981-2003



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

The upward pressure on revenues created by higher product prices was reduced by lower product sales in 2003 relative to 2002. Sales fell a relatively slight 4-percent in 2003 relative to 2002 (**Table 16**). The product sales are chiefly comprised of motor gasoline and distillate, which declined 5-percent and 7-percent, respectively, and was partially offset by other products, which increased by 9 percent (**Table 17**). Thus, the decline in sales of the more highly valued motor gasoline and distillate tended to offset the effects of the product price increases.

Meanwhile, refinery capacity reported by the FRS companies was unchanged (**Table 18**) as small expansions in the capacity of many refineries and Valero's July 2003 acquisition of Orion Refining's St. Charles, Louisiana, refinery[104] offset ChevronTexaco's sale of its El Paso, Texas, refinery in August 2003 to Western Refining.[105] Two of intra-FRS transactions shifted assets around as Premcor acquired Williams' Memphis, Tennessee, refinery in March 2003[106] and Valero purchased El Paso's Corpus Christi, Texas, refinery in February 2003, which it had been leasing and operating since June 1, 2001.[107] Refinery upgrades to meet Phase II-compliant petroleum products and non-methyl tertiary butyl ether (MTBE) motor gasoline[108] increased additions to U.S. refining net investment in place. However, the combination of transactions and environmental investment spending was insufficient to prevent a 55-pecent decline in U.S. refining additions to net investment in place because of the absence of the large transactions that occurred during 2002, the merger of Conoco and Phillips and Shell Oil's acquisition of Equilon and Pennzoil Quaker State.

Table 15. U.S. and Foreign Refining/Marketing[a] Financial Items for FRS Companies, 2002-2003
(Million Dollars)

	2002	2003	Percent Change 2002-2003
Domestic Refining/Marketing Operations			
Refined Product Sales Revenue	272,190	316,815	16.4
Other Revenue[b]	17,135	11,975	-30.1
Operating Expense[b, c]	290,282	318,584	9.7
Operating Income[c]	-957	10,206	--
Net Income, excluding unusual Items	675	7,823	1059.0
Unusual Items	-2,025	-398	--
Net Income	-1,350	7,425	--
Foreign Refining/Marketing Operations [a]			
Refined Product Sales Revenue	142,227	174,778	22.9
Other Revenue[b]	8,446	8,902	5.4
Operating Expense[b, c]	150,031	179,737	19.8
Operating Income[c]	642	3,943	514.2
Net Income, excluding unusual Items	-326	3,039	--
Unusual Items	-74	-123	--
Net Income	-400	2,916	--

[a]In order to prevent disclosure of company-level data the International Marine business segment has been combined with Foreign Refining/Marketing for this presentation. Relative to Foreign Refining/Marketing, International Marine is about one-tenth the size and has little material effect on the overall results of Foreign Refining/Marketing.

[b]Raw materials revenues are netted against total operating expense.

[c]Excludes unusual items.

-- = Not meaningful.

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

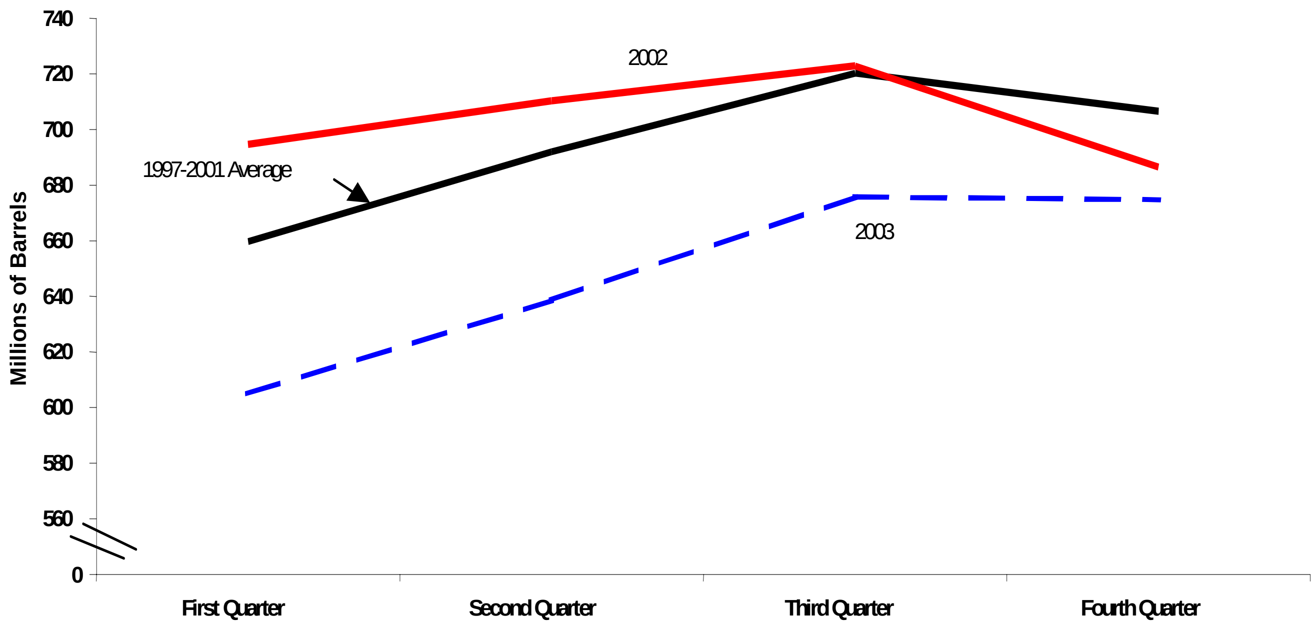
Table 16. Sales, Prices, Costs, and Margins in U.S. Refining/Marketing for FRS Companies, 2002-2003

	2002	2003	Percent Change 2002-2003
Refined Product Sales (Million Barrels per Day)	23.0	22.2	-3.5
	(Nominal Dollars per Barrel)		
Gasoline Average Price	34.80	42.06	20.9
Distillate Average Price	30.48	37.69	23.7
Other Products Average Price	27.81	32.40	16.5
All Refined Products Average Price	32.42	39.09	20.6
Less: Raw Materials Costs and Product Purchases	26.06	31.26	20.0
Equals: Gross Refining Margin	6.36	7.84	23.1
Less: Direct Operating Costs	6.17	5.79	-6.3
Equals: Net Refining Margin[a]	0.19	2.05	979.3
Reseller/wholesaler spread (dealer price - wholesale price)	2.26	5.03	122.9
Retailer spread (company-operated price - dealer price)	4.41	5.77	30.8

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

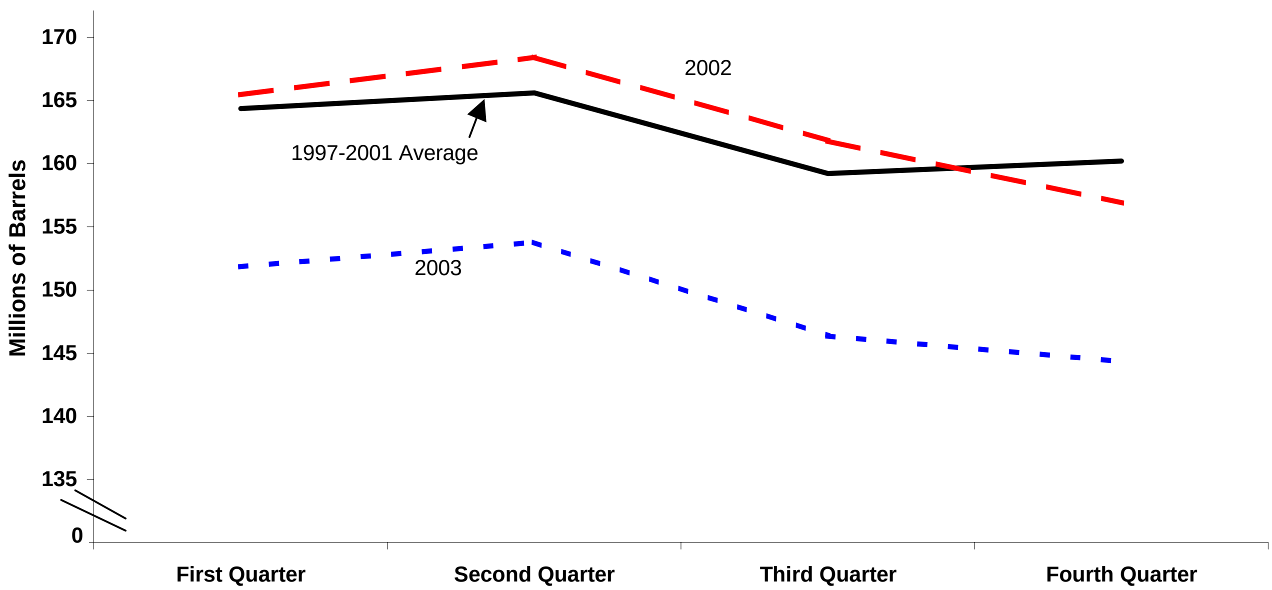
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Figure 26. Quarterly Average U.S. Commercial Petroleum Product Stocks, 1997-2001 Average, 2002, and 2003



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

Figure 27. Quarterly Average U.S. Motor Gasoline Stocks, 1997-2001 Average, 2002, and 2003



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

Industrywide gross refining margins in 2003 were consistently higher than in 2002 for almost the entire year[109] (**Figure 28**). Lower motor gasoline stocks than a year earlier (**Figure 27**) and lower petroleum product stocks in general (**Figure 26**) put upward pressure on the industry-wide gross margins. Meanwhile, U.S. crude oil stock levels were at historically low levels during all of 2003, particularly during the first half of the year, relative to 2002[110] (**Figure 29**), contributing to the 16-percent increase in the price of crude oil[111] and putting downward pressure on the gross margin. The overall result of these (and other) effects was that the industry-wide gross refining margin of 2003 averaged $10.70 per barrel, a 33-percent increase relative to the 2002 average.

Table 17. U.S. Refined Product Margins and Costs per Barrel Sold and Product Sales Volume for FRS Companies, 2002-2003

	2002	2003	Percent Change 2002 - 2003
	(Dollars per Barrel)		
Gross Margin	6.36	7.84	23.1
- Marketing Costs	1.65	1.35	-18.3
- Energy Costs	1.09	1.32	20.8
- Other Operating Costs	3.43	3.12	-9.1
= Net Margin	0.19	2.05	979.3
Product Sales Volume	(Million Barrels)		
Motor Gasoline	12,597	11,952	-5.1
Distillate	6,753	6,265	-7.2
Other Products	3,650	3,985	9.2
Total	22,999	22,202	-3.5

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

Table 18. U.S. and Foreign Refining Investment and Operating Items for FRS Companies, 2002-2003

	2002	2003	Percent Change 2002 - 2003
	(Billion Dollars)		
U.S. Refining Additions to Investment in Place	16.0	7.1	-55.3
U.S. Marketing Additions to Investment in Place	3.8	2.9	-24.3
Foreign Refining/Marketing Additions to Investment in Place	5.0	2.7	-46.0
	(Thousand Barrels per Day)		
U.S. Refining Capacity	14,630	14,619	-0.1
U.S. Refinery Output	14,676	14,587	-0.6
Foreign Refining Capacity	5,642	5,374	-4.8
Foreign Refinery Output	4,873	4,622	-5.2
	(Percent)		
U.S. Refinery Utilization Rate[1]	90.8	92.0	(2)
Foreign Refinery Utilization Rate[1]	85.2	84.8	(2)

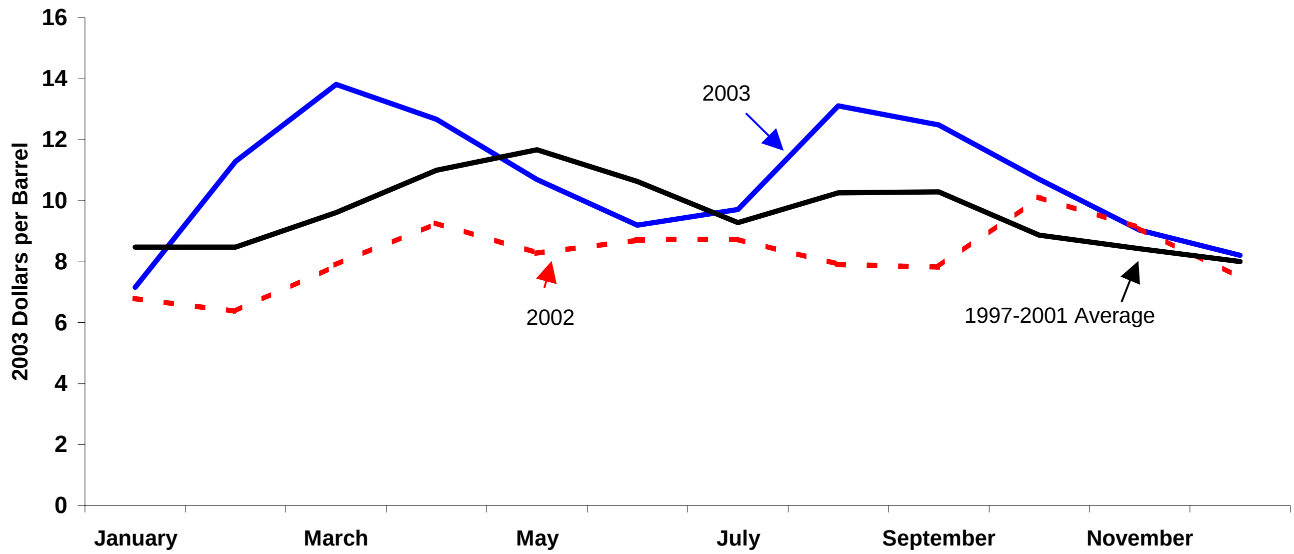
[1]Refinery utilization rate is calculated by dividing runs to stills at own refineries by the average of the year beginning and year ending crude oil distillation capacity.
[2]Not meaningful.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Meanwhile, the gross refining margin received by the FRS companies increased 23 percent compared to 2002 (**Table 16**). The average price received for petroleum products increased $6.67 per barrel, while raw materials and purchased product costs rose $5.20 per barrel, which resulted in a $1.47-per-barrel increase in the gross refining margin.

Successful efforts to increase the complexity of the FRS refineries during the last several years[112] allow the FRS companies to refine a wide range of crude oils, which has enabled them to take advantage of price differences between the relatively lower-cost heavy crude oils and the relatively higher-cost light crude oils and transform them into relatively higher-priced, light products. The price of lighter products (represented by the price of motor gasoline) increased $1.78 per barrel relative to the price of heavier products (represented by the price of residual fuel oil) (**Figure 30**), which tended to put upward pressure on the prices of refined products of the FRS companies. Similarly, during 2003 the price of light crude oil relative to heavy crude increased (**Figure 31**), raising the discount paid for heavy crude oil from $5.79 per barrel in 2002 to $6.93 per barrel in 2003, which put downward pressure on the price of crude oil paid by the FRS companies and contributed to the decline in the raw materials and purchased product costs of the FRS companies. Thus, the revenue side of the net margin was much higher in 2003 than in 2002.

Overall operating costs fell 6 percent between 2002 and 2003 (**Table 29**). However, the changes in the different operating costs varied, as some costs fell while others increased (**Table 17**). Continued efforts by the FRS companies to reduce their energy costs were less successful in 2003 as energy costs increased $0.23 per barrel, a 21-percent increase relative to their 2002 level. Much of the explanation for higher energy costs is the 69-percent increase in natural gas prices in 2003 relative to 2002.[113] Cogeneration projects, one of the major approaches that these companies have taken to reducing their energy costs during the last few years,[114] continue to be undertaken at some refineries[115] and are one of the reasons that energy costs increased by so little relative to the price increase of natural gas.

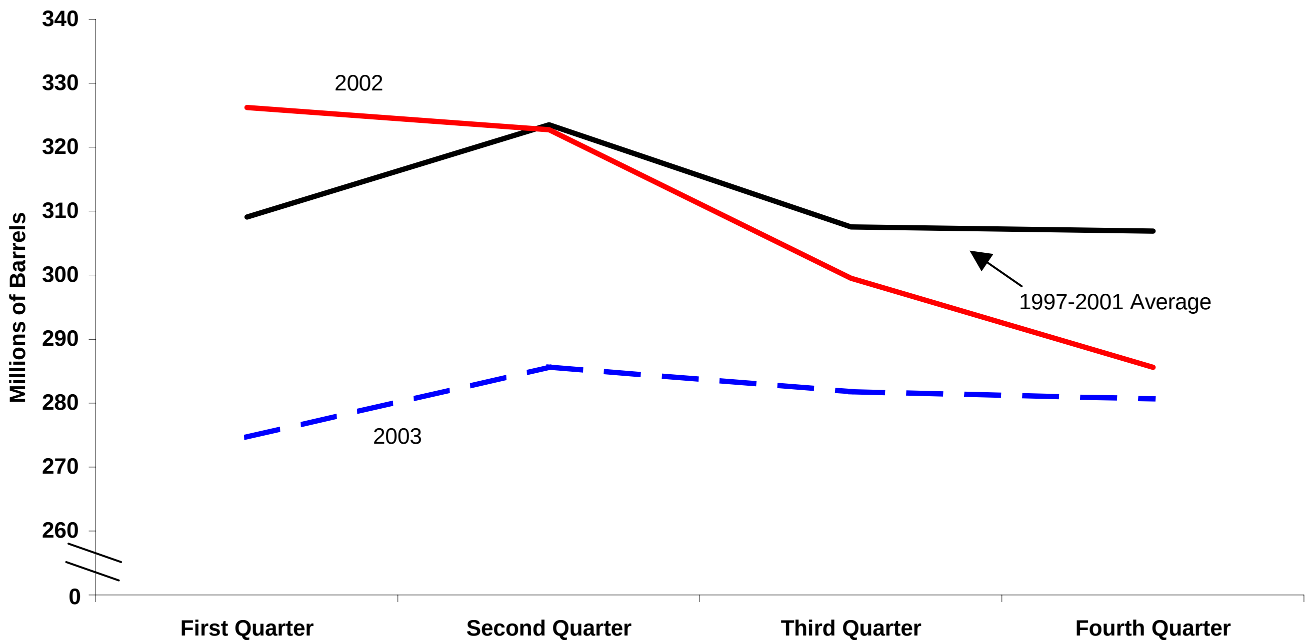
Figure 28. Monthly Gross Refined Product Margin for United States, 1997-2001 Average, 2002, and 2003



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.

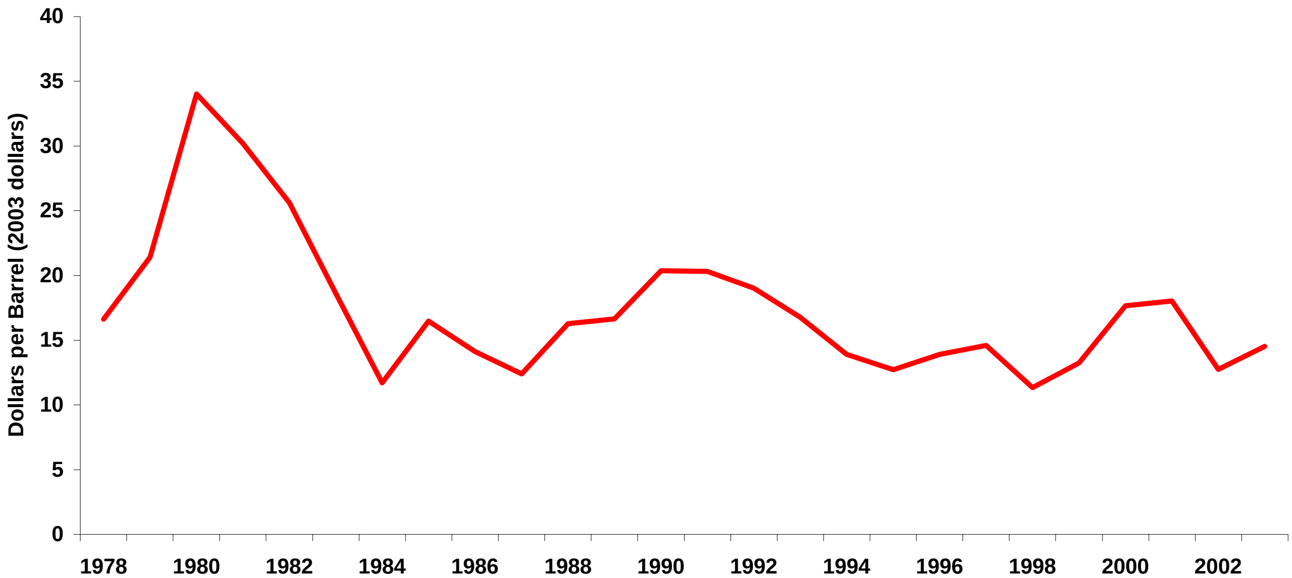
Sources: Energy Information Administration, *Petroleum Marketing Monthly*, DOE/EIA-0380 (April 1997 - March 2004), Table 1, Table 4, and Table 5; and Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0380 (February 1997 - January 2004), Table 3-2b.

Figure 29. Quarterly Average U.S. Crude Oil Stocks, 1997-2001 Average, 2002, and 2003



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

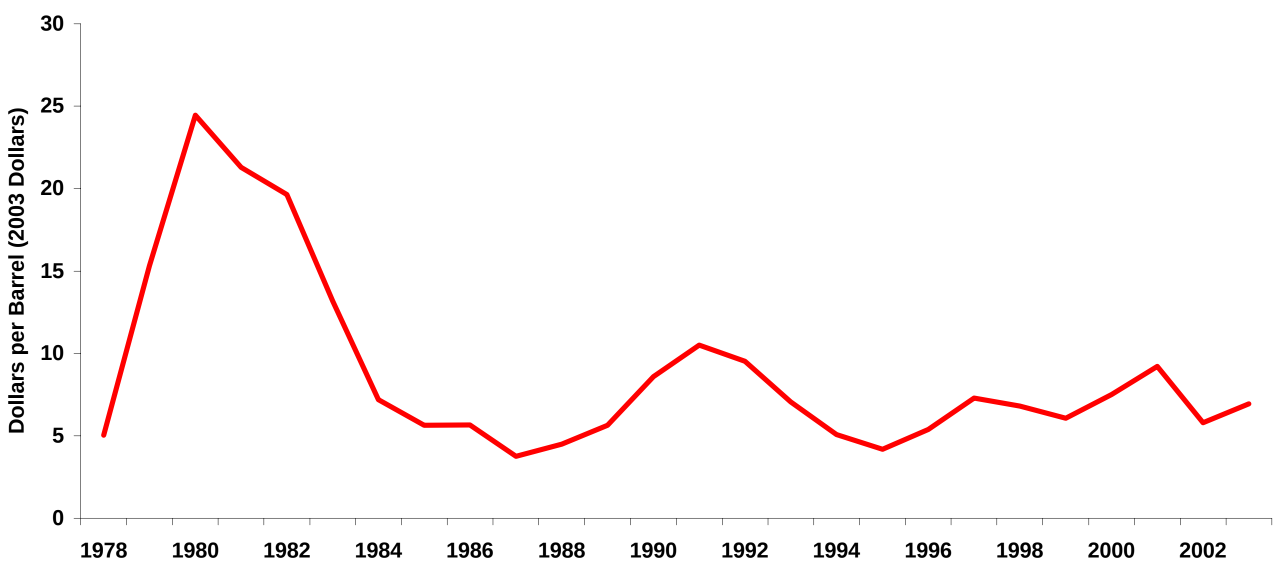
Figure 30. Real Resale Price Difference Between Motor Gasoline and Residual Fuel Oil, 1978-2003



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 gasoline relative to residual fuel oil.

Source: Energy Information Administration, *Petroleum Marketing Monthly*, DOE/EIA-0380, Table 4.

Figure 31. Real Price Difference Between Light Crude Oil and Heavy Crude Oil, 1978-2003



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.

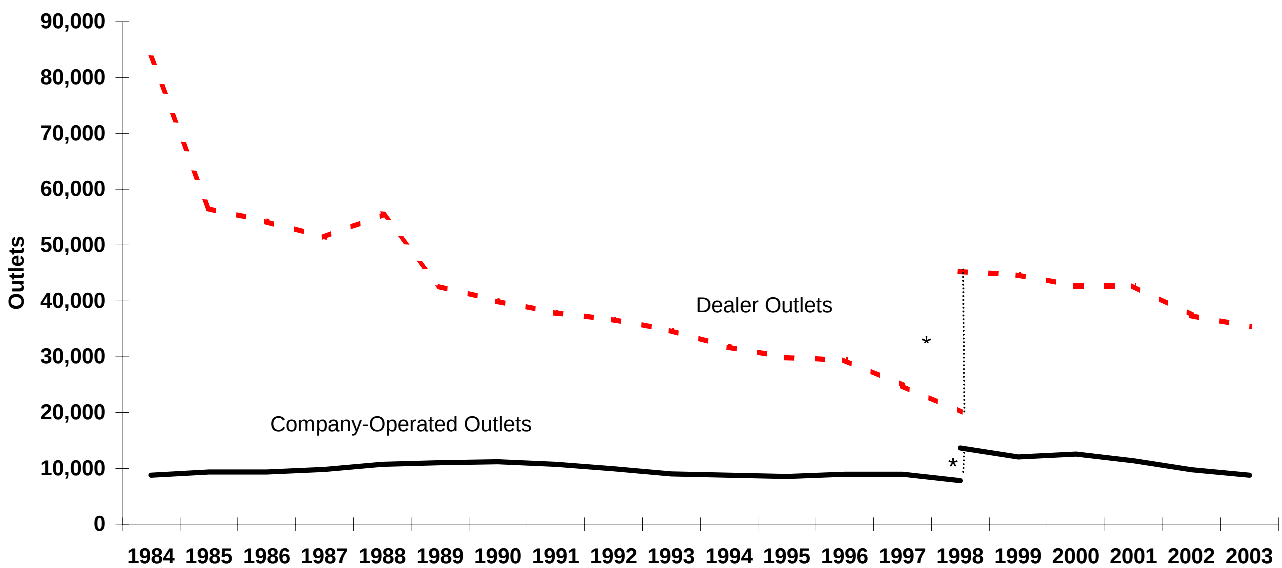
Source: Energy Information Administration, *Petroleum Marketing Monthly*, DOE/EIA-0380, Tables 27 and 28.

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[116] bore fruit in 2003 as marketing costs fell $0.30 per barrel, an 18-percent decline. The decline in marketing costs occurred despite extensive costs of re-branding the marketing outlets of several companies.[117] However, branded marketing outlets directly supplied by the FRS companies continued to decline in 2003 (**Figure 32**), falling 6 percent to 44,207 in 2003 (**Table 19**). Company-operated outlets were reduced by 10 percent while dealer outlets were reduced by only 5 percent. Although efforts to eliminate marginal outlets tends to increase average productivity of the remaining outlets, which is measured by average outlet monthly motor gasoline sales volume, some companies indicated that some extremely productive dealers elected to change brands, which was largely responsible for the 28-percent decline in the productivity of dealer outlets between 2002 and 2003. The slight increase in productivity of company-operated outlets between 2002 and 2003 suggest that much of the available economies may have been squeezed from these operations as the decline in motor gasoline sales volume through company-operated outlets almost matched the decline in the number of company-operated outlets.

Other operating costs related to refining fell slightly between 2002 and 2003, from $3.43 per barrel to $3.12 per barrel. The higher cost structure of the FRS companies that have been involved in recent mergers may have declined somewhat as the mergers of operations and corporate cultures are nearing completion. Further, environmental spending to comply with the Clean Air Act Amendments of 1990 continues, but at a lower rate as another compliance deadline nears.[118]

The year 2003 was one of the more profitable in the history of the FRS and followed a series of highly profitable years, which were broken in 2002 by the most unprofitable year in the history of the FRS. The primary reason for the increased profitability of the FRS U.S. refining/marketing operations in 2003 relative to 2002 was the $1.47 per barrel increase in the gross refining margin, which itself was caused when product prices increased faster than raw materials prices.[119] Although operating costs declined between 2002 and 2003, they only fell $0.39 per barrel. Higher energy costs in 2003 relative to 2002 demonstrate that, although FRS cost-cutting efforts during the last several years have enabled the FRS operations to better withstand the vicissitudes of their industry, they have not eliminated the variability of their returns. Continued efforts to rationalize motor gasoline retailing operations (and the resulting decline in marketing costs) suggest that the FRS companies continue to attempt to place a floor on their profitability.

Figure 32. Company-Operated and Dealer Outlets for FRS Companies, 1984-2003



*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, resulted in the vertical displacement of the series in 1998.

Note: Only outlets directly supplied by the FRS companies are included here.

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

Table 19. Motor Gasoline Distribution and Number of Direct-Supplied Branded Outlets for FRS Companies, 2002-2003

	2002	2003	Percent Change 2002-2003
	(Million Barrels)		
Third-Party Volume			
Wholesale	2,045.1	2,516.7	23.1
Retail			
Dealer	1,167.3	797.1	-31.7
Company-Operated	464.3	431.7	-7.0
Total Retail	1,631.5	1,228.8	-24.7
Direct	819.8	540.8	-34.0
Total Third-Party Volume	4,496.5	4,286.4	-4.7
Intersegment Volume	101.4	76.3	-24.8
	(Number of Direct-Supplied Branded Outlets)		
Dealer Outlets	37,403	35,403	-5.3
Company-Operated Outlets	9,745	8,804	-9.7
Total Retail Outlets	47,148	44,207	-6.2
Average Monthly Outlet Volume	(Thousand Gallons per Month)		
Dealers	109.2	78.8	-27.9
Company-Operated	166.7	171.6	2.9
All Direct-Supplied Outlets	121.1	97.3	-19.7

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

Foreign Refining and Marketing[120]

One year after recording the all-time low in profitability in the 27-year history of the FRS, foreign refining/marketing return on net investment in place returned to an "average" level of approximately 8 percent. That is, this return exceeds the result of 10 of the last 22 years (**Figure 25**). An increase in refined product and other revenue relative to 2002, partially offset by an increase in operating expense, resulted in more than a 500-percent increase in operating income and a $3.3-billion increase in net income (from a net loss of $400 million in 2002 to net income of $2.9 billion (**Table 15**)).

The FRS companies derive their foreign refining/marketing earnings 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[121]). Essentially, the unconsolidated affiliate is more of a property or holding of the parent corporation than a company that the parent actually operates. The effect on financial operations of an unconsolidated affiliate can be seen only 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.

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, 68 percent of FRS unconsolidated foreign refinery capacity was in the Asia-Pacific Region in 2003 (**Table 20**). Almost half of FRS consolidated foreign refinery capacity is located in Europe, 48 percent in 2003.

Since 1997, the contribution to net income from the FRS companies' unconsolidated foreign refining/ marketing operations have been small (**Figure 20**), but it showed signs of recovering to pre-1997 levels in 2003, reaching $490 million, the highest level since 1997, and ending a 2-year string of losses. The companies cited a variety of reasons for the increased profitability of FRS foreign refining/ marketing operations in public statements. These include: increased worldwide demand and product sales,[122] improved refinery output slate,[123] reduced energy[124] and other operating costs,[125] higher utilization rates,[126] and foreign exchange gains.[127]

Table 20. Regional Distribution of Foreign Refinery Capacity for FRS Companies, 2002-2003
(Percent)

	Consolidated Operations		Unconsolidated Affiliates	
	2002	2003	2002	2003
Europe	48.2	48.1	17.9	17.5
Asia	27.9	26.1	68.7	68.2
Latin America	8.8	9.1	0.7	0.7
Canada	12.6	14.1	0.0	0.0
Other	2.5	2.6	12.7	13.6
Total	100.0	100.0	100.0	100.0

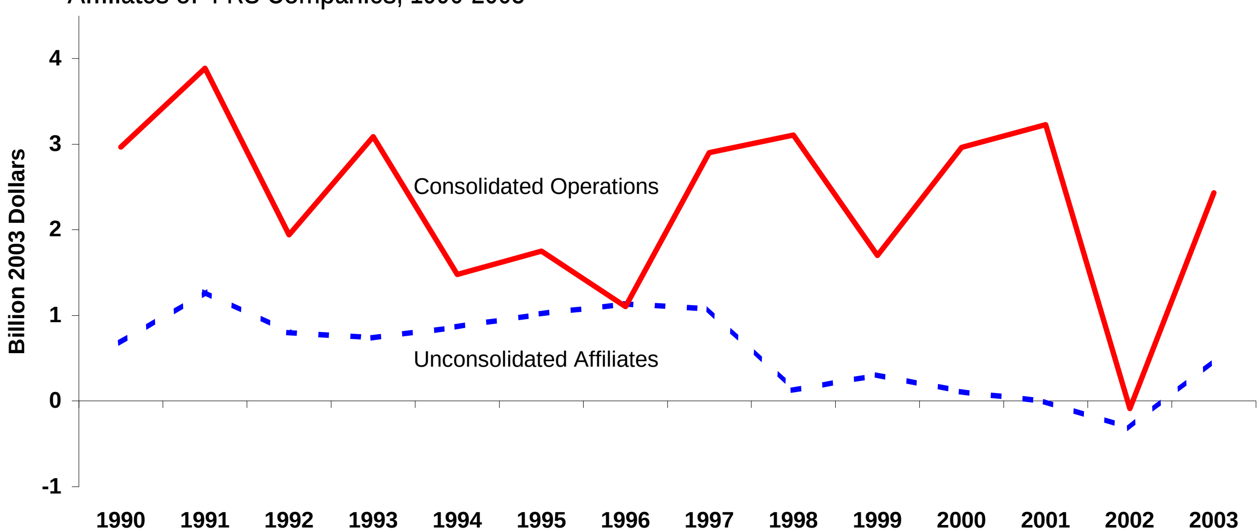
Note: The region denoted as "Other" includes Africa and the Middle East.

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

During 2003, the FRS companies' unconsolidated affiliates generated $490 million of net income, which was an increase of $802 million relative to 2002's loss. The Asia-Pacific refining margins of 2003 were much higher than those of 2002 during almost the entire year, faltering only in November and December (**Figure 34**). Despite the late slump, the gross refining margin in the Asia-Pacific region (represented by the Singapore/Dubai gross refining margin) in 2003 averaged $0.80 per barrel more than in 2002.

Consumption of petroleum products in the Asia-Pacific region (combining Asian Developing Countries with Australia, Japan, and New Zealand) increased between 2002 and 2003 (**Figure 35**), increasing by 4 percent largely because of an increase in the petroleum consumption by the Asian Developing Countries. Increased consumption fueled higher returns from the FRS unconsolidated foreign refining/marketing operations. Company public disclosures noted several reasons for the higher earnings generated by the Asia-Pacific operations of the FRS companies, including increased refinery runs in response to "improved industry economics,"[128] increased fuel oil and distillate demand in Japan,[129] and increased motor gasoline demand caused by increased car ownership in China.[130]

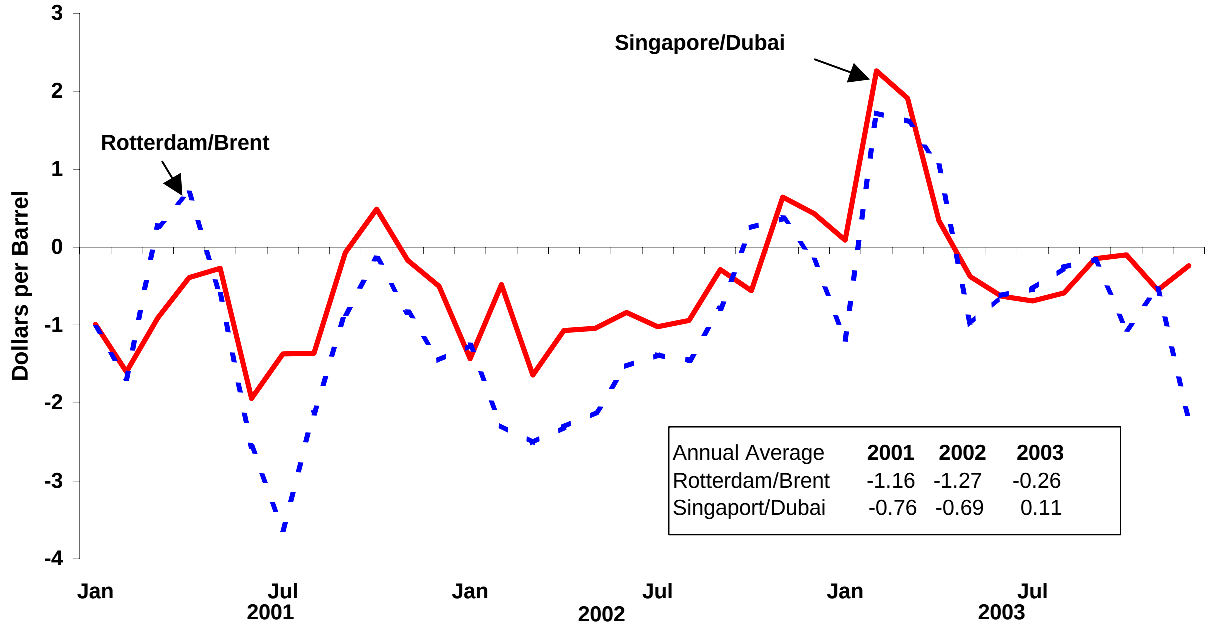
Figure 33. Foreign Refining/Marketing Net Income[a] from Consolidated Operations and Unconsolidated Affiliates of FRS Companies, 1990-2003



[a]The International Marine business segment has been combined with Foreign Refining/Marketing for this presentation in order to prevent disclosure of company-level data. Relative to Foreign Refining/Marketing, International Marine is about one-tenth the size and has little material effect on the overall results of Foreign Refining/Marketing.

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

Figure 34. Foreign Gross Refining Margins, 2001-2003

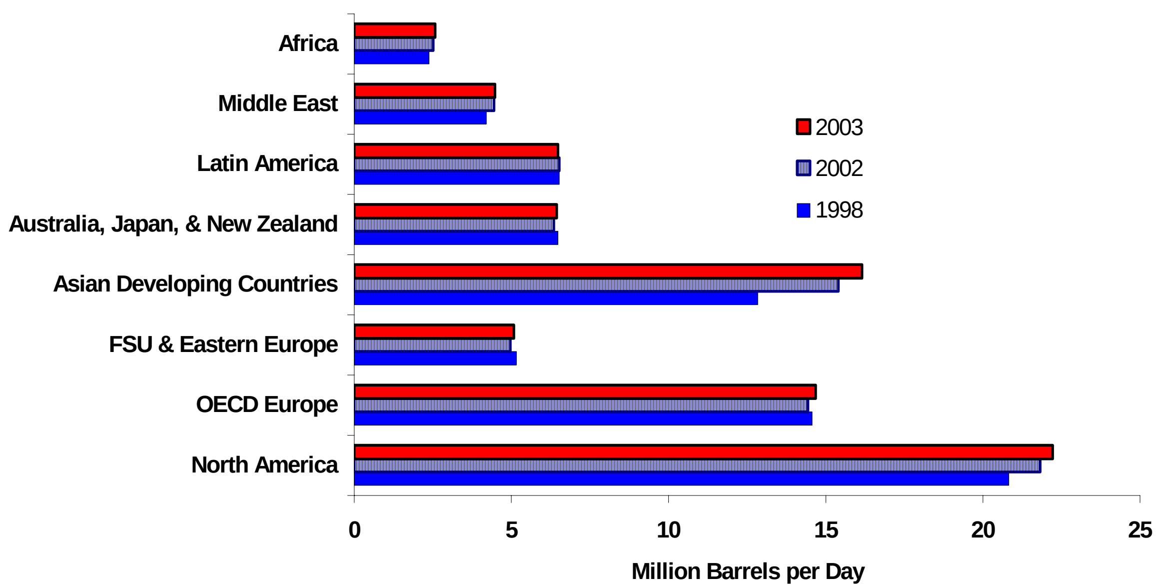


Sources: Energy Intelligence Group, Oil Market Intelligence 2001: January 2002 and July 2001, p. 12; 2002: January 2003 and July 2002, p. 12; and 2003: January 2004 and July 2003, p. 12.

Net income of the FRS companies' consolidated operations (bottom-line net income from foreign refining/marketing less income from unconsolidated affiliates) increased between 2002 and 2003 (**Figure 33**), providing $2,435 million of net income, which was $2,523 million higher than the loss of 2002.[131] Higher earnings were aided by an increase in Europe's consumption of petroleum products (**Figure 34**), which increased 2 percent between 2003 and 2002.

European refining margins (represented by the Rotterdam/Brent gross refining margin) were consistently higher during 2003 than in 2002 until the fourth quarter, during which they were consistently lower (**Figure 34**), much the same as characterized the Asia-Pacific region. The ultimate result was that the average margin for 2003 was $1.01 per barrel greater than the average margin for 2002.

Figure 3-12. Petroleum Consumption by Region, 1998, 2002, and 2003



Source: BP plc, *BP Statistical Review of World Energy* (June 2004), p. 9.

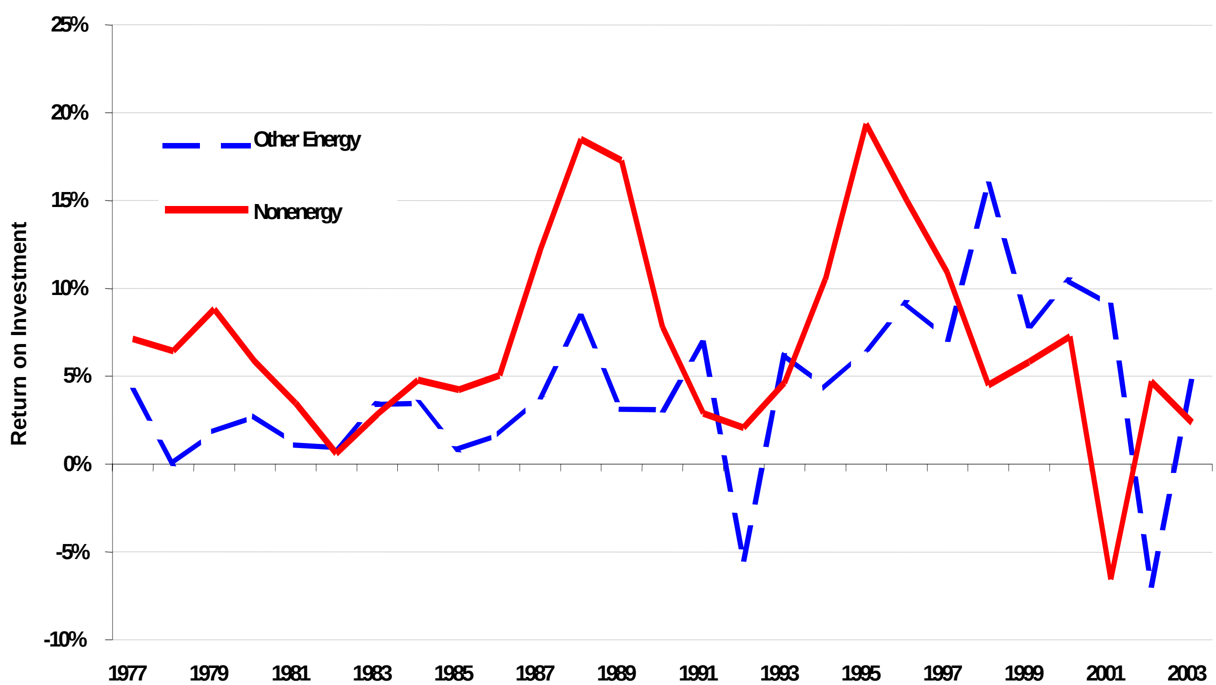
Thus, the industrywide story of slightly higher petroleum product consumption and an appreciable increase in the refining margin provided a background for an equally successful FRS story. Among the reasons cited in public disclosures for the FRS increased earnings from their European operations were increased refinery runs in response to "improved industry economics,"[132] reorganized and upgraded refineries,[133] utilization of low-cost refinery inputs,[134] avoidance of extended refinery shutdowns,[135] consolidation of marketing operations,[136] and benefits of a long-term cost-reduction program.[137]

Other Lines of Business

Net income (excluding unusual items) for the non-energy line of business (consisting primarily of chemicals) rose 5.3 percent to $2.2 billion in 2003 from 2002, providing 3.8 percent of consolidated net income (excluding unusual items) for FRS companies. Higher energy and feedstock costs cut into the bottom line and several companies reported lower earnings from the previous year. Higher margins and reduced operating costs however, were reported as contributing to higher earnings, in the second and fourth quarters in particular.[138] Non-energy's ROI was just 2.4 percent in 2003 (**Figure 36**). Given the low ROI for this segment in recent years, it is not surprising that non-energy's share of net investment in place for FRS companies has declined from 19 percent in 1995 to 7.5 percent in 2003.

Starting in 2003, the FRS survey broke out downstream natural gas and electric power as separate lines of business. (See the box "Changes to the FRS Lines of Business in 2003" in the Executive Summary.) Prior to 2003, both the oil and gas production and the refining and marketing lines of business could sell natural gas or NGLs produced by FRS companies to third parties or unconsolidated affiliates. These two lines of business could also purchase natural gas and NGLs for resale to third parties or unconsolidated affiliates. Beginning with the 2003 reporting year, however, only the downstream natural gas line of business may sell natural gas and NGLs to third parties or unconsolidated affiliates or purchase natural gas and NGLs from third parties or unconsolidated affiliates. The exception is that oil and gas production and refining and marketing are allowed to purchase natural gas for their own use only, not for resale. This has shifted sales and purchases away from both the oil and gas production and refining/marketing lines of business to the newly created downstream natural gas segment. Because of this shift, several tables in this publication include downstream natural gas in the petroleum line of business to maintain consistency with prior years.

Figure 36. Return on Net Investment in Place for Other Energy and Nonenergy, 1977-2003



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

Net income (excluding unusual items) for downstream natural gas was $2.5 billion in 2003, which amounted to about 4.4 percent of the consolidated net income (excluding unusual items) across all lines of business. ROI for downstream natural gas, at 8.9 percent was nearly as high as the ROI for domestic refining and marketing. Net investment in place for downstream natural gas comprised about 7.7 percent of the consolidated total in 2003.

Prior to 2003, the electric power line of business was the largest component of the other energy line of business. Electric power's net income (excluding unusual items) of $1.7 billion in 2003 was 94 percent of total other energy and about 3 percent of consolidated net income (excluding unusual items). The ROI for electric power amounted to 5.2 percent in 2003, well below that of the petroleum and natural gas lines of business but higher than the other energy (excluding electric power) and non-energy lines of business. Electric power comprised 82 percent of other energy's net investment in place in 2003 but only 3.5 percent of the FRS companies' consolidated total.

---

[79] The FRS collects information on major energy companies. These companies have become increasingly involved in the supply and disposition of natural gas and electricity as both industries have deregulated. The previous FRS was not designed to collect detailed information necessary for analyzing major energy companies' activities in electric power and downstream natural gas, so these lines of business have been added to the FRS.

[80] See the box in the Executive Summary for a description of the 2003 changes to the Form EIA-28.

[81] For further information on changes to the FRS for 2003, see "Form EIA-28 Financial Reporting System Instructions 2002," http://www.eia.doe.gov/emeu/perfpro/form/instruct_2002.pdf, and "Form EIA-28 Financial Reporting System Instructions 2003," http://www.eia.doe.gov/emeu/perfpro/form/instruct_2003.pdf.

[82] A breakdown of foreign production segment revenues for oil and natural gas is not available. Note that NGLs are combined with crude and not dry natural gas oil when measuring production and sales volumes in the production segment of the FRS.

[83] NGLs made up 30 percent of total U.S. production of crude oil and NGLs in 2003. See Energy Information Administration, *Advance Summary, U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 2003 Annual Report,* DOE/EIA-0216(2003) Advance Summary (Washington, D.C., September 2004), Table 1.

[84] In this section, oil refers to crude oil and NGLs.

[85] This decline is likely true for the foreign production segment as well; however, foreign raw material purchases are not broken out from other costs (revenues) in the FRS data.

[86] Foreign natural gas production by the FRS companies rose only 0.2 percent in 2003.

[87] This is a very simple and brief summary of the unit-of-production method of amortizing a capital asset. See Financial Accounting Standards Board, "Financial Accounting and Reporting by Oil and Gas Producing Companies," Statement of Financial Accounting Standards No. 19.

[88] As long as the total accumulated cost of reserves and wells does not increase or the estimated amount of reserves does not decrease enough to offset the decline in production.

[89] Other Western Hemisphere consists of Central and South America, Mexico, and the Caribbean.

[90] The four largest producing regions for the FRS companies on a boe basis are U.S. Onshore, U.S. Offshore, OECD Europe, and Canada.

[91] See the more extensive discussion of production taxes in last year's report, Energy Information Administration, *Performance Profiles of Major Energy Producers 2002,* DOE/EIA-0206(02) (Washington, D.C., February 2004), pp. 35–37.

[92] The FRS does not collect production taxes by region for the United States.

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

[94] 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 progressively 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.

[95] See the more extensive discussion of finding costs and oil and gas prices in last year's report, Energy Information Administration, *Performance Profiles of Major Energy Producers 2002,* DOE/EIA-0206(02) (Washington, D.C., February 2004), pp. 66–67.

[96] The loss reported in *Performance Profiles of Major Energy Producers 2002* was 3 percent (Energy Information Administration, *Performance Profiles of Major Energy Producers 2002,* DOE-EIA-0206 (2002) (Washington, DC, January 2004), Table B8, p. 96). However, data revisions have reduced the loss to 2 percent.

[97] As has been mentioned numerous times over the last few years, the net margin is highly correlated with return on investment. The correlation was reestimated for a discussion of the relationship between refining margins and profitability and the correlation coefficient was found to be 0.93. See "Refining Margins as Predictors of Profitability" in Chapter 4 of this publication.

[98] The net margin excludes peripheral activities such as non-petroleum product sales at convenience stores.

[99] Energy Information Administration, *Short-Term Energy Outlook* (Washington, D.C., November 9, 2004), Table A1. This publication is available on the Internet at http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/nov04.pdf (as of November 8, 2004).

[100] Energy Information Administration, *Short-Term Energy Outlook* (Washington, DC, November 9, 2004), Table A2. This publication is available on the Internet at http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/ nov04.pdf (as of November 8, 2004).

[101] See Chapter 2 of this publication for a more extensive review of the events that affected 2003.

[102] Comparing the stock levels of 2003 with the average for the period of 1997 through 2001 tells a similar story, with slightly smaller differences in the first and second quarters and slightly larger differences in the subsequent quarters.

[103] The stock levels of 2003 varied between 7 percent and 10 percent lower relative to the average for the period of 1997 through 2001.

[104] See Valero Corporation, 2003 U.S. Securities and Exchange Commission Form 10-K, p. 5.

[105] See ChevronTexaco Inc., "ChevronTexaco Completes Sale of El Paso Refinery to Western Refining" (September 2, 2003).

[106] Premcor, Inc., "Premcor Completes Purchase of Williams' Memphis Refinery" (March 4, 2003).

[107] Valero Corporation, 2003 U.S. Securities and Exchange Commission Form 10-K, p. 79.

[108] 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).

[109] The gross margins of 2003 exceeded the average level for the 1997 to 2001 period during the beginning and the end of the year, while fluctuating around the average for the 1997 to 2001 period during the middle of the year.

[110] Crude oil stocks were also at historically low levels in 2003 relative to the average during the 1997 to 2001 period.

[111] Energy Information Administration, *Annual Energy Review 2003*, DOE/EIA-0384 (2004) (Washington, D.C., September 13, 2004), Table 5.21 (Real Composite Refiner Acquisition Cost). This publication is available on the Internet at http://www.eia.doe.gov/emeu/aer/petro.html (as of November 9, 2004).

[112] 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 9, 2004).

[113] Energy Information Administration, *Annual Energy Review 2003*, DOE/EIA-0384 (2004) (Washington, D.C., September 13, 2004), Table 6.7 (Nominal Wellhead Price). This publication is available on the Internet at http://www.eia.doe.gov/emeu/aer/natgas.html (as of November 9, 2004).

[114] 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 9, 2004).)

[115] See for example, ExxonMobil Corporation, 2003 U.S. Securities and Exchange Commission Form 10-K filing, p. 6.

[116] Amerada Hess built 4 new sites during 2003 (Amerada Hess Corporation, *2003 Annual Report*, p. 12). BP continued to introduce its BP Connect convenience store format and generally pursuing a "portfolio high-grading program" (BP, plc, 2003 Annual Report on Form 20-F, p. 108). ConocoPhillips exited the New England region and sold its Circle K Corporation subsidiary during 2003 (ConocoPhillips Company, *2002 ConocoPhillips Fact Book*, pp. 39-40). Since 1999, ExxonMobil has reduced the number of outlets in its retail chain by 14 percent maintaining sales volumes, including the addition of 201 On The Run convenience stores worldwide (ExxonMobil Corporation, *2003 Financial and Operating Review*, pp. 68-69)."Marathon consolidated Speedway SuperAmerica operations by selling 193 southeastern state outlets to Sunoco during 2003 (Sunoco, Inc., 2003 U.S. Securities and Exchange Commission Form 10-K, pp. 7-8) while acquiring 60 travel centers from Williams Companies through its Pilot Travel Centers joint venture (Marathon Oil Corporation, 2003 U.S. Securities and Exchange Commission Form 10-K, p. 16). Sunoco divested some retail sites in Michigan and Cincinnati, Columbus, and Dayton, Ohio and acquired 193 Speedway SuperAmerica sites (Sunoco, Inc., 2003 U.S. Securities and Exchange Commission Form 10-K, pp. 7-8). Valero divested or closed 122 outlets during 2003 (Valero Energy Corporation, 2003 U.S. Securities and Exchange Commission Form 10-K, p. 15).

[117] For example, Hess upgraded 10 sites by adding Hess Express convenience stores in addition to building 4 new sites during 2003 (Amerada Hess Corporation, *2003 Annual Report*, p. 12). Shell began converting Louisiana [and probably also elsewhere] Texaco-branded outlets into Shell-branded outlets (see Shell Oil Company press releases (February 10 and 12, 2003). Additionally, Valero re-imaged and upgraded 150 outlets during 2003 (Valero Energy Corporation, 2003 U.S. Securities and Exchange Commission Form 10-K, p. 15).

[118] Although we have no estimate of the significance of the environmental spending in 2003's "other operating costs," a recent study examined these and is available on EIA's web site at http://www.eia.doe.gov/emeu/perfpro/ref_pi2/index.html .

[119] Actually, raw materials prices and the prices paid for petroleum product purchases.

[120] The International Marine business segment has been combined with Foreign Refining/Marketing for this presentation in order to prevent disclosure of company-level data. Relative to Foreign Refining/Marketing, International Marine is about one-tenth the size and has little material effect on the overall results of Foreign Refining/Marketing.

[121] The Caltex joint venture was an unconsolidated affiliate for both of its parents, Chevron and Texaco.

[122] ChevronTexaco Corporation, *2003 Supplement to the Annual Report*, p. 44; and Exxon Mobil, *2003 Annual Report*, pp. 16, 22, and 63.

[123] ChevronTexaco Corporation, *2003 Supplement to the Annual Report*, p. 39.

[124] Exxon Mobil, *2003 Annual Report*, pp. 14 and *2003 Financial and Operating Review*, p. 66.

[125] ChevronTexaco Corporation, *2003 Supplement to the Annual Report*, p. 43.

[126] ConocoPhillips Company, *2003 Annual Report*, p. 43.

[127] ConocoPhillips Company, *2003 Annual Report*, p. 43.

[128] Exxon Mobil Corporation, *2003 Financial and Operating Review*, p. 63.

[129] Nineteen nuclear power plants in Japan were temporarily shut down, leading to this increased demand. See Energy Information Administration, *International Energy Outlook 2004*, DOE/EIA-0484(2004) (Washington, DC, April 2004), pp. 121 and 122.

[130] ChevronTexaco Corporation, *2003 Supplement to the Annual Report*, p. 38.

[131] The revised 2002 value of -$88 million compared to the -$31 million reported for 2002 a year ago is due to the addition of International Marine to Foreign Refining/Marketing in order to avoid disclosure of company-level data. The change makes little material difference in the 2003 results of Foreign Refining/Marketing.

[132] Exxon Mobil Corporation, *2003 Financial and Operating Review*, p. 63.

[133] ChevronTexaco Corporation, *2003 Supplement to the Annual Report*, p. 39.

[134] ConocoPhillips Company, *2003 Annual Report*, pp. 19-20.

[135] ConocoPhillips Company, *2003 Annual Report*, pp. 43.

[136] ChevronTexaco Corporation, *2003 Supplement to the Annual Report*, p. 43.

[137] ConocoPhillips Company, *2003 Annual Report*, pp. 21.

[138]See Energy Information Administration, *Financial News for Major Energy Companies*, http://www.eia.doe.gov/ emeu/perfpro/news_m/003/q4/index.html (as of December 9, 2004) and http://www.eia.doe.gov/emeu/perfpro/ news_m/2003/q2/index.html (as of December 9, 2004).

4. Resource Development Trends

SPECIAL TOPIC: Are the FRS Companies Finding Enough Oil and Gas to Keep Up with Demand?

Almost since oil was discovered in Pennsylvania in 1859, geologists, energy economists, and corporate and government officials have debated whether the supply of oil would be able to keep up with demand. For example, in 1922 the U.S. Geological Survey (USGS) warned that America was going to run out of oil within 20 years.[a] In 1956, M. King Hubbert, at the time a geophysicist with Shell Oil, predicted that U.S. oil production would peak by 1970.[b] While the USGS's 1922 prediction was not realized, crude oil production in the United States did peak in 1970 at 9.6 million barrels per day (mmb/d). In 2003, U.S. oil (crude oil plus natural gas liquids) production stood at 7.4 mmb/d, 34 percent below its 1970 peak.[c] In addition, conditions in the world oil market at the end of 2004 were exacerbated by renewed arguments that worldwide oil production would soon reach its peak.[d] The concern has even been extended to natural gas production.

One factor contributing to the current concern about the adequacy of the supply of oil and gas was the January 2004 announcement by Royal Dutch/Shell that it had overstated its reserves and reserve additions. Although this case is an extreme example, several smaller reductions in oil and gas reserves have since occurred at other companies, most notably El Paso. But substantial companywide reserve reductions are the exception. An oil or gas field's initial proved reserves estimate typically understates its ultimate production capacity, and reserve revisions are more frequently positive than negative. This article provides an overview of how well FRS and other companies have replaced production with reserve additions.

Replacing Production

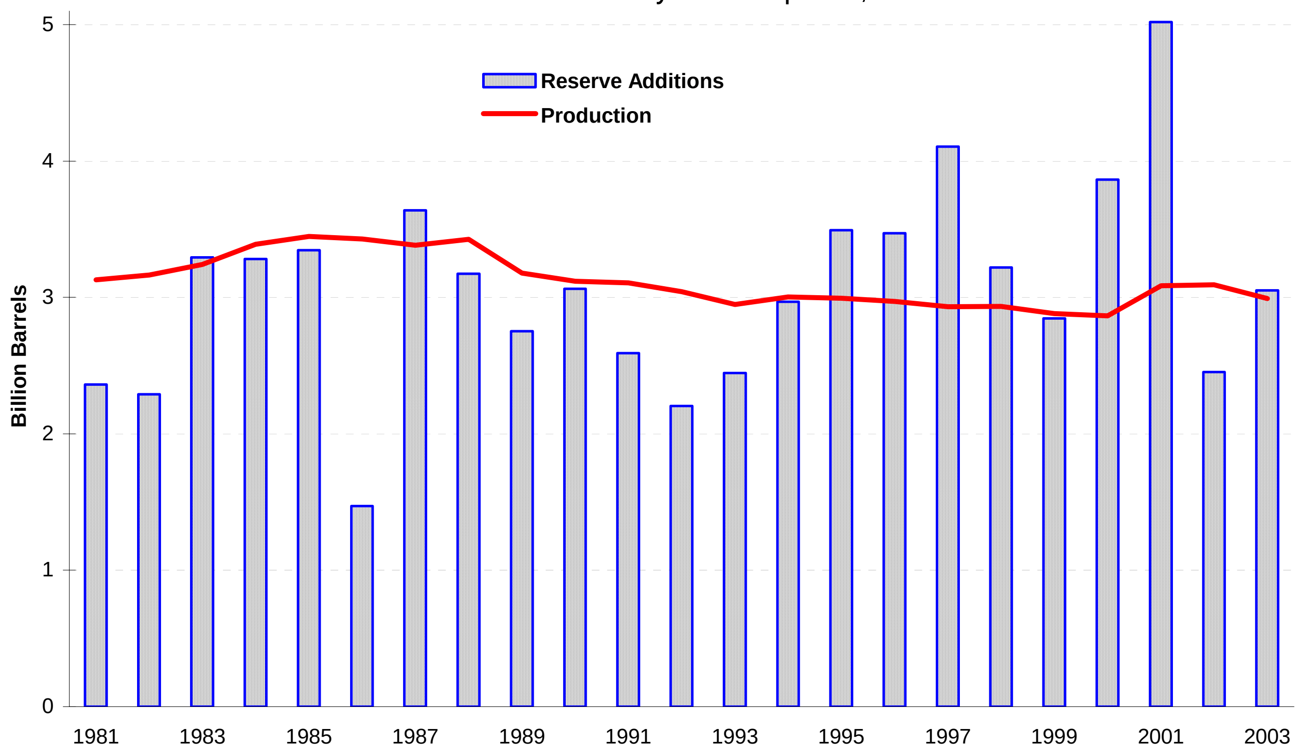
Reserve reductions attract attention because one of the most closely watched indicators of future production potential is the replacement of production by reserve additions. As long as reserve additions exceed production, continued production would seem to be assured, because reserves (the capacity to produce oil or gas in the future) will continue to increase. When production exceeds reserve additions, the stock of reserves available for future production declines. If this outcome persists over a long enough period of time, production of oil or gas will eventually have to decline.

The replacement of worldwide oil production by reserve additions for the Financial Reporting System (FRS) companies during the period 1981 through 2003 appears encouraging in this regard (**Figure 37**). The replacement of oil production by reserve additions has improved in the most recent decade, with reserve additions exceeding production in 7 of the 10 years ending in 2003. In the decade before that, reserve additions exceeded production only in 1 year. For natural gas, the replacement of worldwide production by the FRS companies appears even more heartening (**Figure 38**). Natural gas reserve additions exceeded production in every year for the decade ending in 2003; in the previous decade, gas production exceeded reserve additions only five times.

Two limitations of the FRS data are that companies in the FRS group change over time and the data do not include worldwide production by the entire oil and gas industry. These problems can be avoided by examining worldwide data on oil and gas replacement, which present even stronger evidence for adequate production replacement than the FRS data. **Figure 39** depicts these data for oil, excluding the Organization of Petroleum Exporting Countries (OPEC).[e] Only twice in the decade ending in 2003 did worldwide production exceed reserve additions. In 1997 the gap between production and reserve additions was particularly large. That year, Mexico released its first independently audited petroleum reserve estimates, and its oil reserves fell by 20 billion barrels, almost completely offsetting the reserve gains in the rest of the non-OPEC world. In the previous decade, non-OPEC oil reserve additions failed to replace production five times. The situation with gas reserves is very clear: worldwide non-OPEC reserve additions have more than replaced production, by up to a factor of eight, in every year from 1981 through 2003 (**Figure 40**).

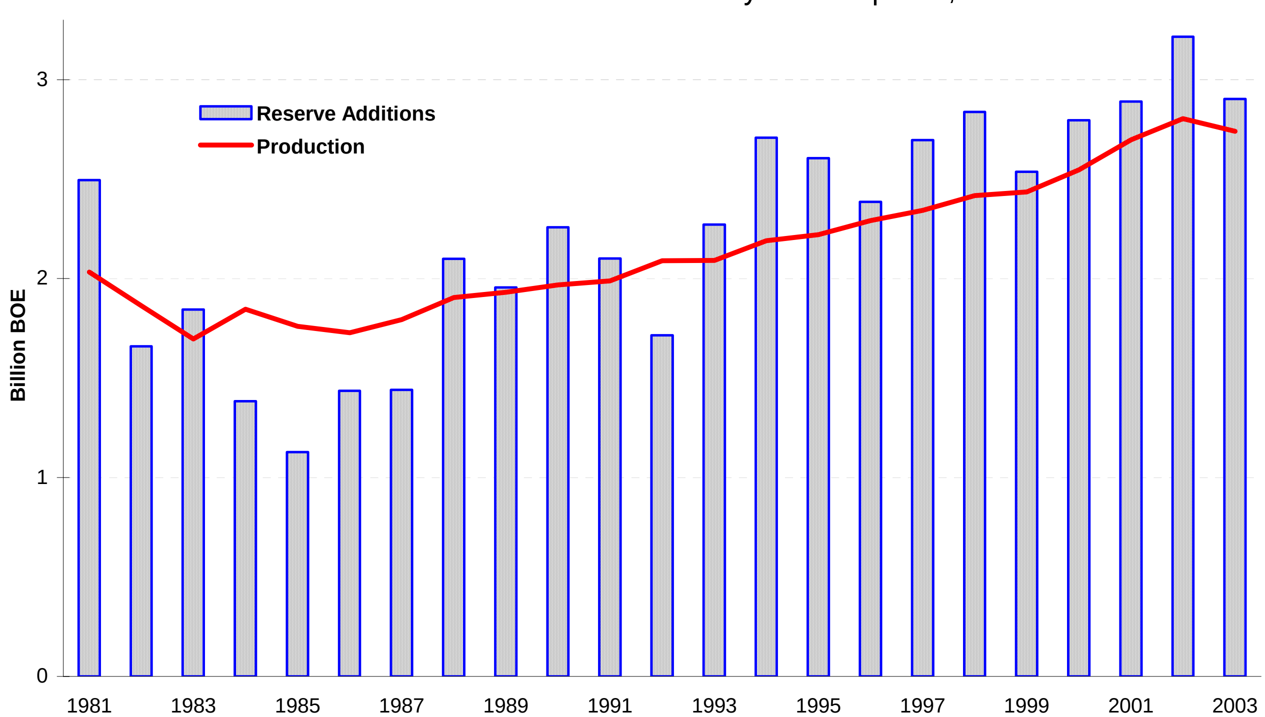
However, the North American gas market, important in and of itself because currently it is partially insulated from the rest of the world by gas transportation limitations, presents a different picture than the rest of the world regarding the replacement of oil and gas production (**Figure 41**).[f] For the FRS companies, gas reserve additions in North America often fell short of production in the years from 1981 through 2003, with an average replacement rate of 85

Figure 37. Worldwide Oil Production and Reserve Additions by FRS Companies, 1981-2003



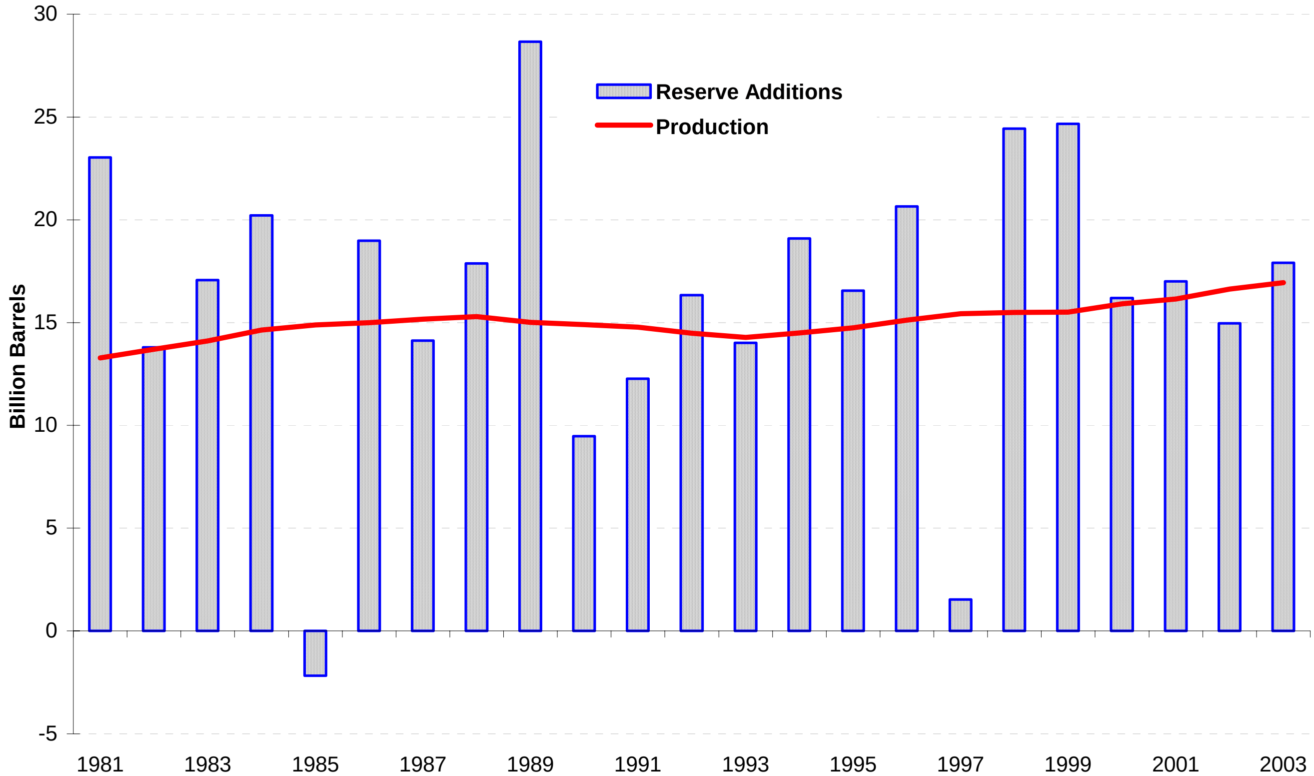
Note: For the entire period, 1981-2003, reserve additions equaled 98 percent of production.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Figure 38. Worldwide Natural Gas Production and Reserve Additions by FRS Companies, 1981-2003



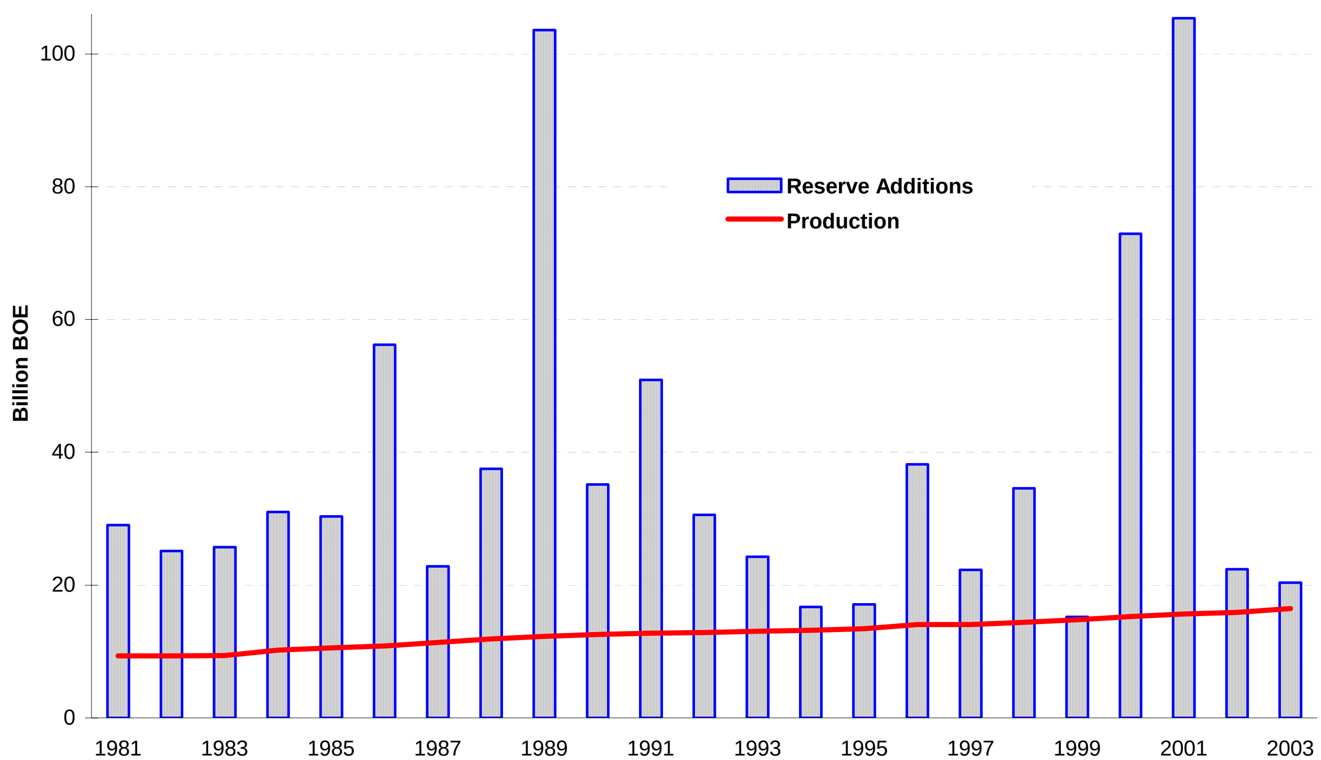
Note: Excludes Alaska natural gas reserve write-downs in 1985 and 1987. For the entire period, 1981-2003, reserve additions equaled 104 percent of production.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Figure 39. Worldwide (Excluding OPEC) Oil Production and Reserve Additions, 1981-2003



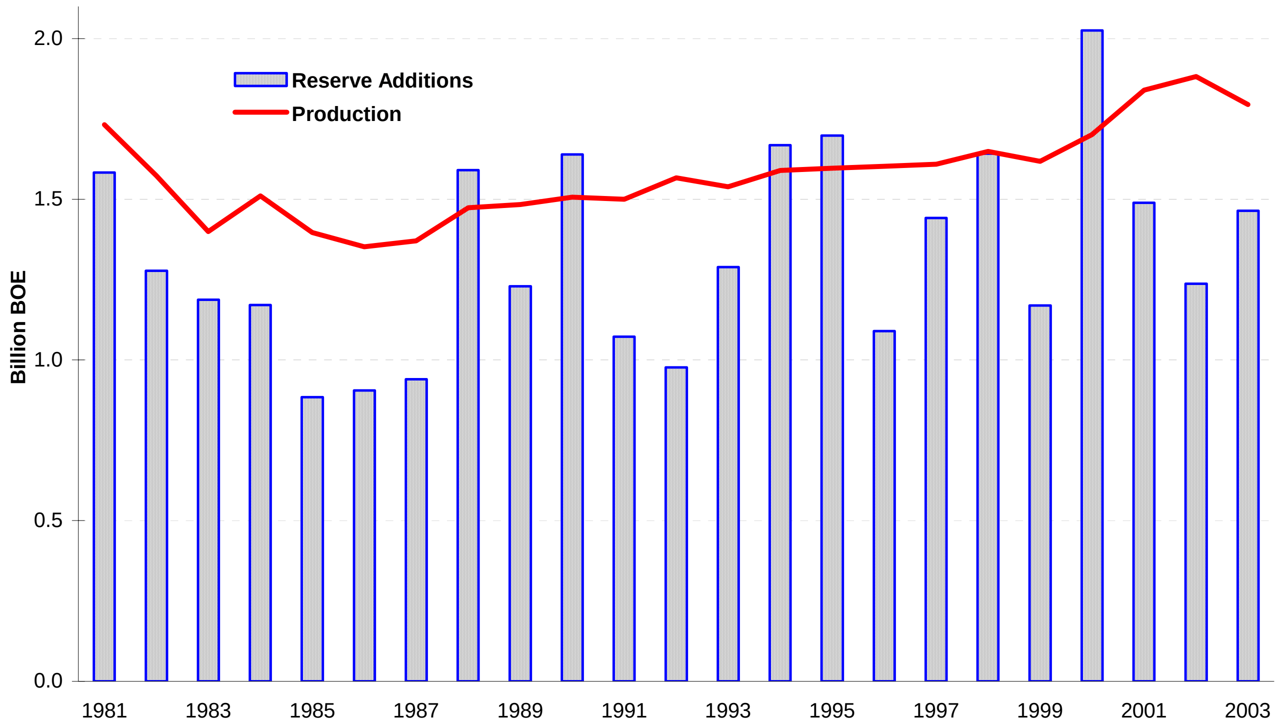
Note: For the entire period, 1981-2003, reserve additions equaled 109 percent of production.
Source: BP Statistical Review of World Energy 2004 (London, June 2004).

Figure 40. Worldwide Natural Gas Production and Reserve Additions, 1981-2003



Note: For the entire period, 1981-2003, reserve additions equaled 295 percent of production.
Source: BP Statistical Review of World Energy 2004 (London, June 2004).

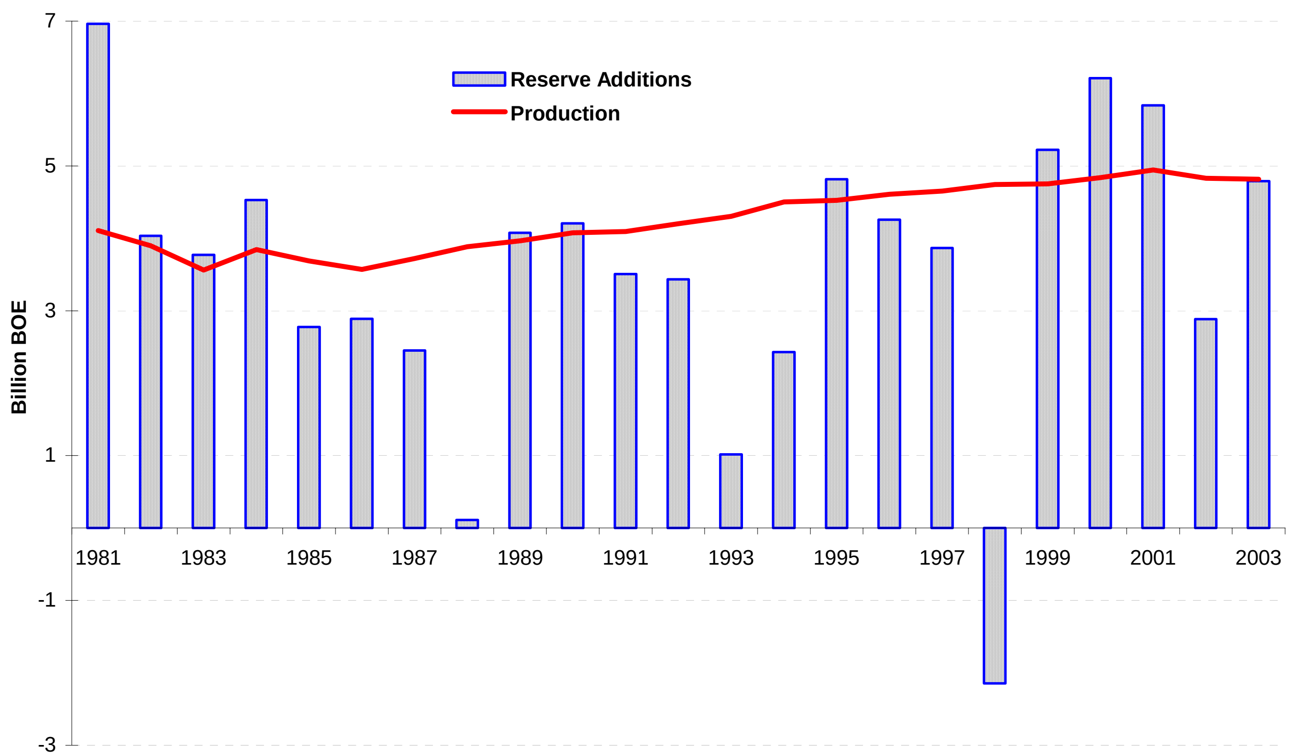
Figure 41. North American Natural Gas Production and Reserve Additions by FRS Companies, 1981-2003



Notes: Excludes Alaska natural gas reserve write-downs in 1985 and 1987. The FRS companies do not produce any gas in Mexico. For the entire period, 1981-2003, reserve additions equaled 85 percent of production.

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

Figure 42. North America Natural Gas Production and Reserve Additions, 1981-2003



Note: For the entire period, 1981-2003, reserve additions equaled 83 percent of production.

Source: BP Statistical Review of World Energy 2004 (London, June 2004).

percent during the period. For the entire oil and gas industry in North America, gas reserve additions have exceeded production more often than for the FRS companies, but when they fell short, reserve additions sometimes lagged production by large amounts, resulting in an average reserve replacement ratio of 83 percent from 1981 through 2003 (**Figure 42**). This evidence supports continued tightness in the North American gas market.

Reserve Additions and Production

The historical record on replacement of worldwide production by reserve additions suggests that, until now, enough reserves have been added to sustain production. However, a reserve replacement rate in excess of 100 percent does not guarantee that production levels will continue to increase. Production could decline even with reserve replacement greater than 100 percent, when, for example, the reserves being added have a low extraction rate, as in the case of unconventional gas, or the reserves being added are not producing because of infrastructure limitations or because the reserves are located in a zone different from the one that currently is being produced.[g] In this case, at some point, the oil or gas supply will not be able to keep up with growing demand. Observers have argued that this situation is now occurring at some major investor-owned oil and gas producers and that it "… paint[s] a picture of an industry that has depleted nearly all of the world's easily exploited reserves outside the Middle East and that is now struggling to sustain production, much less increase it."[h]

Figures 37 through **40** do not support the assertion that the world petroleum industry is struggling to sustain production and indicate the analytical danger in projecting the entire industry from just a few of the largest oil and gas producers. For the FRS companies combined and for the world as a whole, the production of oil and gas has not been falling. The worldwide production of gas by the FRS companies and the production of oil and gas by the entire industry have been increasing since the mid-1980s.[i] During the past 25 years, companies have found more reserves than they have produced, indicating that the potential to maintain, and probably increase, oil and gas production has not diminished.

---

[a]http://www.energyquest.ca.gov/time_machine/1920ce-1930ce.html (November 15, 2004).

[b]M.K. Hubbert, "Nuclear Energy and the Fossil Fuels," *Drilling and Production Practice*, American Petroleum Institute, Proceedings of the Spring 1956 Meetings (San Antonio, Texas, 1956), pp. 7–25.

[c]Natural gas liquids are combined with crude oil to be consistent with FRS definitions. Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(2004/10) (Washington, D.C., October 26, 2004), Table 3.1a.

[d]Kenneth S. Deffeyes, *Hubbert's Peak: The Impending World Oil Shortage* (Princeton University Press, Princeton, New Jersey, 2001).

[e]OPEC is excluded because it regulates the production of crude oil by its members, which may distort production-to-reserves ratios.

[f]This isolation is expected to weaken as more facilities for the regasification of liquefied natural gas are built in North America.

[g]Another reason could be that the cost of production is greater than the market price.

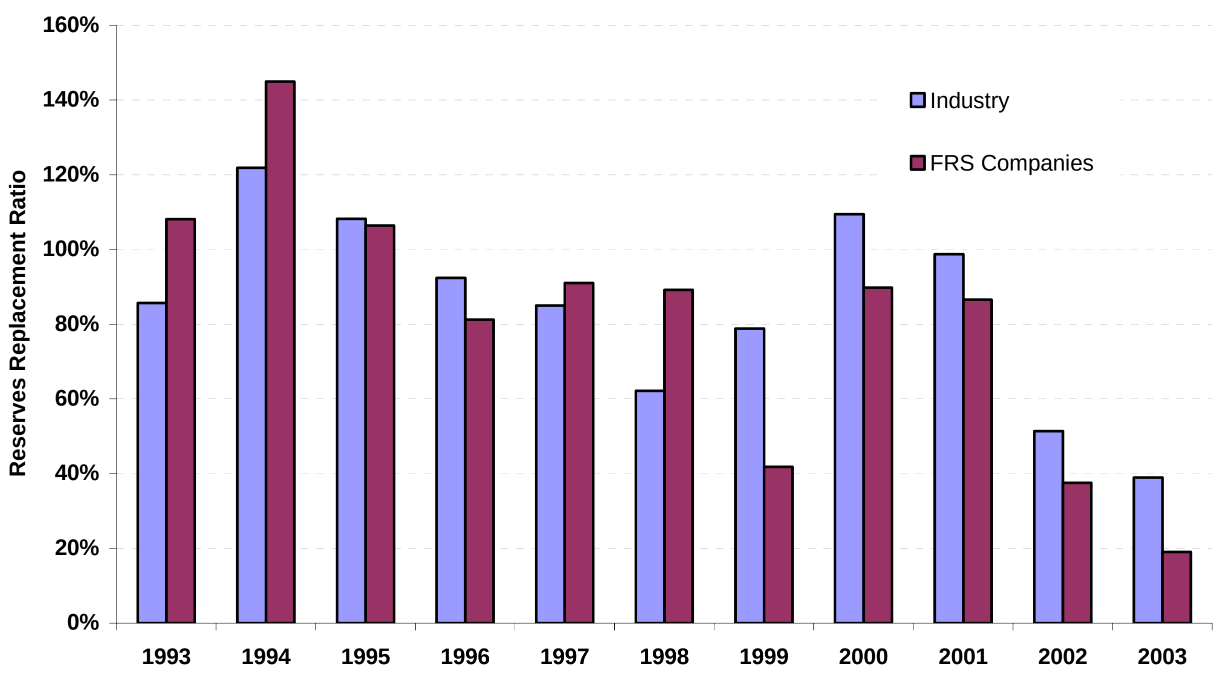
[h]Alex Berenson, "An Oil Enigma: Production Falls Even as Reserves Rise," *The New York Times* (June 12, 2004), p. A1.

[i]Worldwide oil production by the FRS companies has been essentially flat since the early 1990s. But this stagnant production level has masked differing trends among the individual companies. While worldwide oil production by several of the largest FRS companies (and a few of the smaller ones) has declined, it has been offset by increased production by several other of the largest FRS companies and by most of the smaller ones.

SPECIAL TOPIC: The Gulf of Mexico—Is Deep-Shelf Gas the Solution to the Gulf's Declining Natural Gas Reserve Replacement Ratio?

It 2003, dry natural gas production from the Gulf of Mexico's Outer Continental Shelf (OCS) totaled approximately 4.3 trillion cubic feet (tcf), which represents approximately 88 percent of the total offshore production[a] and about 22 percent of total domestic production. The 2003 offshore production of the FRS companies, the vast proportion of which is accounted for by operations in the Gulf of Mexico, was 2.5 tcf, or more than half the Gulf's output.[b] Unfortunately, despite prices that were significantly higher than in the late 1990s, during the past few years, both the FRS companies and the industry as a whole have been unable to add enough reserves to replace the offshore reserves that were produced, as evidenced by a sharp decline in the ratio of reserve additions to production (**Figure 43**). In 2003, the replacement rates for the FRS companies and the industry as a whole were 19 percent and 39 percent, respectively. For the FRS companies, the low offshore replacement rate can be accounted for by the fact that reserve extensions and discoveries were only 1,069 billion cubic feet (bcf), the lowest level since 1987, coupled with a 631-bcf net write-down in reserves. During the 1998–2003 period, the industry's offshore replacement rate was 77 percent. During this same period, the FRS companies only replaced 62 percent of their offshore natural gas reserves. This shortfall in reserve additions has led to a decline in the stock of offshore reserves that, in turn, has resulted in declining offshore production (**Figure 44**).

Figure 43. Offshore Natural Gas Reserve Replacement Ratio for FRS Companies and the Entire U.S. Natural Gas Supply Industry, 1993-2003



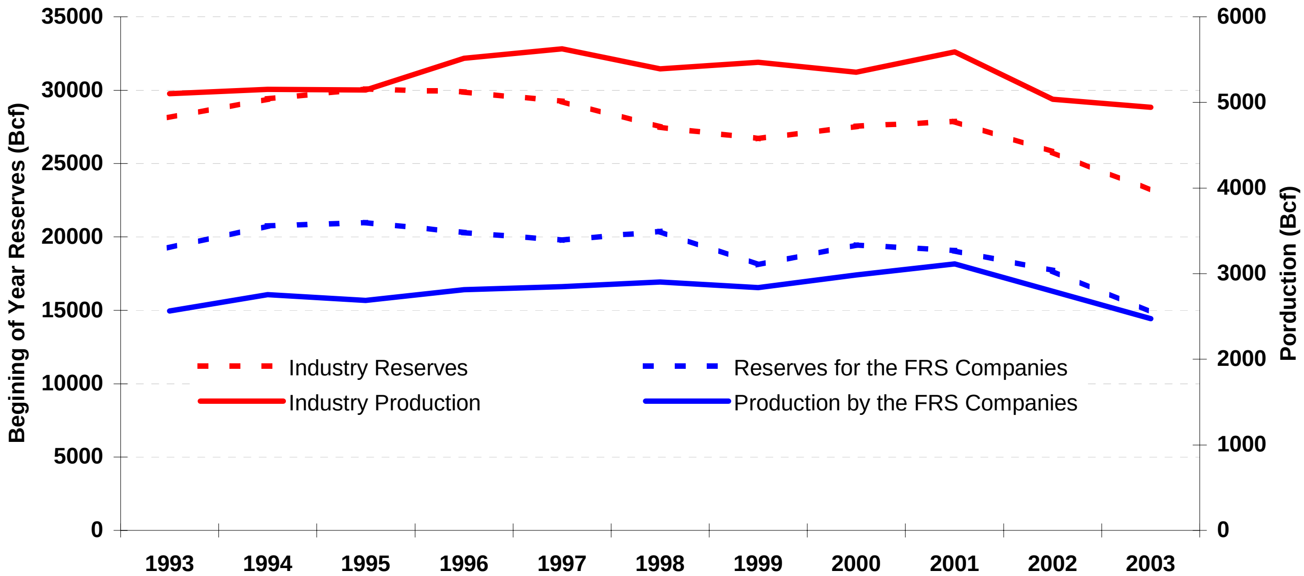
Sources: Energy Information Administration Form EIA-23 and Form EIA-28 (Financial Reporting System).

While this decline in offshore reserves and production is obviously a matter of concern in terms of the industry's future, some are convinced that the development of deep-shelf gas prospects may help to reverse the trend.

The Deep Shelf

The Mineral Management Service (MMS), the Federal agency that manages the resources of the OCS, defines the Deep Shelf to include those gas prospects that lie 15,000 feet or more below the OCS in water depths up to 200 meters.[c] Many of these prospects are accessible using existing infrastructure in the Gulf. The MMS has recently increased the upper limit of its Deep-Shelf gas resource estimate to 55 tcf from its earlier estimate of only 20 tcf.[d] Yet,

Figure 44. Offshore Natural Gas Reserves and Production for FRS Companies and the Entire U.S. Gas Supply Industry, 1993-2003



Note: The reported values are for dry natural gas. Reserve values are as of the December 31 of each year. Sources: Energy Information Administration, Form EIA-23 and Form EIA-28 (Financial Reporting System).

only about 5 percent of the wells drilled in the OCS have a drilling depth greater than 15,000 feet.[e] Factors contributing to the Deep Shelf's underdevelopment include the technical challenges of drilling in a high pressure, high temperature environment, the high cost of drilling deeper wells, and the relatively poor quality of the seismic imaging for deep prospects.

Beginning in 2001, the MMS revised its royalty provisions on new leases to encourage drilling for deep gas in shallow waters.[f] In 2004, MMS extended its royalty relief program to existing leases.[g] Under the program, royalties are suspended on the first 15 bcf of gas produced from depths greater than 15,000 feet and less than 18,000 feet. Royalties are suspended on the first 25 bcf produced from wells that are 18,000 feet or deeper. The dollar value of 25 bcf of royalty relief at a one-sixth royalty rate and market price of $5.00 per thousand cubic feet is approximately $21 million, which is about equal to the cost of drilling a typical deep gas well in the Gulf. Under the program, royalty relief is discontinued if gas prices rise above a price threshold of $9.34 per million British thermal units (mmBtu), indexed for inflation.[h] While some might question the need for these incentives given the current price level for natural gas, others would point out that limitations in seismic imaging and the current high cost of drilling these deep wells may serve as a barrier to developing deep gas and that additional financial incentives may produce a learning curve phenomena that will reduce this barrier.

MMS also has conducted a number of recent lease sales that featured deep gas. Central Gulf of Mexico Lease Sale 190 was held on March 17, 2004. The sum of accepted high bids was approximately $364 million, with about $174 million of these high bids for tracks with a water depth of less than 200 meters where deep gas is usually located.[i] Western Gulf of Mexico Lease Sale 192 was held on August 18, 2004. The sale offered 3,907 tracts comprising approximately 21.2 million acres offshore Texas and Louisiana. Fifty-four companies participated. The MMS received 421 bids on 351 tracts with 135 of these having a water depth less than 200 meters. Net high bids totaled approximately $170 million.[j] Interestingly, the highest bid accepted was a Deep Shelf prospect with water depth less than 200 meters.[k]

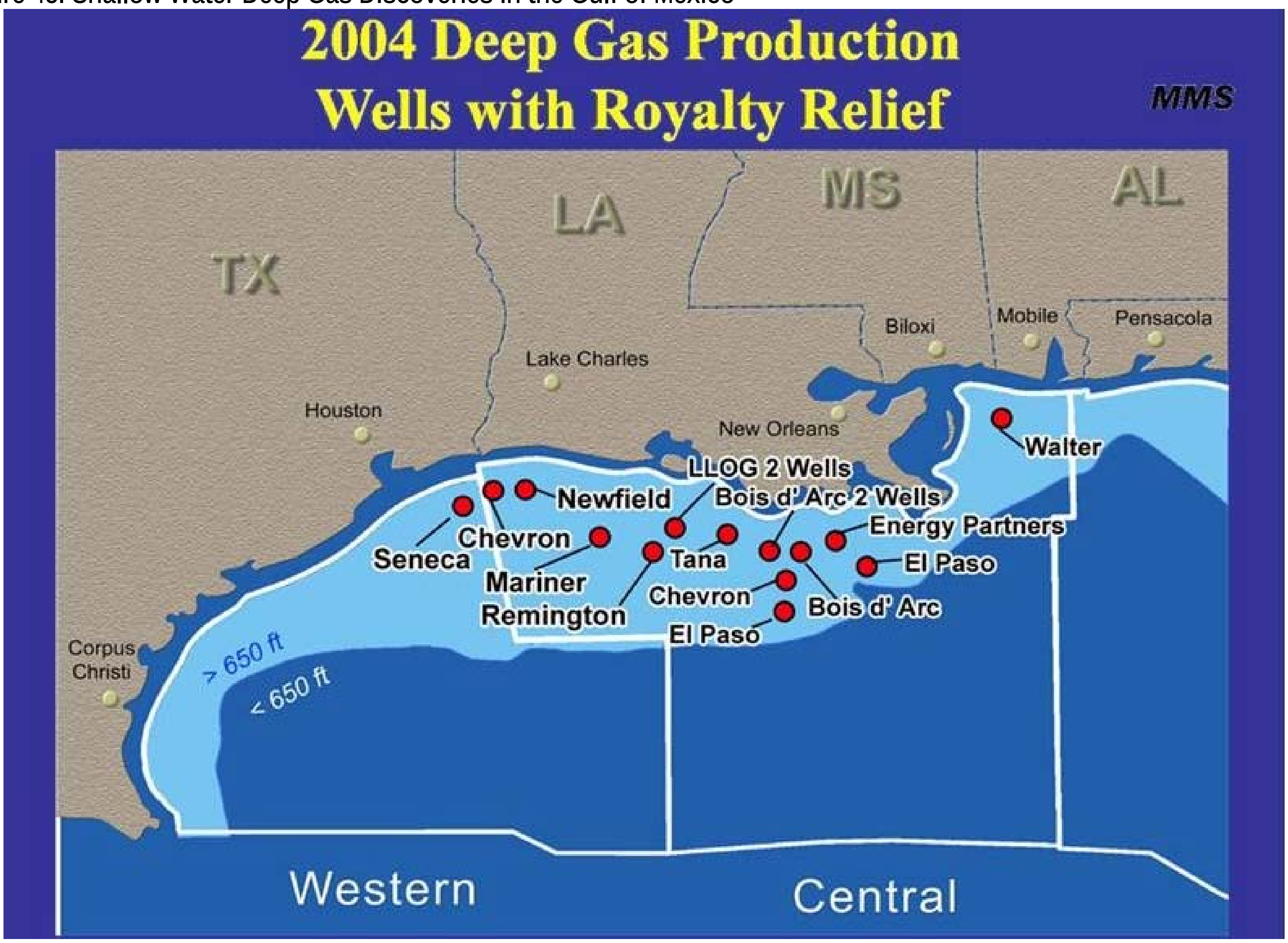
Indicative of the risks of exploring for deep gas, Shell Oil and its 40 percent Canadian-based partner Nexen recently drilled an exploration well named Shark in South Timbalier block 174 in the Gulf of Mexico.[l] The well had a drilling depth of 25,756 feet, which made it the deepest well drilled to date in the Gulf of Mexico shelf. It had been speculated that the prospect could yield from 2 to 3 tcf of gas. Unfortunately, no commercial hydrocarbons were encountered and the well was abandoned. Based on Nexen's subsequent expensing of $25 million (Canadian) of well costs associated with the prospect, the cost of the dry hole was approximately $53 million.[m]

Other companies also have been frustrated by the search for deep gas. Charles R. Williamson, chairman and CEO of the FRS company Unocal, stated: “The exploration program in the Gulf of Mexico (GOM) shelf, including the deep shelf program, had unacceptable returns as a result of lower than expected discovery volumes and drilling cost overruns.” Unocal further stated that its “… exploration capital spending for the GOM shelf will be cut by approximately 50 percent from the 2003 level.”[n]

Other companies have met with better luck exploring for deep gas (**Figure 45**). Some of the more notable discoveries include:

- **West Cameron 77.** This field is located about 10 miles offshore Louisiana in about 40 feet of water.[o] While the water depth is shallow, the discovery well is anything but shallow. With additional drilling to discover deeper pays, the well has a vertical depth of 19,603 feet. Newfield, the operator, expects first production from the field in early 2005. This discovery gives Newfield a track record of 12 successful deep shelf exploration wells out of 19 attempts as of July 2004.[p]
- **Hickory.** Hickory lies in the Grand Isle blocks 110, 111, and 116, approximately 75 miles offshore Louisiana in 320 feet of water.[q] The operator of the field is the FRS company Anadarko (50 percent working interest). Its partners are fellow FRS company Shell Oil (37.5 percent) and Ocean Energy (12.5 percent). Hickory is a sub-salt play, which makes exploration riskier than usual given that the salt formations distort conventional seismic images. The discovery well penetrated approximately 8,000 feet of salt for a total drilling depth of 21,600 feet.[r]

Figure 45. Shallow Water Deep Gas Discoveries in the Gulf of Mexico



Source: U.S. Department of the Interior, Minerals Management Service.

In reviewing the reported dryholes and discoveries, MMS is guardedly optimism about Deep Shelf production. MMS has estimated that 2003 Deep Shelf production was around 1.45 bcf per day.[s] Given the size and pace of recent discoveries, MMS believes that Deep Shelf production will rise to approximately 3 bcf per day by 2013. When shallow gas and deep water gas also are factored in, MMS expects total Gulf of Mexico production to rise to 13.5 bcf per day in 2012, 1.3 bcf per day higher than 2003 estimated production of 12.2 bcf per day.[t]

---

[a]The remaining 12 percent is production from the State waters of the Gulf of Mexico and Federal and State offshore California.

[b]Energy Information Administration, Form EIA-28 (Financial Reporting System).

[c]http://www.gomr.mms.gov/homepg/whatsnew/newsreal/031119.html (as of December 1, 2004)

[d]http://www.gomr.mms.gov/homepg/whatsnew/newsreal/031119.html (as of February 8, 2005)

[e]Minerals Management Service, *The Promise of Deep Gas in the Gulf of Mexico,* OCS Report MMS 2001-037 (2001), p. 3.

[f]http://www.gomr.mms.gov/homepg/offshore/deepgas.html (as of December 1, 2004)

[g]http://www.gomr.mms.gov/homepg/offshore/deepgas.html (as of December 1, 2004)

[h]http://www.mms.gov/econ/PDFs/DeepGasRule.pdf (as of December 1, 2004)

[i] http://www.gomr.mms.gov/homepg/lsesale/190/sale_190.html and http://www.gomr.mms.gov/homepg/whatsnew/newsreal/2004/040618.html (as of December 1, 2004).

[j]http://www.gomr.mms.gov/homepg/whatsnew/newsreal/2004/041118.html (as of December 1, 2004)

[k]http://www.gomr.mms.gov/homepg/whatsnew/newsreal/2004/041118.html (as of December 1, 2004)

[l]http://www.petroleumnews.com/pntruncate/50143092.shtml (as of December 1, 2004)

[m]Nexem expensed $25 million (Canadian), which is equivalent to approximately $21 million (U.S.) (as of December 1, 2004). Dividing by Nexem's 40 percent share gives the approximate project cost of $53 million. The source for this information is http://www.newswire.ca/en/releases/archive/October2004/14/c9409.html (as of December 1, 2004)

[n]http://www.unocal.com/uclnews/2004news/020204.htm (as of December 1, 2004)

[o] http://www.oilonline.com/news/headlines/ephotline/20040728.Newfield.15333.asp (as of December 1, 2004)

[p]http://www.gasandoil.com/goc/discover/dix43330.htm (as of December 1, 2004)

[q]http://www.offshore-technology.com/projects/hickory/ (as of December 1, 2004)

[r]http://www.offshore-technology.com/projects/hickory/ (as of December 1, 2004)

[s]http://www.mms.gov/Assets/PressConference11152004/2004-065.pdf (as of December 1, 2004)

[t]http://www.mms.gov/Assets/PressConference11152004/2004-065.pdf (as of December 1, 2004)

SPECIAL TOPIC: Are Investment Climates Affecting the Supply of Oil and Gas?

Many analyses of oil and gas supply begin and end with a focus on geology, that is, on the volume of recoverable oil and gas. While commercially recoverable quantities of oil and gas are necessary for supply, they are not sufficient. Supplies of oil and gas only will be forthcoming if the resources are present and the investment climate is hospitable. The following examples illustrate some of the issues and difficulties that companies encounter when making investments in oil and gas production.

Indonesia

According to the latest resource assessment by the USGS, Indonesia's oil and gas resources are substantial. Specifically, the USGS believes that there is a 50 percent chance of approximately 7 or more billion barrels of oil yet to be discovered.[a] In addition, the USGS believes there is a 50 percent chance that there are more than 100 tcf of undiscovered natural gas.[b] Despite these ample levels of resources, Indonesia's oil production has fallen by 26 percent during the past decade, to 1.179 million barrels per day in 2003.[c] The root cause of the decline is an investment climate that has been described as one of world's worst.[d] There appears to be an absence of regulatory certainty. For example, in August 2002 the Government transferred a block operated by a subsidiary of ChevronTexaco to the state-owned oil company Pertamina and one of the regional governments in Sumatra.[e] Production at the block has since dropped nearly 10,000 barrels of oil per day. The Government also has arguably undermined the investment climate by missing its self-imposed deadline to issue new oil and gas implementing regulations. Under the draft regulations, existing production-sharing contracts would be superceded by a requirement that companies offer a 10-percent participating interest to locally owned companies. Another issue is what happens when the terminal year of the contract between the producing firm and the government nears. Firms are unlikely to make new investments if the terms or the possibility of a contact extension are uncertain. Indicative of this, reportedly ExxonMobil's Cepu oil and gas block in East Java remains undeveloped as a result of lengthy negotiations over the terms of a contract extension.[f]

Given this hostile investment climate, it is not surprising that oil and gas exploration drilling investment dropped from $500 million in 2002 to $207 million in 2003. What is surprising is that 2003 had been billed as the "Year of Investment."[g]

Venezuela

Venezuela has approximately 78 billion barrels of proved oil reserves (excluding extra-heavy oil and bitumen),[h] more than the combined proved oil reserves of the United States, Mexico, and Canada.[i] Moreover, according to the latest resource assessment by the USGS, Venezuela's unproven oil and gas resources are among the largest in the world. Specifically, the USGS estimates that there is a 50-percent chance that more than 18 billion barrels of oil are yet to be discovered.[j] In addition, the USGS believes that there is a 50-percent chance there is more than 90 tcf of undiscovered natural gas.[k] Venezuela also possesses literally hundreds of billions of barrels of extra-heavy crude oil resources.

Venezuela is emerging from a period of severe political turmoil. Following a failed coup in April 2002, the opponents of President Chávez organized a nationwide strike in December 2002 to call for an early referendum on the President's rule. Employees from Venezuela's State-owned oil company, Petróleos de Venezuela S.A. (PdVSA), also joined the strike. Oil production declined by more than 67 percent.[l] President Chávez responded by declaring the strikers' demands unconstitutional and dismissed nearly half of PdVSA's work force. Oil production soon rebounded to near pre-strike levels, but Chávez's opponents remained undaunted. In June 2004, Venezuela's National Electoral Council (CNE) announced that Chávez's opponents had collected enough signatures to trigger a recall vote. The recall election took place on August 15, 2004, with a majority voting against the recall.[m]

While the resolution of the recall effort has reduced uncertainty in the investment climate, there are remaining negatives. The Overseas Private Investment Corporation (OPIC), an agency of the U.S. government that provides political risk insurance and project financing for American companies investing in developing countries, indicated that it was unlikely to back new ventures in Venezuela.[n] OPIC announced its reluctance to insure new investments in Venezuela after awarding a compensation claim to Science Applications International Corporation (SAIC), a U.S.-based research and engineering company, which claimed that its joint venture investment in Venezuela's State-owned oil company had been expropriated by Chavez's government.

There is also the matter of the fiscal regime. Under Venezuela's 2001 Hydrocarbons Law, which went into effect in January 2002, royalties paid by private companies range from 20 to 30 percent, up from the previous 1 to 16.66 percent. The new law also gives PdVSA at least a 51-percent stake in any upstream project. Companies understood that the law did not apply to the heavy oil projects approved before the law was passed such as Petrozuata, Hamaca, Cerro Negro, and Sincor. These projects had been given a lucrative 1-percent royalty rate as an incentive for development.[o]

On October 10, 2004, President Chávez announced that the government was unilaterally increasing the royalty rate on heavy crude production to 16.66 percent from 1 percent.[p] Moreover, the new higher rate applies to existing projects, rather than just to new projects. While the government claims that the adjustment is permitted under the oil law governing most of the projects, this action can only further undermine trust in the regime.

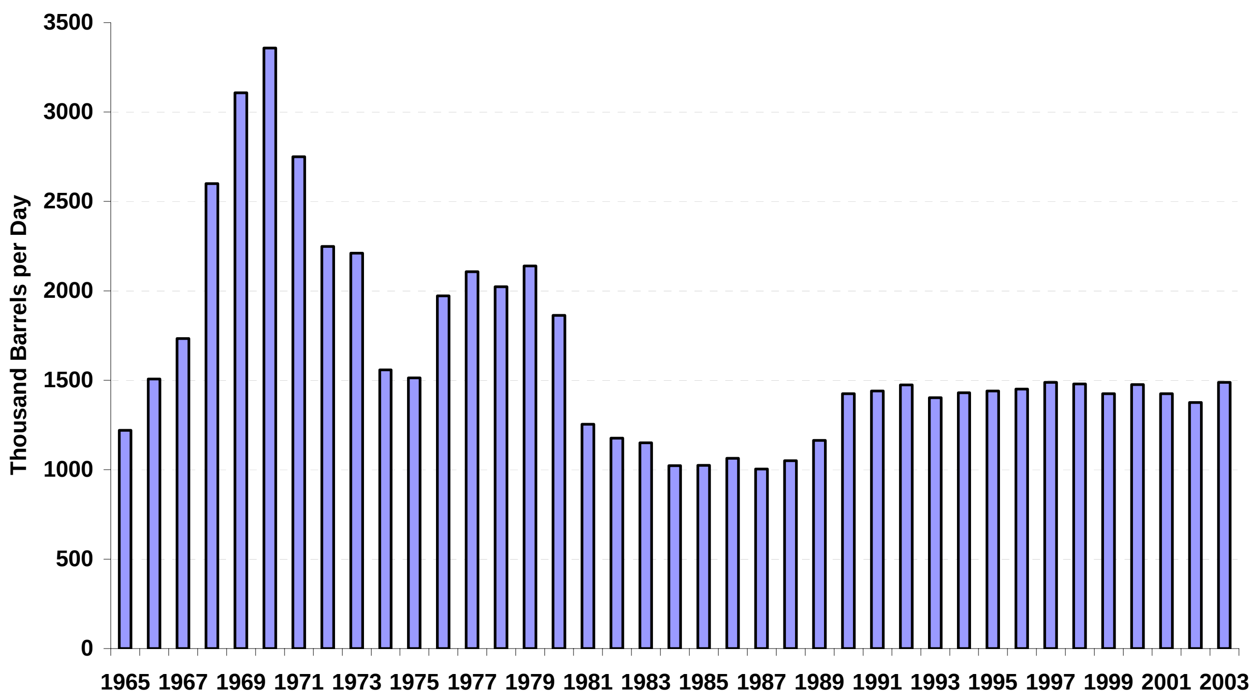
Some evidence indicates that the increase in the royalty rate has led some producers to reassess their investment plans. For example, ChevronTexaco, which has a 30-percent stake in the Hamaca extra-heavy crude project in partnership with ConocoPhillips and PdVSA, had proposed to build another $6 billion project.[q] However, according to Chris Smith, the regional manager for Latin America at ChevronTexaco's Global Gas group, the company is now reevaluating its investments in Venezuela.[r] Thus, while the increase in the royalty rate can be expected to increase government revenues by $766 million per year in the short run, the longer-run impact is far less certain. If prices stay in the neighborhood of their current level of more than $40 per barrel, the companies will almost certainly stay the course with their planned investments in Venezuela. However, these investments will be problematic should prices return to their long-run average of around $23 per barrel.[s]

Libya

Esso (subsequently ExxonMobil) made the first commercial oil find in Libya in 1959.[t] The oil rush was on with the Libyan Ministry of Petroleum granting concessions to more than 30 companies. Exports commenced in 1961. By 1971, Libyan oil production stood at approximately 2.8 million barrels of oil per day.[u] Late in that year, the government of Mu'ammar Qadhafi, which had assumed power in 1969, began to nationalize the oil properties. The first property to be seized was British Petroleum's share of the British Petroleum-Bunker Hunt Sarir field.[v] Indicative of the investment climate, the nationalization apparently was prompted by Qadhafi's displeasure at Great Britain's foreign policy. In any event, Qadhafi followed up the nationalization with a decree in 1973 that the government would assume ownership of 51 percent of the remaining major oil properties. Companies that refused Libyan participation, such as Shell and Texaco, had their properties nationalized. The investment climate went from bad to worse, with both Exxon and Mobil withdrawing from Libya after the United States imposed a trade embargo in 1981.[w] Four other FRS companies (Amerada Hess, Conoco, Marathon, and Occidental) remained in Libya until 1986.[x] In addition to the sanctions by the United States, the United Nations imposed sanctions on Libya in 1992, after it became clear that government officials in Libya were involved in the 1988 bombing of Pan Am flight 103 over Lockerbie, Scotland, that killed 270 people. The United Nations later extended the sanctions to include a ban on the sale of oil equipment.

Not surprisingly, Libya's hostility to investments by U.S.-based firms as well as to the U.S. and U.N. sanctions has exacted a toll on the country's ability to produce oil. Between 1970 and 1987, production declined 70 percent to approximately one million barrels per day (**Figure 46**). Production subsequently rebounded to approximately 1.5 million barrels of oil per day in 2003. However, this is a fraction of what could be produced given that Libya's proven oil reserves were approximately 36 billion barrels as of the end of 2003. Natural gas also has languished. Libya ended 2003 with approximately 46 tcf of proved gas reserves, yet its annual production is only about 0.2 tcf per year.[y]

Figure 46. Libyan Oil Production, 1965-2003



Source: BP Statistical Review of World Energy (June 2004).

In 1999, Libya extradited the two men suspected in the Pan Am flight 103 bombing to the Netherlands to stand trial before a Scottish court. In response to this and other actions, the U.N. suspended its sanctions against Libya in 1999 and lifted them completely in 2003.

In addition, the United States has eased economic sanctions against Libya after Libya followed through on its commitment to rid itself of weapons of mass destruction.

The removal of the sanctions has led to a literal Libyan oil rush. According to at least one report, Libya's Tripoli airport is bustling with oil and gas executives interested in investing in Libya's upstream.[z] The government has accommodated these potential investors by expanding its first open-bid license round to 15 areas.[aa] Among the companies that are reportedly interested in investing in Libya are Anadarko, Amerada Hess, Apache, BP, ConocoPhillips, ChevronTexaco, Exxon Mobil, Kerr-McGee Marathon, Oxy, and Royal Dutch/Shell.

Apparently, potential investing firms believe that Libya's transformation away from that of being a rogue state is genuine and irreversible. With respect to the resource numbers, the investing firms apparently believe that the most recent USGS resource estimates (8.3 billion barrels of undiscovered oil and 21 tcf of undiscovered natural gas) are overly conservative. They argue that Libya is underexplored, but exploration has yielded 12 oil fields with reserves of greater than one billion barrels,[bb] the very type of "elephant" fields that major oil companies need for growth. Both of these beliefs are about to be tested during the next decade.

---

[a]http://energy.cr.usgs.gov/WEcont/regions/reg3/R3cs.pdf (as of December 1, 2004).

[b]Ibid.

[c]BP Statistical Review of World Energy, June 2004.

[d]"Indonesia 2003 Oil Production Drops 8 Percent," available on the Web at http://www.usembassyjakarta.org/ econ/oil-2003-drop.html (as of November 22, 2004).

[e]Ibid.

[f]Ibid.

[g]Ibid.

[h]Energy Information Administration, Country Analysis Briefs, Venezuela, http://www.eia.doe.gov/emeu/cabs/ venez.html (as of March 3, 2005).

[i]Ibid.

[j]http://energy.cr.usgs.gov/WEcont/regions/reg6/r6vene.pdf (as of December 1, 2004).

[k]Ibid.

[l]http://www.eia.doe.gov/emeu/cabs/venez.html (as of December 1, 2004).

[m]http://www.economist.com/background/displaystory.cfm?story_id=3102178 (as of December 1, 2004).

[n]Energy Information Administration, Country Analysis Briefs, Venezuela, http://www.eia.doe.gov/emeu/cabs/ venez.html (as of December 14, 2004).

[o]http://www.gasandoil.com/goc/company/cnl44571.htm (as of December 1, 2004).

[p]http://www.eia.doe.gov/emeu/cabs/venez.html (as of December 1, 2004).

[q]http://www.gasandoil.com/goc/company/cnl44571.htm (as of December 1, 2002).

[r]Ibid.

[s]During the period 1861–2003, the average price of crude oil was $23 per barrel measured in 2003 dollars. Source: BP Statistical Review of World Energy, June 2004.

[t]http://www.countrystudies.US/libya/60.htm (as of December 1, 2004).

[u]BP Statistical Review of World Energy, June 2004 (supplementary tables).

[v]http://www.countrystudies.US/libya/60.htm (as of December 1, 2004).

[w]http://www.eia.doe.gov/emeu/cabs/libya.html (as of December 1, 2004).

[x]Ibid.

[y]BP Statistical Review of World Energy, June 2004.

[z]"Analyst: Libya is 'exploration buzz' among IOCs for 2005," *Oil and Gas Journal Online*, November 8 2004. Available on the Internet at http://ogj.pennnet.com/articles/article_display.cfm?Section=Archives& Article_Category=Gener&ARTICLE_ID=215338&KEYWORD=libya (as of December 1, 2004).

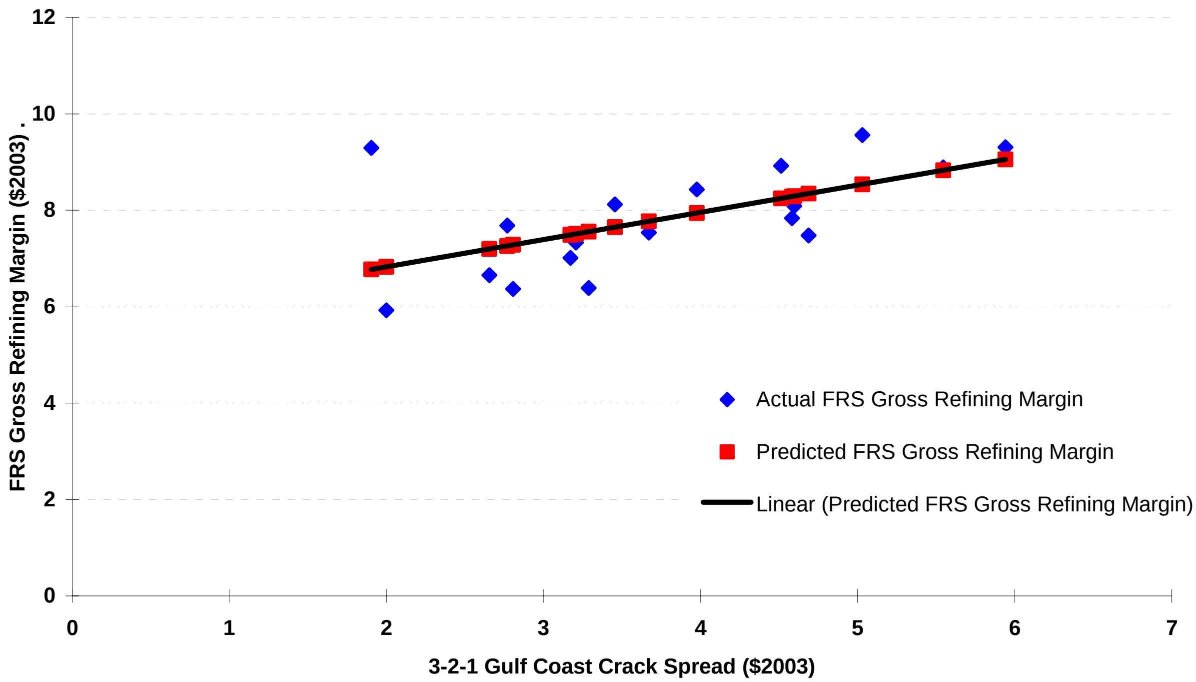
[aa]Ibid.

[bb]http://www.eia.doe.gov/emeu/cabs/libya.html (as of December 1, 2004).

Industry trade publications often portray gross refining margins (the spread between petroleum product prices and crude oil prices) as surrogates of profitability. However, researchers have rarely examined the statistical relationship between gross margins and profitability.[a] The richness of the FRS data, which is extensive enough to calculate both a gross refining margin and a rate of profitability,[b] offers researchers a rare opportunity to examine the statistical relationship between the gross refining margin and the rate of profitability for the same set of companies.

However, before examining the statistical relationship between the FRS gross refining margin and FRS profitability, researchers examine the statistical relationship between one of the most commonly used industry gross refining margins, 3-2-1 crack spread[c], and the FRS gross refining margin. Although the 3-2-1 crack spread omits numerous petroleum products, it includes the two most heavily consumed products and can be calculated easily. Statistical analysis shows a strong, positive correlation between the simple 3-2-1 crack spread and the comprehensive[d] FRS gross refining margin (**Figure 47**).[e] Consequently, there is statistical support[f] exists for generalizing the estimated relationship between the gross refining margin and profitability of the FRS companies to the overall domestic refining industry (i.e., the relationship between the FRS gross refining margin and FRS refining/marketing profitability is instructive of the relationship between industry gross refining margins and industry profitability).

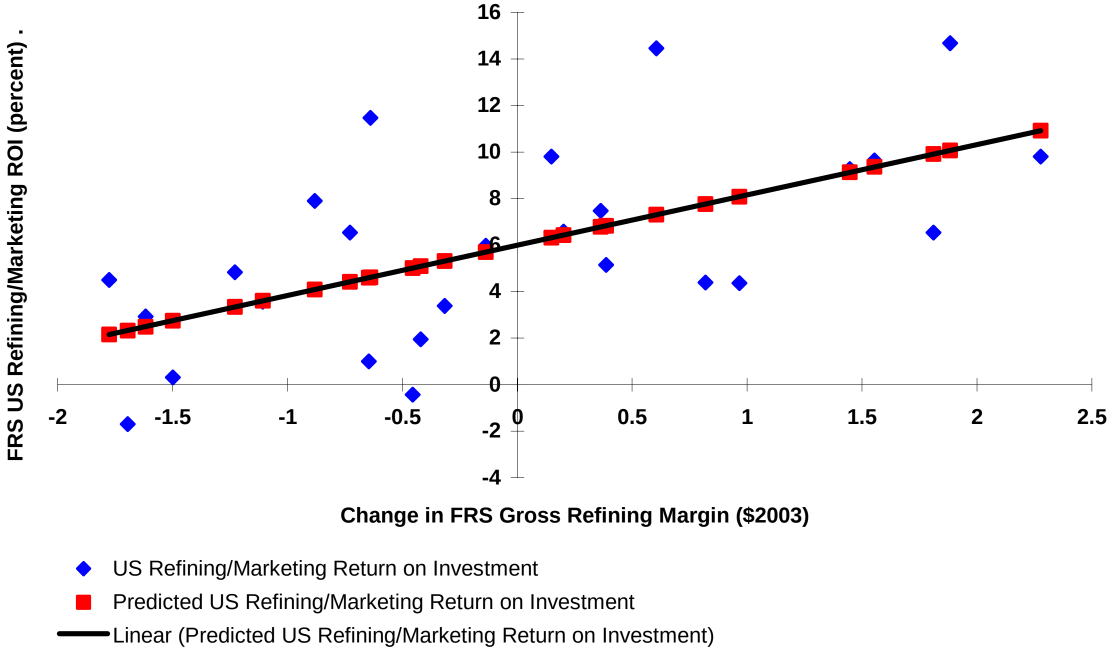
Figure 47. FRS Gross Refining Margin and 3-2-1 Gulf Coast Crack Spread, 1987-2003



Sources: FRS Gross Refining Margin: Energy Information Administration, Form EIA-28 (Financial Reporting System); 3-2-1 Gulf Coast Crack Spread: Reuters.

Applying statistical analysis to estimate the FRS profitability[g] of domestic refining/marketing[h] using the FRS gross refining margin suggests that there is little relationship between the FRS gross refining margin and the FRS domestic refining/marketing profitability.[i] However, one possible reason that the statistical relationship appears so weak is that the gross margin violates one of the statistical properties that must exist for the econometric analysis to provide dependable results.[j] Consequently, the change in the FRS gross refining margin was substituted for the FRS gross margin[k] in the regression in order to eliminate the statistical violation,[l] which resulted in a stronger and statistically significant estimated relationship. However, the change in the FRS gross refining margin explained only 35 percent of the variation in FRS refining/marketing profitability.[m] Consequently, using the change in the FRS gross refining margin is a better predictor of current FRS refining/marketing profitability than using the historical average profitability of approximately 5.8 percent (**Figure 48**),[n] although it is still a weak estimator.

Figure 48. FRS Domestic Refining/Marketing Return on Investment (ROI) and Change in FRS Gross Refining Margin, 1977-2003

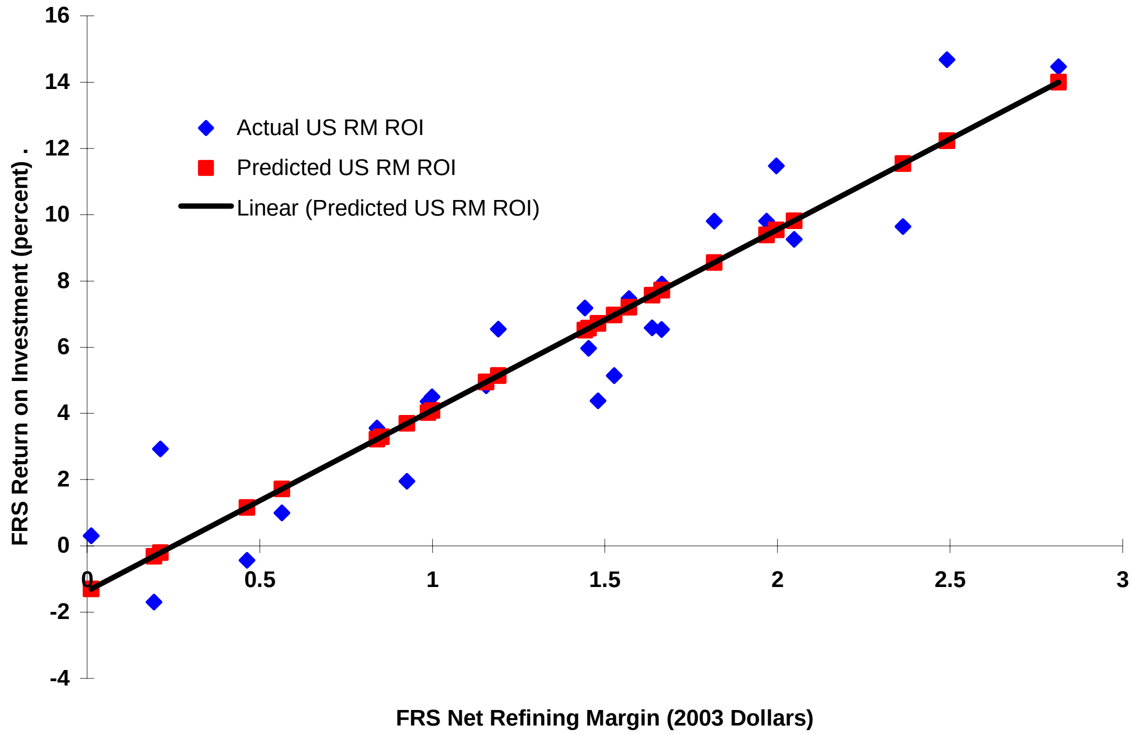


Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Thus, estimating profitability with a simple model (i.e., using only the gross refining margin or the change in a gross refining margin) has significant shortcomings, because almost two-thirds of the variation in FRS domestic refining/marketing profitability is unexplained by the transformed FRS gross refining margin. However, the richness of the FRS data allows the calculation of a second refining margin, a net refining margin. In particular, the FRS gross refining margin minus operating costs (i.e., energy costs, marketing costs, and other refining costs) equals the FRS net refining margin. Applying regression analysis to data for the FRS net refining margin and FRS refining/marketing profitability indicates that a strong, positive relationship exists between the two (**Figure 49).**[p] In particular, changes in the FRS net refining margin account for 88 percent of the variation in FRS refining/marketing profitability. The strength of this relationship routinely is utilized in discussions of year-to-year changes in FRS refining/marketing profitability in *Performance Profils of Major Energy Producers.* In particular, changes in the components of the FRS net refining margin – product prices, raw materials prices, and operating costs – are discussed to explain the reasons for changes in the FRS refining/marketing profitability.

Changes in the gross refining margin systematically reflect a small amount (i.e., 35 percent) of the historical changes in refining/marketing profitability. However, changes in the FRS net refining margin systematically approximate most (i.e., 88 percent) of the historical changes in refining/marketing profitability. The inability of the gross refining margin to account for much of the changes in operating costs renders it an extremely limited proxy for changes in profitability. Although the transformed gross refining margin can be used alone to estimate changes in profitability, it is a very rough measure, and it is beneficial if one can supplement it with some operating cost information (e.g., the price of natural gas to proxy energy costs). In the absence of operating cost information, changes in gross margins probably should be used only to infer the direction of changes in refining/marketing profitability, because they are less reliable approximating the magnitude of profitability changes.

Figure 49. U.S. Refining/Marketing Return on Investment and Net Refined Product Margin for FRS Companies, 1977-2003



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

---

[a]We are aware of only two studies that actually examine the relationship between the net refining margin and profitability, which is found to be strong and positive. The Energy Information Administration performed both studies. The first is *The Impact of Environmental Compliance Costs on U.S. Refining Profitability* (October 1997), http://www.eia.doe.gov/emeu/perfpro/ref_pi/index.html. The second is *The Impact of Environmental Compliance Costs on U.S. Refining Profitability, 1995–2001* (May 2003), http://www.eia.doe.gov/emeu/perfpro/ref_pi2/index.html.

[b]We only examined the relationship between the domestic FRS gross refining margin and the domestic FRS refining/ marketing rate of profitability. Although a rate of profitability for foreign FRS refining/marketing operations can be calculated, there is insufficient information to calculate a foreign FRS gross refining margin.

[c]The 3-2-1 crack spread presumes that 3 barrels of crude oil yield 2 barrels of motor gasoline and 1 barrel of distillate. The spread is calculated by adding the spot price of distillate with two times the spot price of motor gasoline and then subtracting three times the spot price of crude oil.

[d]The FRS gross refining margin is the most comprehensive of gross refining margins because it includes the weighted average price for all petroleum products sold by the FRS companies.

[e]The estimated regression is the FRS gross margin = 5.68 (0.74) + (3-2-1 crack spread * 0.57 (0.19)), where the standard errors of each estimated coefficient are listed in parentheses. The simple correlation coefficient is 0.598 and the adjusted R-square is 0.318. The F-statistic for the regression equation is 8.9, which is significant at a 99-percent level of confidence. The data used to estimate the relationship are for the years 1986 through 2003.

[f]Changes in the 3-2-1 crack spread account for 32 percent of the variation in the FRS gross refining margin, which may be due to the nationwide refining/marketing operations of the FRS companies.

[g]Profitability of the domestic refining/marketing operations of the FRS companies is calculated by dividing the contribution to corporate net income by domestic refining/marketing by net investment in place, which is net property, plant, and equipment plus year-end balance for advances and investments in unconsolidated affiliates. Thus, return on investment would reflect the profitability of each of the FRS lines of business or business segments.

[h]FRS data are collected in such a way that the profitability of refining cannot be calculated in the absence of marketing.

[i] The estimated regression is the FRS return on investment = 2.41 (4.31) + (FRS gross margin * 0.42 (0.49)), where the standard error of each estimated coefficient is listed in parentheses. The simple correlation coefficient is 0.17 and the adjusted R-square is -

0.01. The F-statistic for the regression equation is 0.73, which is significant at a 60-percent level of confidence. The data used to estimate the relationship are for the years 1977 through 2003.

[j]In particular, the FRS gross refining margin is not a stationary variable. See Walter Enders, *Applied Econometric Time Series*, Second Edition (John Wiley and Sons, Inc., Hoboken, New Jersey, 2004), particularly Chapter 6, Cointegration and Error-Correction Models.

[k]That is, the FRS gross refining margin was first differenced.

[l]Statistical testing indicated that the FRS gross refining margin could be made stationary by first differencing it. In particular, the difference between the gross refining margin of a particular year and the gross refining margin of the previous year replaced the gross margin of the particular year and the regression was rerun. Thus, the first year of the data series was lost and the regression's degrees of freedom were reduced by one. See Walter Enders, *Applied Econometric Time Series*, Second Edition (John Wiley and Sons, Inc., Hoboken, New Jersey, 2004), particularly Chapter 6, Cointegration and Error-Correction Models.

[m] The estimated regression is the FRS return on investment$_t$ = 6.03 (0.67) + ((FRS gross margin$_t$ - FRS gross margin$_{t-1}$)* 2.21 (0.57)), where the standard error of each estimated coefficient is listed in parentheses. The simple correlation coefficient is 0.609 and the adjusted R-square is 0.345. The F-statistic for the regression equation is 14.85, which is significant at a 1-percent level of confidence. The data used to estimate the relationship are for the years 1978 through 2003.

[n]The weighted average profitability of FRS domestic refining/marketing operations during the 1977 to 2003 period is 5.8 percent.

[o]Profitability also was estimated using the 3-2-1 crack spread. The statistical relationship was even weaker than that of the FRS gross refining margin. The estimate regression equation is the FRS return on investment = 0.60 (3.72) + (3-2-1 crack spread * 1.39 (0.95)), where the standard error of each estimated coefficient is listed in parentheses. The simple correlation coefficient is 0.35 and the adjusted R-square is 0.06. The F-statistic for the regression equation is 2.17, which is significant at the 80-percent level of confidence. The data used to estimate the relationship are for the years 1986 through 2003.

[p] The estimated regression equation is the FRS return on investment = -1.40 (0.59) + (FRS net margin * 5.52 (0.39)), where the standard error of each estimated coefficient is listed in parentheses. The simple correlation coefficient is 0.94 and the adjusted R-square is 0.88. The F-statistic for the regression equation is 200.5, which is significant at a 99-percent level of confidence. The data used to estimate the relationship are for the years 1977 through 2003.

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

Table B1. Selected U.S. Operating Statistics for FRS Companies and U.S. Industry, 1997-2003

Operating Statistics	1997	1998	1999	2000	2001	2002	2003
Petroleum and Natural Gas							
Net Production							
Crude Oil and Natural Gas Liquids (million barrels)							
FRS Companies	1,458.8	1,388.8	1,305.7	1,267.9	1,363.2	1,346.4	1,277.8
U.S. Industry[1]	3,002.0	2,824.0	2,848.0	2,801.0	2,805.0	2,759.0	2,679.0
FRS as a Percent of U.S. Industry	48.6	49.2	45.8	45.3	48.6	48.8	47.7
Natural Gas (billion cubic feet)							
FRS Companies	8,299.1	8,395.9	7,994.1	8,340.1	8,838.0	8,712.5	8,343.6
U.S. Industry[1]	19,211.0	18,720.0	18,928.0	19,219.0	19,779.0	19,353.0	19,425.0
FRS as a Percent of U.S. Industry	43.2	44.8	42.2	43.4	44.7	45.0	43.0
Net Imports							
Crude Oil and Natural Gas Liquids (million barrels)							
FRS Companies	571.1	634.7	474.9	324.1	716.1	630.5	737.8
U.S. Industry[1]	3,191.0	3,358.5	3,366.4	3,527.0	3,620.1	3,523.2	3,539.0
FRS as a Percent of U.S. Industry	17.9	18.9	14.1	9.2	19.8	17.9	20.8
Refinery Capacity (thousand barrels per day)							
FRS Companies	9,410.0	14,277.0	14,158.0	14,424.0	14,682.0	14,630.0	14,619.0
U.S. Industry[1]	16,128.7	16,567.0	16,787.0	17,177.4	17,367.4	17,338.9	17,500.0
FRS as a Percent of U.S. Industry	58.3	86.2	84.3	84.0	84.5	84.4	83.5
Refinery Output[2] (thousand barrels per day)							
FRS Companies	10,030.0	14,929.0	14,639.0	14,499.0	15,022.0	14,761.0	14,683.0
U.S. Industry[1]	17,234.3	17,499.6	17,493.1	17,763.2	17,688.9	17,654.5	17,969.5
FRS as a Percent of U.S. Industry	58.2	85.3	83.7	81.6	84.9	83.6	81.7
Electric Power							
Net Summer Capacity (million kilowatts)							
FRS Companies	-	-	-	-	-	-	28.9
U.S. Industry	778.6	775.9	785.9	811.7	848.3	905.3	953.2
FRS as a Percent of U.S. Industry	-	-	-	-	-	-	3.0
Net Generation (billion kilowatthours)							
FRS Companies	-	-	-	-	-	-	107.5
U.S. Industry	3,492.0	3,620.0	3,695.0	3,802.0	3,737.0	3,858.0	3,848.0
FRS as a Percent of U.S. Industry	-	-	-	-	-	-	2.8
Coal Production (million tons)							
FRS Companies	163.3	73.9	44.0	35.5	33.0	29.3	18.3
U.S. Industry[1]	1,089.9	1,117.5	1,100.4	1,073.6	1,127.7	1,093.3	1,071.8
FRS as a Percent of U.S. Industry	15.0	6.6	4.0	3.3	2.9	2.7	1.7

[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.

- = Not available.

Note: The data for total U.S. production of crude oil and natural gas liquids and natural gas (dry) utilized in this report are taken from Energy Information Administration, Form EIA-23 (Annual Survey of Domestic Oil and Gas Reserves); see U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 2003 Annual Report November 2004). 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 2,855 million barrels in 2003 and 2,936 million barrels in 2002. (See Energy Information Administration, Petroleum Supply Annual 2003, Volume I (July 2004), p. 2.) For dry natural gas production, the official Energy Information Administration U.S. totals are 19,068 billion cubic feet in 2003 and 18,964 billion cubic feet in 2002. (See Energy Information Administration, Natural Gas Monthly, September 2004, Table 1.)

Sources: Industry data - Petroleum net production: Energy Information Administration (EIA), Form EIA-23; see *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 2003 Annual Report* (November 2004). Net imports: data compiled for the International Energy Agency by the Petroleum Supply Division, Office of Oil and Gas, EIA. Refinery capacity and refinery output: EIA, Forms EIA-820 (Annual Refinery Report) and EIA-810 (Monthly Refinery Report); see *Petroleum Supply Annual*, 2002 and 2003. Electric capacity and electric generation: EIA, Form EIA-860, *Annual Electric Generator Reports*; Form EIA-867, *Annual Nonutility Power Producer Report*; Form EIA-860A, *Annual Electric Generator Report—Utility*; Form EIA-860B, *Annual Electric Generator Report—Nonutility*; Form EIA-906 and Form EIA-759, *Power Plant 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, 2002-2003
(Billion Dollars)

Selected Financial Items	FRS Companies 2002	FRS Companies 2003	S&P Industrials 2002	S&P Industrials 2003
Income Statement				
Operating Revenues	698.9	888.5	4,680.1	5,094.0
Operating Expenses	-659.7	-806.9	-4,194.1	-4,542.5
Operating Income	39.2	81.6	486.0	551.5
Interest Expense	-10.7	-8.8	-97.4	-97.2
Other Income[1]	6.7	16.9	-147.8	-12.6
Income Taxes	-14.6	-32.3	-124.0	-143.7
Net Income	20.6	57.4	116.8	297.9
Cash Flows from Operations[2]				
Net Income	20.6	57.4	116.8	297.9
Other Items, Net[3]	54.4	47.7	454.6	336.9
Net Cash Flow from Operations	75.0	105.1	571.4	634.8
Cash Flows from Investing Activities[2]				
Additions to Property, Plant & Equipment	-91.3	-76.4	-285.4	-271.9
Other Investment Activities, Net[4]	37.2	17.1	-99.9	-44.2
Net Cash Flow from Investing Activities	-54.1	-59.3	-385.2	-316.1
Cash Flows from Financing Activities[2]				
Proceeds from Long-Term Debt	34.1	26.4	437.0	410.7
Proceeds from Equity Security Offerings	4.9	8.4	33.4	41.4
Dividends to Shareholders	-17.7	-42.8	-94.3	-106.0
Reductions in Long-Term Debt	-27.9	-26.2	-317.7	-388.7
Stock Repurchases	-4.7	-6.1	-102.2	-114.9
Other Financing Activities, Net	-7.1	2.5	-83.9	-59.5
Net Cash Flow from Financing Activities	-18.4	-37.8	-127.8	-217.0
Effect of Exchange Rate Changes on Cash	0.6	0.8	4.2	8.9
Increase (Decrease) in Cash and Cash Equivalents	3.0	8.8	62.6	110.7

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

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

[3] "Other Items, Net" includes: Depreciation, Depletion & Amortization, deferred taxes, dry hole expense, minority interest, recognized undistributed earnings/(losses) of unconsolidated affiliates, (gain)/loss on disposition of Property, Plant & Equipment, changes in operating assets and liabilities, and other noncash items, excluding net change in short-term debt; other cash items, net.

[4] "Other Investment Activities, Net" includes additions to investments and advances and proceeds from disposals of PP&E.

Sources: Standard & Poor's (S&P) Industrials data 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, 2002-2003

	FRS Companies		S&P Industrials	
	2002	2003	2002	2003
Balance Sheet	(billion dollars)			
Assets				
Current Assets	156.3	164.9	1,500.6	1,615.8
Noncurrent Assets				
Property, Plant, and Equipment (PP&E)				
Gross	826.3	866.4	3,162.2	3,359.8
and Amortization (DD&A)	-379.6	-396.2	-1,471.1	-1,586.1
Net PP&E	446.6	470.1	1,691.1	1,773.7
Investments and Advances	53.9	54.6	138.0	142.1
Other Noncurrent Assets	115.7	98.9	2,801.5	3,135.6
Subtotal Noncurrent Assets	616.2	623.6	3,023.5	3,251.6
Total Assets	772.5	788.5	6,131.2	6,667.2
Liabilities and Stockholders Equity				
Liabilities				
Current Liabilities	156.7	150.7	1,084.8	1,130.0
Long-Term Debt	154.0	148.9	1,472.6	1,510.2
Other Long-Term Items	156.1	161.3	1,638.5	1,772.2
Minority Interest	11.0	10.4	75.5	71.5
Subtotal Liabilities and Other Items	477.8	471.4	4,271.3	4,484.0
Stockholders' Equity				
Retained Earnings	206.1	218.7	1,069.9	1,298.5
Other Equity	88.7	98.4	790.0	884.8
Subtotal Stockholders' Equity	294.7	317.1	1,859.9	2,183.3
Total Liabilities and Stockholders' Equity	772.5	788.5	6,131.2	6,667.2
Financial Ratios	(percent)			
Net Income/Stockholders' Equity	7.0	18.1	6.3	13.6
Net Income plus Interest/Total Invested Capital	7.0	14.2	6.4	10.7
Dividends/Net Cash Flow from Operations	23.7	40.7	16.5	16.7
Long-term Debt/Stockholders' Equity	52.3	47.0	79.2	69.2

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, 1997-2003
(Billion Dollars)

Balance Sheet Items	1997	1998	1999	2000	2001	2002	2003
Assets							
Current Assets							
Cash & Marketable Securities	12.2	8.1	12.2	18.7	18.6	19.5	27.0
Trade Accounts & Notes Receivable	51.2	47.8	68.1	98.6	71.4	78.7	84.9
Inventories							
Raw Materials & Products	21.4	21.6	23.3	25.6	23.4	23.2	26.8
Materials & Supplies	3.7	3.8	3.9	4.4	7.3	7.6	5.6
Other Current Assets	12.4	12.9	13.4	49.1	26.7	27.4	20.6
Total Current Assets	100.9	94.2	121.0	196.5	147.5	156.3	164.9
Non-current Assets							
Property, Plant & Equipment (PP&E)							
Gross PP&E	636.9	671.0	708.0	757.2	806.0	826.3	866.4
Depletion, and Amortization	-333.3	-334.5	-355.5	-351.6	-373.6	-379.6	-396.2
Net PP&E	303.6	336.5	352.5	405.5	432.4	446.6	470.1
Investments & Advances to Unconsolidated Affiliates	44.2	53.9	58.2	62.3	57.3	53.9	54.6
Other Non-current Assets	35.2	35.8	39.6	86.9	97.9	115.7	98.9
Total Non-current Assets	382.9	426.3	450.3	554.8	587.5	616.2	623.6
Total Assets	483.8	520.4	571.3	751.2	735.0	772.5	788.5
Liabilities & Stockholders' Equity							
Liabilities							
Current Liabilities							
Trade Accounts & Notes Payable	57.7	62.8	79.4	102.4	90.6	91.8	88.2
Other Current Liabilities	49.2	51.1	51.9	96.4	69.2	64.9	62.5
Long-Term Debt	73.4	94.6	104.0	120.0	132.0	154.0	148.9
Deferred Income Tax Credits	46.3	49.0	53.1	68.2	77.0	76.1	83.2
Other Deferred Credits	18.8	18.4	18.8	34.1	23.3	27.9	28.5
Other Long-Term Items	41.6	39.7	42.6	41.2	43.7	52.1	49.7
Minority Interest in Consolidated Affiliates	8.2	10.4	15.2	17.1	15.5	11.0	10.4
Total Liabilities	295.1	326.0	364.9	479.5	451.3	477.8	471.4
Stockholders' Equity	160.8	165.8	170.6	199.2	209.7	206.1	218.7
Retained Earnings	27.9	28.7	35.7	72.5	74.0	88.7	98.4
Other Equity							
Total Stockholders' Equity	188.7	194.4	206.3	271.8	283.7	294.7	317.1
Total Liabilities & Stockholders' Equity	483.8	520.4	571.3	751.2	735.0	772.5	788.5
Memo:							
Foreign Currency Translation Adjustment Cumulative at Year End	-2.7	-2.3	-2.7	-3.0	-5.1	-2.0	2.8
Foreign Currency Translation Adjustment for the Current Year	-3.9	0.0	-0.3	-2.1	-1.0	3.1	7.2

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

Table B5. Consolidating Statement of Income for FRS Companies, 2003
(Million Dollars)

Income Statement Items	Consol -idated	Eliminations & Nontraceables	Petroleum	Coal, Nuclear, & Non-conventional Energy[1]	Down-stream Natural Gas	Electric Power	Non-energy
Operating Revenues	888,503	-97,948	725,540	2,768	167,362	37,207	53,574
Operating Expenses							
General Operating Expenses	751,405	-95,168	600,707	2,081	160,682	34,204	48,899
Depreciation, Depletion, & Allowance	43,854	892	37,877	189	1,957	517	2,422
General & Administrative	11,686	2,215	6,210	66	1,241	375	1,579
Total Operating Expenses	806,945	-92,061	644,794	2,336	163,880	35,096	52,900
Operating Income	81,558	-5,887	80,746	432	3,482	2,111	674
Other Revenue & (Expense)							
Earnings of Unconsolidated Affiliates	9,073	-250	6,831	W	2,006	W	505
Other Dividend & Interest Income	4,686	4,686	-	-	-	-	-
Property, Plant, & Equipment	1,908	188	1,740	W	29	W	-28
Interest Expenses & Financial Charges	-8,764	-8,764	-	-	-	-	-
Minority Interest in Income	-1,719	-1,719	-	-	-	-	-
Foreign Currency Translation Effects	701	701	-	-	-	-	-
Other Revenue & (Expense)	2,079	2,079	-	-	-	-	-
Total Other Revenue & (Expense)	7,964	-3,079	8,571	-296	2,035	256	477
Pretax Income	89,522	-8,966	89,317	136	5,517	2,367	1,151
Income Tax Expense	32,292	-4,657	34,503	30	1,787	819	-190
Discontinued Operations	354	245	534	W	W	W	W
Extraordinary Items & Cumulative Effect of Accounting Changes	-157	739	-207	W	W	W	W
Net Income	57,427	-3,325	55,141	115	3,603	959	934

[1]Beginning in 2003, Coal is combind with Other Energy (Nuclear and Nonconventional Energy).
- = 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, 2003
(Million Dollars)

Income Statement Items	U.S. Petroleum				Foreign Petroleum		
	Consoli-dated	Production	Refining/ Marketing	Pipe-lines[1]	Consoli-dated	Production	Refining/ Marketing & Int'l Marine[2]
Operating Revenues							
Raw Material Sales	139,604	74,466	98,356	W	95,812	67,437	69,030
Refined Products Sales	313,735	W	315,884	0	175,536	W	175,709
Transportation Revenues	3,792	223	1,935	2,695	1,785	236	3,794
Management and Processing Fees	1,381	W	1,301	W	1,716	160	1,808
Other	9,538	728	8,739	81	3,434	W	3,300
Total Operating Revenues	468,050	76,193	426,215	5,294	278,283	69,575	253,641
Operating Expenses							
General Operating Expenses	397,844	27,008	406,580	3,905	223,656	21,844	246,745
Depreciation, Depletion, & Allowance	22,654	16,016	6,138	500	15,223	13,019	2,204
General & Administrative	4,594	1,173	3,282	142	1,616	858	758
Total Operating Expenses	425,092	44,197	416,000	4,547	240,495	35,721	249,707
Operating Income	42,958	31,996	10,215	747	37,788	33,854	3,934
Other Revenue & (Expense)							
Earnings of Unconsolidated Affiliates	2,870	1,677	925	268	3,961	3,471	W
Property, Plant, & Equipment	1,573	847	512	214	167	96	W
Total Other Revenue & (Expense)	4,443	2,524	1,437	482	4,128	3,567	561
Pretax Income	47,401	34,520	11,652	1,229	41,916	37,421	4,495
Income Tax Expense	16,540	11,974	4,165	401	17,963	16,384	1,579
Discontinued Operations	444	W	W	W	W	W	W
Extraordinary Items & Cumulative Effect of Accounting Changes	-414	W	W	W	W	W	W
Contribution To Net Income	30,891	22,630	7,434	827	24,250	21,334	2,916

[1]Beginning in 2003, natural gas and natural gas liquids pipelines are part of the downstream natural gas line of business. See Table B35.

[2]Foreign Refining/Marketing and International Marine are combined to avoid disclosure.

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, 2003
(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	133,975	3,504	26,126	-481	16,016
Refining/Marketing					
Refining	54,640	4,686	6,922	212	4,137
Marketing	15,098	834	1,645	30	1,390
Refining/Marketing Transport					
Pipelines	1,170	782	304	65	354
Marine	1,270	W	452	W	77
Other	1,252	W	223	W	180
Total U.S. Refining/Marketing	73,430	6,755	9,546	441	6,138
Rate Regulated Pipelines					
Refined Products	1,428	936	118	12	52
Crude Oil and Liquids	4,401	439	401	-13	448
Total Rate Regulated Pipelines	5,829	1,375	519	-1	500
Total U.S. Petroleum	213,234	11,634	36,191	-41	22,654
Foreign					
Production	134,201	16,518	24,825	1,475	13,019
Refining/Marketing & International Marine[1]	29,480	6,946	2,453	300	2,204
Total Foreign Petroleum	163,681	23,464	27,278	1,775	15,223
Total Petroleum	376,915	35,098	63,469	1,734	37,877
Downstream Natural Gas					
United States					
Processing and Gathering					
NGL Production	W	506	W	66	W
Other Processing and Gathering	6,486	W	966	W	252
LNG Import/Export Facilities	W	W	W	W	W
Total Processing and Gathering	9,757	514	1,240	-10	437
Marketing/Trading	W	W	W	W	W
Transmission					
Pipelines	6,177	1,649	922	W	345
Storage	609	0	29	0	23
Other	1,739	0	32	0	18
Total Transmission	8,525	1,649	983	W	386
Distribution	W	W	W	0	W
Total U.S. Downstream Natural Gas	23,713	2,197	5,120	165	1,178
Total Foreign Downstream Natural Gas	11,895	2,801	1,437	97	779
Total Downstream Natural Gas	35,608	4,998	6,557	262	1,957

[1]Foreign Refining/Marketing and International Marine combined to avoid disclosure.
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, 2003 (Continued)
(Million Dollars)

	Year End Balance		Activity During Year		
	Net PP&E	Investments & Advances	Additions to PP&E	Additions to Investments & Advances	DD&A
Electric Power					
United States					
Generation					
Regulated	W	W	W	W	W
Non-Regulated	W	W	W	26	62
Total Generation	9,878	1,078	1,396	26	242
Marketing/Trading	W	W	W	W	W
Transmission	W	W	W	W	W
Distribution	W	W	W	W	W
Total U.S. Electric Power	15,285	1,086	1,820	38	509
Foreign Electric Power	W	W	W	W	W
Total Electric Power	W	W	W	W	W
Nuclear, Nonconventional, & Coal					
Foreign	2,399	W	469	W	101
United States	1,204	379	72	171	88
Total Nuclear, Nonconventional, & Coal	3,603	462	541	202	189
Nonenergy					
Foreign Chemicals	7,449	3,086	412	W	729
U.S. Chemicals	18,942	4,964	2,037	287	1,606
Foreign Other Nonenergy	W	1,764	W	W	W
U.S. Other Nonenergy	W	1,086	W	571	W
Total Nonenergy	28,248	10,900	2,517	1,021	2,422
Nontraceable	9,689	731	1,210	120	892
Consolidated	470,122	54,555	76,399	3,542	43,854

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, 2002-2003
(Percent)

Line of Business	All FRS		Top Four		Five through Twelve		All Other	
	2002	2003	2002	2003	2002	2003	2002	2003
Petroleum	6.5	13.4	7.5	13.4	7.2	14.6	2.7	11.8
U.S. Petroleum	6.0	13.7	7.2	13.9	6.7	14.8	2.6	11.8
Oil and Gas Production	10.5	16.5	12.7	17.4	10.1	16.8	6.1	13.2
Refining/Marketing	-1.7	9.3	-2.7	9.1	1.2	7.7	-2.0	10.4
Pipelines	5.2	11.5	10.0	9.3	3.7	13.3	13.6	20.9
Foreign Petroleum	7.2	13.0	7.7	12.9	10.2	14.0	2.9	11.9
Oil and Gas Production	9.2	14.2	10.1	14.5	14.3	14.3	2.9	11.8
Refining/Marketing	-1.1	7.7	0.0	7.7	-38.4	-950.0	3.2	12.5
International Marine	-6.2	W	-5.7	W	-30.8	0.0	0.0	0.0
Downstream Natural Gas[1]	-	8.9	-	20.4	-	3.7	-	2.1
Electric Power[1]	-	5.2	-	7.8	-	4.6	-	0.0
Nuclear, Nonconventional, & Coal	-6.9	2.8	-33.1	18.9	1.8	-111.3	13.4	13.5
Nonenergy	4.7	2.4	5.3	7.0	-2.0	-10.8	13.1	2.4

[1]The downstream natural gas and electric power lines of business were added to the EIA-28 survey form beginning with the 2003 reporting year.

- = Data not available.

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, 1997-2003
(Million Dollars)

	1997	1998	1999	2000	2001	2002	2003
Sources of R&D Funds							
Federal Government	W	W	27	W	W	W	W
Internal Company	2,841	1,668	1,377	1,316	1,542	1,742	1,523
Other Sources	W	W	20	W	W	W	W
Total Sources	2,885	1,707	1,424	1,326	1,570	1,753	1,534
Breakdown of R&D Expenditures							
Oil & Gas Recovery	585	606	430	453	592	464	370
Gas to Liquids	-	-	-	-	-	-	52
Other Petroleum	380	365	345	327	376	656	357
Coal Gasification/Liquefaction	W	W	W	W	0	0	W
Other Coal	W	W	W	W	0	0	W
Downstream Natural Gas	-	-	-	-	-	-	W
Wind Generation	-	-	-	-	-	-	0
Solar Generation	-	-	-	-	-	-	W
Distributed Generation	-	-	-	-	-	-	0
Fuel Cells	-	-	-	-	-	-	W
Other Nonconventional Energy	54	28	34	W	W	59	54
Nonenergy	1,738	616	538	452	526	517	676
Unassigned	120	85	W	W	W	W	W
Total Expenditures	2,885	1,707	1,424	1,326	1,570	1,753	1,534

- = Data not available prior to 2003.

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, 2003
(Percent)

Line of Business	Top Four	Five through Twelve	All Other	All FRS
Petroleum	60.4	22.7	17.0	100.0
United States	47.6	30.2	22.3	100.0
Production	45.4	38.5	16.0	100.0
Refining/Marketing	48.9	17.6	33.6	100.0
Refining	44.7	19.1	36.2	100.0
Marketing	60.1	10.1	29.8	100.0
Rate Regulated Pipelines	74.3	10.4	15.3	100.0
Foreign	75.8	13.7	10.6	100.0
Production	71.1	17.0	11.9	100.0
Refining/Marketing	95.0	0.0	5.0	100.0
International Marine	100.0	0.0	0.0	100.0
Downstream Natural Gas	32.3	54.6	13.1	100.0
U.S. Downstream Natural Gas	15.7	74.1	10.2	100.0
Processing and Gathering	23.3	59.7	17.0	100.0
Marketing/Trading	10.5	89.3	0.1	100.0
Transmission	13.3	82.8	3.9	100.0
Distribution	-0.5	78.0	22.5	100.0
Foreign Downstream Natural Gas	61.6	20.3	18.2	100.0
Electric Power	19.8	80.2	0.0	100.0
U.S. Electric Power	10.1	89.9	0.0	100.0
Generation	15.1	84.9	0.0	100.0
Marketing/Trading	0.0	100.0	0.0	100.0
Transmission	0.0	100.0	0.0	100.0
Distribution	0.0	100.0	0.0	100.0
Foreign Electric Power	100.0	0.0	0.0	100.0
Generation	100.0	0.0	0.0	100.0
Marketing/Trading	0.0	0.0	0.0	100.0
Transmission	0.0	0.0	0.0	100.0
Distribution	0.0	0.0	0.0	100.0
Nuclear, Nonconventional, & Coal	69.9	11.6	18.5	100.0
Nonenergy	64.8	22.7	12.5	100.0
Chemicals	67.1	19.5	13.5	100.0
Other Nonenergy	48.1	46.0	5.9	100.0
Consolidated	57.5	27.0	15.5	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, 1997-2003
(Million Dollars)

Cash Flows [1]	1997	1998	1999	2000	2001	2002	2003
Cash Flows From Operations							
Net Income .	32,082	12,519	22,866	53,192	37,735	20,592	57,427
Minority Interest in Income	896	764	1,161	1,912	2,172	1,068	1,719
Noncash Items:							
Depreciation, Depletion, & Allowance	29,569	35,445	32,452	37,621	46,377	45,529	43,854
Dry Hole Expense, This Year	2,069	2,518	1,808	1,328	2,344	1,925	1,668
Deferred Income Taxes	2,301	-1,123	-25	5,611	3,145	-143	6,033
Recognized Undistributed (Earnings)/Losses of Unconsolidated Affiliates	-374	2,987	136	-3,319	-318	1,144	-1,429
Property, Plant, & Equipment (PP&E)	-2,716	-2,658	-1,922	-2,065	-1,176	-1,374	-1,908
Changes in Operating Assets and Liabilities and Other Noncash Items	298	-3,792	-2,259	-6,269	2,848	-636	-661
Other Cash Items, Net	1,197	1,502	581	629	-3,490	6,847	-1,591
Net Cash Flow From Operations	65,322	48,162	54,798	88,640	89,637	74,952	105,112
Cash Flows From Investing Activities							
Additions to PP&E:							
Due to Mergers and Acquisitions	-5,579	-18,868	-5,961	-49,722	-40,971	-34,175	-11,367
Other	-48,666	-51,046	-44,775	-52,470	-59,313	-57,170	-65,054
Total Additions to PP&E	-54,245	-69,914	-50,736	-102,192	-100,284	-91,345	-76,421
Additions to Investments and Advances	-7,685	-5,223	-6,874	-7,156	-10,086	-7,529	-3,542
Proceeds From Disposals of PP&E	9,320	16,243	13,267	26,663	7,683	15,186	16,112
Other Investment Activities, Net	6,587	4,235	3,523	8,742	8,406	29,572	4,572
Cash Flow From Investing Activities	-46,023	-54,659	-40,820	-73,943	-94,281	-54,116	-59,279
Cash Flows From Financing Activities							
Proceeds From Long-Term Debt	17,901	27,072	29,862	33,292	54,987	34,094	26,352
Proceeds From Equity Security Offerings	1,507	9,112	3,557	30,606	6,267	4,878	8,397
Reductions in Long-Term Debt	-19,774	-18,019	-24,988	-29,323	-34,264	-27,863	-26,222
Purchase of Treasury Stock	-7,910	-5,776	-424	-5,362	-7,474	-4,680	-6,059
Dividends to Shareholders	-16,941	-17,169	-16,081	-18,981	-17,132	-17,744	-42,808
Other Financing Activities, Including Net Change in Short-Term Debt	5,537	6,859	-3,377	-17,205	3,848	-7,063	2,496
Cash Flow From Financing Activities	-19,680	2,079	-11,451	-6,973	6,232	-18,378	-37,844
Effect of Exchange Rate on Cash	-255	-13	-24	-119	-308	571	816
and Cash Equivalents	-636	-4,431	2,503	7,605	1,280	3,029	8,805

[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, 1997-2003
(Million Dollars)

	1997	1998	1999	2000	2001	2002	2003
Income Taxes (as per Financial Statements)							
Current Paid or Accrued:							
Alternative Minimum Tax	5,656	603	1,375	11,705	8,812	390	7,516
U.S. Federal Investment Tax Credit	-93	-85	-90	-129	-246	-245	-236
Effect of Alternative Minimum Tax	-400	-16	445	-1,222	-632	69	-330
U.S. State & Local Income Taxes	794	443	371	1,338	1,067	478	1,094
Foreign Income Taxes							
Canada	932	456	597	1,765	1,139	1,236	1,567
Europe and Former Soviet Union [1]	2,927	1,798	3,110	7,002	6,515	5,619	6,858
Africa	1,926	449	1,607	3,617	3,057	2,884	3,851
Middle East	802	745	1,286	2,380	1,937	1,753	2,115
Other Eastern Hemisphere	1,901	992	1,679	2,214	1,676	1,674	2,763
Other Western Hemisphere	1,739	428	346	900	695	669	1,127
Total Foreign	10,227	4,868	8,625	17,878	15,019	13,835	18,281
Total Current	16,184	5,813	10,726	29,570	24,020	14,527	26,325
Deferred							
U.S. Federal, before Investment Tax Credit	1,477	-373	1,480	3,168	2,403	241	4,770
U.S. Federal Investment Tax Credit	-2	-28	-14	-78	-10	-18	-17
Effect of Alternative Minimum Tax	400	-16	-415	1,233	650	-69	335
U.S. State & Local Income Taxes	54	104	136	221	26	76	310
Foreign	519	-791	-1,075	910	567	-191	569
Total Deferred	2,448	-1,104	112	5,454	3,636	39	5,967
Total Income Tax Expense	18,632	4,709	10,838	35,024	27,656	14,566	32,292
Income Tax Expense To Statutory Rate							
Consolidated Pretax Income/(Loss)	51,453	16,017	33,837	86,702	68,246	36,171	89,522
Less: Foreign Source Income not Subject to U.S. Tax	5,827	251	2,160	13,355	8,918	8,816	17,818
Equals: Income Subject to U.S. Tax	45,626	15,766	31,677	73,347	59,328	27,355	71,704
Less: U.S. State & Local Income Taxes	785	570	486	1,497	895	345	955
Less: Applicable Foreign Income Taxes Deducted	312	32	107	353	82	252	315
Equals: Pretax Income Subject to U.S. Tax	44,529	15,164	31,084	71,497	58,351	26,758	70,434
Tax Provision Based on Previous Line	15,621	5,332	10,902	25,032	20,438	9,363	24,657
Increase/(Decrease) in Taxes Due To:							
Foreign Tax Credits Recognized	-6,982	-3,563	-5,963	-9,787	-8,513	-7,283	-11,385
U.S. Federal Investment Tax Credit Recognized	-137	-124	-98	-129	-486	-245	-257
Statutory Depletion	-63	-30	-8	-3	-1	-3	-6
Effect of Alternative Minimum Tax	0	-16	23	11	16	0	0
Other	-1,399	-1,485	-2,068	-447	-582	-1,462	-963
Actual U.S. Federal Tax Provision (Refund)	7,040	114	2,788	14,677	10,872	370	12,046

[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, 1997-2003
(Million Dollars)

	1997	1998	1999	2000	2001	2002	2003
Production Taxes							
Oil and Gas Production	1,965	1,176	1,674	2,604	2,506	2,187	3,127
Coal, Nuclear, & Nonconventional Energy	172	47	43	W	W	35	W
Other [1]	W	0	0	W	W	0	W
Total Production Taxes	2,137	1,223	1,717	2,635	2,543	2,222	3,154
Superfund	14	12	13	12	17	11	20
Import Duties	77	60	71	111	69	64	80
Sales, Use, and Property	2,407	2,648	2,268	2,356	2,373	2,360	2,023
Payroll	1,406	1,357	1,289	1,259	1,193	1,121	1,134
Other Taxes	559	360	467	789	546	378	403
Total Taxes Paid (Other Than Income Taxes)	6,600	5,660	5,825	7,162	6,741	6,156	5,067
Excise Taxes Collected	30,984	39,918	46,293	47,084	44,310	43,464	41,907

[1] Nonenergy, and beginning in 2003, Downstream Natural Gas..
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, 1997-2003
(Million Dollars)

	1997	1998	1999	2000	2001	2002	2003
United States							
Exploration							
Acquisition of Unproved Acreage	2,653	3,912	633	4,010	3,527	2,281	1,389
Geological and Geophysical	750	916	621	849	758	821	659
Drilling and Equipping [1]	2,905	2,964	1,921	2,550	3,276	2,555	2,525
Other	690	954	659	610	770	832	703
Total Exploration	6,998	8,746	3,834	8,019	8,331	6,489	5,276
Development							
Acquisition of Proved Acreage	2,928	3,568	1,144	27,939	7,383	7,572	6,051
Lease Equipment	1,823	2,688	2,431	1,907	3,818	3,325	3,636
Drilling and Equipping [1]	8,540	7,769	5,022	8,788	11,671	10,711	10,581
Other [2]	1,557	1,657	1,056	1,391	2,655	3,715	1,652
Total Development	14,848	15,682	9,653	40,025	25,527	25,323	21,920
Development	21,846	24,428	13,487	48,044	33,858	31,812	27,196
Foreign							
Exploration							
Acquisition of Unproved Acreage	565	2,159	2,252	4,105	4,696	2,588	1,346
Geological and Geophysical	897	1,065	885	875	1,028	939	866
Drilling and Equipping [1]	2,684	2,650	1,579	1,824	2,677	2,108	2,243
Other	1,128	1,299	903	1,087	1,146	864	949
Total Exploration	5,274	7,173	5,619	7,891	9,547	6,499	5,404
Development							
Acquisition of Proved Acreage	1,641	7,121	2,083	11,644	12,186	8,600	3,060
Lease Equipment	2,207	2,505	2,142	1,842	3,186	2,538	4,701
Drilling and Equipping [1]	6,426	6,206	5,143	5,057	7,060	8,040	9,793
Other [2]	2,383	3,388	2,531	2,364	3,965	5,695	5,250
Total Development	12,657	19,220	11,899	20,907	26,397	24,873	22,804
Development	17,931	26,393	17,518	28,798	35,944	31,372	28,208

[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, 2003
(Million Dollars)

Exploration and Development Expenditures	Worldwide	United States Total	United States Onshore	United States Offshore	Foreign
Exploration Expenditures					
Unproved Acreage	2,735	1,389	522	867	1,346
Drilling and Equipping:					
Completed Well Costs	-	1,934	548	1,386	-
Work-in-progress Adjustment	-	591	173		-
Total Drilling and Equipping	4,768	2,525	721	1,804	2,243
Geological and Geophysical	1,525	659	265	394	866
Other, Including Direct Overhead	1,652	703	305	398	949
Total Exploration Expenditures	10,680	5,276	1,813	3,463	5,404
Development Expenditures					
Proved Acreage (Including Mergers and Acquisitions)	9,111	6,051	3,952	2,099	3,060
Drilling and Equipping:					
Completed Well Costs	-	7,914	6,009	1,905	-
Work-in-progress Adjustment	-	2,667	878	1,789	-
Total Drilling and Equipping	20,374	10,581	6,887	3,694	9,793
Lease Equipment	8,337	3,636	1,112	2,524	4,701
Other Development					
Support Equipment	751	333	170	163	418
Other, Including Direct Overhead	6,151	1,319	809	510	4,832
Total Development Expenditures	44,724	21,920	12,930	8,990	22,804
Total Exploration and Development Expenditures	55,404	27,196	14,743	12,453	28,208

- = Not available.

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

Table B16. Exploration and Development Expenditures by Region, for FRS Companies, 1997-2003
(Million Dollars)

	1997	1998	1999	2000	2001	2002	2003
Exploration Expenditures							
U.S. Onshore	3,396	3,941	1,174	4,136	4,779	3,023	1,813
U.S. Offshore	3,602	4,805	2,660	3,883	3,552	3,466	3,463
Total United States	6,998	8,746	3,834	8,019	8,331	6,489	5,276
Canada	310	638	420	1,184	3,899	1,694	1,311
OECD Europe	1,684	1,916	767	869	756	1,223	629
Former Soviet Union and E. Europe	285	630	354	317	374	470	691
Africa	807	1,092	1,268	910	1,579	1,292	1,645
Middle East	53	141	96	56	197	121	132
Other Eastern Hemisphere	1,341	1,563	1,192	1,675	1,478	1,121	662
Other Western Hemisphere	794	1,193	1,522	2,880	1,264	578	334
Total Foreign	5,274	7,173	5,619	7,891	9,547	6,499	5,404
Worldwide Exploration Expenditures	12,272	15,919	9,453	15,910	17,878	12,988	10,680
Development Expenditures							
U.S. Onshore	9,624	9,519	5,396	22,953	19,465	19,307	12,930
U.S. Offshore	5,224	6,163	4,257	17,072	6,062	6,016	8,990
Total United States	14,848	15,682	9,653	40,025	25,527	25,323	21,920
Canada	1,688	4,168	1,636	3,697	11,425	4,993	3,592
OECD Europe	5,368	6,670	3,370	6,651	4,617	8,571	5,101
Former Soviet Union and E. Europe	343	637	252	576	507	803	1,429
Africa	2,171	2,042	1,826	1,809	3,968	3,799	7,542
Middle East	590	801	297	494	542	653	844
Other Eastern Hemisphere	1,643	2,386	2,250	5,112	3,513	5,074	3,499
Other Western Hemisphere	854	2,516	2,268	2,568	1,826	980	797
Total Foreign	12,657	19,220	11,899	20,907	26,397	24,873	22,804
Worldwide Development Expenditures	27,505	34,902	21,552	60,932	51,924	50,196	44,724
Expenditures							
U.S. Onshore	13,020	13,460	6,570	27,089	24,244	22,330	14,743
U.S. Offshore	8,826	10,968	6,917	20,955	9,614	9,482	12,453
Total United States	21,846	24,428	13,487	48,044	33,858	31,812	27,196
Canada	1,998	4,806	2,056	4,881	15,324	6,687	4,903
OECD Europe	7,052	8,586	4,137	7,520	5,373	9,794	5,730
Former Soviet Union and E. Europe	628	1,267	606	893	881	1,273	2,120
Africa	2,978	3,134	3,094	2,719	5,547	5,091	9,187
Middle East	643	942	393	550	739	774	976
Other Eastern Hemisphere	2,984	3,949	3,442	6,787	4,991	6,195	4,161
Other Western Hemisphere	1,648	3,709	3,790	5,448	3,090	1,558	1,131
Total Foreign	17,931	26,393	17,518	28,798	35,944	31,372	28,208
Expenditures	39,777	50,821	31,005	76,842	69,802	63,184	55,404

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

Table B17. Production (Lifting) Costs by Region for FRS Companies, 1997-2003
(Million Dollars)

	1997	1998	1999	2000	2001	2002	2003
United States							
Taxes Other Than Income Taxes	1,965	1,176	1,674	2,604	2,506	2,187	3,127
Other Costs	10,147	9,787	9,494	8,417	10,377	10,345	10,424
Total Production Costs	12,112	10,963	11,168	11,021	12,883	12,532	13,551
U.S. Onshore	9,604	8,198	8,039	8,254	9,838	9,650	10,549
U.S. Offshore	2,508	2,765	3,129	2,767	3,045	2,882	3,002
Canada							
Royalty Expenses	W	W	W	W	0	0	0
Taxes Other Than Income Taxes	W	W	W	W	105	109	119
Other Costs	961	1,037	1,120	1,379	1,842	2,303	2,818
Total Production Costs	1,049	1,129	1,252	1,496	1,947	2,412	2,937
OECD Europe							
Royalty Expenses	217	251	62	W	W	49	W
Taxes Other Than Income Taxes	360	269	330	W	W	456	W
Other Costs	3,950	3,980	3,666	3,485	3,496	3,416	4,098
Total Production Costs	4,527	4,500	4,058	4,025	4,151	3,921	4,884
Former Soviet Union and E. Europe							
Royalty Expenses	W	W	W	W	W	0	0
Taxes Other Than Income Taxes	W	W	W	W	W	0	30
Other Costs	188	207	111	179	155	111	177
Total Production Costs	192	208	148	196	191	111	207
Africa							
Royalty Expenses	W	W	W	W	W	0	0
Taxes Other Than Income Taxes	W	W	W	W	W	377	590
Other Costs	861	1,194	1,153	1,208	1,384	1,730	1,743
Total Production Costs	1,310	1,490	1,268	1,784	1,847	2,107	2,333
Middle East							
Royalty Expenses	141	130	112	137	0	0	0
Taxes Other Than Income Taxes	70	49	77	75	55	46	20
Other Costs	280	250	235	175	407	502	516
Total Production Costs	491	429	424	387	462	548	536
Other Eastern Hemisphere							
Royalty Expenses and Taxes Other Than Income Taxes	456	240	507	618	527	580	675
Other Costs	1,144	1,074	1,097	1,392	1,931	2,002	1,836
Total Production Costs	1,600	1,314	1,604	2,010	2,458	2,582	2,511
Other Western Hemisphere							
Royalty Expenses and Taxes Other Than Income Taxes	156	87	184	304	143	276	392
Other Costs	470	552	443	533	600	633	578
Total Production Costs	626	639	627	837	743	909	970
Total Foreign							
Royalty Expenses	891	740	384	437	153	150	W
Taxes Other Than Income Taxes	1,050	675	1,172	1,947	1,831	1,743	W
Other Costs	7,854	8,294	7,825	8,351	9,815	10,697	11,766
Total Production Costs	9,795	9,709	9,381	10,735	11,799	12,590	14,378

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, 1997-2003
(Thousand Acres)

	1997	1998	1999	2000	2001	2002	2003
Net Acreage							
U.S. Onshore							
Developed	25,474	26,396	25,895	31,760	34,332	37,103	36,721
Undeveloped	31,154	30,598	25,880	37,657	43,293	40,280	42,891
U.S. Offshore							
Developed	5,343	4,634	4,988	5,383	5,881	5,281	5,375
Undeveloped	22,983	23,168	24,940	21,483	20,933	21,929	20,875
Foreign							
Developed	21,984	24,887	26,337	32,535	32,903	37,603	33,952
Undeveloped	472,106	514,511	416,209	416,941	424,465	429,394	312,769
Gross Acreage							
U.S. Onshore							
Developed	45,249	49,097	45,978	57,626	63,721	69,641	65,367
Undeveloped	55,530	51,364	42,325	59,295	69,790	64,841	66,918
U.S. Offshore							
Developed	10,665	8,861	9,534	10,588	11,317	9,802	9,331
Undeveloped	30,845	32,439	35,689	31,609	30,523	32,384	31,134
Foreign							
Developed	58,198	64,358	59,247	71,330	70,112	81,171	70,516
Undeveloped	924,839	1,083,355	835,615	882,761	834,500	799,007	608,666

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

Table B19. U.S. Net Wells Completed for FRS Companies and U.S. Industry, 1997-2003

	1997	1998	1999	2000	2001	2002	2003
Number of Net Wells Completed During Year for FRS Companies							
Onshore							
Net Exploratory Wells							
Dry Holes	163	159	93	86	122	119	93
Oil Wells	90	55	26	19	59	21	19
Gas Wells	170	142	105	217	351	164	164
Total Exploratory Wells	424	356	225	321	533	304	275
Net Development Wells							
Dry Holes	301	256	162	229	266	220	225
Oil Wells	3,016	2,510	1,130	1,775	1,815	1,187	1,567
Gas Wells	2,261	2,074	1,519	2,927	5,226	4,982	5,539
Total Development Wells	5,577	4,841	2,812	4,930	7,307	6,389	7,331
Offshore							
Net Exploratory Wells							
Dry Holes	98	91	59	73	63	52	43
Oil Wells	31	22	28	28	39	35	20
Gas Wells	73	63	61	59	63	53	36
Total Exploratory Wells	202	176	148	159	165	140	98
Net Development Wells							
Dry Holes	46	32	26	29	38	38	13
Oil Wells	181	115	145	128	240	135	95
Gas Wells	168	133	153	157	170	134	75
Total Development Wells	396	280	324	315	448	307	183
Total United States							
Net Exploratory Wells							
Dry Holes	261	249	153	158	185	171	135
Oil Wells	121	77	54	47	98	56	38
Gas Wells	243	205	166	275	415	217	199
Total Exploratory Wells	626	531	372	480	698	443	373
Net Development Wells							
Dry Holes	347	288	188	258	305	259	238
Oil Wells	3,197	2,625	1,275	1,903	2,054	1,321	1,662
Gas Wells	2,429	2,208	1,672	3,084	5,396	5,116	5,614
Total Development Wells	5,973	5,121	3,136	5,245	7,755	6,696	7,514
Number of Net Wells Completed							
Net Exploratory Wells							
Dry Holes	2,145	1,843	1,157	1,343	1,731	1,277	1,339
Oil Wells	434	306	153	269	331	233	280
Gas Wells	542	589	520	612	968	689	781
Total Exploratory Wells	3,121	2,739	1,830	2,224	3,030	2,199	2,399
Net Development Wells							
Dry Holes	3,659	3,138	2,273	2,684	2,716	2,332	2,688
Oil Wells	9,889	6,566	4,119	7,266	7,862	6,016	6,396
Gas Wells	10,592	11,494	10,530	15,761	20,685	16,116	19,100
Total Development Wells	24,140	21,198	16,921	25,710	31,262	24,464	28,183
Number of Net In-Progress Wells							
Onshore							
Exploratory Wells	135	51	40	70	85	66	84
Development Wells	929	392	464	716	1,052	1,315	1,209
Total In-Progress Wells	1,064	444	504	786	1,138	1,381	1,293
Offshore							
Exploratory Wells	92	52	68	50	56	55	46
Development Wells	128	73	87	110	63	47	78
Total In-Progress Wells	220	124	155	160	118	102	124
Total United States							
Exploratory Wells	226	103	108	120	141	120	130
Development Wells	1,058	465	551	826	1,115	1,362	1,286
Total In-Progress Wells	1,284	568	659	946	1,256	1,482	1,416

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 2004, 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, 1997-2003

	1997	1998	1999	2000	2001	2002	2003
FRS Companies							
Onshore				(thousand feet)			
Exploratory Well Footage							
Dry Hole Footage	1,700	1,714	921	955	1,085	1,000	823
Oil Well Footage	1,027	406	312	199	397	141	152
Gas Well Footage	1,521	1,548	1,150	1,399	2,016	1,284	1,655
Total Exploratory Footage	4,248	3,668	2,383	2,553	3,498	2,425	2,630
Development Well Footage							
Dry Hole Footage	1,926	1,939	1,252	1,597	2,029	1,716	1,507
Oil Well Footage	14,534	12,513	4,449	9,374	9,435	6,928	8,716
Gas Well Footage	16,751	16,521	12,291	20,516	26,653	32,078	40,507
Total Development Footage	33,211	30,973	17,992	31,487	38,117	40,722	50,730
Offshore							
Exploratory Well Footage							
Dry Hole Footage	1,362	1,345	848	1,151	1,004	652	628
Oil Well Footage	397	443	434	364	551	589	289
Gas Well Footage	981	1,285	1,002	1,141	759	697	504
Total Exploratory Footage	2,740	3,073	2,284	2,656	2,314	1,938	1,421
Development Well Footage							
Dry Hole Footage	459	344	199	411	353	369	165
Oil Well Footage	1,736	1,428	1,280	1,505	2,260	1,362	1,216
Gas Well Footage	1,584	1,398	1,295	1,899	1,917	1,370	905
Total Development Footage	3,779	3,170	2,774	3,815	4,530	3,101	2,286
Total United States							
Exploratory Well Footage							
Dry Hole Footage	3,062	3,059	1,769	2,107	2,089	1,652	1,451
Oil Well Footage	1,424	849	746	563	948	730	441
Gas Well Footage	2,502	2,833	2,152	2,540	2,775	1,981	2,159
Total Exploratory Footage	6,988	6,741	4,667	5,209	5,812	4,363	4,051
Development Well Footage							
Dry Hole Footage	2,385	2,283	1,451	2,008	2,382	2,085	1,672
Oil Well Footage	16,270	13,941	5,729	10,879	11,695	8,290	9,932
Gas Well Footage	18,335	17,919	13,586	22,415	28,570	33,448	41,412
Total Development Footage	36,990	34,143	20,766	35,303	42,647	43,823	53,016
Total United States Industry							
Exploratory Well Footage							
Dry Hole Footage	13,861	12,398	7,646	8,965	11,312	8,587	8,826
Oil Well Footage	3,432	2,505	1,045	1,918	2,435	1,611	1,996
Gas Well Footage	3,955	4,196	3,315	4,518	6,909	5,062	5,912
Total Exploratory Footage	21,248	19,098	12,006	15,422	20,656	15,260	16,734
Development Well Footage							
Dry Hole Footage	19,666	18,005	12,508	14,145	14,013	12,098	14,739
Oil Well Footage	47,773	32,125	17,705	31,681	36,334	26,401	30,002
Gas Well Footage	65,860	70,746	52,204	75,736	102,922	87,326	110,559
Total Development Footage	133,298	120,875	82,417	121,563	153,269	125,825	155,300
Number of Net Producing				(number of wells)			
Onshore							
Oil Wells	75,493	69,401	58,987	68,274	66,667	69,021	71,863
Gas Wells	48,779	49,429	44,880	64,696	82,083	89,102	105,439
Total Producing Wells	124,272	118,830	103,867	132,970	148,750	158,123	177,302
Offshore							
Oil Wells	3,760	3,421	2,855	3,536	4,738	4,384	3,777
Gas Wells	2,898	2,737	2,707	3,111	3,606	3,011	2,306
Total Producing Wells	6,658	6,158	5,562	6,647	8,344	7,395	6,083
Total United States							
Oil Wells	79,253	72,822	61,842	71,810	71,405	73,405	75,640
Gas Wells	51,677	52,166	47,587	67,807	85,689	92,113	107,744
Total Producing Wells	130,930	124,987	109,429	139,617	157,094	165,518	183,384

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 2004, 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, 1997-2003

	1997	1998	1999	2000	2001	2002	2003
Canada							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	22.8	54.8	36.4	126.3	106.4	156.6	146.4
Oil Wells	10.7	10.0	25.8	23.3	63.1	74.0	51.0
Gas Wells	49.2	66.3	127.5	194.2	165.9	329.4	454.6
Total Exploratory Wells	82.7	131.1	189.7	343.8	335.4	560.0	652.0
Development Wells							
Dry Holes	59.6	58.8	58.3	138.2	228.8	151.2	161.4
Oil Wells	778.6	198.9	352.1	373.3	818.1	794.1	586.4
Gas Wells	275.1	422.4	758.7	891.5	2,025.1	2,381.1	2,651.9
Total Development Wells	1,113.3	680.1	1,169.1	1,403.0	3,072.1	3,326.4	3,399.7
Net In-Progress Wells at Year End	30.6	24.3	76.3	116.8	307.2	190.0	275.8
Net Producing Wells							
Oil Wells	9,364.7	10,532.3	10,155.9	12,094.8	17,640.5	14,203.0	13,167.6
Gas Wells	6,199.5	8,872.7	10,038.7	15,242.7	25,230.5	26,434.9	28,418.4
Total Producing Wells	15,564.2	19,405.0	20,194.6	27,337.5	42,870.9	40,637.9	41,586.0
Europe and Former Soviet Union [1]							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	56.6	36.3	15.4	15.7	15.6	11.2	12.7
Oil Wells	19.2	11.8	9.2	5.2	25.9	5.3	6.1
Gas Wells	8.9	12.0	4.0	6.4	8.6	3.1	3.5
Total Exploratory Wells	84.7	60.1	28.6	27.3	50.1	19.6	22.3
Development Wells							
Dry Holes	3.2	7.8	2.6	10.3	5.4	4.6	6.0
Oil Wells	80.7	118.5	75.4	67.7	91.8	63.0	98.6
Gas Wells	25.1	60.5	30.4	30.4	31.8	41.2	23.0
Total Development Wells	109.0	186.8	108.4	108.4	129.0	108.8	127.6
Net In-Progress Wells at Year End	62.7	54.5	31.6	63.7	69.3	38.7	49.1
Net Producing Wells							
Oil Wells	1,328.0	1,294.4	1,218.8	1,431.3	1,478.2	1,225.7	1,325.3
Gas Wells	766.8	805.3	626.6	737.7	717.2	788.7	639.1
Total Producing Wells	2,094.8	2,099.7	1,845.4	2,169.0	2,195.4	2,014.4	1,964.4
Africa and Middle East							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	25.3	33.1	14.9	37.2	21.9	26.8	25.2
Oil Wells	W	W	9.9	W	W	W	29.1
Gas Wells	W	W	10.0	W	W	W	5.6
Total Exploratory Wells	46.1	65.0	34.8	50.7	50.9	67.5	59.9
Development Wells							
Dry Holes	W	W	5.8	W	W	11.3	13.2
Oil Wells	151.6	218.4	206.3	239.3	159.8	209.4	293.7
Gas Wells	W	W	8.6	W	W	13.5	8.7
Total Development Wells	157.8	225.6	220.7	252.0	186.9	234.2	315.6
Net In-Progress Wells at Year End	29.0	18.0	36.8	35.2	35.4	57.0	64.6
Net Producing Wells							
Oil Wells	1,644.6	1,924.2	1,969.8	1,954.1	2,063.8	2,209.2	2,357.1
Gas Wells	59.5	62.7	83.2	79.0	121.2	140.2	152.0
Total Producing Wells	1,704.1	1,986.9	2,053.0	2,033.1	2,185.0	2,349.4	2,509.1

See footnotes at end of table.

Table B21. Number of Net Wells Completed, In-Progress Wells, and Producing Wells by Foreign Regions for FRS Companies, 1997-2003 (Continued)

	1997	1998	1999	2000	2001	2002	2003
Other Eastern Hemisphere							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	39.8	47.1	35.4	40.7	39.1	36.8	37.2
Oil Wells	16.1	36.6	41.6	31.3	19.9	11.0	8.9
Gas Wells	15.8	13.8	16.0	20.7	42.3	26.6	13.4
Total Exploratory Wells	71.7	97.5	93.0	92.7	101.3	74.4	59.5
Development Wells							
Dry Holes	4.7	11.5	1.9	4.4	7.1	3.0	2.5
Oil Wells	162.6	149.5	82.4	140.6	595.3	554.8	649.6
Gas Wells	116.5	101.2	104.5	113.5	117.0	201.7	147.9
Total Development Wells	283.8	262.2	188.8	258.5	719.4	759.5	800.0
Net In-Progress Wells at Year End	61.4	64.5	56.2	80.5	67.1	30.9	50.5
Net Producing Wells							
Oil Wells	1,767.0	1,707.2	1,654.2	1,950.2	7,852.9	7,458.6	7,794.1
Gas Wells	633.8	862.2	882.2	927.4	1,090.3	1,288.8	1,275.4
Total Producing Wells	2,400.8	2,569.4	2,536.4	2,877.6	8,943.2	8,747.4	9,069.5
Other Western Hemisphere							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	5.7	14.6	7.9	14.5	31.9	13.2	10.7
Oil Wells	4.7	10.4	3.2	W	W	W	3.8
Gas Wells	0.0	4.5	3.8	W	W	W	0.0
Total Exploratory Wells	10.4	29.5	14.9	23.4	40.0	21.3	14.5
Development Wells							
Dry Holes	W	W	W	W	W	W	W
Oil Wells	141.4	212.8	81.4	205.8	240.5	217.0	218.0
Gas Wells	W	W	W	W	W	W	W
Total Development Wells	148.3	224.5	91.7	245.0	262.9	245.1	236.2
Net In-Progress Wells at Year End	24.4	28.9	27.2	31.3	47.4	31.6	8.6
Net Producing Wells							
Oil Wells	605.0	2,045.6	2,426.5	2,597.2	2,580.2	2,439.6	2,721.4
Gas Wells	72.2	190.9	161.4	253.1	262.7	274.0	288.5
Total Producing Wells	677.2	2,236.5	2,587.9	2,850.3	2,842.9	2,713.6	3,009.9
Total Foreign							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	150.2	185.9	110.0	234.4	214.9	244.6	232.2
Oil Wells	71.0	97.6	89.7	74.1	136.0	134.3	98.9
Gas Wells	74.4	99.7	161.3	229.4	226.8	363.9	477.1
Total Exploratory Wells	295.6	383.2	361.0	537.9	577.7	742.8	808.2
Development Wells							
Dry Holes	75.5	83.7	70.1	156.7	252.5	171.2	184.3
Oil Wells	1,314.9	898.1	797.6	1,026.7	1,905.5	1,838.3	1,846.3
Gas Wells	421.8	597.4	911.0	1,083.5	2,212.2	2,664.5	2,848.5
Total Development Wells	1,812.2	1,579.2	1,778.7	2,266.9	4,370.3	4,674.0	4,879.1
Net In-Progress Wells at Year End	208.1	190.2	228.1	327.5	526.4	348.2	448.6
Net Producing Wells							
Oil Wells	14,709.3	17,503.7	17,425.2	20,027.6	31,615.6	27,536.1	27,365.5
Gas Wells	7,731.8	10,793.8	11,792.1	17,239.9	27,421.9	28,926.6	30,773.4
Total Producing Wells	22,441.1	28,297.5	29,217.3	37,267.5	59,037.4	56,462.7	58,138.9

[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, 2002 and 2003

Drilling and Equipping Measures	Total United States			U.S. Onshore			U.S. Offshore		
	2002	2003	Change	2002	2003	Change	2002	2003	Change
Exploration									
Oil Wells									
Wells Completed	55.5	38.4	-30.8	21.0	18.9	-10.0	34.5	19.5	-43.5
Average Depth (thousand feet)	13.2	11.5	-12.7	6.7	8.0	19.8	17.1	14.8	-13.2
Gas Wells									
Wells Completed	216.7	199.2	-8.1	164.0	163.5	-0.3	52.7	35.7	-32.3
Average Depth (thousand feet)	9.1	10.8	18.6	7.8	10.1	29.3	13.2	14.1	6.7
Dry Holes									
Wells Completed	171.2	135.0	-21.1	118.8	92.5	-22.1	52.4	42.5	-18.9
Average Depth (thousand feet)	9.6	10.7	11.4	8.4	8.9	5.7	12.4	14.8	18.8
Development									
Oil Wells									
Wells Completed	1,321.3	1,662.0	25.8	1,186.6	1,566.8	32.0	134.7	95.2	-29.3
Average Depth (thousand feet)	6.3	6.0	-4.8	5.8	5.6	-4.7	10.1	12.8	26.3
Gas Wells									
Wells Completed	5,115.7	5,613.6	9.7	4,982.0	5,538.8	11.2	133.7	74.8	-44.1
Average Depth (thousand feet)	6.5	7.4	12.8	6.4	7.3	13.6	10.2	12.1	18.1
Dry Holes									
Wells Completed	258.7	237.9	-8.0	220.4	224.9	2.0	38.3	13.0	-66.1
Average Depth (thousand feet)	8.1	7.0	-12.8	7.8	6.7	-13.9	9.6	12.7	31.7

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

Table B23. Oil and Gas Reserves for FRS Companies and U.S. Industry, 2003

	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	24,342.0	732.0	0.0	1,872.0	23,202.0	39.1
FRS Companies	11,331.0	600.1	-23.3	819.2	11,088.6	73.3
All Other	13,011.0	131.9	23.3	1,052.8	12,113.4	12.5
U.S. Offshore						
Total U.S. Industry	6,329.0	626.0	0.0	807.0	6,148.0	77.6
FRS Companies	4,445.6	234.0	17.9	458.7	4,238.8	51.0
All Other	1,883.4	392.0	-17.9	348.3	1,909.2	112.5
U.S. Total						
Total U.S. Industry	30,671.0	1,358.0	0.0	2,679.0	29,350.0	50.7
FRS Companies	15,776.6	834.1	-5.4	1,277.8	15,327.4	65.3
All Other	14,894.4	523.9	5.4	1,401.2	14,022.6	37.4
FRS Companies' Foreign Oil Reserves						
Canada	2,182.3	327.2	-32.5	217.9	2,259.1	150.2
Europe	3,825.8	262.9	86.2	533.9	3,640.9	49.2
FSU and Eastern Europe	1,308.2	653.7	44.9	33.3	1,973.5	1,965.0
Africa	5,738.3	W	W	409.2	6,127.2	W
Middle East	786.1	W	W	112.4	746.6	W
Other Eastern Hemisphere	2,674.2	243.1	-75.2	295.9	2,546.1	82.1
Other Western Hemisphere	1,434.8	2.8	-80.3	111.0	1,246.3	2.5
Total Foreign	17,949.7	2,216.6	87.0	1,713.6	18,539.7	129.3
Worldwide Total for FRS Companies	33,726.3	3,050.7	81.6	2,991.5	33,867.2	102.0
Dry Natural Gas	(billion cubic feet)					
U.S. Onshore						
Total U.S. Industry	160,722.0	19,579.0	0.0	14,873.0	165,429.0	131.6
FRS Companies	68,859.6	6,584.7	955.3	5,871.7	70,527.9	112.1
All Other	91,862.4	12,994.3	-955.3	9,001.3	94,901.1	144.4
U.S. Offshore						
Total U.S. Industry	26,224.0	1,944.0	0.0	4,552.0	23,615.0	42.7
FRS Companies	17,072.5	470.2	-219.0	2,471.9	14,851.7	19.0
All Other	9,151.5	1,473.8	219.0	2,080.1	8,763.3	70.9
U.S. Total						
Total U.S. Industry	186,946.0	21,523.0	0.0	19,425.0	189,044.0	110.8
FRS Companies	85,932.0	7,054.9	736.3	8,343.6	85,379.6	84.6
All Other	101,014.0	14,468.1	-736.3	11,081.4	103,664.4	130.6
FRS Companies' Foreign Gas Reserves						
Canada	14,991.7	1,174.5	-32.9	1,743.1	14,390.3	67.4
Europe	19,504.3	2,531.0	-213.0	2,247.7	19,574.6	112.6
FSU and Eastern Europe	1,357.2	637.2	0.0	37.4	1,957.0	1,703.1
Africa	8,983.6	813.3	W	W	8,479.4	W
Middle East	688.3	596.9	W	W	1,189.8	W
Other Eastern Hemisphere	23,929.0	3,055.1	730.6	1,809.8	25,904.9	168.8
Other Western Hemisphere	19,617.1	439.1	40.5	893.4	19,203.4	49.2
Total Foreign	89,071.2	9,247.2	-572.0	7,047.1	90,699.3	131.2
Worldwide Total for FRS Companies	175,003.2	16,302.1	164.3	15,390.7	176,078.9	105.9

[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* , 2002 and 2003 (November 2003 and November 2004). FRS companies' data - Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B24. Oil and Gas Reserve Balances by Region for FRS Companies, 2003

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	33,726	15,777	11,331	4,446	17,950
Revisions of Previous Estimates	375	-174	112	-286	549
Improved Recovery	629	318	295	23	311
Purchases of Minerals-in-Place	923	494	362	131	429
Extensions & Discoveries	2,047	690	193	497	1,357
Production	-2,991	-1,278	-819	-459	-1,714
Sales of Minerals-in-Place	-841	-499	-386	-113	-342
End of period	33,867	15,327	11,089	4,239	18,540
Proportionate Interest in Investee Reserves and Foreign Access Reserves	--	--	--	--	6,841
Natural Gas Reserves	(billion cubic feet)				
Beginning of Period	175,003	85,932	68,860	17,072	89,071
Revisions of Previous Estimates	-73	-1,701	-1,070	-631	1,628
Improved Recovery	2,644	2,217	2,186	32	426
Purchases of Minerals-in-Place	5,625	3,728	2,845	882	1,898
Extensions & Discoveries	13,732	6,539	5,469	1,069	7,193
Production	-15,391	-8,344	-5,872	-2,472	-7,047
Sales of Minerals-in-Place	-5,461	-2,991	-1,890	-1,101	-2,470
End of Period	176,079	85,380	70,528	14,852	90,699
Proportionate Interest in Investee Reserves and Foreign Access Reserves	--	--	--	--	29,398

See footnotes at end of table.

Table B24. Oil and Gas Reserve Balances by Region for FRS Companies, 2003 (Continued)

Reserves Statistics	Total	Canada	Europe and Former Soviet Union [1]	Africa and Middle East	Other Eastern Hemisphere	Other Western Hemisphere
	Foreign					
Crude Oil and Natural Gas Liquids	(million barrels)					
Beginning of Period	17,950	2,182	5,134	6,524	2,674	1,435
Revisions of Previous Estimates	549	0	220	258	99	-29
Improved Recovery	311	13	99	127	55	16
Purchases of Minerals-in-Place	429	6	244	W	23	W
Extensions & Discoveries	1,357	314	597	342	88	16
Production	-1,714	-218	-567	-522	-296	-111
Sales of Minerals-in-Place	-342	-39	-113	W	-98	W
End of period	18,540	2,259	5,614	6,874	2,546	1,246
Proportionate Interest in Investee Reserves and Foreign Access Reserves	6,841	W	3,345	W	W	2,108
Natural Gas Reserves	(billion cubic feet)					
Beginning of Period	89,071	14,992	20,861	9,672	23,929	19,617
Revisions of Previous Estimates	1,628	-615	975	527	706	35
Improved Recovery	426	6	101	18	W	W
Purchases of Minerals-in-Place	1,898	426	113	W	1,171	W
Extensions & Discoveries	7,193	1,784	2,092	865	2,309	143
Production	-7,047	-1,743	-2,285	-316	-1,810	-893
Sales of Minerals-in-Place	-2,470	-459	-326	W	W	-15
End of Period	90,699	14,390	21,532	9,669	25,905	19,203
Proportionate Interest in Investee Reserves and Foreign Access Reserves	29,398	W	19,649	W	W	2,621

[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, 2003 and Percent Change from 2002

	United States			Foreign
	Total	Onshore	Offshore	Total
Expenditures (million dollars)				
FRS Companies	27,196.0	14,743.0	12,453.0	28,208.0
Percent Change	-14.5	-34.0	31.3	-10.1
Wells Completed				
FRS Companies	7,886.1	7,605.4	280.7	5,687.3
Percent Change	10.5	13.6	-37.1	5.0
Industry[1]	30,583.0	30,029.0	555.0	31,079.0
Percent Change	14.7	14.6	18.3	44.6
Success Rate[2]				
FRS Companies	95.3	95.8	80.2	92.7
Industry[1]	86.8	87.3	62.9	94.1
Crude Oil and NGL Production[3]				
FRS Companies	1,277.8	819.2	458.7	1,753.7
Percent Change	-5.1	-5.7	-3.9	-1.4
Industry [1]	2,679.0	1,872.0	807.0	24,063.4
Percent Change	-2.9	-8.6	13.5	5.7
Interests[4] (million barrels)				
FRS Companies	15,327.4	11,088.6	4,238.8	25,380.5
Percent Change	-3.3	-2.6	-5.1	0.1
(billion cubic feet)				
FRS Companies	8,343.6	5,871.7	2,471.9	7,047.1
Percent Change	-4.2	-0.8	-11.5	0.2
Industry[1]	19,425.0	14,873.0	4,552.0	71,832.0
Percent Change	0.4	1.3	-2.4	5.1
(billion cubic feet)				
FRS Companies	85,379.6	70,527.9	14,851.7	120,097.5
Percent Change	-0.5	3.5	-16.2	1.1

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, 2003 and Percent Change from 2002 (Continued)

	Foreign						
	Total	Canada	Europe & Former Soviet Union [5]	Africa	Middle East	Other Eastern Hemisphere	Other Western Hemisphere
Exploration and Development Expenditures (million dollars)							
FRS Companies	28,208.0	4,903.0	7,850.0	9,187.0	976.0	4,161.0	1,131.0
Percent Change	-10.1	-26.7	-29.1	80.5	26.1	-32.8	-27.4
Wells Completed							
FRS Companies	5,687.3	4,051.7	149.9	260.1	115.4	859.5	250.7
Percent Change	5.0	4.3	16.7	29.0	15.4	3.1	-5.9
Foreign Industry[1]	31,079.0	19,737.0	4,655.0	943.0	849.0	1,868.0	3,027.0
Percent Change	44.6	38.6	(6)	10.4	-19.1	13.3	0.4
Success Rate[2] (percent)							
FRS Companies	92.7	92.4	87.5	88.7	92.1	95.4	95.3
Foreign Industry[1]	94.1	93.7	97.9	93.6	97.4	86.6	94.4
Crude Oil and NGL Production[3] (million barrels)							
FRS Companies	1,753.7	217.9	567.2	409.2	152.5	295.9	111.0
Percent Change	-1.4	-7.2	-3.6	10.3	2.9	-6.6	-6.9
Foreign Industry[1]	24,063.4	1,089.9	6,178.4	3,066.4	8,251.6	1,633.7	3,843.4
Percent Change	5.7	3.7	7.5	5.8	7.8	-2.7	2.8
Crude Oil and NGL Reserve Interests[4] (million barrels)							
FRS Companies	25,380.5	2,296.0	8,959.7	6,127.2	2,076.9	2,566.0	3,354.7
Percent Change	0.1	1.5	7.1	6.8	-2.0	-5.3	-19.3
Natural Gas Production (billion cubic feet)							
FRS Companies	7,047.1	1,743.1	2,285.1	220.2	95.4	1,809.8	893.4
Percent Change	0.2	-6.5	-0.7	2.8	5.5	-2.1	24.9
Foreign Industry[1]	71,832.0	6,371.7	36,143.7	4,991.4	9,096.8	9,756.9	5,471.5
Percent Change	5.1	-1.6	5.0	6.2	9.4	2.7	12.5
Natural Gas Reserve Interests (billion cubic feet)							
FRS Companies	120,097.5	14,411.3	41,180.7	8,479.4	8,089.6	26,112.4	21,824.1
Percent Change	1.1	-5.0	0.8	-5.6	26.8	2.8	-0.9

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

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

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

[4]Foreign includes net ownership interest reserves (73.0 percent of total foreign) and "Other Access" reserves (27.0 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.

[6]Not meaningful. (Data for 2002 for the Former Soviet Union was not available, so percent change is not between comparable data.)

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* , 2002, and 2003 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 2004, p. 84. Reserve Additions, Foreign - *British Petroleum Statistical Review of World Energy 2003 and 2004.* Wells Completed, Foreign - *World Oil* , August 2003 and September 2004. 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,1997-2003
(million barrels)

	1997	1998	1999	2000	2001	2002	2003
U.S. Refining/Marketing							
Sources							
Acquisitions from U.S. Production Segment	1,542	1,484	1,516	1,238	1,358	1,368	1,195
Unconsolidated Affiliates	468	1,935	2,181	2,149	2,629	1,709	1,130
Purchases from Third Parties	4,444	4,968	5,205	5,340	3,679	4,219	4,980
Net Transfers from Foreign Refining/Marketing Segment	571	635	475	324	716	631	738
Total Sources	7,025	9,021	9,377	9,050	8,383	7,926	8,043
Dispositions							
Net Change in Inventories	14	31	-1	-4	-1	-28	30
Input to Refineries	3,259	4,883	4,872	4,690	4,668	4,715	4,791
Sales to:							
Unaffiliated Third Parties	3,424	3,730	4,147	4,281	3,391	3,056	2,851
Other Segments Excluding Foreign Refining/Marketing	328	377	359	84	325	183	372
Total Dispositions	7,025	9,021	9,377	9,050	8,383	7,926	8,043
Foreign Refining/Marketing							
Sources							
Acquisitions from Foreign Production Segment	1,391	1,380	1,462	1,585	1,661	1,590	1,502
Purchases							
Other Foreign Segments	W	W	W	W	W	W	W
Unconsolidated Affiliates	W	W	W	W	W	W	W
Unaffiliated Third Parties							
Foreign Access	228	209	W	W	W	W	W
Foreign Governments (Open Market)	851	679	W	W	W	W	W
Other Unaffiliated Third Parties	1,785	2,000	2,244	2,165	2,459	1,626	1,816
Net Transfers to U.S. Refining/Marketing Segment	-571	-635	-475	-324	-716	-631	-738
Total Sources	3,699	4,021	4,307	4,067	4,200	3,287	3,328
Dispositions							
Net Change in Inventories	18	155	-19	10	-2	0	17
Input to Refineries	1,435	1,419	1,641	1,673	1,682	1,639	1,646
Sales	2,246	2,446	2,685	2,384	2,520	1,647	1,666
Total Dispositions	3,699	4,021	4,307	4,067	4,200	3,287	3,328

W = Data withheld to avoid disclosure.

Table B27. U.S. Purchases and Sales of Oil, Natural Gas, Other Raw Materials, and Refined Products for FRS Companies, 1997-2003

	1997	1998	1999	2000	2001	2002	2003
Purchases	Values (million dollars)						
U.S. Refining/Marketing Segment							
Raw Materials							
Crude Oil and NGL	126,535	106,128	152,880	253,092	192,228	186,084	224,749
Natural Gas	18,657	15,177	20,387	58,679	38,947	33,744	4,941
Other Raw Materials	3,159	5,348	5,705	8,395	7,852	7,950	11,436
Total Raw Materials	148,351	126,653	178,972	320,166	239,027	227,778	241,126
Refined Products							
Motor Gasoline	18,613	24,249	36,095	65,488	64,609	60,791	68,149
Distillate Fuels	9,565	10,574	17,433	35,116	31,323	27,238	27,702
Other Refined Products	9,141	8,786	9,963	17,036	18,895	15,460	18,176
Total Refined Products	37,319	43,609	63,491	117,640	114,827	103,489	114,027
U.S. Production Segment							
Crude Oil and NGL	5,399	4,694	5,695	4,794	1,979	721	2,133
Natural Gas	11,220	8,922	8,608	12,208	14,113	11,785	1,896
Total Raw Materials	16,619	13,616	14,303	17,002	16,092	12,506	4,029
Sales							
U.S. Refining/Marketing Segment							
Raw Materials							
Crude Oil and NGL	70,437	50,702	72,955	121,118	86,675	75,241	91,722
Natural Gas	18,252	15,270	20,023	56,482	37,648	32,882	W
Other Raw Materials	1,499	2,172	1,576	2,403	2,203	944	W
Total Raw Materials	90,188	68,144	94,554	180,003	126,526	109,067	98,356
Refined Products							
Motor Gasoline	71,185	84,968	109,301	176,394	167,735	160,010	183,020
Distillate Fuels	36,962	39,513	51,810	91,998	83,702	75,136	86,115
Other Refined Products	20,964	23,283	28,506	42,269	40,172	37,044	46,749
Total Refined Products	129,111	147,764	189,617	310,661	291,609	272,190	315,884
U.S. Production Segment							
Crude Oil and NGL	30,604	19,688	25,186	38,314	31,613	30,930	35,019
Natural Gas	29,459	23,649	23,178	40,719	47,390	40,208	39,447
Total Raw Materials	60,063	43,337	48,364	79,033	79,003	71,138	74,466
Purchases	Volumes						
U.S. Refining/Marketing Segment							
Raw Materials							
Crude Oil and NGL (million barrels)	7,025	9,021	9,377	9,050	8,383	7,926	8,043
Natural Gas (billion cubic feet)	7,573	7,425	9,285	13,323	9,147	10,458	1,030
Refined Products (million barrels)							
Motor Gasoline	689	1,272	1,533	1,708	1,892	1,886	1,811
Distillate Fuels	397	625	837	943	987	952	780
Other Refined Products	329	464	446	535	625	583	542
Total Refined Products	1,415	2,361	2,815	3,186	3,504	3,420	3,133
U.S. Production Segment							
Crude Oil and NGL (million barrels)	308	394	367	200	88	37	78
Natural Gas (billion cubic feet)	4,551	4,295	3,835	3,276	3,461	3,956	365
Sales							
U.S. Refining/Marketing Segment							
Raw Materials							
Crude Oil and NGL (million barrels)	3,752	4,107	4,506	4,365	3,716	3,239	3,222
Natural Gas (billion cubic feet)	7,242	6,764	8,834	13,001	8,460	9,783	W
Refined Products (million barrels)							
Motor Gasoline	2,371	3,789	4,070	4,286	4,539	4,598	4,354
Distillate Fuels	1,473	2,146	2,344	2,444	2,540	2,465	2,288
Other Refined Products	1,008	1,342	1,407	1,405	1,528	1,332	1,422
Total Refined Products	4,852	7,277	7,820	8,135	8,606	8,395	8,064
U.S. Production Segment							
Crude Oil and NGL (million barrels)	1,860	1,805	1,667	1,484	1,498	1,433	1,336
Natural Gas (billion cubic feet)	12,421	11,765	10,952	11,348	11,957	13,109	8,466

Note: Beginning in 2003, purchases of natural gas by the Petroleum line of business are for own use only, and sales of natural gas are to the downstream natural gas line of business.

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

Table B28. U.S. and Foreign Petroleum Refining Statistics for FRS Companies, 1997-2003

	1997	1998	1999	2000	2001	2002	2003
U.S. Refining	(thousand barrels per calendar day)						
Runs to Stills							
At Own Refineries	9,060	13,699	13,476	13,361	13,875	13,307	13,278
By Refineries of Others	5	0	82	86	105	80	84
Total Runs to Stills	9,065	13,699	13,558	13,447	13,980	13,387	13,362
Refinery Output at Own Refineries and Refineries of Others							
Reformulated Motor Gasoline	768	1,552	1,792	2,129	2,061	1,991	1,726
Oxygenated Motor Gasoline	749	1,018	609	412	588	552	515
Other Motor Gasoline	2,980	4,665	4,588	4,207	4,373	4,456	4,695
Total Motor Gasoline	4,497	7,235	6,989	6,748	7,022	6,999	6,936
Distillate Fuels	2,921	4,278	4,167	4,376	4,331	4,167	4,398
Other Refined Products	2,612	3,416	3,483	3,375	3,669	3,595	3,349
Total Refinery Output	10,030	14,929	14,639	14,499	15,022	14,761	14,683
Refinery Capacity at End of Year	9,410	14,277	14,158	14,424	14,682	14,630	14,619
	(number of refineries)						
Number of Wholly-Owned Refineries	60	95	94	90	99	84	79
	(thousand barrels per calendar day)						
Foreign Refining							
Runs to Stills							
At Own Refineries	3,961	4,043	4,407	4,513	4,620	4,778	4,550
By Refineries of Others	340	292	397	403	339	325	370
Total Runs to Stills	4,301	4,335	4,804	4,916	4,959	5,103	4,920
Refinery Output at Own Refineries							
Motor Gasoline	1,041	1,135	1,247	1,295	1,293	1,427	1,400
Distillate Fuels	1,648	1,787	1,901	1,738	1,744	2,041	1,971
Other Refined Products	1,283	1,213	1,315	1,717	1,729	1,405	1,251
Total Refinery Output at Own Refineries	3,972	4,135	4,463	4,750	4,766	4,873	4,622
Refinery Output at Refineries of Others							
Motor Gasoline	75	83	122	123	120	117	125
Distillate Fuels	154	121	135	171	155	175	180
Other Refined Products	110	87	146	80	84	70	73
Total Refinery Output at Refineries of Others	339	291	403	374	359	362	378
Total Refinery Output	4,311	4,426	4,866	5,124	5,125	5,235	5,000
Refinery Capacity at End of Year	4,270	4,508	4,930	5,134	5,572	5,642	5,374
	(number of refineries)						
Number of Wholly-Owned Refineries	20	20	19	18	23	22	19
Number of Partially-Owned Refineries	15	15	18	18	18	19	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, 2003

(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]	14,683	7,002	1,834	5,847	17,970	81.7
Percent Gasoline						
Reformulated/Oxygenated	15.3	13.3	16.4	17.3	19.5	64.1
Other	32.0	32.4	34.4	30.7	27.2	96.1
Percent Distillate	30.0	30.2	27.0	30.6	30.2	81.0
Percent Other	22.8	24.1	22.3	21.4	23.1	80.6
Refinery Capacity						
Years Change (Net)	-11	1	-375	363	161	(5)
At Year End	14,619	6,555	2,157	5,907	17,500	83.5
Utilization Rate[4]	90.8	93.6	70.4	95.9	90.7	(5)
Foreign						
Refinery Output Volume[3]	5,000	4,804	0	196	-	(5)
Percent Gasoline	30.5	30.1	0.0	40.8	-	(5)
Percent Distillate	43.0	42.9	0.0	45.4	-	(5)
Percent Other	26.5	27.0	0.0	13.8	-	(5)
Refinery Capacity						
Years Change (Net)	-268	12	0	-280	-	(5)
At Year End	5,374	5,159	0	215	-	-
Utilization Rate[3]	82.6	84.5	0.0	55.2	-	(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.

- = Not available.

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

Sources: Industry data, U.S. - Refinery output and refinery capacity: Energy Information Administration, Forms EIA-820 (Annual Refinery Report) and EIA-810 (Monthly Refinery Report); see *Petroleum Supply Annual,* 2002 and 2003. Industry data, Foreign - Refinery Capacity: *British Petroleum Statistical Review of World Energy* , 2003 and 2004.
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, 1997-2003

U.S. Dispositions	1997	1998	1999	2000	2001	2002	2003
Motor Gasoline	Values (million dollars)						
Intersegment Sales	581	966	1,521	1,802	2,521	3,500	3,083
U.S. Third-Party Sales							
Wholesale-Resellers	31,895	38,659	51,908	83,203	69,799	68,576	99,798
Company Operated Automotive Outlets	11,855	15,497	17,334	24,870	22,843	18,662	21,861
Company Lessee and Open Automotive Outlets	20,517	23,966	29,434	48,693	45,798	41,774	35,767
Other (Industrial, Commercial and Other Retail)	6,337	5,880	9,104	17,826	26,774	27,498	22,511
Total Third-Party Sales	70,604	84,002	107,780	174,592	165,214	156,510	179,937
Total Motor Gasoline Sales	71,185	84,968	109,301	176,394	167,735	160,010	183,020
Distillate Fuels							
Intersegment Sales	191	682	708	444	535	2,387	1,057
Third-Party Sales	36,771	38,831	51,102	91,554	83,167	72,749	85,058
Total Distillate Fuels Sales	36,962	39,513	51,810	91,998	83,702	75,136	86,115
Other Refined Products							
Intersegment Sales	3,322	2,059	2,779	6,078	7,386	4,474	4,235
Third-Party Sales	17,642	21,224	25,727	36,191	32,786	32,570	42,514
Total Other Refined Products Sales	20,964	23,283	28,506	42,269	40,172	37,044	46,749
Total U.S. Refined Products							
Intersegment Sales	4,094	3,707	5,008	8,324	10,442	10,361	8,375
Third-Party Sales	125,017	144,057	184,609	302,337	281,167	261,829	307,509
Total U.S. Refined Products Sales	129,111	147,764	189,617	310,661	291,609	272,190	315,884
Motor Gasoline	Volumes (million barrels)						
Intersegment Sales	18	50	66	47	79	101	76
U.S. Third-Party Sales							
Wholesale-Resellers	1,150	1,901	2,059	2,126	1,956	2,045	2,508
Company Operated Automotive Outlets	335	558	540	543	545	464	432
Company Lessee and Open Automotive Outlets	615	965	1,006	1,105	1,182	1,167	797
Other (Industrial, Commercial and Other Retail)	253	316	399	465	777	820	541
Total Third-Party Sales	2,353	3,739	4,004	4,239	4,460	4,496	4,277
Total Motor Gasoline Sales	2,371	3,789	4,070	4,286	4,539	4,598	4,354
Distillate Fuels							
Intersegment Sales	8	38	33	13	17	85	30
Third-Party Sales	1,464	2,109	2,310	2,430	2,522	2,380	2,258
Total Distillate Fuels Sales	1,473	2,146	2,344	2,444	2,540	2,465	2,288
Other Refined Products							
Intersegment Sales	254	141	153	213	258	162	125
Third-Party Sales	755	1,201	1,254	1,191	1,269	1,170	1,298
Total Other Refined Products Sales	1,008	1,342	1,407	1,405	1,528	1,332	1,422
Total U.S. Refined Products							
Intersegment Sales	280	229	252	274	354	348	231
Third-Party Sales	4,572	7,048	7,568	7,861	8,252	8,046	7,833
Total U.S. Refined Products Sales	4,852	7,277	7,820	8,135	8,606	8,395	8,064
Number of Active Automotive Outlets at Year End	Number of Automotive Outlets						
Company Operated	8,942	13,645	12,018	12,583	11,380	9,745	8,804
Lessee Dealers	12,852	16,396	17,847	16,953	11,474	9,347	8,746
Open Dealers	11,959	28,859	26,805	25,707	31,231	28,056	26,657
Total Outlets	33,753	58,900	56,670	55,243	54,085	47,148	44,207

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, 2002-2003
(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								
2003	76.3	40.42	75.8	40.28	W	W	0.0	0.00
2002	101.4	34.51	72.8	35.17	28.6	32.85	0.0	0.00
Percent Change	-24.8	17.1	4.2	14.5	W	W	0.0	0.0
Wholesale/Resellers								
2003	2,507.7	39.80	1,178.7	42.37	220.9	41.09	1,108.1	36.80
2002	2,045.1	33.53	821.6	34.71	245.0	34.79	978.6	32.23
Percent Change	22.6	18.7	43.5	22.1	-9.8	18.1	13.2	14.2
Dealer-Operated Outlets								
2003	797.1	44.87	322.1	47.38	W	W	368.4	42.33
2002	1,167.3	35.79	693.6	36.18	108.5	37.20	365.1	34.63
Percent Change	-31.7	25.4	-53.6	31.0	W	W	0.9	22.2
Company-Operated Outlets								
2003	431.7	50.64	176.7	50.47	W	W	142.0	51.62
2002	464.3	40.20	201.8	37.42	122.3	41.04	140.1	43.46
Percent Change	-7.0	26.0	-12.4	34.9	W	W	1.3	18.8
Other [1]								
2003	540.8	41.62	294.3	44.17	W	W	82.9	38.82
2002	819.8	33.54	390.8	34.99	325.4	32.07	103.6	32.71
Percent Change	-34.0	24.1	-24.7	26.2	W	W	-19.9	18.7
Total Gasoline								
2003	4,353.7	42.04	2,047.7	44.04	604.5	42.87	1,701.4	39.34
2002	4,597.9	34.80	2,180.6	35.49	829.9	34.89	1,587.4	33.81
Percent Change	-5.3	20.8	-6.1	24.1	-27.2	22.9	7.2	16.4
Distillate								
2003	2,287.7	37.64	1,074.9	39.24	299.9	36.30	912.9	36.21
2002	2,464.7	30.48	1,168.0	31.38	498.6	29.45	798.2	29.82
Percent Change	-7.2	23.5	-8.0	25.0	-39.9	23.3	14.4	21.4
All Other Products								
2003	1,422.4	32.87	626.9	32.00	177.8	39.64	617.7	31.79
2002	1,332.1	27.81	555.7	28.65	324.8	28.91	451.6	25.99
Percent Change	6.8	18.2	12.8	11.7	-45.3	37.1	36.8	22.3
Total Refined Products								
2003	8,063.7	39.17	3,749.5	40.65	1,082.2	40.52	3,232.0	37.01
2002	8,394.7	32.42	3,904.2	33.29	1,653.4	32.07	2,837.1	31.44
Percent Change	-3.9	20.8	-4.0	22.1	-34.5	26.3	13.9	17.7

[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, 1997-2003
(Million Dollars)

Revenues and Costs	1997	1998	1999	2000	2001	2002	2003
Refined Product Revenues	129,111	147,764	189,617	310,661	291,609	272,190	315,884
Refined Product Costs							
Raw Materials Processed [1]	58,888	60,094	83,348	135,624	109,565	115,277	138,367
Refinery Energy Expense	5,005	5,349	6,427	10,838	11,321	9,178	10,699
Other Refinery Expense	8,436	12,219	11,734	10,635	12,274	16,202	14,677
Product Purchases	37,319	43,609	63,491	117,640	114,827	103,489	114,027
Other Product Supply Expense	3,777	5,160	4,915	6,655	6,552	12,562	10,568
Marketing Expense [2]	8,538	10,308	11,100	11,128	13,672	13,889	10,959
Total Refined Product Costs	121,963	136,739	181,015	292,520	268,211	270,597	299,297
Refined Product Margin	7,148	11,025	8,602	18,141	23,398	1,593	16,587
Refined Products Sold (million barrels)	4,852.2	7,276.9	7,820.2	8,134.7	8,606.3	8,394.7	8,063.7
Dollars per Barrel Margin [3]	1.47	1.52	1.10	2.23	2.72	0.19	2.06
Other Refining/Marketing Revenues [4]	9,693	15,997	14,282	14,196	16,918	15,878	10,674
Other Refining/Marketing Expenses							
Depreciation, Depletion, & Allowance	3,674	4,700	5,273	4,712	5,259	5,617	6,138
Other [5]	8,419	15,547	12,546	16,865	18,683	12,811	10,908
Total Other Expenses	12,093	20,247	17,819	21,577	23,942	18,428	17,046
Refining/Marketing Operating Income	4,748	6,775	5,065	10,760	16,374	-957	10,215
Miscellaneous Revenue & Expense [6]	204	1,315	1,367	1,265	1,866	1,002	1,384
Less Income Taxes	1,876	2,142	1,714	4,360	6,271	67	4,165
Refining/Marketing Net Income	3,106	5,932	4,883	7,659	11,951	-1,350	7,434

[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, 1997-2003
(Million Dollars)

General Operating Expenses	1997	1998	1999	2000	2001	2002	2003
Raw Material Supply							
Raw Material Purchases	148,351	126,653	178,972	320,166	239,027	227,778	241,126
Other Raw Material Supply Expense	4,523	5,183	3,184	2,371	4,196	4,520	3,218
Total Raw Material Supply Expense	152,874	131,836	182,156	322,537	243,223	232,298	244,344
Less: Cost of Raw Materials Input To Refining	64,132	62,955	85,270	139,931	114,400	121,192	146,446
Net Raw Material Supply	88,742	68,881	96,886	182,606	128,823	111,106	97,898
Refining							
Raw Materials Input to Refining	64,132	62,955	85,270	139,931	114,400	121,192	146,446
Less: Raw Material Used as Refinery Fuel	3,798	3,598	4,254	6,910	7,132	7,954	7,621
Refinery Process Energy Expense	5,005	5,349	6,427	10,838	11,321	9,178	10,699
Other Refining Operating Expenses	9,173	12,984	12,928	13,675	14,657	17,459	15,978
Refined Product Purchases	37,319	43,609	63,491	117,640	114,827	103,489	114,027
Other Refined Product Supply Expenses	3,777	5,160	4,915	6,655	6,552	12,562	10,568
Total Refining	115,608	126,459	168,777	281,829	254,625	255,926	290,097
Marketing							
Cost of Other Products Sold	6,255	6,844	5,305	7,342	9,797	8,677	7,391
Other Marketing Expenses	8,538	10,308	11,100	11,128	13,672	13,889	10,959
Subtotal	14,793	17,152	16,405	18,470	23,469	22,566	18,350
Expense of Transport Services for Others	376	4,297	4,191	3,691	4,002	439	235
Total Marketing	15,169	21,449	20,596	22,161	27,471	23,005	18,585
General Operating Expenses	219,519	216,789	286,259	486,596	410,919	390,037	406,580

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

Table B34. U.S. Coal Reserves Balance for FRS Companies, 1997-2003
(Million Tons)

Reserves and Production Statistics	1997	1998	1999	2000	2001	2002	2003
Changes to U.S. Coal Reserves							
Beginning of Period	9,410	7,502	5,334	4,410	2,530	1,320	728
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	-127	-17	-25	-58	-354	27	W
Production	-163	-74	-44	-36	-33	-29	-18
Dispositions of Minerals-in-Place	-774	-2,113	-802	-1,799	W	W	W
End of Period Reserves	8,498	5,334	4,507	2,530	1,320	856	574
Weighted Average Annual Production Capacity	215	65	55	51	40	40	24
Reserves and Production:							
Total United States							
FRS Companies' Reserves	8,498	5,334	4,507	2,530	1,320	856	574
FRS Companies' Production	163	74	44	36	33	29	18
U.S. Industry Production	1,090	1,118	1,100	1,074	1,128	1,093	1,072
Region							
East							
FRS Companies' Reserves	2,477	1,774	1,676	1,034	557	227	W
FRS Companies' Production	43	24	21	20	16	14	W
U.S. Industry Production	468	460	426	420	433	399	376
Midwest							
FRS Companies' Reserves	2,080	1,372	1,055	1,051	394	W	W
FRS Companies' Production	17	12	W	W	W	W	W
U.S. Industry Production	112	110	104	87	95	93	89
West							
FRS Companies' Reserves	3,940	2,188	1,776	446	370	W	W
FRS Companies' Production	104	38	W	W	W	W	W
U.S. Industry Production	511	548	571	566	597	601	603
Mining Method							
Underground							
FRS Companies' Reserves	3,880	2,352	1,853	1,752	886	620	382
FRS Companies' Production	51	28	21	21	18	16	8
U.S. Industry Production	421	418	392	374	381	357	353
Surface							
FRS Companies' Reserves	4,618	2,982	2,654	779	434	236	W
FRS Companies' Production	112	46	23	15	15	13	W
U.S. Industry Production	669	700	709	700	747	736	718

W = Data withheld to avoid disclosure.

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

Table B35. Consolidating Statement of Income for FRS Companies, U.S. and Foreign Downstream Natural Gas Segments, 2003
(Million Dollars)

Income Statement Items	U.S. Downstream Natural Gas					Foreign
	Consolidated	Processing and Gathering	Marketing/ Trading	Transmission	Distribution	
Operating Revenues						
Natural Gas Sales	104,300	19,145	99,432	-	2,017	53,365
NGL Products Sales	14,185	8,164	8,918	-	0	3,724
Transportation Sales	2,730	100	W	2,421	W	W
Other Product Sales	8	-	W	-	-	W
Trading/Derivatives	483	0	449	0	0	W
Management and Processing Fees	512	493	9	W	W	307
Other Revenues	1,632	601	955	W	W	48
Total Operating Revenues	123,850	28,503	109,782	2,465	2,478	57,622
Operating Expenses						
General Operating Expenses	118,734	27,064	108,344	719	1,985	56,058
Depreciation, Depletion, & Allowance	1,178	437	W	386	W	779
General & Administrative	1,069	177	W	250	W	172
Total Operating Expenses	120,981	27,678	W	1,355	W	57,009
Operating Income	2,869	825	W	1,110	W	613
Other Revenue & (Expense)						
Earnings of Unconsolidated Affiliates	83	129	W	W	0	W
Property, Plant, & Equipment	30	15	W	W	0	W
Total Other Revenue & (Expense)	113	144	-94	63	0	1,922
Pretax Income	2,982	969	W	1,173	W	2,535
Income Tax Expense	1,069	317	W	446	W	718
Discontinued Operations	W	W	W	W	0	W
Extraordinary Items and Cumulative Effect of Accounting Changes	W	W	-94	W	0	W
Contribution To Net Income	1,694	646	W	694	W	1,909

- = Not available.

W = Data withheld to avoid disclosure.

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

Table B36. Consolidating Statement of Income for FRS Companies, U.S. Electric Power Segments, 2003
(Million Dollars)

Income Statement Items	U.S. Electric Power		
	Consolidated	Non-Regulated Generation	Marketing/ Trading
Operating Revenues			
Power Sales	34,611	1,428	30,214
Transportation Sales	W	0	W
Other Product Sales	W	0	W
Trading/Derivatives	667	0	667
Other Revenues	141	62	W
Total Operating Revenues	37,009	1,490	31,183
Operating Expenses			
General Operating Expenses	34,021	1,637	29,798
Depreciation, Depletion, & Allowance	509	62	W
General & Administrative	375	77	W
Total Operating Expenses	34,905	1,776	29,841
Operating Income	2,104	-286	1,342
Other Revenue & (Expense)			
Earnings of Unconsolidated Affiliates	W	W	W
Gain(Loss) on Disposition of Property, Plant, & Equipment	W	W	W
Total Other Revenue & (Expense)	-76	-236	-56
Pretax Income	2,028	-522	1,286
Income Tax Expense	813	-108	523
Discontinued Operations	W	W	W
Extraordinary Items and Cumulative Effect of Accounting Changes	W	W	W
Contribution To Net Income	626	-387	126

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