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Performance Profiles of Major Energy Producers 2001

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Data File Information

Historical Financial Reporting System (FRS) data are available from the Energy Information Administration's File Transfer Protocol (FTP) site. These data cover the years 1977 through 2001, published in the Energy Information Administration's annual editions of *Performance Profiles of Major Energy Producers.* There are two different sets of data: aggregate data from the FRS survey form and multi-year tables from Appendix B of *Performance Profiles of Major Energy Producers.*

The Financial Reporting System 1977-2001 data files can be downloaded from the Energy Information Administration's FTP site by accessing the following EIA Web site: http://www.eia.doe.gov/emeu/finance/page2.html. For further assistance, please contact the National Energy Information Center at (202) 586-8800, FAX (202) 586-0727, TTY (202) 586-1181, or by email: infoctr@eia.doe.gov.

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Preface

Performance Profiles of Major Energy Producers presents a comprehensive annual financial review and analysis of the domestic and worldwide activities and operations of the major U.S.-based energy-producing companies.[1] (For a list of the companies covered in this report, the Financial Reporting System (FRS) companies, see Chapter 1, the box entitled "The FRS Companies in 2001" on page 1.) Emerging issues in financial performance are also analyzed. The report primarily examines these companies' (the majors') operations on a consolidated corporate level, by individual lines of business, by major functions within each line-of-business, and by various geographic regions. A companion analysis of foreign investment[2] (trends and transactions) in U.S. energy resources, assets, and companies was previously included as a separate chapter in the report. However, the Foreign Direct Investment report is now published separately on the Internet (see http://www.eia.doe.gov/emeu/finance/fdi/index.html).

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

This edition of *Performance Profiles* reviews financial and operating data for the calendar year 2001. Although the focus is on 2001 activities and results, important trends prior to that time and emerging issues relevant to U.S. energy company operations are also discussed.

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

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

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

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

Endnotes

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

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

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Executive Summary

Lower crude oil prices and a drop in energy demand in the latter part of the year led to lower profits for major energy companies in 2001. Key developments in 2001 included:

- Lower rates of economic growth in most areas of the world: the growth rate of real Gross Domestic Product (GDP) worldwide fell from 3.9 percent in 2000 to 1.1 percent in 2001.

- Lower oil prices: on an annual basis, the world oil price declined from $27.70 per barrel in 2000 to $22.00 per barrel in 2001

- Declining natural gas prices: monthly U.S. natural gas prices at the wellhead declined from $8.06 per thousand cubic feet in January 2001 to $2.38 per thousand cubic feet in December. On an annual basis, though, the price of natural gas was up 12 percent, from $3.69 per thousand cubic feet in 2000 to $4.12 per thousand cubic feet in 2001.

- Attacks of September 11: the aftermath of these attacks had adverse impacts on the U.S. economy as well as the demand for petroleum products.

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

Through Form EIA-28, major U.S. energy companies annually report to the FRS (see the box entitled "The FRS Companies in 2001" on page 1 in Chapter 1 of this report). The FRS companies report financial and operating information by major lines of business, including oil and gas production ("upstream"), petroleum refining and marketing ("downstream"), other energy operations, and nonenergy businesses.

Profits of Major Energy Companies Riddled by Asset Writedowns and Lower Oil Prices in 2001

Net income of the FRS companies totaled $37.7 billion in 2001, down 29 percent from the record high net income of 2000. A large amount of asset writedowns and other unusual items had a sizable impact on reported financial results. Most of the unusual items were due to accounting rules that require that the value of oil and gas assets on a company's balance sheet be reduced when end-of-year oil and gas prices are significantly below prior-year levels, as was true at the end of 2001. Excluding unusual items, the FRS companies' net income in 2001 was $51.2 billion, 8 percent below the level of 2000.

Lower oil prices reduced the FRS companies' income from their upstream operations. In 2001, the average oil price realized by FRS producers was down nearly $5 per barrel from 2000. Although the FRS companies' worldwide oil production was up 8 percent and gas production was up 6 percent, and their average natural gas price for the year was 11 percent higher, these developments could not offset the effects of lower oil prices. Excluding unusual items, the FRS companies' net income from worldwide upstream operations in 2001 was $36.7 billion, a 9-percent decline from results in the prior year.

The nonenergy line of business was also a source of lower earnings. The FRS companies' businesses outside of energy did very poorly in 2001. Their chemical operations were hurt by high natural gas prices in the first half of 2001 (natural gas is a key component of many feed stocks used in the manufacture of chemicals), economic slowdowns and recession, and chronic worldwide overcapacity. As a result, the profitability of these operations hit a 20-year low. Other diversified businesses include telecommunications, non-fuel minerals, technology investments, real estate, and insurance, among others. Declines in income were widespread among the FRS companies as established nonenergy businesses were hurt by economic recession and fledgling technology ventures contributed costs but little revenue. Excluding unusual items, net income from nonenergy businesses fell from $4.5 billion in 2000 to $0.3 billion in 2001.

The main source of earnings growth in 2001 was U.S. petroleum refining and marketing operations. Net income from U.S. refining/marketing operations, excluding unusual items, totaled $12.8 billion in 2001, a 48-percent increase from net income in 2000. Most of this growth in income was achieved in the first half of 2001. Colder-than-normal temperatures in the 2000 to 2001 winter added to heating oil demand and also served to drive up natural gas prices. High natural gas prices in the first half of 2001 induced electric utilities and other industrial facilities to switch fuels from natural gas to petroleum, adding to overall petroleum demand. Gasoline demand was rising into the driving season when temporary supply shortfalls hit some areas of the country, resulting in spikes in gasoline prices. As a result, the margin between refined product prices and crude oil input costs soared in the first half of 2001. Subsequently, economic recession and the attacks of September 11 cut demand for most petroleum products, leading to a squeeze on refiners' margins.

Foreign refining/marketing operations were apparently hit harder by the events of 2001 than were U.S. operations. Net income, excluding unusual items, from the FRS companies' foreign refining/marketing operations totaled $3.2 billion in 2001, up only 6 percent.

Capital Expenditures: Mergers and Acquisitions Again Loom Large

Capital expenditures of the FRS companies totaled an all-time high of $110.4 billion in 2001, up 1 percent from expenditures in 2000. As in 2000, mergers and acquisitions were prominent, accounting for $46.7 billion of capital expenditures. About a third of the merger and acquisition activity in 2001, based on dollar value, involved transactions between FRS companies – the largest being Phillips Petroleum's acquisition of Tosco ($9.4 billion) followed by Valero Energy's merger with Ultramar Diamond Shamrock ($6.1 billion). Other multi-billion-dollar transactions clustered around acquisitions of upstream Canadian companies, mainly for their natural gas reserves, and gas-rich U.S. companies. Excluding the effects of mergers and acquisitions, the FRS companies' capital expenditures increased by 26 percent between 2000 and 2001.

Most of the increase in capital expenditures, apart from mergers and acquisitions, was for upstream exploration and development. The FRS companies' exploration and development expenditures for unproved acreage, seismic work, drilling, and production equipment, were up 35 percent in 2001 compared to expenditures in 2000. The U.S. onshore, which includes Alaska, registered the largest increase, $6.1 billion, in expenditures. Natural gas was the favored target. The FRS companies' gas well completions onshore increased 77 percent in 2001 compared with completions in 2000, but oil well completions were up only 4 percent.

Outside the United States, Canada registered the largest increase in the FRS companies' exploration and development spending. In 2001, expenditures for Canadian prospects more than doubled, as oil well completions and gas well completions each more than doubled between 2000 and 2001.

Africa was the other region where exploration and development expenditures surged in 2001. Both sub-Saharan Africa and North Africa were areas of heightened exploration and development activity. For the FRS companies involved in sub-Saharan projects, exploration and development expenditures for Africa in 2001 totaled $3.4 billion, about double the level of the prior year. For the seven FRS companies involved in North Africa, expenditures totaled $0.7 billion, about 50 percent above spending in 2000.

Businesses outside of energy and chemicals (the "other nonenergy" line of business) experienced the greatest cutback in capital expenditures: from $6.5 billion in 2000 to $3.4 billion in 2001, a 47-percent decline. The major source of the decline was Williams Companies' spin-off of their communications business in early 2001. USX Corporation's reorganization into two companies, Marathon Oil Corporation and U.S. Steel Corporation, also contributed to the decline in expenditures in that, prior to the 2001 reporting year, USX, which contained both these corporations, was an FRS respondent. After the reorganization, only Marathon qualified as an FRS major energy company. The sharp reduction in capital expenditures for other nonenergy in 2001 is part of the long-running retrenchment in this area by the FRS companies (see "Telecommunications -- The End of the Line for Diversification?" in Chapter 4 for further discussion).

Worldwide Reserve Additions at Highest Level in at Least 28 Years

The FRS companies' worldwide additions to their oil and gas reserves from exploration and development activities, excluding reserves gained through acquisitions and mergers, totaled 7.9 billion barrels (oil equivalent) in 2001. This surpassed 1997's prior peak (over the 1974 to 2001 period of FRS data collection) of 6.8 billion barrels (oil equivalent). The 7.9 billion barrels replaced 137 percent of their worldwide oil and gas production.

In the United States, the FRS companies added 3.3 billion barrels (oil equivalent) of oil and gas to their reserves in 2001, second to 1998's 3.9 billion barrels of reserve additions. The FRS companies' U.S. oil and gas reserve additions in 2001 (excluding purchases of proven reserves) replaced 113 percent of their U.S. production.

Mergers, acquisitions, and sales of proven oil and gas reserve properties, on balance, added another 3.1 billion barrels (oil equivalent) to the FRS companies' worldwide oil and gas reserve base in 2001. All told, the FRS companies' worldwide reserve additions, from all sources, were nearly double their worldwide oil and gas production in 2001.

Recent Trends in Ownership: Survival and Turnover

A recurrent focus of the *Performance Profiles of Major Energy Producers* reports is important trends among the major energy producers as well as developments within the reporting year. Ownership of upstream and downstream assets has changed considerably in recent years. Some of the trends in ownership are reviewed in Chapter 4.

In the context of global oil production, publicly traded companies have grown in importance during the most recent decade. The share of world oil production of publicly traded companies among the world's top 20 producers has nearly doubled, from 11 percent in 1992 to 21 percent in 2001. Part of this growth is attributable to the mega-mergers of recent years. These mergers included the intra-FRS mergers of Exxon with Mobil, Chevron with Texaco, and BP with Amoco and then ARCO as well as French-based Total Petroleum's mergers with Elf Aquitaine and Petrofina. However, most of the gain was due to privatizations, either total or partial, of formerly state-owned companies. These privatizations allowed ownership through stock purchase of Russia's YUKOS and LUKoil, PetroChina (formerly, China National Petroleum), and Brazil's Petrobras.

In the United States over the same period, half of the companies constituting the top 20 in U.S. oil production and U.S. gas production in 1992 merged or were acquired by the end of 2001. In oil production, there were 12 companies that were among the top 20 in 1992 and 2001 ("survivors") and 8 that were not ("entrants"). In natural gas production there were 10 survivors and 10 entrants. Taking oil and gas together, there were, on balance, 12 survivors and 11 entrants, a turnover rate of nearly 50 percent. Although the overall production shares of the survivors increased, concentration in terms of ownership hardly changed.

In U.S. refining, most of the changes in ownership of refinery capacity occurred in the 1996 to 2001 period. In 1996, 16 FRS companies owned and operated U.S. refineries. These 16 companies accounted for 65 percent of U.S. refining capacity. In 2001, only 10 of the original 16 of 1996 FRS refining companies still owned U.S. refineries. These 10 companies accounted for 44 percent of U.S. refining capacity. What happened to the other refiners and their capacity? Four companies (Amoco, ARCO, Mobil, and Texaco) were acquired by surviving FRS refiners while Unocal divested its refining assets and Ashland committed its refineries to a joint venture in which it became a minority owner. A significant amount of the FRS refinery capacity of 1996 was sold to then small refiners, who, unlike the FRS refiners of the time, did not possess any capability to produce oil (i.e., they were not vertically integrated). This latter group of specialized refiners accounted for only 14 percent of refining capacity in 1996. However, their prominence in refining grew so rapidly that they are now considered major energy companies and became FRS respondents in 1998 ('entrants"). In 2001, this group of 10 companies (including Tosco who was acquired by FRS survivor Phillips Petroleum in 2001) accounted for 39 percent of U.S. refining capacity. The inclusion of these latter refiners into the FRS group increased the FRS companies' share of total U.S. refining capacity to 83 percent in 2001 versus 65 percent in 1996.

1. MARKET DEVELOPMENTS AND FRS COMPANIES IN 2001

Developments in Global Oil and Natural Gas Markets

The 30 major U.S. energy companies[1] reporting to the Energy Information Administration's Financial Reporting System (FRS) derive the bulk of their revenues and income from petroleum operations, including natural gas production. A majority of these companies are multinational, with 41 percent of the majors' net investment located abroad. Worldwide petroleum and natural gas market developments are of primary importance to the companies' financial performance. (For a list of these companies, see the box entitled "The FRS Companies in 2001.")

The FRS Companies in 2001

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

Demand for oil and natural gas in 2001 generally declined throughout the year. Declining energy demand reflected a sharp slowdown in global economic growth. World economic growth, as measured by the annual percent change in real Gross Domestic Product (GDP), was only 1.1 percent in 2001, down from real GDP growth of 3.9 percent in 2000.[3] In the United States, real GDP growth fell from 4.1 percent to 1.2 percent between 2000 and 2001. Nearly all regions of the world showed a similar pattern of reduced economic growth.

In the world oil market, demand was flat between 2000 and 2001 on an annual basis.[4] World oil demand in the first quarter of 2001 grew 1.2 percent compared to the first quarter of 2000, but by the fourth quarter, demand was 1 percent below that of the prior year. The decline in world oil demand was led by the United States, where first quarter oil consumption was up 3 percent but by the fourth quarter demand was 3 percent below the fourth quarter of 2000.

On the supply side, overall world oil production in 2001 was also essentially flat on an annual basis. Although members of the Organization of Petroleum Exporting Countries (OPEC), excluding Iraq, cut their oil production by an average of nearly 700 thousand barrels per day during the year, the OPEC cuts were matched by increased oil production by Russia and Mexico.

As a result of the decline in oil demand during 2001, worldwide petroleum (oil and refined products) inventories generally rose. In the United States, commercial petroleum inventories at the end of 2001 were 12 percent above prior-year levels. The growth in inventories put downward pressure on oil prices throughout the year. World oil prices (as measured by the refiner acquisition cost of imported crude oil) fell from $25 per barrel in December 2000, to $16 per barrel in December 2001. On an annual basis, world oil prices fell from $28 per barrel in 2000 to $22 per barrel in 2001.

Natural gas prices in the United States declined even more steeply during the year. At the beginning of the year, in January, a colder-than-normal winter combined with already tight supply conditions raised U.S. natural gas prices at the wellhead to a peak of $8 per thousand cubic feet. Domestic natural gas producers responded to the incentive of high prices, increasing production by over 2 percent for the year. Natural gas imports, mostly from Canada, were up 6 percent. However, U.S. natural gas consumption, which was up 3 percent in the first quarter of 2001 compared with the first quarter of 2000, began to fall after the end of the 2000-to-2001 heating season. In the fourth quarter of 2001, U.S. natural gas consumption was 14 percent less than in the final quarter of 2000. The sharp drop in demand was mainly due to milder temperatures compared to the fourth quarter of 2000, although industrial demand was down as well.

The excess supply of natural gas relative to demand served to rebuild inventories, which were at unusually low levels at the beginning of 2001. The sharp upswing in natural gas storage levels had a depressing effect on natural gas prices. By December, the U.S. wellhead price had fallen to $2.38 per thousand cubic feet. Nevertheless, on an annual basis, the wellhead price was $4.12 per thousand cubic feet in 2001, $0.43 higher than in 2000, equivalent to $2.40 per barrel of oil equivalent. Outside the United States, natural gas prices were also higher, particularly in Europe. The FRS companies' average natural gas price in their foreign upstream (i.e., oil and gas production) operations was $0.32 higher.

In the FRS companies' upstream operations, lower oil prices outweighed the effects of higher natural gas prices and the companies' increased oil and gas production, leading to a decline in worldwide oil and gas revenues and income.

Downstream operations (petroleum refining, marketing, and transport) of the FRS companies fared better in 2001 than upstream operations, posting large gains in income and in rates of return to refining and marketing investments. Most of the gains were made in the first half of 2001. Overall U.S. petroleum demand was up 2 percent in the first half of 2001 compared with demand in the first half of 2000. The growth in first-half demand was led by heating oil (up 9 percent) and jet fuel (up 3 percent). Petroleum prices were generally higher in the first half as well, especially motor gasoline prices. Although gasoline demand was up only 1 percent, gasoline prices spiked in April and May in some areas of the country. The margin between product prices received by refiners and crude oil input costs hit a record level (at least since 1983 when EIA first collected these data) in the second quarter of 2001 of about $16 per barrel. Based on financial results for the first half of 2001, it appeared that U.S. refiners might be on their way to a record year for income and profitability.

The market for petroleum products began to turn at mid-year. In the third quarter of 2001, overall demand for petroleum products in the United States was down 2 percent compared with the prior year.

The fall in demand reflected a downturn in economic activity and the initial impacts of the attacks of September 11. Domestic demand for petroleum products, apart from gasoline, continued to deteriorate into the fourth quarter of 2001. Jet fuel was especially hard hit as fourth-quarter demand was down 15 percent compared with the prior year. By year's end, the good times had faded for U.S. refiners: fourth-quarter margins were only half of their second-quarter values. Nevertheless, for the year as a whole, the FRS companies' downstream income in 2001 was above that of 2000, both in the United States and abroad, on the strength of market developments in the first half of the year.

Chemical manufacturing is a business that is affected by both energy and overall market developments. Ten FRS companies had chemical businesses in 2001. Chemical earnings were hurt by unusually high natural gas prices early in 2001, as natural gas is a key component of many feedstocks used in the manufacture of chemicals. Reduced economic growth in most of the industrialized countries and chronic worldwide overcapacity in the chemical industry put downward pressures on prices throughout the year. The result was the lowest rate of return to the FRS companies' chemical operations in 20 years.

Changes in the FRS Group in 2001

Mergers and Acquisitions

In 2001, four FRS companies were acquired by other FRS companies. On January 29, 2001, El Paso and Coastal merged in a transaction valued at $24.0 billion. El Paso was the successor company. On September 17, 2001, Phillips Petroleum acquired Tosco in a transaction valued at $9.4 billion. On October 9, 2001, Chevron and Texaco merged into ChevronTexaco in a transaction valued at $39.3 billion. On December 31, 2001, Valero Energy merged with Ultramar Diamond Shamrock in a transaction valued at $6.1 billion. Valero Energy was the successor company. In comparison with Phillips Petroleum and Valero Energy, Tosco and Ultramar Diamond Shamrock continued to report to the FRS on a stand-alone basis in 2001.

Exits

Enron Corporation, an FRS respondent since 1992, filed for bankruptcy protection under Chapter 11 on December 2, 2001. The U.S. Securities and Exchange Commission did not require Enron to file a Form 10-K or an audited financial statement for the 2001 reporting year. Lacking either a Form 10-K or audited financial statements for 2001, Enron was not required to file Form EIA-28 (the Financial Reporting System) for 2001.

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

For the reporting year 2001, 30 major energy companies reported their financial and operating data to the EIA Financial Reporting System (FRS) on Form EIA-28.[5] These companies (referred to as the FRS companies in this report) occupy a significant position in the U.S.[6] economy. In 2001, operating revenues of the FRS companies totaled $806 billion, which is equal to 11 percent of the $7.4 trillion in revenues of the Fortune 500 largest U.S. corporations.[7]

The reporting companies engage in a wide range of business activities, but their most important activities are in the energy sector. About 94 percent, or $777 billion, of allocated operating revenues were derived from energy sales. Nearly all of these revenues were derived from the companies' core petroleum operations (which includes natural gas) (Figure 1). (For the purposes of this report, the petroleum line of business includes natural gas.[8])

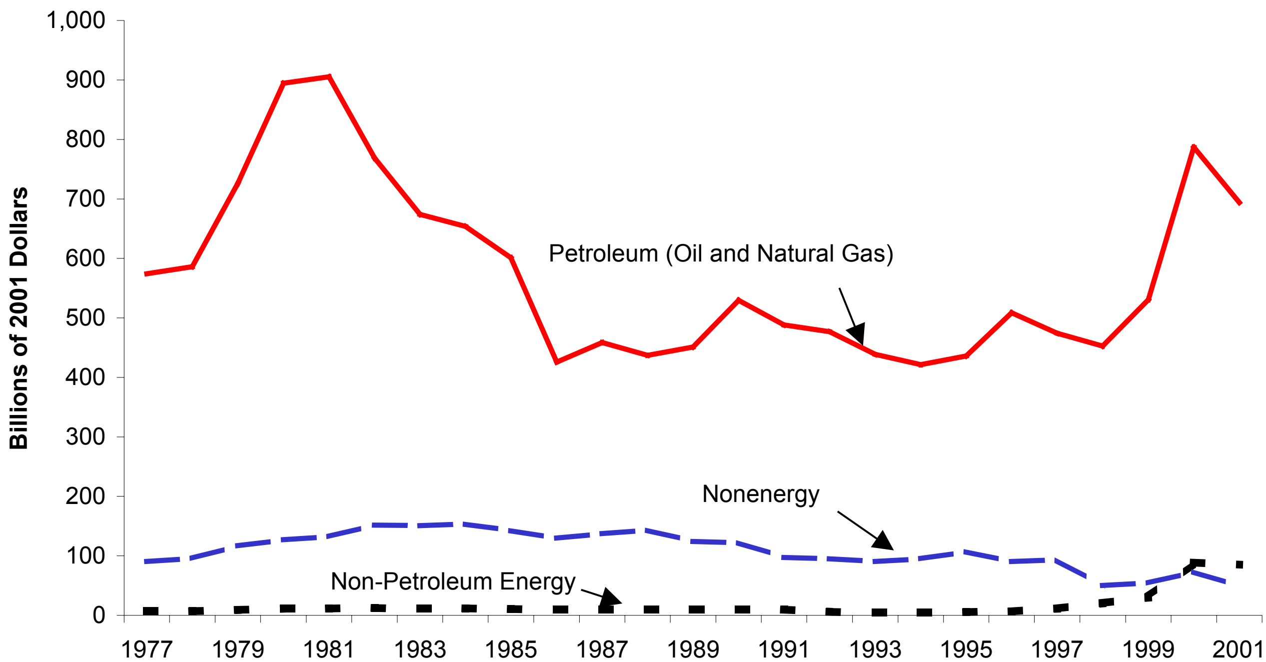
In 2001, the FRS companies accounted for 46 percent of total U.S. oil (crude oil and natural gas liquids (NGL)) production, 46 percent of natural gas production, and 92 percent of U.S. refining capacity (Figure 2). The bulk of the FRS companies' assets and new investments were devoted to sustaining various aspects of petroleum production, processing, transportation, and marketing.

Energy production other than oil and natural gas is a relatively small, but growing, part of the FRS companies' operations. During 2001, the combined operating revenues of the coal and other energy operations of the FRS companies totaled $85 billion, or 10 percent of allocated revenues. Increased activity in electricity more than offset the continued decline in coal activity by the FRS companies in 2001. In particular the FRS companies accounted for 29 percent of U.S. coal production in 1991, 15 percent in 1997, 7 percent in 1998, and 3 percent in 2001, with these declines largely being due to the relative lack of profitability attributable to this line of business. Meanwhile, FRS other energy (exclusive of coal), which is chiefly composed of electricity operations, increased from 0.4 percent of allocated revenues in 1996 to 10.1 percent in 2001.

During the 1980's, the FRS companies were major producers of domestic uranium. However, no FRS company has produced uranium oxide since 1991.

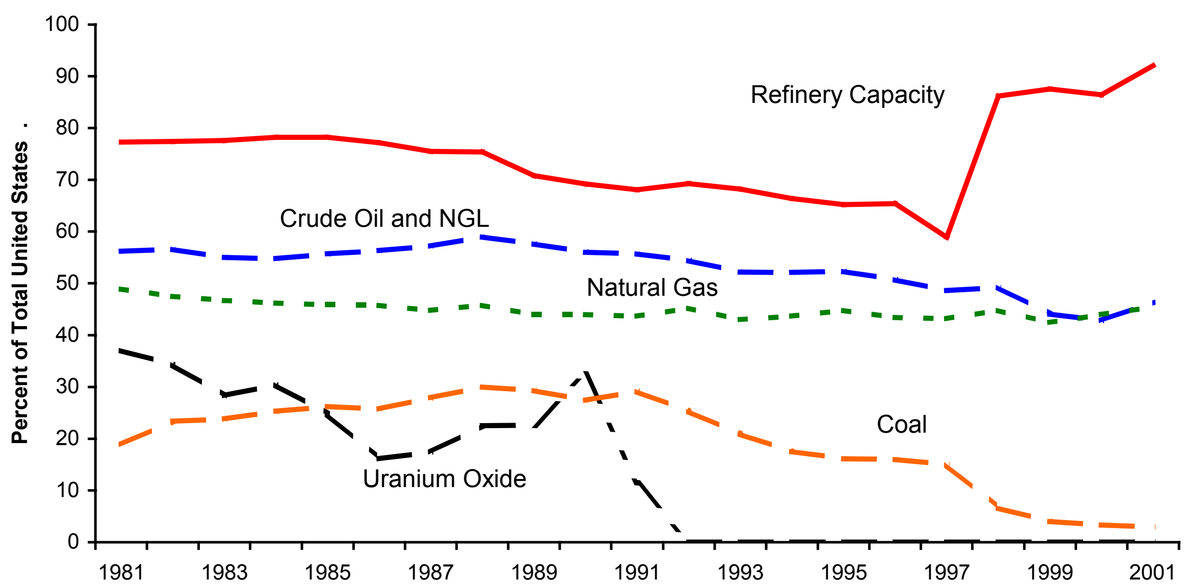
Nonenergy businesses, mainly chemicals, accounted for about 6 percent, or $48 billion, of the FRS companies' allocated revenues in 2001.

Figure 1. Operating Revenues by Line of Business for FRS Companies, 1977-2001



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

Figure 2. Shares of U.S. Energy Production and Refinery Capacity for FRS Companies, 1981-2001



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).

Endnotes

[1] The U.S.-based energy companies that respond to the Financial Reporting System (FRS) Form EIA-28 are considered to be U.S. majors by the Energy Information Administration (see P.L. 95-91, Sec. 205 (h)). Per the requirements of that statue, the Administrator of the Energy Information Administration designates "major energy-producing companies" and selects them as respondents to the FRS. Currently, the Administrator uses the following selection criteria: at least 1 percent of U.S. crude oil or natural gas liquids reserves or production, or at least 1 percent of U.S. natural gas reserves or production, or at least 1 percent of U.S. crude oil distillation capacity. The companies that reported to the FRS for the years 1974 through 2001 are listed in Appendix A, Table A1 (available on the EIA website at http://www.eia.doe.gov/emeu/pefpro/tabal.html). Three of the FRS companies are owned by foreign companies: BP America—owned by BP plc; Total Fina Elf Holdings USA—owned by TotalFinaElf; and Shell Oil—owned by Royal Dutch/Shell.

[2] BP America, the U.S. subsidiary of BP plc of the United Kingdom, is the FRS respondent.

[3] Real GDP growth rates are from Global Insight, *World Overview* (September 2002).

[4] In this chapter, energy data were obtained from Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(2002/09) (Washington, DC, September 2002).

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

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

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

[8] 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.

2. FINANCIAL DEVELOPMENTS IN 2001

Net income of major energy companies that report to EIA's Financial Reporting System (FRS)[9] totaled $37.7 billion in 2001, down 29 percent from the record high net income of $53.2 billion in 2000 (Table 1). Profitability of the FRS companies in 2001, as measured by return on equity,[10] dipped noticeably (Figure 3), but at 13.3 percent exceeded the historical 12.6-percent average. The FRS companies' financial performance in 2001, though off from the prior year, was much better than other U.S. industrial corporations generally. Overall, U.S. industrial corporations (as represented by the S&P Industrials[11]), suffered a 56-percent decline in net income. Profitability of the S&P Industrials was the second-worst in at least 30 years.

The interpretation of financial results is affected by a large amount of unusual items in 2001. Unusual items are composed of gains and charges recognized in a company's income statement that are of a non-recurring nature and generally unrelated to ongoing operations. In 2001, unusual items reduced net income by $13.5 billion, but in 2000, the comparable reduction was a much smaller $2.3 billion. Three categories of unusual items accounted for most of the 2001 amount:

First, oil and gas producers reduced asset values carried on their books, mainly in response to lower oil and natural gas prices at the end of 2001 compared to prices at the end of 2000 (with $6.4 billion charged largely against oil and gas production operations).

Second, merger-related expenses and writedowns associated with the assimilation and sorting of assets gained in the mergers of Chevron and Texaco, El Paso and Coastal, and Exxon and Mobil were taken (with $2.7 billion against various lines of business and corporate overhead).

Third, the treatment of USX's (now Marathon Oil in the FRS respondent group) spinoff of U.S. Steel and Williams Companies' spinoff of Williams Communications as discontinued operations in 2001 had a negative $2.5-billion impact on net income from their nonenergy line of business.

Excluding unusual items, the FRS companies' net income in 2001 was $51.2 billion, 8 percent below the level of 2000.

Enron, an FRS respondent since 1992, was not included in the FRS for the 2001 reporting year due to the company's bankruptcy filing in December, 2001. Interpretation of results in the "other energy" line of business can be affected by the absence of Enron from the FRS. Whenever this occurs, the impact of Enron's absence will be indicated by reporting two results, one that includes Enron and one that excludes Enron.

Financial results varied across lines of business in 2001. Most of the gains in income between 2000 and 2001 came from downstream petroleum (refining, marketing, and transport) operations. These gains were offset by lower upstream (oil and gas production) income stemming from lower oil prices. Declines in income from nonenergy businesses, which exceeded 100 percent, also contributed to the decline in overall net income.

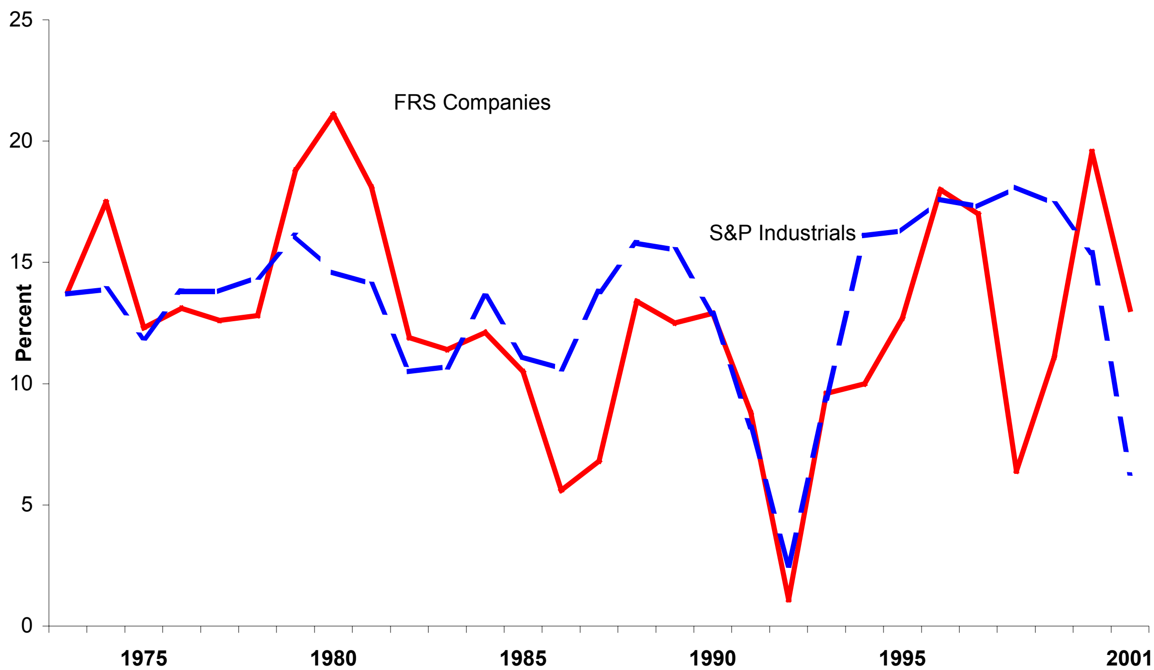
Table 1. Consolidated Income Statement for FRS Companies and the S&P Industrials, 2000-2001
(Billion Dollars)

	FRS Companies			S&P Industrials		
Income Statement Items	**2000**	**2001**	**Percent Change 2000-2001**	**2000**	**2001**	**Percent Change 2000-2001**
Operating Revenues	910.6	803.7	-11.7	4,712.6	4,841.7	2.7
Operating Expenses	-826.8	-735.6	-11.0	-4,146.2	-4,386.4	5.8
Operating Income	83.8	68.1	-18.7	566.4	455.3	-19.6
Interest Expense	-10.6	-9.1	-14.3	-97.7	-103.0	5.4
Other Revenue (Expense)	15.0	6.3	-57.9	24.9	-104.2	--
Income Tax Expense	-35.0	-27.7	-21.0	-184.9	-112.2	-39.3
Net Income	53.2	37.7	-29.1	308.7	136.0	-56.0
Net Income Excluding Unusual Items	55.5	51.2	-7.7	NA	NA	

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

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

Figure 3. Return on Equity for FRS Companies and the S&P Industrials, 1973-2001



Sources: FRS Companies: Energy Information Administration, Form EIA-28 (Financial Reporting System). S&P Industrials and S&P 500: Compustat PC Plus, a service of Standard and Poor's. S&P Industrials not available after 2000.

Income and Cash Flow

Petroleum Refining and Marketing Provide Earnings Growth

Net income[12] from U.S. refining/marketing operations of the FRS companies, excluding unusual items, totaled $12.8 billion in 2001, a 48-percent increase from net income in 2000 (Table 2). Most of this growth in income was achieved in the first half of 2001. Colder-than-normal temperatures in the 2000 to 2001 winter added to heating oil demand and also contributed to increased natural gas prices. High natural gas prices during the first half of 2001 induced electric utilities and other industrial facilities to switch fuels from natural gas to petroleum, adding to overall petroleum demand. Gasoline demand was rising into the driving season when temporary supply shortfalls hit some areas of the country, resulting in spikes in gasoline prices. As a result, the spread between refined product prices and crude oil input costs soared in the first half of 2001.

Table 2. Contributions to Net Income by Line of Business for FRS Companies, 2000-2001
(Million Dollars)

Line of Business	Net Income			Net Income Excluding Unusual Items		
	2000	2001	Percent Change 2000-2001	2000	2001	Percent Change 2000-2001
Petroleum[a]						
U.S. Petroleum						
Production	21,865	17,646	-19.3	22,031	20,635	-6.3
Refining/Marketing	7,659	11,951	56.0	8,657	12,829	48.2
Pipelines	2,314	3,345	44.6	2,389	3,754	57.1
Total U.S. Petroleum	31,838	32,942	3.5	33,077	37,218	12.5
Foreign Petroleum[a]						
Production	18,471	14,558	-21.2	18,516	16,101	-13.0
Refining/Marketing	2,900	3,115	7.4	3,065	3,239	5.7
International Marine	49	176	259.2	49	176	259.2
Total Foreign Petroleum	21,420	17,849	-16.7	21,630	19,516	-9.8
Total Petroleum	53,258	50,791	-4.6	54,707	56,734	3.7
Coal	27	134	396.3	34	136	300.0
Other Energy	2,741	1,993	-27.3	2,761	2,000	-27.6
Nonenergy	3,565	-2,726	-176.5	4,535	320	-92.9
Total Allocated	59,591	50,192	-15.8	62,037	59,190	-4.6
Nontraceables and Eliminations	-6,399	-12,457	--	-6,559	-7,975	--
Consolidated Net Income[b]	53,192	37,735	-29.1	55,478	51,215	-7.7

[a]The Petroleum line of business includes natural gas operations.
[b]The total amount of unusual items was -$2,286 million and -$13,480 million in 2000 and 2001, respectively.
-- = Not meaningful.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

The second half of 2001 can be fairly described as a reversal of fortune for U.S. refining and marketing. Economic recession cut diesel demand. Airlines were hit by a retreat from air travel following the attacks of September 11 as well as economic recession that cut jet fuel demand. Relatively mild temperatures in the fourth quarter resulted in a lessened demand for heating oil. As a result of these second-half developments, the spread between refined product prices and crude oil input costs fell by 50 percent, or by $8 a barrel, from the second quarter to the fourth quarter of 2001.

The FRS companies' foreign refining/marketing operations did less well than U.S. operations. Net income, excluding unusual items, from the FRS companies' foreign refining/marketing operations totaled $3.2 billion in 2001, up 6 percent. These operations were apparently hit harder by the events of 2001 than were U.S. operations. On the positive side, Exxon Mobil said that, "the improvement was driven by stronger marketing margins, partly offset by weaker European refining margins,"[13] while ChevronTexaco noted that downstream earnings in Asia-Pacific and Africa were up significantly because of improved marketing margins, earnings in Latin America were level, and European earnings were hurt by low margins and lower sales volumes.[14] However, Conoco cited lower refining margins and an April explosion and fire at its UK refinery as reasons for lower foreign downstream earnings in 2001.[15] El Paso, which acquired a refinery in Aruba in its merger with Coastal, also suffered a refinery mishap in 2001, citing "… negative margins in refining resulting from a fire at our Aruba facility in April 2001."[16]

Lower Oil Prices Reduce Upstream Income

Lower oil prices adversely affected U.S. oil and gas production operations of the FRS companies in 2001. Wellhead crude oil prices in the United States declined steadily during the year, from $25 per barrel in February to $22 in September, and then fell sharply to under $16 in December. For the year, U.S. crude oil prices were down $5 per barrel from 2000. Domestic natural gas prices at the wellhead hit an all-time monthly peak of $8.06 per thousand cubic feet in January, 2001, but by December stood at $2.38. For the year, natural gas prices at the wellhead averaged $4.12 which, being about 43 cents higher than the average for 2000, provided a partial offset to lower oil prices. Other offsets included increased oil production by FRS companies, up 8 percent both in the United States and abroad, and increased natural gas production, up 6 percent in both the United States and abroad.

Excluding unusual items, the FRS companies' net income from U.S. oil and gas production was $20.6 billion in 2001, down 6 percent from net income in 2000. In foreign oil and gas production, net income, excluding unusual items, was $16.1 billion in 2001, a 13-percent decline. The somewhat steeper decline abroad reflected the higher proportion of oil in foreign upstream operations, 61 percent vs. 46 percent, and consequent greater exposure to lower oil prices.

Pipelines Deliver Strong Financial Results

The pipeline networks of the FRS companies registered a healthy increase in net income, excluding unusual items, of 57 percent between 2000 and 2001.

The FRS companies are in two groups with respect to pipeline ownership: a company is either specialized in natural gas pipelines or liquids (crude oil and petroleum products) pipelines. Companies with significant natural gas pipeline ownership have tended to combine these operations with complementary business activities such as natural gas trading, natural gas gathering (i.e., inter-field collection of gas production), and natural gas processing. This development followed the full deregulation of U.S. natural gas markets in 1993. Full deregulation provided opportunities for natural gas trading and had the effect of reducing the role of interstate natural gas pipelines to that of common carriers. The split between revenues from transportation services and other revenues of FRS companies that own natural gas pipelines reflects the growth in complementary businesses: between 1991 and 2001, transport revenues grew 20 percent while other revenues increased 30 percent.

In contrast, liquids pipelines have remained largely rate-regulated. The Trans Alaska Pipeline System (TAPS), which transports oil from Alaska's North Slope to the port of Valdez, is owned by FRS companies as is a major share of lower 48 pipeline capacity.

Between the two groups of FRS pipeline owners, liquids pipelines registered somewhat greater growth in net income: 61 percent compared to 56 percent for natural gas pipelines.

Excluding Enron, Other Energy Earnings Unchanged

The "other energy" line of business was originally intended to collect financial information for major energy companies' nonconventional energy activities. In the late 1970's and early 1980's, FRS companies were prominent in the development and production of synfuels (e.g., tar sands, coal gasification/liquefaction, oil shale) and renewable energy resources (e.g., solar, geothermal). When oil prices began declining after 1981 and crashed in 1986, most nonconventional energy prospects became uneconomic. By 1990, only a handful of nonconventional activities remained among the FRS companies.[17]

The composition of the other energy line of business has changed substantially since then. Most of the revenues and investment in other energy now comes from electric power businesses and associated trading activities. Nonconventional energy activity is now largely related to production of oil from tar sands in Canada, geothermal energy production in Asia, and various developmental efforts involving synthetic fuels.

Additionally, the other energy line of business has been the FRS companies' most rapidly growing line of business since the mid-1990's, albeit from a relatively small base. The rapid growth was due to investment in electric power and the increased number of energy services (i.e., natural gas and power) companies in the FRS group.

In 2001, net income from the other energy line of business, excluding unusual items, was $2.0 billion, down 28 percent from net income in 2000. However, this decline is largely traceable to the absence of Enron from the FRS group in 2001. Excluding Enron, net income was nearly flat between 2000 and 2001. (For further detail on the other energy line of business, see the Other Energy section in Chapter 3.)

Results Beyond Energy Turn Down Sharply

The "nonenergy" line of business consists of chemical manufacturing and an agglomeration of businesses outside energy. Net income from the nonenergy line of business fell from $4.5 billion in 2000 to $0.3 billion in 2001, a 93-percent decline. Both segments of the nonenergy line of business did very poorly in 2001.

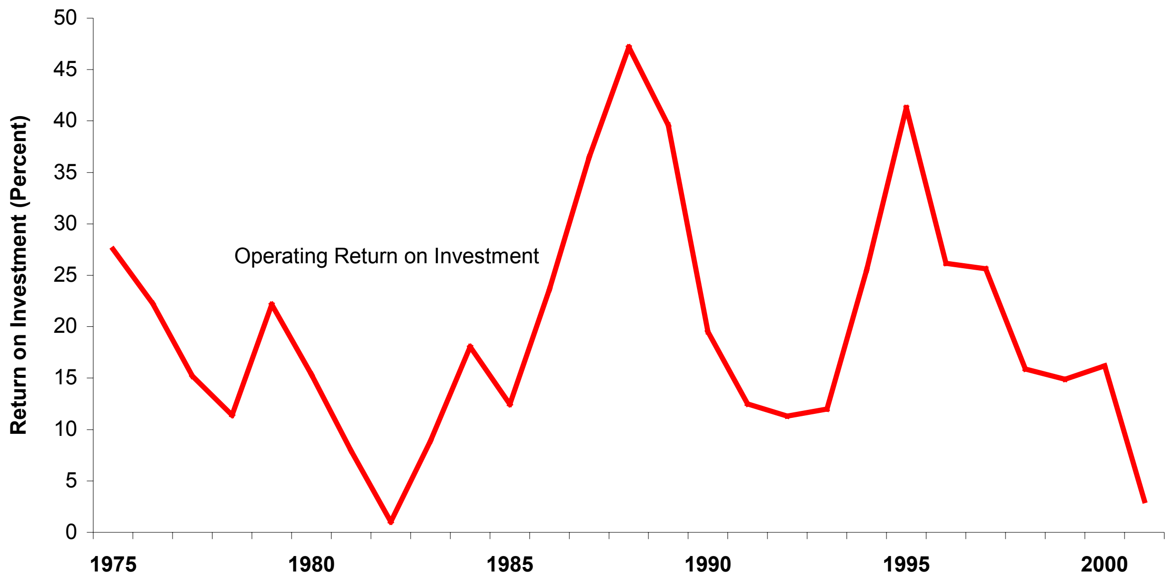
Operating income from the FRS companies' chemical operations,[18] excluding unusual items, was down 77 percent between 2000 and 2001 (Table 3). Continuing a downward trend, the profitability of these operations was at the lowest level since 1982 (Figure 4). Revenues from the FRS companies' chemical operations fell $2.9 billion while operating costs showed little change. Chemical manufacturing was hurt by economic slowdowns and recession, chronic worldwide overcapacity, and high natural gas prices in the first half of 2001.

Table 3. Operating Income in Chemicals and Other Nonenergy Segments for FRS Companies, 2000-2001
(Million Dollars)

Segment	2000	2001	Percent Change 2000-2001
Operating Income, Excluding Unusual Items			
Chemicals	3,794	880	-76.8
Other Nonenergy	3,236	-1,150	--

-- = not meaningful
Sources: Energy Information Administration, Form EIA-28 (Financial Reporting System), except for chemicals segment operating income, which was compiled from company annual reports to shareholders.

Figure 4. Operating Return on Investment in Chemicals for FRS Companies, 1975-2001



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

Every FRS chemical manufacturer reported sharp declines in income. For example, Occidental Petroleum noted that, "Petrochemical margins were under pressure throughout 2001 due to weak demand and significant capacity additions …".[19] Exxon Mobil agreed, saying that, "The business saw higher feedstock and energy costs in North America early in the year as well as weak global demand and industry overcapacity."[20] ChevronTexaco observed that, "Results reflected a protracted period of generally weak demand for commodity chemicals and industry overcapacity."[21]

Other nonenergy consists of diverse enterprises including telecommunications, non-fuel minerals, technology investments, real estate, and insurance. Operating income fell from $3.2 billion in 2000 to a loss of $1.2 billion in 2001. Half of this decline is traceable to the absence of Enron as a 2001 FRS respondent and the absence of U.S. Steel's results due to their spinoff by parent USX (now Marathon

Oil in the FRS respondent group). Declines in income were widespread as established nonenergy businesses were hurt by economic recession and fledgling technology ventures contributed costs but little revenue. Exxon Mobil, for example, noted that earnings from its Chilean copper production were hurt by a significant decline in copper prices.[22] El Paso reported operating losses in their telecommunications business of $72 million in 2001. One exception to this trend was Williams Companies who reported a small but positive operating income due to the absence of heavy losses from the telecommunications business that the company spun off.

Cash Flow at Record Level Despite Decline in Income

Cash flow is the cash realized during a company's fiscal year from ongoing operations. In 2001, the FRS companies' cash flow totaled $89.6 billion (Table 4). This was the highest level in the 1986 to 2001 period (prior to 1986, the measure of funds from operations was working capital rather than cash).

Table 4. Line-of-Business Contributions to Pretax Cash Flow for FRS Companies, 2000-2001
(Billion Dollars)

Contribution to Pretax Cash Flow [a]	2000	2001	Percent Change 2000-2001
Petroleum[b]			
Oil and Gas Production	88.4	85.0	-3.8
Refining, Marketing, and Transport	27.4	34.8	27.1
Coal and Other Energy	4.4	3.3	-24.5
Chemicals	4.5	1.9	-58.3
Other Nonenergy	4.2	-0.1	-102.1
Nontraceable	-6.2	-7.3	--
Total Contribution to Pretax Cash Flow[a]	122.7	116.8	-4.8
Current Income Taxes	-29.6	-24.0	-18.8
Other (Net)	-4.5	-3.2	--
Cash Flow from Operations	88.6	89.6	1.1

[a]Defined as the sum of operating income, depreciation, depletion, and amortization, and dry hole expense.
[b]The Petroleum line of business includes natural gas operations.
-- = Not meaningful.
Note: Sum of components may not equal total due to independent rounding. Percent changes were calculated from unrounded data.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

How could cash flow increase when net income fell by $15 billion? The seeming disparity stems from the inclusion of noncash items in the calculation of income. Cash is defined as currency, demand deposits, and interest-bearing assets of less than 30 days maturity. Generally, cash flow from operations is computed by adding to (subtracting from) net income those cost (revenue) items that did not actually involve an outlay (receipt) of cash.[23] Unusual items tend to be of a noncash nature and the value is largely added back to net income in arriving at cash flow. In 2001, unusual items totaled $13.5 billion, which was much more than the $2.3 billion in 2000, thus the net income decline of $15 billion.

Among the lines of business, downstream petroleum stood out as the only positive contributor to growth in cash flow. Cash flow from worldwide oil and gas production was down $3.4 billion, a 4-percent decrease from 2000. Other nonenergy operations, which performed poorly in 2001, went from being a contributor of $4.2 billion to cash flow in 2000 to being a drain on cash flow, amounting to a negative $0.1 billion in 2001.

The line-of-business results above are on a pre-tax basis. Current income taxes (i.e., the amount of taxes deemed payable in the reporting year) reduce cash flow. The negative impact of current taxes in 2001 was $5.6 billion less than in 2000. This was a 19-percent decline that was roughly in line with the 21-percent decline in the FRS companies' taxable income (Table B12).

Targets of Investment

Mergers and Acquisitions Prominent Again

Capital expenditures of the FRS companies (as measured by additions to investment in place[24]) in 2001, at $110.4 billion, were at an all-time high, just a shade above the previous record of $109.3 billion in 2001 (Table 5). Mergers and acquisitions, which accounted for $46.7 billion of capital expenditures in 2001, though down from 2000, were at a very high level by historical standards (Figure 5).

The two largest mergers among FRS companies in 2001, Chevron's merger with Texaco, which had a value of $39.3 billion, and El Paso's merger with Coastal, which had a value of $24.0 billion (Table 6), had no effect on reported capital expenditures since they were accounted for on a pooling-of-interest basis. In a pooling-of-interest merger, the current book value of the acquired company's assets and liabilities are added to the surviving company's balance sheet. In mergers between FRS companies, such as the Chevron-Texaco and El Paso-Coastal mergers, accounted for as pooling of interests, the effect of the merger is to merely shift existing asset values between companies and is not counted as a capital expenditure. After June 2001, pooling-of-interest accounting is no longer allowed under U.S. financial accounting standards.

Among the FRS companies' lines of business, oil and gas production operations accounted for a major share of mergers and acquisition spending. Canadian producers were the main target in 2001. Acquisitions of Canadian companies that exceeded $1 billion in value included Conoco's acquisition of Gulf Canada, Devon Energy's acquisition of Anderson Exploration, Burlington Resources' acquisition of Canadian Hunter, and Anadarko Petroleum's acquisition of Berkley Petroleum. Other FRS companies who acquired Canadian oil and natural gas assets included Apache and El Paso. Acquisitions in 2001 increased the FRS companies' Canadian oil and natural gas reserve base by 1.7 billion barrels (crude oil equivalent) or by 31 percent. Natural gas appeared to be the main attraction in Canada as natural gas accounted for 57 percent of reserve acquisitions in 2001 and 65 percent in the previous year.

Natural gas was also the focus of the FRS companies' U.S. upstream acquisitions in 2001, as natural gas accounted for 87 percent of U.S. oil and natural gas reserve acquisitions. Three of the largest acquisitions involved natural gas-rich Rocky Mountain properties: Williams' acquisition of Barrett Resources, a producer of coal bed methane in Wyoming's Powder River Basin; Kerr-McGee's acquisition of H. S. Resources and its natural gas reserves located primarily in the Denver-Julesberg basin of Colorado; and Marathon's (formerly USX) acquisition of Pennaco Energy, also a producer of coal bed methane in the Powder River Basin. Dominion Resources further diversified its asset base into natural gas through its $2.3-billion acquisition of Louis Dreyfus Natural Gas and its natural gas reserves in Texas and the Gulf Coast. Continued acquisitions and development of coal bed methane properties served to increase the FRS companies' role in U.S. production of coal bed methane (Figure 6).

Table 5. Additions to Investment in Place by Line of Business for FRS Companies, 2000-2001
(Billion Dollars)

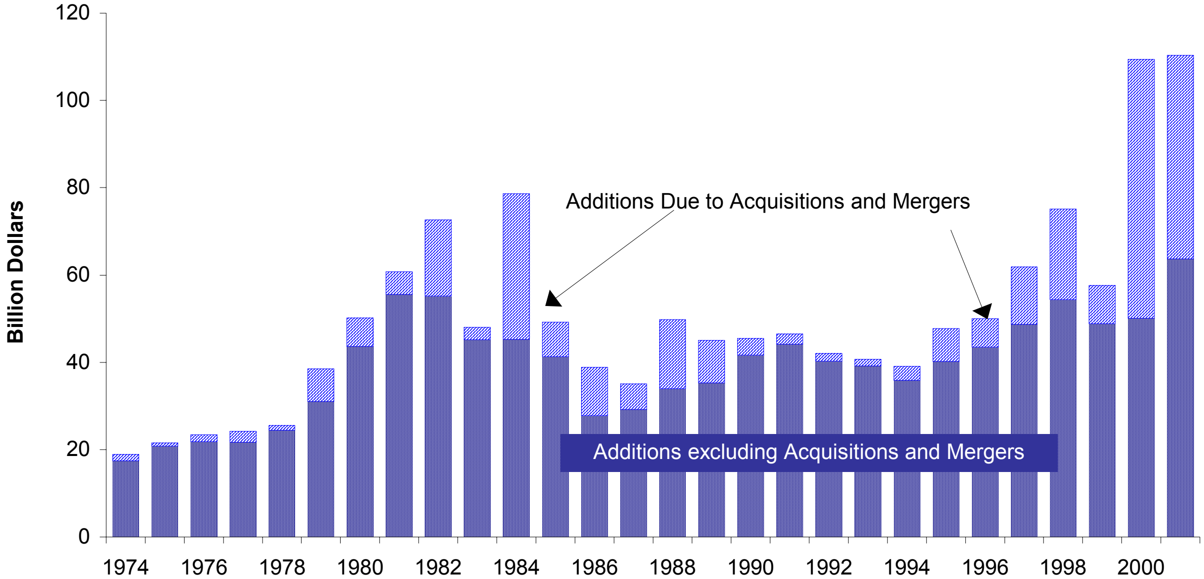
Lines of Business	2000	2001	Percent Change 2000-2001	Percent Change Excluding Mergers and Acquisitions 2000-2001
Petroleum [a]				
U.S. Petroleum				
Production	44.8	33.0	-26.4	80.2
Refining/Marketing				
Refining	8.2	12.1	47.7	-22.8
Marketing	3.4	5.6	64.3	10.1
Transport	0.5	1.6	244.8	244.8
Total Refining/Marketing	12.0	19.2	59.9	4.6
Pipelines	4.0	3.8	-4.9	140.3
Total U.S. Petroleum	60.8	56.0	-7.9	56.1
Foreign Petroleum [a]				
Production	29.5	35.9	21.6	21.8
Refining/Marketing	2.4	4.6	91.1	75.6
International Marine	0.01	0.03	128.6	128.6
Total Foreign Petroleum	31.9	40.5	26.8	28.4
Total Petroleum [a]	92.7	96.5	4.1	43.7
Coal	0.2	0.1	-32.4	-32.4
Other Energy	5.4	5.0	-7.5	-70.2
Nonenergy				
Chemicals	3.7	3.8	3.6	0.3
Other Nonenergy	6.5	3.4	-47.2	-12.5
Total Nonenergy	10.2	7.2	-28.8	-6.6
Nontraceables	0.9	1.5	74.5	139.0
Additions to Investment in Place [b]	109.3	110.4	0.9	26.1
Additions Due to Mergers and Acquisitions	58.8	46.7	-20.6	
Total Additions Excluding Mergers and Acquisitions	50.5	63.7	26.1	
Addendum: Environmental Capital Expenditures	1.7	2.1	19.3	

[a]The Petroleum line of business includes natural gas operations.
[b]Additions to investment in place = additions to property, plant, and equipment, plus additions to investments and advances.
-- = Not meaningful.
Note: Sum of components may not equal total due to independent rounding. Percent changes were calculated from unrounded data.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System), except for environmental capital expenditures, which came from company filings of Securities and Exchange Commission Form 10-K.

The largest oil-related transaction in 2001 was Amerada Hess' $3.2-billion acquisition of Triton Energy. Triton, though based in Dallas, had oil reserves primarily in offshore West Africa as well as in Latin America and Asia.

U.S. refining and marketing was also an area of merger and acquisition activity, with transactions totaling $11 billion in value in 2001.[25] However, unlike the upstream acquisitions that added to the FRS companies' oil and natural gas reserve base, the refining/marketing transactions served mainly to shuffle physical assets, such as refineries and service stations, between FRS companies. Phillips Petroleum's acquisition of Tosco, valued at $9.4 billion was the largest transaction. Tosco was an FRS respondent with significant refining capacity and gasoline marketing networks on the west coast and east coast. Subsequent to BP's[26] sale of ARCO's Alaskan assets to Phillips (a divestiture required for antitrust approval of BP's acquisition of ARCO in 2000), Phillips viewed a west coast outlet for its Alaskan oil production as a potential enhancement to its bottom line. Acquisition of Tosco gave Phillips a set of assets that integrated its recently gained Alaskan oil production and interest in the Trans Alaskan

Figure 5. Additions to Investment in Place and Value of Acquisitions and Mergers for FRS Companies, 1974-2001



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

Pipeline System with Tosco's west coast refineries and network of west coast retail gasoline outlets. This configuration is reminiscent of ARCO's Alaska/west coast operation prior to its acquisition by BP.

Valero Energy also became a west coast refiner in 2001. Valero merged with Ultramar Diamond Shamrock (UDS), an FRS company, in a transaction valued at $6.1 billion and acquired Huntway Refining for $78 million. Valero gained four California refineries with 387 thousand barrels per day (mbd) of crude distillation capacity. In addition, the UDS merger brought four refineries, in Colorado, Oklahoma, and Texas, with a total capacity of 357 mbd, 2,500 company-owned gas stations, and a refinery in Quebec, Canada.

Two other large downstream acquisitions involved intra-FRS transfers of refining assets: Tesoro Petroleum's acquisition of BP's refineries in North Dakota and Utah, which added 166 mbd to Tesoro's refining capacity, and Valero's acquisition of El Paso's Corpus Christi, Texas refinery (134 mbd capacity).

Outside of petroleum and natural gas, electricity was the most active area of merger and acquisition activity. Electricity is reported in the "other energy" line of business. Dominion Resources and El Paso were responsible for nearly all of the acquisitions in "other energy" in 2001. Dominion Resources acquired the Millstone Power Station for $1.2 billion. Millstone, located in Connecticut, includes two active nuclear power plants and one inactive nuclear plant. The acquisition increased Dominion's electric service area to New England. El Paso spent over $2 billion in acquiring electricity assets in the United States and abroad. The bulk of El Paso's acquisitions were for equity interests, rather than physical assets, in the United States and Brazil.

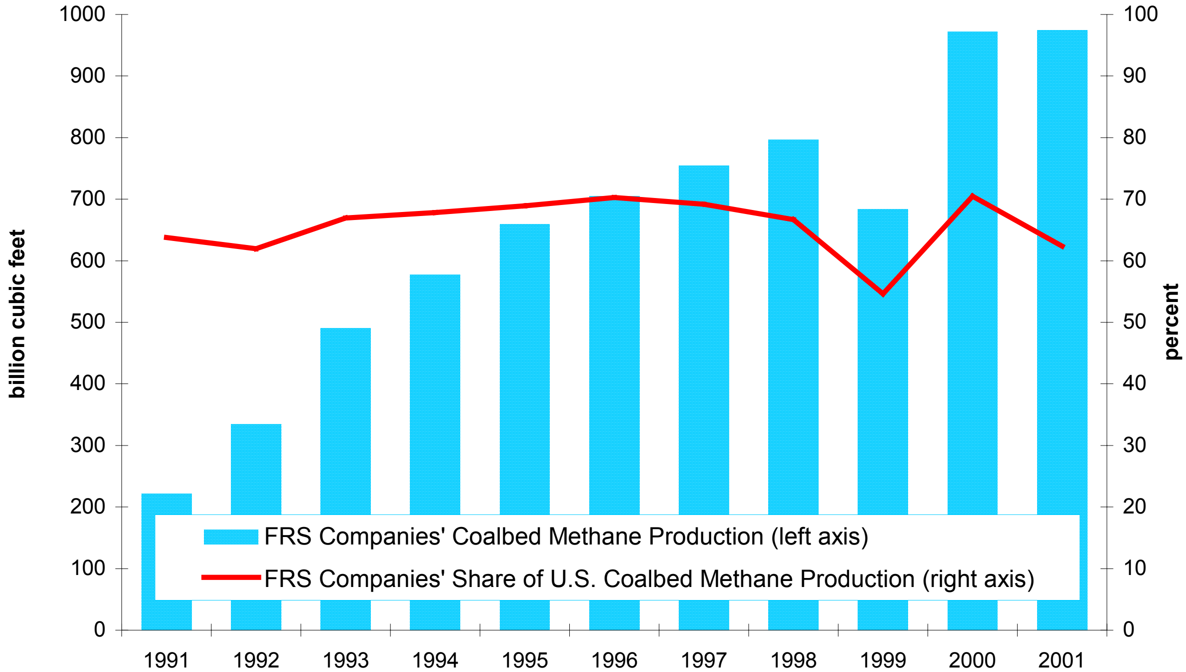
Excluding the effects of mergers and acquisitions, the FRS companies' capital expenditures totaled $63.7 billion in 2001, a 26-percent increase from the prior year. Oil and gas production accounted for almost all of the increase in capital expenditures, excluding mergers and acquisitions, in 2001.

Table 6. Value of Mergers, Acquisitions, and Related Transactions by FRS Companies, 2001
(Million Dollars)

Line of Business and Acquiring Company	Merger or Acquisition	Reported Value of Acquisition
	Mergers and Acquisitions between FRS Companies	
ChevronTexaco	Merger of Chevron and Texaco	39,300
El Paso	Merger of El Paso and Coastal	24,000
Phillips Petroleum	Acquisition of Tosco	9,390
Valero Energy	Acquisition of Ultramar Diamond Shamrock	6,130
Tesoro Petroleum	BP's Mandan, North Dakota and Salt Lake City, Utah refineries and associated facilities	671
Valero Energy	El Paso's Corpus Christi refinery	294
Sunoco	Retail outlets from Coastal	59
	Other Acquisitions by FRS Companies	
Foreign Oil and Natural Gas Production		
Conoco	Acquisition of Gulf Canada	9,414
Devon Energy	Acquisition of Anderson Exploration, Ltd.	6,243
Amerada Hess	Acquisition of Triton Energy Ltd.	3,200
Burlington Resources	Acquisition of Canadian Hunter Exploration Ltd.	2,100
Anadarko Petroleum	Acquisition of Berkely Petroleum	1,015
Apache	Fletcher Challenge Energy	668
Apache	Repsol YPF's oil and gas concession interests	447
El Paso	Acquisition of Velvet Exploration, Ltd.	249
Anadarko Petroleum	Acquisition of Gulfstream Resources Canada Ltd.	128
Unocal	Acquisition of Tethys Energy, Inc	117
BP	Acquisition of Cairns Ltd which holds a 9.7% interest in the Tangguh LNG project	107
U.S. Oil and Natural Gas Production		
Williams Companies	Acquisition of Barrett Resources	2,800
Dominion Resources	Acquisition of Louis Dreyfus Natural Gas	2,300
Kerr-McGee	Acquisition of HS Resources	1,800
ChevronTexaco	Redeemable, convertible preferred shares of Dynegy	1,500
Amerada Hess	Exploration and production assets of LLOG Exploration Co.	767
Marathon	Acquisition of Pennaco Energy, Inc.	506
Unocal	Acquisition of Hallwood Energy Corp.	276
Unocal	Oil and gas properties from International Paper	267
ChevronTexaco	EnerVest San Juan Acquisition L.P.	121
Unocal	Joint venture with Forest Oil	113
Refining, Marketing, and Transport		
Ultramar Diamond Shamrock	Additional consideration to Tosco for the Golden Eagle Refinery purchased in 2000	150
Tosco	Operating assets of the Irish National Petroleum Corp. Ltd.	100
Valero Energy	Acquisition of the Huntway Refining Co.	78
Other Energy		
El Paso	Investment in power projects in the U.S. and Brazil	2,278
Dominion Resources	Millstone Power Station	1,200
Chemicals		
Sunoco	Acquisition of Aristech Chemical Corp	669
Nonenergy		
Williams Companies	Headquarters building and others assets from Williams Communication	276

Sources: Company annual reports to shareholders and press releases.

Figure 6. U.S. Coalbed Methane Production for FRS Companies, 1991-2001



Source: Special compilation from Form EIA-23 (Annual Survey of Domestic Oil and Gas Reserves) by the Reserves and Production Division, Office of Oil and Gas, Energy Information Administration

Spending at the Wellhead Up 35 Percent in 2001

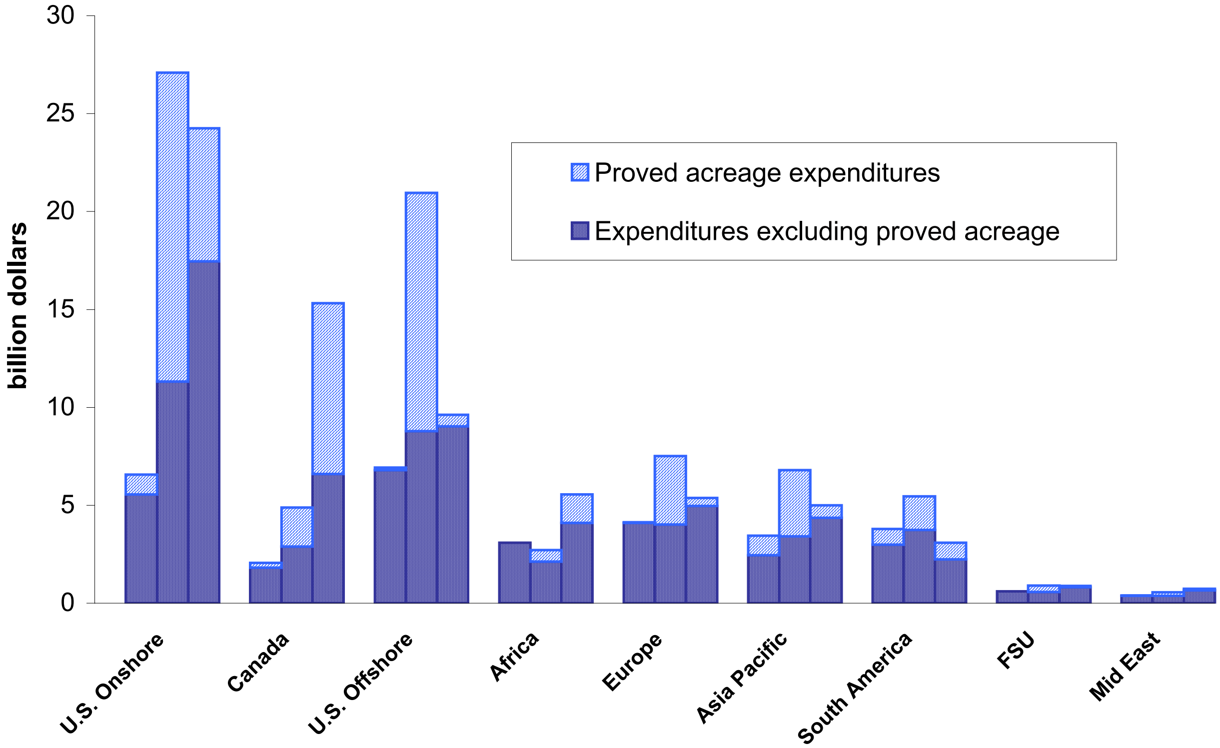
Worldwide exploration and development expenditures,[27] excluding the effects of mergers and acquisitions (as measured by expenditures for proved acreage), were up 35 percent between 2000 and 2001. All regions except South America showed an increase in expenditures (Figure 7).

Onshore locales in the United States registered the largest increase in exploration and development expenditures (excluding expenditures for proved acreage). Expenditures were up $6.1 billion, a 54-percent increase. The step-up in onshore spending was widespread with only two companies reporting lower expenditures in 2001. Natural gas was the favored target. The FRS companies' natural gas well completions onshore increased 77 percent in 2001 compared with completions in 2000, but oil well completions were up only 4 percent.

Canada registered the largest increase in the FRS companies' exploration and development spending (excluding expenditures for proved acreage) among the foreign regions. In 2001, expenditures for Canadian prospects more than doubled, increasing by $3.7 billion, relative to expenditures in 2000. As was true for the U.S. onshore, the upswing in Canadian expenditures was widespread, with 12 of 15 companies reporting increased spending. However, in contrast to the U.S. onshore, the increase in expenditures appeared more evenly directed between oil and gas, as oil well completions and natural gas well completions each more than doubled between 2000 and 2001.

Africa was the other region where exploration and development expenditures (excluding expenditures for proved acreage) surged in 2001. Two general subregions in Africa can be distinguished: sub-Saharan Africa and North Africa. The FRS companies tend to concentrate in one or the other region, with the 14 FRS companies involved in Africa evenly split between the two regions. Sub-Saharan

Figure 7. Exploration and Development Expenditures by Region for FRS Companies, 1999-2001



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

African projects are mostly in offshore West Africa, particularly Nigeria and Angola, although other sub-Saharan countries are attracting investment as well. Deepwater projects have become the main target of exploration and development. Deepwater fields in West Africa tend to be oil-rich and large but also require large expenditure outlays to develop.

Most of the FRS companies' North African exploration and development is in Algeria and Egypt. The drilling and production are largely in onshore prospects, although offshore Egypt has attracted some attention in recent years. Oil accounts for 89 percent of upstream production. Field sizes, as measured by reserves added per well completed, tend to be large relative to North America but only about one-third the size of sub-Saharan fields on average.

Both sub-Saharan Africa and North Africa were areas of heightened exploration and development activity. For the FRS companies involved in sub-Saharan projects, exploration and development expenditures (excluding proved property purchases) for Africa in 2001 totaled $3.4 billion, about double the level of the prior year. For the seven FRS companies involved in North Africa, expenditures totaled $0.7 billion, about 50 percent above spending in 2000.

The sizeable drop in expenditures in South America appeared to be the result of the effects of BP's acquisition of ARCO in 2000. The value of ARCO's South American assets were reflected not only as acquisitions of proved properties but also in some of the other categories of exploration and development expenditures, such as unproved acreage and natural gas processing equipment. Excluding

BP, the FRS companies' exploration and development expenditures (excluding proved property acquisitions) for South America were up 16 percent between 2000 and 2001.

Oil and Gas Reserve Additions in 2001 at Peak Levels

The continued heavy capital outlays by FRS companies for upstream mergers and acquisitions are reflected in patterns of recent additions to their U.S. oil and natural gas reserve base. As shown in Figure 8, well over half of the FRS companies' additions to their U.S. oil and gas reserves in 2001 came through mergers and acquisitions, rather than through the drill bit. Nevertheless, in 2001, reserves added by the FRS companies through exploration and drilling, as opposed to mergers and acquisitions, hit a new peak.

The FRS companies' worldwide oil and natural gas reserve additions, excluding purchases of proved reserves, totaled 7.9 billion barrels (oil equivalent) in 2001. This surpassed 1997's prior peak of 6.8 billion barrels (over the 1974 to 2001 period of FRS data collection). The 7.9 billion barrels replaced 137 percent of their worldwide oil and gas production. In the United States, the FRS companies added 3.3 billion barrels (oil equivalent) of oil and natural gas to their reserves in 2001, second to 1998's 3.9 billion barrels of reserve additions. The FRS companies' U.S. oil and natural gas reserve additions in 2001 (excluding purchases of proven reserves) replaced 113 percent of their U.S. production.

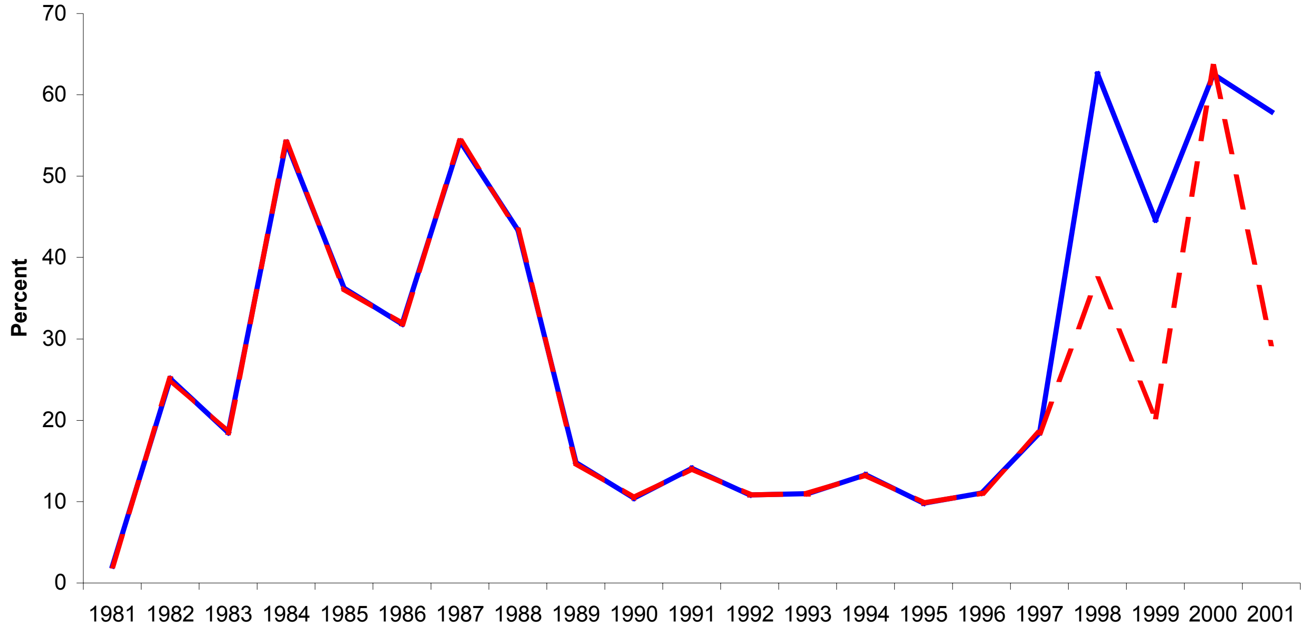
Although mergers and acquisitions have grown in importance as sources of additional oil and natural gas for surviving FRS companies, this trend does not appear to have strongly curtailed exploration and development. In fact, after adjusting for inflation, the FRS companies' exploration and development expenditures in 2001, excluding purchases of proven reserves, were at a level not seen since the first half of the 1980's when oil prices, in 2001 dollars, ranged from $40 per barrel to $60 per barrel.

The recent surge in upstream mergers and acquisitions is in contrast to the earlier 1990 to 1996 period when reserves gained through mergers and acquisitions averaged only 10 percent of all reserve additions. Contrasting the 1990 to 1996 period with the 1997 to 2001 period reveals some clear shifts in upstream strategies in terms of exploration vis-à-vis development.

Exploration involves leasing unproved acreage, employing seismic and other exploratory activities, and exploratory drilling. Exploration is the way in which future oil and gas prospects are added to the portfolio of potential future reserves. Development involves drilling of production wells and installation of associated oil and gas production equipment. Although reserves can be added during the development process, development is essentially an extractive activity. Without replenishment of prospects, the reserve base eventually declines. Has the recent surge in upstream mergers and acquisitions come at the expense of exploratory efforts?

Figure 9 shows that in both the United States and abroad, mergers and acquisitions appeared to be more of a substitute for development than for exploration. When looking at shares of total spending, in the 1990 to 1996 period (when mergers and acquisitions accounted for less than 10 percent of exploration and development spending), over 60 percent of expenditures were allocated to development. In the more recent 1997 to 2001 period (when mergers and acquisitions were more than 25 percent of upstream expenditures), development spending's share was 45 percent, an 18-percentage point decline in the United States and a 16-percentage point decline abroad. In contrast, exploration's share declined only 4 percentage points in the United States and 5 percentage points outside of the United States. Thus, as mergers and acquisitions grew in importance in recent years, the FRS companies increased their emphasis on exploration relative to development.

Figure 8. Share of Total U.S. Oil and Natural Gas Reserve Additions Due to Mergers and Acquisitions for FRS Companies, 1981-2001

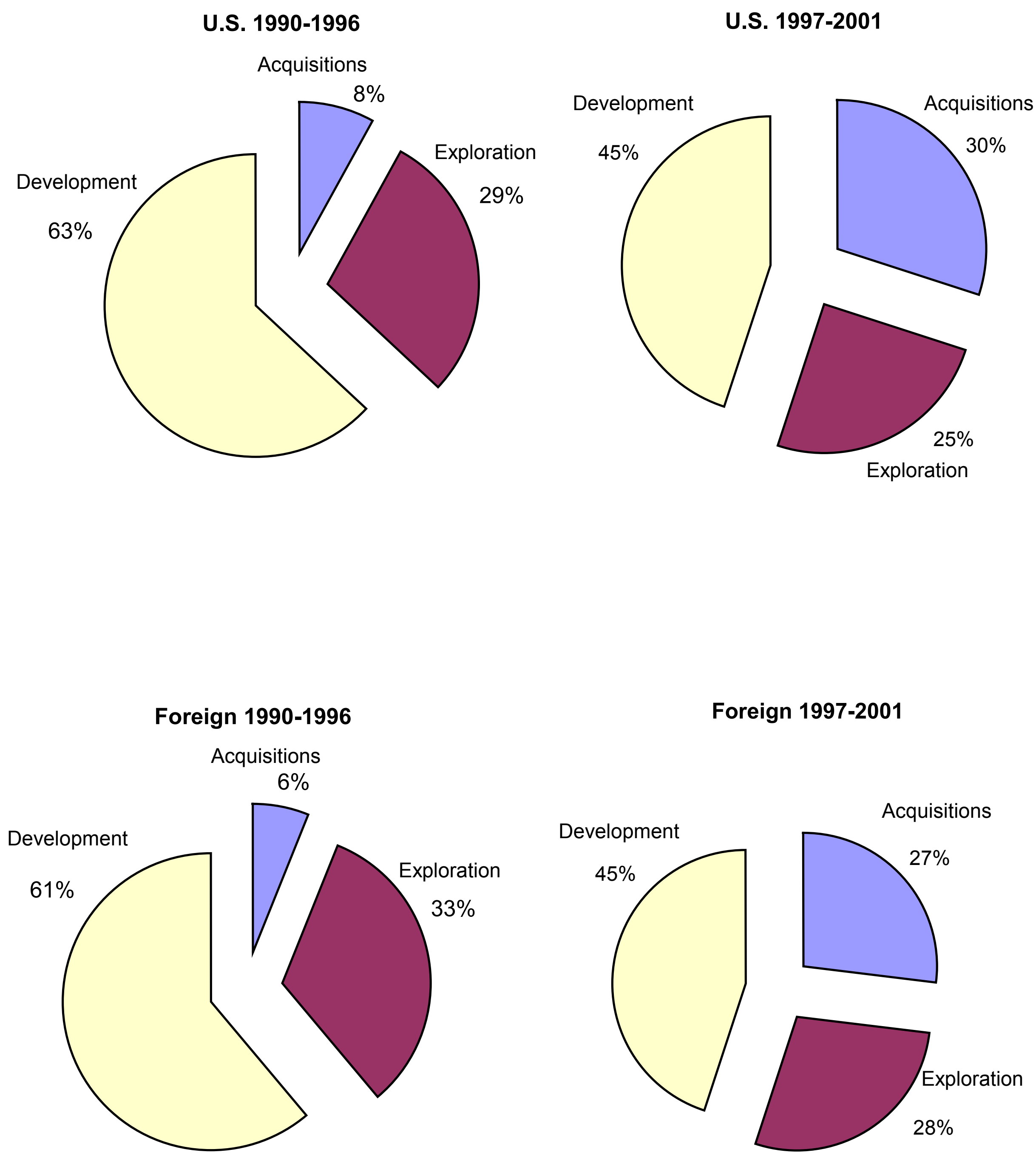


Note: Solid line includes U.S. reserves added in BP-Amoco (1998), Exxon-Mobil (1999), BP Amoco-ARCO (2000), Chevron-Texaco (2001), and El Paso-Coastal (2001) mergers as purchases. Dashed line excludes these effects.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Apart from Mergers and Acquisitions, Capital Expenditures Beyond the Wellhead Hold Steady

Excluding the effects of mergers and acquisitions, capital expenditures for lines of business outside oil and gas production totaled $22.7 billion in 2001, 2 percent less than in 2000. Apart from the effects of mergers and acquisitions, only pipelines appeared to stand out as a target of investment in 2001. Capital expenditures for pipelines, excluding mergers and acquisitions, increased by 140 percent between 2000 and 2001 (Table 5). However, the large increase is mainly the result of the reduced impact of mergers and acquisitions on pipelines investment in 2001 compared to 2000. In 2000, acquisitions with large impacts on expenditures for pipelines included Phillips Petroleum's acquisition of ARCO's Alaskan assets from BP and El Paso's acquisition of PG&E Corporation's midstream natural gas operations in Texas. In 2001, the heightened spending for pipelines, apart from mergers and acquisitions, was concentrated in natural gas pipelines and was associated with investments in unconsolidated affiliates rather than property, plant, and equipment. (Unconsolidated affiliates are subsidiaries in which a company has less than a majority ownership interest.) In natural gas pipelines, Williams reported an increase of $208 million in capital expenditures "… primarily to expand deliverability into the east and west coast markets and upgrade current facilities,"[28] while El Paso reported a $386-million increase in capital expenditures for its "Pipelines" business segment.[29]

Figure 9. Composition of Exploration and Development Expenditures for FRS Companies, 1990-1996, 1997-2001



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

Other energy, which is primarily electric power and associated trading and marketing activities, continued to be a source of growth. Results reported in Table 5 indicate that capital expenditures for other energy dropped 8 percent between 2000 and 2001. However, these results are strongly influenced by the absence of Enron as an FRS respondent in 2001. Excluding Enron, the FRS companies' capital expenditures for other energy were up more than 50 percent between 2000 and 2001. About 70 percent of the capital expenditures for other energy in 2001 are traceable to acquisitions, including the previously noted Dominion Resources' acquisition of the Millstone Power Station and El Paso's increased investments in electric power enterprises in the United States and Brazil. Other FRS companies reporting increased expenditures in other energy included BP who hiked capital expenditures for its "Gas and Power" business from $25 million to $124 million between 2000 and 2001,[30] and Shell Oil reported a $164-million acquisition of wind farms in Wyoming and Texas.[31]

The other nonenergy line of business registered the greatest cutback in capital expenditures among all the lines of business, from $6.5 billion in 2000 to $3.4 billion in 2001, a 47-percent decline. Excluding Enron, the decline in capital expenditures for the other nonenergy line of business was still a sizeable 33 percent. The major source of the decline was Williams Companies' spinoff of their communications business in early 2001. In 2000, Williams reported $3.4 billion in capital expenditures for their communications business,[32] but because of the spinoff of this business to its shareholders, Williams reported no capital expenditures for it in 2001. USX Corporation's reorganization into two companies, Marathon Oil Corporation and U.S. Steel Corporation, also contributed to the decline in expenditures. Prior to the 2001 reporting year, USX, which contained both these corporations, was an FRS respondent. After the reorganization, only Marathon qualified as a major energy company. In 2000, USX's other nonenergy capital expenditures included $254 million in capital expenditures by U.S. Steel Corporation[33] but, in 2001, U.S. Steel and its capital expenditures were no longer part of the FRS.

The sharply reduced capital expenditures for other nonenergy in 2001 is part of the long-running retrenchment in this area by the FRS companies (see "Telecommunications -- The End of the Line for Diversification?" in Chapter 4 for further discussion). This line of business is not wholly without interest or activity, though. For example, BP, in their segment consisting of "… real estate interests, technology companies, and other activities" indicated an increase in capital outlays for these activities of nearly $1 billion from 2000 to 2001.[34]

Sources and Uses of Cash

Table 7 shows where the FRS companies obtained the cash ("sources") to pay for their deployment of capital ("uses") during 2001. Some of the strongest differences between 2000 and 2001 were in the sources of cash.

First, note that the $89.6-billion cash flow realized from operations in 2001 was only 1 percent above cash flow in 2000 (7 percent excluding Enron). The contrasts between the two years were in external funding and cash raised from asset sales, not cash flow.

Debt Load Rises Due to Mergers and Acquisitions

Proceeds from long-term debt issuance totaled $55.0 billion in 2001, the highest level over the 1974 to 2001 period of FRS data collection even after adjusting for inflation, and well above the $33.3 billion raised by debt issuance in 2000. The large increase in debt is traceable to mergers and acquisitions. Those FRS companies with mergers and acquisitions that exceeded $1 billion in value in 2001 accounted for 74 percent of long-term debt issuance.

Table 7. Sources and Uses of Cash for FRS Companies, 2000-2001
(Billion Dollars)

Sources and Uses of Cash	2000	2001	Percent Change 2000-2001
Main Sources of Cash			
Cash Flow from Operations	88.6	89.6	1.1
Proceeds from Long-Term Debt	33.3	55.0	65.2
Proceeds from Disposals of Assets	26.7	7.7	-71.2
Proceeds from Equity Security Offerings	30.6	6.3	-79.5
Main Sources of Cash			
Additions to Investment in Place	109.3	110.4	0.9
Reductions in Long-Term Debt	29.3	34.3	16.9
Dividends to Shareholders	19.0	17.1	-9.7
Purchase of Treasury Stock	5.4	7.5	39.4
Other Investment and Financing Activities, Net	-8.6	11.9	--
Net Change in Cash and Cash Equivalents	7.6	1.3	--

-- = Not meaningful.
Note: Sources minus uses plus other investment and financing activities (net) may not equal net change in cash and cash equivalents due to independent rounding.
Percent changes were calculated from unrounded data.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

The converse of debt issuance is reduction of long-term debt. In practice, part of the cash expended for debt reduction is for rollovers of debt and part is for the actual reduction of outstanding debt. Since long-term debt issuance greatly exceeded debt reduction in 2001, $55.0 billion vs. $34.3 billion, the overall level of debt in the FRS companies' balance sheets increased. The ratio of long-term debt to stockholders' equity is an often-used measure of the role of debt in the balance sheet. Figure 10 reveals an uptick in this ratio for FRS companies in 2001, but an even steeper rise for other industrial companies, as represented by the Standard & Poors' Industrials.

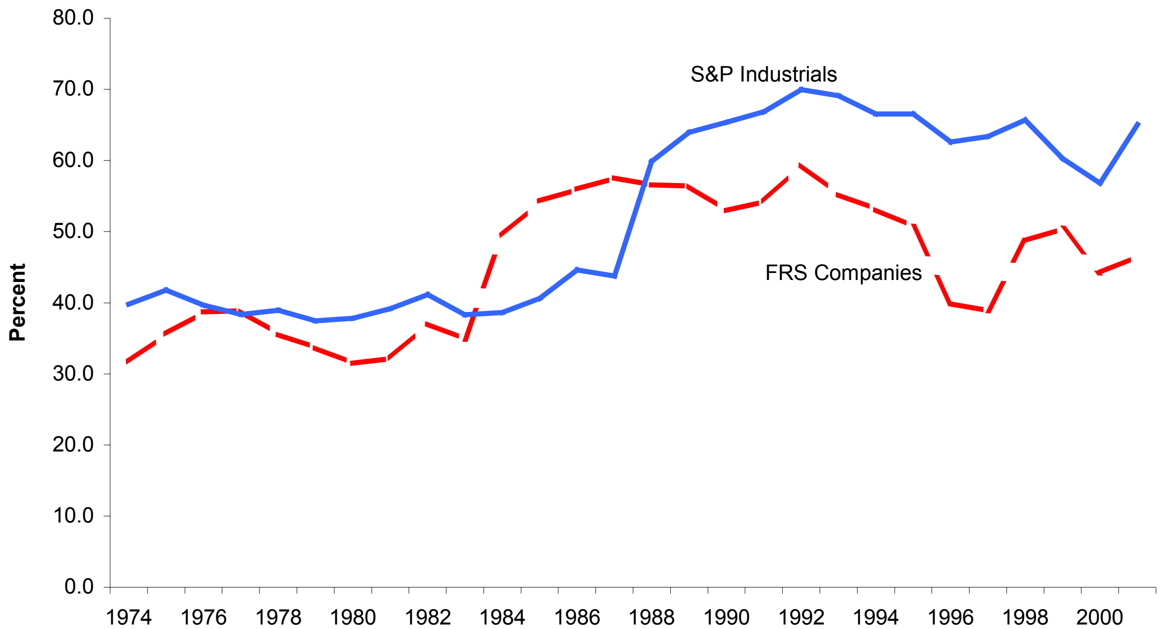
It should be noted that a few FRS companies were able to make sizeable reductions in their long-term debt positions in 2001: BP reduced their long-term debt by $1.9 billion, ChevronTexaco by $3.8 billion, and Occidental Petroleum by $1.1 billion.[35]

Issuance of stock in 2001, with a value of $6.3 billion, was much below the $30.6 billion raised by stock issues in 2000. However, in 2000, BP made a payment of $27.0 billion in stock for the acquisition of ARCO, which accounted for most of the stock issuance. Stock issues in 2001 were almost entirely due to FRS companies involved in mergers and acquisitions, indicating that they used stock as well as debt to close the transactions.

Cash raised through sales of productive assets was also way down in 2001 as compared with the prior year. Cash from asset sales by FRS companies in 2001 was $7.7 billion, the lowest value since 1994.

In 2000, the amount of cash raised through asset disposals by the FRS companies was an extraordinarily large $26.7 billion. The bulk of the asset sales was due to divestitures required for antitrust approval of the merger between Exxon and Mobil and BP's acquisition of ARCO. Exxon Mobil reported $5.8 billion of asset sales in 2000 and BP reported $11.4 billion.[36]

Figure 10. Long-Term Debt/Equity Ratio for FRS Companies and the S&P Industrials, 1974-2001



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

Endnotes

[9] For a list of the FRS companies in 2000, see the box entitled, "The FRS Companies in 2001," in Chapter 1.
[10] Return on equity, a frequently used measure of corporate profitability, is measured by the ratio of net income to stockholders' equity.
[11] The Standard and Poor's Industrials is a well-recognized database that includes nearly 400 of the largest U.S. industrial companies. Financial statistics for the S&P Industrials were obtained by accessing Compustat PC Plus, a service of Standard & Poor's, Inc.
[12] Line-of-business profit measures should be distinguished from measures that reflect company-wide results because the former reflect only allocated income, expense, and asset items. Two measures of income are presented: *operating income* and *contribution to net income*. Operating income by line of business is similar in concept to the operating income measure for total company operations. It is the net of operating revenues and operating expenses (including depreciation, depletion, and amortization) for a line of business. Contribution to net income equals operating income plus income from unconsolidated affiliates and gains on disposals of property, plant, and equipment less income taxes imputed to the line of business and excludes certain non-allocable items, primarily interest expense. Interest expense is the principal source of difference between a company-wide net income figure and line-of-business contributions to net income (see Appendix A for further discussion).
[13] Exxon Mobil Corp., 2001 Securities and Exchange Commission Form 10K, pp. 22, 24.
[14] ChevronTexaco Corp., 2001 Securities and Exchange Commission Form 10K, p. FS-6.
[15] Conoco, Inc., *2001 Annual Report*, p. 42.
[16] El Paso Corp., *2001 Annual Report*, p. 35.
[17] For a review of the FRS companies' investment in nonconventional energy over the 1974 to 1993 period, see Chapter 6 of *Performance Profiles of Major Energy Producers 1993* available at http://www.eia.doe.gov/emeu/finance/histlib.html.
[18] For FRS purposes, separate reporting of income for chemical and other nonenergy segments was discontinued beginning with the 1987 reporting year. However, the disclosures of chemical segment revenues and operating income made by the FRS companies in their annual reports to shareholders closely track, in the aggregate, comparable disclosures in the Form EIA-28 from 1974 through 1986, when income statement items were collected for chemical businesses by the FRS. Thus, the public disclosures of chemical segment revenue and operating income were utilized for 1987 through 2001. Revenues and operating income for the other nonenergy segment after the 1986 reporting year were obtained by subtracting the publicly disclosed chemical segment values from the nonenergy line-of-business values reported on Form EIA-28.
[19] Occidental Petroleum Corp., 2001 Securities and Exchange Commission Form 10K, p. 63.
[20] Exxon Mobil Corp., *2001 Summary Annual Report*, pp. 22, 29.
[21] ChevronTexaco Corp., 2001 Securities and Exchange Commission Form 10K, p. FS-7.
[22] Exxon Mobil Corp., *2001 Summary Annual Report*, p. 25.
[23] The largest of these non-cash items is the cost of depreciation, depletion, and amortization. Also, outlays (receipts) of cash that were recognized as non-cash items in previous income statements (e.g., provisions for a legal settlement taken as a charge against income in a previous year but not actually paid until the current year) are subtracted from (added to) net income in computing cash flow. Lastly, changes in working capital (excluding cash) due to operations are subtracted.
[24]To the extent possible, capital expenditures are measured by *additions to investment in place*, which is defined as additions to property, plant, and equipment (PP&E) plus additions to investment and advances. In 2001, additions to PP&E accounted for 91 percent of capital expenditures so measured.
[25] Figure 5 and Table 5 show the value of property, plant and equipment, and investments and advances added to the companies' books as a result of acquisitions rather than the value of the transactions. The reported value of an acquisition shown in Table 2-6 can differ from the effect on additions to investment in place due to assumptions of liabilities and goodwill assets acquired.
[26] BP America, the U.S. subsidiary of BP plc of the United Kingdom, is the FRS respondent.
[27] Exploration and development expenditures include capital expenditures for oil and gas production and exploration expenses, which are not capitalized but are charged against income.
[28] The Williams Companies, 2001 Securities and Exchange Commission Form 10K, pp. 66 and 132.
[29] El Paso Corporation, *2001 Annual Report*, p. 114.
[30] BP Corporation North America, Inc., *Consolidated Financial Statements*, December 31, 2001, pp. 31-32.
[31] Shell Oil Company, *20001 Financial Review*, p. 9.
[32] The Williams Companies, 2000 Securities and Exchange Commission Form 10K, p. 207.
[33] USX Corp., *The 2000 U.S. Steel Group Annual Report*, p. S-4.
[34] BP Corporation North America, Inc., *Consolidated Financial Statements*, December 31, 2001, pp. 31-32.

[35] BP Corporation North America, Inc., *Consolidated Financial Statements*, December 31, 2001, p. 4; ChevronTexaco Corp., 2001 Securities and Exchange Commission Form 10K, p. FS-18; Occidental Petroleum Corp., 2001 Securities and Exchange Commission Form 10K, p. 37.

[36] Exxon Mobil Corp., 2000 Securities and Exchange Commission Form 10K, p. 31; BP America Inc., *Consolidated Financial Statements*, December 31, 2000, p. 6.

3. BEHIND THE BOTTOM LINE

Oil and Natural Gas Production

Higher Natural Gas Prices and Increased Production Offset by Lower Oil Prices

Worldwide net income from the FRS companies' oil and gas production operations totaled $32.2 billion in 2001, a 20-percent decline from net income in 2000 (Table 8). Excluding the effects of unusual items, the decline was a less steep 11 percent. The decline in upstream income was a bit steeper for foreign operations than for U.S. operations. Although income was down, as was profitability, the return on investment in oil and gas production was still at a high level in 2001 (Figure 11). The breakdown of revenues, costs, prices, and production in Tables 8 and 9 allow a detailed review of the sources of the decline in upstream earnings.

In U.S. upstream operations, oil and gas revenues were flat at $79.0 billion. The FRS companies' U.S. oil production was up 8 percent (Table 9) between 2000 and 2001, with increases from both onshore and offshore locales (Figure 12a). The uptick in onshore oil production was the first since the 1980's. Domestic natural gas production continued to grow, rising by 6 percent. Also, natural gas prices realized by the FRS companies in their U.S. upstream operations were 10 percent higher (equivalent to about $2 per barrel). These developments were favorable to upstream earnings growth, but were just offset by the $4.72-per-barrel decline in the FRS companies' U.S. oil price, resulting in zero revenue growth.

In foreign upstream operations, revenues of $62.7 billion in 2001 were down 8 percent from the prior year. Since oil is a larger share of the FRS companies' foreign upstream production than their U.S. upstream production -- 61 percent vs. 46 percent, respectively, in 2001 -- foreign revenues were more adversely affected by the oil price decline in 2001.

Foreign oil production of the FRS companies was up 8 percent between 2000 and 2001, with greater production from Asia-Pacific fields accounting for three-quarters of the increase and increased Canadian oil production accounting for the balance. (For a discussion of changes in the structure of worldwide oil production, see the Highlight entitled "Top Oil Corporations Nearly Double Share of World Oil Production.*") Foreign natural gas production was up 6 percent over the same period, with Canadian operations accounting for 80 percent of the growth. The FRS companies' increased Canadian natural gas production in large part reflects their heavy acquisition of Canadian producers and properties in recent years. Producing fields in South America and Africa also yielded increased natural gas production.

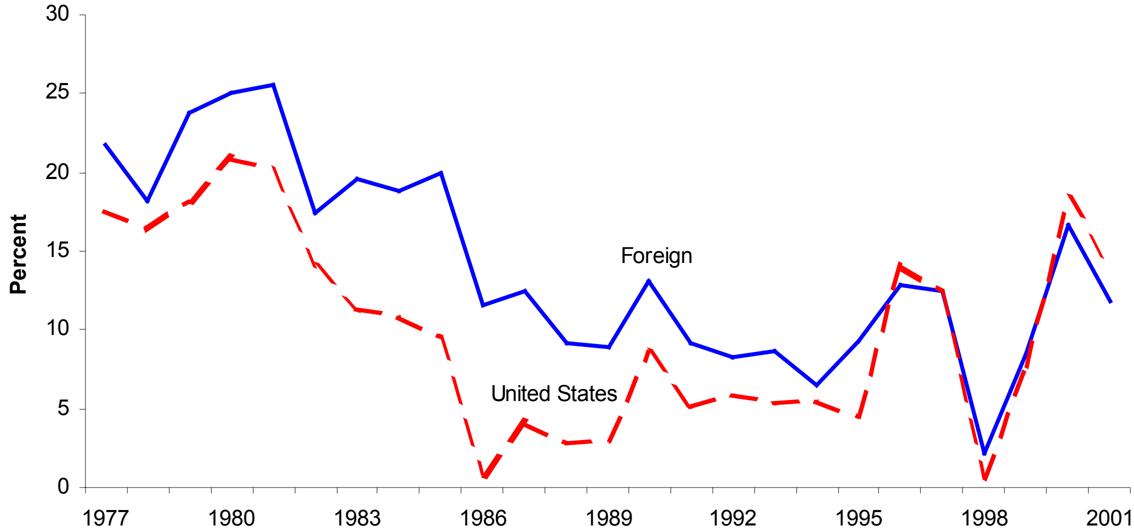
On the cost side, U.S. upstream operating expenses were up 12 percent and a less steep 3 percent abroad. Most of the increase in operating expenses came from writedowns of oil and natural gas asset values in 2001. Writedowns of assets are required under financial accounting standards when the value of an asset carried on the balance sheet exceeds estimated future cash flows or exceeds the market value of the asset. (Note that asset values on the books cannot be increased if the converse is true.) Most oil and gas producers wrote down upstream asset values because estimated cash flows dropped based on the decline in end-of-year oil and gas prices between 2002 and 2001.

Table 8. Income Components and Financial Ratios in Oil and Natural Gas Production for FRS Companies, 2000-2001
(Billion Dollars)

Components of Income and Financial Ratios	Worldwide		United States		Foreign	
	2000	2001	2000	2001	2000	2001
Oil and Natural Gas Revenues						
Oil	NA	NA	38.3	31.6	NA	NA
Natural Gas	NA	NA	40.7	47.4	NA	NA
Total Revenues	147.4	141.7	79.0	79.0	68.4	62.7
Expenses						
Depreciation, Depletion, and Amortization	23.9	32.2	13.1	20.0	10.8	12.1
Lifting Costs	21.8	24.7	11.0	12.9	10.7	11.8
Exploration Expenses	5.4	6.3	3.2	3.0	2.3	3.3
General and Administrative Expenses	2.3	2.7	1.3	1.9	1.0	0.8
Raw Material Purchases	27.9	23.2	17.0	16.9	10.9	6.3
Other Costs (Revenues)	3.2	2.5	2.2	-1.0	1.0	3.5
Total Operating Expenses	84.3	91.2	47.6	53.3	36.6	37.9
Operating Income	63.1	50.5	31.4	25.7	31.8	24.8
Other Income (Expense)[a]	5.5	4.8	1.4	1.6	4.0	3.2
Income Tax Expense	28.3	23.1	11.0	9.6	17.3	13.4
Net Income	40.3	32.2	21.9	17.6	18.5	14.6
Less Unusual Items	-0.2	-4.5	-0.2	-3.0	0.0	-1.5
Net Income, Excluding Unusual Items	40.5	36.7	22.0	20.6	18.5	16.1
Unit Values (Dollars Per Barrel of Production COE)[b]						
Direct Lifting Costs (Excluding Taxes)	3.10	3.49	3.06	3.53	3.14	3.45
Production Taxes	0.92	0.78	0.95	0.85	0.90	0.70
Ratios (Percent)						
Return on Investment[c]	17.4	12.2	17.7	13.1	17.1	11.2
Effective Tax Rate[d]	41.2	41.7	33.4	35.3	48.4	48.0

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

Figure 11. Return on Investment in U.S. and Foreign Oil and Natural Gas Production for FRS Companies, 1977-2001



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

Table 9. Average Prices, Sales, and Production in Oil and Gas for FRS Companies, 2000-2001

Prices, Sales, and Production	2000	2001	Percent Change 2000-2001
Worldwide Oil and Gas Production[a]			
Crude Oil and NGL (Million Barrels)	2,864	3,087	7.8
Dry Natural Gas (Billion Cubic Feet)	14,306	15,148	5.9
Total (Million Barrels COE)[b]	5,411	5,784	6.9
Domestic Oil and Gas Production[a]			
Crude Oil and NGL (Million Barrels)	1,268	1,363	7.5
Dry Natural Gas (Billion Cubic Feet)	8,340	8,838	6.0
Total (Million Barrels COE)[b]	2,752	2,936	6.7
Domestic Oil and Gas Sales Volumes			
Crude Oil and NGL (Million Barrels)	1,484	1,498	0.9
Dry Natural Gas (Billion Cubic Feet)	11,348	11,876	4.7
Total (Million Barrels COE)[b]	3,503	3,612	3.1
Domestic Production Average Sales Prices			
Crude Oil and NGL (Dollars Per Barrel)	25.83	21.11	-18.3
Dry Natural Gas (Dollars Per Thousand Cubic Feet)	3.59	3.96	10.4
Composite (Dollars Per Barrel COE)[b]	22.56	21.79	-3.4
Foreign Oil and Gas Production[a]			
Crude Oil and NGL (Million Barrels)	1,596	1,724	8.0
Dry Natural Gas (Billion Cubic Feet)	5,966	6,310	5.8
Total (Million Barrels COE)[b]	2,658	2,847	7.1
Foreign Production Average Sales Prices			
Crude Oil and NGL (Dollars Per Barrel)	26.34	22.04	-16.3
Dry Natural Gas (Dollars Per Thousand Cubic Feet)	2.59	2.91	12.5
Canada	3.60	3.63	0.7
OECD Europe	2.63	3.18	21.1
Other Foreign	2.18	2.25	3.2
Composite (Dollars Per Barrel COE)[b]	21.95	19.97	-9.0

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

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

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

Figure 12a. Oil Production for FRS Companies, 1981-2001

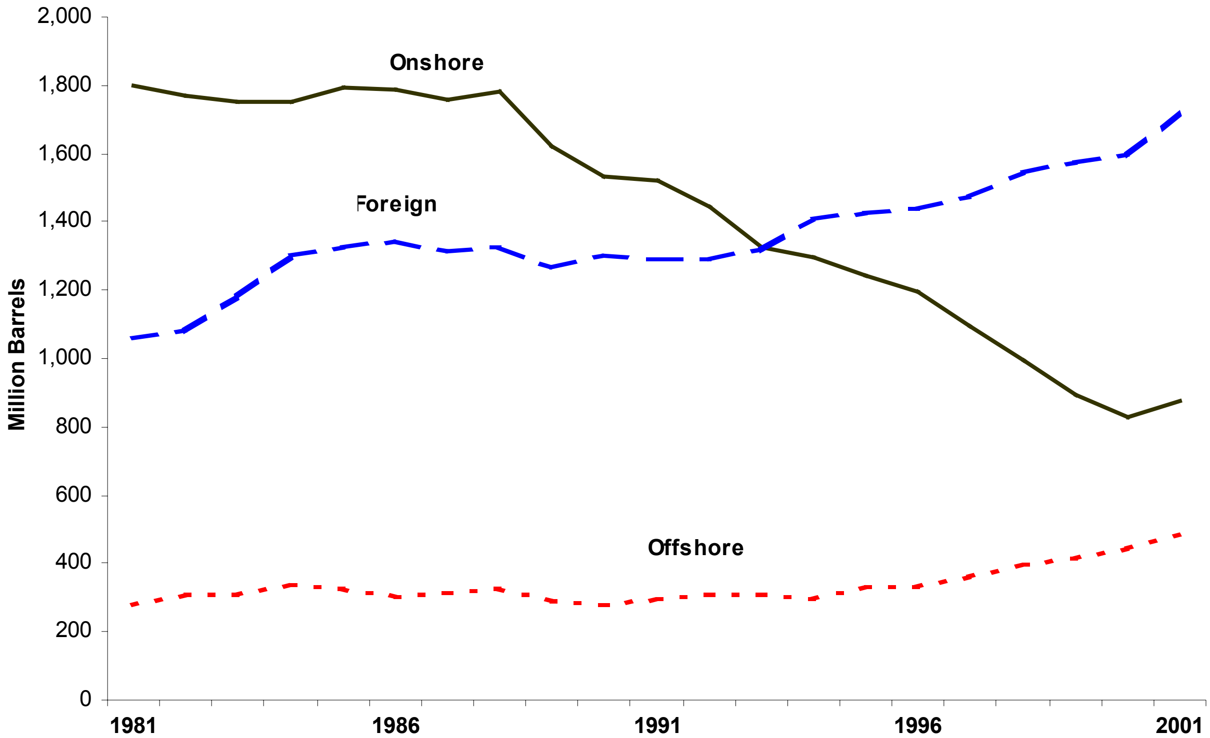
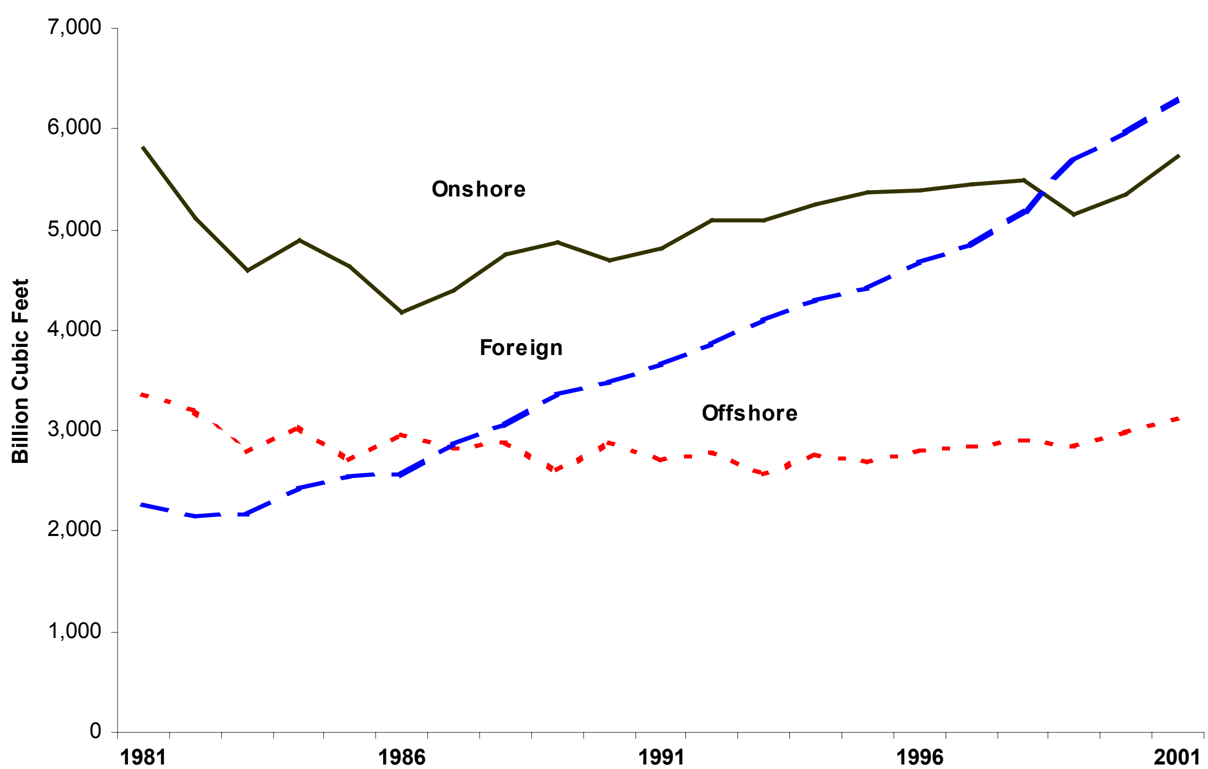


Figure 12b. Natural Gas Production for FRS Companies, 1981-2001



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

Top Oil Corporations Nearly Double Share of World Oil Production

An increased role for companies that are publicly traded and not wholly state-owned was the most notable change in the structure of the top producers in the international oil market between 1992 and 2001.[a] These companies produced 21 percent of the world's oil in 2001, up from 11 percent in 1992, while increasing their number in the group from six to nine (Table 10). One cause of this larger role for publicly traded companies was several mergers (involving almost all of them) that have occurred in the last few years.[b] The largest of these mergers, in 1999, created Exxon Mobil, the fifth-largest producer of oil in the world in 2001. Its two predecessors were both members of the top 20 in 1992, with Exxon tenth and Mobil seventeenth. Other recent mergers involving 1992 top-20 companies include BP's merger with Amoco and subsequently with Atlantic Richfield, and Chevron's merger with Texaco.[c] The merger of Total and Petrofina to form Totalfina and the latter's merger with Elf Acquitaine to form TotalFinaElf combined three companies that were not in the 1992 top 20. These combinations resulted in larger publicly traded companies that generally had higher ranks in the top-20 list in 2001 than their predecessors did in 1992.

Another cause of the increased role for publicly traded companies was the privatization of formerly state-owned companies during the 1990's. The Russian government, which has dramatically reduced its role in the economy, privatized YUKOS and, to a large extent, LUKoil.[d] In addition, Elf Acquitaine was privatized in 1993, before being acquired by Totalfina, while PetroChina (formerly China National Petroleum) and Petroleo Brasileiro (Petrobras) were partially privatized during the 1990's. Including partially privatized companies raises the publicly traded companies' share to 21 percent in 2001.

The other changes in the top-20 list were the entrances of Iraq National Oil (INOC) and Petrobras and the exit of Sonatrach. INOC was not on the list in 1992 because its production had been reduced dramatically by the Gulf war and an embargo on Iraqi exports. Petrobras, which produced 97 percent of Brazil's oil in 2001, was able to move onto the list because of the swell in Brazilian production between 1992 and 2001, which more than doubled over the period. Sonatrach dropped off the list because its production was essentially flat during the period, while publicly traded companies were increasing their investment in Algerian oil production.

Sonatrach's exit points to another change in the top-20 list: a large increase in the amount of production required for inclusion in the top 20. The production of the last company on the list in 2001 was 30 percent higher than it was in 1992. The combination of this increase and the only 3-percent increase in production by the largest producer compressed the list, with the ratio of the production of the top company to the bottom company declining from 11.7:1 to 9.3:1 over the period.

The structure of an industry can be measured by two statistics, concentration ratios and the Herfindahl-Hirschman Index (HHI). They both attempt to measure the size and distribution of the companies in a market. To calculate these statistics, the largest companies in a market are first ordered from biggest to smallest in terms of market share. A concentration ratio is the sum of the market-share percentages of the top companies. The HHI is the sum of squares of the shares of the top companies.[e] The Department of Justice and the Federal Trade Commission use the HHI when considering mergers between companies. They define an industry with an HHI below 1,000 as unconcentrated, one with an HHI between 1,000 and 1,800 as moderately concentrated, and one with an HHI more than 1,800 as highly concentrated.[f]

The HHI (20 firm) for the international oil market was 282 in 2001, indicating an unconcentrated industry and declining slightly in value from 1992 (Table 10). The decline in Saudi Arabian Oil's share was by far the largest contributor to this decline. The 4-firm and 8-firm concentration ratios also declined slightly because of the declining shares of the top 4 and top 8 firms. However, the 20-firm ratio increased slightly, indicating that the concentration of the smaller of the top-20 firms increased enough to more than offset the declining concentration of the larger of the firms.

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[a] "Oil" often is defined to include three liquid hydrocarbons, crude oil, lease condensate, and natural gas liquids. However, lease condensate and particularly natural gas liquids, which are produced in much smaller amounts than crude oil, may not be included as part of oil production and reserves by some international data sources. This inconsistency complicates the analysis of international oil production and reserves, including the one here, and to some extent limits their usefulness.
[b] Royal Dutch/Shell was the only not-state-owned top-20 company in 1992 that has not been involved in a large merger since then.
[c] The combined 2001 production of Conoco and Phillips Petroleum, merged in 2002, would have placed twentieth on the list had the merger been completed in 2001 and would have magnified the trend away from state-owned companies.
[d] The State still owns 13.5 percent of LUKoil.
[e] Concentration ratios can range up to 100; at that value the specified firms would include all the firms in the industry. HHI's can range up to 10,000; at that value there would be only one firm in the industry.
[f] U.S. Department of Justice and U.S. Federal Trade Commission, Horizontal Merger Guidelines, revised April 8, 1997, § 1.51.

Asset writedowns were also taken by companies recently involved in mergers accounted for as a pooling of interests. A surviving company involved in a merger accounted for by the pooling-of-interests method transfers the value of assets and liabilities from the acquired company's balance sheet to its own. When the surviving company sorts the acquired assets for retention or sale, the company will write down the value of those assets destined for sale to their market values. In 2001, the FRS companies charged \$5.3 billion against pre-tax income for asset writedowns in U.S. oil and gas production operations and \$2.7 billion in foreign upstream operations. In 2000, the comparable amounts were \$0.4 billion in both U.S. and foreign operations. Asset writedowns are usually included in depreciation, depletion, and amortization (DD&A). Higher expenses for DD&A were the main source of increased operating costs in the FRS companies' upstream operations between 2000 and 2001.

Lifting costs also increased by \$1.9 billion in the United States and \$1.1 billion abroad. Lifting costs are the costs of extracting oil and gas. They are largely composed of expenses for operation, maintenance, and repair of producing wells and associated field equipment. Lifting costs increased, in part, because the FRS companies increased their oil and gas production (Table 9). Lifting costs per barrel of production were also higher (Figure 13) which contributed to increased operating expenses in 2001. The next section of this chapter reviews lifting costs.

Other cost items that were higher in 2001 included general and administrative expenses in the United States, up \$0.6 billion, and exploration expenses abroad, up \$1.0 billion.

Direct Lifting Costs Increase in Most Regions

While both domestic and foreign direct lifting costs increased in 2001 for the FRS companies, foreign costs increased less than domestic costs (Table 11). Lifting costs (production costs) are the out-of-pocket costs per barrel of oil and natural gas produced (measured on a barrel-of-oil equivalent basis) to operate and maintain wells and related equipment and facilities after hydrocarbons (both crude oil and natural gas) have been found, acquired, and developed for production. Total lifting costs are direct lifting costs plus production taxes. Taking a clue from the large increase in U.S. onshore total lifting costs in 2001, it is probable that U.S. onshore direct lifting costs increased even more, because production taxes, which are levied mostly against onshore production, declined. The long-term trend in lifting costs remains downward, but 2001 may prove to be a pivotal year, because it is the first since

Table 10. Worldwide Oil Production of 20 Largest Producers, 1992 and 2001
(Million Barrels)

1992			2001		
Company	Production	Percent of Worldwide Total	Company	Production	Percent of Worldwide Total
Saudi Arabian Oil	2,970	12.4	Saudi Arabian Oil	3,056	11.2
National Iranian Oil	1,261	5.3	National Iranian Oil	1,385	5.1
China National Petroleum	1,035	4.3	Petroleos Mexicanos	1,299	4.8
Petroleos Mexicanos	1,012	4.2	Petroleos de Venezuela	1,193	4.4
Petroleos de Venezuela	865	3.6	Exxon Mobil (United States)	899	3.3
Royal Dutch/Shell (Netherlands/United Kingdom)	783	3.3	Royal Dutch/Shell (Netherlands/United Kingdom)	810	3.0
Nigerian National Petroleum	694	2.9	Nigerian National Petroleum	767	2.8
Abu Dhabi National Oil	692	2.9	PetroChina	764	2.8
Exxon (United States)	580	2.4	Kuwait Petroleum	745	2.7
Pertamina (Indonesia)	557	2.3	Iraq National Oil	715	2.6
National Oil (Libya)	545	2.3	ChevronTexaco (United States)	714	2.6
British Petroleum (United Kingdom)	425	1.8	BP plc (United Kingdom)	677	2.5
LUKoil (Russia)	415	1.7	LUKoil (Russia)	570	2.1
Kuwait Petroleum	321	1.3	Abu Dhabi National Oil	568	2.1
Chevron (United States)	301	1.3	TotalFinaElf (France)	531	2.0
Sonatrach (Algeria)	282	1.2	National Oil (Libya)	496	1.8
Mobil (United States)	278	1.2	Petroleo Brasileiro (Brazil)	486	1.8
YUKOS (Russia)*	272	1.1	Pertamina (Indonesia)	438	1.6
Atlantic Richfield (United States)	270	1.1	YUKOS (Russia)	362	1.3
Ministry of Petroleum & Minerals (Oman)	253	1.1	Petroleum Development Oman	330	1.2
Top 20 Total	13,811	57.5	**Top 20 Total**	16,802	61.8
Publicly Traded Total	2,637	11.0	**Publicly Traded Total**	5,813	21.4
Worldwide Total	24,006		**Worldwide Total**	27,190	

Concentration Measures

Herfindahl-Hirschman Index (20 firm)	**290**	**Herfindahl-Hirschman Index (20 firm)**	**282**
Concentration Ratio (4 firm)	**26.2**	**Concentration Ratio (4 firm)**	**25.5**
Concentration Ratio (8 firm)	**38.8**	**Concentration Ratio (8 firm)**	**37.4**
Concentration Ratio (20 firm)	**57.5**	**Concentration Ratio (20 firm)**	**61.8**

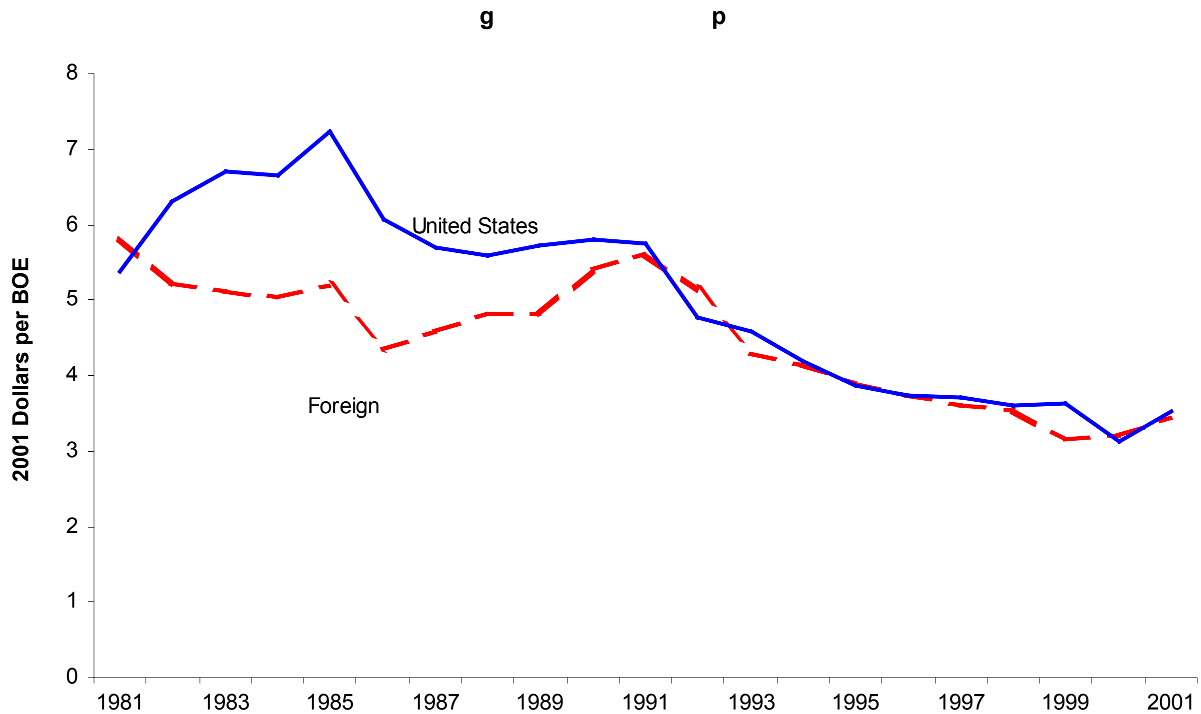
*Production is for 1994.

Notes: Publicly traded companies are denoted by underlines. LUKoil is still 13.5-percent state-owned. Because lease condensate and natural gas liquids (NGLs) are not consistently included in reported or estimated international oil production of international oil and gas companies, the production numbers above may or may not include them. For details, see sources below.

1990 that foreign and domestic direct lifting costs both increased (Figure 13). More likely, 2001, like 1990, will only be a temporary departure from the downward trend.

One cause of higher direct lifting costs can be launching new projects, such as bringing new production online or initiating enhanced recovery programs, which often have higher costs initially. In the U.S. onshore in 2001, there were several FRS companies reporting new projects. For example, Exxon Mobil, which is the largest resource owner in the Prudhoe Bay field in Alaska, began enhanced recovery

Figure 13. Direct Oil and Natural Gas Lifting Costs for FRS Companies, 1981-2001



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).

projects at the Pt. McIntyre and Eileen West End fields, and the Borealis field (partly owned by Exxon Mobil) began producing in 2001.[37] BP[38] brought the Northwest, Northstar, and (along with Exxon Mobil) Borealis fields (as well as the Meltwater satellite development project) online in Alaska in the second half of the year.[39] In addition, BP initiated production at the Martin No. 1 well in the Tuscaloosa Trend and began a program to aggressively optimize well operating conditions at the Hugoton field in Western Kansas to stem production declines there. Occidental Petroleum used added compression and other aggressive reservoir exploitation programs to accelerate natural gas production at Elk Hills and take advantage of California's high price for natural gas during 2001.[40]

Total lifting costs outside the United States increased somewhat in 2001 (Table 11). However, the Middle East showed a large increase while the Other Western Hemisphere (Latin America) showed a large decrease. The cause of decreased costs in Latin America was a decline in production taxes, which historically have been more variable than production costs. Nevertheless, production declines can be a cause of higher direct lifting costs, which require fixed costs to be spread over less output. Production by the FRS companies in the Middle East declined in 2001, in part because OPEC production cuts were likely passed on to the FRS companies operating in the Middle East. The production decline may have contributed to the increased lifting costs there.

In the Former Soviet Union and Eastern Europe, direct lifting costs decreased substantially from the prior year for the FRS companies in 2001. However, more than half of this decline was offset by an increase in production taxes, leaving a more modest decline in total lifting costs. While production costs can increase when output declines, because fixed costs are spread over less output, the opposite effect can happen when production increases at established projects. This may have been the case in the

Former Soviet Union and Eastern Europe, where several FRS companies reported increased production in 2001. In the Caspian Sea area, Exxon Mobil increased production at the Tengiz field in Kazakhstan and at the Megastructure development in the Azerbaijan sector of the Sea itself.[41] Exxon Mobil and its predecessors have been involved in these two producing fields for several years.[42] Also in the Caspian, BP increased production at the Chirag 1 platform in the Azeri-Chirag-Gunashli fields in Azerbaijan, which produced its first oil in 1997.[43]

Table 11. Lifting Costs by Region for FRS Companies, 2000-2001
(Dollars Per Barrel of Oil Equivalent)

Region	Direct Lifting Costs			Production Taxes			Total		
	2000	2001	Percent Change	2000	2001	Percent Change	2000	2001	Percent Change
United States									
Onshore	--	--	--	--	--	--	4.64	5.19	11.9
Offshore	--	--	--	--	--	--	2.85	2.93	2.8
Total United States	3.06	3.53	15.6	0.95	0.85	-9.8	4.00	4.39	9.6
Foreign									
Canada	3.59	3.92	9.2	0.30	0.22	-26.7	3.89	4.14	6.4
OECD Europe	3.40	3.51	3.3	0.53	0.66	24.9	3.92	4.16	6.2
Former Soviet Union and Eastern Europe	4.70	3.85	-18.1	0.45	0.89	100.3	5.15	4.74	-7.8
Africa	3.26	3.58	9.8	1.55	1.20	-23.0	4.81	4.77	-0.8
Middle East	1.27	3.05	139.5	1.54	0.41	-73.3	2.81	3.46	22.9
Other Eastern Hemisphere	2.77	3.21	16.1	1.23	0.88	-28.7	4.00	4.09	2.3
Other Western Hemisphere	2.69	2.75	2.3	1.53	0.66	-57.2	4.22	3.41	-19.3
Total Foreign	3.14	3.45	9.7	0.90	0.70	-22.3	4.04	4.14	2.6
Worldwide Total	3.10	3.49	12.7	0.92	0.78	-15.8	4.02	4.27	6.1

-- = 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).

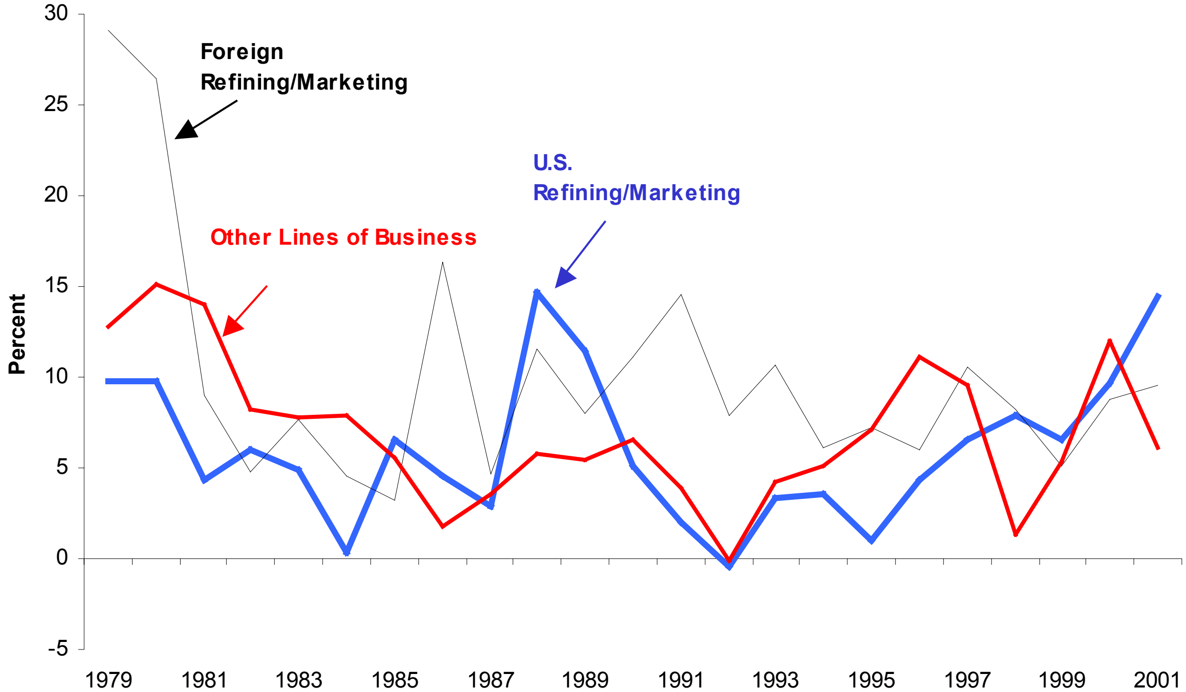
U.S. Refining and Marketing

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

U.S. refining and marketing operations of the Financial Reporting System (FRS) companies achieved a profit rate (measured by return on investment)[44] in 2001 that fell just short of[45] the highest level in the history of the FRS data survey (Figure 14). The period 1996 through 2001 marks a sort of "golden age" of U.S. refining and marketing as profitability has increased each year (with the exception of 1999), and been comparable to other lines of business of the FRS companies (including 1999).

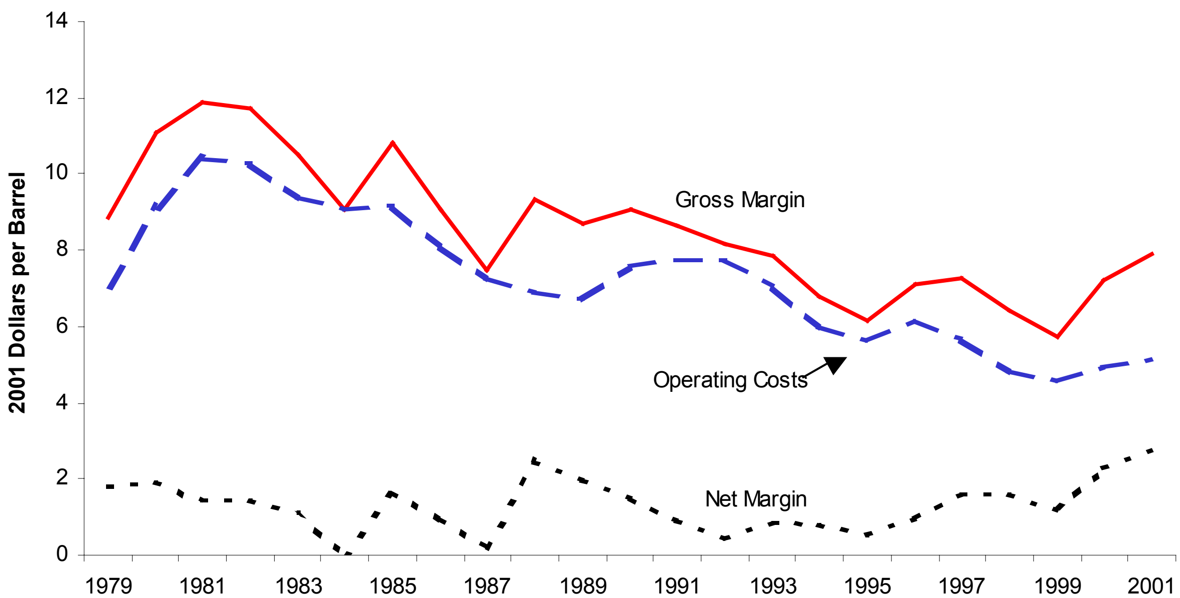
Insight into this recent, profitable era of the FRS companies' domestic refining and marketing operations can be provided by examining the net refined product margin (net margin), which is highly correlated with profitability.[46] The net margin is the gross margin (refined product revenues minus purchases 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.[47] At $2.72 per barrel, the net margin of 2001 was the highest (after adjusting for inflation) in the history of the FRS data survey, exceeding the previous all-time high of $2.43 (in 2001 dollars) that was set in 1988 (Figure 15).

Figure 14. Return on Investment in U.S. and Foreign Refining/Marketing, and Other Lines of Business for FRS Companies, 1979-2001



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

Figure 15. U.S. Refined Product Margins and Costs per Barrel of Petroleum Product Sold for FRS Companies, 1979-2001



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).

Product Sales Revenue Falls As Product Prices Decline

Revenues from petroleum product sales declined 6 percent between 2000 and 2001, but were more than offset by a slightly larger decrease in operating expenses and a 12-percent increase in revenue from other sources (e.g., raw materials sales and transportation revenues) (Table 12).[48] Excluding unusual items,[49] net income increased 48 percent, rising from $8.7 billion in 2000 to $12.8 billion in 2001.

Table 12. U.S. and Foreign Refining/Marketing Financial Items for FRS Companies, 2000-2001
(Million Dollars)

	2000	2001	Percent Change 2000 - 2001
Domestic Refining/Marketing Operations			
Refined Product Sales Revenue	310,661	291,609	-6.1
Other Revenue[a]	17,236	19,301	12.0
Operating Expense[a, b]	317,137	294,536	-7.1
Operating Income[b]	10,760	16,374	52.2
Net Income, excluding unusual Items	8,657	12,829	48.2
Unusual Items	-998	-878	
Net Income	7,659	11,951	56.0
Foreign Refining/Marketing Operations			
Refined Product Sales Revenue	147,597	142,949	-3.1
Other Revenue[a]	4,754	14,249	199.7
Operating Expense[a, b]	147,956	152,420	3.0
Operating Income[b]	4,395	4,778	8.7
Net Income, excluding unusual Items	3,065	3,239	5.7
Unusual Items	-165	-124	
Net Income	2,900	3,115	7.4

[a]Raw materials revenues are netted against total operating expense.
[b]Excludes unusual items.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Part of the reason for the decline in sales revenues from domestic refining/marketing between 2000 and 2001 was that petroleum product prices fell 11 percent over that period (Table 13). In particular, the price of motor gasoline fell 10 percent, distillate fell 13 percent, and other products fell an average of 13 percent. Essentially flat economic growth[50] and warmer winter weather (5 percent fewer heating degree-days[51]) in 2001 compared to 2000 exerted little upward pressure on prices. Further, higher levels of industry-wide petroleum product stocks (Figure 16) in 2001 compared to 2000 exerted downward pressure on petroleum product prices. Lower industry-wide stocks of motor gasoline over the first part of 2001 (compared to 2000, Figure 17) served to ease the downward pressure on motor gasoline relative to other products. Gasoline prices also benefited from price spikes in April and May in some parts of the country due to refinery fires.

Higher Product Sales Ameliorate Effect of Lower Product Prices

The downward pressure on revenues exerted by the lower prices received by the FRS companies for petroleum products in 2001 relative to 2000 was somewhat abated by higher product sales (Table 14).

The FRS companies' sales of motor gasoline increased 6 percent, heating oil and diesel fuel sales rose 4 percent, and sales of other products increased 9 percent.

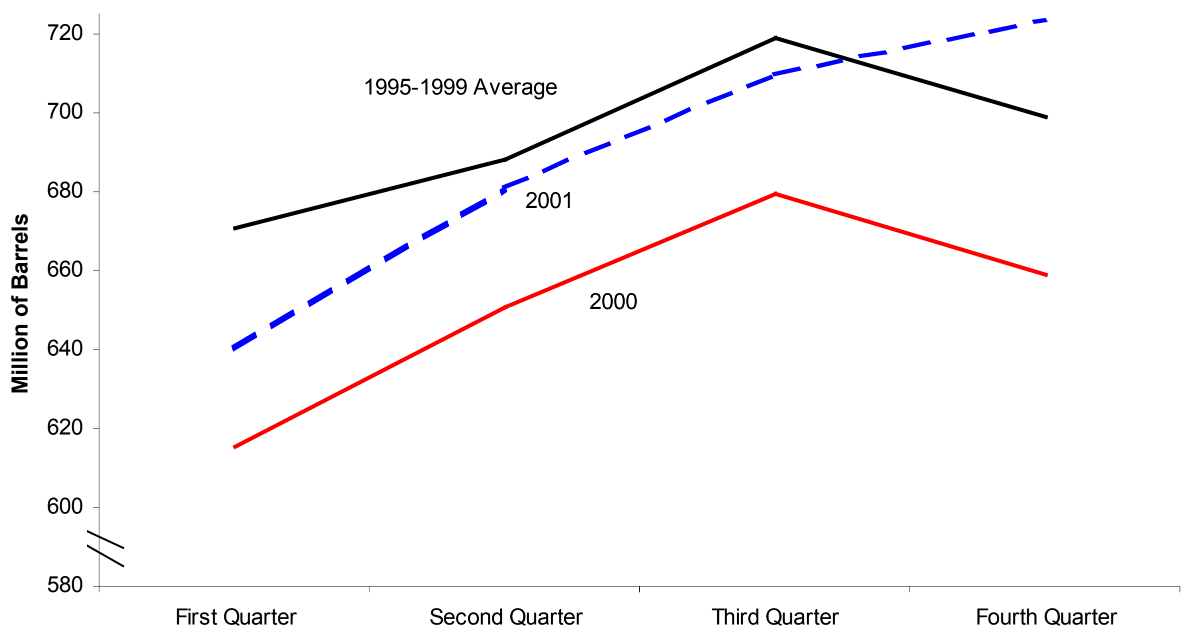
Table 13. Sales, Prices, Costs, and Margins in U.S. Refining/Marketing for FRS Companies, 2000-2001

	2000	2001	Percent Change 2000-2001
Refined Product Sales (Million Barrels per Day)	22.3	23.6	5.8
	(Nominal Dollars per Barrel)		
Gasoline Average Price	41.15	36.96	-10.2
Distillate Average Price	37.65	32.96	-12.5
Other Products Average Price	30.09	26.30	-12.6
All Refined Products Average Price	38.19	33.88	-11.3
Less: Raw Materials Costs and Product Purchases	31.13	26.04	-16.4
Equals: Gross Refining Margin	7.06	7.85	11.2
Less: Direct Operating Costs	4.83	5.13	6.1
Equals: Net Refining Margin[a]	2.23	2.72	21.9
Reseller/wholesaler spread (dealer price - wholesale price)	4.94	3.05	-38.2
Retailer spread (company-operated price - dealer price)	1.69	3.16	86.9

[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 16. Quarterly U.S. Commercial Petroleum Product Stocks, 1995-1999, 2000, and 2001

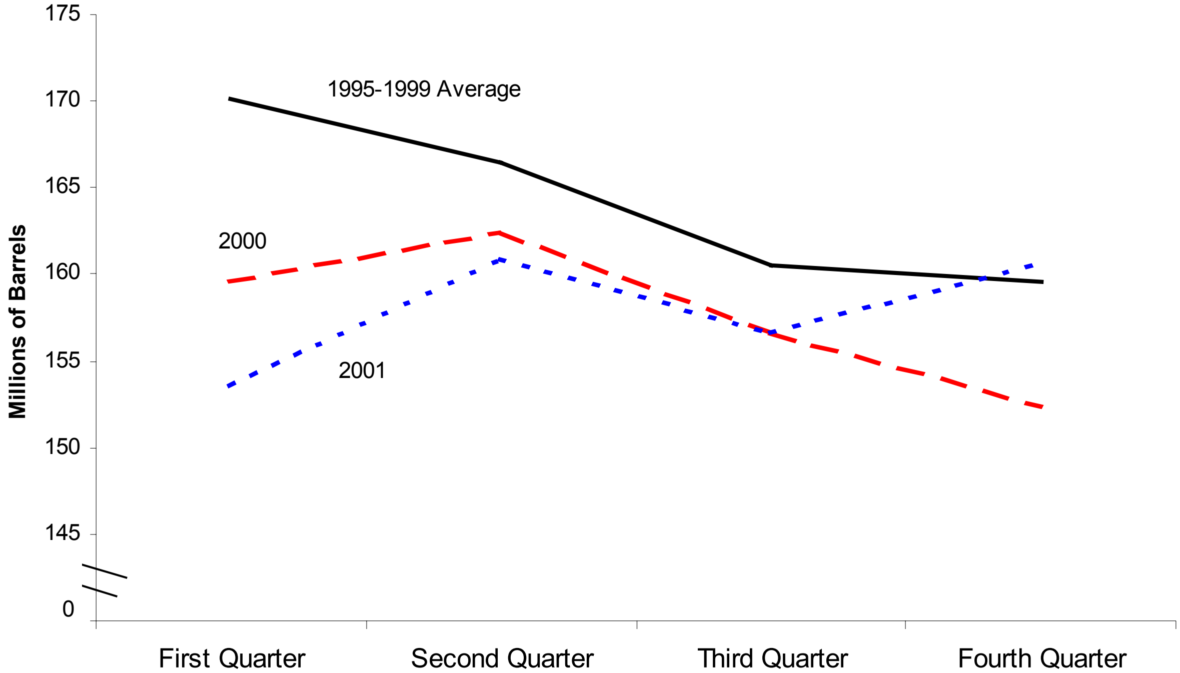


Source: Energy Information Administration, Petroleum Supply Monthly, DOE/EIA-0109 (Various issues, Washington, DC), Table 51.

Refinery capacity of the FRS companies continued to grow slowly, increasing about 1 percent between 2000 and 2001 (Table 15) after increasing slightly less than 2 percent between 1999 and 2000.[52] Although there were many refinery sales and purchases of FRS refineries during 2001, all were intra-FRS transactions (see Chapter 2 discussion) and had no net effect on total FRS refining capacity.

However, these transactions contributed much of the 48-percent increase in U.S. refining additions to net investment in place for 2001 relative to 2000. Additionally, some companies indicated that they are upgrading their refineries.[53] Much of the 86-percent increase in capital expenditures for U.S. marketing was also due to intra-FRS transactions.

Figure 17. Quarterly U.S. Motor Gasoline Stocks, 1995-1999, 2000, and 2001



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

Table 14. U.S. Refined Product Margins and Costs per Barrel Sold and Product Sales Volume for FRS Companies, 2000-2001

	2000	2001	Percent Change 2000 - 2001
	(Dollars per Barrel)		
Gross Margin	7.06	7.85	11.2
- Marketing Costs	1.37	1.59	15.9
- Energy Costs	1.33	1.37	2.8
- Other Operating Costs	2.13	2.17	1.8
= Net Margin	2.23	2.72	21.7
Product Sales Volume	(Million Barrels)		
Motor Gasoline	11,743	12,435	5.9
Distillate	6,695	6,958	3.9
Other Products	3,849	4,185	8.7
Total	22,287	23,579	5.8

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

Table 15. U.S. and Foreign Refining Investment and Operating Items for FRS Companies, 2000-2001

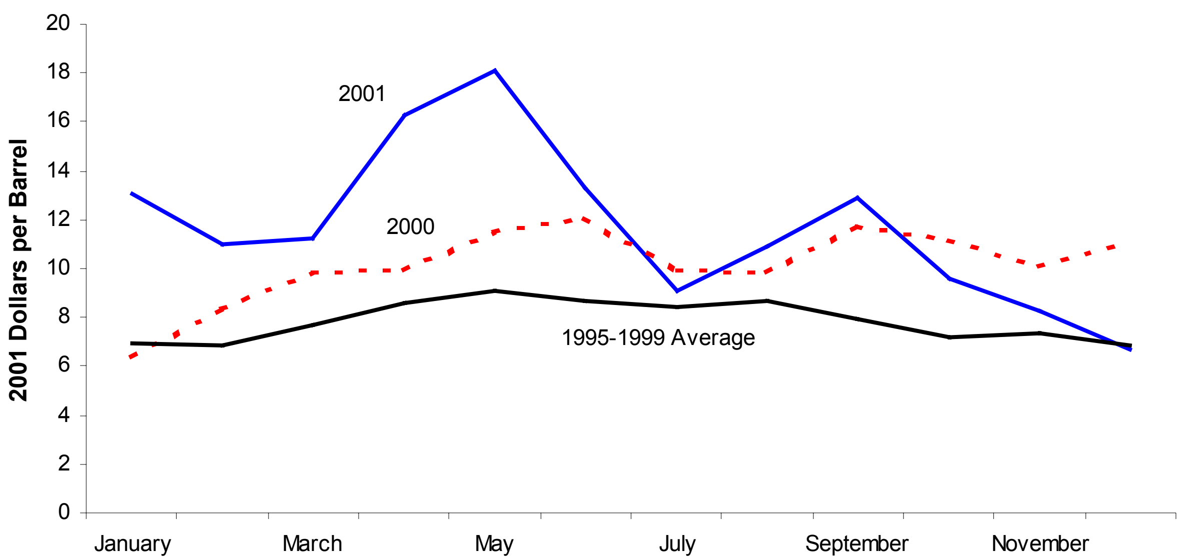
	2000	2001	Percent Change 2000-2001
	(Billion Dollars)		
U.S. Refining Additions to Investment in Place	8.2	12.1	47.7
U.S. Marketing Additions to Investment in Place	3.9	7.2	85.7
Foreign Refining/Marketing Additions to Investment in Place	2.4	4.6	91.1
	(Thousand Barrels per Day)		
U.S. Refining Capacity	14,378	14,586	1.4
U.S. Refinery Output	14,499	15,022	3.6
Foreign Refining Capacity	5,134	5,448	6.1
Foreign Refinery Output	5,124	5,062	-1.2
	(Percent)		
U.S. Refinery Utilization Rate[1]	93.7	95.8	(2)
Foreign Refinery Utilization Rate[1]	89.7	85.2	(2)

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

[2]Not meaningful.

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

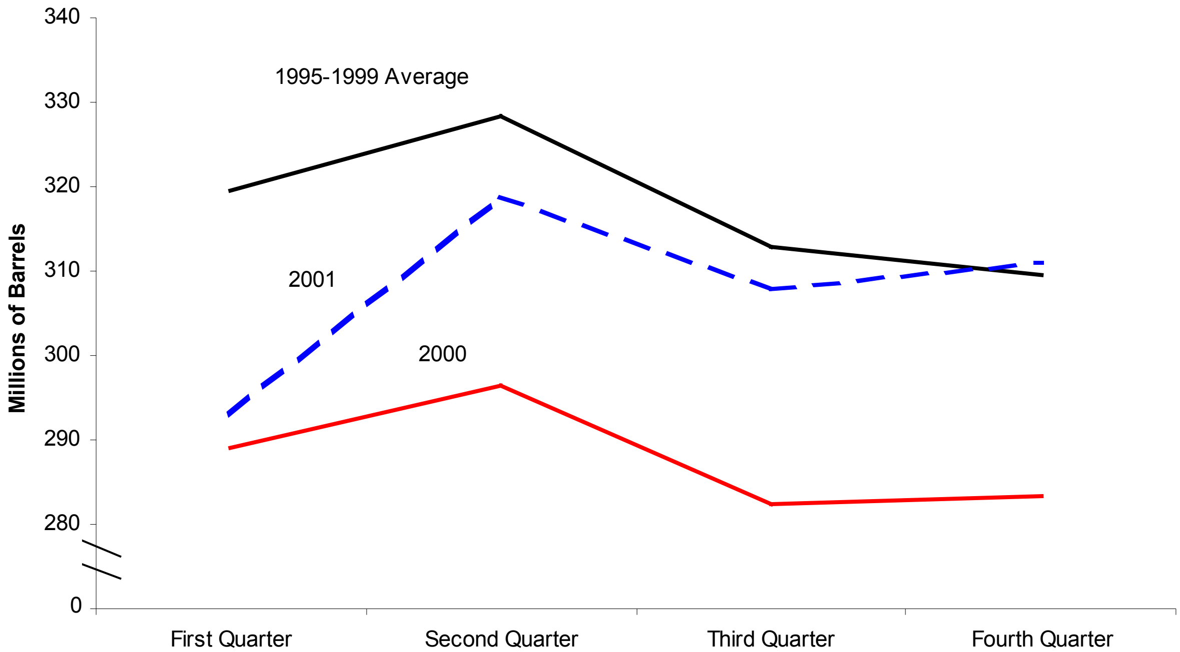
Figure 18. Monthly Gross Refined Product Margin for United States, 1995-1999, 2000, and 2001



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 1995 - March 2002), Table 1, Table 4, and Table 5; and Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0380 (February 1995 - January 2002), Table 3-2b.

Figure 19. Quarterly U.S. Crude Oil Stocks, 1995-1999, 2000, and 2001



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

Gross Margin and Operating Costs Rise Despite Stable Energy Costs

Industry-wide gross refining margins in 2001 were generally higher than those of 2000 until the end (i.e., fourth quarter) of the year (Figure 18). The gross margin was elevated by relatively lower stocks of motor gasoline (compared with those of 2000). Domestic crude oil stock levels were higher in 2001 than they were a year ago (and by the end of the year reached the 1995 to 1999 average), which put downward pressure on the price of crude oil, which fell $5.30/barrel (19 percent) from the 2000 average of $28.26/barrel (Figure 19).[54] Although the industry-wide gross margin of 2001 was lower than that of 2000 in the fourth quarter, the average gross margin for 2001 was $11.59/barrel, a 17-percent increase from the 2000 value of $9.91/barrel. The FRS gross margin, which includes product purchases and resales of refined products, increased $0.79 (11 percent) per barrel between 2000 and 2001 (Table 13).

Operating costs increased in 2001 relative to 2000, rising 4 percent, $0.30 per barrel, following an 8-percent increase between 1999 and 2000 (Table 14). Of the categories of operating costs, energy costs changed the least, essentially keeping pace with inflation.[55] Companies generally were able to avoid large increases in their energy costs because one of the significant costs, the industry-wide price for natural gas, increased only 3 percent, from $4.38 per thousand cubic feet to $4.51 per thousand cubic feet.[56] Although several companies reported lower energy costs, no particular reasons were provided. However, several companies have undertaken cogeneration projects at several refineries[57] in the last few years and this may be part of the reason for lower energy costs in 2001.

Acquisitions and Mergers Increase Marketing Costs Despite Continued Cost-Cutting Efforts

Marketing costs, however, increased 16 percent in 2001 relative to 2000 (Table 14). Certainly the mergers of 2001, in which Valero acquired Ultramar Diamond Shamrock, Phillips Petroleum acquired Tosco, and Chevron merged with Texaco to create ChevronTexaco, required the integration of separate marketing networks and led to higher marketing costs. Further, Phillips acquired several Coastal-branded retail outlets and supply contracts for others from El Paso.[58] Additionally, Amerada Hess acquired outlets in New England and began a joint venture in the southeastern United States.[59]

Attempting to lower marketing costs, the FRS companies continued to relentlessly restructure, refocus, and retrench their motor gasoline marketing operations throughout 2001. They again reduced the number of direct-supplied branded outlets, which fell 2 percent from 55,243 in 2000 to 54,085 in 2001 (Table 16). A net of more than 1,200 company-operated outlets were sold to non-FRS companies during 2001,[60] which resulted in a 10-percent decline relative to 2000.

Table 16. Motor Gasoline Distribution and Number of Direct-Supplied Branded Outlets for FRS Companies, 2000-2001

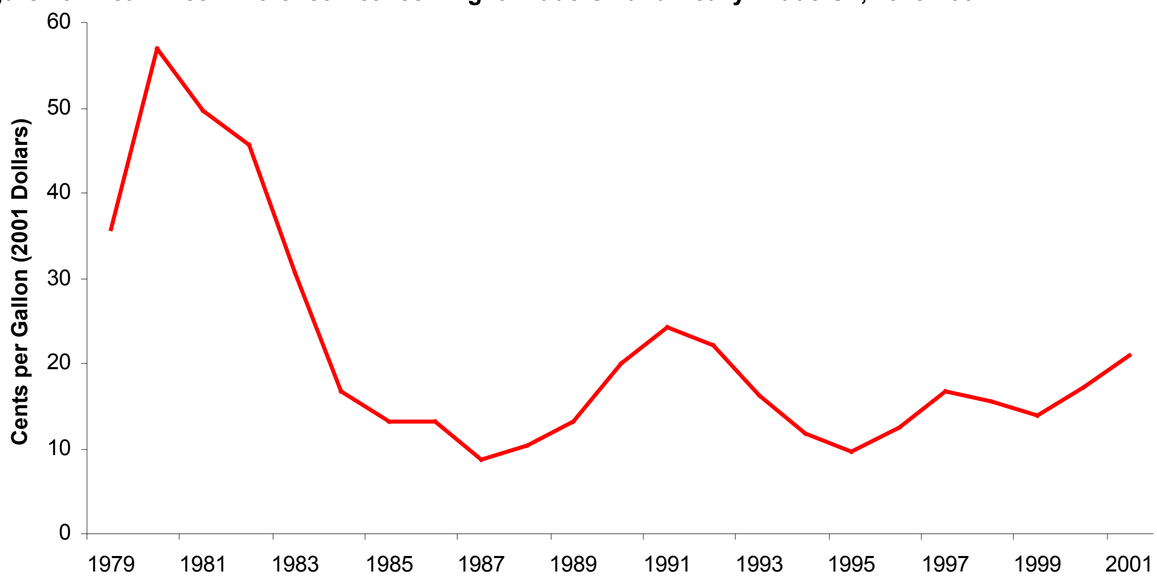
	2000	2001	Percent Change 2000-2001
	(Million Barrels)		
Third-Party Volume			
Wholesale	2,125.9	1,955.8	-8.0
Retail			
Dealer	1,104.6	1,182.1	7.0
Company-Operated	543.3	545.1	0.3
Total Retail	1,647.9	1,727.3	4.8
Direct	464.9	729.3	56.9
Total Third-Party Volume	4,238.8	4,412.4	4.1
Intersegment Volume	105.4	126.4	20.0
	(Number of Direct-Supplied Branded Outlets)		
Dealer Outlets	42,660	42,705	0.1
Company-Operated Outlets	12,583	11,380	-9.6
Total Retail Outlets	55,243	54,085	-2.1
Average Monthly Outlet Volume	(Thousand Gallons per Month)		
Dealers	90.6	96.9	6.9
Company-Operated	151.1	167.7	10.9
All Direct-Supplied Outlets	104.4	111.8	7.1

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

The productivity of the retail outlets retained by the FRS companies increased by 7 percent in 2001 relative to 2000 (Table 16). The productivity of company-operated outlets increased 11 percent from a monthly average of 151,100 gallons per outlet in 2000 to 167,700 gallons in 2001. The productivity of dealer outlets increased from 90,600 gallons per outlet to 96,900 gallons per outlet, also a 7-percent increase.

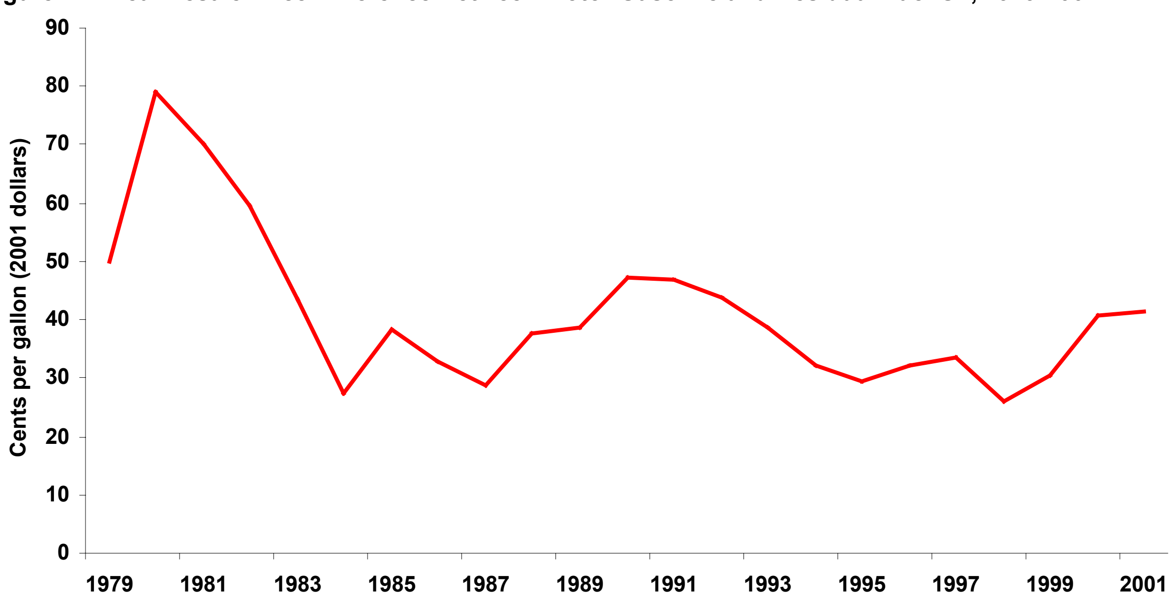
Sophisticated refineries, such as those owned by the FRS companies,[61] are able to take advantage of price differences between lower quality crude oil and higher quality crude oil. The price differences between heavy and light crude has grown over the last two years (Figure 20), increasing by 24 percent (from 13.9 to 17.2 cents per gallon) between 1999 and 2000 and by 22 percent (17.2 to 21.0 cents per gallon) between 2000 and 2001. Thus, the FRS refiners were able to lower their raw materials costs, relative to less sophisticated refiners, by taking advantage of these price differences. Additionally, the sophistication of the FRS refineries allows them to produce more light products and fewer heavy products. Consequently, the recent increase in the price difference between light and heavy products (approximated by the price difference between motor gasoline and residual fuel oil) contributed to the recent profitability of the FRS refiners (Figure 21).

Figure 20. Real Price Difference Between Light Crude Oil and Heavy Crude Oil, 1979-2001



Note: The more expensive light crude oil is defined here as having an API gravity of 40.1 or greater and heavy crude oil is defined as having an API gravity of 20 or less.
Source: Energy Information Administration, *Petroleum Marketing Monthly*, DOE/EIA-0380, Tables 27 and 28.

Figure 21. Real Resale Price Difference Between Motor Gasoline and Residual Fuel Oil, 1979-2001



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

Planned outages of refineries (e.g., turnarounds) were delayed in response to high refining margins during the first half of 2001, contributing to the slight increase in the domestic refinery utilization rate (Table 15) relative to 2000. Further, the higher utilization rate contributed to an almost 4-percent increase in refinery output in 2001 compared to a year earlier.

Thus, 2001 was the most profitable of a recent run of profitable years for the domestic refining/marketing operations of the FRS companies. In 2000, the reduced operating costs were chiefly responsible for the increased net margin and, by implication, also had much to do with the increased profitability of domestic refining/marketing. However, in 2001, the higher gross margin elevated the net margin. The ability of the FRS companies to capitalize on greater price differences between light and heavy crude oils and light and heavy refined products with their sophisticated refineries played a large role in the increased profitability of FRS domestic refining/marketing profitability in 2001.

Foreign Refining and Marketing

Profitability of Foreign Refining/Marketing Operations Highest Since 1997

Foreign refining/marketing generated $143 billion in sales revenues in 2001, resulting in net income before unusual items of $3.1 billion, a 7-percent increase relative to 2000 (Table 12). Sales revenues in 2001 were $4.6 billion (3 percent) lower than those of 2000, but net income exclusive of unusual items was $0.2 billion higher, a 6-percent increase, at $3.2 billion. Profitability was 10 percent, the highest since 1997 (Figure 14).

The FRS companies' foreign refining/marketing earnings are derived from two sources: unconsolidated affiliates and consolidated operations. The corporate parent of an unconsolidated affiliate owns 50 percent, or less, of the affiliate, and does not directly control the affiliate (a joint venture, for example, is usually an unconsolidated affiliate from the perspective of at least one of the partners[62]). Essentially, the unconsolidated affiliate is more of a property or holding of the parent corporation than it is a company that the parent actually operates. The effect on financial operations of an unconsolidated affiliate can only be seen on the parent corporation's income statement, where the parent company's proportional share of the affiliate's net income is reported. Conversely, a fully consolidated affiliate is directly controlled by the parent corporation (although it could be owned by several companies, with the parent corporation owning more than 50 percent). In addition, all operating and financial information about a fully consolidated affiliate (such as revenues) is reported in the public financial disclosures of the parent corporation.

Unconsolidated/Consolidated Results Approximate Asia-Pacific/Europe Operations

Historically, the operations of the FRS companies' unconsolidated foreign refining/marketing affiliates have been mainly in the Asia-Pacific region. Much of the Asia/Pacific refinery capacity owned by the FRS companies was held by a joint venture between Chevron and Texaco called Caltex. The merger of Chevron and Texaco, which created ChevronTexaco, effectively ended Caltex's existence as a separate company. (See the Highlight "Caltex, 1936-2001" for more information about the Caltex joint venture.)

Caltex, 1936 to 2001

Following the merger of Chevron and Texaco in 2001, Caltex was folded into ChevronTexaco Global Energy, Inc., its international operating entity. The continued use of the Caltex brand name in the Asia-Pacific region is the last remaining vestige of the oldest FRS joint venture. The following narrative recounts a few significant events in the joint venture's history.

The Caltex joint venture between the partners Chevron (Standard Oil of California) and Texaco (Texas Oil Company) began operation in 1936. Caltex was one of the earliest refining/marketing joint ventures, and, until Texaco and Saudi Aramco created the Star Enterprise joint venture in 1988, it was without peer. However, refining/marketing joint ventures eventually became both popular and prevalent in the 1990's. Ashland and USX/Marathon combined their downstream operations to create Marathon Ashland Petroleum, and Shell and Texaco combined their western U.S. operations to create Equilon, and most[a] of Shell's non-western operations and Star Enterprise to form Motiva.

Although Caltex has been known as a refining/marketing joint venture, it was not founded as such. Instead, it was a joint venture that combined Chevron's (then commonly referred to as SOCAL, short for Standard Oil of California) oil and gas production operations in Bahrain, Saudi Arabia, and the East Indies and Texaco's Africa and Asia marketing operations. Chevron desired an outlet for the crude oil that it was producing, especially the sour (i.e., high sulfur) crude of Bahrain, while Texaco needed petroleum products that could be sold by its marketing operations.[b] Caltex was formally established to "operate in Africa, the Middle East, Asia, Australia, and New Zealand. Chevron's solution was to grant Texaco 50 percent of Chevron's Bahrain and Saudi Arabian concessions in return for receiving 50 percent of Texaco's Far Eastern marketing network."[c] This arrangement ameliorated the problems of both companies.

During 1937, Caltex expanded its marketing operations in Australia, Africa, China, India, and parts of Asia. In 1947 Caltex expanded into Europe by adding Texaco's European operations, a move that was reversed 20 years later when Caltex's European interests were transferred back to its parents, Texaco and Chevron. In 1968 Caltex expanded into Korea and by 1988 Caltex had expanded its operations in Australia, Hong Kong, Thailand, and the Philippines and re-entered China by opening an office in Beijing and a marketing outlet. During the 1990's Caltex expanded into India, Sri Lanka, Vietnam, Cambodia, Indonesia, and Lebanon.[d]

Caltex is considered to have pioneered production-sharing contracts with a 1960's production-sharing agreement with Indonesia. This contract recognized Caltex as a contractor, rather than a concessionaire. The implication thereby was that the country was sovereign and that Caltex was subordinate to the country. Such formal recognition of the relationship between Indonesia and Caltex created a more politically tenable situation in Indonesia and smoothed the way for subsequent agreements between Indonesia and foreign oil companies.[e]

Caltex's existence as a stand-alone company formally ended in 2001 with the merger of the two parent companies, which created ChevronTexaco. At that time, Caltex's assets included two wholly owned and eight partially-owned refineries with a total capacity of 840 thousand barrels per day and approximately 8,650 branded retail outlets in approximately 30 countries. ChevronTexaco continues to use the Caltex brandname although Caltex no longer exists as a stand-alone company.

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[a]Shell's non-western assets that were not included in Motiva were Shell's two petrochemical refineries and its Deer Park, Texas refining joint venture with Petroleos de Mexicanos (PEMEX, the state oil company of Mexico).

[b]Daniel Yergin, *The Prize*, Simon and Schuster (New York, 1991), p. 299.
[c]Neil H. Jacoby, *Multinational Oil*, Macmillan Publishing Co., Inc. (New York, 1974), p. 36.
[d]Caltex Corporation, "About Caltex." Web site: http://www.caltex.com/Caltex.com/about/corp_caltexstory.asp (as of September 26, 2002).
[e]Daniel Yergin, *The Prize*, Simon and Schuster (New York, 1991), p. 652.

About 69 percent of the refinery capacity of unconsolidated affiliates in 2001 was in the Asia-Pacific region, a 2-percentage point increase since 2000 (Table 17). Although the change was small, numerous marginal changes in refinery capacity, many of which were declines, underlay the summary statistics. Further, Caltex's consolidation by ChevronTexaco shifted 72,000 barrels of capacity from unconsolidated operations to consolidated affiliates.[63] All the rest of Caltex's refinery capacity was unconsolidated from Caltex's perspective (and represented the sum of their shares of the total refinery capacity of all refineries in which Caltex had ownership) and, from the perspective of Chevron and Texaco (now ChevronTexaco), Caltex was unconsolidated. Even though Caltex is now consolidated from the perspective of ChevronTexaco, almost all of the Caltex's refinery capacity (with the exception of a refinery in the Philippines) remains unconsolidated from ChevronTexaco's perspective because ChevronTexaco's ownership of these refineries remains less than 100 percent. Thus, although the merger of Chevron and Texaco, which created ChevronTexaco, resulted in their Caltex joint venture being consolidated, it had surprisingly little effect on the relative refining capacity that is consolidated versus that which is unconsolidated.[64]

Table 17. Regional Distribution of Foreign Refinery Capacity for FRS Companies, 2000-2001
(Percent)

	Consolidated Operations		Unconsolidated Affiliates	
	2000	2001	2000	2001
Europe	49.4	51.0	20.5	18.0
Asia	24.0	25.0	66.8	68.7
Latin America	10.0	11.6	0.6	0.5
Canada	13.9	9.7	0.0	0.0
Other	2.8	2.7	12.0	12.7
Grand Total	100.0	100.0	100.0	100.0

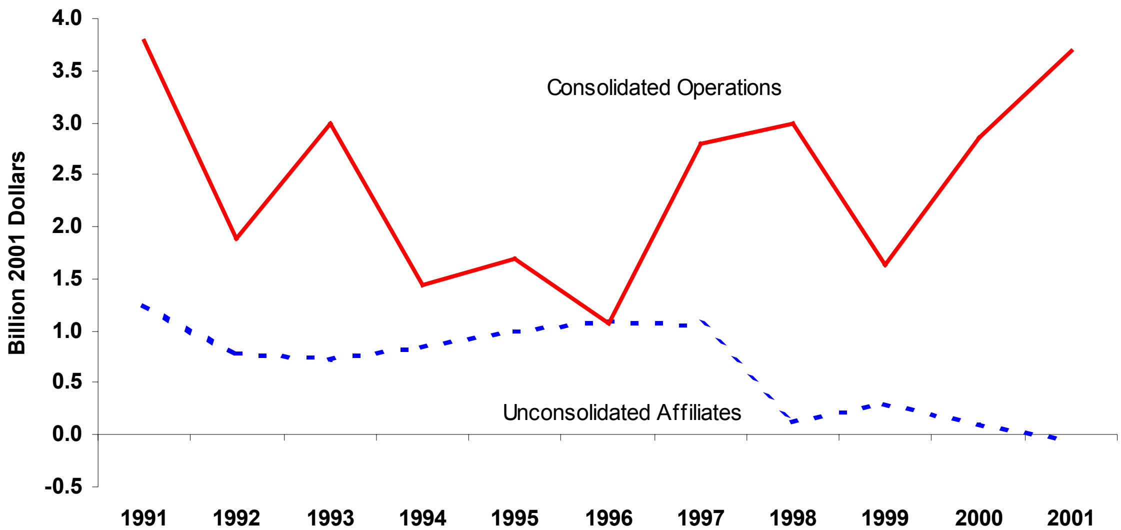
Note: The region denoted as "Other" includes Africa and the Middle East.
Sources: Company Annual Reports and filings of U.S. Securities and Exchange Commission Form 10-K.

The FRS companies' consolidated foreign/marketing operations are mainly located in Europe. In 2001, 51 percent of consolidated refinery capacity was located in Europe, a 2-percentage point increase since 2000. The main sources of the change were marginal declines in the reported capacities of several refineries, which slightly shifted the proportions (Table 17). Further, the net effect of two transactions further reduced consolidated capacity. Phillips Petroleum sold its ownership in the 117,000 barrels per day Teesside, UK refinery at the end of 2000,[65] but acquired Tosco, which itself had earlier acquired Ireland's 70,000 barrels per day Whitegate refinery.[66]

Consolidated Operations Dwarf Unconsolidated Affiliates As Net Income Contributor

The contribution to net income from the FRS companies' unconsolidated affiliates has been significantly lower than earnings from consolidated operations since 1997 (Figure 22). Between 1991 and 1997, the ratio of net income from unconsolidated affiliates to the net income from consolidated operations averaged 43 percent, ranging between a high of 103 percent and a low of 24 percent. Since 1997, the ratio has averaged 7 percent, ranging between a high of 18 percent and a low of 4 percent, exclusive of the small loss earned in 2001. The change in the relationship between earnings from consolidated versus those of unconsolidated foreign refining/marketing operations provides some indication of the ongoing economic troubles of Asia-Pacific.

Figure 22. Foreign Refining/Marketing Net Income from Consolidated Operations and Unconsolidated Affiliates of FRS Companies, 1991-2001



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

Generally Negative Results Characterize Asia-Pacific Markets

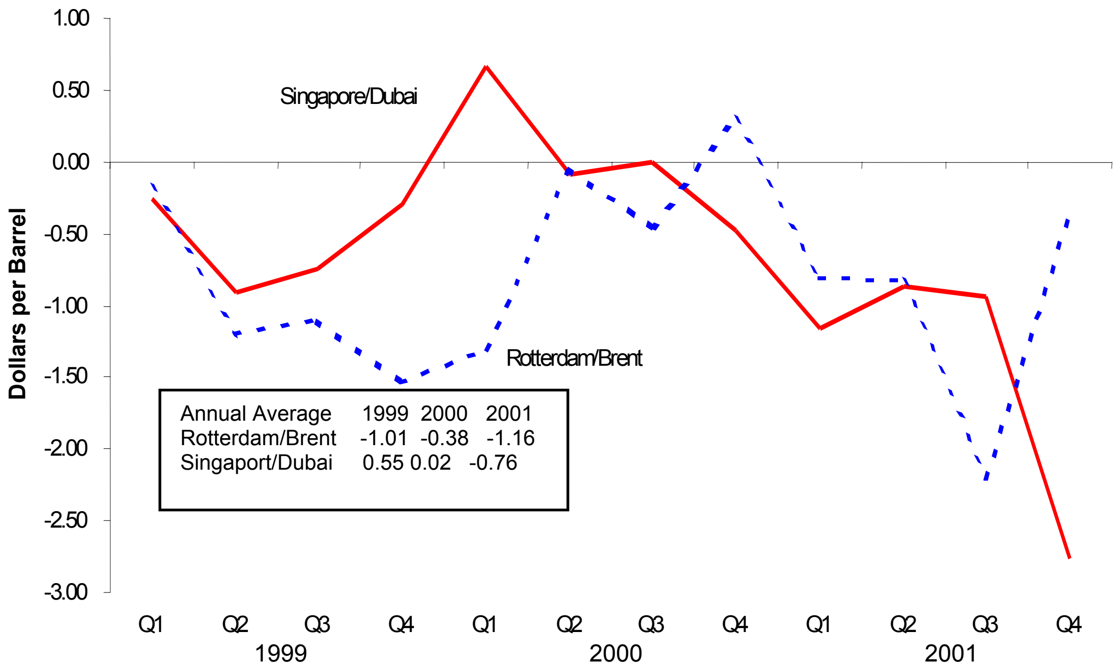
During 2001, the FRS companies' unconsolidated affiliates generated a loss of $4 million, which was a $107-million reduction from 2000's level of positive income of $103 million. Results for unconsolidated affiliates largely reflect conditions in the Asia-Pacific region (Table 17). Refining margins for Asia-Pacific (represented by the Singapore/Dubai refining margin) were $0.78 per barrel lower than a year earlier with the greatest reductions during the first and fourth quarters of 2001 (Figure 23). The results were mixed, with half of the companies reporting an increase in earnings, or a reduction in losses, and half reporting a decrease in earnings, or an increase in losses. For example, Conoco reported it had 6 percent of the Thailand motor gasoline market and that its lubricants sales are growing in Asia Pacific.[67] Similarly, ChevronTexaco noted that margins "improved in most of the Asia ... operating areas."[68] Alternatively, Exxon Mobil noted that Asia-Pacific refining margins were lower "... than already poor 2000 margins. Persistent weak demand continued to hamper margin recovery."[69]

However, despite the lingering economic problems following the Asian financial crisis, the Asia-Pacific region has experienced the highest growth rate in the consumption of petroleum products of any region in the world since 1996 (Figure 24) at 20 percent for the five-year period. Consequently, selective investment,[70] such as cogeneration facilities in refineries,[71] continues despite the current low earnings.

Earnings in Europe Increase Despite Falling Margins

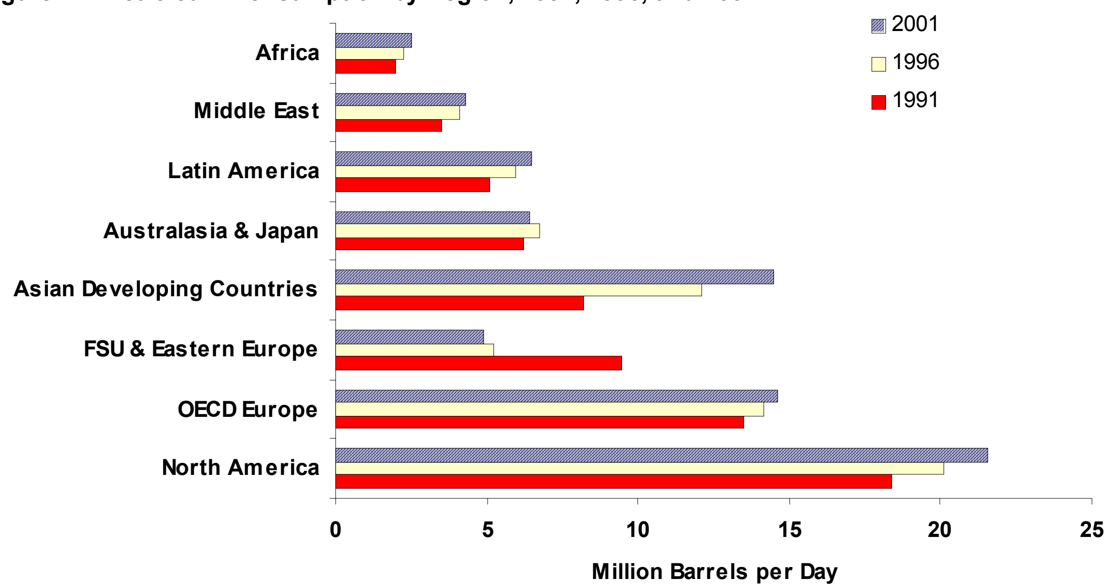
Net income from the FRS companies' consolidated operations (bottom line net income from foreign refining/marketing less income from unconsolidated affiliates) was 7 percent higher in 2001 than a year earlier, reaching $3.1 billion. This result occurred despite Europe having the lowest five-year growth rate of petroleum consumption since 1996 (Figure 24) at 3 percent.

Figure 23. Foreign Refining Margins, 1999-2001



Sources: Energy Intelligence Group, Oil Market Intelligence 1999: January 2000 and July 1999, p. 12; 2000: January 2001 and July 2000, p. 12; and 2001: January 2002 and July 2001, p. 12.

Figure 24. Petroleum Consumption by Region, 1991, 1996, and 2001



Source: BP plc, *BP Statistical Review of World Energy* (June 2002). p. 9.

European refining margins (represented by the Rotterdam/Brent refining margin) were low during the first half of 2001, fell substantially during the third quarter, and recovered to a yearly high in the fourth quarter (Figure 23). However, the overall result was that European refining margins[72] were $0.78 per barrel lower in 2001 than in 2000, exactly the same value in the Asia/Pacific markets. The financial results of the FRS companies reporting consolidated refining/marketing operations were generally good, with many of the companies reporting higher net income than in 2000, citing higher margins[73] and sales.[74] Only a few companies reported lower earnings than in 2000 (and none reported losses), citing lower margins and sales.[75] Additionally, Conoco's wholly-owned Humber, United Kingdom refinery was shut down for 10 weeks following an explosion.[76]

Foreign Marketing Operations Being Refocused

The FRS companies continued to refocus their foreign marketing operations during 2001. For example, Conoco sold 175 outlets in the United Kingdom.[77] In contrast, Exxon Mobil expanded marketing operations, opening a total of more than 250 new outlets in several different countries worldwide,[78] while standardizing the image of its worldwide outlets.[79] Similarly, ChevronTexaco acquired an independent fuel marketer with more than 100 outlets in New Zealand[80] and also refurbished outlets in Belgium, Luxembourg, the Netherlands, and the United Kingdom.[81]

Exxon Mobil introduced continuously open, unattended outlets (called Esso Express) in France and Belgium in 2001[82] and expanded their alliances with European grocery chains to include a Dutch grocer in addition to the UK grocer announced in 2000. Further, Exxon Mobil has opened grocery co-branded outlets[83] in the United Kingdom and Thailand.[84]

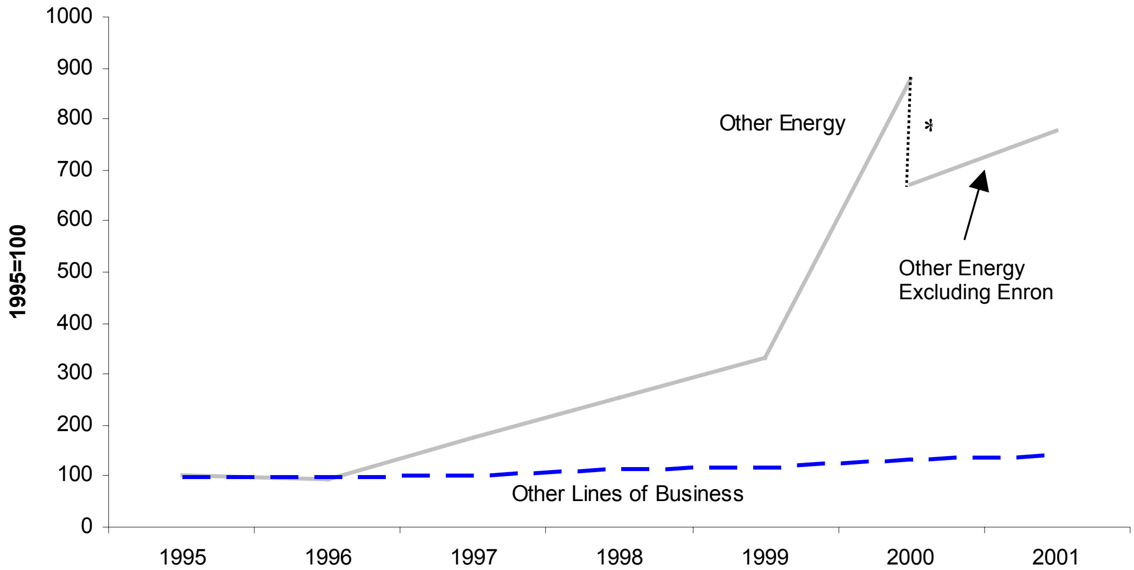
Other Energy

The FRS "other energy" line of business consists of energy operations other than the production of oil, natural gas, or coal. This includes electric power production and supply, transportation of power, energy trading operations, energy management services, and nonconventional energy production. Whether measured by asset growth or revenues, the other energy line of business has grown much faster in recent years than all other lines of business of FRS companies (Figure 25).

Revenue and Income, Sans Enron, Continue to Grow

There has been tremendous growth in revenue from the FRS companies' other energy line of business. Between 1995 and 2000, the FRS companies' other energy revenues grew at an annual rate of 127 percent. In 2001, excluding Enron which did not report to the FRS in that year, revenues were up 96 percent (Table 18). Much of that growth has been driven by the electric power businesses and electricity and natural gas trading activities. Prominent among these companies in revenue growth in 2001 were the three FRS companies that were also biggest in terms of other energy revenue base: El Paso, BP, and Dominion. Blurring this picture, possibly, are revelations that some reported trading activity in the industry consisted of transactions that "wash" or offset themselves, designed specifically to boost reported revenues despite not materially affecting any other business attributes, such as income. This type of trading activity ("wash" trades) was admittedly occurring in Enron, a company that eventually failed. Several other companies admitted to "wash trades," such as CMS and Dynegy. Williams was accused but the company denied it. (For further information on Enron, see the Highlight entitled "What Factors Undermined Enron's Success In Energy Trading?"

Figure 25. Net Investment in Place in Other Energy and All Other Businesses for FRS Companies, 1995-2001
(1995=100)



*Because of Enron's absence from the Financial Reporting System in 2001, the Other Energy line of business data are presented with and without Enron's data for year 2000.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table 18. Income Components for Other Energy for FRS Companies, With and Without Enron, 2000-2001

Income Components	2000	ex-Enron 2000	2001	Percent Change ex-Enron 2000-2001
	(Million Dollars)			
Operating Revenue	84,987	42,807	83,811	95.8
Operating Expenses	81,948	40,884	81,678	99.8
Operating Income	3,039	1,923	2,133	10.9
Equity Income	753	651	902	38.6
Net Income	2,741	1,904	1,993	4.7
unusual items	-20	-20	-7	--
Net Income excluding unusual items	2,761	1,924	2,000	4.0

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

What Factors Undermined Enron's Success In Energy Trading?

Enron Corp. was created in July 1985 by the merger of Houston Natural Gas Corporation and InterNorth, Inc., the parent company of Northern Natural Gas Company, a natural gas company based in Omaha, Nebraska. Originally a natural gas pipeline company which grew to own approximately 37,000 miles of pipeline, Enron became more widely known as it remade itself into a high-tech company, pioneering the trading of natural gas and later electricity and financial instruments (known as derivatives). Enron's derivatives were primarily associated with their energy business lines (i.e., natural gas and electricity), and risk-related variables (e.g., weather) that were relevant to these businesses. All this collapsed as Enron filed for protection from creditors under a Chapter 11 reorganization on December 2, 2001, the biggest corporate bankruptcy ever up to that time.

Where did Enron go wrong?

First, Enron had adopted a strategy of becoming a major force in the businesses it operated in while minimizing the ownership of hard assets in those businesses – the Enron "asset-light" approach. Rather than own, it employed contracts to control the facilities involved in its operations.

Second, much of Enron's growth was fueled by borrowing, which Enron made opaque to outside parties through the use of various financial techniques and instruments, such as the often-mentioned "special purpose entities," an accounting technique originally designed to leverage risk for the banking industry.

In addition, much of Enron's profits came from trading activities. To be successful in this business, a trading company must have sufficient net worth and cash liquidity -- or effectively maintain the image of such -- so that trading partners continue to be willing to make deals without fear of much counter-party risk (the inability of a trading partner to make good on its obligation).

Despite being heavily in debt, Enron made several major investments (including some in non-core businesses), such as building a major power plant in India, and laying thousands of miles of fiber optic lines. These investments turned sour and lost large sums of money (such as when telecommunications demand failed to materialize as expected and huge fiber optic overcapacity resulted), exacerbating and making more apparent the extent of the company's financial troubles.

Together, these factors helped lead to the unraveling of Enron. Once it became clear that many of these large investments were turning sour, suspicions arose that Enron might be on substantially less sound financial footing than was previously assumed, and traders began shunning Enron. With trading evaporated as a profit base, the financial drain on Enron accelerated, and the company collapsed.

These same three companies reporting the highest revenue growth also more than accounted for the modest 4 percent growth in net income, excluding unusual items. Other companies on balance reported lower income. Williams pointed to the impact of the Enron experience: "Events in 2001 significantly impacted the risk environment all businesses face and raised a level of uncertainty in the capital markets … If Williams' credit ratings were to decline below investment grade, its ability to participate in the Energy Marketing and Trading business could be significantly limited."[85] Shell had $78 million of losses in its Other Businesses segment, "mainly due to costs associated with the exit of several retail power markets, and increases in reserves."[86] Meanwhile, ChevronTexaco's decline in income in this area was due to special items and merger effects; excluding these items, income was essentially unchanged.[87]

Growth in equity income (income from equity ownership in other companies) was led by El Paso and ChevronTexaco. For El Paso, some of the increase resulted from higher earnings from an unconsolidated affiliate called Chaparral which owns and operates electric power facilities, rising from a loss of $5 million in 2000 to earnings of $75 million in 2001.[88] ChevronTexaco's equity ownership in Dynegy Inc. (Dynegy) accounted for $61 million of this increase, increasing from $127 million to $188 million, both from a greater ownership share in Dynegy and higher Dynegy income in 2001.[89]

Nonconventional Energy: Tar Sands and Geothermal Stand Out

The FRS "other energy" line of business was originally conceived primarily for nonconventional energy investments, which include renewable resources, such as wind, solar, and geothermal energy, and hydrocarbons from tar sands, oil shale, coal gasification and liquefaction, among other sources. However, nonconventional energy is no longer a primary target of investment for the FRS companies. Although it was the lion's share of other energy until the mid-1990's, the FRS companies' forays into nonconventional energy were generally unprofitable, and most FRS companies started to scale back their investments in nonconventional energy during the 1980's.

Nonetheless, two nonconventional energy projects stand out: Canadian tar sands by Exxon Mobil and geothermal energy in Southeast Asia by Unocal. Exxon Mobil has been extracting oil from Canadian tar sands since the 1970's. The company reports a year-end 2001 total of 821 million barrels of Canadian tar sand reserves, compared to its 11,491 million barrels of worldwide (non-tar sand) crude oil and natural gas liquids reserves.[90]

The 2001 Canadian tar sands reserve level represents a 35-percent increase over the 610 million barrels of those reserves in 2000. Gross synthetic crude oil produced from those tar sands was 80 million barrels in 2001, up from 73 million barrels in 2000, though the bottom-line impact of this production increase was more than offset by the 19-percent decrease in crude oil prices from 2000 to 2001.[91]

Unocal has over 35 years experience in geothermal energy. It operates major geothermal fields producing steam for electricity at Tiwi and Mak-Ban in the Philippines, and Gunung Salak and Wayang Windu in Indonesia. These four projects supply steam for a total of 1,200 megawatts of generating capacity.[92] Unocal's total 2001 geothermal energy production averaged 14 million kilowatt-hours, the equivalent of 22,000 barrels of oil per day, down from 25,000 barrels per day in 2000. Its net proved geothermal reserves at year-end 2001 were the equivalent of 162 million barrels of oil, compared to 170 million barrels in 2000. Unocal continues to be active in geothermal energy: in 2001 the company purchased 50-percent ownership of a 110-megawatt power plant and related steam field in the Wayang Windu area of West Java, Indonesia.[93]

Unocal's Geothermal and Power Operations business segment after-tax earnings were $11 million in 2001, down $13 million from 2000. The decline was primarily due to Unocal's having to make higher provisions for past-due receivables related to the Gunung Salak project.[94]

Endnotes

[37]Exxon Mobil Corporation, 2001 *Financial and Operating Review*, p. 34.
[38] BP America, the U.S. subsidiary of BP plc of the United Kingdom, is the FRS respondent.
[39]BP plc, 2001 Report to the Securities and Exchange Commission on Form 20-F, p. 28.
[40]Occidental Petroleum, *2001 Annual Report*, p. 4.
[41]Exxon Mobil Corporation, 2001 *Financial and Operating Review,* pp. 52-53.
[42]Exxon Mobil Corporation, "The frontier in exploration runs deep, very deep," *the Lamp,* Spring 2000.
[43]BP plc, 2001 Report to the Securities and Exchange Commission on Form 20-F, p. 32; Amoco, 1997 Report to the Securities and Exchange Commission on Form 10-K.
[44] Return on investment is net income divided by net investment in place, which is net property, plant, and equipment plus year-end balance for investments and advances to unconsolidated affiliates.
[45] The all-time high was recorded in 1988 and was 14.7 percent. The level achieved in 2001 was 14.5 percent.
[46] The net margin and return on investment have a correlation coefficient of 92 percent. See Energy Information Administration, *The Impact of Environmental Compliance Costs on U.S. Refining Profitability* (Washington, DC, October 1997), Figure 5. Web address: http://www.eia.doe.gov/emeu/perfpro/ref_pi/fig5.gif (as of October 30, 2002).
[47] The net margin excludes peripheral activities such as non-petroleum product sales at convenience stores.
[48] The increase in other revenue, which was about 7 percent of domestic refining/marketing revenue in 2001 (5 percent in 2000), was chiefly driven by ChevronTexaco, probably from the earnings received from Texaco's share of Equilon and Motiva.
[49] Unusual items are revenues and costs associated with activities not a part of the on-going activities of the company, such as write-downs of asset values.
[50] Percent changes in Gross Domestic Product (after adjusting for general price changes) (GDP) measure economic growth. See Energy Information Administration, *Monthly Energy Review* August 2002, DOE/EIA-0035(2002/08) (Washington, DC, August 2002), Table 1.9.
[51] Energy Information Administration, *Short-Term Energy Outlook*, (Washington, DC, December 2001 and October 2002), Table 1.
[52] Energy Information Administration, *Performance Profiles of Major Energy Producers 2000*, DOE/EIA-0206(2000) (Washington, DC, January 2002), Table 16. Web address: http://www.eia.doe.gov/emeu/perfpro/table16.html (as of October 29, 2002).
[53] For example, Exxon Mobil (*2001 Annual Report*, p. 18) and Phillips (press release, June 20, 2001).
[54] Energy Information Administration, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 29, 2002), Table 5.19. Web address: http://www.eia.doe.gov/emeu/aer/petro.html (as of October 30, 2002).
[55] Based on the implicit GDP deflator, inflation during 2001 was 2.4 percent. See U.S. Department of Commerce, Bureau of Economic Analysis, http://www.bea.doc.gov/bea/dn/gdplev.xls (as of November 5, 2002).
[56] Energy Information Administration, *Monthly Energy Review August 2002*, DOE/EIA-0035(2002/08) (Washington, DC, August 2002), Table 9.11.
[57] See Energy Information Administration, *Performance Profiles of Major Energy Producers 1999*, DOE/EIA-0206(99) (Washington, DC, January 2001), p. 39 (Web address: http://www.eia.doe.gov/).
[58] Phillips Petroleum, "Phillips Petroleum to Acquire Coastal's Midcontinent Gasoline Marketing Assets" (December 12, 2000).
[59] Amerada Hess, press release (January 29, 2001), and *2001 Annual Report*, p. 22 and "Amerada Hess to Explore Joint Venture with North Carolina Retail Marketer," press release (October 10, 2000).
[60] BP America, El Paso (Coastal-branded outlets), Exxon Mobil, Marathon, Phillips/Tosco, Williams Companies (Mapco-branded) contributed almost all of the divested outlets.
[61] Energy Information Administration, *Performance Profiles of Major Energy Producers 1997*, DOE/EIA-0206(97) (Washington, DC, January 1999), page 44. Web address: http://tonto.eia.doe.gov/FTPROOT/financial/020697.pdf (as of October 31, 2002).
[62]The Caltex joint venture was an unconsolidated affiliate for both of its parents, Chevron and Texaco.
[63]ChevronTexaco Corporation, *Statistical Supplement to the 2001 Annual Report*, p. 42; and "Caltex Group of Companies Combined Financial Statements," p. 4 in Texaco, Inc., 2000 Securities and Exchange Commission Form 10K.
[64] What is at issue is that all but one of the Caltex refineries were unconsolidated (i.e., only partially owned by Caltex), so only the ownership of this single refinery became consolidated into the parent ChevronTexaco, along with residual shares of the other Caltex refineries that Caltex partially owned.

[65]Phillips Petroleum Company, *2000 Annual Report* , p. 45.
[66]See, Tosco Corporation, *2000 Annual Report,* p. 9; and "Tosco to Pay $100 Million for Irish State Oil Refinery," *Financial Times* (May 28, 2001).
[67]Conoco, Inc., *2001 Annual Report*, p. 16.
[68]ChevronTexaco Corporation, *2001 Annual Report*, p. 31.
[69]Exxon Mobil Corporation, *Statistical Supplement to the 2001 Annual Report,* p. 65. This marked the fourth-consecutive year that Exxon Mobil Corporation complained of low Asia-Pacific margins.
[70]Conoco increased its ownership of the Melaka refinery in Malaysia, see Conoco Inc., press release (February 27, 2001).
[71]Exxon Mobil Corporation, *2001 Annual Report*, p. 18.
[72] These refining margins are included to indicate relative, not absolute, changes. These margins represent markets in which the FRS companies operate, but are not margins of the FRS companies.
[73]Exxon Mobil Corporation, *Statistical Supplement to the 2001 Annual Report*, p. 65.
[74]Texaco Inc., *2000 Annual Report*, p. 29.
[75]ChevronTexaco Corporation, *2001 Annual Report*, pp. 31 and 35.
[76]Conoco, Inc., *2001 Annual Report*, p. 17.
[77]Conoco, Inc., press release (December 4, 2001).
[78]Exxon Mobil Corporation, *2001 Annual Report*, p. 18.
[79]Exxon Mobil Corporation, *2001 Annual Report*, p. 19.
[80]ChevronTexaco Corporation, *Statistical Supplement to the 2001 Annual Report*, p. 43.
[81]ChevronTexaco Corporation, *Statistical Supplement to the 2001 Annual Report*, p. 46.
[82]Exxon Mobil Corporation, *2001 Annual Report*, p. 20.
[83]A co-branded outlet is a motor gasoline retail outlet that displays two brandnames, one is a motor gasoline brandname, and the other is a brandname in another industry, often the fast food industry in the United States. Outside the United States the other industry often is the grocery industry. In this particular instance the co-branded outlets are effectively grocery stores with a motor gasoline outlet located somewhere on the same property. Additional discussion of co-branded, or multi-format outlets can be found in Energy Information Administration, *Performance Profiles of Major Energy Producers 1996*, DOE/EIA-0206(96) (Washington, DC, January 1998), p. 51 (web address: http://tonto.eia.doe.gov/FTPROOT/financial/020696.pdf) and *Performance Profiles of Major Energy Producers 1995*, DOE/EIA-0206(95) (Washington, DC, January 1997), p. 44 (web address: http://tonto.eia.doe.gov/FTPROOT/financial/020695.pdf).
[84]Exxon Mobil Corporation, *2001 Annual Report,* p. 19.
[85]The Williams Companies, Inc. 2001 Securities and Exchange Commission Form 10-K, pp. 29-30.
[86]Shell Oil Company, *2001 Financial Review*, p. 9.
[87]ChevronTexaco Corporation, *2001 Supplement to the Annual Report*, p.4.
[88]El Paso Corporation, 2001 Securities and Exchange Commission Form 10-K, pp. 36, 117.
[89]ChevronTexaco Corporation, 2001 Securities and Exchange Commission Form 10-K, p. FS-32.
[90] Exxon Mobil Corporation, *2001 Financial and Operating Review*, p.36.
[91] Exxon Mobil Corporation, *2001 Financial and Operating Review*, p.37.
[92] Unocal Corporation, 2001 Securities and Exchange Commission Form 10-K, p.18.
[93] Unocal Corporation, 2001 Securities and Exchange Commission Form 10-K, p.20.
[94] Unocal Corporation, 2001 Securities and Exchange Commission Form 10-K, pp. 34, 39.

4. Resource Development Trends and Emerging Issues

Resource Development Costs and Potential

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

- Variations in regional finding costs
- The impact of mergers and acquisitions on U.S. oil and gas producers
- Increased investment in natural gas
- The status of private investment in Venezuela
- FRS companies in China and Russia
- FRS companies' involvement in Canadian tar sands projects

SPECIAL TOPIC: Reasons for Finding Costs Changes Vary in 2001

Regional Finding Costs Differ in Magnitude and Direction

The FRS companies had large changes in finding costs in each region of the world for the three years ending in 2001 (Table 19). However, these changes ended up largely offsetting each other, resulting in worldwide finding costs remaining essentially unchanged. Finding costs are the costs of adding oil (crude oil and natural gas liquids) and gas (dry natural gas) proven reserves via exploration and development activities.[a] They are measured for oil and gas on a combined basis in units of dollars per barrel of oil equivalent (BOE). Conceptually, finding costs are all the costs incurred (no matter when these costs were incurred or actually recognized on a company's books) in finding any particular proven reserves (not including the purchases of already discovered reserves). In practice, finding costs are actually measured as the ratio of exploration and development expenditures (except the expenditures on proved acreage) to proven reserve additions (excluding net purchases of proven reserves) over a specified period of time.[b] Finding costs are generally measured in *Performance Profiles* as a weighted average over a period of three years (to accommodate leads and lags in data reporting), and, if several years of data are presented, they are usually reported in constant dollars (to facilitate comparisons over time).

The regions with the largest changes in finding costs were Canada and the Other Western Hemisphere (increases) and the Other Eastern Hemisphere and the Former Soviet Union and Eastern Europe (decreases) (Table 19). Canada saw the largest absolute and relative increase in finding costs for the three years ending in 2001. Exploration and development expenditures were up 70 percent, led by expenditures for the acquisition of unproved acreage by the FRS companies which soared 250 percent. However, reserve additions through the drill bit increased only 9 percent above their corresponding amount for the previous three years. The increase in expenditures for unproved acreage is in large part due to several mergers, particularly Conoco's purchase of Gulf Canada, Devon Energy's acquisition of Anderson Exploration, Burlington Resources' acquisition of Canadian Hunter Exploration, and Anadarko Petroleum's purchase of Berkley Petroleum. All of these mergers added substantial Canadian unproved acreage to the acquiring company. Conoco is now the fifth-largest oil and gas producer in Canada, while Devon's purchase included 1.5 million net acres in one of Canada's most prospective exploratory region, the far north.[c] Burlington added a portfolio of attractive acreage and exploration and exploitation potential to its holdings, while Anadarko increased its Canadian reserves acreage position from three million to nearly five million net acres.[d] Exxon Mobil (including both companies in previous years) was the largest contributor to drill-bit reserve growth in Canada. The company reports higher spending on major projects in Canada and an increase in the number of net exploration and development wells drilled there from 274 to 509 between 2000 and 2001.[e]

Table 19. Finding Costs by Region for FRS Companies, 1998-2000 and 1999-2001
(Dollars per Barrel of Oil Equivalent)

Region	1998-2000	1999-2001	Percent Change
United States			
Onshore	4.90	6.01	22.8
Offshore	9.99	6.99	-30.1
Total United States	6.47	6.39	-1.3
Foreign			
Canada	6.84	10.70	56.5
OECD Europe	7.43	5.51	-25.9
Former Soviet Union and Eastern Europe	7.01	3.26	-53.5
Africa	2.78	3.68	32.3
Middle East	5.61	7.66	36.7
Other Eastern Hemisphere	7.49	4.07	-45.7
Other Western Hemisphere	4.37	6.22	42.5
Total Foreign	5.26	5.25	-0.1
Worldwide	5.81	5.78	-0.6

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).

The Other Western Hemisphere (largely South America) also saw a large proportional increase in finding costs for the three years ending in 2001. In this case, the primary cause was a large decline in total reserves found by the drill bit. In fact, in 2001, some FRS companies had large negative revisions of previous reserves estimates while others had much smaller additions to reserves.

The Former Soviet Union and Eastern Europe had the largest absolute and relative decrease in finding costs for the 1999 to 2001 period. Two developments pushed down the finding costs in this region, a notable increase in the quantity of reserves added through the drill bit and a large decline in expenditures for unproven acreage. BP[f] and Unocal both have substantial exploration and development activities in Azerbaijan, located on the Caspian Sea. BP is the operator and holds major interests in the Azeri-Chirag-Gunashli oil fields and the Shah Deniz natural gas field.[g] Unocal has a 10-percent working interest in the Azeri-Chirag-Gunashli fields.[h] The decline in expenditures for unproven acreage was to a large extent the result of the exclusion of Phillips Petroleum's (now part of Conoco Phillips) significant acquisition expenditures for leases and interests in Kazakhstan, also on the Caspian, in 1998 which are not included in the 1991 – 2001 finding costs.[i]

The Other Eastern Hemisphere also had a large decline in finding costs for the 1999 to 2001 period, even with a notable increase in development expenditures, because reserves added through the drill bit more than doubled. ChevronTexaco has development projects underway in Indonesia, Papua New Guinea, the Philippines, and China.[j] In addition to ChevronTexaco, several FRS companies had substantial operations for the three years ending in 2001 in the Other Eastern Hemisphere, including Unocal, Conoco, and Shell Oil.

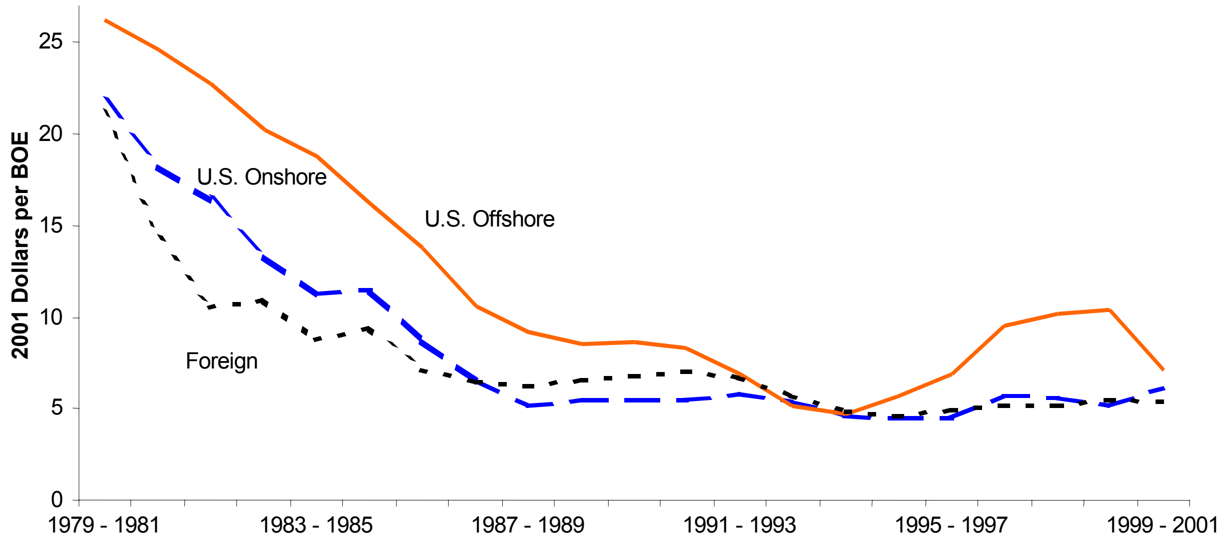
Offshore Finding Costs Run Counter to Recent Trend

Until 2001, finding costs in the U.S. Offshore (largely Gulf of Mexico) region had been rising steadily in recent years (Figure 26). They were the highest of any FRS region for the three years ending in 2000 (Table 19). However, offshore finding costs for the three years ending in 2001 erased more than half of the increase from the preceding five-year rise and brought offshore finding costs closer to their long-term trend. A combination of a substantial increase in reserve additions through the drill bit and, to a lesser extent, a fall in expenditures for unproved acreage were the driving forces behind this decline. BP is the largest leaseholder in the Gulf and has interests in nine of the ten largest developments there.[k] In addition to a discovery at Blind Faith, BP booked 30 million barrels of oil equivalent gross reserves in two major prospects, the Pompano Subsalt and MC29. Some of BP's other projects, such as the Nile, King, and King West subsea developments and the Troika and Mars fields, also have exploration and development activities ongoing. Expenditures for unproved acreage declined largely because Sonat's (merged into El Paso Energy in 1999) purchase of Zilkha Energy in 1998 was dropped from the 1991 - 2001 calculation.

While foreign finding costs remained essentially flat, U.S. onshore finding costs rose 23 percent for the three years ending in 2001 (Table 19). This increase was largely brought about by a swell in development spending in the 1999 to 2001 period. In Alaska, BP is carrying out extensive development programs, especially at Prudhoe Bay and its satellite fields, to mitigate natural production declines.[l] BP is conducting development drilling at the Borealis and Northwest Eileen fields in Alaska, where 19 new wells were drilled in 2001. The company is also pursuing development projects in the lower-48 States. A highlight of BP's development spending there is a drilling program in the Overthrust Belt and Greater Green River Basin areas of Southern Wyoming, which broke several company drilling records in 2001. In addition, Phillips Petroleum acquired Atlantic Richfield's Alaskan oil and gas assets in 2000, and, like BP, is conducting extensive development programs in Alaska, including satellite and infield development at Prudhoe Bay in the Kuparak area.[m]

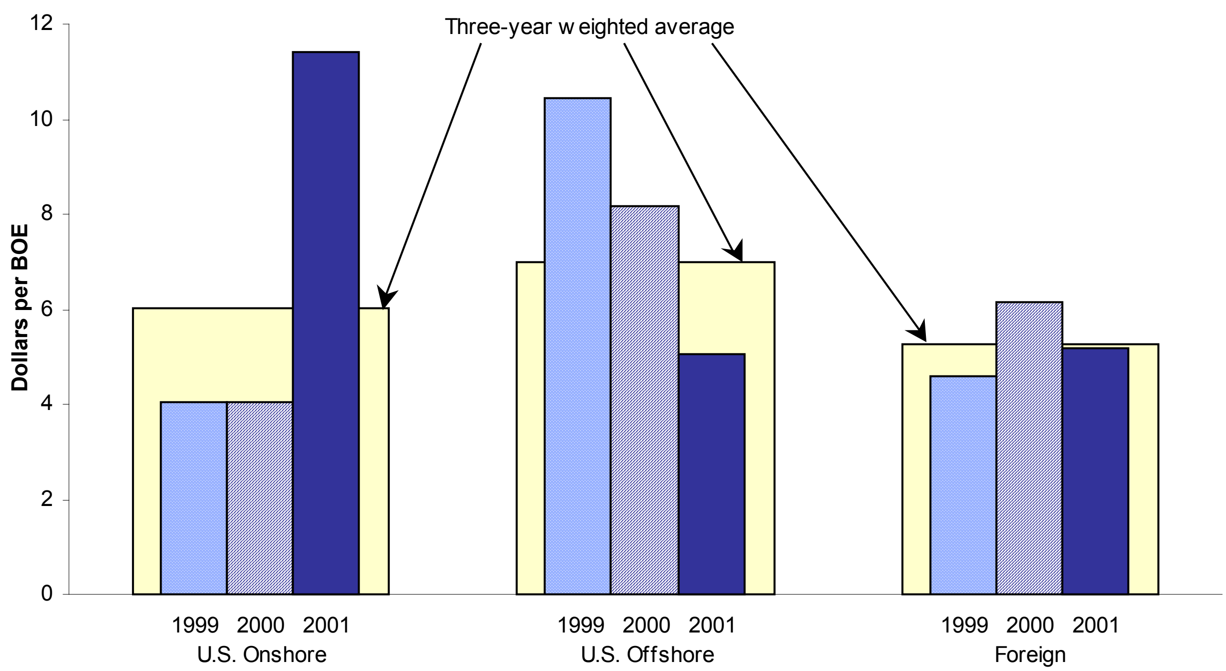
One-year finding costs can provide additional information on near-term changes in three-year finding costs. Although one-year finding costs vary more than three-year costs, they can also pick up trends sooner than three-year costs. In 1998, one-year finding costs in the U.S. Offshore region surged to their highest level since the 1980's but have been declining since then, prefacing the decline in three-year costs for the 1999 to 2001 period (Figure 27). One-year finding costs for the U.S. Onshore region reached their highest level since the 1980's in 2001, leading to a sharp increase in three-year costs. Foreign one-year finding costs have been relatively stable in recent years.

Figure 26. U.S. Onshore, U.S. Offshore, and Foreign Three-Year Weighted Average Finding Costs for FRS Companies, 1979-1981 to 1999-2001



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. Values tend to be associated with the middle year of the 3-year average and plotted to reflect that. That is, the 1979 to 1981 average is plotted as though it is a value for 1980.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Figure 27. Finding Costs for FRS Companies, Annual and Three-Year Weighted Average, 1999-2001



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

[a]Alternatively, finding costs are the exploration and development costs of replacing reserves removed through production.
[b]One inherent limitation of measuring finding costs this way is that the expenditures and the reserve additions recognized in a particular interval do not usually correspond exactly with each other. Expenditures are usually recognized in the period that that the payment actually occurred. Proven reserves are usually recognized when there is reasonable certainty that they can be produced economically. There is no reason that these must occur in the same time period (oil and gas wells are often operated for a long time), so that some expenditures may not be recognized in the same time period that their corresponding reserves are recognized. One way to moderate this limitation is to increase the length of the time period over which finding costs are measured, allowing reserve additions and exploration and development expenditures to match up more closely. However, the longer the time period over which finding costs are measured, the more out of date they become, because they include older and older expenditures and reserves, and costs and technology are constantly changing. The only way to solve the correspondence problem would be to calculate an average finding cost for all of the oil and gas produced by a well after it is permanently shut in. But then many costs included would be far out of date.
[c]Conoco Inc., 2001 Report to the U.S. Securities and Exchange Commission on Form 10-K, p. 6, and Devon Energy, 2001 Report to the U.S. Securities and Exchange Commission on Form 10-K, p. 23.
[d]Burlington Resources, 2001 Report to the U.S. Securities and Exchange Commission on Form 10-K, p. 1, and Anadarko Petroleum, 2001 Report to the U.S. Securities and Exchange Commission on Form 10-K, p. 14.
[e]Exxon Mobil Corporation, 2001 Report to the U.S. Securities and Exchange Commission on Form 10-K, pp. 10 and 28, and 2000 Report to the U.S. Securities and Exchange Commission on Form 10-K, p. 10
[f]BP America, the U.S. subsidiary of BP plc of the United Kingdom, is the FRS respondent.
[g]BP plc, 2001 Report to the U.S. Securities and Exchange Commission on Form 20-F, pp. 32-33.
[h]Unocal Corporation, 2001 Report to the U.S. Securities and Exchange Commission on Form 10-K, p. 15.
[i]Phillips Petroleum Company, *1998 Annual Report*, http://www.phillips66.com/annual98/1exploration.htm, November 3, 2002.
[j]ChevronTexaco Corporation, *2001 Supplement to the Annual Report*, pp. 22-26.
[k]BP plc, 2001 Report to the U.S. Securities and Exchange Commission on Form 20-F, pp. 19 and 27.
[l]BP plc, 2001 Report to the U.S. Securities and Exchange Commission on Form 20-F, pp. 27-29.
[m]Phillips Petroleum Company, *2001 Annual Report*, p. 11.

SPECIAL TOPIC: U.S. Oil and Gas Producers -- Mergers and Acquisitions Create Turnover, But Concentration Not Altered

Half of the companies constituting the top-20 oil and top-20 natural gas producers in the United States in 1992 merged or were acquired by the end of 2001.[a] These deals freed up slots on the top-20 lists for the entrance of several new companies. However, even after all of these mergers and acquisitions, the concentration of the industry changed little over the period, with the top-20 companies continuing to produce about half of the total output of oil and gas in the United States.

The top-three producers of oil and of natural gas in the United States, BP (BP America), ChevronTexaco, and Exxon Mobil, have all been involved in major mergers in the past few years, with British Petroleum and BP Amoco (BP's[b] predecessors) acquiring Amoco and Atlantic Richfield, respectively, and the mergers of Chevron with Texaco and Exxon with Mobil. These combinations involved six of the top-seven 1992 producers of oil and of natural gas in 1992 (Tables 20 and 21). Other major combinations among members of the 1992 group were Anadarko Petroleum's acquisition of Union Pacific Resources, Kerr-McGee's acquisition of Oryx Energy, and Devon Energy's purchase of PennzEnergy (earlier spun off from Pennzoil) and Santa Fe Snyder Energy Resources (the outcome of an earlier merger between Santa Fe Energy Resources and Snyder Oil).[c]

Table 20. U.S. Oil Production of 20 Largest Producers, 1992 and 2001
(Million Barrels)

1992			2001		
Company	Production	Percent of U.S. Total	Company	Production	Percent of U.S. Total
British Petroleum	251.8	7.8	BP	243.0	8.7
Atlantic Richfield	242.0	7.5	ChevronTexaco	224.0	8.0
Exxon	216.0	6.7	Exxon Mobil	210.0	7.5
Royal/Dutch Shell	163.0	5.1	Phillips Petroleum	154.0	5.5
Chevron	158.0	4.9	Royal/Dutch Shell	108.0	3.9
Texaco	158.0	4.9	Occidental Petroleum	78.0	2.8
Mobil	114.0	3.5	Anadarko Petroleum	48.0	1.7
Amoco	107.0	3.3	Marathon Oil	46.0	1.6
Phillips Petroleum	50.0	1.6	Devon Energy	32.0	1.1
Unocal	47.0	1.5	Unocal	29.0	1.0
USX-Marathon	42.0	1.3	Burlington Resources	28.7	1.0
Conoco	41.0	1.3	Kerr-McGee	28.0	1.0
Union Pacific Resources	31.8	1.0	Amerada Hess	28.0	1.0
Oryx Energy	30.0	0.9	Conoco	27.0	1.0
Amerada Hess	27.0	0.8	Apache	24.2	0.9
Occidental Petroleum	22.0	0.7	Mitchell Energy & Development	21.8	0.8
Santa Fe Energy Resources	21.4	0.7	Pioneer Natural Resources	15.9	0.6
Mitchell Energy & Development	19.2	0.6	Nuevo Energy	14.5	0.5
Burlington Resources	15.4	0.5	El Paso	13.8	0.5
Pennzoil	15.0	0.5	Ocean Energy	10.2	0.4
Top-20 Total	1,771.6	55.0	**Top-20 Total**	1,384.1	49.3
U.S. Total	3,219.0	100.0	**U.S. Total**	2,805.0	100.0

Concentration Measures

Herfindahl-Hirschman Index (20 firm)	**272**	**Herfindahl-Hirschman Index (20 firm)**	**262**
Concentration Ratio (4 firm)	**27**	**Concentration Ratio (4 firm)**	**30**
Concentration Ratio (8 firm)	**44**	**Concentration Ratio (8 firm)**	**40**
Concentration Ratio (20 firm)	**55**	**Concentration Ratio (20 firm)**	**49**

Sources: *Oil&Gas Journal,* September 20, 1993 and October 1, 2001, BP and Royal/Dutch Shell, 2001 Reports to the Securities and Exchange Commission on Form 20-F, Occidental Petroleum, 2001 Report to the Securities and Exchange Commission on Form 10-K, Energy Information Administration, "Advance Summary U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 2001 Annual Report," DOE/EIA-0216(2001)Advance Summary, September 2002, Table 1.

Other transactions and corporate restructurings resulted in several newcomers to the top-20 lists. El Paso, which was initially spun off from Burlington Resources as a natural gas transmission company, acquired two natural gas producers, Sonat and then Coastal, on its way to becoming the sixth largest natural gas producer in the United States. Pioneer Natural Resources arose from a merger between Parker & Parsley Petroleum and MESA, and Ocean Energy merged with Seagull Energy and United Meridian to join the top-20 group. In addition, Dominion Resources, formerly an electric and gas utility, purchased Consolidated Natural Gas to solidify its entry in natural gas exploration and production.[d] Nuevo Energy made a large purchase of oil and gas reserves in California and Apache made numerous smaller purchases of reserves to boost them into the top-20 producers. Two companies that were restructured also made the 2001 lists. EOG Resources was spun off from Enron and USX separated its two divisions, Marathon and United States Steel, and re-established them as independent companies.

Table 21. U.S. Natural Gas Production of 20 Largest Producers, 1992 and 2001
(Billion Cubic Feet)

1992			2001		
Company	**Production**	**Percent of U.S. Total**	**Company**	**Production**	**Percent of U.S. Total**
Chevron	847	4.9	BP	1,358	6.9
Amoco	845	4.8	Exxon Mobil	1,114	5.6
Texaco	672	3.9	ChevronTexaco	988	5.0
Exxon	649	3.7	Royal/Dutch Shell	581	2.9
Mobil	600	3.4	Anadarko Petroleum	573	2.9
Royal/Dutch Shell	532	3.1	El Paso	552	2.8
Atlantic Richfield	440	2.5	Burlington Resources	409	2.1
Unocal	359	2.1	Phillips Petroleum	402	2.0
Phillips Petroleum	350	2.0	Devon Energy	376	1.9
Burlington Resources	300	1.7	Unocal	371	1.9
Conoco	279	1.6	Conoco	291	1.5
Occidental Petroleum	226	1.3	Marathon Oil	289	1.5
USX-Marathon	224	1.3	EOG Resources	252	1.3
Amerada Hess	220	1.3	Dominion Resources	230	1.2
Oryx Energy	214	1.2	Apache	225	1.1
Union Pacific Resources	211	1.2	Occidental Petroleum	223	1.1
Enron	200	1.1	Kerr-McGee	195	1.0
Pennzoil	161	0.9	Amerada Hess	155	0.8
Anadarko Petroleum	144	0.8	XTO Energy	152	0.8
Consolidated Natural Gas	128	0.7	Ocean Energy	152	0.8
Top-20 Total	7,600.5	43.6	**Top-20 Total**	8,888	44.9
U.S. Total	17,423	100.0	**U.S. Total**	19,779	100.0

Concentration Measures

Herfindahl-Hirschman Index (20 firm)	**129**	**Herfindahl-Hirschman Index (20 firm)**	**157**
Concentration Ratio (4 firm)	**17**	**Concentration Ratio (4 firm)**	**20**
Concentration Ratio (8 firm)	**28**	**Concentration Ratio (8 firm)**	**30**
Concentration Ratio (20 firm)	**44**	**Concentration Ratio (20 firm)**	**45**

Sources: *Oil&Gas Journal,* September 20, 1993 and October 1, 2001, BP and Royal/Dutch Shell, 2001 Reports to the Securities and Exchange Commission on Form 20-F, Occidental Petroleum, 2001 Report to the Securities and Exchange Commission on Form 10-K, Energy Information Administration, "Advance Summary U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 2001 Annual Report," DOE/EIA-0216(2001)Advance Summary, September 2002.

Despite all of these mergers and acquisitions, concentration in U.S. oil production and natural gas production changed little between 1992 and 2001 (Tables 20 and 21). Both industries remained unconcentrated, and overall concentration in oil production actually declined slightly, with the Herfindahl-Hirschman Index falling from 272 in 1992 to 262 in 2001.[e] The production of oil and of natural gas did become more concentrated at the top, with the 4-firm concentration ratios for both groups increasing 3 percentage points. In contrast, the 8-firm and 20-firm concentration ratios fell for oil, and, while all concentration ratios were slightly higher for natural gas production in 2001, the 8-firm and 20-firm ratios exceeded the 4-firm ratio less than in 1992, indicating less concentration in natural gas production as well below the top companies.[f]

The companies that were on the top-20 list of producers in 2001 can be divided into two groups, survivors and entrants. Survivors are companies that were on the top-20 list in 1992 or are composed of companies that were on the list. Entrants are companies that were not in the top-20 list in 1992, although they may have acquired or merged with companies that were on the list in the earlier year. When the companies are divided into these two groups, contrasts between them become apparent. For both oil production and natural gas, entrants more than replaced their production during 1992 through 2001 with reserves added through the drill bit, while survivors did not (Table 22).[g] However, the groups are not consistent in the manner in which they added reserves through the drill bit. Entrants use improved recovery techniques for a higher proportion of their natural gas reserves additions than survivors, while survivors use improved recovery for a higher proportion of their oil reserves additions through the drill bit.

Table 22. Top-20 Producers' Reserve Additions Through Exploration and Development, 1992-2001
(Percent)

	Survivors			Entrants		
	Oil	Natural Gas	Total	Oil	Natural Gas	Total
Extensions and Discoveries	59	86	72	68	76	73
Improved Recovery Techniques	25	2	14	9	17	14
Revisions to Estimates	15	12	14	24	7	13
Total	100	100	100	100	100	100
Production Replacement Rate (Excluding Purchases and Sales)	94	88	91	142	101	112

Note: Sum of components may not add to total due to independent rounding.
Source: Derived from data provided by John S. Herold, Inc.

[a]Two mergers since the end of 2001 have further altered the lists for 2002. Devon Energy acquired Mitchell Energy & Development and Conoco and Phillips Petroleum merged.
[b]BP America, the U.S. subsidiary of BP plc of the United Kingdom, is the FRS respondent.
c[b]Other notable mergers in which one of the top-20 companies was involved included Kerr-McGee's acquisition of HS Resources, Burlington Resources' purchase of Louisiana Land & Exploration, Occidental Petroleum's acquisition of Altura Energy, and Unocal's purchase of Titan Exploration.
[d]Dominion Resources also purchased Louis Dreyfus Natural Gas in 2001.
[e]For a brief introduction to concentration measures, see "Top Oil Corporations Nearly Double Share of World Oil Production" in Chapter 3.
[f]In oil production, concentration in 2001 compared to 1992 began to decrease with the fifth company on the list, in natural gas, where concentration overall increased slightly, it nonetheless was less beginning with the fourth company on the list.
[g]These results are based on calculations using reserves and production data provided by John S. Herold, Inc.

SPECIAL TOPIC: Upstream Investment Focuses on Natural Gas, Large Projects

In the U.S. oil and gas industry of just a few decades ago, the basic strategy for growth was to find good acreage in the United States on which to drill for oil. Natural gas was widely viewed as less profitable than oil and, because of nationalizations and wars in the Middle East, drilling overseas was widely viewed as overly risky given international politics. Since then, almost everything has changed.

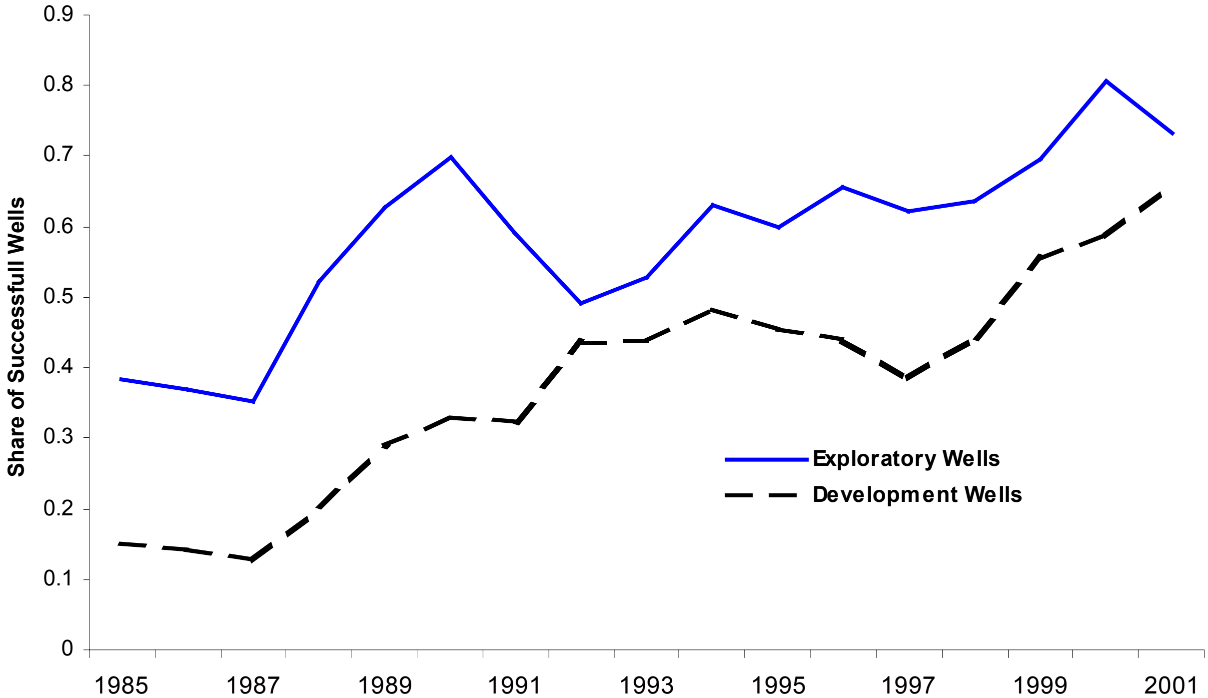
Over the period 1990 to 2001, worldwide demand for natural gas increased by 22 percent while oil demand grew a more modest 14 percent.[a] In addition, the Energy Information Administration produced evidence that suggests that the profit margins for gas were higher than for oil throughout most of the 1980's and 1990's.[b] This combination of higher unit profits and growing demand has led to an increased focus on natural gas as a means to achieve upstream profitability and growth. This change is evident in the natural gas well share of worldwide well completions by the FRS companies, which has been increasing since the mid-1980's (Figure 28).

In addition to an increased emphasis in natural gas, the FRS companies have shifted their operations overseas in search of new oil and gas reserves. One reason for this is that oil and gas historically tend to be cheaper to find overseas than in the United States (Figure 26). This can be seen in the substantially increased share of the FRS companies' exploration and development expenditures accounted for by activities outside the United States during the 1980's and into the early 1990's. In the 1990's, U.S. and overall foreign finding costs have roughly converged, resulting in a 50-50 split of exploration and development expenditures between the United States and overseas in recent years (Figure 29).

In addition, there is increasing recognition that, as with financial portfolios, there tends to be an inherent tradeoff between the expected returns of oil and gas projects and their riskiness.[c] While projects such as deepwater Gulf of Mexico oil and gas, liquefied natural gas (LNG) in Indonesia, oil in West Africa, and oil and gas in the Caspian may have considerably higher expected returns than conventional oil and gas in the lower 48 States, they also have substantially more risk. Firms can therefore be expected to seek to assemble a portfolio of projects, some of which are individually quite risky, but taken as a group have much less risk. This can maximize long-run shareholder value while keeping the portfolio's overall level of risk within acceptable limits.

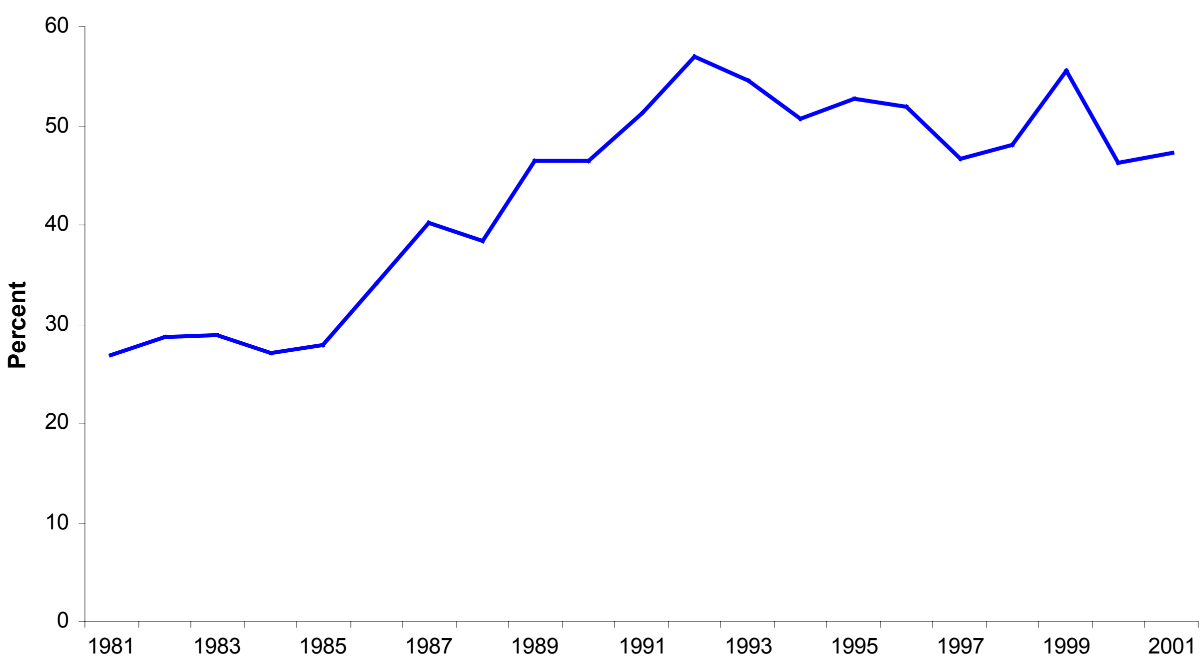
Effective application of this portfolio approach to upstream investments requires that a firm have a sufficiently large number of diverse projects in its portfolio. Over the next decade much of the growth in the world's energy supply likely will come from a relatively small number of large projects in a number of different countries. Natural gas projects under consideration include operations in Trinidad, Algeria, Australia, and the deepwater Gulf of Mexico. Potential oil projects are located in Canada (oil sands), the offshore of West Africa, the Caspian Sea region, and Russia. The common denominator across these projects is their massive scale. For instance, a deepwater prospect in the Gulf of Mexico or in the offshore of West Africa can easily cost a billion dollars, substantially more than a typical project of a decade ago.

Figure 28. The Natural Gas Share of FRS Successful Exploratory and Developmental Oil and Gas Well Completions, 1985-2001.



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

Figure 29. Foreign Expenditures Share of Worldwide Exploration and Development Expenditures by FRS Companies, 1981-2001



Note: Excludes expenditures on proved acreage.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Following are examples of projects that are being considered by the FRS companies.

Advanced Technology in the Deepwater: One firm that has embraced the advanced technology strategy is BP[d], which recently announced that it plans to invest $15 billion by 2010 in the Gulf of Mexico to develop six large fields, including the requisite undersea pipeline system. The fields to be developed include Thunder Horse, which is estimated to contain over one billion barrels of oil equivalent (boe), making it the largest find to date in the region. While BP's current daily production of 340,000 boe makes it the second largest producer in the Gulf, the company is hopeful that its investment program will allow it to double production there by 2007.[e] The risks posed by this strategy include the substantial challenges of deploying deepwater exploration, development, and production technologies without endangering either the environment or the bottom line.

Nonconventional Gas: Environmental concerns are expected to substantially increase the future demand for natural gas. However, there is some question whether this projected demand increase can be sustained by conventional natural gas supply at current prices. This has led producers to reconsider the role of nonconventional gas in their exploration and development portfolios. Drilling for nonconventional gas such as coalbed methane before 1993 was motivated largely by production tax credits that were in excess of 50 percent of the market price.[f] With the expiration of the credits for new wells, drilling for coalbed methane is no longer subsidized. Because of the relative maturity of the conventional onshore resource base, the technological advances in nonconventional gas production over the last decade, and the experience gained when the credits were in effect, nonconventional gas drilling in 2000, that latest year for which data are available, was 21 percent higher than in 1992, the last year that newly drilled nonconventional wells were eligible for the tax credit.[g]

Nonconventional Oil: While there is some controversy about how much conventional oil remains to be discovered and produced, there is little question that the world is endowed with hundreds of billions of barrels of unexploited heavy crude oils such as the bitumen deposits in Canada and Venezuela's Orinoco Belt. The accepted wisdom has long been that these crudes were too expensive to produce at current prices. Technological advances, especially those in horizontal drilling, have substantially altered this state of affairs (also see Special Topic: "Canada's Oil Sands – Confounding the Doomsday Predictions?"). In Venezuela there are four projects in various stages of development. The projects currently produce about 450,000 barrels per day (b/d) of synthetic crude oil, which is expected to increase to 600,000 b/d by 2006. The FRS companies involved in these projects include Conoco and Phillips (now Conoco Phillips), Exxon Mobil, and ChevronTexaco. In Canada, Shell Canada, a unit of Royal/Dutch Shell, and ChevronTexaco are investing in projects that will contribute to a nearly tripling of production by 2010. Since each barrel of nonconventional oil production entails 5 to 7 times the carbon emissions of conventional light oil production, these projects carry with them the risk that they may prove unprofitable should carbon emissions be limited.[h]

Liquefied Natural Gas (LNG): While the world contains vast untapped resources of natural gas, a significant portion is located in remote areas. Given the anticipated large growth in natural gas demand, firms are increasingly implementing a strategy of satisfying this demand by developing remote fields and transporting the gas to market as LNG. For example, the FRS company ChevronTexaco, along with Royal/Dutch Shell, is a partner in a project in the Tangguh field in Indonesia, owned by BP. The project is scheduled to ship its first LNG by 2005 to 2006. In Australia, a consortium of companies known as the North West Shelf Venture was recently awarded a contract to supply China's soon to be constructed Guangdong LNG terminal, China's first LNG import project. Under the deal, the Venture will supply the equivalent of approximately 118 billion cubic feet of natural gas per year in the form of LNG over a 25-year period.[i] Other companies involved include Woodside Energy, BHP Billiton, and Japan

Australia LNG. Each firm currently has a one-sixth share but this will change with the expected inclusion of China National Offshore Oil (CNOOC) in the venture.

Another example of remote natural gas reserves occurs in the Artic regions of Alaska and Canada. Almost 42 trillion cubic feet of natural gas were discovered and booked as proved reserves over 20 years ago in the North Slope of Alaska and the McKenzie Delta in Canada's Northwest Territories. Because of a lack of a market for the natural gas, it has largely been unexploited. Given that the gas resides in known reservoirs, many of which, at least on the North Slope, are already producing oil, there is little geologic risk associated with the development of the gas. However, there are huge financial risks involved: the construction of a pipeline is projected to cost up to $20 billion. While the financial risks of constructing the pipeline are large, so too are the potential rewards. At the current market price, the gas would yield revenues of approximately four billion dollars per year if delivered to the lower 48 States. Companies included in the proposed project include the FRS companies BP, Exxon Mobil, and Conoco Phillips.

Special Situations: The opening up of countries that were previously closed to exploration and development by multinational firms such as the FRS companies has given rise to several unique opportunities. Among these opportunities include Russia's Sakhalin Island, off Russia's eastern coast. Over the next four years, two groups of companies, one headed by Royal/Dutch Shell and the other by Exxon Mobil, will invest $13 billion in Sakhalin projects.[j] In terms of geological risks, the investment is a prudent one given that the island's offshore shelf is believed to contain oil and gas resources that could rival those of the North Sea. By 2006, the two current major projects, Sakhalin I and II are expected to produce 420,000 boe per day of oil and gas. The oil from the projects will either be transported to the Russian mainland or exported by tanker. The gas from the project will either be transported to Japan by pipeline or exported as LNG.

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[a]BP plc, *BP Statistical Review of World Energy* (June 2002).
[b]Energy Information Administration, "The Majors' Shift to Natural Gas" (September 2001), http://www.eia.doe.gov/emeu/finance/sptopics/majors/index.html.
[c]Wood, David, "Portfolio Optimization Benefits from Integrating Analysis of Risk, Strategy, and Valuation," *Oil & Gas Journal*, Volume 100.27 (July 8, 2002), p. 26.
[d]BP America, the U.S. subsidiary of BP plc of the United Kingdom, is the FRS respondent.
[e]"This Oil's Domestic, but It's Deep and Its Risky," *New York Times* (August 11, 2002), p. 1.
[f]Energy Information Administration, "The Majors' Shift to Natural Gas" (September 2001), http://www.eia.doe.gov/emeu/finance/sptopics/majors/index.html.
[g] Special compilation by the Energy Information Administration, Office of Integrated Analysis and Forecasting.
[h]Natural Resources Canada, "Canada's Emission Outlook: An Update" (April 5, 2001). Web site: http://climatechange.nrcan.gc.ca/english/Publications.asp?x=3 (as of November 10, 2002).
[i]"NWS to supply Guangdong LNG, partner with CNOOC," *Oil & Gas Journal* (August 19, 2002), p. 9.
[j] "For Big Oil, Open Door In Far East Of Russia," *New York Times* (August 6, 2002), p. W1.

SPECIAL TOPIC: Venezuela -- Half Open or Half Closed to Private E&D Investment?

In the mid–1970's, the Venezuelan government nationalized the petroleum properties of the FRS and other multinational oil companies with operations in Venezuela. Over the next decade and a half, especially after the oil price collapse of 1986, oil production in Venezuela largely languished as a result of under investment and lack of access to new technologies. However, policymakers began to rethink their policy of state ownership of oil production in 1989. At that time, the Venezuelan government began to develop a policy known as "Apertura Petróleos" (or Petroleum Opening) that encouraged foreign investment in its oil industry. The central goal of the new policy was to increase Venezuela's productive capacity, either through the rejuvenation of its mature existing fields, the discovery of new fields of medium and light crude outside of the traditional producing regions, or the development of its huge resources of extra-heavy crude oil.

There is little doubt that policy change had a major stimulative effect on Venezuela's upstream capacity. For instance, in the first phase of the program in the early 1990's, a total of 14 contracts were awarded to private companies to operate fields that were either inactive or had been abandoned. Under these contracts, the operator made a 20-year commitment that mandated certain minimum investment levels. In return, the operator received a fee for each barrel of oil produced. While the potential for these projects was originally estimated to be 125,000 barrels per day (b/d), they soon grew to more than twice this volume. In 1996, the Venezuelan Congress authorized profit sharing agreements under which private firms have the right to explore and develop new fields of light oil outside the traditional producing region. The Venezuelan Congress also approved four joint ventures between Petróleos de Venezuela, (PdVSA), Venezuela's state-owned oil company, and several multinational companies, including some of the FRS companies. There was even talk of taking the policy one step further by privatizing PdVSA.[a]

In December 1998, Hugo Chávez won Venezuela's presidential election with 56 percent of the vote, running on a populist agenda. Privatization of PdVSA was explicitly banned under the new constitution that he proposed in 1999. Moreover, a new hydrocarbons law was decreed in November 2001. Royalty rates on oil production were increased from 16.6 percent to 30 percent. Projects that can prove that they would not be financially viable at the new 30-percent rate would be allowed the lower rate of 20 percent. In addition, PdVSA must hold a 51-percent stake in any new exploration and production agreements.

In natural gas, PdVSA traditionally has had a monopoly on Venezuelan natural gas production. Further, while the country has 58 percent of the gas reserves in Central and South America, its production is only 29 percent of the region's total.[b] In contrast to the Chavez policy on oil and to the surprise of some analysts, the Chavez government enacted legislation in 1999 to stimulate gas production by opening up the sector to foreign investment in exploration, production, distribution, transmission, and gasification (although no company would be allowed to explore, produce, and transport in the same region). This law sets royalty payments at 20 percent and income-tax rates at 34 percent.

Following through on the legislation, in August of 2002 the government reached an accord with the FRS company ChevronTexaco, and also BP[c], Britain's BG Group, Statoil, and TotalFinaElf, to explore and develop four blocks in the 10,800 square mile Plataforma Deltana offshore field.[d] There is a possibility that another FRS company, Exxon Mobil, will develop a fifth block. This area is located near Venezuela's border with Trinidad and is estimated to contain 20 trillion cubic feet of natural gas.[e] Under the terms of the agreement, PdVSA will own up to a 35-percent interest in the projects. Development plans call for the gas to be exported to the United States, Europe, and Brazil in the form of liquefied natural gas.

Note: At the writing of *Performance Profiles*, the political situation in Venezuela is exceptionally fluid and subject to change, which may alter the environment for private E&D.

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[a]Katsouris, Christina, "PDVSA chief mulls sale of minority stake in firm as country reforms petroleum sector," *The Oil Daily (*April 24, 1996), p. 1.
[b]BP plc, *BP Statistical Review of World Energy,* (June 2002), pp. 20 and 22.
[c]"Venezuela Opens Offshore Field to Foreign Firms," *Wall Street Journal,* (August 26, 2002), p. A8.
[c] BP America, the U.S. subsidiary of BP plc of the United Kingdom, is the FRS respondent.
[d]Alexander's Oil and Gas Connections, "Seven oil majors sign agreement for Plataforma Deltana region," Volume 7, Number 18, (September 19, 2002). Located on the Internet at http://www.gasandoil.com/goc/company/cnl23899.htm (as of November 18, 2002).

SPECIAL TOPIC: FRS Companies in Russia and China -- A New Era?

Given Russia's bountiful hydrocarbon resources, there was considerable optimism at the time of the Soviet Union's collapse that the country would soon be a lucrative target for upstream investments by multinational oil companies, including the FRS companies. This optimism was soon dashed by the unsettled conditions of Russia's property rights and tax code structure. However, in recent years, there is evidence that Russia is reforming its policies in light of the reality that an onerous tax code is not conducive to investment. China also has increased reliance on market forces, which, along with its seemingly ever-increasing demand for energy, has led some to conclude that a new era in China's energy sector is emerging.

Russia began restructuring its oil and gas sector in 1993 by reorganizing its state-owned enterprises as joint-stock companies.[a] This resulted in the creation of a group of large, vertically-integrated companies, such as LUKoil, YUKOS, Gazprom, Surgutneftegaz, Tyumen Oil (TNK), Tatneft, and Sibneft. Since then, the government has auctioned off large quantities of its shares in these companies. For example, in 1999 the government auctioned 9 percent of Lukoil for $200 million (plus $240 million in investment commitments) and 48.7 percent of TNK for $90 million (plus $184 million in investment commitments). Despite this trend toward privatization, foreign investment in Russia's oil sector has been muted because of the business environment and tax regime. When Russia passed production-sharing agreement (PSA) legislation in the mid-1990's, the legislation was widely viewed as failing to adequately protect foreign investment, and few agreements were concluded. International oil companies claim a stable PSA regime could unlock tens of billions of dollars of investment in Russia's oil sector, but Russia's parliament has been unable to agree on a final form for a national PSA model.

Some observers argue that progress is being made in improving Russia's business climate. According to David O'Reilly, chairman and chief executive of ChevronTexaco "…considerable progress has been made in regulatory reforms, tax reform and improvement of the judiciary system" and "…most of what is left to be done will probably be complete by 2003."[b]

In the early 1990's, project-specific PSAs were put into effect. Two of these PSAs are located on Sakhalin Island, off Russia's eastern coast. For a discussion of these projects, see "Upstream Investment Focuses on Natural Gas, Large Projects." Development of ChevronTexaco's Kirinsky block in the offshore Sakhalin III project is contingent on the proposed final form PSA legislation. At this time, the proposed code is still being considered by the Russian Parliament. Development of the field would probably begin no sooner than 2005, even if the new legislation is approved in early 2003.

To help meet its projected increase in natural gas demand, China has embarked on an ambitious program to increase its domestic production of natural gas. The most notable example of a policy shift is the recent approval of an $8.5-billion project to develop gas reserves in the Tarim basin in the western part of the country and move the gas by pipeline to Shanghai and other eastern cities.[c] The 2,584-mile-long pipeline would initially deliver 424 billion cubic feet of natural gas per year to the eastern markets. In 2002, PetroChina signed a framework for a joint venture with Royal/Dutch Shell, Exxon Mobil, and Gazprom. Under the agreement, PetroChina and Sinopec (China Petroleum & Chemical) would have a combined 55-percent equity interest in the project, while the outside partners would each have a 15-percent interest. One issue clouding the development of the project is its economic viability in light of China's low energy prices and the large costs of transporting the gas over 2,600 miles. Another issue is whether the Tarim basin has sufficient gas resources to fill the pipeline over its projected 45-year life. While some have suggested that possible shortfalls in supply could be avoided if the pipeline were to go through Russian territory in order to gain access to Russian supplies, this option would significantly increase the cost of the overall project.

In a separate development, Royal/Dutch Shell recently announced that it would invest $400 million to develop two offshore blocks in China's Bohai Sea.[d] Shell and its partner, China National Offshore Oil, have identified 600 to 700 million barrels of proven oil reserves and 1 trillion cubic feet of proven natural gas reserves in the two blocks. Kerr-McGee is also active in this offshore area. The company has five Bohai Bay discoveries to date and has recently announced plans to develop one of them using a floating production, storage, and offloading vessel. It projects production from the discovery to exceed 50,000 barrels per day by mid-2005.[e]

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[a]Energy Information Administration, "Russia: Energy Sector Restructuring" (April 2002), http://www.eia.doe.gov/emeu/cabs/russrest.html#OIL.
[b]ChevronTexaco, "Board of Directors Completes First Overseas Meeting in Russia and Kazakhstan" (October 30, 2002), http://www.chevrontexaco.com/news/spotlight/kazakhstan.asp.
[c]This cost estimate of $8.5 billion does not include the cost of developing the reserves nor the estimated nine billion dollars to build the gas distribution system in Shanghai and the other eastern cities. See, Alexanders' Gas and Oil Connections, "Historic gas deal signed in Beijing," Volume 7, Number 15 (August 08, 2002). Located on the Internet at http://www.gasandoil.com/goc/company/cns23255.htm (as of November 18, 2002).
[d]Alexander's Gas and Oil Connections, "Shell to invest $ 400 million in China's Bohai Sea," Volume 7, Number 16 (August 23, 2002). Located on the Internet at http://www.gasandoil.com/goc/company/cns23413.htm (as of November 18, 2002).
[e]"Kerr-McGee sanctions development in Bohai Bay, China," Oil & Gas Journal Online (May 20, 2002). Located on the Internet at http://ogj.pennnet.com/articles/web_article_display.cfm?Section=Archives&Article_Category=ExplD&ARTICLE_ID=144165&KEYWORD=%20%20Kerr%2DMcGee%20sanctions%20development%20in%20Bohai%20Bay%2C%20China (as of November 18, 2002).

SPECIAL TOPIC: Canada's Oil Sands -- Confounding the Doomsday Predictions?

Some experts argue that worldwide conventional oil production will peak within the next few years.[a] This prediction is based on a methodology advanced by M. King Hubbert that concludes that while the production of oil can increase for some period of time, it eventually reaches a maximum and then declines until the resource is totally depleted. In 1956, Hubbert used this methodology to correctly predict that U.S. oil production would peak in the early 1970's.[b]

However, others argue that, while conventional resources may be limited, the world has enormous resources of unconventional oil that are increasingly competitive with conventional crude.[c] One outstanding example is the case of Canada's oil sands. Canada's resources of oil sands or crude bitumen lie almost exclusively within three regions in the province of Alberta known as Athabasca, Cold Lake, and Peace River. The Alberta Energy and Utilities Board has estimated the ultimate volume of crude bitumen in place to be 2.5 trillion barrels.[d] About 370 billion barrels of this volume are believed to be economically recoverable at current prices and with current technology.[e] Of the economically recoverable reserves, about 15 percent can be recovered using surface mining where the bitumen deposits are dug from the earth, while the remaining 85 percent require the use of in situ production processes, in which a well is drilled and the bitumen is extracted, often using unconventional technologies.

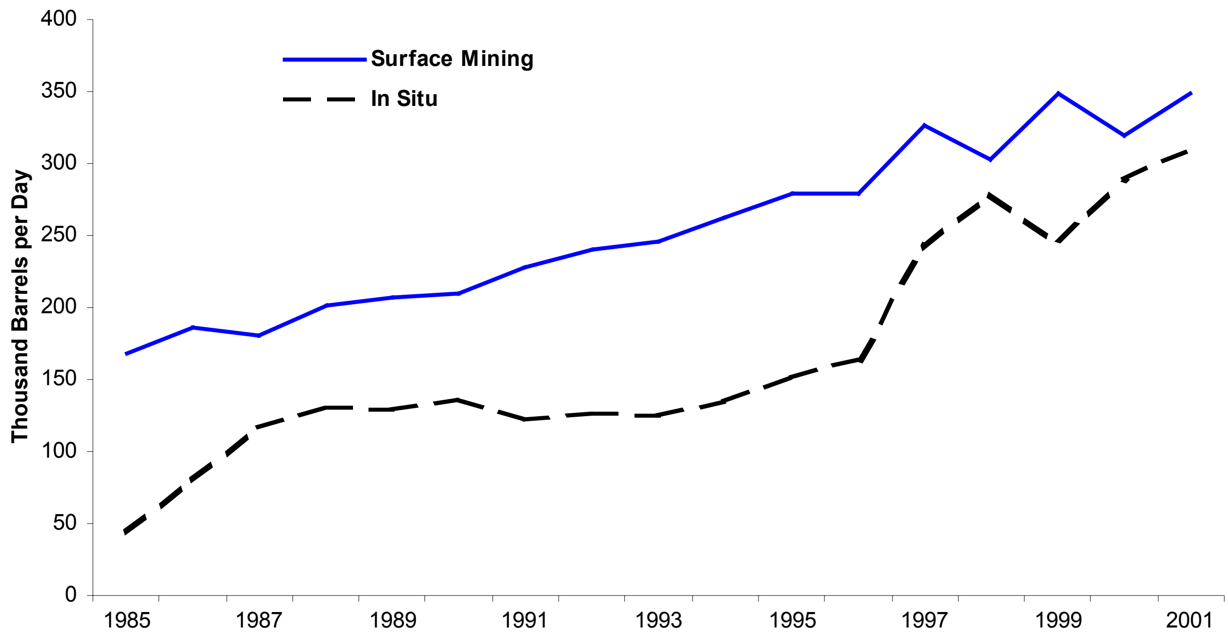
The first commercial crude-bitumen mining project in Canada commenced in 1967. While initial production was modest because of high costs, it has nevertheless steadily increased as producers have learned more about exploiting the resource (Figure 30). A reduction in the effective tax rate on oil sands production in the 1990's, along with improvements in crude bitumen mining technology, have reduced the breakeven price of surface mining operations by more than 50 percent over the past twenty years.[f] Currently, the breakeven price for mining operations is in the range of $9 to $11 (U.S. dollars) per barrel.[g]

The first commercial crude-bitumen production project using in situ techniques in Canada began in 1978. The traditional application of in situ production techniques involved drilling a well into the oil sands and extracting the bitumen almost as if it were conventional crude oil. The maturation of horizontal well technology and the development of steam assisted gravity drainage (SAGD) extraction techniques have revolutionized the in situ production industry. With the SAGD technology, two horizontal wells are drilled into the same reservoir, one directly above the other (Figure 31). Steam is injected into the top well, which heats up the surrounding tar-like bitumen and causes it to drain with the aid of gravity into the well bore of the lower well (Figure 31).

While the cost of drilling the wells with SAGD technology is considerably higher than for a conventional vertical well, the productivity levels of the wells are increased dramatically. For example, it is not atypical for a well with these advanced technologies to produce 1,000 barrels per day (b/d) of bitumen. This is more than 20 times the productivity of the average bitumen well in Alberta.[h] Because of the high productivity of the wells, these technologies are believed to have reduced the breakeven supply price to $4 to $5 (U.S. dollars) per barrel.[i]

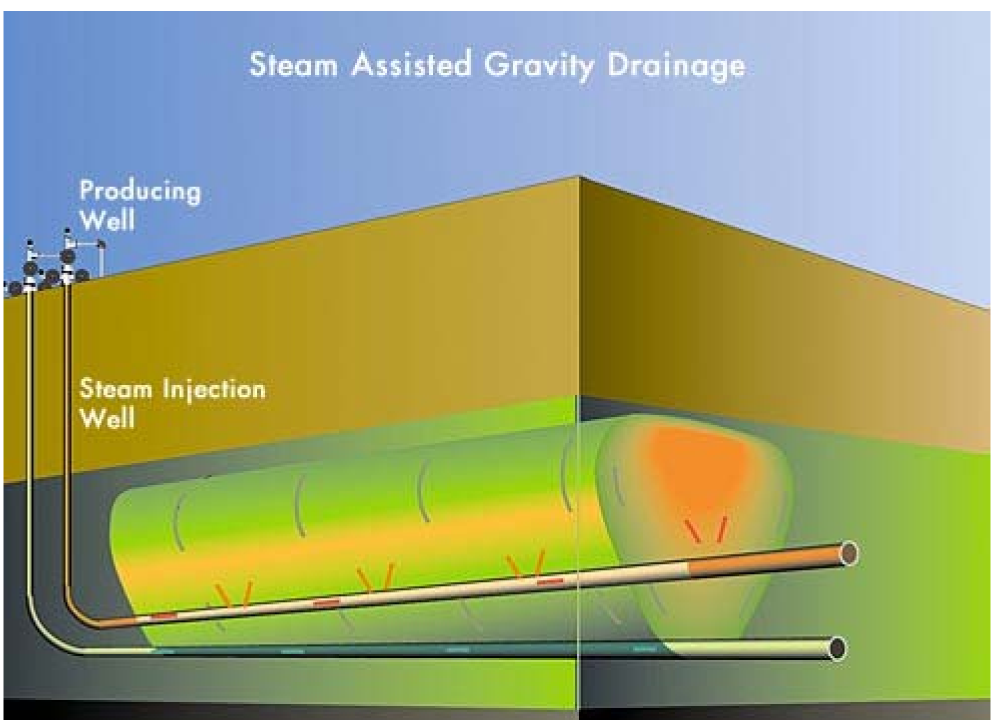
The decreases in supply costs for both mining and in situ oil sands production have encouraged oil producers to plan additional ventures. Based on publicly announced projects, production is anticipated

Figure 30. Oil Sands Production in Canada, 1985-2001



Source: Canadian Association of Petroleum Producers, *Statistical Handbook for Canada's Upstream Petroleum Industry,* 2002, Table 2-10a and 2-10-1a.

Figure 31. Steam Assisted Gravity Drainage Technology



Source: EnCana Corporation, "Operations and Projects" section of company's web site (http://www.encana.ca/index2.shtml). EnCana Corporation is located in Calgary, Alberta, Canada. This figure is the property of EnCana Corporation and appears courtesy of EnCana Corporation.

to increase to almost 1.9 million b/d by 2010.[j] Planned, under-construction, and recently completed SAGD and oil sands mining projects (undertaken by both FRS and non-FRS companies) include:

McKay River: Petro-Canada recently started up operations at its $290 million (Canadian) SAGD MacKay River oil sands facility 35 miles northwest of Fort McMurray, Alberta. This project represents the largest commercial advanced-technology operation to date in Canada. While the project entails only approximately 30 well pairs, it is expected to produce 30,000 b/d by year-end 2003 and retain that level for the full 25-year life of the project.[k]

Firebag: This SAGD project will be operated by Suncor. The project will operate on leases covering more than 620 square miles with estimated bitumen resources of almost 10 billion barrels. The project is planned in four phases, with each phase contributing 35,000 b/d to production.[m]

Foster Creek: This project in the Cold Lake region began as a 2,000 b/d pilot project in 1997 to test SAGD technology. EnCana, a large independent producer formed by the recent merger of PanCanadian Energy and Alberta Energy, is developing the project. It is estimated that SAGD technology will enable 350 million barrels to be recovered by this undertaking.[n] Production is expected to average 20,000 b/d in 2003 and 30,000 b/d in 2004. Subsequent project phases are believed to have the potential to produce more than 100,000 b/d as early as 2007.

Cold Lake: Imperial Oil's (an affiliate of Exxon Mobil) Cold Lake operation is the largest in situ bitumen project in Canada.[o] In 2000, the latest year for which data are available, the project produced approximately 120,000 b/d of bitumen using cyclic steam-stimulation. In addition, Exxon Mobil has recently applied for regulatory approval to produce an extra 30,000 b/d of bitumen from a new operating area known as Nabiye.[p] Development of this project could be complete as early as late 2006. Exxon Mobil has also applied to expand some of its other existing operations in the Cold Lake area. It expects that these expansions will increase its total Cold Lake production to about 180,000 b/d by the end of the decade.

The Athabasca Oil Sands Project: This surface mining project has a current estimated cost of $5.2 billion, up from its original estimate of $3.8 billion. Costs are higher than expected because increased oil-sand mining and drilling has bid up the costs of constructing new facilities. The project is now on track to start up in late 2002, and will produce 155,000 b/d of bitumen at full production. Partners in the project include Shell Canada, a unit of Royal/Dutch Shell, ChevronTexaco, and Western Oil Sands.[q]

Project Millennium: Suncor Energy completed its $3.4 billion Millennium mining expansion project in late 2001. This expansion increased its production capacity to 225,000 b/d from 115,000 b/d. While costs average $16.35 per barrel in early 2002, Suncor believes that this was attributable to growing pains, and that it can drive down costs to $8.50 to $9.50 per barrel.[r]

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[a]For example, see Kenneth S. Deffeyes, *Hubbert's Peak: The Impending World Oil Shortage* (Princeton University Press, Princeton, NJ), 2001.
[b]Hubbert, M.K, "Nuclear energy and the fossil fuels." American Petroleum Institute, Drilling and Production Practice, *Proceedings of the Spring 1956 Meetings,* San Antonio Texas, 1956, pp. 7-25.
[c]Some economists argue that the Hubbert approach is flawed because it assumes that recoverable petroleum resources are fixed, while the amount of oil which can be recovered depends on both the total amount of oil (a geological factor which is fixed), and dynamic variables like price, infrastructure, and technology**.** For more on this point, see Lynch, Michael**, "**Forecasting Oil Supply: Theory and Practice," *Quarterly Review of Economics and Finance,* v. 422, no. 2 (2001), pp. 373-389.

[d]Alberta Energy and Utilities Board, *Alberta's Reserves 2001 and Supply/Demand Outlook 2002-2011,* Statistical Series 2002-1179, http://www.eub.gov.ab.ca/bbs/products/STs/ST98-2002.pdf.
[e]Alberta Energy and Utilities Board, *Alberta's Reserves 2001 and Supply/Demand Outlook 2002-2011,* Statistical Series 2002-1179, http://www.eub.gov.ab.ca/bbs/products/STs/ST98-2002.pdf.
[f]National Energy Board of Canada, *Canada's Oil Sands: A Supply and Market Outlook to 2015* (October 2000), p. 35.
[g]National Energy Board of Canada, *Canada's Oil Sands: A Supply and Market Outlook to 2015* (October 2000), p. 35.
[h]Canadian Association of Petroleum Producers, *Statistical Handbook for Canada's Upstream Petroleum Industry,* 2002, Tables 3-2 and 3-17a.
[i]Canadian Energy Research Institute, "Supply Costs and Economic Potential for the Steam Assisted Gravity Drainage Process" (August 1999).
[j]National Energy Board of Canada, *Canada's Oil Sands: A Supply and Market Outlook to 2015* (October 2000), p. 1.
[k]"Petro-Canada opens MacKay River steam-assisted oil sands facility," Oil and Gas Journal Online (October 14, 2002), http://ogj.pennnet.com/articles/web_article_display.cfm?Section=OnlineArticles&Article_Category=DriPr&ARTICLE_ID=158785&KEYWORD=Mackay%20River&x=y.
[l]"In situ projects gaining ground in Canadian oil sands development boom," *Oil and Gas Journal*, v. 100.23 (June 10, 2002), p. 24.
[m]"In situ projects gaining ground in Canadian oil sands development boom," *Oil and Gas Journal*, v. 100.23 (June 10, 2002), p. 24.
[n] Encana, "EnCana cash flow tops $ 1 billion in third quarter," Press Release (November 5, 2002).
[o] "Imperial plans $1 billion oil sands expansion," Oil and Gas Journal Online (February 20, 2002), http://ogj.pennnet.com/articles/web_article_display.cfm?Section=Archives&Article_Category=TOPST&ARTICLE_ID=92863&KEYWORD=imperial%20oil.
[p] Imperial Oil, "Cold Lake Expansion Projects," Press Release (June 4, 2002).
[q]"In situ projects gaining ground in Canadian oil sands development boom," *Oil and Gas Journal*, v. 100.23 (June 10, 2002), p. 24.
[r]"In situ projects gaining ground in Canadian oil sands development boom," *Oil and Gas Journal*, v. 100.23 (June 10, 2002), p. 24.

Emerging Issues

This section of *Performance Profiles* examines developments in the organizational structure of the U.S. energy industry. Specifically, this section presents three analyses ("Special Topics") that discuss:

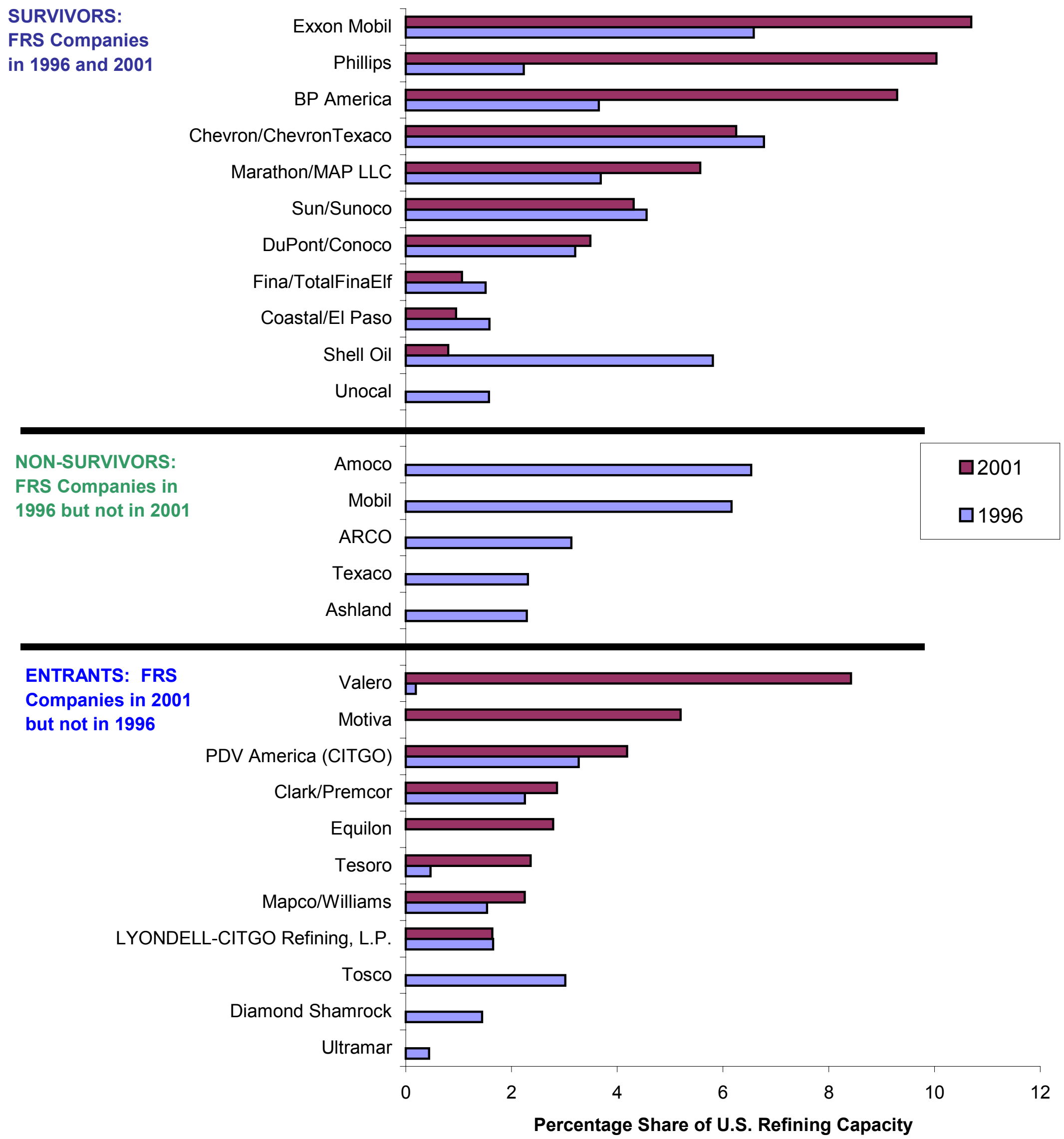
- Consolidation in the U.S. petroleum refining industry
- A review of the major energy companies' involvement in diversified enterprises
- The FRS companies role in the U.S. liquefied natural gas markets

SPECIAL TOPIC: **Downstream Evolution -- Consolidation in U.S. Refining**

Recent interest in the U.S. refining industry prompted by petroleum product price spikes and subsequent Federal investigations[a] suggest an interest in the ownership structure of the U.S. refining industry. The following presentation is provided to illustrate how the industry has evolved to its current state or configuration.[b]

In order to make the review and exposition of the recent changes in the U.S. refining industry more tractable, the FRS refiners in 1996 and 2001 have been separated into one of three categories: Survivors, Non-Survivors, and Entrants (Figure 32). The Survivors are FRS companies that had U.S. refining operations or capacity in 1996 and are still FRS companies for 2001 (but don't necessarily still have refining operations or capacity). Non-Survivors were FRS refiners in 1996, but were not FRS companies in 2001. Finally, Entrants were refiners in 1996 (but not FRS companies) and had become FRS companies by 2001.

Figure 32. U.S. Refining Capacity Shares, FRS Companies, 1996 and 2001



Notes: Refining capacity is measured by crude oil distillation capacity. Also, companies that had different names in 1996 and 2001 (due to merger or other reasons) are listed with their 1996 name first and the 2001 name next with a slash separating the two names. BP America is the FRS company, and not the parent.

Source: Energy Information Administration, *Petroleum Supply Annual 1997* , DOE/EIA-0340(96)/1 (Washington, DC, June 1998), Table 40 and *Petroleum Supply Annual 2001* , DOE/EIA-0340(2001)/1 (Washington, DC, June 2002), Table 40. Web address: http://www.eia.doe.gov/oil_gas/petroleum/data_publications/petroleum_supply_annual/psa_volume1/psa_volume1_historical.html .

Examination of Figure 32 reveals the following:

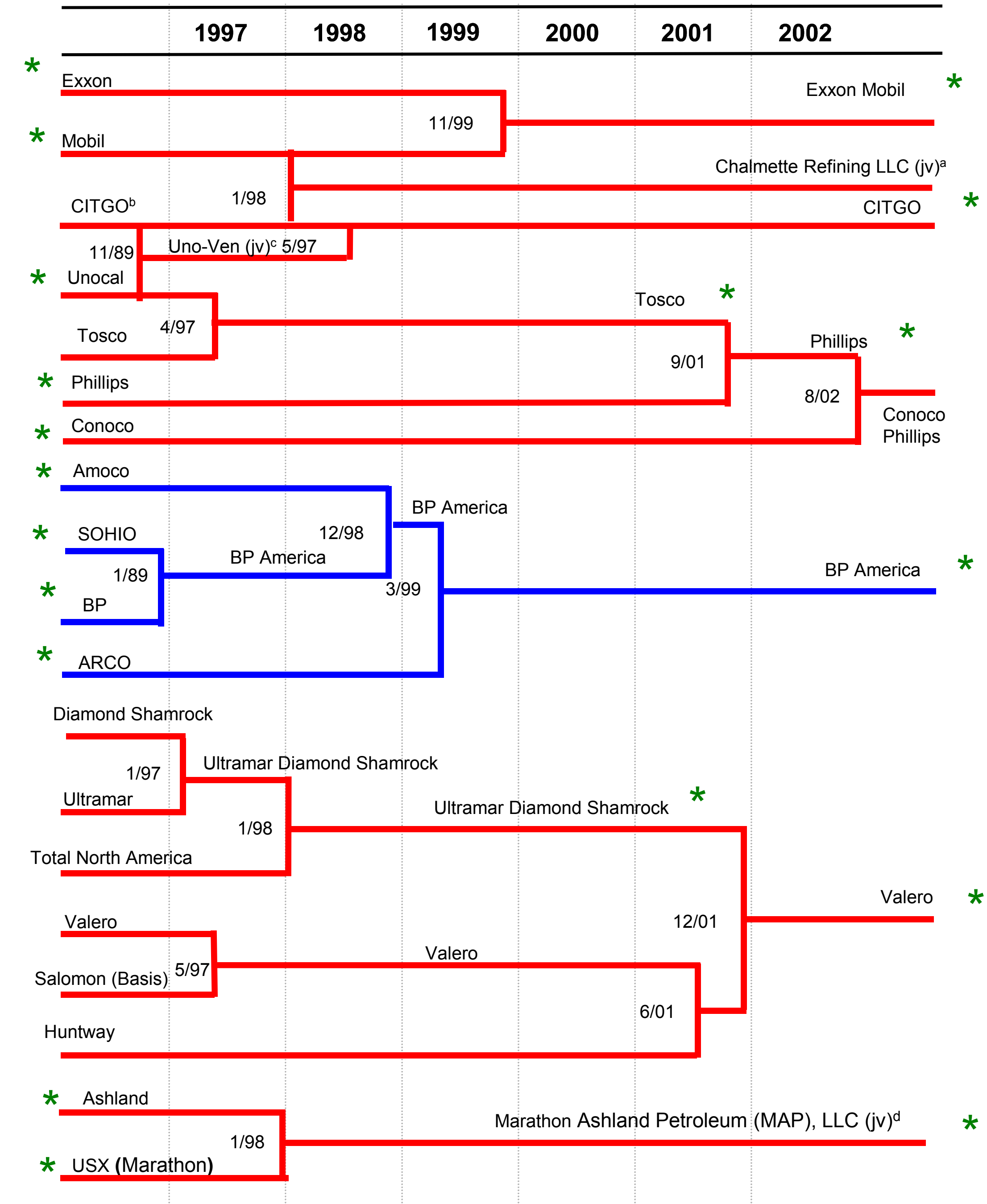
- Most (all except Unocal) of the Survivors still engage in U.S. refining and more Survivors have increased their share of U.S. refining capacity[c] than have decreased their share. On balance, the Survivors' share increased from 41 percent to 53 percent.
- All of the Survivors whose share of U.S. refining capacity grew between year-end 1996 and year-end 2001 did so almost entirely because of merger and/or direct or indirect acquisition.[d] None of the Survivors whose share of U.S. refining capacity declined were involved in mergers or acquisitions of refining assets.
- All of the Non-Survivors both exited the U.S. refining/marketing industry and the FRS survey respondent group. All of the Non-Survivors were acquired by another company (Amoco, Mobil, ARCO, and Texaco) or transferred their refining assets into a joint venture controlled by another company (Ashland).
- Some of the Non-Survivors were extremely significant refiners (i.e., Amoco, Mobil, and Texaco[e]) while others were essentially mid-level refiners (ARCO and Ashland).
- Most of the Entrants were small refiners in 1996 (CITGO and Tosco are somewhat exceptional in this regard) and became, at least in comparison, much larger (LYONDELL-CITGO Refining, L.P. is an exception) between year-end 1996 and year-end 2001.[f]
- The Entrants still in existence at year-end 2001 were almost equally divided between joint ventures (Motiva, Equilon, and LYONDELL-CITGO) and stand-alone companies (Valero, CITGO, Premcor, Tesoro, and Williams).

Not only has the U.S. refining industry undergone considerable change in the past 5 years (Figure 33), but the cast of companies composing the largest 5 or 10 refiners in the United States also has undergone substantial change (Figure 32). Perhaps the most interesting group of companies is the Entrants. These companies are non-vertically integrated refiners[g] and they collectively and individually experienced significant growth during the 1990's.[h] The companies generally pursued one of two (or a combination of the two) strategies: a) acquisition of assets, or b) acquisition of or merger with entire companies.

Generally, Tosco pursued the former strategy with the exception of its acquisition of the convenience store company Circle K in 1996. Ultramar Diamond Shamrock pursued the latter strategy, first merging Ultramar and Diamond Shamrock in 1997 and then acquiring Total North America in 1998. Probably the most prominent of all the non-vertically integrated refiners during the 1990's were Tosco and Ultramar Diamond Shamrock (UDS), both of which were prominent in the events of 2001 because each was acquired by another company. Tosco was acquired by Phillips (whose subsequent merger with Conoco was approved in August 2002) and UDS was acquired by Valero, another of the fast-growing non-vertically integrated refiners of the 1990's.[i]

Valero, too, exhibited a combination of the two strategies. Beginning with a single refinery with a total capacity of 29,900 barrels per day as recently as year-end 1996, Valero first acquired Basis Petroleum from Salomon Brothers in May 1997.[j] This single transaction increased Valero's refining capacity by more than 9-fold (to 309,500 barrels per day). Subsequently, Valero acquired Exxon Mobil's Benicia, California refinery[k] and associated retail outlets during 2000. During 2001, Valero acquired Huntway Refining (a California-based asphalt and road oil refiner) in June, El Paso's (formerly Coastal's) Corpus Christi refinery in July, and Ultramar Diamond Shamrock (UDS) in December.[l] The acquisition of UDS essentially doubled Valero's refinery capacity, adding almost 600,000 barrels of U.S. refining capacity[m] in addition to a Canadian refinery and associated marketing operations.

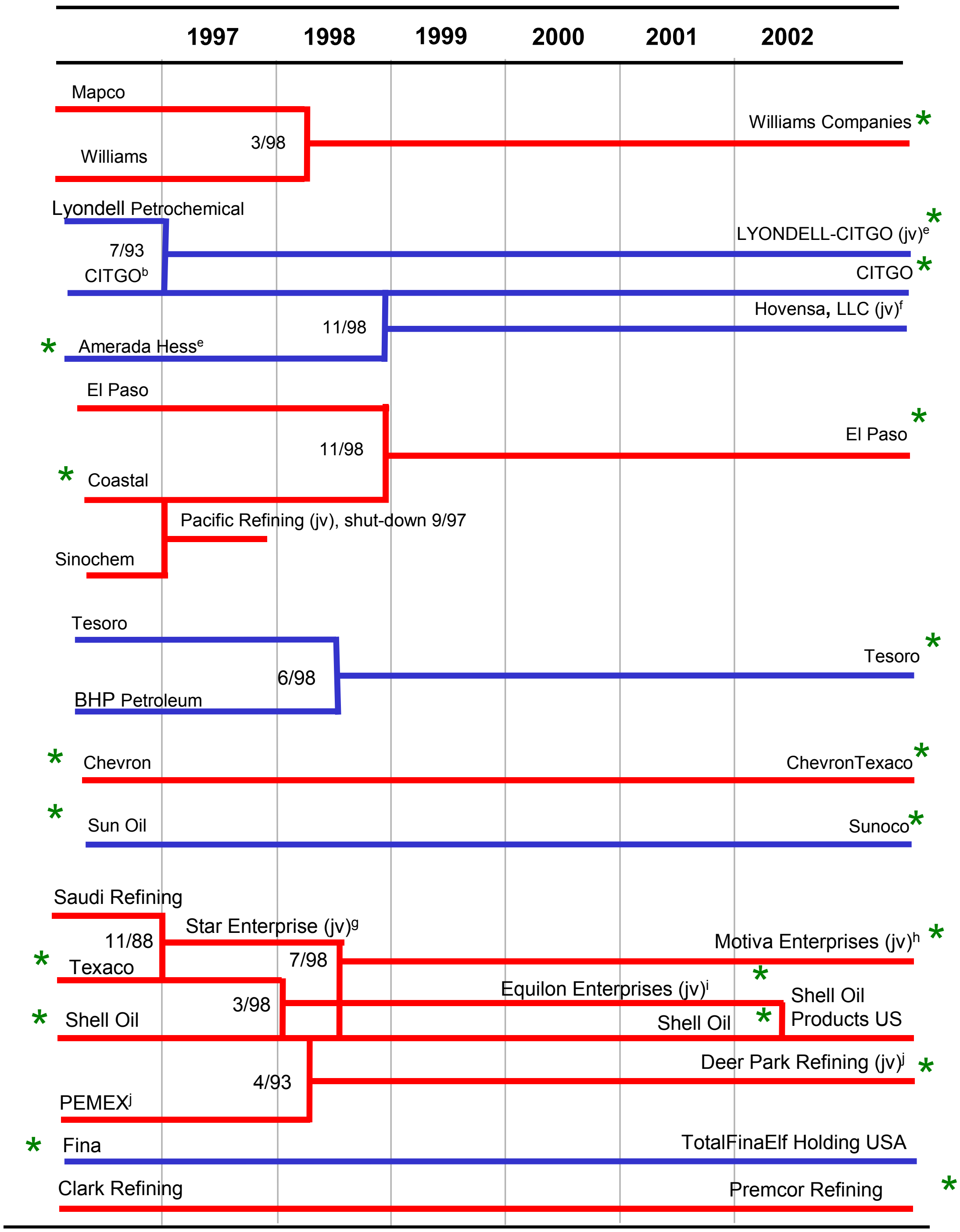
Figure 33. Genealogy of the 2001 FRS Refiners



*Indicates company was an FRS respondent in the nearest year; i.e., a star to the left of a company name indicates that company was an FRS company in 1997. Alternatively, if the star is to the right of the company, then it was an FRS respondent in 2001.

Footnotes and source notes are at the end of the figure.

Figure 33. Genealogy of the 2001 FRS Refiners (continued)



*Indicates company was an FRS respondent in the nearest year; i.e., a star to the left of a company name indicates that company was an FRS company in 1997. Alternatively, if the star is to the right of the company, then it was an FRS respondent in 2001.

Footnotes and source notes are at the end of the figure.

Figure 33. Genealogy of the 2001 FRS Refiners (continued)

[a]For the purpose of simplification, the partner of the Chalmette joint venture is given as CITGO because CITGO operates all U.S. refineries owned by Petroleos de Venezuela, S.A. (PdVSA). However, the partner in the joint venture is actually a U.S. affiliate of CITGO's parent PdVSA. Chalmette is a 50/50 joint venture.

[b]For the purpose of simplification, the partner of U.S.-based joint venture between PdVSA is given as CITGO, regardless as to which U.S. affiliate of PdVSA actually is the partner because CITGO operates all U.S. refineries owned by Petroleos de Venezuela, S.A. (PdVSA).

[c]For the purpose of simplification, the partner of the Uno-Ven joint venture is given as CITGO because CITGO operates all U.S. refineries owned by Petroleos de Venezuela, S.A. (PdVSA). However, the partner in the joint venture is actually a U.S. affiliate of CITGO's parent Petroleos de Venezuela, S.A. (PdVSA). Uno-Ven was a 50/50 joint venture, which was dissolved in May 1997.

[d]Marathon Ashland Petroleum is 62 percent owned by Marathon Oil, which formerly was known as USX Corporation. Ashland owns the remaining 38 percent of the venture.

[e]For the purpose of simplification, the partner of the LYONDELL-CITGO refining joint venture is given as CITGO because CITGO operates all U.S. refineries owned by Petroleos de Venezuela, S.A. (PdVSA). However, the partner in the joint venture is actually a U.S. affiliate of CITGO's parent Petroleos de Venezuela, S.A. (PdVSA). LYONDELL-CITGO refining is a 50/50 joint venture.

[f]For the purpose of simplification, the partner of the Hovensa joint venture is given as CITGO because CITGO operates all U.S. refineries owned by Petroleos de Venezuela, S.A. (PdVSA). However, the partner in the joint venture is actually a U.S. affiliate of CITGO's parent Petroleos de Venezuela, S.A. (PdVSA). Hovensa is a 50/50 joint venture that includes Hess' U.S. Virgin Islands 495,000 barrels per day refinery. It is included here because of the relative size of the refinery and its proximity to U.S. markets.

[g]Star Enterprise was a 50/50 joint venture between the U.S. affiliate of Saudi Aramco, the state oil company of Saudi Arabia and Texaco. The venture sold motor gasoline and petroleum products under the Texaco brand name in the southeastern and Midwestern U.S.

[h]Motiva Enterprises was a joint venture between Star Enterprise and Shell Oil that sold motor gasoline and petroleum products under the Shell and Texaco brand names. Motiva is now a 50/50 joint venture between Saudi Refining and Shell Oil after Texaco sold its ownership to its partners as a precondition of the U.S. Federal Trade Commission approving the merger of Chevron and Texaco.

[i]Equilon Enterprises was a 56/44 joint venture between Shell Oil and Texaco, respectively, that operated in the western United States. As a precondition of the U.S. Federal Trade Commission's approval of the merger of Chevron and Texaco, Texaco sold its ownership in Equilon to Shell Oil, which then fully owned Equilon and consolidated Equilon and its other fully owned U.S. assets into Shell Oil Products US as of March 2002.

[j]Deer Park Refining is a 50/50 joint venture between Shell Oil and Petroleos de Mexicanos (PEMEX), the state oil company of Mexico. Although this presentation may suggest that PEMEX no longer exists, this is not true. However, PEMEX has no other existence in the U.S. refining/marketing industry outside this joint venture.

Sources: Energy Information Administration, *Petroleum Supply Annual* [1997-2001], Volume 1, DOE/EIA-0340 (Washington, DC, June), Tables 40, 48, and 49; and company news releases and other public disclosures.

Further, joint ventures are a common method of attempting to reduce operating costs. A joint venture has some of the benefits of acquisition while avoiding some of the costs. Perhaps the most enticing aspect of a joint venture is that it permits what amounts to a "partial merger," allowing companies to selectively merge some operations (e.g., U.S. refining) while withholding others (e.g., all non-U.S. refining operations). PDV America and its CITGO affiliate have widely used this technique in creating refining joint ventures. Texaco, too, was involved in 3 separate U.S. refining joint ventures, beginning in 1988, and concluding with its merger with Chevron in 2001.

When one closely examines Figures 32 and 33, perhaps the most compelling conclusion is also one of the most obvious: the largest refiners in the United States are much different at the end of 2001 than at the end of 1996 (Figure 32 and Figure 33). A related point is that the path to the top has generally entailed an acquisitive journey, but the means of acquisition have varied. The most successful companies seem to have employed multiple methods of acquisition, including one or more of the following: a) company acquisition, b) asset acquisition, and c) joint ventures.

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[a] Investigations include many congressional hearings and studies, including the recent report by the Senate Permanent Subcommittee on Investigations (see, http://frwebgate.access.gpo.gov/cgi-

bin/getdoc.cgi?dbname=107_senate_hearings&docid=f:80298.pdf for the Subcommittee's report on motor gasoline prices, as of November 18, 2002), and at least one on-going investigation by the U.S. General Accounting Office.

[b] One will note that the idea for Figure 33 was provided by recent work by the U.S. Department of Energy's Office of Strategic Petroleum Reserves.

[c] Shell Oil's share of U.S. refining capacity decreased between year-end 1996 and year-end 2001 because almost all of its U.S. refining capacity was placed in the joint ventures Equilon and Motiva. However, since March 2002 the capacity of Equilon has been consolidated within Shell Oil, which was then renamed Shell Oil Products US, following Texaco's divestiture of its shares of Equilon and Motiva as of February 13, 2002. See, Shell Oil Company, press release (February 13, 2002). Web site: https://www.piersystem.com/external/final_View.cfm?pressID=8398&CID=69 (as of November 13, 2002).

[d] Marathon's Marathon Ashland Petroleum LLC joint venture is an example of indirect acquisition as Marathon effectively acquired control over Ashland's refining/marketing assets through the creation of the joint venture, which is controlled by Marathon because of its 62-percent ownership of the joint venture.

[e] Texaco's refinery capacity in 1996 was diminished considerably through its participation in the Star Enterprise joint venture with Saudi Refining (the U.S. affiliate of the state oil company of Saudi Arabia, Saudi Aramco) in which more than half its refining capacity was committed beginning in November 1988.

[f] Diamond Shamrock, Tosco, and Ultramar may seem to also be exceptions, but were acquired during 2001. Tosco was the 3rd-largest refiner in the United States at the end of 2000 and Ultramar Diamond Shamrock was the 10th-largest. See, Energy Information Administration, *Petroleum Supply Annual 2000*, Volume 1, DOE/EIA-0340(2000)/1 (Washington, DC, June 2001), Tables 36 and 40. Web site: http://www.eia.doe.gov/oil_gas/petroleum/data_publications/petroleum_supply_annual/psa_volume1/psa_volume1_historical.html (as of November 12, 2002).

[g] Williams Companies, which is perhaps best described as an energy services company, is an exception to this generalization. However, its inclusion in the FRS is based on its March 1998 acquisition of Mapco, an non-vertically integrated refiner.

[h] See Energy Information Administration, *Performance Profiles of Major Energy Producers 1997*, DOE/EIA-0206(97) (Washington, DC, January 1999), pp. 60-64. Web site: http://tonto.eia.doe.gov/FTPROOT/financial/020697.pdf (as of November 12, 2002).

[i] Phillips, too, had a smaller transaction in 2000 in which it acquired some of ARCO's Alaskan assets as part of the consent agreement that resulted in the U.S. Federal Trade Commission's approval of the BP Amoco (now BP) acquisition of ARCO. In addition to crude oil producing properties, Phillips acquired ARCO's Alaskan refineries, one of which was subsequently sold to BP during 2001.

[j] Energy Information Administration, *Petroleum Supply Annual 1997*, Volume 1, DOE/EIA-0384(97) (Washington, DC, June 1998), Table 38. Web site: http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_supply_annual/psa_volume1/historical/1997/psa_volume1_1997.html (as of November 12, 2002).

[k] Energy Information Administration, *Petroleum Supply Annual 2000*, Volume 1, DOE/EIA-0384(2000) (Washington, DC, June 2001), Table 49. Web site: http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_supply_annual/psa_volume1/historical/2000/psa_volume1_2000.html (as of November 12, 2002).

[l] Energy Information Administration, *Petroleum Supply Annual 2001*, Volume 1, DOE/EIA-0384(2001) (Washington, DC, June 2002), Table 49. Web site: http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_supply_annual/psa_volume1/historical/2001/psa_volume1_2001.html (as of November 12, 2002).

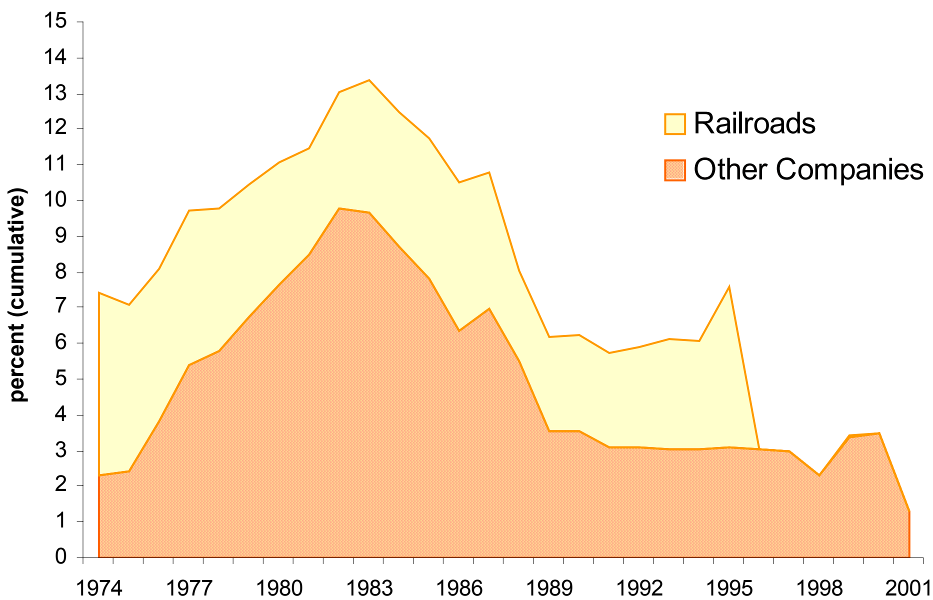
[m] Energy Information Administration, *Petroleum Supply Annual 2001*, Volume 1, DOE/EIA-0384(2001) (Washington, DC, June 2002), Tables 40 and 49. Web site: http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_supply_annual/psa_volume1/historical/2001/psa_volume1_2001.html (as of November 12, 2002).

SPECIAL TOPIC: Telecommunications -- The End of the Line for Diversification?

Businesses beyond energy and chemicals have had a varied history as targets of investment of FRS companies. This special topic provides a brief review of the major energy companies' involvement in diversified enterprises and factors that influenced it over the 1974 through 2001 span of FRS data collection.

These diversified enterprises are classified in the "other nonenergy" line of business for FRS purposes. The FRS companies' commitment to other nonenergy, as measured in this line of business' share of total net investment in place (i.e., net property, plant, and equipment plus investments and advances), reached a peak of 13 percent in 1983 (Figure 34). Almost 20 years later, the comparable share was only 1 percent in 2001. At its height of interest, capital expenditures for other nonenergy ranked only behind U.S. oil and gas production and foreign oil and gas production among the FRS lines of business.

Figure 34. Other Nonenergy Share of Net Investment for FRS Companies, 1974-2001



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

It should be noted first that investment in railroad operations was, until 1996, a significant component of the investment base in the other nonenergy line of business. Burlington Northern and Union Pacific were originally selected as FRS respondents because of their prominence in U.S. coal production and large holdings of U.S. coal reserves. By the mid-1980's, Burlington Northern had become a major U.S. natural gas producer. In 1987, Burlington Northern separated its railroad operations from its energy operations by spinning off Burlington Resources to its shareholders. Burlington Resources has been the FRS respondent since then. Union Pacific was a vertically integrated petroleum company as well as a leading railroad company when selected for the original FRS respondent group. In the late 1980's, Union Pacific divested its refining and marketing operations. In 1996, Union Pacific separated its railroad and other transportation operations from its energy operations when it spun off Union Pacific Resources Group to shareholders. Another FRS company, Anadarko Petroleum, subsequently acquired Union Pacific Resources in 2000.

The focus of this review is on the diversification patterns of FRS companies other than the railroads. Inspection of Figure 34 suggests that the FRS companies' involvement with diversified businesses can be divided into five periods.[a]

1974 to 1983 – Investment in Diversified Businesses Grows Rapidly

The 1974 to 1983 period was the period of greatest growth for the other nonenergy line of business. The asset base in other nonenergy grew more than five-fold, thirteen-fold excluding the railroads. All but five of the then 26 FRS companies participated in this upswing in capital expenditures. Newcomers to diversification made the bulk of these investments. The 15 companies with less than 5 percent of their investment base allocated to other nonenergy in 1974 accounted for nearly 90 percent of the growth in capital expenditures for diversification efforts.

Some of the targets of diversification reflected transference of expertise from core petroleum and chemical operations to nonenergy industries. (Integrated petroleum and chemical manufacturing in the FRS context include the functions of extraction, bulk movement and storage of commodities, marine transport, refining, distribution, and marketing to final consumers, including advertising, credit, and direct mail.) Related diversification moves during this period included investments in primary metals and nonfuel minerals mining, engineering and construction, real estate development, timber, agribusiness, trucking, insurance, computer services, and direct mail retailing. More conglomerate moves included department stores, automobile parts, shipbuilding, meatpacking, cable television, and office and other electronic equipment.

The FRS companies' commitment reached a peak in 1983, a year after DuPont and USX became FRS companies through their acquisitions of Conoco and Marathon, respectively.

Why were the U.S. major energy companies pursuing nonenergy prospects at the time that oil prices were escalating, reaching over $60 per barrel (in 2001 dollars)?

During this period, many of the majors were constrained in their opportunities to invest in oil and gas production. Nationalizations of oil reserves by key oil-producing countries eliminated a substantial amount of upstream prospects abroad. Other oil-producing countries adopted policies that discouraged foreign investment in oil and gas. The majors turned increasingly to U.S. oil and gas development as the target of their upstream investment. Hordes of other companies were entering U.S. oil and gas development as well, in part encouraged by high oil prices, in part encouraged by tax laws then that specifically favored producers other than the majors. The result was an unprecedented level of drilling that served to drive up the costs of finding oil and gas, reducing the attractiveness of U.S. oil and gas investment for the majors.

Downstream operations in the United States and abroad were experiencing a diminished outlook for petroleum demand. Sharply higher petroleum product prices induced conservation and other efforts to reduce petroleum consumption. In the United States, policies at the time encouraged the building of refinery capacity by companies other than the majors, resulting in an excess of basic refining capacity. Thus, developments in oil and gas markets during the 1974 to 1981 period of oil price escalations had some tendencies to push the majors to investment targets outside of oil and natural gas.

Also driving the majors to invest generally was the simultaneous surge in cash flow at the time that crude oil prices were escalating: between 1974 and 1981, cash flow from operations more than tripled. Corporate culture and tax laws at the time strongly favored reinvestment of cash flow rather than payouts to shareholders such as dividends.

1984 to 1989 – Consolidation and Retrenchment

Falling oil prices, developments in the capital markets, and poor returns to nonenergy investments reversed the trend toward nonenergy diversification.

Oil prices began to decline in late 1981, falling from $37 per barrel to $27 per barrel in 1985. Oil prices then crashed in 1986, falling to $11 per barrel in July.[b] The resulting drop in cash flow tended to reduce investment generally, and diversification in particular.

Capital markets were changing. Shareholders were demanding rates of return at least as good as those available in global capital markets. The view of investors was that reinvestment should only be undertaken if it could match or better these returns; otherwise cash flow should be paid out to shareholders. Major energy companies had to cope with declining cash flow, lower expected returns from oil and gas production, and shareholder demands for greater payouts. Investments in businesses outside of core competencies became harder to justify.

Diversified businesses became targets of retrenchment for the FRS companies. The profitability of these operations had been low and declining. Divesting those businesses with subnormal performance would raise overall rates of return as well as providing cash.

Excluding the railroads, the FRS companies' asset base in other nonenergy declined by 62 percent between 1983 and 1989. Companies making multi-billion dollar divestitures of nonenergy businesses included Standard Oil of Ohio (now BP[c]), ARCO, and Mobil. Texaco sold most of the nonenergy assets gained in its acquisition of highly diversified Getty Oil in 1984. The most diversified company, Tenneco, left energy altogether in 1988, thereby reducing the FRS companies' apparent commitment to diversified enterprises.

Retrenchment paid off, as the rate of return to the other nonenergy line of business generally rose over the period.

1990 to 1997 – Reduced Commitment Appears to Hold Steady

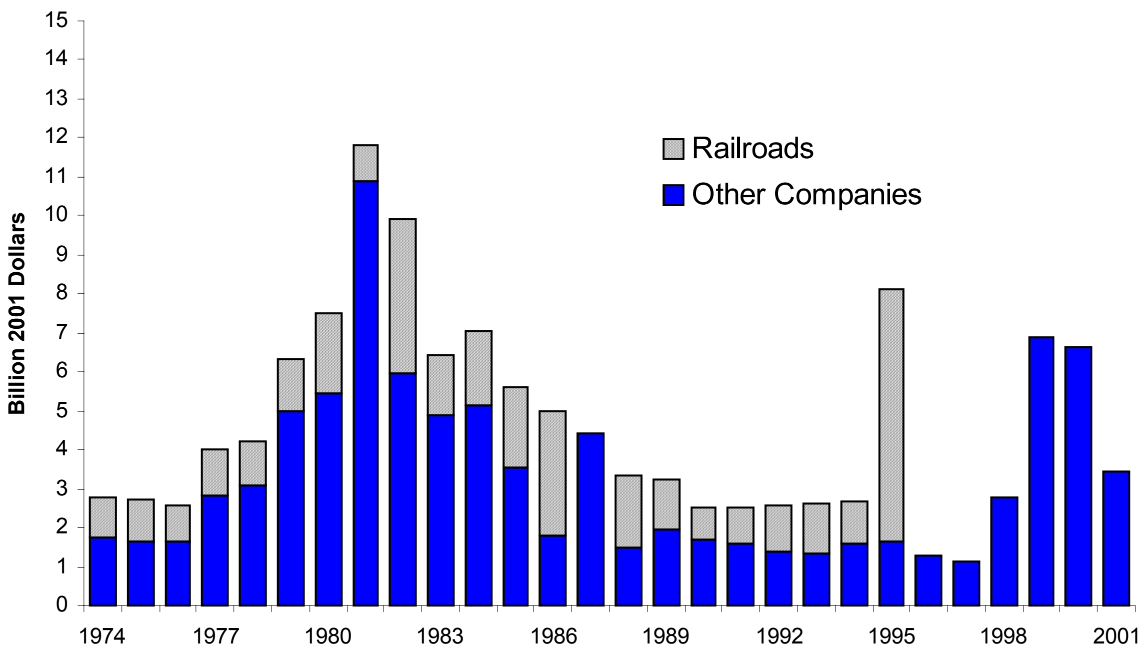
Excluding the railroads, the FRS companies' net investment in place in other nonenergy changed little, both in value and as a share of total net investment. However, most companies reduced their commitment to this line of business during the 1990 to 1997 period. BP, Kerr-McGee, Occidental Petroleum, Sunoco, and Texaco completed their exits from the other nonenergy line of business.

An exception to this trend was Exxon Mobil. Over the period, this company continued to add to their asset base in Chilean copper production and electricity production in Hong Kong. Hong Kong Electric was classified in the other nonenergy line of business until 1998. Exxon Mobil reclassified the subsidiary into the "other energy" line of business per EIA request. This change largely accounts for the dip in the other nonenergy share of net investment in 1998.

1998 to 2000 – The Short-lived Telecommunications Boom

In 1997, capital expenditures for the other nonenergy line of business, adjusted for inflation, were at the lowest level over the 1974 to 2001 period of FRS data collection (Figure 35). Capital expenditures then surged in the 1998 to 2000 period, reaching a level second only to that of 1981. The upswing was largely due to investments in telecommunications. (Telecommunications in this context consists mostly of fiber optic networks but also includes broadband services.) The investments appear to have been premised on achieving synergies with existing pipeline networks and energy trading operations.

Figure 35. Other Nonenergy Additions to Investment in Place, 1974-2001



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

Taking advantage of their transmission and distribution networks, Williams Companies and Enron led the investment in telecommunications. Williams owned or leased and operated a national inter-city fiber optic network. These assets were used to provide communications services to a variety of businesses. Williams reported capital expenditures for its "Communications" business of $0.5 billion in 1997 and 1998, $1.7 billion in 1999, and $3.4 billion in 2000.[d] Enron, through 2000, was constructing a fiber optic communications network in the United States and had related facilities in Tokyo and seven major European cities. Enron reported ownership and contractual interest of 18,000 miles of fiber optic network capacity in the United States. The company also reported that it was developing a trading platform for broadband services.[e]

Enron also made other sizable investments in other nonenergy businesses during the period. In 1998, Enron acquired water supply and wastewater services assets in the United Kingdom for $0.9 billion. These assets were the core for Azurix, a global water and wastewater services business. In 2000, Enron acquired MG plc, an international metals trading company, in a transaction valued at $2.0 billion.

2001 – Telecommunications Divested, U.S. Steel Departs

In April 2001, Williams Companies spun off its subsidiary, Williams Communications, to its shareholders. This transaction excised the company's telecommunications business from the FRS database. Enron, and its nonenergy assets, exited the FRS due to its bankruptcy filing in December 2001 (see the Highlight entitled, "What Factors Undermined Enron's Success in Energy Trading?" in Chapter 3). In April 2001, FRS company USX announced its intention to spin off its U.S. Steel subsidiary to shareholders. The spin off (separating U.S. Steel's operations from the FRS database and leaving Marathon Oil as the FRS respondent) was completed at year-end.

The above developments accounted for the fall in capital expenditures for other nonenergy in 2001. In 2001, the other nonenergy line of business' share of total net investment of the FRS companies was down to 1 percent (Figure 34).

Are there any prospects for a resurgence of nonenergy businesses as targets of investment of the U.S. major energy companies? Based on past experience and the realities of today's capital markets, it seems unlikely that even another huge increase in cash flow comparable to that of the 1974 to 1981 period would induce an upswing in diversification. One possibility, though, lies in development and manufacture of plant and equipment for renewable energy production. Examples include solar energy systems and wind energy turbines.[f] Investments such as these, although directed ultimately to energy production, would be considered to be in manufacturing and fall into the other nonenergy line of business.

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[a]The first two sections draw on material first presented in Chapter 6 of *Performance Profiles of Major Energy Producers 1993* http://www.eia.doe.gov/emeu/finance/histlib.html
[b]Energy Information Administration, *Historical Monthly Energy Review* 1973-1992, DOE/EIA-0035(73-92)(Washington D.C., August 1994), p. 249.
[c]BP America, the U.S. subsidiary of BP plc of the United Kingdom, is the FRS respondent.
[d]The Williams Companies, Inc., 2000 Securities and Exchange Commission Form 10K, p. F-62.
[e]Enron Corporation, 2000 Securities and Exchange Commission Form 10K, p. 11.
[f]For example, see BP at http://wwww.bp.com/environ_social/environment/renew_energy/our_perform.asp and Shell Oil at http://www.shell.com/home/Framework?siteId=rw-br.

SPECIAL TOPIC: The FRS Companies Refocus on LNG

Liquefied natural gas (LNG) is natural gas that has been chilled sufficiently to become liquid in form. For analytic purposes, LNG is best viewed not as a separate fuel unto itself, but instead simply as natural gas that has been transformed into liquid form. Natural gas is converted to liquid form primarily for transportability by water, since there may be insufficient or no natural gas pipeline capacity in the production area to transport the natural gas anywhere, or at least to the desired marketing area. Landlocked areas with natural gas resources require a pipeline for delivery to a body of water for shipping. Once converted to LNG, the gas is transported in chilled containers aboard ship.

The first appearance of LNG to any significant commercial extent was in the 1960's in Algeria.[a] In the 1970's the first LNG projects in the United States were initiated, due to the economic environment --

domestic natural gas prices had increased to high levels, and government regulation of the natural gas market had contributed to creating supply shortages.

In the 1980's, the tight market situation eased as natural gas prices dropped dramatically, contrary to the long-term expectations formed during the 1970's. As domestic supplies of natural gas proved sufficient, the LNG market in the United States shrunk, the result being that operations at two of the four LNG import facilities in the U.S. were discontinued.

In the 1990's, a variety of developments occurred leading to the reemergence of a stronger LNG market, on both the supply and demand side. Consumption of natural gas has increased steadily, as it has become a fuel of choice for environmental reasons. In the electric power generation sector, advances in natural gas-fired generation technologies such as combined-cycle technologies have boosted demand significantly, as most electric generation capacity additions are natural gas-fired.

In addition, the growth of oil production has, as a byproduct, led to increased availability of natural gas suitable for little else but to be transformed into LNG. Oil exploration and development has gradually moved to more remote areas, including many offshore sites, where there is no pipeline infrastructure to market the associated natural gas that is produced. As a result, more "stranded gas" needs to be dealt with, some of which is currently just flared. This gas represents a low-cost source of supply of natural gas suitable for LNG.

Meanwhile, costs of delivering natural gas in liquefied form have declined throughout the supply chain in recent years.[b] Liquefaction costs have declined. Shipping costs have also declined as ships employ more modern technologies. In addition, companies continue testing new technologies, such as regasifying the LNG on specialized ships located offshore the market area, which may have the potential to further boost LNG trade volumes.

In the post-2000 era, natural gas prices are expected to rise to $3.26 per thousand cubic feet (mcf) (in 2001 dollars) in the year 2020.[c] Demand is expected to continue to grow, and domestic supplies are expected to be insufficient by themselves to meet that demand. Imports of natural gas by pipeline from Canada are expected to remain the main supplement to domestic supplies. However, LNG represents an additional source of supply for domestic needs and is expected to grow significantly.

The United States imported 238 billion cubic feet (bcf) of LNG in 2001, with 93.9 percent of the total coming from Trinidad, Algeria, Nigeria, and Qatar (Table 23). The United States exported 7 billion cubic feet of LNG in 2001 to two countries, Japan and Mexico; all but 0.6 percent goes to Japan, and is exported from the Kenai LNG Marine Terminal on Alaska's Kenai Peninsula.

Table 23. LNG Imports to the United States by Origin, 2001
(Million Cubic Feet)

	Algeria	Australia	Nigeria	Qatar	Trinidad	Other	Total
Imports	64,945	2,394	37,966	22,758	98,009	12,055	238,127

Source: Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0130(2002/09) (Washington, D.C., September 2002), Table 5.

The FRS companies play an integral role in the domestic LNG market. The FRS companies own two of the four LNG import and regasification facilities on the mainland United States, as well as the sole U.S. liquefaction and export facility, which is on Alaska's Kenai Peninsula.

As discussed in the EIA report *The Majors Shift to Natural Gas* (link to http://www.eia.doe.gov/emeu/finance/sptopics/majors/ind), the FRS companies have increasingly become natural gas companies. Since these companies have significant experience with all aspects of natural gas markets and technologies, they are well positioned to be leaders in the development of LNG projects and growth of LNG markets. In addition, due to their size they tend to have the "deep pockets" helpful to finance such large-scale projects, including liquefaction facilities, LNG ships, and regasification facilities.

Existing and Planned LNG Facilities of the FRS Companies

To see how the FRS companies plan on using their capital to ensure their place in the domestic as well as worldwide LNG market, it is useful to understand what their current LNG plants and projects are, and what planned facilities they have announced, both domestically and abroad.

El Paso Corporation. El Paso has only one existing LNG facility, an LNG terminal at Elba Island, near Savannah, Georgia. This facility, which has a capacity of 446 million cubic feet (mmcf) per day, is owned by El Paso's subsidiary Southern LNG.[d] Although the facility was mothballed in 1982, it was reactivated in December 2001. Activity at this reopened facility has been slow; over six months passed before a second LNG cargo arrived in April, from Trinidad.

Nonetheless, El Paso plans a major expansion at Elba Island. By 2005, the company plans to expand the terminal's storage capacity by 3.3 bcf, or approximately 80 percent, to 7.3 bcf.[e] This expansion will increase the facility's regasification send-out rate by 360 mmcf per day, to approximately 800 mmcf per day. The company estimates the expansion will cost $145 million. The facility will supply natural gas to markets in Georgia, Florida and South Carolina.

The existing 446 mmcf per day LNG capacity is owned by another El Paso subsidiary, El Paso Merchant Energy Company, which holds the right to 100 percent of that capacity. Relative to the planned expansion, however, Shell Gas & Power has contracted with El Paso for rights to all of that additional capacity, for a 30-year term. This capacity will provide an outlet for West African and South American LNG projects in which Shell has ownership interests.

In addition, El Paso has explored a variety of other potential LNG projects, mainly new regasification terminals. Some or all of the facilities would be offshore, using regasification ships that El Paso would commission specifically for the purpose of receiving supplies from traditional LNG ships. Offload rates would be 400-500 mmcf per day, a rate slower than with conventional regasification terminals due to the lack of floating storage facilities. The following list enumerates the leading options, although it is not clear at this time which of these projects will actually come to pass.

Regasification Facilities

- Baja California, Mexico: El Paso Global LNG and Phillips Petroleum Company are jointly developing plans for an LNG regasification terminal in Baja California, Mexico to provide supplies to California and northern Mexico. The facility would deliver approximately 212 bcf per year of LNG to markets in Southern California and Mexico's Baja California peninsula.[f] Supplies of LNG would be purchased by El Paso from a plant to be built by Phillips near Darwin, Australia. Once transported to and regasified at the new LNG terminal in Baja California, this will provide a new source of natural gas supplies to the growing Southern California markets. El Paso would be the marketer of the natural gas. Plans are for LNG sales to El Paso to begin in 2005.

- Altamira, Mexico: El Paso Global LNG and Shell Gas and Power have signed an agreement for construction of a 0.5-to-1.0-bcf-per-day LNG regasification terminal in Mexico's east coast Tamaulipas state at Altamira.[g] The joint venture facility would receive gas from Africa, the Caribbean, and South America and provide supplies to northeastern Mexico, primarily for increasing electric power usage.

- The Bahamas: El Paso Global LNG has developed plans for an LNG terminal in the Bahamas. If built, this terminal could be linked with the Bahama Cay international pipeline and the associated Bahama Cay pipeline. In October 2001, each of these pipelines held open seasons to measure shipper interest in capacity on the combined 125-mile system.[h]

Shipping Services

In tandem with El Paso's plans for LNG receiving and regasification facilities, El Paso is contracting for transportation services for the proposed offshore gas terminals. The El Paso subsidiary El Paso Shipping Holding Company has entered into four long-term charter party arrangements for LNG vessels and holds options for charter parties on additional vessels. The ships would be constructed in South Korea with deliveries commencing in 2003.[i]

Natural Gas Supplies

Completing the planning picture, El Paso Global LNG has entered into several contracts for LNG supply.[j] One is a contract entered into in October 2001 with the Snohvit Sellers Group of Norway to bring 88 bcf of LNG to the North American east coast. Another is a contract with Port Fortin LNG Export Partners providing access to 102 bcf of LNG from Port Fortin, Trinidad.

The Williams Companies. As of the end of 2001, Williams' biggest LNG facility is its major import and regasification facility at Cove Point in Lusby, Maryland. It connects to the Williams Gas Pipeline's Transco system, delivering supplies to the Mid-Atlantic region. The facility has a storage capacity of 5 bcf, and a regasification send-out capacity of 1 bcf per day, with capacity to expand to 3 bcf per day.[k] Cove Point will become the nation's largest LNG import facility once the renovation and reactivation is complete with a send-out capacity of 1 bcf per day. It was constructed in the mid-1970's at a cost of approximately $400 million.[l] Williams purchased the Cove Point facility in June 2000 from affiliates of Columbia Energy Group. The facility operated from 1978 to 1980, at which time it was closed. In 1995 it was partially reactivated to provide natural gas peaking services.

In October 2001, the U.S. Federal Energy Regulatory Commission (FERC) authorized Williams to reactivate the Cove Point LNG facility and to expand it.[m] Construction began in 2002, with a proposed in-service date for the reactivated facility in the spring of 2003, and a new fifth tank expected to be operational by the 4th quarter of 2004. After expansion, the storage capacity will be 7.8 bcf. The total project is estimated to cost approximately $103 million.

Trinidad and Tobago are expected to be the main supplier of LNG to the facility. The LNG tanker discharging service is fully subscribed under 20-year binding agreements.

In addition to the Cove Point facility, The William Companies own and operate three other LNG facilities in the United States.[n] These facilities are peak-shaving facilities – facilities in which natural gas is liquefied and injected into a storage tank during periods of low natural gas demand, for later vaporization and injection into the pipeline system during high demand periods. These facilities are:

- Transco Station 240: This facility, located in Carlstadt, New Jersey, connects to the Williams Gas Pipeline's Transco system. It has a storage capacity of 2 bcf.

- Pine Needle LNG Facility: This facility, located in Stokesdale, North Carolina, also connects to the Williams Gas Pipeline's Transco system. It has a storage capacity of 4 bcf.
- Northwest Plymouth LNG: This facility, located in Plymouth, Washington, connects to the Williams Gas Pipeline's West system. It has a storage capacity of 2.4 bcf.

Dominion Resources. Note that in September 2002, Dominion Resources, another FRS respondent, bought the Cove Point LNG facility (described above under The Williams Companies) from The Williams Companies in a transaction valued at $217 million.[o]

ChevronTexaco. ChevronTexaco, from the Chevron side of its recent merger, has ownership in two major production ventures in Australia:[p]

- a 16.7-percent ownership share in the North West Shelf (NWS) Project, an area 1,000 miles north of Perth and 70 to 90 miles offshore. About 1 bcf of gas per day in the form of LNG was sold primarily under long-term contract to Japanese utilities. In addition, NWS Partners formed Australia LNG in 1999 to market the LNG. Australia LNG markets uncommitted gas to new Asian markets outside Japan, in particular Korea, China, India and Taiwan.
- a significant, but minority share in the West Australian Petroleum Pty Ltd. (WAPET) operated permit areas.

ChevronTexaco is also evaluating both offshore California and Baja California for one or more LNG import facilities.

From the Texaco side of its recent merger, ChevronTexaco is considering building an offshore LNG receiving terminal off the coast of Louisiana south of the Henry Hub natural gas pipeline interconnection.[q] This location has the advantage of an extensive pipeline grid that is already in-place to deliver the regasified supply. ChevronTexaco is also considering building an LNG plant in Angola, where it has extensive offshore oil and associated gas reserves.

Marathon Oil Corporation. In partnership with Pertamina, Golar LNG Limited, and Gropo GGS, S.A. de C.V., Marathon has developed plans for an LNG marine terminal and re-gasification facility and a 400-megawatt power generation plant near Tijuana in the Mexican State of Baja California.[r] Output capacity would be 1 bcf of natural gas per day, for both local consumption and export, with operation to begin in 2005. The project would supply natural gas and electricity domestically to the Mexican State of Baja California and for export to southern California.

A significant portion of the LNG for the Baja Project is expected to be supplied from the Asia-Pacific region, in particular, by Pertamina, the state-owned oil company of Indonesia.

Phillips Petroleum Company. Phillips Petroleum is the operator and a 70-percent majority owner of the only LNG export facility in the United States, located at Port Nikiski on the Kenai Peninsula in southern Alaska.[s] Phillips built this 230-mmcf-per-day export facility in a joint venture with Marathon, which owns a 30-percent share of the facility.[t] Export began in 1969, under a 15-year contract to supply LNG to Tokyo Electric and Tokyo Gas. Shipping to those two utilities has continued since then uninterrupted. As part of the venture, Marathon pioneered the development of the world's first ocean tankers specially designed to transport LNG.[u] The Kenai plant initiated the Pacific LNG trade. While Phillips operates the LNG facility itself, Marathon coordinates shipping to the Japanese utilities on behalf of the joint venture.[v] In this role, Marathon delivered over 78 bcf of natural gas to Asia in 2001.[w] Phillips developed the (self-named) Phillips' Optimized Cascade LNG Process for liquefaction, first used in the Kenai LNG facility.[x] Phillips licenses its proprietary LNG manufacturing technology to other users worldwide, with current capacity in place of approximately 400 bcf per year.

Phillips also is a partner in a number of other LNG projects. Their participation in the Baja California, Mexico project has already been described in the El Paso section of this special topic. Other such partnerships include:

- Timor Sea LNG to Japan: Under the name of its subsidiary, Darwin LNG Pty Ltd and other Australian affiliates, Phillips has signed an agreement to develop the Bayu-Undan project in the Timor Sea.[y] The Bayu-Undan field contains estimated reserves of 3.4 trillion cubic feet of natural gas. The field is about 500 kilometers northwest of Darwin, Australia, and 250 kilometers south of Suai, East Timor. In an agreement with the Tokyo Electric Power Company and Tokyo Gas Company, 130 bcf per year of LNG would be supplied over a 17-year period. The first delivery is scheduled for January 2006. As part of the project, Phillips would build an LNG facility at Wickham Point near Darwin, Australia. The full cost of developing the Bayu-Undan, building the associated pipelines and the LNG plant, is estimated at approximately $3 billion. Phillips is operator of the Bayu-Undan project, with a controlling interest of 58.6 percent (after a planned sale of a 10.08-percent interest in the Bayu-Undan field to Tokyo Electric Power and Tokyo Gas). Kerr-McGee Corporation, another FRS company, is among the other participants in this project, with an interest of 11.2 percent. The project requires approval from the Australian Government.

  Nigerian LNG: Phillips' subsidiary Phillips Oil Company (Nigeria) Limited, entered into an agreement in September 2001 (in partnership with the Nigerian National Petroleum Company, and the Nigerian Agip Oil Company) to develop a new offshore LNG facility in Nigeria.[z] This preliminary agreement establishes a study team to evaluate the project. If initiated and completed, the facility would have a capacity of 240 bcf per year, and be located offshore in the Niger Delta near the existing Brass River crude terminal. Onshore oil and gas fields, already operated by an existing joint venture among the same companies would supply the natural gas.

Exxon Mobil. Exxon Mobil Corporation, through its subsidiaries, has had a presence in Qatar since 1935.[aa] The company has a 25-percent interest in the RasGas joint venture in Qatar, with production capacity of 290 bcf per year.[bb] Exxon Mobil also has 10-percent interest in Qatargas LNG facilities, which sold over 6 million tons of LNG in 2000.

In addition, Exxon Mobil, with a 30-percent interest in joint venture with Qatar Petroleum (70 percent), in 2001 entered into a sales agreement with Petronet Ltd. of India to supply LNG for 25 years, with 240 bcf per year to be delivered beginning in 2003 to an import terminal at Dahej, Gujarat State, that is currently under construction.[cc]

BP. [dd] Trinidad and Tobago**:** A subsidiary of BP, BP Trinidad and Tobago Company (formerly Amoco Trinidad), is the largest shareholder (at a 34-percent interest) of Atlantic LNG Company of Trinidad and Tobago, which was formed in July of 1995.[ee] Atlantic LNG built an LNG facility in Point Fortin in Trinidad and Tobago, which began operation in 1999. In that year, Atlantic exported 51 billion cubic feet of natural gas to the United States and 25 billion cubic feet to Spain.

BP supplies all of the natural gas for Train I of the Atlantic LNG project. This facility is currently being expanded with the addition of two additional trains currently under construction at a cost of $1.1 billion, which will add 3.3 million metric tons per year each by late 2003.[ff] This expansion will triple Atlantic's LNG export capacity.

China: China is planning an LNG import terminal in Guangdong province, which, in 2001, BP won the right to build though not necessarily supply.[gg] If it were to earn supply rights, BP Amoco would likely turn to the Tangguh project in Irian Jaya, Indonesia for supply.

Basque Region of Spain: In 2000, BP Amoco initiated a project scheduled for completion in 2003, to put an LNG plant in the port of Bilbao in Spain's Basque region, along with a companion 1200 megawatts power plant which would use the LNG. BP has a 25-percent share in this project, called Bahia de Bizkaia, along with its partners Repsol-YPF, Iberdrola, and the Basque energy authority Eve. The project's regasification plant is slated to have a capacity of 95 billion cubic feet per year.[hh]

What Might the Future Hold for LNG?

According to the Energy Information Administration's (EIA's) *Annual Energy Outlook 2003,* demand for natural gas is slated to increase over the long haul, as are natural gas prices. Therefore, it is likely there will be strong incentives to find and produce more natural gas in the future.

As existing natural gas reserves get depleted, producers will need to turn to new sources, including natural gas in more remote areas. Many areas with natural gas lack the necessary infrastructure for local consumption of the resource: a pipeline grid and energy users with natural gas-fired technologies for residential heating, power production, and the like. Such areas with limited potential for local use for the natural gas are candidates to be sources of LNG in the future.

The expectation of rising natural gas prices, along with the potential continued decline in the costs in the LNG supply chain -- liquifying the natural gas, transporting it in the form of LNG, and regasifying -- makes LNG appear likely to grow in the future.[ii] For more information on possible future LNG scenarios, see the EIA service report entitled *U.S. Natural Gas Markets: Mid-Term Prospects for Natural Gas Supply* (available on the Internet at http://www.eia.doe.gov/oiaf/servicerpt/natgas/index.html).

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[a]Royal Dutch Shell initiated export of LNG from Algeria to the United Kingdom. See *Oil & Gas Journal*, Volume 99.29 (July 16, 2001), p. 60.
[b] See "LNG Costs and Markets Have Changed in Recent Years," Petroleum News Alaska, March 28, 2001, P.1. Web address: http://www.petroleumnewsalaska.com/pnarch/010328-25.html.
[c]Energy Information Administration, *Annual Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001), p. 3. Web address: http://www.eia.doe.gov/oiaf/aeo/index.html (as of November 19, 2002).
[d]El Paso Corporation, May 2002 discussion on "El Paso Global LNG." Web address: http://www.epenergy.com/portfolio/lng.asp.
[e]El Paso Corporation, Press Release (September 10, 2001).
[f] El Paso Corporation, November 2002 discussion on "Planning for Tomorrow's Capacity." Web address: http://www.epenergy.com/portfolio/lng_future.asp. Also, Phillips Petroleum Company, Press Release (March 8, 2001).
[g]El Paso Corporation, November 2002 discussion on "Planning for Tomorrow's Capacity." Web address: http://www.epenergy.com/portfolio/lng_future.asp. Also, Energy Information Administration, *International Energy Outlook 2002*, DOE/EIA-0383(2002) (Washington, DC, December 2001). Web address: http://www.eia.doe.gov/oiaf/ieo/nat_gas.html.
[h]El Paso Corporation, November 2002 discussion on "Planning for Tomorrow's Capacity." Web address: http://www.epenergy.com/portfolio/lng_future.asp.

[i]El Paso Corporation, May 2002 discussion on "Ensuring Supply Security." Web address: http://www.epenergy.com/portfolio/lng_supply.asp.
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[k]The Williams Companies, Inc., November 2002 discussion on "Cove Point LNG Terminal." Web address: http://www.williams.com/productservices/gaspipelines/covepoint.jsp.
[l]The Williams Companies, Inc., Press Release (May 3, 2000).
[m]The Williams Companies, Inc., Press Release (October 12, 2001).
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[o]Dominion Resources, Inc., Press Release (September 5, 2002).
[p]ChevronTexaco Corporation, November 2002 discussion on "Worldwide Upstream." Web address: http://www.chevron.com/about/annual%2Dsupplement/p12.html.
[q]ChevronTexaco Corporation, Press Release (May 15, 2001). Also *LNG Express* (May 24, 2001). Web address: http://www.lngexpress.com/lng2001/pressrelease.asp.
[r]Marathon Oil Corporation, Press Release (February 28, 2002). Also, Marathon Oil Corporation, November 2002 discussion on "Integrated Natural Gas." Web address: http://www.marathon.com/our_business/marathon_oil_company/integrated_natural_gas/default.htm.
[s]Phillips Petroleum Company, Press Release (September 14, 2000).
[t]Marathon Oil Corporation, Press Release (February 28, 2002). Also, Marathon Oil Corporation, November 2002 discussion on "Integrated Natural Gas." Web address: http://www.marathon.com/our_business/marathon_oil_company/integrated_natural_gas/default.htm.
[u]Marathon Oil Corporation, "Our History" section of company web site. Web address: http://www.marathon.com/about_us/our_history/default.htm (as of November 19, 2002).
[v]Marathon Oil Corporation, Press Release (February 28, 2002). Also, Marathon Oil Corporation, November 2002 discussion on "Integrated Natural Gas." Web address: http://www.marathon.com/our_business/marathon_oil_company/integrated_natural_gas/default.htm.
[w]Marathon Oil Corporation, Press Release (February 28, 2002). Also, Marathon Oil Corporation, November 2002 discussion on "Alaska." Web address: http://www.marathon.com/our_business/marathon_oil_company/production/alaska/default.htm.
[x]Phillips Petroleum Company, Press Release (September 14, 2000).
[y]Phillips Petroleum Company, Press Release (March 12, 2002).
[z]Phillips Petroleum Company, Press Release (September 7, 2001).
[aa]Exxon Mobil Corporation, Press Release (April 4, 2001).
[bb]Exxon Mobil Corporation, *2000 Financial & Operating Review*. Web address: http://www.exxonmobil.com/shareholder_publications/c_fo_00/c_upstream_11.html
[cc]Exxon Mobil Corporation, Press Release (April 4, 2001).
[dd]BP America, the U.S. subsidiary of BP plc of the United Kingdom, is the FRS respondent.
[ee]Petroleum Economist, Fundamentals of the Global LNG Industry 2001, p.89.
[ff]*International Energy Outlook 2002*, Energy Information Administration. Web address: http://www.eia.doe.gov/oiaf/ieo/nat_gas.html.
[gg]BP, December 2002 discussion on "Business Overview." Web address: http://170.224.225.30/location_rep/china/bus_overview/index.asp. Also, *International Energy Outlook 2002*, Energy Information Administration. Web address: http://www.eia.doe.gov/oiaf/ieo/nat_gas.html.
[hh]Petroleum Economist, Fundamentals of the Global LNG Industry 2001, p.89.
[ii]See Overview section of *Annual Energy Outlook 2002*, Energy Information Administration. Web address: http://www.eia.doe.gov/oiaf/archive/aeo02/index.html. Also see "LNG Costs and Markets Have Changed in Recent Years," Petroleum News Alaska, March 28, 2001, P.1. Web address: http://www.petroleumnewsalaska.com/pnarch/010328-25.html.

Appendix A

The Financial Reporting System (FRS)

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

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

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

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

Appendix B

Detailed Statistical Tables

Table B1. Selected U.S. Operating Statistics for FRS Companies and U.S. Industry, 1995-2001

Operating Statistics	1995	1996	1997	1998	1999	2000	2001
Petroleum and Natural Gas							
Net Production							
Crude Oil and Natural Gas Liquids (million barrels)							
FRS Companies	1,570.6	1,532.4	1,458.8	1,388.8	1,305.7	1,267.9	1,363.2
U.S. Industry[1]	3,004.0	3,023.0	3,002.0	2,824.0	2,848.0	2,801.0	2,805.0
FRS as a Percent of U.S. Industry	52.3	50.7	48.6	49.2	45.8	45.3	48.6
Natural Gas (billion cubic feet)							
FRS Companies	8,055.3	8,191.6	8,299.1	8,395.9	7,994.1	8,340.1	8,838.0
U.S. Industry[1]	17,966.0	18,861.0	19,211.0	18,720.0	18,928.0	19,219.0	19,779.0
FRS as a Percent of U.S. Industry	44.8	43.4	43.2	44.8	42.2	43.4	44.7
Net Imports							
Crude Oil and Natural Gas Liquids (million barrels)							
FRS Companies	612.1	565.7	571.1	634.7	474.9	324.1	716.1
U.S. Industry[1]	2,810.0	2,946.6	3,191.0	3,358.5	3,366.4	3,527.0	3,620.1
FRS as a Percent of U.S. Industry	21.8	19.2	17.9	18.9	14.1	9.2	19.8
Refinery Capacity (thousand barrels per day)							
FRS Companies	10,427.0	10,477.0	9,410.0	14,277.0	14,158.0	14,378.0	14,586.0
U.S. Industry[1]	15,981.0	16,031.8	16,128.7	16,567.0	16,787.0	17,177.4	16,367.4
FRS as a Percent of U.S. Industry	65.2	65.4	58.3	86.2	84.3	83.7	89.1
Refinery Output[2] (thousand barrels per day)							
FRS Companies	10,652.0	10,954.0	10,030.0	14,929.0	14,639.0	14,499.0	15,022.0
U.S. Industry[1]	16,534.7	16,800.7	17,234.3	17,499.6	17,493.1	17,763.2	17,688.9
FRS as a Percent of U.S. Industry	64.4	65.2	58.2	85.3	83.7	81.6	84.9
Coal Production							
(million tons)							
FRS Companies	165.4	169.4	163.3	73.9	44.0	35.5	33.0
U.S. Industry[1]	1,033.0	1,063.9	1,089.9	1,117.5	1,100.4	1,073.6	1,127.7
FRS as a Percent of U.S. Industry	16.0	15.9	15.0	6.6	4.0	3.3	2.9

[1] U.S. area is defined to include the 50 States, District of Columbia, U.S. Virgin Islands, and Puerto Rico.

[2] For FRS companies, includes refinery output at own refineries for own account and at others' refineries for own account.

Note: The data for total U.S. production of crude oil and natural gas liquids and natural gas (dry) utilized in this report are taken from Energy Information Administration, Form EIA-23 (Annual Survey of Domestic Oil and Gas Reserves); see U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 2001 Annual Report November 2002). 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 2,940 million barrels in 2001 and 2,968 million barrels in 2000. (See Energy Information Administration, Petroleum Supply Annual 2001, Volume I (June 2002), p. 2.) For dry natural gas production, the official Energy Information Administration U.S. totals are 19,449 billion cubic feet in 2001 and 18,987 billion cubic feet in 2000. (See Energy Information Administration, Natural Gas Monthly, September 2002, Table 1.)

Sources: Industry data - Petroleum net production: Energy Information Administration, Form EIA-23; see U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 2001 Annual Report (November 2002). Net imports: data compiled for the International Energy Agency by the Petroleum Supply Division, Office of Oil and Gas, Energy Information Administration. Refinery capacity and refinery output: Energy Information Administration, Forms EIA-820 (Annual Refinery Report) and EIA-810 (Monthly Refinery Report); see Petroleum Supply Annual, 2000 and 2001. Coal production: 1995-2000--EIA, *Coal Industry Annual*, annual reports; 2001 - EIA, *Annual Coal Report 2002*.

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, 2000-2001
(Billion Dollars)

Selected Financial Items	FRS Companies 2000	FRS Companies 2001	S&P Industrials 2000	S&P Industrials 2001
Income Statement				
Operating Revenues	910.6	803.7	4,712.6	4,841.7
Operating Expenses	-826.8	-735.6	-4,146.2	-4,386.4
Operating Income	83.8	68.1	566.4	455.3
Interest Expense	-10.6	-9.1	-97.7	-103.0
Other Income[1]	15.0	6.3	24.9	-104.2
Income Taxes	-35.0	-27.7	-184.9	-112.2
Net Income	53.2	37.7	308.7	136.0
Cash Flows from Operations[2]				
Net Income	53.2	37.7	308.7	136.0
Other Items, Net[3]	35.4	51.9	253.8	449.8
Net Cash Flow from Operations	88.6	89.6	562.5	585.7
Cash Flows from Investing Activities[2]				
Additions to Property, Plant & Equipment	-102.2	-100.3	-355.9	-369.1
Other Investment Activities, Net[4]	28.2	6.0	-202.3	-112.4
Net Cash Flow from Investing Activities	-73.9	-94.3	-558.2	-481.5
Cash Flows from Financing Activities[2]				
Proceeds from Long-Term Debt	33.3	55.0	435.3	537.8
Proceeds from Equity Security Offerings	30.6	6.3	69.5	70.7
Dividends to Shareholders	-19.0	-17.1	-95.4	-98.5
Reductions in Long-Term Debt	-29.3	-34.3	-308.8	-369.4
Stock Repurchases	-5.4	-7.5	-122.8	-111.1
Other Financing Activities, Net	-17.2	3.8	33.3	-58.1
Net Cash Flow from Financing Activities	-7.0	6.2	11.0	-28.7
Effect of Exchange Rate Changes on Cash	-0.1	-0.3	-3.8	-2.8
Increase (Decrease) in Cash and Cash Equivalents	7.6	1.3	11.4	72.8

[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, 2000-2001

	FRS Companies		S&P Industrials	
	2000	2001	2000	2001
Balance Sheet	(billion dollars)			
Assets				
Current Assets	196.5	147.5	1,436.5	1,454.5
Noncurrent Assets				
Property, Plant, and Equipment (PP&E)				
Gross	757.2	806.0	2,970.1	3,194.0
Accumulated Depreciation, Depletion, and Amortization (DD&A)	-351.6	-373.6	-1,336.3	-1,425.3
Net PP&E	405.5	432.4	1,633.8	1,768.7
Investments and Advances	62.3	57.3	189.8	169.4
Other Noncurrent Assets	86.9	97.9	2,549.4	2,909.3
Subtotal Noncurrent Assets	554.8	587.5	3,042.5	3,301.3
Total Assets	751.2	735.0	5,809.4	6,301.9
Liabilities and Stockholders Equity				
Liabilities				
Current Liabilities	198.8	159.8	1,144.3	1,134.1
Long-Term Debt	120.0	132.0	1,136.3	1,399.1
Other Long-Term Items	143.6	144.0	1,451.1	1,535.7
Minority Interest	17.1	15.5	77.9	82.9
Subtotal Liabilities and Other Items	479.5	451.3	3,809.7	4,151.7
Stockholders' Equity				
Retained Earnings	199.2	209.7	1,249.1	1,127.8
Other Equity	72.5	74.0	750.5	1,022.4
Subtotal Stockholders' Equity	271.8	283.7	1,999.6	2,150.2
Total Liabilities and Stockholders' Equity	751.2	735.0	5,809.4	6,301.9
Financial Ratios	(percent)			
Net Income/Stockholders' Equity	19.6	13.3	15.4	6.3
Net Income plus Interest/Total Invested Capital	16.3	11.3	13.0	6.7
Dividends/Net Cash Flow from Operations	21.4	19.1	17.0	16.8
Long-term Debt/Stockholders' Equity	44.2	46.5	56.8	65.1

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, 1995-2001
(Billion Dollars)

Balance Sheet Items	1995	1996	1997	1998	1999	2000	2001
Assets							
Current Assets							
Cash & Marketable Securities	12.2	13.4	12.2	8.1	12.2	18.7	18.6
Trade Accounts & Notes Receivable	48.8	56.2	51.2	47.8	68.1	98.6	71.4
Inventories							
Raw Materials & Products	22.6	22.7	21.4	21.6	23.3	25.6	23.4
Materials & Supplies	4.1	3.8	3.7	3.8	3.9	4.4	7.3
Other Current Assets	10.9	12.1	12.4	12.9	13.4	49.1	26.7
Total Current Assets	98.6	108.2	100.9	94.2	121.0	196.5	147.5
Non-current Assets							
Property, Plant & Equipment (PP&E)							
Gross PP&E	640.2	635.0	636.9	671.0	708.0	757.2	806.0
Accumulated Depreciation, Depletion, and Amortization	-329.8	-331.6	-333.3	-334.5	-355.5	-351.6	-373.6
Net PP&E	310.5	303.4	303.6	336.5	352.5	405.5	432.4
Investments & Advances	29.0	32.3	44.2	53.9	58.2	62.3	57.3
Other Non-current Assets	26.5	26.8	35.2	35.8	39.6	86.9	97.9
Total Non-current Assets	366.0	362.4	382.9	426.3	450.3	554.8	587.5
Total Assets	464.6	470.6	483.8	520.4	571.3	751.2	735.0
Liabilities & Stockholders' Equity							
Liabilities							
Current Liabilities							
Trade Accounts & Notes Payable	53.1	61.4	57.7	62.8	79.4	102.4	90.6
Other Current Liabilities	50.8	48.8	49.2	51.1	51.9	96.4	69.2
Long-Term Debt	84.6	70.9	73.4	94.6	104.0	120.0	132.0
Deferred Income Tax Credits	45.5	45.5	46.3	49.0	53.1	68.2	77.0
Other Deferred Credits	17.3	19.2	18.8	18.4	18.8	34.1	23.3
Other Long-Term Items	40.7	40.6	41.6	39.7	42.6	41.2	43.7
Minority Interest in Consolidated Affiliates	5.8	6.6	8.2	10.4	15.2	17.1	15.5
Total Liabilities	297.9	292.9	295.1	326.0	364.9	479.5	451.3
Stockholders' Equity	151.4	156.3	160.8	165.8	170.6	199.2	209.7
Retained Earnings	15.3	21.4	27.9	28.7	35.7	72.5	74.0
Other Equity							
Total Stockholders' Equity	166.7	177.8	188.7	194.4	206.3	271.8	283.7
Total Liabilities & Stockholders' Equity	464.6	470.6	483.8	520.4	571.3	751.2	735.0
Memo:							
Foreign Currency Translation Adjustment Cumulative at Year End	1.5	1.2	-2.7	-2.3	-2.7	-3.0	-5.1
Foreign Currency Translation Adjustment for the Current Year	0.7	-0.4	-3.9	0.0	-0.3	-2.1	-1.0

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

Table B5. Consolidating Statement of Income for FRS Companies, 2001
(Million Dollars)

Income Statement Items	Consolidated	Eliminations & Nontraceables	Petroleum	Coal	Other Energy	Non-energy
Operating Revenues	803,737	-19,619	689,712	1,347	83,811	48,486
Operating Expenses						
General Operating Expenses	669,239	-16,553	560,587	975	79,200	45,030
Depreciation, Depletion, & Allowance	46,377	2,023	40,796	128	877	2,553
General & Administrative	19,998	4,247	11,734	43	1,601	2,373
Total Operating Expenses	735,614	-10,283	613,117	1,146	81,678	49,956
Operating Income	68,123	-9,336	76,595	201	2,133	-1,470
Other Revenue & (Expense)						
Earnings of Unconsolidated Affiliates	6,380	-320	6,360	W	W	-564
Other Dividend & Interest Income	3,727	3,727	-	-	-	-
Gain/Loss on Disposition of Property, Plant & Equipment	1,176	48	345	W	W	758
Interest Expenses & Financial Charges	-9,051	-9,051	-	-	-	-
Minority Interest in Income	-2,172	-2,172	-	-	-	-
Foreign Currency Translation Effects	-289	-289	-	-	-	-
Other Revenue & (Expense)	352	352	-	-	-	-
Total Other Revenue & (Expense)	123	-7,705	6,705	W	W	194
Pretax Income	68,246	-17,041	83,300	211	3,052	-1,276
Income Tax Expense	27,656	-5,066	32,484	77	1,067	-906
Discontinued Operations	-2,467	17	W	0	W	W
Extraordinary Items and Cumulative Effect of Accounting Changes	-388	-499	W	0	W	W
Net Income	37,735	-12,457	50,791	134	1,993	-2,726

- = 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, 2001
(Million Dollars)

Income Statement Items	U.S. Petroleum				Foreign Petroleum			
	Consoli-dated	Production	Refining/ Marketing	Pipe-lines	Consoli-dated	Production	Refining/ Marketing	Int'l Marine
Operating Revenues								
Raw Material Sales	144,450	79,003	126,526	3,187	86,601	62,670	62,418	0
Refined Products Sales	284,595	W	291,609	W	142,097	1,682	142,949	0
Transportation Revenues	12,154	1,264	2,626	10,163	2,338	351	W	3,505
Management and Processing Fees	3,025	W	2,383	W	1,853	169	W	W
Other	18,885	2,460	14,292	2,147	13,929	1,959	11,980	W
Total Operating Revenues	463,109	83,831	437,436	15,903	246,818	66,831	219,616	3,658
Operating Expenses								
General Operating Expenses	381,000	36,269	410,919	7,873	199,802	29,079	210,573	3,437
Depreciation, Depletion, & Allowance	26,518	20,039	5,259	1,220	14,278	12,135	2,095	48
General & Administrative	8,756	1,858	4,884	2,014	2,978	818	2,170	-10
Total Operating Expenses	416,274	58,166	421,062	11,107	217,058	42,032	214,838	3,475
Operating Income	46,835	25,665	16,374	4,796	29,760	24,799	4,778	183
Other Revenue & (Expense)								
Earnings of Unconsolidated Affiliates	3,364	1,348	1,554	462	2,996	2,965	-4	W
Gain(Loss) on Disposition of Property, Plant & Equipment	136	262	281	-407	209	252	-46	W
Total Other Revenue & (Expense)	3,500	1,610	1,835	55	3,205	3,217	-50	38
Pretax Income	50,335	27,275	18,209	4,851	32,965	28,016	4,728	221
Income Tax Expense	17,387	9,641	6,271	1,475	15,097	13,439	1,613	W
Discontinued Operations	W	0	W	W	0	0	0	W
Extraordinary Items and Cumulative Effect of Accounting Changes	12	12	W	W	-19	-19	0	W
Contribution To Net Income	32,942	17,646	11,951	3,345	17,849	14,558	3,115	W

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), Investments and Advances, Additions to PP&E and Investments and Advances, and Depreciation, Depletion, and Amortization (DD&A), by Lines of Business for FRS Companies, 2001
(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	128,260	6,377	31,158	1,816	20,039
Refining/Marketing					
Refining	46,238	7,927	12,130	-61	3,287
Marketing	19,354	1,587	5,007	582	1,609
Refining/Marketing Transport					
Pipelines	3,823	1,134	904	144	162
Marine	1,052	W	248	W	68
Other	1,441	W	278	W	133
Total U.S. Refining/Marketing	71,908	10,718	18,567	670	5,259
Rate Regulated Pipelines					
Refined Products	1,857	463	400	W	121
Natural Gas	23,356	3,180	2,406	858	950
Crude Oil and Liquids	5,058	469	373	W	149
Total Rate Regulated Pipelines	30,271	4,112	3,179	627	1,220
Total U.S. Petroleum	230,439	21,207	52,904	3,113	26,518
Foreign					
Production	117,649	12,401	33,955	1,913	12,135
Refining/Marketing	26,640	W	3,645	W	2,095
International Marine	597	W	31	W	48
Total Foreign Petroleum	144,886	18,604	37,631	2,850	14,278
Total Petroleum	375,325	39,811	90,535	5,963	40,796
Coal					
Foreign	W	W	W	W	W
United States	W	W	W	0	W
Total Coal	1,450	W	109	W	128
Other Energy					
Foreign	2,684	3,199	902	764	120
United States	13,994	2,175	2,757	609	757
Total Other Energy	16,678	5,374	3,659	1,373	877
Nonenergy					
Foreign Chemicals	7,101	2,397	731	135	441
U.S. Chemicals	20,219	5,652	2,842	86	1,479
Foreign Other Nonenergy	870	2,555	W	1,437	W
U.S. Other Nonenergy	2,130	668	W	1,115	W
Total Nonenergy	30,320	11,272	4,451	2,773	2,553
Nontraceable	8,628	763	1,530	-29	2,023
Consolidated	432,401	57,259	100,284	10,086	46,377

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, 2000-2001
(Percent)

Line of Business	All FRS		Top Four		Five through Twelve		All Other	
	2000	2001	2000	2001	2000	2001	2000	2001
Petroleum	13.9	12.2	16.1	12.5	10.6	11.8	11.9	12.2
U.S. Petroleum	13.2	13.1	16.7	12.7	9.6	12.7	11.7	14.5
Oil and Gas Production	17.7	13.1	20.4	12.3	18.5	14.0	11.0	13.3
Refining/Marketing	9.6	14.5	11.1	16.7	-5.5	10.9	13.4	15.1
Pipelines	6.0	9.7	7.9	8.2	5.3	11.0	7.1	25.7
Foreign Petroleum	15.1	10.9	15.6	12.3	14.4	9.0	12.3	7.7
Oil and Gas Production	17.1	11.2	18.7	13.0	14.6	9.3	12.3	7.9
Refining/Marketing	8.7	9.5	8.2	10.0	12.5	5.7	12.0	5.7
International Marine	6.4	25.9	4.1	24.9	450.0	W	0.0	0.0
Coal	1.7	9.0	12.1	5.1	-5.3	34.4	-12.3	W
Other Energy	11.0	9.0	18.2	15.2	10.0	5.7	9.1	2.8
Nonenergy	7.3	-6.6	8.2	2.9	5.9	-33.9	7.3	-1.3

[1]Not meaningful.
W = Data withheld to avoid disclosure.
Note: Return on investment measured as contribution to net income/net investment in place.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B9. Research and Development Expenditures for FRS Companies, 1995-2001
(Million Dollars)

	1995	1996	1997	1998	1999	2000	2001
Sources of Research & Development Funds							
Federal Government	W	W	W	W	27	W	W
Internal Company	2,817	2,675	2,841	1,668	1,377	1,316	1,542
Other Sources	W	W	W	W	20	W	W
Total Sources	2,861	2,717	2,885	1,707	1,424	1,326	1,570
Breakdown of Research & Development Expenditures							
Oil & Gas Recovery	494	482	585	606	430	453	592
Other Petroleum	461	432	380	365	345	327	376
Coal Gasification/Liquefaction	W	W	W	W	W	W	W
Other Coal	W	W	W	W	W	W	W
Nuclear and Other Energy	50	51	54	28	34	W	W
Nonenergy	1,744	1,617	1,738	616	538	452	526
Unassigned	100	127	120	85	W	W	W
Total Expenditures	2,861	2,717	2,885	1,707	1,424	1,326	1,570

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, 2001
(Percent)

Line of Business	Top Four	Five through Twelve	All Other	All FRS
Petroleum	52.1	27.7	20.2	100.0
United States	43.6	34.3	22.0	100.0
Production	45.0	37.3	17.7	100.0
Refining/Marketing	34.7	28.3	37.0	100.0
Refining	33.0	28.6	38.4	100.0
Marketing	44.3	23.3	32.4	100.0
Rate Regulated Pipelines	59.6	37.5	2.9	100.0
Foreign	65.1	17.6	17.4	100.0
Production	58.9	20.6	20.4	100.0
Refining/Marketing	88.7	5.8	5.6	100.0
International Marine	99.4	0.6	0.0	100.0
Coal	81.7	2.1	16.2	100.0
Other Energy	35.6	62.8	1.6	100.0
Nonenergy	63.7	24.3	11.9	100.0
Chemicals	59.9	26.7	13.5	100.0
Other Nonenergy	85.6	11.1	3.3	100.0
Consolidated	52.9	28.7	18.4	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, 1995-2001
(Million Dollars)

Cash Flows [1]	1995	1996	1997	1998	1999	2000	2001
Cash Flows From Operations							
Net Income	21,131	32,029	32,082	12,519	22,866	53,192	37,735
Minority Interest in Income	731	845	896	764	1,161	1,912	2,172
Noncash Items:							
Depreciation, Depletion, & Allowance	36,698	29,331	29,569	35,445	32,452	37,621	46,377
Dry Hole Expense, This Year	1,510	1,812	2,069	2,518	1,808	1,328	2,344
Deferred Income Taxes	-327	2,863	2,301	-1,123	-25	5,611	3,145
Recognized Undistributed (Earnings)/Losses of Unconsolidated Affiliates	-845	-226	-374	2,987	136	-3,319	-318
(Gain)/Loss on Disposition of Property, Plant & Equipment	-2,445	-1,940	-2,716	-2,658	-1,922	-2,065	-1,176
Changes in Operating Assets and Liabilities and Other Noncash Items	-763	-365	298	-3,792	-2,259	-6,269	2,848
Other Cash Items, Net	2,808	-165	1,197	1,502	581	629	-3,490
Net Cash Flow From Operations	58,498	64,184	65,322	48,162	54,798	88,640	89,637
Cash Flows From Investing Activities							
Additions to Property, Plant & Equipment:							
Due to Mergers and Acquisitions	-4,137	-2,281	-5,579	-18,868	-5,961	-49,722	-40,971
Other	-40,356	-41,872	-48,666	-51,046	-44,775	-52,470	-59,313
Total Additions to PP&E	-44,493	-44,153	-54,245	-69,914	-50,736	-102,192	-100,284
Additions to Investments and Advances	-3,208	-5,799	-7,685	-5,223	-6,874	-7,156	-10,086
Proceeds From Disposals of Property, Plant & Equipment	9,063	10,942	9,320	16,243	13,267	26,663	7,683
Other Investment Activities, Net	4,086	1,608	6,587	4,235	3,523	8,742	8,406
Cash Flow From Investing Activities	-34,552	-37,402	-46,023	-54,659	-40,820	-73,943	-94,281
Cash Flows From Financing Activities							
Proceeds From Long-Term Debt	19,929	10,708	17,901	27,072	29,862	33,292	54,987
Proceeds From Equity Security Offerings	3,471	1,171	1,507	9,112	3,557	30,606	6,267
Reductions in Long-Term Debt	-18,657	-18,883	-19,774	-18,019	-24,988	-29,323	-34,264
Purchase of Treasury Stock	-10,035	-1,299	-7,910	-5,776	-424	-5,362	-7,474
Dividends to Shareholders	-15,238	-15,585	-16,941	-17,169	-16,081	-18,981	-17,132
Other Financing Activities, Including Net Change in Short-Term Debt	-2,350	-578	5,537	6,859	-3,377	-17,205	3,848
Cash Flow From Financing Activities	-22,880	-24,466	-19,680	2,079	-11,451	-6,973	6,232
Effect of Exchange Rate on Cash	14	3	-255	-13	-24	-119	-308
Net Increase/(Decrease) in Cash and Cash Equivalents	1,080	2,319	-636	-4,431	2,503	7,605	1,280

[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, 1995-2001
(Million Dollars)

	1995	1996	1997	1998	1999	2000	2001
Income Taxes (as per Financial Statements)							
Current Paid or Accrued:							
U.S. Federal, before Investment Tax Credit & Alternative Minimum Tax	4,486	6,141	5,656	603	1,375	11,705	8,812
U.S. Federal Investment Tax Credit	-162	-146	-93	-85	-90	-129	-246
Effect of Alternative Minimum Tax	151	-325	-400	-16	445	-1,222	-632
U.S. State & Local Income Taxes	649	745	794	443	371	1,338	1,067
Foreign Income Taxes							
Canada	634	745	932	456	597	1,765	1,139
Europe and Former Soviet Union [1]	2,752	3,862	2,927	1,798	3,110	7,002	6,515
Africa	1,204	1,956	1,926	449	1,607	3,617	3,057
Middle East	1,024	1,326	802	745	1,286	2,380	1,937
Other Eastern Hemisphere	1,882	2,195	1,901	992	1,679	2,214	1,676
Other Western Hemisphere	514	729	1,739	428	346	900	695
Total Foreign	8,010	10,813	10,227	4,868	8,625	17,878	15,019
Total Current	13,134	17,228	16,184	5,813	10,726	29,570	24,020
Deferred							
U.S. Federal, before Investment Tax Credit	-793	1,410	1,477	-373	1,480	3,168	2,403
U.S. Federal Investment Tax Credit	61	69	-2	-28	-14	-78	-10
Effect of Alternative Minimum Tax	-158	312	400	-16	-415	1,233	650
U.S. State & Local Income Taxes	-30	56	54	104	136	221	26
Foreign	537	930	519	-791	-1,075	910	567
Total Deferred	-383	2,777	2,448	-1,104	112	5,454	3,636
Total Income Tax Expense	12,751	20,005	18,632	4,709	10,838	35,024	27,656
Reconciliation of Accrued U.S. Federal Income Tax Expense To Statutory Rate							
Consolidated Pretax Income/(Loss)	34,233	52,808	51,453	16,017	33,837	86,702	68,246
Less: Foreign Source Income not Subject to U.S.	4,038	6,230	5,827	251	2,160	13,355	8,918
Equals: Income Subject to U.S. Tax	30,195	46,578	45,626	15,766	31,677	73,347	59,328
Less: U.S. State & Local Income Taxes	440	782	785	570	486	1,497	895
Less: Applicable Foreign Income Taxes Deducted	377	554	312	32	107	353	82
Equals: Pretax Income Subject to U.S. Tax	29,378	45,242	44,529	15,164	31,084	71,497	58,351
Tax Provision Based on Previous Line	10,281	15,834	15,621	5,332	10,902	25,032	20,438
Increase/(Decrease) in Taxes Due To:							
Foreign Tax Credits Recognized	-5,661	-6,926	-6,982	-3,563	-5,963	-9,787	-8,513
U.S. Federal Investment Tax Credit Recognized	-97	-123	-137	-124	-98	-129	-486
Statutory Depletion	-70	-54	-63	-30	-8	-3	-1
Effect of Alternative Minimum Tax	0	1	0	-16	23	11	16
Other	-868	-1,273	-1,399	-1,485	-2,068	-447	-582
Actual U.S. Federal Tax Provision (Refund)	3,585	7,459	7,040	114	2,788	14,677	10,872

[1] OECD (Organization for Economic Cooperation & Development) 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, 1995-2001
(Million Dollars)

	1995	1996	1997	1998	1999	2000	2001
Production Taxes							
Oil and Gas Production	1,693	2,098	1,965	1,176	1,674	2,604	2,506
Coal	157	139	172	47	43	30	35
Other	11	1	1	0	0	25	1
Total Production Taxes	1,861	2,238	2,138	1,223	1,717	2,659	2,542
Superfund	293	14	W	W	W	W	W
Import Duties	104	260	W	W	W	W	W
Sales, Use, and Property	2,886	2,516	2,407	2,648	2,268	2,356	2,373
Payroll	1,844	1,531	1,406	1,357	1,289	1,259	1,193
Other Taxes	566	514	559	360	467	789	546
Total Taxes Paid (Other Than Income Taxes)	7,554	7,073	6,601	5,660	5,825	7,186	6,740
Excise Taxes Collected	30,813	32,426	30,984	39,918	46,293	47,084	44,310

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, 1995-2001
(Million Dollars)

	1995	1996	1997	1998	1999	2000	2001
United States							
Exploration							
Acquisition of Unproved Acreage	595	997	2,653	3,912	633	4,010	3,527
Geological and Geophysical	486	625	750	916	621	849	758
Drilling and Equipping [1]	1,833	2,338	2,905	2,964	1,921	2,550	3,276
Other	596	693	690	954	659	610	770
Total Exploration	3,510	4,653	6,998	8,746	3,834	8,019	8,331
Development							
Acquisition of Proved Acreage	980	922	2,928	3,568	1,144	27,939	7,383
Lease Equipment	1,425	1,613	1,823	2,688	2,431	1,907	3,818
Drilling and Equipping [1]	5,433	6,154	8,540	7,769	5,022	8,788	11,671
Other [2]	1,086	1,290	1,557	1,657	1,056	1,391	2,655
Total Development	8,924	9,979	14,848	15,682	9,653	40,025	25,527
Total U.S. Exploration and Development	12,434	14,632	21,846	24,428	13,487	48,044	33,858
Foreign							
Exploration							
Acquisition of Unproved Acreage	214	745	565	2,159	2,252	4,105	4,696
Geological and Geophysical	843	869	897	1,065	885	875	1,028
Drilling and Equipping [1]	2,114	2,277	2,684	2,650	1,579	1,824	2,677
Other	989	919	1,128	1,299	903	1,087	1,146
Total Exploration	4,160	4,810	5,274	7,173	5,619	7,891	9,547
Development							
Acquisition of Proved Acreage	371	1,932	1,641	7,121	2,083	11,644	12,186
Lease Equipment	1,537	2,064	2,207	2,505	2,142	1,842	3,186
Drilling and Equipping [1]	4,535	5,278	6,426	6,206	5,143	5,057	7,060
Other [2]	2,568	2,534	2,383	3,388	2,531	2,364	3,965
Total Development	9,011	11,808	12,657	19,220	11,899	20,907	26,397
Total Foreign Exploration and Development	13,171	16,618	17,931	26,393	17,518	28,798	35,944

[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, 2001
(Million Dollars)

	Worldwide	United States			Foreign
		Total	Onshore	Offshore	
Exploration and Development Expenditures					
Exploration Expenditures					
Unproved Acreage	8,223	3,527	2,950	577	4,696
Drilling and Equipping:					
Completed Well Costs	-	2,432	774	1,658	-
Work-in-progress Adjustment	-	844	333	511	-
Total Drilling and Equipping	5,953	3,276	1,107	2,169	2,677
Geological and Geophysical	1,786	758	292	466	1,028
Other, Including Direct Overhead	1,916	770	430	340	1,146
Total Exploration Expenditures	17,878	8,331	4,779	3,552	9,547
Development Expenditures					
Proved Acreage (Including Mergers and Acquisitions)	19,569	7,383	6,793	590	12,186
Drilling and Equipping:					
Completed Well Costs	-	9,665	6,422	3,243	-
Work-in-progress Adjustment	-	2,006	1,156	850	-
Total Drilling and Equipping	18,731	11,671	7,578	4,093	7,060
Lease Equipment	7,004	3,818	2,907	911	3,186
Other Development					
Support Equipment	577	163	112	51	414
Other, Including Direct Overhead	6,043	2,492	2,075	417	3,551
Total Development Expenditures	51,924	25,527	19,465	6,062	26,397
Total Exploration and Development Expenditures	69,802	33,858	24,244	9,614	35,944

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

Table B16. Exploration and Development Expenditures by Region, 1995-2001
(Million Dollars)

	1995	1996	1997	1998	1999	2000	2001
Exploration Expenditures							
U.S. Onshore	1,644	1,826	3,396	3,941	1,174	4,136	4,779
U.S. Offshore	1,866	2,827	3,602	4,805	2,660	3,883	3,552
Total United States	3,510	4,653	6,998	8,746	3,834	8,019	8,331
Canada	493	355	310	638	420	1,184	3,899
OECD Europe	1,242	1,345	1,684	1,916	767	869	756
Former Soviet Union and E. Europe	181	194	285	630	354	317	374
Africa	707	779	807	1,092	1,268	910	1,579
Middle East	90	45	53	141	96	56	197
Other Eastern Hemisphere	1,016	1,462	1,341	1,563	1,192	1,675	1,478
Other Western Hemisphere	431	630	794	1,193	1,522	2,880	1,264
Total Foreign	4,160	4,810	5,274	7,173	5,619	7,891	9,547
Worldwide Exploration Expenditures	7,670	9,463	12,272	15,919	9,453	15,910	17,878
Development Expenditures							
U.S. Onshore	6,051	6,087	9,624	9,519	5,396	22,953	19,465
U.S. Offshore	2,873	3,892	5,224	6,163	4,257	17,072	6,062
Total United States	8,924	9,979	14,848	15,682	9,653	40,025	25,527
Canada	1,406	1,210	1,688	4,168	1,636	3,697	11,425
OECD Europe	3,962	4,222	5,368	6,670	3,370	6,651	4,617
Former Soviet Union and E. Europe	178	267	343	637	252	576	507
Africa	1,336	2,014	2,171	2,042	1,826	1,809	3,968
Middle East	271	418	590	801	297	494	542
Other Eastern Hemisphere	1,414	2,670	1,643	2,386	2,250	5,112	3,513
Other Western Hemisphere	444	1,007	854	2,516	2,268	2,568	1,826
Total Foreign	9,011	11,808	12,657	19,220	11,899	20,907	26,397
Worldwide Development Expenditures	17,935	21,787	27,505	34,902	21,552	60,932	51,924
Total Exploration and Development Expenditures							
U.S. Onshore	7,695	7,913	13,020	13,460	6,570	27,089	24,244
U.S. Offshore	4,739	6,719	8,826	10,968	6,917	20,955	9,614
Total United States	12,434	14,632	21,846	24,428	13,487	48,044	33,858
Canada	1,899	1,565	1,998	4,806	2,056	4,881	15,324
OECD Europe	5,204	5,567	7,052	8,586	4,137	7,520	5,373
Former Soviet Union and E. Europe	359	461	628	1,267	606	893	881
Africa	2,043	2,793	2,978	3,134	3,094	2,719	5,547
Middle East	361	463	643	942	393	550	739
Other Eastern Hemisphere	2,430	4,132	2,984	3,949	3,442	6,787	4,991
Other Western Hemisphere	875	1,637	1,648	3,709	3,790	5,448	3,090
Total Foreign	13,171	16,618	17,931	26,393	17,518	28,798	35,944
Worldwide Exploration and Development Expenditures	25,605	31,250	39,777	50,821	31,005	76,842	69,802

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

Table B17. Production (Lifting) Costs by Region for FRS Companies, 1995-2001
(Million Dollars)

	1995	1996	1997	1998	1999	2000	2001
United States							
Taxes Other Than Income Taxes	1,693	2,098	1,965	1,176	1,674	2,604	2,506
Other Costs	10,429	10,221	10,147	9,787	9,494	8,417	10,377
Total Production Costs	12,122	12,319	12,112	10,963	11,168	11,021	12,883
U.S. Onshore	9,769	9,855	9,604	8,198	8,039	8,254	9,838
U.S. Offshore	2,353	2,464	2,508	2,765	3,129	2,767	3,045
Canada							
Royalty Expenses	W	W	W	W	W	W	0
Taxes Other Than Income Taxes	W	W	W	W	W	W	105
Other Costs	1,082	993	961	1,037	1,120	1,379	1,842
Total Production Costs	1,174	1,082	1,049	1,129	1,252	1,496	1,947
OECD[1] Europe							
Royalty Expenses	235	251	217	251	62	W	W
Taxes Other Than Income Taxes	311	400	360	269	330	W	W
Other Costs	4,116	3,996	3,950	3,980	3,666	3,485	3,496
Total Production Costs	4,662	4,647	4,527	4,500	4,058	4,025	4,151
Former Soviet Union and E. Europe							
Royalty Expenses	W	W	W	W	W	W	W
Taxes Other Than Income Taxes	W	W	W	W	W	W	W
Other Costs	127	133	188	207	111	179	155
Total Production Costs	128	134	192	208	148	196	191
Africa							
Royalty Expenses	W	W	W	W	66	96	W
Taxes Other Than Income Taxes	W	W	W	W	49	W	402
Other Costs	607	812	861	1,194	1,153	1,208	1,384
Total Production Costs	916	1,259	1,310	1,490	1,268	1,784	1,847
Middle East							
Royalty Expenses	W	W	W	W	W	137	0
Taxes Other Than Income Taxes	W	W	W	W	W	75	55
Other Costs	258	296	280	250	235	175	407
Total Production Costs	403	483	491	429	424	387	462
Other Eastern Hemisphere							
Royalty Expenses and							
Taxes Other Than Income Taxes	400	542	456	240	507	618	527
Other Costs	1,110	1,161	1,144	1,074	1,097	1,392	1,931
Total Production Costs	1,510	1,703	1,600	1,314	1,604	2,010	2,458
Other Western Hemisphere							
Royalty Expenses and							
Taxes Other Than Income Taxes	129	180	156	87	184	304	143
Other Costs	428	389	470	552	443	533	600
Total Production Costs	557	569	626	639	627	837	743
Total Foreign							
Royalty Expenses	680	901	891	740	384	437	153
Taxes Other Than Income Taxes	942	1,196	1,050	675	1,172	1,947	1,831
Other Costs	7,728	7,780	7,854	8,294	7,825	8,351	9,815
Total Production Costs	9,350	9,877	9,795	9,709	9,381	10,735	11,799

[1]Organization for Economic Cooperation and Development
W = Data withheld to avoid disclosure.
-- = Not applicable.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B18. Oil and Gas Acreage for FRS Companies, 1995-2001
(Thousand Acres)

	1995	1996	1997	1998	1999	2000	2001
Net Acreage							
U.S. Onshore							
Developed	27,429	26,733	25,474	26,396	25,895	31,760	34,332
Undeveloped	38,792	31,659	31,154	30,598	25,880	37,657	43,293
U.S. Offshore							
Developed	6,154	5,470	5,343	4,634	4,988	5,383	5,881
Undeveloped	14,334	16,880	22,983	23,168	24,940	21,483	20,933
Foreign							
Developed	18,063	22,574	21,984	24,887	26,337	32,535	32,903
Undeveloped	449,255	445,176	472,106	514,511	416,209	416,941	424,465
Gross Acreage							
U.S. Onshore							
Developed	50,016	46,887	45,249	49,097	45,978	57,626	63,721
Undeveloped	61,651	53,775	55,530	51,364	42,325	59,295	69,790
U.S. Offshore							
Developed	11,291	9,668	10,665	8,861	9,534	10,588	11,317
Undeveloped	18,595	21,786	30,845	32,439	35,689	31,609	30,523
Foreign							
Developed	49,946	59,926	58,198	64,358	59,247	71,330	70,112
Undeveloped	892,178	857,130	924,839	1,083,355	835,615	882,761	834,500

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

Table B19. U.S. Net Wells Completed for FRS Companies and U.S. Industry, 1995-2001

	1995	1996	1997	1998	1999	2000	2001
Number of Net Wells Completed During Year for FRS Companies							
Onshore							
Net Exploratory Wells							
Dry Holes	232	274	163	159	93	86	122
Oil Wells	104	91	90	55	26	19	59
Gas Wells	201	207	170	142	105	217	351
Total Exploratory Wells	538	572	424	356	225	321	533
Net Development Wells							
Dry Holes	262	319	301	256	162	229	266
Oil Wells	1,908	2,095	3,016	2,510	1,130	1,775	1,815
Gas Wells	2,156	2,049	2,261	2,074	1,519	2,927	5,226
Total Development Wells	4,326	4,463	5,577	4,841	2,812	4,930	7,307
Offshore							
Net Exploratory Wells							
Dry Holes	72	84	98	91	59	73	63
Oil Wells	32	36	31	22	28	28	39
Gas Wells	53	87	73	63	61	59	63
Total Exploratory Wells	157	206	202	176	148	159	165
Net Development Wells							
Dry Holes	18	23	46	32	26	29	38
Oil Wells	151	158	181	115	145	128	240
Gas Wells	95	153	168	133	153	157	170
Total Development Wells	265	334	396	280	324	315	448
Total United States							
Net Exploratory Wells							
Dry Holes	304	358	261	249	153	158	185
Oil Wells	137	127	121	77	54	47	98
Gas Wells	255	293	243	205	166	275	415
Total Exploratory Wells	695	778	626	531	372	480	698
Net Development Wells							
Dry Holes	280	342	347	288	188	258	305
Oil Wells	2,059	2,253	3,197	2,625	1,275	1,903	2,054
Gas Wells	2,252	2,202	2,429	2,208	1,672	3,084	5,396
Total Development Wells	4,591	4,797	5,973	5,121	3,136	5,245	7,755
Number of Net Wells Completed During Year for Total U.S. Industry							
Net Exploratory Wells							
Dry Holes	2,302	2,154	2,145	1,843	1,146	1,298	1,474
Oil Wells	866	484	434	306	151	264	309
Gas Wells	992	575	542	589	529	606	968
Total Exploratory Wells	4,160	3,213	3,121	2,739	1,826	2,168	2,752
Net Development Wells							
Dry Holes	2,778	3,184	3,659	3,138	2,217	2,538	2,539
Oil Wells	6,788	7,911	9,889	6,566	4,083	7,278	7,900
Gas Wells	7,284	8,729	10,592	11,494	10,526	16,336	22,497
Total Development Wells	16,849	19,824	24,140	21,198	16,827	26,153	32,937
Number of Net In-Progress Wells At Year End for FRS Companies							
Onshore							
Exploratory Wells	135	133	135	51	40	70	85
Development Wells	541	675	929	392	464	716	1,052
Total In-Progress Wells	676	808	1,064	444	504	786	1,138
Offshore							
Exploratory Wells	46	45	92	52	68	50	56
Development Wells	57	93	128	73	87	110	63
Total In-Progress Wells	103	138	220	124	155	160	118
Total United States							
Exploratory Wells	181	178	226	103	108	120	141
Development Wells	598	768	1,058	465	551	826	1,115
Total In-Progress Wells	779	946	1,284	568	659	946	1,256

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

Sources: Industry data - Special compilation provided by the Office of Oil and Gas, Energy Information Adminstration. Totals are based on data which appeared in the Energy Information Administration's Monthly Energy Review, September 2002, 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, 1995-2001

	1995	1996	1997	1998	1999	2000	2001
FRS Companies							
Onshore				(thousand feet)			
Exploratory Well Footage							
Dry Hole Footage	1,799	2,052	1,700	1,714	921	955	1,085
Oil Well Footage	836	732	1,027	406	312	199	397
Gas Well Footage	1,456	1,860	1,521	1,548	1,150	1,399	2,016
Total Exploratory Footage	4,091	4,644	4,248	3,668	2,383	2,553	3,498
Development Well Footage							
Dry Hole Footage	1,550	2,224	1,926	1,939	1,252	1,597	2,029
Oil Well Footage	10,053	10,956	14,534	12,513	4,449	9,374	9,435
Gas Well Footage	14,468	14,304	16,751	16,521	12,291	20,516	26,653
Total Development Footage	26,071	27,484	33,211	30,973	17,992	31,487	38,117
Offshore							
Exploratory Well Footage							
Dry Hole Footage	891	1,091	1,362	1,345	848	1,151	1,004
Oil Well Footage	408	408	397	443	434	364	551
Gas Well Footage	702	1,824	981	1,285	1,002	1,141	759
Total Exploratory Footage	2,001	3,323	2,740	3,073	2,284	2,656	2,314
Development Well Footage							
Dry Hole Footage	155	244	459	344	199	411	353
Oil Well Footage	1,588	1,704	1,736	1,428	1,280	1,505	2,260
Gas Well Footage	1,011	1,538	1,584	1,398	1,295	1,899	1,917
Total Development Footage	2,754	3,486	3,779	3,170	2,774	3,815	4,530
Total United States							
Exploratory Well Footage							
Dry Hole Footage	2,690	3,143	3,062	3,059	1,769	2,107	2,089
Oil Well Footage	1,244	1,140	1,424	849	746	563	948
Gas Well Footage	2,158	3,684	2,502	2,833	2,152	2,540	2,775
Total Exploratory Footage	6,092	7,967	6,988	6,741	4,667	5,209	5,812
Development Well Footage							
Dry Hole Footage	1,705	2,468	2,385	2,283	1,451	2,008	2,382
Oil Well Footage	11,641	12,660	16,270	13,941	5,729	10,879	11,695
Gas Well Footage	15,479	15,842	18,335	17,919	13,586	22,415	28,570
Total Development Footage	28,825	30,970	36,990	34,143	20,766	35,303	42,647
Total United States Industry							
Exploratory Well Footage							
Dry Hole Footage	13,562	13,199	13,861	12,398	7,533	8,590	9,286
Oil Well Footage	5,502	3,504	3,432	2,505	1,028	1,883	2,311
Gas Well Footage	6,398	3,782	3,955	4,196	3,320	4,481	7,122
Total Exploratory Footage	25,462	20,485	21,248	19,098	11,881	14,954	18,719
Development Well Footage							
Dry Hole Footage	14,353	16,656	19,666	18,005	12,271	13,298	13,910
Oil Well Footage	32,776	36,988	47,773	32,125	17,729	32,180	37,632
Gas Well Footage	45,098	54,376	65,860	70,746	52,550	79,624	115,535
Total Development Footage	92,227	108,020	133,298	120,875	82,551	125,103	167,077
Number of Net Producing Wells for FRS Companies				(number of wells)			
Onshore							
Oil Wells	94,867	87,461	75,493	69,401	58,987	68,274	66,667
Gas Wells	50,388	48,779	48,779	49,429	44,880	64,696	82,083
Total Producing Wells	145,256	136,240	124,272	118,830	103,867	132,970	148,750
Offshore							
Oil Wells	4,180	3,552	3,760	3,421	2,855	3,536	4,738
Gas Wells	3,042	2,556	2,898	2,737	2,707	3,111	3,606
Total Producing Wells	7,221	6,108	6,658	6,158	5,562	6,647	8,344
Total United States							
Oil Wells	99,047	91,013	79,253	72,822	61,842	71,810	71,405
Gas Wells	53,430	51,335	51,677	52,166	47,587	67,807	85,689
Total Producing Wells	152,477	142,348	130,930	124,987	109,429	139,617	157,094

Sources: Well footage, U.S. - special compilation provided by the Office of Oil and Gas, Energy Information Administration. Totals are based on data which appeared in the Energy Information Administration's *Monthly Energy Review* , September 2002, 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, 1995-2001

	1995	1996	1997	1998	1999	2000	2001
Canada							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	107.5	86.2	22.8	54.8	36.4	126.3	106.4
Oil Wells	66.6	46.0	10.7	10.0	25.8	23.3	63.1
Gas Wells	74.0	96.1	49.2	66.3	127.5	194.2	165.9
Total Exploratory Wells	248.1	228.3	82.7	131.1	189.7	343.8	335.4
Development Wells							
Dry Holes	42.7	48.1	59.6	58.8	58.3	138.2	228.8
Oil Wells	569.5	559.4	778.6	198.9	352.1	373.3	818.1
Gas Wells	189.6	233.7	275.1	422.4	758.7	891.5	2,025.1
Total Development Wells	801.8	841.2	1,113.3	680.1	1,169.1	1,403.0	3,072.1
Net In-Progress Wells at Year End	43.1	17.2	30.6	24.3	76.3	116.8	307.2
Net Producing Wells							
Oil Wells	9,793.9	8,719.5	9,364.7	10,532.3	10,155.9	12,094.8	17,640.5
Gas Wells	5,998.6	5,784.8	6,199.5	8,872.7	10,038.7	15,242.7	25,230.5
Total Producing Wells	15,792.5	14,504.3	15,564.2	19,405.0	20,194.6	27,337.5	42,870.9
Europe and Former Soviet Union [1]							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	42.1	49.4	56.6	36.3	15.4	15.7	15.6
Oil Wells	21.4	14.5	19.2	11.8	9.2	5.2	25.9
Gas Wells	10.6	11.4	8.9	12.0	4.0	6.4	8.6
Total Exploratory Wells	74.1	75.3	84.7	60.1	28.6	27.3	50.1
Development Wells							
Dry Holes	2.2	5.3	3.2	7.8	2.6	10.3	5.4
Oil Wells	72.4	77.6	80.7	118.5	75.4	67.7	91.8
Gas Wells	29.0	31.0	25.1	60.5	30.4	30.4	31.8
Total Development Wells	103.6	113.9	109.0	186.8	108.4	108.3	129.0
Net In-Progress Wells at Year End	73.0	68.7	62.7	54.5	31.6	63.7	69.3
Net Producing Wells							
Oil Wells	1,359.4	1,445.5	1,328.0	1,294.4	1,218.8	1,431.3	1,478.2
Gas Wells	741.9	765.2	766.8	805.3	626.6	737.7	717.2
Total Producing Wells	2,101.3	2,210.7	2,094.8	2,099.7	1,845.4	2,169.0	2,195.4
Africa and Middle East							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	28.4	19.8	25.3	33.1	14.9	37.2	21.9
Oil Wells	W	W	W	W	9.9	W	W
Gas Wells	W	W	W	W	10.0	W	W
Total Exploratory Wells	42.8	44.0	46.1	65.0	34.8	50.7	50.9
Development Wells							
Dry Holes	W	W	W	W	5.8	W	W
Oil Wells	109.7	133.0	151.6	218.4	206.3	239.3	159.8
Gas Wells	W	W	W	W	8.6	W	W
Total Development Wells	119.2	144.0	157.8	225.6	220.7	252.0	186.9
Net In-Progress Wells at Year End	41.9	36.9	29.0	18.0	36.8	35.2	35.4
Net Producing Wells							
Oil Wells	1,509.0	1,688.9	1,644.6	1,924.2	1,969.8	1,954.1	2,063.8
Gas Wells	41.9	49.9	59.5	62.7	83.2	79.0	121.2
Total Producing Wells	1,550.9	1,738.8	1,704.1	1,986.9	2,053.0	2,033.1	2,185.0

[1]OECD(Organization for Economic Cooperation and Development) 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 B21. Number of Net Wells Completed, In-Progress Wells, and Producing Wells by Foreign Regions for FRS Companies, 1995-2001 (Continued)

	1995	1996	1997	1998	1999	2000	2001
Other Eastern Hemisphere							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	47.4	42.6	39.8	47.1	35.4	40.7	39.1
Oil Wells	13.1	21.6	16.1	36.6	41.6	31.3	19.9
Gas Wells	44.4	46.3	15.8	13.8	16.0	20.7	42.3
Total Exploratory Wells	104.9	110.5	71.7	97.5	93.0	92.7	101.3
Development Wells							
Dry Holes	1.5	3.7	4.7	11.5	1.9	4.4	7.1
Oil Wells	92.7	103.1	162.6	149.5	82.4	140.6	595.3
Gas Wells	32.4	91.7	116.5	101.2	104.5	113.5	117.0
Total Development Wells	126.6	198.5	283.8	262.2	188.8	258.5	719.4
Net In-Progress Wells at Year End	92.5	72.4	61.4	64.5	56.2	80.5	67.1
Net Producing Wells							
Oil Wells	1,476.2	1,622.0	1,767.0	1,707.2	1,654.2	1,950.2	7,852.9
Gas Wells	401.4	561.2	633.8	862.2	882.2	927.4	1,090.3
Total Producing Wells	1,877.6	2,183.2	2,400.8	2,569.4	2,536.4	2,877.6	8,943.2
Other Western Hemisphere							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	9.2	12.4	5.7	14.6	7.9	14.5	31.9
Oil Wells	4.7	9.0	4.7	10.4	3.2	W	W
Gas Wells	0.0	2.0	0.0	4.5	3.8	W	W
Total Exploratory Wells	13.9	23.4	10.4	29.5	14.9	23.4	40.0
Development Wells							
Dry Holes	W	W	W	W	W	W	W
Oil Wells	120.5	123.3	141.4	212.8	81.4	205.8	240.5
Gas Wells	W	W	W	W	W	W	W
Total Development Wells	133.1	129.8	148.3	224.5	91.7	245.0	262.9
Net In-Progress Wells at Year End	20.2	16.1	24.4	28.9	27.2	31.3	47.4
Net Producing Wells							
Oil Wells	2,980.6	2,478.9	605.0	2,045.6	2,426.5	2,597.2	2,580.2
Gas Wells	57.6	77.3	72.2	190.9	161.4	253.1	262.7
Total Producing Wells	3,038.2	2,556.2	677.2	2,236.5	2,587.9	2,850.3	2,842.9
Total Foreign							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	234.6	210.4	150.2	185.9	110.0	234.4	214.8
Oil Wells	119.7	110.9	71.0	97.6	89.7	74.1	136.0
Gas Wells	129.5	160.2	74.4	99.7	161.3	229.4	226.8
Total Exploratory Wells	483.8	481.5	295.6	383.2	361.0	537.9	577.6
Development Wells							
Dry Holes	51.9	67.9	75.5	83.7	70.1	156.7	252.5
Oil Wells	964.8	996.4	1,314.9	898.1	797.6	1,026.7	1,905.5
Gas Wells	267.6	363.1	421.8	597.4	911.0	1,083.5	2,212.2
Total Development Wells	1,284.3	1,427.4	1,812.2	1,579.2	1,778.7	2,266.8	4,370.3
Net In-Progress Wells at Year End	270.7	211.3	208.1	190.2	228.1	327.5	526.4
Net Producing Wells							
Oil Wells	17,119.1	15,954.8	14,709.3	17,503.7	17,425.2	20,027.6	31,615.5
Gas Wells	7,241.4	7,238.4	7,731.8	10,793.8	11,792.1	17,239.9	27,421.9
Total Producing Wells	24,360.5	23,193.2	22,441.1	28,297.5	29,217.3	37,267.5	59,037.4

[1]OECD (Organization for Economic Cooperation and Development) Europe combined with the former Soviet Union and Eastern Europe to avoid disclosure.

W = data withheld to avoid disclosure.

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

Table B22. Completed Wells and Average Depth, Onshore and Offshore, for FRS Companies, 2000 and 2001

Drilling and Equipping Measures	Total United States			U.S. Onshore			U.S. Offshore		
	2000	2001	Percent Change	2000	2001	Percent Change	2000	2001	Percent Change
Exploration									
Oil Wells									
Wells Completed	46.5	97.9	110.5	18.9	58.8	211.1	27.6	39.1	41.7
Average Depth (thousand feet)	12.1	9.7	-20.0	10.5	6.8	-35.9	13.2	14.1	6.9
Gas Wells									
Wells Completed	275.1	414.7	50.7	216.5	351.4	62.3	58.6	63.3	8.0
Average Depth (thousand feet)	9.2	6.7	-27.5	6.5	5.7	-11.2	19.5	12.0	-38.4
Dry Holes									
Wells Completed	158.4	185.2	16.9	85.8	122.4	42.7	72.6	62.8	-13.6
Average Depth (thousand feet)	13.3	11.3	-15.2	11.1	8.9	-20.4	15.9	16.0	0.9
Development									
Oil Wells									
Wells Completed	1,902.8	2,054.3	8.0	1,774.5	1,814.6	2.3	128.3	239.7	86.9
Average Depth (thousand feet)	5.7	5.7	-0.4	5.3	5.2	-1.6	11.7	9.4	-19.6
Gas Wells									
Wells Completed	3,083.8	5,396.3	75.0	2,926.5	5,226.1	78.6	157.3	170.2	8.2
Average Depth (thousand feet)	7.3	5.3	-27.2	7.0	5.1	-27.3	12.1	11.3	-6.7
Dry Holes									
Wells Completed	258.4	304.7	17.9	229.2	266.3	16.2	29.2	38.4	31.5
Average Depth (thousand feet)	7.8	7.8	0.6	7.0	7.6	9.3	14.1	9.2	-34.6

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

Table B23. Oil and Gas Reserves for FRS Companies and U.S. Industry, 2001

	Beginning Reserves	Plus Reserve Additions [1]	Plus Net Purchases	Less Production	Equals Ending Reserves	Replacement Rate
Crude Oil and Natural Gas Liquids	(million barrels)					(percent)
U.S. Onshore						
Total U.S. Industry	25,177.0	1,140.0	0.0	2,075.0	24,242.0	54.9
FRS Companies	11,991.7	671.6	-99.1	876.9	11,687.4	76.6
All Other	13,185.3	468.4	99.1	1,198.1	12,554.6	39.1
U.S. Offshore						
Total U.S. Industry	5,213.0	1,714.0	0.0	730.0	6,197.0	234.8
FRS Companies	3,545.0	1,312.4	-0.9	486.3	4,370.2	269.9
All Other	1,668.0	401.6	0.9	243.7	1,826.8	164.8
U.S. Total						
Total U.S. Industry	30,390.0	2,854.0	0.0	2,805.0	30,439.0	101.7
FRS Companies	15,536.7	1,984.1	-100.0	1,363.2	16,057.5	145.5
All Other	14,853.3	869.9	100.0	1,441.8	14,381.5	60.3
FRS Companies' Foreign Oil Reserves						
Canada	2,045.6	148.0	593.8	203.9	2,583.5	72.6
Europe	4,511.3	482.0	33.5	578.3	4,448.6	83.3
FSU and Eastern Europe	730.9	295.5	17.5	35.8	1,008.1	825.9
Africa	5,014.8	471.8	130.5	359.3	5,257.8	131.3
Middle East	817.5	125.5	32.2	117.9	857.4	106.5
Other Eastern Hemisphere	1,865.0	1,477.1	43.1	320.2	3,065.0	461.4
Other Western Hemisphere	1,614.0	34.5	59.9	108.7	1,599.7	31.7
Total Foreign	16,599.3	3,034.4	910.4	1,724.0	18,820.1	176.0
Worldwide Total for FRS Companies	32,136.0	5,018.4	810.5	3,087.2	34,877.7	162.6
Dry Natural Gas	(billion cubic feet)					
U.S. Onshore						
Total U.S. Industry	149,494.0	20,225.0	0.0	14,591.0	155,127.0	138.6
FRS Companies	61,720.6	4,811.1	5,892.1	5,723.0	66,700.9	84.1
All Other	87,773.4	15,413.9	-5,892.1	8,868.0	88,426.1	173.8
U.S. Offshore						
Total U.S. Industry	27,933.0	5,588.0	0.0	5,188.0	28,333.0	107.7
FRS Companies	19,472.2	2,696.7	9.5	3,115.0	19,063.3	86.6
All Other	8,460.8	2,891.3	-9.5	2,073.0	9,269.7	139.5
U.S. Total						
Total U.S. Industry	177,427.0	25,813.0	0.0	19,779.0	183,460.0	130.5
FRS Companies	81,192.8	7,507.8	5,901.6	8,838.0	85,764.3	84.9
All Other	96,234.2	18,305.2	-5,901.6	10,941.0	97,695.8	167.3
FRS Companies' Foreign Gas Reserves						
Canada	11,374.2	860.0	5,199.9	1,496.7	15,937.3	57.5
Europe	21,841.3	1,845.3	13.9	2,352.1	21,348.4	78.5
FSU and Eastern Europe	1,121.3	26.5	0.0	25.2	1,122.7	105.4
Africa	3,794.5	1,382.2	247.1	156.3	5,267.6	884.1
Middle East	518.7	34.9	146.0	88.7	610.9	39.4
Other Eastern Hemisphere	22,377.3	2,794.8	1,235.0	1,576.8	24,830.3	177.2
Other Western Hemisphere	15,010.1	1,786.1	154.7	614.3	16,336.5	138.3
Total Foreign	76,037.4	8,729.8	6,996.6	6,310.2	85,453.7	138.3
Worldwide Total for FRS Companies	157,230.2	16,237.6	12,898.3	15,148.1	171,217.9	107.2

[1] Excludes net purchases of minerals in place; includes crude oil and natural gas liquids (measured in millions of barrels) and natural gas (measured in millions of barrels of crude oil equivalent). The conversion factor for natural gas is 0.178 barrels of crude / 1000 cubic feet. Reserve additions include the net of corrections and adjustments.

- = Not available.

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*, 2000 and 2001 (December 2001 and November 2002). FRS companies' data - Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B24. Oil and Gas Reserve Balances by Region for FRS Companies, 2001

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	32,136	15,537	11,992	3,545	16,599
Revisions of Previous Estimates	1,712	141	8	133	1,571
Improved Recovery	653	355	326	29	299
Purchases of Minerals-in-Place	1,273	173	153	19	1,100
Extensions & Discoveries	2,653	1,489	338	1,151	1,164
Production	-3,087	-1,363	-877	-486	-1,724
Sales of Minerals-in-Place	-462	-273	-253	-20	-189
End of period	34,878	16,058	11,687	4,370	18,820
Proportionate Interest in Investee Reserves and Foreign Access Reserves	--	--	--	--	5,981
Natural Gas Reserves	(billion cubic feet)				
Beginning of Period	157,230	81,193	61,721	19,472	76,037
Revisions of Previous Estimates	-1,368	-1,953	-1,971	18	585
Improved Recovery	1,356	1,040	1,011	28	316
Purchases of Minerals-in-Place	13,833	6,414	6,218	195	7,419
Extensions & Discoveries	16,250	8,420	5,770	2,650	7,829
Production	-15,148	-8,838	-5,723	-3,115	-6,310
Sales of Minerals-in-Place	-935	-512	-326	-186	-423
End of Period	171,218	85,764	66,701	19,063	85,454
Proportionate Interest in Investee Reserves and Foreign Access Reserves	--	--	--	--	26,549

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

Table B24. Oil and Gas Reserve Balances by Region for FRS Companies,2001 (Continued)

Reserves Statistics	Foreign Total	Canada	Europe and Former Soviet Union [1]	Africa and Middle East	Other Eastern Hemisphere	Other Western Hemisphere
Crude Oil and Natural Gas Liquids	(million barrels)					
Beginning of Period	16,599	2,046	5,242	5,832	1,865	1,614
Revisions of Previous Estimates	1,571	11	182	179	1,271	-71
Improved Recovery	299	15	100	144	W	W
Purchases of Minerals-in-Place	1,100	731	53	163	43	109
Extensions & Discoveries	1,164	122	496	275	175	96
Production	-1,724	-204	-614	-477	-320	-109
Sales of Minerals-in-Place	-189	-138	-2	0	W	W
End of period	18,820	2,584	5,457	6,115	3,065	1,600
Proportionate Interest in Investee Reserves and Foreign Access Reserves	5,981	W	2,460	W	W	2,113
Natural Gas Reserves	(billion cubic feet)					
Beginning of Period	76,037	11,374	22,963	4,313	22,377	15,010
Revisions of Previous Estimates	585	-669	487	896	1,010	-1,139
Improved Recovery	316	42	111	21	W	W
Purchases of Minerals-in-Place	7,419	5,418	184	W	1,244	W
Extensions & Discoveries	7,829	1,487	1,275	500	1,743	2,825
Production	-6,310	-1,497	-2,377	-245	-1,577	-614
Sales of Minerals-in-Place	-423	-218	-170	W	W	W
End of Period	85,454	15,937	22,471	5,878	24,830	16,337
Proportionate Interest in Investee Reserves and Foreign Access Reserves	26,549	W	18,765	W	W	2,696

[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, 2001 and Percent Change from 2000

	United States			Foreign Total
	Total	Onshore	Offshore	
Exploration and Development Expenditures (million dollars)				
FRS Companies	33,858.0	24,244.0	9,614.0	35,944.0
Percent Change	-29.5	-10.5	-54.1	24.8
Wells Completed				
FRS Companies	8,453.0	7,839.6	613.5	4,947.9
Percent Change	47.7	49.3	29.5	76.4
Industry[1]	35,688.0	-	-	25,680.0
Percent Change	26.0	-	-	6.7
Success Rate[2]				
FRS Companies	94.2	95.0	83.5	90.6
Industry[1]	88.8	89.0	44.3	89.7
Crude Oil and NGL Production[3] (million barrels)				
FRS Companies	1,363.2	876.9	486.3	1,757.7
Percent Change	7.5	6.0	10.3	7.8
Industry [1]	2,805.0	2,075.0	730.0	23,165.1
Percent Change	0.1	-1.4	4.9	-0.4
Crude Oil and NGL Reserve Interests[4] (million barrels)				
FRS Companies	16,057.5	11,687.4	4,370.2	24,801.5
Percent Change	3.6	-2.3	23.5	6.5
Natural Gas Production (billion cubic feet)				
FRS Companies	8,838.0	5,723.0	3,115.0	6,310.2
Percent Change	6.0	6.9	4.3	0.7
Industry[1]	19,779.0	14,591.0	5,188.0	66,304.0
Percent Change	2.9	2.7	3.5	-0.2
Natural Gas Reserve Interests (billion cubic feet)				
FRS Companies	85,764.3	66,700.9	19,063.3	112,002.8
Percent Change	5.6	8.0	-2.1	10.9

[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 (75.9 percent of total foreign) and "Other Access" reserves (24.1 percent of total foreign). "Other Access" reserves include proportional interest in investee reserves and foreign access reserves.

- = Not available.

Sources: Reserve additions, U.S. - Energy Information Administration Form EIA-23 (Annual Survey of Domestic Oil and Gas Reserves); see *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves* , 2000, and 2001 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* , September 2002, p. 84. Reserve Additions, Foreign - *British Petroleum Statistical Review of World Energy 2001 and 2002.* Wells Completed, Foreign - *World Oil* , August 2001 and 2002. FRS companies' data - 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, 2001 and Percent Change from 2000 (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	35,944.0	15,323.5	6,254.0	5,547.0	739.0	4,991.0	3,089.5
Percent Change	24.8	213.9	-25.7	104.0	34.4	-26.5	-43.3
Wells Completed							
FRS Companies	4,947.9	3,407.5	179.1	149.4	88.3	820.7	302.9
Percent Change	76.4	95.1	32.0	6.0	-45.4	133.7	12.9
Foreign Industry[1]	25,680.0	17,705.0	775.0	642.0	758.0	2,063.0	3,737.0
Percent Change	6.7	4.6	-17.2	-0.3	-1.3	12.7	26.1
Success Rate[2] (percent)							
FRS Companies	90.6	90.2	88.3	83.1	93.4	94.4	88.8
Foreign Industry[1]	89.7	89.8	82.1	86.8	96.4	85.3	92.5
Crude Oil and NGL Production[3] (million barrels)							
FRS Companies	1,757.7	203.9	614.1	359.3	151.6	320.2	108.7
Percent Change	7.8	22.0	-3.2	2.6	-2.0	43.2	8.1
Foreign Industry[1]	23,165.1	1,008.5	5,642.9	2,852.1	8,115.0	1,691.8	3,854.8
Percent Change	-0.4	1.7	2.9	-0.3	-3.6	-2.2	2.4
Crude Oil and NGL Reserve Interests[4] (million barrels)							
FRS Companies	24,801.5	2,621.8	7,916.8	5,257.8	2,198.6	3,093.9	3,712.5
Percent Change	6.5	28.2	6.4	4.8	1.8	1.3	3.7
Natural Gas Production (billion cubic feet)							
FRS Companies	6,310.2	1,496.7	2,377.3	156.3	88.7	1,576.8	614.3
Percent Change	0.7	22.6	-1.6	35.3	-9.3	0.6	-27.7
Foreign Industry[1]	66,304.0	6,071.6	34,234.0	4,377.2	8,048.4	8,814.4	4,758.4
Percent Change	-0.2	2.4	-3.9	-3.6	10.0	5.2	2.4
Natural Gas Reserve Interests (billion cubic feet)							
FRS Companies	112,002.8	15,965.1	41,236.5	5,267.6	4,848.0	25,653.3	19,032.4
Percent Change	10.9	40.4	-0.7	38.8	58.1	6.7	10.6

[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 (75.9 percent of total foreign) and "Other Access" reserves (24.1 percent of total foreign). "Other Access" reserves include proportional interest in investee reserves and foreign access reserves.

[5]OECD (Organization for Economic Cooperation and Development) Europe combined with the former Soviet Union and Eastern Europe to avoid disclosure.

Sources: Reserve additions, U.S. - Energy Information Administration Form EIA-23 (Annual Survey of Domestic Oil and Gas Reserves); see *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves* , 2000, and 2001 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* , September 2002, p. 84. Reserve Additions, Foreign - *British Petroleum Statistical Review of World Energy 2001 and 2002.* Wells Completed, Foreign - *World Oil* , August 2001 and 2002.
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,1995-2001
(million barrels)

	1995	1996	1997	1998	1999	2000	2001
U.S. Refining/Marketing							
Sources							
Acquisitions from U.S. Production Segment	1,658	1,599	1,542	1,484	1,516	1,238	1,358
Purchases from Other U.S. Segments and Unconsolidated Affiliates	432	459	468	1,935	2,181	2,149	2,629
Purchases from Third Parties	4,100	4,488	4,444	4,968	5,205	5,340	3,679
Net Transfers from Foreign Refining/Marketing Segment	612	566	571	635	475	324	716
Total Sources	6,802	7,112	7,025	9,021	9,377	9,050	8,383
Dispositions							
Net Change in Inventories	23	21	14	31	-1	-4	-1
Input to Refineries	3,565	3,563	3,259	4,883	4,872	4,690	4,668
Sales to:							
Unaffiliated Third Parties	2,961	3,291	3,424	3,730	4,147	4,281	3,391
Other Segments Excluding Foreign Refining/Marketing	252	237	328	377	359	84	325
Total Dispositions	6,802	7,112	7,025	9,021	9,377	9,050	8,383
Foreign Refining/Marketing							
Sources							
Acquisitions from Foreign Production Segment	1,249	1,371	1,391	1,380	1,462	1,585	1,661
Purchases							
Other Foreign Segments	93	88	13	246	87	57	33
Unconsolidated Affiliates	89	89	2	141	21	15	61
Unaffiliated Third Parties							
Foreign Access	107	145	228	209	228	345	59
Foreign Governments (Open Market)	621	844	851	679	741	224	643
Other Unaffiliated Third Parties	2,063	1,819	1,785	2,000	2,244	2,165	2,459
Net Transfers to U.S. Refining/Marketing	-612	-566	-571	-635	-475	-324	-716
Total Sources	3,610	3,790	3,699	4,021	4,307	4,067	4,200
Dispositions							
Net Change in Inventories	1	38	18	155	-19	10	-2
Input to Refineries	1,520	1,605	1,435	1,419	1,641	1,673	1,682
Sales	2,090	2,147	2,246	2,446	2,685	2,384	2,520
Total Dispositions	3,610	3,790	3,699	4,021	4,307	4,067	4,200

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

Table B27. U.S. Purchases and Sales of Oil, Natural Gas, Other Raw Materials, and Refined Products for FRS Companies, 1995-2001

	1995	1996	1997	1998	1999	2000	2001
Purchases	Values (million dollars)						
U.S. Refining/Marketing Segment							
Raw Materials							
Crude Oil and NGL	111,556	138,397	126,535	106,128	152,880	253,092	192,228
Natural Gas	9,747	15,651	18,657	15,177	20,387	58,679	38,947
Other Raw Materials	3,892	2,697	3,159	5,348	5,705	8,395	7,852
Total Raw Materials	125,195	156,745	148,351	126,653	178,972	320,166	239,027
Refined Products							
Motor Gasoline	14,131	18,078	18,613	24,249	36,095	65,488	64,609
Distillate Fuels	6,773	9,634	9,565	10,574	17,433	35,116	31,323
Other Refined Products	10,114	10,246	9,141	8,786	9,963	17,036	18,895
Total Refined Products	31,018	37,958	37,319	43,609	63,491	117,640	114,827
U.S. Production Segment							
Crude Oil and NGL	3,353	5,163	5,399	4,694	5,695	4,794	1,979
Natural Gas	6,981	10,715	11,220	8,922	8,608	12,208	14,113
Total Raw Materials	10,334	15,878	16,619	13,616	14,303	17,002	16,092
Sales							
U.S. Refining/Marketing Segment							
Raw Materials							
Crude Oil and NGL	53,544	69,485	70,437	50,702	72,955	121,118	86,675
Natural Gas	9,295	15,790	18,252	15,270	20,023	56,482	37,648
Other Raw Materials	2,325	1,276	1,499	2,172	1,576	2,403	2,203
Total Raw Materials	65,164	86,551	90,188	68,144	94,554	180,003	126,526
Refined Products							
Motor Gasoline	65,701	75,330	71,185	84,968	109,301	176,394	167,735
Distillate Fuels	30,420	41,618	36,962	39,513	51,810	91,998	83,702
Other Refined Products	24,577	24,577	20,964	23,283	28,506	42,269	40,172
Total Refined Products	120,698	141,525	129,111	147,764	189,617	310,661	291,609
U.S. Production Segment							
Crude Oil and NGL	26,303	32,948	30,604	19,688	25,186	38,314	31,613
Natural Gas	18,696	26,840	29,459	23,649	23,178	40,719	47,390
Total Raw Materials	44,999	59,788	60,063	43,337	48,364	79,033	79,003
Purchases	Volumes						
U.S. Refining/Marketing Segment							
Raw Materials							
Crude Oil and NGL (million barrels)	6,802	7,112	7,025	9,021	9,377	9,050	8,383
Natural Gas (billion cubic feet)	6,543	7,506	7,573	7,425	9,285	13,323	9,147
Refined Products (million barrels)							
Motor Gasoline	588	677	689	1,272	1,533	1,708	1,892
Distillate Fuels	321	380	397	625	837	943	987
Other Refined Products	422	363	329	464	446	535	625
Total Refined Products	1,330	1,420	1,415	2,361	2,815	3,186	3,504
U.S. Production Segment							
Crude Oil and NGL (million barrels)	237	300	308	394	367	200	88
Natural Gas (billion cubic feet)	4,395	4,723	4,551	4,295	3,835	3,276	3,461
Sales							
U.S. Refining/Marketing Segment							
Raw Materials							
Crude Oil and NGL (million barrels)	3,213	3,528	3,752	4,107	4,506	4,365	3,716
Natural Gas (billion cubic feet)	6,089	7,195	7,242	6,764	8,834	13,001	8,460
Refined Products (million barrels)							
Motor Gasoline	2,422	2,488	2,371	3,789	4,070	4,286	4,539
Distillate Fuels	1,374	1,562	1,473	2,146	2,344	2,444	2,540
Other Refined Products	1,183	1,069	1,008	1,342	1,407	1,405	1,528
Total Refined Products	4,979	5,119	4,852	7,277	7,820	8,135	8,606
U.S. Production Segment							
Crude Oil and NGL (million barrels)	1,875	1,933	1,860	1,805	1,667	1,484	1,498
Natural Gas (billion cubic feet)	12,108	12,281	12,421	11,765	10,952	11,348	11,957

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

Table B28. U.S. and Foreign Petroleum Refining Statistics for FRS Companies, 1995-2001

	1995	1996	1997	1998	1999	2000	2001
U.S. Refining	(thousand barrels per calendar day)						
Runs to Stills							
At Own Refineries	9,669	9,777	9,060	13,699	13,476	13,361	13,875
By Refineries of Others	5	5	5	0	82	86	105
Total Runs to Stills	9,674	9,782	9,065	13,699	13,558	13,447	13,980
Refinery Output at Own Refineries and Refineries of Others							
Reformulated Motor Gasoline	0	1,302	768	1,552	1,792	2,129	2,061
Oxygenated Motor Gasoline	0	165	749	1,018	609	412	588
Other Motor Gasoline	0	3,410	2,980	4,665	4,588	4,207	4,373
Total Motor Gasoline	4,849	4,877	4,497	7,235	6,989	6,748	7,022
Distillate Fuels	2,901	3,323	2,921	4,278	4,167	4,376	4,331
Other Refined Products	2,902	2,754	2,612	3,416	3,483	3,375	3,669
Total Refinery Output	10,652	10,954	10,030	14,929	14,639	14,499	15,022
Refinery Capacity at End of Year	10,427	10,477	9,410	14,277	14,158	14,378	14,586
	(number of refineries)						
Number of Wholly-Owned Refineries	69	69	60	95	94	90	99
	(thousand barrels per calendar day)						
Foreign Refining							
Runs to Stills							
At Own Refineries	3,962	3,936	3,961	4,043	4,407	4,513	4,507
By Refineries of Others	323	506	340	292	397	403	339
Total Runs to Stills	4,285	4,442	4,301	4,335	4,804	4,916	4,846
Refinery Output at Own Refineries							
Motor Gasoline	1,175	1,172	1,041	1,135	1,247	1,295	1,267
Distillate Fuels	1,662	1,690	1,648	1,787	1,901	1,738	1,739
Other Refined Products	1,183	1,280	1,283	1,213	1,315	1,717	1,697
Total Refinery Output at Own Refineries	4,020	4,142	3,972	4,135	4,463	4,750	4,703
Refinery Output at Refineries of Others							
Motor Gasoline	70	107	75	83	122	123	120
Distillate Fuels	140	234	154	121	135	171	155
Other Refined Products	113	165	110	87	146	80	84
Total Refinery Output at Refineries of	323	506	339	291	403	374	359
Total Refinery Output	4,343	4,648	4,311	4,426	4,866	5,124	5,062
Refinery Capacity at End of Year	4,450	4,346	4,270	4,508	4,930	5,134	5,448
	(number of refineries)						
Number of Wholly-Owned Refineries	24	20	20	20	19	18	23
Number of Partially-Owned Refineries	13	12	15	15	18	18	28

- = Not available.

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

Table B29. U.S. and Foreign Refinery Output and Capacity for FRS Companies, Ranked by Total Energy Assets, and Industry, 2001
(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]	15,022	5,154	2,938	6,930	17,689	84.9
Percent Gasoline						
Reformulated/Oxygenated	17.6	15.5	9.7	22.6	15.6	96.2
Other	29.1	29.0	38.4	25.3	30.7	80.4
Percent Distillate	28.8	26.6	29.2	30.4	30.2	81.0
Percent Other	24.4	28.9	22.7	21.8	23.5	88.4
Refinery Capacity						
Years Change (Net)	208	146	2,190	-2,128	-810	(5)
At Year End	14,586	4,595	3,893	6,098	16,367	89.1
Utilization Rate[4]	95.8	98.0	104.1	91.2	92.6	(5)
Foreign						
Refinery Output Volume[3]	5,062	4,569	0	493	-	(5)
Percent Gasoline	27.4	26.2	0.0	38.1	-	(5)
Percent Distillate	37.4	37.0	0.0	41.2	-	(5)
Percent Other	35.2	36.7	0.0	20.7	-	(5)
Refinery Capacity						
Years Change (Net)	314	471	0	-157	-	(5)
At Year End	5,448	4,800	0	648	-	-
Utilization Rate[3]	85.2	88.3	0.0	65.7	-	(5)

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

[2]For foreign FRS, the "Five through Twelve" and "All Other" groups are combined to avoid disclosure.

[3]For FRS companies, includes refinery output at own refineries for own account and at others' refineries for own account.

[4]Defined as average daily crude runs at own refineries, for own account, and for account of others, divided by average daily crude distillation capacity.

[5]Not meaningful.

- = Not available.

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

Sources: Industry data, U.S. - Refinery output and refinery capacity: Energy Information Administration, Forms EIA-820 (Annual Refinery Report) and EIA-810 (Monthly Refinery Report); see *Petroleum Supply Annual,* 2000 and 2001. Industry data, Foreign - Refinery Capacity: *British Petroleum Statistical Review of World Energy* , 2001 and 2002.

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, 1995-2001

U.S. Dispositions	1995	1996	1997	1998	1999	2000	2001
	Values (million dollars)						
Motor Gasoline							
Intersegment Sales	365	400	581	966	1,521	1,802	4,092
U.S. Third-Party Sales							
Wholesale-Resellers	27,386	32,500	31,895	38,659	51,908	83,203	69,799
Company Operated Automotive Outlets	10,088	11,293	11,855	15,497	17,334	24,870	22,843
Company Lessee and Open Automotive Outlets	20,494	21,725	20,517	23,966	29,434	48,693	45,798
Other (Industrial, Commercial and Other Retail)	7,368	9,412	6,337	5,880	9,104	17,826	25,203
Total Third-Party Sales	65,336	74,930	70,604	84,002	107,780	174,592	163,643
Total Motor Gasoline Sales	65,701	75,330	71,185	84,968	109,301	176,394	167,735
Distillate Fuels							
Intersegment Sales	219	291	191	682	708	444	1,752
Third-Party Sales	30,201	41,327	36,771	38,831	51,102	91,554	81,950
Total Distillate Fuels Sales	30,420	41,618	36,962	39,513	51,810	91,998	83,702
Other Refined Products							
Intersegment Sales	3,952	4,124	3,322	2,059	2,779	6,078	7,386
Third-Party Sales	20,625	20,453	17,642	21,224	25,727	36,191	32,786
Total Other Refined Products Sales	24,577	24,577	20,964	23,283	28,506	42,269	40,172
Total U.S. Refined Products							
Intersegment Sales	4,536	4,815	4,094	3,707	5,008	8,324	13,230
Third-Party Sales	116,162	136,710	125,017	144,057	184,609	302,337	278,379
Total U.S. Refined Products Sales	120,698	141,525	129,111	147,764	189,617	310,661	291,609
	Volumes (million barrels)						
Motor Gasoline							
Intersegment Sales	11	12	18	50	66	47	126
U.S. Third-Party Sales							
Wholesale-Resellers	1,117	1,154	1,150	1,901	2,059	2,126	1,956
Company Operated Automotive Outlets	309	319	335	558	540	543	545
Company Lessee and Open Automotive Outlets	680	653	615	965	1,006	1,105	1,182
Other (Industrial, Commercial and Other Retail)	304	350	253	316	399	465	729
Total Third-Party Sales	2,411	2,476	2,353	3,739	4,004	4,239	4,412
Total Motor Gasoline Sales	2,422	2,488	2,371	3,789	4,070	4,286	4,539
Distillate Fuels							
Intersegment Sales	11	12	8	38	33	13	54
Third-Party Sales	1,363	1,550	1,464	2,109	2,310	2,430	2,485
Total Distillate Fuels Sales	1,374	1,562	1,473	2,146	2,344	2,444	2,540
Other Refined Products							
Intersegment Sales	222	209	254	141	153	213	258
Third-Party Sales	961	860	755	1,201	1,254	1,191	1,269
Total Other Refined Products Sales	1,183	1,069	1,008	1,342	1,407	1,405	1,528
Total U.S. Refined Products							
Intersegment Sales	245	232	280	229	252	274	439
Third-Party Sales	4,734	4,886	4,572	7,048	7,568	7,861	8,167
Total U.S. Refined Products Sales	4,979	5,119	4,852	7,277	7,820	8,135	8,606
Number of Active Automotive Outlets at Year End	Number of Automotive Outlets						
Company Operated	8,549	8,927	8,942	13,645	12,018	12,583	11,380
Lessee Dealers	15,861	15,247	12,852	16,396	17,847	16,953	11,474
Open Dealers	13,950	14,151	11,959	28,859	26,805	25,707	31,231
Total Outlets	38,360	38,325	33,753	58,900	56,670	55,243	54,085

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, 2000-2001
(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								
2001	126.4	32.36	125.5	32.34	W	W	W	W
2000	47.4	38.01	47.3	38.01	W	W	W	W
Percent Change	166.7	-14.8	165.4	-14.9	W	W	W	W
Wholesale/Resellers								
2001	1,955.8	35.69	676.6	36.06	324.4	36.80	954.9	35.05
2000	2,125.9	39.14	661.7	39.69	201.6	41.91	1,262.6	38.41
Percent Change	-8.0	-8.8	2.2	-9.1	60.9	-12.2	-24.4	-8.7
Dealer-Operated Outlets								
2001	1,182.1	38.74	634.5	38.22	76.7	37.59	471.0	39.63
2000	1,104.6	44.08	565.3	45.51	0.0	0.00	539.3	42.58
Percent Change	7.0	-12.1	12.2	-16.0	0.0	0.0	-12.7	-6.9
Company-Operated Outlets								
2001	545.1	41.90	149.4	40.35	118.7	43.65	277.0	41.99
2000	543.3	45.77	165.4	48.35	39.8	43.64	338.2	44.76
Percent Change	0.3	-8.5	-9.6	-16.6	198.3	0.0	-18.1	-6.2
Other [1]								
2001	729.3	34.56	209.8	36.34	198.3	32.90	321.2	34.41
2000	464.9	38.34	112.8	40.40	98.6	39.09	253.5	37.14
Percent Change	56.9	-9.9	86.0	-10.1	101.1	-15.8	26.7	-7.3
Total Gasoline								
2001	4,538.9	36.96	1,795.7	36.95	719.1	36.94	2,024.1	36.96
2000	4,286.2	41.15	1,552.4	42.73	340.2	41.29	2,393.6	40.11
Percent Change	5.9	-10.2	15.7	-13.5	111.4	-10.5	-15.4	-7.8
Distillate								
2001	2,539.8	32.96	988.6	33.55	415.6	33.55	1,135.6	32.22
2000	2,443.7	37.65	847.6	38.06	230.6	37.30	1,365.5	37.45
Percent Change	3.9	-12.5	16.6	-11.9	80.2	-10.1	-16.8	-14.0
All Other Products								
2001	1,527.6	26.30	641.4	26.66	286.0	25.03	600.2	26.51
2000	1,404.8	30.09	478.1	31.29	134.9	27.75	791.8	29.76
Percent Change	8.7	-12.6	34.2	-14.8	112.0	-9.8	-24.2	-10.9
Total Refined Products								
2001	8,606.3	33.88	3,425.7	34.04	1,420.7	33.55	3,759.9	33.86
2000	8,134.7	38.19	2,878.1	39.46	705.7	37.40	4,550.9	37.51
Percent Change	5.8	-11.3	19.0	-13.7	101.3	-10.3	-17.4	-9.7

[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, 1995-2001
(Million Dollars)

Revenues and Costs	1995	1996	1997	1998	1999	2000	2001
Refined Product Revenues	120,698	141,525	129,111	147,764	189,617	310,661	291,609
Refined Product Costs							
Raw Materials Processed [1]	62,142	70,339	58,888	60,094	83,348	135,624	109,245
Refinery Energy Expense	4,101	5,480	5,005	5,349	6,427	10,838	11,804
Other Refinery Expense	8,854	9,882	8,436	12,219	11,734	10,635	12,111
Product Purchases	31,018	37,958	37,319	43,609	63,491	117,640	114,827
Other Product Supply Expense	3,432	4,072	3,777	5,160	4,915	6,655	6,552
Marketing Expense [2]	8,709	9,318	8,538	10,308	11,100	11,128	13,672
Total Refined Product Costs	118,256	137,049	121,963	136,739	181,015	292,520	268,211
Refined Product Margin	2,442	4,476	7,148	11,025	8,602	18,141	23,398
Refined Products Sold (million barrels)	4,978.8	5,118.6	4,852.2	7,276.9	7,820.2	8,134.7	8,606.3
Dollars per Barrel Margin [3]	0.49	0.87	1.47	1.52	1.10	2.23	2.72
Other Refining/Marketing Revenues [4]	10,449	10,731	9,693	15,997	14,282	14,196	16,918
Other Refining/Marketing Expenses							
Depreciation, Depletion, & Allowance	4,732	3,847	3,674	4,700	5,273	4,712	5,259
Other [5]	7,166	7,873	8,419	15,547	12,546	16,865	18,683
Total Other Expenses	11,898	11,720	12,093	20,247	17,819	21,577	23,942
Refining/Marketing Operating Income	993	3,487	4,748	6,775	5,065	10,760	16,374
Miscellaneous Revenue & Expense [6]	-107	-101	204	1,315	1,367	1,265	1,866
Less Income Taxes	371	1,135	1,876	2,142	1,714	4,360	6,271
Refining/Marketing Net Income	508	2,251	3,106	5,932	4,883	7,659	11,951

[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, 1995-2001
(Million Dollars)

General Operating Expenses	1995	1996	1997	1998	1999	2000	2001
Raw Material Supply							
Raw Material Purchases	125,195	156,745	148,351	126,653	178,972	320,166	239,027
Other Raw Material Supply Expense	4,699	4,067	4,523	5,183	3,184	2,371	4,196
Total Raw Material Supply Expense	129,894	160,812	152,874	131,836	182,156	322,537	243,223
Less: Cost of Raw Materials Input To Refining	64,086	75,892	64,132	62,955	85,270	139,931	114,400
Net Raw Material Supply	65,808	84,920	88,742	68,881	96,886	182,606	128,823
Refining							
Raw Materials Input to Refining	64,086	75,892	64,132	62,955	85,270	139,931	114,400
Less: Raw Material Used as Refinery Fuel	2,588	3,922	3,798	3,598	4,254	6,910	7,452
Refinery Process Energy Expense	4,101	5,480	5,005	5,349	6,427	10,838	11,804
Other Refining Operating Expenses	9,551	10,631	9,173	12,984	12,928	13,675	14,494
Refined Product Purchases	31,018	37,958	37,319	43,609	63,491	117,640	114,827
Other Refined Product Supply Expenses	3,432	4,072	3,777	5,160	4,915	6,655	6,552
Total Refining	109,600	130,111	115,608	126,459	168,777	281,829	254,625
Marketing							
Cost of Other Products Sold	4,389	5,449	6,255	6,844	5,305	7,342	9,797
Other Marketing Expenses	8,709	9,318	8,538	10,308	11,100	11,128	13,672
Subtotal	13,098	14,767	14,793	17,152	16,405	18,470	23,469
Expense of Transport Services for Others	627	507	376	4,297	4,191	3,691	4,002
Total Marketing	13,725	15,274	15,169	21,449	20,596	22,161	27,471
Total U.S. Refining/Marketing Segment General Operating Expenses	189,133	230,305	219,519	216,789	286,259	486,596	410,919

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

Table B34. U.S. Coal Reserves Balance for FRS Companies, 1995-2001
(Million Short Tons)

Reserves and Production Statistics	1995	1996	1997	1998	1999	2000	2001
Changes to U.S. Coal Reserves							
Beginning of Period	13,395	10,493	9,410	7,502	5,334	4,410	2,530
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	-699	8	-127	-17	-25	-58	-354
Production	-165	-169	-163	-74	-44	-36	-33
Dispositions of Minerals-in-Place	-2,128	-1,150	-774	-2,113	-802	-1,799	W
End of Period Reserves	10,493	9,542	8,498	5,334	4,507	2,530	1,320
Weighted Average Annual Production Capacity	184	192	215	65	55	51	40
Reserves and Production:							
Total United States							
FRS Companies' Reserves	10,493	9,542	8,498	5,334	4,507	2,530	1,320
FRS Companies' Production	165	169	163	74	44	36	33
U.S. Industry Production	1,033	1,064	1,090	1,118	1,100	1,074	1,128
Region							
East							
FRS Companies' Reserves	2,763	2,675	2,477	1,774	1,676	1,034	557
FRS Companies' Production	46	44	43	24	21	20	16
U.S. Industry Production	435	452	468	460	426	420	433
Midwest							
FRS Companies' Reserves	3,206	2,467	2,080	1,372	1,055	1,051	394
FRS Companies' Production	17	18	17	12	W	W	W
U.S. Industry Production	109	112	112	110	104	87	95
West							
FRS Companies' Reserves	4,524	4,400	3,940	2,188	1,776	446	W
FRS Companies' Production	103	107	104	38	W	W	W
U.S. Industry Production	489	500	511	548	571	566	597
Mining Method							
Underground							
FRS Companies' Reserves	5,337	4,571	3,880	2,352	1,853	1,752	886
FRS Companies' Production	62	59	51	28	21	21	18
U.S. Industry Production	396	410	421	418	392	374	381
Surface							
FRS Companies' Reserves	5,156	4,970	4,618	2,982	2,654	779	434
FRS Companies' Production	103	110	112	46	23	15	15
U.S. Industry Production	637	654	669	700	709	700	747

W = Data withheld to avoid disclosure.

Sources: Coal production: 1995-2000--Energy Information Administration, *Coal Industry Annual* , annual reports; 2001 - EIA, *Annual Coal Report 2001*. FRS Companies' data - Energy Information Administration, Form EIA-28 (Financial Reporting System).