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Performance Profiles of Major Energy Producers 1996

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Contacts

This report was prepared in the Office of Energy Markets and End Use of the Energy Information Administration, U.S. Department of Energy, under the general direction of W. Calvin Kilgore. The project was directed by Mark E. Rodekohr, Director of the Energy Markets and Contingency Information Division (202) 586-1441, and Mary E. Northup, Chief of the Financial Analysis Branch (202) 586-1445. Kathy L. Washington performed the desktop publishing and formatting effort for this report. Specific technical information concerning this report and the associated data survey (Form EIA-28) may be obtained from Jon A. Rasmussen (202) 586-1449. The following authors contributed to this report: Neal Davis (Chapter 4), Susanne Johnson (Chapters 4 and 5), Jon Rasmussen (Executive Summary, Chapters 1, 2, 3, and 6), and Larry Spancake (Chapters 3 and 5).

Data File Information

Historical Financial Reporting System (FRS) data are available from the Energy Information Administration's File Transfer Protocol (FTP) site and are also available on a 3.5-inch high-density diskette. These data cover the years 1977 through 1996, 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 1977-1996 data files can be downloaded from the Energy Information Administration's FTP site (ftp://ftp.eia.doe.gov/pub/energy.overview/frs/), or by accessing the Energy Information Administration's Worldwide Web site (http://www.eia.doe.gov/emeu/finance/page2.html). For further assistance, please contact the National Energy Information Center at (202) 586-8800, FAX (202) 586-0727, TTY (202) 586-1181, or on INTERNET infoctr@eia.doe.gov.

To receive the Financial Reporting System 1977-1996 diskette, please contact Gregory P. Filas at telephone (202) 586-1347, Fax (202) 586-9753, or on INTERNET greg.filas@eia.doe.gov.

Preface

This publication examines developments in the operations of the major U.S. energy-producing companies on a corporate level, by major line of business, by major function within each line of business, and by geographic area.

Pursuant to Section 205(h) of the Department of Energy Organization Act, which established the Financial Reporting System (FRS), the Energy Information Administration (EIA), through its Form EIA-28, collects financial information and other measures of energy-related business efforts and results for major energy companies. Since the FRS data are collected on a uniform, segmented basis, the comparability of information across energy lines of business is unique to this reporting system. For example, petroleum activities can be compared to activities in other lines of energy business or nonenergy areas, and domestic activities can be compared to foreign activities.

This report presents financial and operating data collected on Form EIA-28 for the calendar year 1996. Trends in foreign direct investment in U.S. energy are analyzed for the year 1995.

In 1996, 24 companies filed Form EIA-28. The analysis and data presented in this report represent the operations of the FRS companies in the context of their worldwide operations and in the context of the major energy markets which they serve. Both energy and nonenergy developments of these companies are analyzed. Although the focus is on developments in 1996, important trends prior to that time are also featured.

Economic performance, in financial and physical dimensions, continues to serve as a significant factor in evaluating past decisions and guiding future options in the development and supply of energy resources. The information contained in this report is intended to promote an understanding and provide a critical review of the possible motivations and apparent consequences of investment decisions by some of the largest corporations in the energy industry. The information is intended for use by the U.S. Congress, Government agencies, industry analysts, and the general public.

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Executive Summary

Performance Profiles of Major Energy Producers 1996 is the twentieth annual report of the Energy Information Administration's (EIA) Financial Reporting System (FRS). The report examines financial and operating developments in energy markets, with particular reference to the 24 major U.S. energy companies required to report annually on Form EIA-28 (see Chapter 1, box entitled "The FRS Companies in 1996"). Financial information is reported by major lines of business, including oil and gas production ("upstream"), petroleum refining and marketing ("downstream"), other energy operations, and nonenergy business. Financial and operating results are presented in the context of energy market developments, with a view toward identifying changing corporate strategies and measuring the performance of ongoing operations both in the United States and abroad. Main developments in 1996 are described below.

Net Income Hits Record Level

Overall net income of the FRS companies was a record \$32.0 billion in 1996, 52 percent greater than net income in 1995. The FRS companies' overall profitability continued to rise in 1996, reaching the highest level since the oil price escalations of 1979-1981. The results for 1996 again demonstrate, as in 1979-1981, how the combination of unexpected demand increases and already tight supplies can have very substantial effects on energy producer profits.

Market developments in the United States played a key role, as a cold winter early in 1996 increased the demand for heating fuels. The effects on petroleum and natural gas prices of increased demand for heating oil and natural gas were amplified by some of the lowest beginning-of-year inventories of petroleum and natural gas during the past two decades.

The impacts of the U.S. winter spilled over to the start of the driving season at the same time that world crude oil prices were rising. The consequence was a run-up in gasoline prices predictably accompanied by public concerns about the distribution of gains and losses stemming from tightened gasoline supplies. In the second half of 1996, petroleum markets settled down, with petroleum product prices about matching the pace of crude oil input costs.

Net income from the FRS companies' U.S. refining/marketing operations in 1996 more than doubled from the income of the prior year. However, U.S. refining/marketing income was at an historically low level in 1995 and, although the profitability of U.S. refining/marketing in 1996 was at a five-year high, the rate of return to U.S. refining/marketing assets remained among the lowest of the FRS companies' lines of business.

The main source of higher earnings for the FRS companies in 1996 was oil and gas production. Higher prices for both oil and gas and modest increases in production for all but U.S. oil output led to an \$8-billion rise in net income from these operations. Domestic oil and gas profitability, which generally had been below average since the oil price collapse of 1986, reached a level not seen since 1985.

The third most important source of earnings improvement was attributable to reductions in long-term debt. The FRS companies utilized a large part of their record-high cash flow, which reached \$64.2 billion in 1996, to reduce long-term debt in their balance sheets to a 13-year low. Interest expense declined by \$1 billion (after tax) almost entirely as a result of debt reduction in 1996.

Advancing Technologies and Added Frontiers Lead to Resurgence in Upstream Investment

In 1996, the FRS companies made their first pronounced upswing in worldwide expenditures for oil and gas exploration and development in the 1990's. Overall, 1996 exploration and development expenditures totaled \$31.7 billion, 24 percent over 1995 expenditures and the second highest in a decade. Higher oil and gas prices, of course, offered incentives for increased drilling and accelerated development of reserves. Other, longer term factors also encouraged this surge in upstream investment. Among these other factors were the cost-reducing effects of 3-D seismic, horizontal drilling, and new offshore production technologies. Additional factors contributing to the increase were the opportunities associated with the more hospitable investment environments in countries such as Algeria, Venezuela, the countries of the Former Soviet Union, and even the United States.

In the United States, the FRS companies spent $6.7 billion in 1996 on offshore (almost entirely in the Gulf of Mexico) exploration and development, 42 percent above 1995 spending. Technological developments have made deep water exploration and production a target of opportunity in the Gulf of Mexico, while advances in imaging technology, such as 3-D seismic, have not only increased drilling success rates but have also allowed hydrocarbon deposits to be clearly distinguished in formerly ambiguous geologic formations, such as offshore subsalt formations and onshore reef formations. Also adding to the attractiveness of the Gulf of Mexico as an investment target in 1996 was the first year of royalty relief under the OCS Deep Water Relief Act and a doubling of exploratory acreage awarded by the Minerals Management Service over 1995 levels.

Onshore U.S. exploration and development activity was buoyed by the joint application of 3-D seismic and horizontal drilling in such areas as the Austin Chalk in southern Texas and Louisiana, where reservoirs can be problematic to exploit using traditional techniques. Increased activity in Alaska (the FRS companies account for over 90 percent of Alaskan oil and gas production on a net ownership basis) also helped boost onshore activity. Nevertheless, the FRS companies' onshore exploration and development expenditures in 1996 were nearly flat from 1995 at $7.9 billion. Also, for six of the last seven years, including 1996, the FRS companies overall were net sellers of proven onshore reserves.

Abroad, the FRS companies increased their expenditures by $3.9 billion. Asia-Pacific, South America, and Africa accounted for nearly all of the added spending. Countries targeted in the Asia-Pacific region were Australia (including Mobil's $1.4 billion acquisition of Australia's Ampolex), China, Indonesia, Malaysia, Myanmar, the Phillippines, and Thailand. Many of the FRS companies' developments in the Asia-Pacific region are in offshore environments which offer opportunities for application of advancing technologies. In South America, Venezuela became prominent as an investment target after the Venezuelan government opened up their oil and gas reserves to joint ventures with the state energy company, Petroleos de Venezuela. Africa offered a variety of opportunities in the long-established oil-producing countries of Algeria and Nigeria as well as newer oil plays in Angola and other offshore locales in West Africa.

U.S. Refining Investment Plunges as Environmental Projects are Completed

Other lines of business were generally more notable for their reduced levels of capital expenditures. The "other nonenergy" line of business, which encompasses activities outside energy and chemicals, registered the largest decline, $6.2 billion. This decline was almost entirely caused by Union Pacific's spinoff of its energy subsidiary, Union Pacific Resources Group (which became an FRS respondent), and the resulting exit of railroad operations from the FRS data base, in 1996. Union Pacific's restructuring removed 60 percent of net investment from the FRS other nonenergy asset base.

Within energy operations, the only significant cutback in capital expenditures was in U.S. refining operations. The FRS companies' capital expenditures for U.S. refining in 1996, at $2.1 billion, not only were down 41 percent from 1995 expenditures and $3.0 billion from peak expenditures in 1992, but, when adjusted for inflation, were at their lowest level over the 1974-1996 period of FRS data collection.

This cutback appeared to reflect the completion of projects related to environmental quality requirements. The path of expenditures for U.S. refining operations in the 1990's has fairly closely paralleled pollution abatement capital expenditures for refiners' environmental compliance. Pollution abatement capital expenditures of the FRS companies have declined sharply from their peak level in 1993 and did so again in 1996. Also, the FRS refiners with the steepest reductions in capital expenditures for U.S. refining were significantly involved in the California market. Environmental standards for gasoline and diesel in California are the strictest in the United States. Companies in this group noted that significant environmental projects related to California were completed in 1996.

Cost-cutting and Efficiency Gains Continue

Although increased demand and tight supplies were the dominant influences on the FRS companies' earnings performance in 1996, ongoing efforts to cut costs and increase efficiency continued to be evident in 1996.

Overall downsizing by the FRS companies abated somewhat in 1995. Excluding the effects of Union Pacific's railroad exiting the FRS group, total employment of the FRS companies in 1996 was down 3 percent from employment in the prior year, about half the annual rate at which employment was cut in the prior 6 years.

In upstream operations, the per-barrel cost of extracting oil and gas has fallen sharply in the 1990's, both in the United States and abroad. Two developments, lower operating costs per well and greater production per well, have contributed to this trend. In the United States, cost-cutting has generally played a larger role in the decline in extraction costs than has increased well productivity. In foreign oil and gas production, increased production per well has been the primary source of lower extraction costs.

In the 1990's, until 1996, the FRS companies' U.S. refining / marketing operations suffered from generally declining profitability and low rates of return. During this period, reductions in average operating costs by FRS refiners were the only offset to the declining spread between prices received by refiners and their raw material input costs. In 1996, these trends halted, as margins improved and operating costs increased. However, the increase in operating costs was almost entirely concentrated among refiners with heavy involvement in the California motor fuels market. The increased costs appeared to reflect the added costs of complying with California's more stringent environmental requirements for motor gasoline and diesel. For other FRS refiners, operating costs per barrel of refined product sold hardly changed between 1995 and 1996.

1. Energy Markets in 1996

The 24 major energy companies reporting to the Energy Information Administration's (EIA) Financial Reporting System (FRS) (see the box entitled "The FRS Companies in 1996") derive the bulk of their revenues and income from petroleum operations, including natural gas production (see the box entitled "The FRS Companies in the U.S. Economy and Energy Markets").[1] A majority of FRS companies are multinational, with 38 percent of their net investment located abroad. Worldwide petroleum and natural gas market developments are of primary importance to the FRS companies' financial performance. Developments in chemical markets are also important in that 16 FRS companies have asset commitments in chemical manufacturing.

The FRS companies' financial performance in 1996 was favorably affected by developments in U.S. petroleum and natural gas markets. Energy market developments outside the United States had mixed results on the FRS companies' bottom lines.

Key events included a cold winter in 1996 in most of North America and parts of Europe and low stocks of crude oil and petroleum products in the United States at the onset of the year. Upward pressures on petroleum and natural gas prices continued after the 1996 heating season as the pace of global economic growth picked up during the year.

Growth in energy demand is strongly linked to economic growth. On a worldwide basis, real gross domestic product (GDP) grew at an annual rate of 2.7 percent in 1996, up from the 2.3-percent rates of 1994 and 1995.[2] Areas registering above-average growth were concentrated among the industrializing countries and included Asia-Pacific (outside Japan), with a 7.5-percent growth rate; Africa with a 4.7-percent rate; and Latin America, which grew 3.6 percent in part due to the recovery of Mexico from its currency crisis. Domestic GDP grew at a 2.8-percent clip in 1996, up from 2.0 percent the year before.

Crude oil prices, which held steady during most of 1995, rose steadily throughout most of 1996. The countries of the Organization of Petroleum Exporting Countries (OPEC) were able to maintain supplies at favorable levels in the face of a generally increasing pace of worldwide economic growth and petroleum demand. As measured by the U.S. refiner acquisition cost of imported crude oil, prices began the year at not quite a dollar a barrel over January 1995 prices. By December 1996, the price of oil, at $23 per barrel, was well over $5 a barrel higher than December, 1995 prices. For the year, 1996 crude oil prices were 20 percent above 1995 prices.

In the United States, the year 1996 began with a considerably chillier winter than the year before, resulting in an increased demand for heating fuels. The number of heating degree days, an indicator of heating demand, for the first quarter of 1996 was 11 percent above heating degree days during the first quarter of 1995. Upward pressures on U.S. petroleum prices were exacerbated by low inventories of heating oil and crude oil. Entering 1996, privately-held crude oil stocks were at a 20-year low for end-of-year stocks and distillate stocks were at their

The FRS Companies in 1996

Amerada Hess Corporation	Fina, Inc.
Amoco Corporation	Kerr-McGee Corporation
Anadarko Petroleum, Inc.	Mobil Corporation
Ashland Oil, Inc.	Occidental Petroleum Corporation
Atlantic Richfield Company (ARCO)	Oryx Energy Company
BP America, Inc.	Phillips Petroleum Company
Burlingtron Resources, Inc.	Shell Oil Company
Chevron Corporation	Sun Company
Coastal Corporation	Texaco, Inc.
E.I. du Pont de Nemours and Company	Union Pacific Resources Group
Enron Corporation	Unocal Corporation
Exxon Corporation	USX Corporation

The FRS Companies in the U.S. Economy and Energy Markets

Major energy-producing companies annually report to the Energy Information Administration (EIA) on Form EIA-28 (Financial Reporting System). These reports include data and information on financial and operating developments. For the reporting year 1996, 24 companies filed this information.[a]

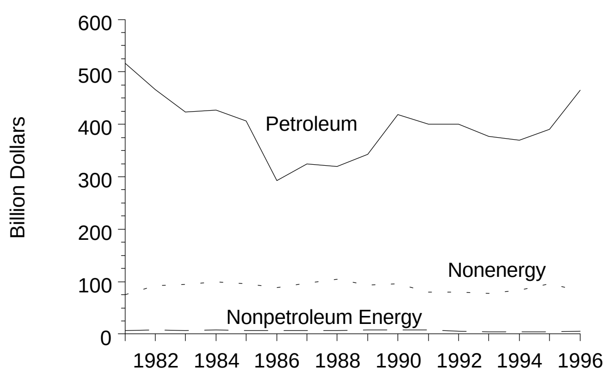
The FRS companies occupy a major position in the U.S.[b] economy. In 1996, their sales equaled 11 percent of the $5.1 trillion in sales of the *Fortune* 500 largest U.S. corporations.[c] Of the top 25 companies (based on sales) on the *Fortune 500* list in 1996, 6 were FRS companies.

The reporting companies engage in a wide range of business activities, but their most important activities are in the energy sector. About 85 percent, or $465 billion, of allocated operating revenues were derived from energy sales. Nearly all of these revenues were derived from the companies' core petroleum operations (Figure 1). (For purposes of this report, petroleum is defined to include natural gas.)

In 1996, the FRS companies accounted for 51 percent of total U.S. crude oil and natural gas liquids (NGL) production, 43 percent of U.S. natural gas production, and 65 percent of U.S. refinery capacity (Figure 2). The bulk of the FRS companies' assets and new investments was devoted to sustaining various aspects of petroleum production, processing, transportation, and marketing. Nonenergy businesses, mainly chemicals, accounted for about 15 percent, or $83 billion, of the FRS companies' allocated revenues in 1996.

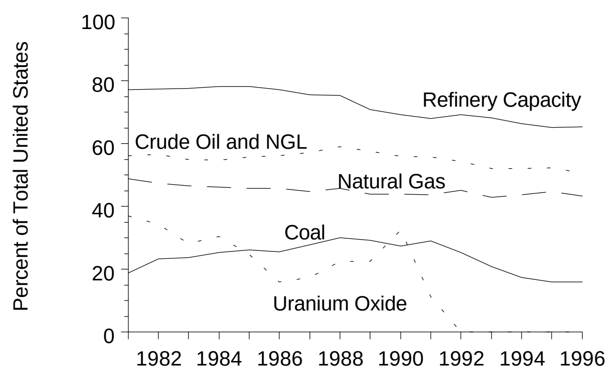
Energy production other than oil and natural gas is a relatively small part of the FRS companies' operations. The combined operating revenues of coal and other energy operations of the FRS companies totaled $6 billion in 1996, or only 1 percent of allocated revenues. Nonetheless, the FRS companies are significant participants in the coal market, producing 16 percent of U.S. coal in 1996. The FRS companies no longer produce uranium oxide.

Figure 1. Operating Revenues by Line of Business for FRS Companies, 1981-1996



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

Figure 2. Shares of U.S. Energy Production and Refinery Capacity for FRS Companies, 1981-1996



Sources: Table B1; Total industry uranium oxide production is from Energy Information Administration, *Uranium Industry Annual 1992* (October 1993).

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[a]Aggregate time series data from Form EIA-28 for 1977 through 1996 and previous editions of this report can be obtained from the EIA (see contacts, p. ii) on the Internet or on paper or diskette.
[b]For purposes of this report, the term "United States" typically includes the 50 States, the District of Columbia, Puerto Rico, and the U.S. Virgin Islands.
[c]The *Fortune 500* is a list of the 500 largest U.S. industrial companies, ranked by total sales, published annually by *Fortune* magazine.

second-lowest level. The results of these developments were a sharp jump in distillate prices (up 17 percent in the first quarter) and increased use of already highly utilized refining capacity to produce more distillate. However, stepped-up distillate production diverted refining capacity away from motor gasoline production, which would normally have gone to building gasoline inventories for the advent of the driving season.

Springtime demand for gasoline in the United States was especially strong in 1996. Demand in April and May was nearly 3 percent above demand in April and May of the year before. Adding further to pressures on gasoline prices were crude oil prices that had already risen 20 percent in the first four months of 1996. Despite the rise in crude oil prices, the spread between product prices received by U.S. refiners and crude oil input prices increased considerably, with the price-cost margin in the second quarter of 1996 at its highest level in six years. For the second half of 1996, U.S. refined product prices roughly matched changes in crude oil costs.

Natural gas prices in the United States were similarly affected by market developments in 1996. Subnormal winter temperatures led to a 6-percent increase in U.S. natural gas consumption in the first quarter of 1996 compared with consumption in first quarter of 1995. Working gas in storage was at a 20-year low entering 1996. Canada was also experiencing a colder than usual winter, a development which, together with pipeline capacity constraints, meant that U.S. imports of Canadian natural gas could not relieve the upward pressures on price. Natural gas prices continued to rise for the remainder of 1996, as did oil prices, and were up 45 percent on an annual basis over the 1995 annual wellhead prices of U.S. natural gas of $1.55 per thousand cubic feet.

The events of 1996 resulted in a rare combination of financial results for U.S.-based petroleum and natural gas companies generally and for the FRS companies' U.S. operations in particular: substantial increases in earnings from both U.S. oil and gas production *and* U.S. refining / marketing operations. In a more typical year, rising oil prices benefit upstream earnings but result in lessened refined product demand and higher input costs, which lower the return to refining operations. A reverse pattern typically prevails when crude oil prices decline. The FRS companies experienced a more typical pattern of earnings in their foreign petroleum operations.

Although oil prices realized by the FRS companies in foreign oil production were up about as much as in the United States, natural gas prices they realized outside North America increased only about 8 percent compared with a 40-percent increase in their U.S. natural gas prices. Nevertheless, the FRS companies registered sharp gains in foreign upstream income. In foreign refining and marketing operations, the spread between refined product prices and crude oil input prices varied by location. For example, 1996 refiner margins in Singapore were up, but Rotterdam margins declined relative to margins in 1995. On balance, the FRS companies' foreign refining / marketing operations did not fare as well in 1996 as their U.S. refining / marketing operations, registering a decline in earnings.

Chemical manufacturing is an important source of income and target of investment for a majority of the FRS companies. Chemical operations in the United States were hurt by a price-cost squeeze in 1996, after experiencing strong back-to-back increases in income in 1994 and 1995. In the United States, growth in demand for chemicals was 2 percent in 1996 (measured by the industrial production index) which was below the growth of the previous two years. Chemical prices overall (measured by the producer price index) were flat in 1996, probably reflecting growth in capacity following the most recent upswing in profitability. However, the prices of chemical feedstocks and fuel, which are largely derived from petroleum and natural gas components, were up sharply in 1996. As a consequence, price-cost margins deteriorated and chemical earnings were generally down.

This report reviews the FRS companies' 1996 financial performance and corporate strategies in the context of domestic and foreign energy market developments. Chapter 2 presents an overview of sources of income, cash flow, taxation, and deployment of funds, including FRS company investment patterns across their lines of business. Chapter 3 reviews the FRS companies' performance in oil and gas exploration, development, and production from a global perspective. Chapter 4 examines developments in the FRS companies' global refining, marketing, and transport activities.

Chapter 5 reviews the FRS companies involvement in energy sources other than petroleum and natural gas. Chapter 6 presents a summary of foreign direct investment in U.S. energy[3] which, prior to the 1994 reporting year, was published separately in the *Profiles of Foreign Direct Investment in U.S. Energy* report. The coverage of foreign direct investment developments discussed in this chapter lags the discussion of the FRS companies by one year. This is due to the later release date of much of the foreign direct investment data. Appendix A describes the structure of the FRS data collection system, and Appendix B presents detailed statistical tables. Appendix C lists transactions related to foreign direct investments in U.S. energy. A glossary provides key definitions.

Endnotes

[1] The companies that reported to the FRS system for the years 1974 through 1996 are listed in Appendix A, Table A1. Three of the FRS companies are majority-owned by foreign companies: BP America—100-percent owned by British Petroleum, Fina—79-percent owned by Petrofina, and Shell Oil—100-percent owned by Royal Dutch / Shell.

[2] In this chapter, international energy data were obtained from Energy Information Administration, *International Energy Annual 1996*, DOE / EIA-0219(96) (Washington, DC, December 1997); international natural gas trade data were obtained from British Petroleum Company, p.l.c., *BP Statistical Review of World Energy* (London, June 1997); annual U.S. energy industry price and quantity data are from the Energy Information Administration, *Annual Energy Review 1996,* DOE / EIA-0384(96)(Washington, DC, July 1997); monthly data are from Energy Information Administration, *Monthly Energy Review* DOE / EIA-0035(97 / 04) (Washington, DC, April 1997); GDP data are from the WEFA Group, *World Economic Outlook* (August 1997); and refining margin data are from the Energy Information Administration, *Petroleum Marketing Monthly*, DOE / EIA-0380(97 / 04) (Washington, DC, April 1997).

[3] The purpose of this 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…."

2. Key Financial Developments

In 1996, net income of the 24 major energy companies reporting to the Energy Information Administration's Financial Reporting System (FRS) soared to a record level. The income gains came largely from upstream operations (oil and gas exploration, development, and production), as oil prices and natural gas prices in 1996 reached levels not seen since the oil market disruptions during the Persian Gulf conflict in late 1990 and early 1991. Domestic petroleum refining and marketing contributed to bottom-line gains in 1996, reversing a near-continual decline in the financial performance of these operations over the previous seven years. Additionally, an emphasis on debt reduction by the FRS companies in recent years paid off in 1996, contributing $1 billion (after tax) to net income through lower interest expense.

Net income of the FRS companies in 1996 was $32.0 billion, the highest level in 23 years of FRS data collection and 52 percent above the prior year's level (Table 1). Overall profitability, as measured by return on equity, of the FRS companies rose to 18 percent in 1996, a level exceeded only by the profitability realized during of the oil price escalations of the 1979 through 1981 period (Figure 3). Return on equity for other large U.S. industrial companies,[4] though at a record high in 1996, was slightly below that of the FRS companies. The sharp gain in the FRS companies' net income resulted not only from developments in 1996 but was also the cumulation of bottom-line improvements since 1992, when their overall profitability was close to zero.

Sources of Income

Higher Oil and Gas Prices Lead to Surge in Upstream Income

The 1996 results for the FRS companies' oil and gas production operations demonstrate the dominance of prices in the financial performance of these operations. Since the oil price collapse of late 1986 and early 1987, the FRS companies, as well as other U.S. oil and gas producers, have been relentlessly cutting costs—both the costs of production and the costs of replacing production through additions to oil and gas reserves. Despite these efforts, the profitability of upstream operations did not

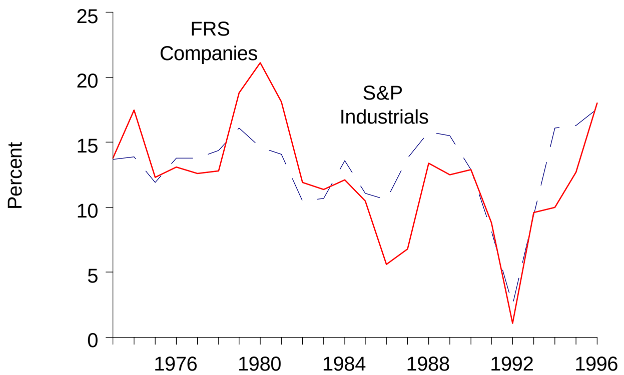
Table 1. Consolidated Income Statement for FRS Companies and the S&P Industrials, 1995 and 1996
(Billion Dollars)

	FRS Companies			S&P Industrials		
Income Statement Items	1995	1996	Percent Change 1995-1995	1995	1996	Percent Change 1995-1995
Operating Revenues	481.6	541.4	12.4	3,379.0	3,586.5	6.1
Operating Expenses	-449.1	-492.7	9.7	-3,009.9	-3,192.1	6.1
Operating Income	32.5	48.7	49.6	369.2	394.4	6.8
Interest Expense	-8.4	-6.9	-17.1	-73.7	-73.4	-0.5
Other Revenue (Expense)	9.7	10.3	5.9	-8.2	20.7	--
Income Tax Expense	-12.8	-20.1	56.9	-107.9	-122.9	13.8
Net Income	21.1	32.0	51.6	179.4	218.9	22.0
Net Income Excluding Unusual Items	25.0	30.5	21.8	NA	NA	

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

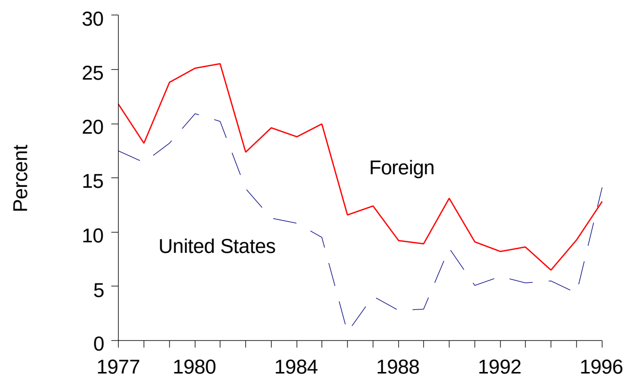
Sources: **FRS Companies**: Energy Information Administration, Form EIA-28, "Financial Reporting System"; **S&P Industrials**: Compustat PC Plus, a service of Standard and Poor's.

Figure 3. Return on Equity for FRS Companies and the S&P Industrials, 1973-1996



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 4. Return on Investment in U.S. and Foreign Oil and Gas Production for FRS Companies, 1977-1996



Sources: Energy Information Administration, Form EIA-28, "Financial Reporting System."

come close to pre-collapse levels until 1996 (Figure 4). A combination of market developments in 1996 (described in Chapter 1) led to substantial increases in oil and gas prices compared to prices in recent years. Oil prices, as measured by the annual price of imported crude oil, were up 20 percent (or $3.50 per barrel) from 1995 and natural gas prices, measured at the U.S. wellhead, were up 45 percent (or $3.93 per barrel of oil equivalent).[5]

The FRS companies net income from U.S. oil and gas production,[6] excluding unusual items,[7] doubled between 1995 and 1996 (Table 2), while the profitability of these operations tripled, reaching a level not realized since the years before the oil price collapse (Figure 4). Cost-cutting really was not a factor in the 1996 surge in upstream earnings. The lack of noticeable cost cutting is in contrast to the first half of the 1990's, when cost reductions were the main source of the FRS companies' earnings improvement in U.S. oil and gas production. The only cost item registering a clear reduction was the allowance for depreciation, depletion, and amortization (DD&A), which was inflated in the previous year due to one-time charges against income for a new accounting standard.[8]

Foreign oil and gas operations yielded a lesser 36-percent gain in net income (excluding unusual items) primarily due to modest rises in natural gas prices outside North America (Table 2). Although Canadian natural gas prices realized by the FRS companies were up nearly 40 percent, natural gas prices in Europe and elsewhere registered only an 8-percent rise (see Table 13 in Chapter 3). As was the case with U.S. oil and gas production, foreign upstream operations exhibited little in the way of cost-cutting in 1996 apart from DD&A allowances.

U.S. Refining and Marketing Profitability Reverses Course, Reaching a 6-year High

Market developments that had put continual downward pressure on rates of return to the FRS companies' U.S. refining and marketing investments during the 1990's generally turned around in 1996. Petroleum product price rises outpaced crude oil price increases in 1996. Product price pressures stemming from a combination of strong demand for distillate (particularly heating oil in the first quarter of the year) and gasoline (at the outset of the driving season in the Spring) were amplified by abnormally low inventories of these products in the first half of the year. Not only did the margin between petroleum prices and raw material input costs increase, but the price spread between light and heavy products widened in 1996, following a general deterioration in the first half of the 1990's. This development favored most of the FRS refiners who, through earlier investments in refinery upgrading, are capable of producing proportionately greater yields of gasoline and distillate. Payoffs to investments for crude oil processing capability also increased in 1996. Many of the FRS companies have invested heavily in such upgrades. Widening of the price spread between high quality crude oils (i.e. light and low in sulfur content) and low quality crude oils tends to give refiners with upgraded processing capability a cost advantage compared with other refiners. In 1996, the difference in prices between high and low quality crudes increased after declining during most of the 1990's, a development which generally benefited the FRS companies' U.S. refining operations.

Net income from U.S. refining/marketing operations, excluding unusual items, doubled between 1995 and 1996

Table 2. Contributions to Net Income by Line of Business for FRS Companies, 1995-1996
(Million Dollars)

Line of Business	Net Income 1995	Net Income 1996	Net Income Percent Change 1995-1996	Net Income Excluding Unusual Items 1995	Net Income Excluding Unusual Items 1996	Net Income Excluding Unusual Items Percent Change 1995-1996
Petroleum						
U.S. Petroleum						
Production	3,698	11,816	219.5	5,706	11,536	102.2
Refining/Marketing	508	2,251	343.1	1,220	2,476	103.0
Pipelines	2,167	1,635	-24.6	2,206	1,779	-19.4
Total U.S. Petroleum	6,373	15,702	146.4	9,132	15,791	72.9
Foreign Petroleum						
Production	5,942	9,190	54.7	6,134	8,359	36.3
Refining/Marketing	2,409	1,984	-17.6	2,673	2,182	-18.4
International Marine	-38	31	--	-13	31	--
Total Foreign Petroleum	8,313	11,205	34.8	8,794	10,572	20.2
Total Petroleum	14,686	26,907	83.2	17,926	26,363	47.1
Coal	311	458	47.3	495	283	-42.8
Other Energy	173	215	24.3	214	240	12.1
Nonenergy	12,642	8,032	-36.5	12,589	8,180	-35.0
Total Allocated	27,812	35,612	28.0	31,224	35,066	12.3
Nontraceables and Eliminations	-6,681	-3,583	--	-6,205	-4,581	--
Consolidated Net Income[a]	21,131	32,029	51.6	25,019	30,485	21.8

[a]The total amount of unusual items was -$3,888 million and $1,544 million in 1995 and 1996, respectively.
-- = Not meaningful.
Source: Energy Information Administration, Form EIA-28, "Financial Reporting System."

(Table 2) to $2.4 billion. The return on U.S. refining/marketing investment, though still low in 1996, was at a six-year peak (Table 3). However, refining/marketing operating costs were up about 10 percent in 1996, following recent years' cost-cutting. The increase in costs appeared to be concentrated in West Coast operations, probably reflecting the higher environmental standards for reformulated motor fuels in that part of the country. (See Chapter 4 for a more detailed discussion.)

Net income from the FRS companies' petroleum refining and marketing operations abroad, by contrast, fell 18 percent to $2.2 billion. As noted in the previous edition of this report and discussed in detail in Chapter 4 in this report, net income from foreign refining and marketing largely reflects developments in European petroleum markets and Asia-Pacific markets. Further, most of the European operations are consolidated for financial reporting purposes (i.e., financial results are fully contained in revenues, costs, and other components of the companies' income statement) but most of the Asia-Pacific operations are reported as income from unconsolidated affiliates (i.e., only the company's proportionate share in the subsidiaries' net income is reported in the income statement). Caltex, a largely downstream joint venture between Chevron and Texaco, operates throughout Asia and Pacific locales and is the most prominent of the FRS companies' unconsolidated affiliates in foreign refining/marketing. Texaco provided a useful synopsis of developments in downstream petroleum markets outside North America in their annual report:[9] "Results for 1996, as compared with 1995, reflect the impact of lower margins in both the Europe and Caltex operating areas, partly offset by higher Latin American results. Marketing margins in Europe were significantly depressed from excess gasoline supply and a highly competitive market in the U.K., although both these factors were partially offset by improved refining operations and margins. In the

Table 3. Return on Investment by Line of Business for FRS Companies, 1986-1996
(Percent)

Line of Business	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996
Petroleum	5.5	6.2	7.3	6.7	9.5	7.0	5.6	6.4	5.6	5.7	10.1
U.S. Petroleum	3.0	4.9	6.3	5.8	7.9	4.9	4.4	4.9	5.2	4.0	9.9
Oil and Gas Production	0.8	4.1	2.8	2.9	8.5	5.1	5.9	5.3	5.5	4.4	14.1
Refining/Marketing	4.5	2.9	14.7	11.5	5.1	2.0	-0.4	3.4	3.6	1.0	4.4
Pipelines	13.2	12.8	9.6	10.2	11.2	10.7	8.4	6.4	7.6	9.1	6.9
Foreign Petroleum	12.8	9.5	9.9	8.7	12.5	11.0	7.9	9.2	6.2	8.4	10.6
Oil and Gas Production	11.6	12.4	9.2	8.9	13.1	9.1	8.2	8.6	6.5	9.3	12.8
Refining/Marketing	16.3	4.7	11.6	8.0	11.2	14.6	7.8	10.6	6.1	7.2	6.0
International Marine	5.3	-3.6	6.8	12.4	11.7	15.6	-1.2	1.2	-2.0	-2.5	2.2
Coal	2.7	5.1	6.7	5.0	3.3	8.7	-9.3	7.6	4.0	6.9	9.9
Other Energy	-0.8	0.5	-2.5	-2.3	2.6	2.8	1.8	4.1	4.8	6.1	7.9
Nonenergy	5.1	12.2	20.3	17.3	7.8	2.9	2.1	4.7	10.5	19.4	15.0

Note: Return on investment measured as contribution to net income/net investment in place.
Source: Energy Information Administration, Form EIA-28, "Financial Reporting System."

Caltex operating markets, significantly lower margins in Australia, Korea, Thailand and Japan, primarily due to higher crude costs not fully recovered in the market, were somewhat offset by higher margins in Bahrain and Singapore. In Latin America, improved results in Brazil came from increased volumes and higher product margins..."

On balance, the FRS companies' foreign refining/marketing income from unconsolidated affiliates declined from $0.7 billion in 1995 to $0.5 billion in 1996, excluding unusual items, and net income from fully consolidated operations declined from $1.9 billion to $1.7 billion, excluding unusual items.

Pipeline operations yielded a drop in income in excess of $400 million (Table 2). Almost all of the decline (89 percent) can be traced to the principal owners of the Trans Alaskan Pipeline System (TAPS). Oil production from Alaska's North Slope has been declining since 1989 due to the maturing of the region's oldest fields (mainly Prudhoe Bay). In 1996, Alaskan oil production was down 6 percent from 1995's level. The pipeline segment of the principal TAPS owners registered a revenue drop which was not matched by a similar decline in operating costs, resulting in a steep 44-percent drop in net income. Other FRS companies with liquids pipelines, in total, registered only a 1-percent decline in net income, as oil production from the Lower 48 was flat between 1995 and 1996. Net income for FRS companies whose primary involvement in pipelines is in natural gas transmission was down 9 percent. For the natural gas pipeline group, growth in transport revenues, which exceeded overall growth in natural gas consumption in the United States (9 percent vs. 2 percent), was more than offset by increased operating expenses.

Electricity Powers Other Energy's Bottom Line

The bulk of activity in the other energy line of business is related to electricity (cogeneration and power production and related energy services), tar sands production in Canada, and geothermal power production. This line of business is relatively small, accounting for less than 1 percent of total FRS revenues, and only 8 companies report sales in it. Nevertheless, this line of business has been growing, with revenues doubling over the 1990 to 1996 period (compared to 6-percent revenue growth for all FRS businesses), and has produced positive income and income growth in the 1990's. Prior to 1990, this line of activity yielded operating losses for 16 consecutive years. Financial performance continued to improve in 1996. Revenues increased from $1.4 billion in 1995 to $2.4 billion in 1996 and net income, excluding unusual items, was up 12 percent, to $240 million. Only Unocal reported a decline in income, $5 million in geothermal operations, due to higher exploration expenses in Indonesia.[10]

Income from coal operations in 1996, as reported by the 11 FRS coal producers, appeared to increase 47 percent from 1995's level. This result was strongly influenced by nonrecurring charges for a change in accounting standards in 1995, totaling $172 million, and a $177-million gain from Coastal's sale of western U.S. coal properties to ARCO in 1996. Absent these and other unusual items, net income from coal operations was down 43 percent. However, this latter result probably overstates the decline in financial performance of the FRS companies' U.S. coal operations. For companies reporting coal production and revenues primarily from U.S. operations in both 1995 and 1996, average realized coal prices were up $0.19 per ton, while out-of-pocket operating expenses were up $0.49 per ton, resulting in a 6-percent reduction in pretax cash flow per ton produced (see Chapter 5 for a detailed discussion).

Nonenergy Income Tumbles from Peak as Chemical Revenues Fall and the Railroad Departs

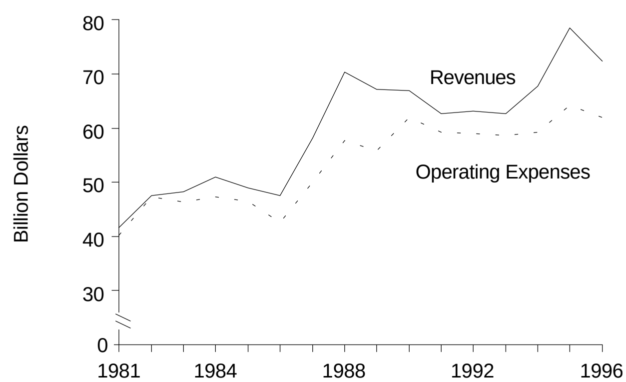
Net income of the FRS companies' nonenergy line of business in 1996 was $8.2 billion, down sharply from the all-time record net income of $12.6 billion in 1995. The FRS companies' chemical operations account for the bulk of investment in this line of business.

A typical pattern in the FRS companies' chemical operations begins with a sharp upswing in demand, which raises the rate of return to chemical assets followed, with about a one-year lag, by an increase in capital expenditures directed to these operations. When demand falls and reduces chemical profitability, capital expenditures continue to rise for another year or so, exacerbating the downward pressures on profitability. In 1996, a two-year surge in chemical demand, during which the FRS companies' chemical income[11] more than tripled, came to an end. Exxon's comment typified most FRS companies' view of chemical industry developments in 1996: "World demand for chemicals continued to grow at a healthy 5 percent per year in 1996, though lower prices and higher feedstock costs reduced margins to a more typical range from the record levels in 1995."[12] Revenues of the FRS companies' chemical operations fell by $6.2 billion (Figure 5), leading to a squeeze on price-cost margins. As a result, operating income fell 28 percent from income in the prior year to $10.3 billion in 1996 (Table 4).

The other nonenergy line of business, which encompasses a diversity of products and services, has generally been a target of continuing retrenchment by FRS companies since the mid-1980's. In 1996, the largest single divestiture ever of other nonenergy assets among the FRS companies occurred when Union Pacific spun off its natural resources subsidiary, Union Pacific Resources, to its shareholders. Beginning with the 1996 reporting year, Union Pacific Resources became the respondent for FRS purposes and Union Pacific, the railroad company, exited the FRS group, thereby removing $15.4 billion[13] (60 percent) of net investment in place from the FRS companies' other nonenergy asset base.

The exit of Union Pacific and its railroad assets from the FRS group also had a large effect on aggregate income from the other nonenergy line of business. Including the railroad's financial results, operating income from the other nonenergy line of business fell from $2.1 billion in

Figure 5. Revenues and Operating Expenses for the Chemical Segment for FRS Companies, 1981-1996



Sources: **1981-1986**: Energy Information Administration, Form EIA-28, "Financial Reporting System." **1987-1996**: Company annual reports to shareholders.

Table 4. Operating Income in Chemicals and Other Nonenergy Segments for FRS Companies, 1995-1996
(Million Dollars)

Segment	1995	1996	Percent Change 1995-1996
Operating Income, Excluding Unusual Items			
Chemicals	14,264	10,279	-27.9
Other Nonenergy	2,066	371	-82.0

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.

1995 to $0.4 billion in 1996, an 82-percent decline. However, even when Union Pacific's 1995 operating income is excluded, income was down 49 percent among the remaining FRS companies with other nonenergy assets.

Prominent among the FRS companies with asset commitments in the other nonenergy line of business are Exxon, USX, and Ashland. Exxon reported that their earnings decline in this line of business"… resulted chiefly from lower copper prices…" although Exxon produced a record amount of copper in 1996.[14] USX reported that their "… U.S. Steel Group results from operations were negatively impacted by lower average steel product prices and by planned and unplanned blast furnace outages."[15] Ashland's other nonenergy business consists primarily of construction and construction materials located across 13 "Sun Belt" states. In contrast to overall FRS company results, Ashland's other nonenergy business registered a rise in operating income, from $75 million in 1995 to $83 million in 1996. Ashland reported that their highway construction group was able "… to take full advantage of a strong construction economy."[16]

Results for "nontraceables and eliminations" have rarely been reviewed in previous editions of this report. This category consists largely of interest expense on debt, and interest is not allocated to the lines of business for FRS reporting purposes. In 1996, the FRS companies reduced their interest expense by $1.4 billion from that in the previous year (Table 1), the largest such reduction in the 23 years of FRS data collection (second largest, if Union Pacific is excluded). Applying the 35-percent Federal corporate tax rate indicates that lower interest expense added $0.9 billion to net income in 1996, ranking behind only upstream production and U.S. refining / marketing as a source of increased income. Lower interest expense in part reflected the generally lower interest rates of 1996. For example, the Moody's AAA corporate bond rate averaged 7.4 percent in 1996 compared with 7.6 percent in 1995.[17] Much more important, though, was the FRS companies' deployment of cash flow and other capital resources to the reduction of debt on their balance sheets.

Cash: Sources and Uses

Cash Flow From Operations Reaches Record Level

Cash flow from the FRS companies' operations totaled $64.2 billion in 1996 (Table 5), an all-time record.[18] Line-of-business contributions to cash flow generally reflected the pattern of contributions to net income. Oil and gas production added $15 billion (pretax) more to cash flow in 1996 than in 1995. U.S. refining and marketing's contribution to cash flow increased $1.6 billion, while the balance of the FRS companies' downstream operations yielded less cash flow in 1996. Chemical and other nonenergy business recorded sharp drops in cash flow, consistent with the declines in financial performance in 1996 in these lines of activity.

Table 5. Line-of-Business Contributions to Pretax Cash Flow for FRS Companies, 1995-1996
(Billion Dollars)

Contribution to Pretax Cash Flow [a]	1995	1996	Percent Change 1995-1996
Petroleum			
Oil and Gas Production	38.1	53.1	39.3
U.S. Refining and Marketing	5.7	7.3	28.1
Other Refining, Marketing, and Transport	8.2	6.9	-15.3
Coal and Other Energy	1.2	1.2	-3.0
Chemicals	17.8	13.1	-26.1
Other Nonenergy	2.8	1.0	-65.6
Nontraceable	-3.0	-2.7	--
Total Contribution to Pretax Cash Flow[a]	70.7	79.8	12.8
Current Income Taxes	-13.1	-17.2	31.2
Other (Net)	0.9	1.6	--
Cash Flow from Operations	58.5	64.2	9.7

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

Cash raised from asset disposals totaled $10.9 billion, almost $2 billion more than in 1995 (Table 6). However, as Table 7 indicates, a number of transactions were sales of equity involving formation of subsidiaries or other gains of ownership rather than outright divestiture of assets. That is, a number of FRS companies were able to add to their cash balances by forming a subsidiary from current operations and selling equity ownership in the subsidiary.

The apparent increase in cash gained from asset sales also somewhat misrepresents the FRS companies' pace of restructuring in 1996. Outright retrenchments, apart from Union Pacific's spinoff of Union Pacific Resources (noted in the previous section), included sales by Chevron and Mobil of their remaining land development businesses and Unocal's sale of California oil and gas properties. Downsizing eased again in 1996 as employment (excluding the effects of the Union Pacific spinoff) was cut 3 percent in 1996 following a 4-percent reduction in 1995 which was down from the 7-percent annual reduction of the prior 5 years (Figure 6).

Debt Reduction Intensifies

Cash raised through the issue of long-term debt by the FRS companies, at $10.7 billion in 1996 (Table 6), was at a 13-year low. Sharply lower debt issuance, together with continued high levels of outlays for debt reduction, which totaled $18.4 billion in 1996, diminished the amount of debt in the FRS companies' balance sheets. One frequently used measure of debt structure in companies' balance sheets is the ratio of long-term debt (the book value of obligations to lenders) to stockholders' equity (the book value of ownership). The FRS companies managed in 1996 to reduce their dependence on debt to a level not seen since the early 1980's. The massive reduction in debt of $13.7 billion (Table B9 in Appendix B) ($8.0 billion excluding Union Pacific) was the primary source of reduced interest expense in 1996. Other large industrial companies also reduced long-term debt in 1996, but their reductions appear to be well behind the pace set by the FRS companies (Figure 7) and generally had little effect on their interest expense between 1995 and 1996 (Table 1).

Was the reduction in the FRS companies' long-term debt simply a substitution of short-term borrowing for long-term borrowing? The spread between long-term and short-term interest rates favored such a move.[19] However, the answer is no. Balance sheet data indicate that there was not a large substitution of long-term for short-term debt among the FRS companies. Short-term debt, measured by notes payable in the balance sheet, hardly changed, totaling $19.5 billion for the FRS companies in 1995 and $19.2 billion in 1996.

The largest year-to-year change in cash outlays was for repurchases of company stock. The FRS companies' stock repurchases were dominated by DuPont's repurchase of

Table 6. Sources and Uses of Cash for FRS Companies, 1995-1996
(Billion Dollars)

Sources and Uses of Cash	1995	1996	Percent Change 1995-1996
Main Sources of Cash			
Cash Flow from Operations	58.5	64.2	9.7
Proceeds from Long-term Debt	19.9	10.7	-46.3
Proceeds from Disposals of Assets	9.1	10.9	20.7
Proceeds from Equity Security Offerings	3.5	1.2	-66.3
Main Uses of Cash			
Additions to Investment in Place	47.7	50.0	4.7
Reductions in Long-term Debt	18.7	18.9	1.2
Dividends to Shareholders	15.2	15.6	2.3
Purchase of Treasury Stock	10.0	1.3	-87.1
Other Investment and Financing Activities, Net	1.7	1.0	--
Net Change in Cash and Cash Equivalents	1.1	2.3	--

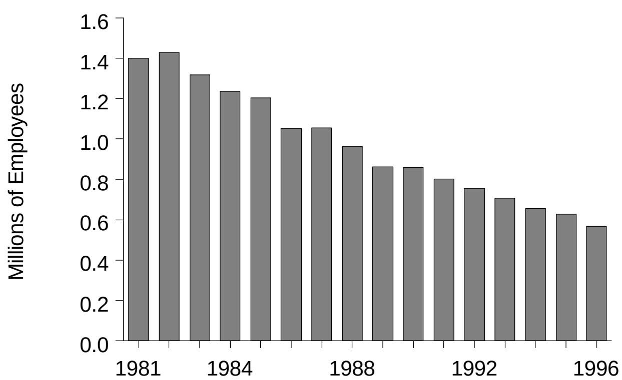
-- = Not meaningful.
Note: Sources minus Uses plus Other Investment and Financing Activities (Net) may not equal Net Change in Cash and Cash Equivalents due to independent rounding. Percent changes were calculated from unrounded data.
Source: Energy Information Administration, Form EIA-28, "Financial Reporting System."

Table 7. Major Divestitures, Ownership Sales, and Related Transactions by FRS Companies, 1996
(Million Dollars)

Company	Transaction	Reported Value of Transaction
Asset Disposals		
Caltex (joint venture of Chevron and Texaco)	Sale of Nippon Petroleum Refining Co. (Japan)	1,000
Coastal	Sale of western U.S. coal operations to ARCO and Itochu	610
Amerada Hess	Sale of Canadian oil and gas production assets	558
Unocal	Sale of California oil and gas properties to Nuevo Energy	479
Chevron	Sale of land development business	400
Mobil	Sale of Mobil Land Development	400
Sun	Sale of international oil and gas production business	278
Equity-related Transactions		
Chevron	Merged U.S. natural gas marketing assets into NGC	740
Mobil	Sold U.S. natural gas gathering and processing assets to PanEnergy and formed the joint venture, PanEnergy Marketing, with PanEnergy with a 40-percent ownership share	300
DuPont	Formation of Conoco Oil and Gas Associates LP	297
Kerr-McGee	Merged North American oil and gas-producing properties with Devon Energy for 31 percent ownership of Devon Energy	226

Sources: Company annual reports to shareholders, *Oil and Gas Investor* (September 1996 and April 1997), and various issues of *Energy Alert*.

Figure 6. Number of Employees of FRS Companies, 1981-1996



Source: Company annual reports to shareholders.

23 percent of their common stock held by Seagram for $8.8 billion in 1995. Apart from this transaction, the FRS companies' stock repurchases changed little from 1995 to 1996, remaining in the $1.0 to $2.0 billion range typical of the 1990's.

Despite the sharp cutbacks in overall debt levels, the FRS companies increased their capital expenditures by 5 percent to $50.0 billion, the highest level in the post oil price-collapse era (Figure 8). Although the year-to-year increase in overall capital expenditures was modest, the FRS companies made some clear shifts in their targets of investment in 1996.

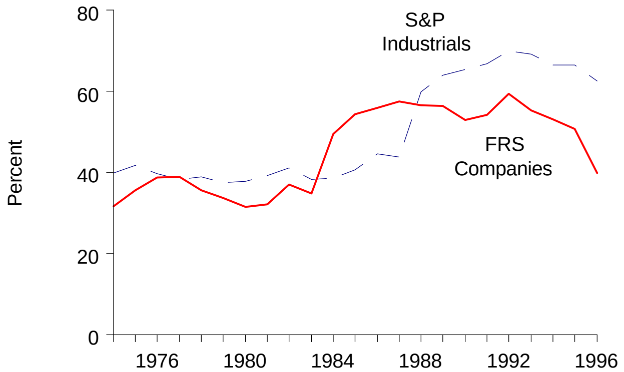
Targets of Investment

Gulf of Mexico, Asia-Pacific, and Africa Lead Upswing in Oil and Gas Investment

The primary target of the FRS companies' capital expenditures in 1996, as measured by additions to investment in place,[20] was oil and gas production. Worldwide upstream capital expenditures, at $28.8 billion, accounted for a majority of the FRS companies' capital expenditures in 1996 and were up nearly $7 billion from expenditures in the prior year (Table 8).

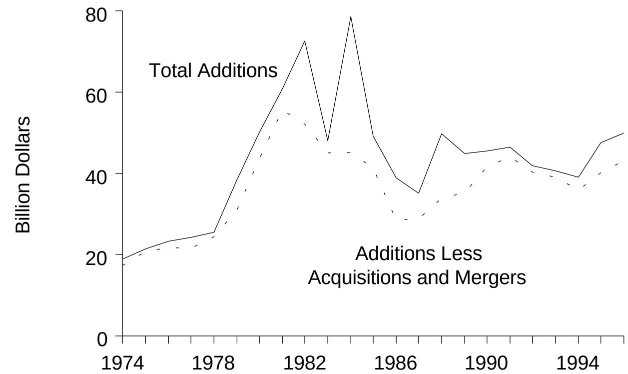
In the United States, offshore locales in the Gulf of Mexico were the focus of increased expenditures and activity among the FRS companies. Although higher oil and gas prices in 1996 undoubtedly encouraged this development, the interest in the Gulf of Mexico reflected longer term considerations.

Figure 7. Long-term Debt / Equity Ratio for FRS Companies and the S&P Industrials, 1974-1996



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 8. Additions to Investment in Place and Value of Acquisitions and Mergers for FRS Companies, 1974-1996



Sources: Energy Information Administration, Form EIA-28, "Financial Reporting System," and company filings of Securities and Exchange Commission Form 10-K.

Among the important factors were, and continue to be, applications of advancing technologies. Innovative subsea exploration techniques and ever more sophisticated offshore platform construction have made deep-water oil and gas development feasible and frequently economic. Horizontal drilling and other directional drilling techniques have enabled more rapid and complete extraction of hydrocarbons, thereby spreading the enormous costs of offshore development over more units of production. The increased use of 3-D seismography, which takes advantage of ever-advancing computer-based imaging technology, has not only increased drilling success rates but has also allowed hydrocarbon deposits to be clearly distinguished in formerly ambiguous geologic formations.

Also contributing to the attractions of the Gulf of Mexico as a target of investment has been the increased offerings of Federal Outer Continental Shelf (OCS) acreage for competitive bidding. The amount of OCS acreage awarded by the Minerals Management Service doubled from 1995 to 1996, to 8 million acres, after quadrupling between 1992 and 1995. Much of the increase consists of deep-water sites (greater than 2,500 feet water depth), reflecting the increased capability of the FRS companies to exploit such sites.

The FRS companies' offshore U.S. exploration and development expenditures increased by $2.0 billion, or 42 percent, between 1995 and 1996.[21] Onshore expenditures, by contrast, were only up 3 percent. Capital expenditures for offshore unproved acreage doubled, reflecting the increase in OCS acreage available for bid. Natural gas price increases at the wellhead of over 40 percent contributed to a doubling of expenditures for offshore exploratory drilling for natural gas. Capital expenditures for development of offshore fields to bring them into actual production increased by $0.9 billion, with outlays for oil and gas drilling and installation of lease equipment for improved recovery from producing wells all showing sizable increases.

Outside the United States, the regions which registered the heftiest increases in spending included Asia-Pacific, South America, and Africa. The FRS companies' upstream expenditures in the Asia-Pacific region increased from $2.4 billion in 1995 to $4.6 billion in 1996. Mobil's acquisition of Ampolex, a major upstream company in Australia, for $1.4 billion (Table 9)[22] accounted for a large share of the increase in expenditures.[23] Other Asia-Pacific countries with increased upstream activity noted by FRS companies in their *1996 Annual Reports* included Indonesia (Mobil and Unocal), offshore China (Phillips Petroleum and Texaco), Malaysia (Exxon), Myanmar (Unocal), and Thailand (Unocal).

The FRS companies' exploration and development spending in Africa increased by $0.8 billion in 1996, up 37 percent from that of the year before. A number of areas in Africa can be distinguished as investment targets. Two long-established oil-producing nations, Nigeria and Algeria, have recently received renewed exploration and development interest. Nigeria, which has been an established oil producer for decades, has opened offshore locales for drilling and production. Other sub-Saharan countries located on Africa's west coast are more recent additions to areas available for exploration and

Table 8. Additions to Investment in Place by Line of Business for FRS Companies, 1995-1996
(Billion Dollars)

Line of Business	1995	1996	Percent Change 1995-1996	Percent Change Excluding Mergers and Acquisitions 1995-1996
Petroleum				
U.S. Petroleum				
Production	11.4	14.1	23.2	27.3
Refining/Marketing				
Refining	3.6	2.1	-40.7	-42.7
Marketing	1.9	2.1	9.9	13.0
Transport	0.3	0.5	61.8	61.8
Total Refining/Marketing	5.8	4.7	-18.9	-19.6
Pipelines	1.0	1.4	38.1	30.4
Total U.S. Petroleum	18.2	20.1	10.7	11.7
Foreign Petroleum				
Production	10.7	14.7	37.3	19.6
Refining/Marketing	3.0	3.5	18.9	18.9
International Marine	0.3	0.1	-73.2	-73.2
Total Foreign Petroleum	14.0	18.3	31.2	17.4
Total Petroleum	32.2	38.5	19.6	14.1
Coal	0.3	0.7	171.9	55.7
Other Energy	0.4	0.6	44.0	44.0
Nonenergy				
Chemicals	6.1	7.4	22.4	2.7
Other Nonenergy	7.3	1.2	-83.9	-55.7
Total Nonenergy	13.4	8.6	-35.7	-15.5
Nontraceables	1.5	1.6	--	--
Additions to Investment in Place[a]	47.7	50.0	4.7	--
Additions Due to Mergers and Acquisitions	7.5	6.8	-10.1	--
Total Additions Excluding Mergers and Acquisitions	40.2	43.2	7.5	--
Addendum: Environmental Capital Expenditures	3.5	2.3	-34.4	--

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

-- = Not meaningful.

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

Source: Energy Information Administration, Form EIA-28, "Financial Reporting System," except for environmental capital expenditures, which came from company filings of *Securities and Exchange Commission Form 10-K*.

Table 9. Value of Mergers, Acquisitions, and Related Transactions by FRS Companies, 1996
(Million Dollars)

Line of Business and Acquiring Company	Acquisition	Reported Value of Acquisition
U.S. Oil and Gas Production		
Burlington Resources	Purchase of Gulfstream Resources, Inc.	77
Enron	South Texas Lobo Trend field from Amoco	47
Shell Oil	Assets from Benton Oil and Gas	35
Union Pacific Resources	Aviara Energy's Austin Chalk assets	27
DuPont (Conoco)	Natural gas gathering and processing system in Texas	24
Union Pacific Resources	Various assets of Tri-C Resources	23
Foreign Oil and Gas Production		
Mobil	Purchase of Ampolex, Ltd. (Australia)	1,394
Mobil	25 percent equity interest in Tengiz (Kazakhstan) joint venture oil field	1,100
Amoco	50 percent ownership interest in Empresa Petrolera Chaco, a former state-owned Bolivian company	307
ARCO	Acquisition of enhanced oil recovery project with Sonatrach, the state-owned Algerian oil company	225
Oryx Energy	65 percent of Chevron's interest in 4 North Sea (UK) producing fields	91
ARCO	Purchased additional LUKoil (Russia) bonds	88
Exxon	3 percent interest in Azerbaijan project from Pennzoil	80
Phillips Petroleum	Bridge Oil's Timor Sea (Australia) unit	78
Amerada Hess	Interest in a production sharing contract in Indonesia	40
Refining, Marketing, and Transport		
ARCO	Purchase of Zhenai Refining and Chemical Co. (China) convertible bonds	130
Enron	38 percent interest in Promigas, a Colombian gas pipeline and distribution company	101
Sun	Acquisition of Kendall/Amalie business	74
Coastal	13.2 percent interest in the Iroquois Gas Transmission System from Tenneco	39
Anadarko Petroleum	Gas gathering assets (OK) from PanEnergy	36
Fina	Acquisition of 34.4 percent interest in Southwest Convenience Stores	20
Coastal	Acquired Primark Storage Leasing unit	14
Coal		
ARCO	Purchased 65 percent interest in Canyon Fuel Co. (UT) from Coastal	411
Chemicals		
ARCO	TDI technology and plant (LA) from Olin	565

See footnotes at end of table.

Table 9. Value of Mergers, Acquisitions, and Related Transactions by FRS Companies, 1996 (Continued)

Line of Business and Acquiring Company	Acquisition	Reported Value of Acquisition
Amoco	Alphaolefins and related businesses from Albermarle Corp.	535
Occidental Petroleum	Acquisition of a 64 percent interest in INDESPEC	87
Occidental Petroleum	Purchase of antimony oxide operations from Laurel Industries	79
DuPont	MSA nylon business	61
Occidental Petroleum	Natural Gas Odorizing from Helmerich & Payne	48
Occidental Petroleum	Sodium silicate plant from Power Silicates Mfg.	19

Sources: Company annual reports to shareholders, *Oil and Gas Investor* (September 1996 and April 1997), and various issues of *Energy Alert*.

production activity. Most prominent in this group is Angola, but the Congo, Equatorial Guinea, and Zaire are also attracting investment. Algeria has opened a few areas to exploration in recent years. Anadarko Petroleum has been noticeably active in this area, possibly encouraged by Sonatrach's (Algeria's state energy company) minority ownership share in Anadarko, gained as part of a settlement in the mid-1980's. Anadarko spent $85 million on exploration and development in Algeria in 1996 and planned to spend $191 million in 1997.[24] ARCO signed an agreement with Sonatrach for an enhanced oil recovery project with an initial acquisition cost of $225 million (Table 9) and an anticipated overall investment of $1.3 billion.[25] Also in Algeria, Mobil reported drilling a second wildcat discovery well.[26]

South America attracted $1.6 billion of exploration and development expenditures in 1996 from the FRS companies, nearly double the $0.9 billion of expenditures in 1995. The opening up of Venezuela to joint venture investments with Petroleos de Venezuela (PDVSA) (Venezuela's state energy company) beginning in 1995, appeared to be a key factor in this surge of upstream expenditures. FRS companies' activities in Venezuela in 1996 included:

- Texaco's heavy oil project in partnership with ARCO, Phillips, and Corpoven (a subsidiary of PDVSA)[27]

- Mobil's gain of an exploration block in Lake Maracaibo[28]

- Amoco's two successful wildcat discovery wells[29]

- DuPont's Conoco subsidiary's initial participation in a joint venture to produce and upgrade extra heavy crude oil[30]

- Occidental Petroleum's enhanced oil recovery project.[31]

Other countries with heightened upstream activity in 1996 in the region noted by FRS companies in their *1996 Annual Reports* were Colombia (Amoco, Chevron, and Occidental Petroleum), Ecuador (Occidental Petroleum), Peru (Occidental Petroleum), and Trinidad and Tobago (Amoco).

Completion of Environmental Upgrades Leads to 10-Year Low in U.S. Refining Capital Expenditures

After reaching an all-time peak in 1988-1989, the profitability of the FRS companies' U.S. refining/marketing assets generally declined in the first half of the 1990's to near-zero levels. Nevertheless, the FRS companies' capital expenditures for U.S. refining operations more than doubled from 1989 to 1992. Since 1992, the FRS companies have reduced their expenditures, which reached $2.1 billion in 1996, the lowest level since 1987. When adjusted for inflation (via the implicit gross domestic product deflator),[32] 1996 capital expenditures for U.S. refining were at an all-time low over the 1974 through 1996 period of FRS data collection.

The upswing in capital expenditures in the early 1990's was driven mainly by increased expenditures for pollution abatement largely traceable to the Clean Air Act Amendments of 1990, passed by the U.S. Congress. This legislation required U.S. refiners to produce oxygenated gasolines by late 1992, lower sulfur diesel fuels by late 1993, and reformulated gasoline by January 1, 1995. In addition, the State of California imposed even more stringent requirements on gasoline and diesel. Based on data derived from surveys on capital expenditures for pollution abatement conducted by the Bureau of the Census and the American Petroleum Institute,[33] the FRS companies' capital expenditures for pollution abatement in their U.S. refining operations were estimated at $0.6 billion in 1990, rising to a peak of $1.9 billion in 1992.[34] For 1996, the FRS companies' overall pollution abatement capital expenditures fell 34 percent (Table 8). Applying this relative decline to estimated 1995 expenditures suggests that the FRS companies' pollution abatement expenditures for U.S. refining were about $0.7 billion in 1996.

The decline in U.S. refining capital expenditures was widespread, with 13 of 19 refiners reporting reduced expenditures and 3 refiners reporting essentially no change between 1995 and 1996. Nearly two-thirds of the reduction in the FRS companies' U.S. refining capital expenditures was traceable to refiners with significant involvement in the California market. ARCO, Chevron, Shell, and Texaco all noted in their *1996 Annual Reports* or related disclosures that they completed large projects directed to complying with California's reformulated gasoline and low-sulfur diesel fuel requirements, which, in turn, reportedly accounted for their decline in capital expenditures for U.S. refining.

By contrast, capital expenditures for marketing of U.S. refined products were up 10 percent between 1995 and 1996, the third consecutive annual increase. Most of the growth in marketing expenditures appeared to be directed toward gaining added value from company-owned retail gasoline outlets by extending the scope of products and services offered at these sites. There was also some expansion of gasoline retailing, as the number of company-owned outlets increased four percent. Mobil, by constructing 150 convenience stores in 1996, with another 150 planned for 1997, blended both expansion and value-added goals.[35] Similarly, Phillips Petroleum began a program in 1996 to increase the number of company-operated retail outlets featuring larger convenience stores with fast-food offerings.[36] On a somewhat different tack in 1996, Shell Oil embarked on new marketing initiatives, including preventive maintenance services for commercial customers and quick-lube service for trucks.[37]

Although only a minority of FRS companies have refining and / or marketing operations outside the United States, the geographical scope of these operations is truly global. Generally, investment in foreign downstream assets has tended to move toward regions that are experiencing the most pronounced economic growth (e.g., Asia-Pacific) or have recently opened up to foreign investment (e.g., Eastern Europe and China). Also, capital expenditures continue to be allocated for upgrading of refineries in mature, industrial regions (such as Western Europe) to produce a larger slate of lighter products or for compliance with heightened environmental standards. This pattern prevailed again in 1996 as the FRS companies' capital expenditures for foreign refining and marketing were up 19 percent from 1995, to $3.5 billion.

Companies reporting sizable increases in foreign downstream capital expenditures in 1996 included:

- Mobil, which in its *Fact Book* reported a $343-million increase in capital expenditures for foreign downstream operations, noted that they have undertaken a variety of upgrades to their refineries in Australia, Japan, Singapore, and Saudi Arabia.

- Texaco in its *1996 Annual Report* reported an additional $80 million in capital outlays for international petroleum marketing and noted that they are targeting high growth areas, particularly Latin America, for added transport fuel distribution networks.

- DuPont's Conoco reported that it had gained a 16-percent interest in two Czech Republic refineries in 1996 (via additions to investments and advances) (Table 9), as well as adding a vacuum distillation unit to their UK refinery.

Capital Expenditures for Coal and Other Energy Nearly Double

Total capital expenditures for 1996 energy operations other than petroleum and natural gas totaled $1.3 billion, 86 percent above 1995's expenditures (Table 8).

The 172-percent increase in the FRS companies' capital expenditures for coal resulted in large part from continued restructuring of U.S. coal operations and overstates the expansionary tendencies of the FRS companies in this line of activity. The largest single outlay for coal operations in 1996 was ARCO's acquisition of western U.S. coal properties from Coastal, another FRS coal producer, for $411 (Table 9). This transaction was basically a transfer between companies rather than a net expansion in FRS coal production capacity. Also, Ashland reconsolidated its Ashland Coal subsidiary in 1995, an action which had the accounting effect of reducing their additions to investment in place for coal to near zero in 1995.

Excluding these two transactions, the FRS companies' capital expenditures for coal production were down 29 percent between 1995 and 1996. Nevertheless, FRS coal producers increased their U.S. production capacity by 4 percent, and one coal producer increased its capital expenditures for coal operations. Sun reported that its

U.S. coal operations are now restructured and revitalized, with growth prospects in the form of new long-term supply agreements. Sun also reported an increase from $7 million in capital expenditures for coal operations in 1995 to $34 million in 1996.[38]

Other energy activities, though small in relation to the total size of the FRS companies, continued to be an area of growth for some FRS companies. Capital expenditures were up 44 percent in 1996 following a 52-percent rise in 1995. Enron's and Coastal's power operations, which include power production and cogeneration and associated services, and Unocal's foreign geothermal production appeared to be the focuses of increased investment in the other energy line of business in 1996. Coastal acquired a 15-percent ownership share in a natural gas-fired cogeneration project in Thailand, while Enron indicated a sizable increase in investments and advances in their power project subsidiaries. Unocal reported a $63-million increase in capital expenditures related to increased geothermal exploration and development activities in Indonesia.

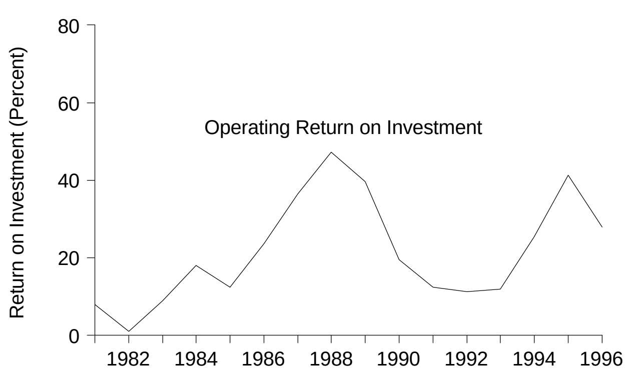
Chemical Expenditures Keep Rising as Profitability Drops

The FRS companies' capital expenditures for their chemical operations, which totaled $7.4 billion in 1996, up 22 percent from 1995's level, nearly matched the all-time high registered in 1990 (Figure 9b). The upswing in chemical outlays continued into 1996 although income and profitability fell sharply (Table 4 and Figure 9a).

However, these findings need to be tempered with two observations. First, most of the $1.4-billion increase in chemical investment was traceable to large acquisitions in 1996: ARCO's acquisition of chemical facilities from Olin for $565 million and Amoco's acquisition of a chemical line from Albermarle Corp. for $535 million (Table 9). Excluding the effects of mergers and acquisitions, capital expenditures for chemical operations were essentially flat between 1995 and 1996 (Table 8). Second, there tends to be about a one-year lag between movements in the rate of return to chemical investments and capital expenditures (Figure 9). Given this pattern and the continued decline in chemical earnings through the first half of 1997, the FRS companies' capital expenditures for chemical operations can be expected to decline in 1997.

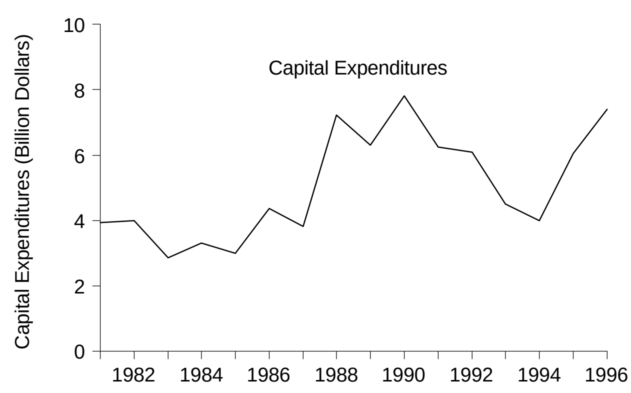
The other nonenergy line of business was the target of a huge cutback in capital outlays of $6.1 billion between 1995 and 1996. Most of this apparent disfavor of diversified businesses was attributable to Union Pacific's spinoff of its energy subsidiary, Union Pacific Resources, in 1996 and the resulting exit of its railroad operations from the FRS database. Of special note were Union Pacific's acquisitions of the Chicago and Northwestern Railroad and 25-percent ownership of Southern Pacific in 1995. These two transactions had an impact of $4.6 billion on the FRS companies' total capital outlays for the other nonenergy line of business. However, even excluding Union Pacific's 1995 capital expenditures, other energy capital outlays were still down 19 percent. Apparently, the sharp decline in income from this line of business (even excluding Union Pacific's results) reduced its attractiveness as a target of investment.

Figure 9a. Operating Return on Investment in Chemicals for FRS Companies, 1981-1996



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

Figure 9b. Capital Expenditures for Chemicals for FRS Companies, 1981-1996



Sources: Energy Information Administration, Form EIA-28, "Financial Reporting System"; and company annual reports to stockholders.

Taxes

The FRS companies' worldwide income taxes increased from 37 percent of pretax income in 1995 to 38 percent in 1996 (Figure 10a). The effective tax rate for the FRS companies was slightly higher than for the S&P Industrials group, which remained at 36 percent.

Deferred Taxes Increase

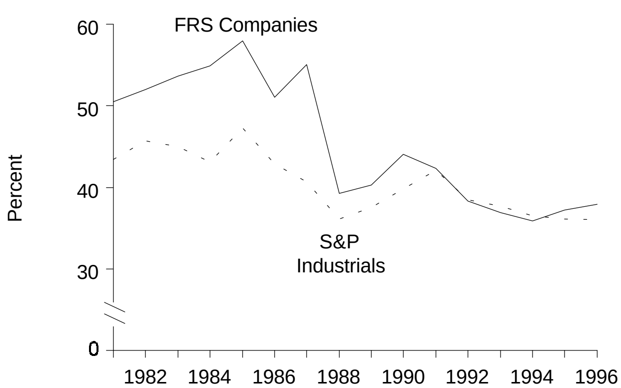
For financial reporting purposes, income taxes are categorized as current or deferred. Basically, current taxes are deemed payable in the reporting year while deferred taxes represent the difference between income tax expense accrued under Generally Accepted Accounting Principles and income taxes payable in the reporting period.[39]

Deferred tax expense of the FRS companies totaled $2.8 billion in 1996, $3.2 billion higher than the FRS companies' overall deferred tax credit of $0.4 billion in 1995 (Table 10). This unusually large increase in deferred taxes resulted from the implementation of Financial Accounting Standard 121 (FAS 121) *Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of*. This accounting change required a review by U.S. corporations of the value of their assets in relation to expected cash flows from the assets and the current market value of the assets.[40] Implementation of this standard resulted in writedowns of FRS companies' asset values totaling $6.0 billion in 1995, an amount which, in turn, had a sizable effect on deferred taxes. The following two paragraphs explain the technical aspects of this development.

The deferred tax credits in 1995 appear to be due to the writedowns of property carrying costs resulting from the implementation of FAS 121. As a general rule, the properties' financial statement basis would be greater than their income tax basis because these assets would have either been expensed or depreciated by the use of an accelerated method for income tax reporting purposes. Because the financial statement basis would be higher than the income tax carrying basis, a deferred tax expense/liability would have been recorded. When these items were written off in 1995 for FAS 121 purposes, the difference between the financial statement carrying basis and the income tax basis would have been reduced, or even eliminated, a condition which would have resulted in a lower tax liability and a deferred income tax credit.

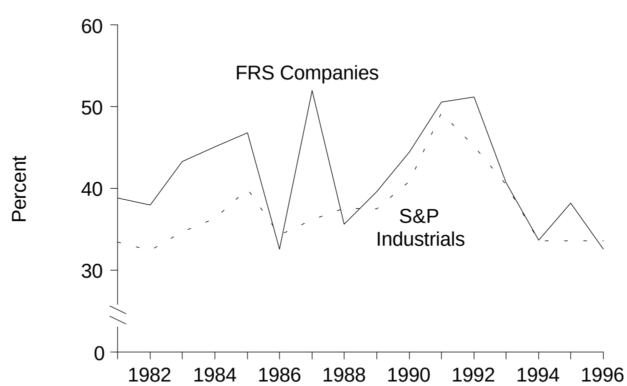
The deferred tax increase from $0.7 billion in 1994 to $2.8 billion in 1996 is due in part to a reduction in the 1996 financial statement depreciation of the items written off due to the implementation of FAS 121 in 1995. Financial statement depreciation of items with a lower tax basis reduces the difference between the financial statement and income tax carrying basis. As this difference decreases, the deferred tax liability decreases, resulting in a deferred tax credit. As a result, 1996 deferred income tax expense increased because a lesser amount of deferred income tax credits were available to offset the deferred income tax expense associated with adding new property with a financial statement carrying basis greater than the income tax carrying basis.

Figure 10a. Current and Deferred Income Expense/Pretax Income, 1981-1996



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 10b. Current Income Tax Expense/Pretax Income, 1981-1996



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

Table 10. Composition of Income Tax Expense for FRS Companies, 1995-1996
(Billion Dollars)

Component	1995	1996	Percent Change 1995-1996
Pretax Income	34.2	52.8	54.3
U.S. Federal Income Taxes			
Current	4.5	5.7	26.7
Deferred	-0.9	1.8	--
Total U.S. Federal	3.6	7.5	108.1
State and Local Income Taxes			
Current	0.6	0.7	14.8
Deferred	0.0	0.1	--
Total State and Local	0.6	0.8	29.4
Foreign Income Taxes			
Current			
Canada	0.6	0.7	17.5
OECD Europe	2.8	3.9	40.3
Africa	1.2	2.0	62.5
Middle East	1.0	1.3	29.5
Other Eastern Hemisphere	1.9	2.2	16.6
Other Western Hemisphere	0.5	0.7	41.8
Total Current	8.0	10.8	35.0
Deferred	0.5	0.9	73.2
Total Foreign	8.5	11.7	37.4
Total Income Tax Expense	12.8	20.0	56.9
Total Current	13.1	17.2	31.2
Total Deferred	-0.4	2.8	--

-- = Not meaningful.

Note: Sum of components may not equal total due to independent rounding. The Former Soviet Union and Eastern Europe are included in OECD Europe to avoid disclosure.

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

U.S. Upstream Tax Rates Rise as Tax Credits Lag Income Growth

The effective tax rates across the FRS companies' lines of business held fairly steady between 1995 and 1996, with the exception of U.S. oil and gas production (Table 11). In U.S. oil and gas production, the effective tax rate in 1996 was 32 percent, up sharply from 20 percent in 1995 and 1994. This increased tax bite was traceable largely to the workings of Internal Revenue Code Section 29 (Section 29) tax credits.

Section 29 tax credits apply to the production of oil produced from shale and tar sands; gas produced from geopressurized brine, Devonian shale, coal seams, and tight sand formations; and liquid, gaseous, or solid synthetic fuels produced from coal. Most of the FRS companies' Section 29 credits come from coal bed methane production in the San Juan Basin located in New Mexico and Colorado, as well as coal bed methane production in Alabama, Kansas, Oklahoma, Pennsylvania, Utah, Virginia, West Virginia, and Wyoming. Section 29 credits are adjusted upward with general inflation, rather than adjusted with the prices of oil or natural gas.

As U.S. natural gas prices for the FRS companies increased 42 percent from 1995 to 1996, the credit per unit of qualified Section 29 production increased at only the rate of inflation. For the FRS companies, Section 29 credits were up 6 percent, from $574 million in 1995 to $610 million in 1996.[41] However, pretax income from U.S. oil and gas production more than tripled. As a result, Section 29 credits had a much smaller relative impact on income tax expense in 1996 than in 1995.

Table 11. Income Tax Expense, Pretax Income, and Effective Tax Rates by Line of Business, 1995-1996

Line of Business	1995 Pretax Income	1995 Income Tax Expense	1995 Effective Tax Rate	1996 Pretax Income	1996 Income Tax Expense	1996 Effective Tax Rate
	billion dollars		percent	billion dollars		percent
Petroleum						
U.S. Petroleum	9.2	2.6	28.2	23.7	7.6	32.0
Oil and Gas Production	4.8	1.0	20.3	17.3	5.5	31.7
Refining/Marketing/Pipelines	4.4	1.6	36.9	6.4	2.1	32.9
Foreign Petroleum	16.0	7.7	48.1	22.4	11.2	50.0
Oil and Gas Production	12.6	6.7	52.8	19.4	10.2	52.7
Refining/Marketing/Marine	3.4	1.0	30.6	3.0	1.0	32.7
Coal	0.4	0.1	20.4	0.7	0.2	32.2
Other Energy	0.3	0.1	36.6	0.4	0.1	40.2
Nonenergy	18.1	5.5	30.3	11.6	3.5	30.5
Total Allocated	44.0	16.0	36.3	58.7	22.7	38.6
Nontraceables and Eliminations	-9.8	-3.2	--	-5.9	-2.7	--
Total Consolidated	34.2	12.8	37.2	52.8	20.0	37.9

-- = Not meaningful.

Note: Sum of components may not equal total due to independent rounding. Effective tax rates are calculated from unrounded data.

Source: Energy Information Administration, Form EIA-28, “Financial Reporting System.”

Endnotes

[4] The Standard and Poor's Industrials is a well recognized database that includes nearly 400 of the largest U.S. industrial companies. In 1996, 19 of the FRS companies were included in the S&P Industrials. Financial statistics for the S&P Industrials were obtained by accessing Compustat PC Plus, a service of Standard & Poor's, Inc.

[5] Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(97/10) (Washington, DC, October 1997), Tables 9.1 and 9.11.

[6] 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 disposal 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.) Line-of-business returns on investment are based on historical costs and measure ex-post average profitability, not marginal or prospective rates of return.

[7] Unusual items are composed of gains and charges recognized in a company's income statement that are of a non-recurring nature and are generally unrelated to current operations. These items include effects of accounting changes, litigation settlements, gains and losses from large divestitures of assets, provisions for the cost of restructuring, and provisions of reserves for future liabilities.

[8] For a complete review of Financial Accounting Standard 121, see "New Accounting Standard Leads to Billions in Asset Writeoffs" in Energy Information Administration, *Performance Profiles of Major Energy Producers 1995*, DOE/EIA-0206(95) (Washington, DC, February 1997), p. 6.

[9] Texaco Inc., *1996 Annual Report*, p. 31.

[10] Unocal Corp., *1996 Annual Report*, p. 35.

[11] 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 1981 through 1986. Thus, the public disclosures of chemical segment revenue and operating income were utilized for 1987 through 1996. 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. It should be noted that the results for chemicals are qualitatively unchanged if DuPont, the largest FRS chemical producer, is excluded.

[12] Exxon Corp., *1996 Annual Report*, p. 17.

[13] Union Pacific, *1995 Annual Report*, p. 35.

[14] Exxon Corp., *1996 Annual Report*, p. 19.

[15] USX Corp., *1996 Securities and Exchange Commission Form 10-K*, p. S-24.

[16] Ashland Inc., *1996 Annual Report*, p. 39.,

[17] WEFA Group, *First Quarter 1997 U.S. Long-Term Historical Data* (Eddystone, PA, 1997), p. 3.1.

[18] Cash is defined as currency, demand deposits, and interest-bearing assets of less than 30 days maturity. Generally, cash flow from operations is computed by adding to (subtracting from) net income those cost (revenue) items that did not actually involve an outlay (receipt) of cash. The largest of these non-cash items is the cost of depreciation, depletion, and amortization. Also, outlays (receipts) of cash that were recognized as non-cash items in previous income statements (e.g., provisions for a legal settlement taken as a charge against income in a previous year but not actually paid until the current year) are subtracted from (added to) net income in computing cash flow. Lastly, changes in working capital (excluding cash) due to operations are subtracted.

[19] For example, the difference between the AAA corporate bond rate and the 6-month commercial paper rate was 1.7 percentage points in 1995 and 2.0 percentage points in 1996 (WEFA Group, *First Quarter 1997 U.S. Long-Term Historical Data*, p. 3.71).

[20] To the extent possible, capital outlays are measured by additions to investment in place, which are defined as additions to property, plant, and equipment (PP&E) plus additions to investment and advances. In 1996, additions to PP&E accounted for 88 percent of capital outlays so measured. However, because additions to investments and advances were not collected for some FRS segments prior to 1981, capital outlays are sometimes measured solely by additions to PP&E.

[21] Exploration and development expenditures include both capital expenditures (additions to PP&E) and exploration expenses. In 1996, capital expenditures were 83 percent of exploration and development expenditures.

[22] Figure 8 and Table 8 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 9 is generally the cash outlay and can differ from the effect on additions to investment in place due to assumptions of liabilities and goodwill assets acquired.

[23] Mobil's acquisition of a 25 percent share of the Tengiz joint venture in Kazakhstan for $1.1 billion (Table 2-9) was accounted for as an addition to investments and advances and is included in the capital expenditures shown in Table 2-8 but not in exploration and development expenditures.

[24] Anadarko Petroleum Inc., *1996 Annual Report*, p. 50.

[25] Atlantic Richfield Co., *1996 Securities and Exchange Commission Form 10-K*, p. 5.

[26] Mobil Corp., *Fact Book 1996*, p. 18.

[27] Texaco Inc., *1996 Annual Report*, p. 16.

[28] Mobil Corp., *Fact Book 1996*, p. 24.

[29] Amoco Corp., *1996 Securities and Exchange Commission Form 10-K*, pp. 6-7.

[30] E.I. du Pont de Nemours and Company, *1996 Annual Report*, p. 18.

[31] Occidental Petroleum Corp., *1996 Annual Report*, p. 57.

[32] The U.S. Department of Commerce's gross domestic product implicit price deflator was taken from Energy Information Administration, *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997), p. 367. Price deflated data are used only when long-term general price inflation is likely to obscure the interpretation of trends.

[33] U.S. Bureau of the Census, *Pollution Abatement Costs and Expenditures: 1994*, MA200(94)-1 (Washington, DC, May 1996) and American Petroleum Institute, *Petroleum Industry Environmental Performance*, 5th Annual Report (Washington, DC, May 1997). The FRS companies' costs and expenditures were estimated on the basis of their share of U.S. crude distillation capacity.

[34] Energy Information Administration, *The Impact of Environmental Compliance Costs on U.S. Refining Profitability* (Washington, DC, October 1997), Figure 3, available on the Internet at http://www.eia.doe.gov/emeu/perfpro/ref_pi/contents.html.

[35] Mobil Corp., *Fact Book 1996*, p. 52.

[36] Phillips Petroleum Co., *1996 Securities and Exchange Commission Form 10-K*, p. 14.

[37] Shell Oil Co., *1996 Annual Report*, p. 11.

[38] Sun Company Inc., *1996 Annual Report*, p. 18.

[39] Basically, deferred taxes originate because of timing differences in reporting revenue and expense for financial reporting and tax reporting. Financial reporting attempts to match items of income and expense in the periods in which they occur. Tax reporting may permit different timing for recognizing revenues and deducting expenses. For example, faster writeoffs of depreciable properties are permitted under tax laws while they may not be acceptable under financial accounting principles. Accelerated writeoffs result in lower taxable income and thus lower tax liability in the year taken. In future periods, however, taxable income and income taxes payable may be higher than pretax income for financial reporting purposes because the timing differences between tax and financial reporting are reversed.

[40] See *Performance Profiles of Major Energy Producers 1995*, p. 6.

[41] Based on company annual reports and supplementary information filed with *Form EIA-28*. A few companies included enhanced oil recovery tax credits.

3. Oil and Gas Exploration, Development, and Production

Financial Results

Higher Prices Produce Surge in Income

Both domestic and foreign net income (excluding the effects of unusual items[42]) from oil and gas production for the FRS companies in 1996 were at their highest level, adjusted for inflation, since the year before the oil price collapse of 1986 (Table 12). These increases in net income were due largely to substantial increases in the prices of oil and natural gas (Table 13).

The effect of these price rises on domestic operations was more pronounced than on foreign operations. The greater rise in the FRS companies' U.S. oil price was due mostly to a larger proportion of natural gas liquids (NGLs) in the composition of their domestic oil production compared to their foreign oil production, which is almost entirely crude oil. In 1996, NGL prices rose more sharply than did crude oil prices in the United States. Also, natural gas prices realized by the FRS companies in their foreign operations were moderated by lesser price rises outside North America (Table 13).

The FRS companies' upstream production continued on an upward trend, with the exception of a decline in U.S. onshore oil production. The FRS companies' offshore oil production was up slightly. Domestic natural gas production, however, was the highest for the FRS companies since 1982, with increased production coming almost entirely from offshore fields.

The FRS companies' foreign oil and gas production both reached levels not realized since the nationalizations of the 1970's, with Africa, the Middle East, and the Former Soviet Union accounting for most of the increase. However, in contrast to a recent trend, the involvement of the FRS companies in domestic natural gas storage, reselling, and marketing, as measured by the difference between natural gas sales and production, basically leveled off in 1996.

On the cost side, depreciation, depletion, and amortization (DD&A) for the FRS companies declined noticeably in 1996, in part because of a change in accounting practices by many of the FRS companies in the previous year (Table 12). Financial Accounting Standard 121 (FAS 121) resulted in large writeoffs of assets for the FRS companies in 1995, when the companies that were significantly affected by the standard adopted it.[43] Because it was effectively adopted last year by many of the FRS companies, the standard had no direct effect on 1996 DD&A. However, it indirectly decreased DD&A in 1996 (and will in subsequent years) because implementation of FAS 121 permanently reduced the value of some of the assets that are depreciated, depleted, or amortized. This reduction in asset value reduces the annual charges to DD&A for those assets. The decline in DD&A in 1996 boosted operating income but had no effect on cash earnings. The increases in the value of raw material purchases, which are mostly natural gas and natural gas liquids, reflected the price increases for oil and gas.

Both domestic and foreign income taxes rose substantially in 1996, largely because of the increases in pretax income. Domestic income tax expenses for the FRS companies rose more than fivefold while income before taxes almost quadrupled. The primary reason for the steep rise in taxes is that tax credits for nonconventional production of gas did not keep pace with income growth. (See "Taxes" in Chapter 2). As a result, the effective income tax rate in U.S. oil and gas production rose from 20 percent in 1995 to 32 percent in 1996. The results for foreign production were less striking, as the effective income tax rate remained at 53 percent.

Lifting Costs Continue Downward Trend

Production (or lifting) costs are the out-of-pocket costs of extracting oil and gas. They include direct lifting costs, production taxes, and related payments. Direct lifting costs per barrel measure the costs of physically extracting each barrel of oil or equivalent barrel of gas from hydrocarbon deposits.

Worldwide direct lifting costs, which measure the costs of extracting oil and gas, averaged $3.40 per barrel of oil equivalent (BOE) in 1996 (Table 14). Direct lifting costs continued to decline in real terms, but more slowly than

Table 12. Income Components and Financial Ratios in Oil and Gas Production for FRS Companies, 1995-1996
(Billion Dollars)

Components of Income and Financial Ratios	United States 1995	United States 1996	Foreign 1995	Foreign 1996
Oil and Gas Revenues				
Oil	26.3	32.9	NA	NA
Gas	18.7	26.8	NA	NA
Total Revenues	45.0	59.8	40.5	47.8
Expenses				
DD&A	13.7	10.5	7.8	7.2
Lifting Costs	12.1	12.3	9.1	9.9
Exploration Expenses	1.1	1.6	2.8	3.7
General and Administrative Expenses	1.1	1.2	0.9	0.8
Raw Material Purchases	10.3	15.9	9.0	9.2
Other Costs (Revenues)	-2.3	2.0	0.1	-0.2
Total Operating Expenses	40.7	43.4	29.6	30.6
Operating Income	4.3	16.5	10.9	17.2
Other Income (Expense)[a]	0.4	0.9	1.8	2.3
Income Tax Expense	1.0	5.5	6.7	10.2
Net Income	3.7	11.8	5.9	9.2
Less Unusual Items	-2.0	0.3	-0.2	0.8
Net Income, Excluding Unusual Items	5.7	11.5	6.1	8.4
Unit Values (Dollars Per Barrel of Production COE)[b]				
Direct Lifting Costs (Excluding Taxes)	3.47	3.43	3.40	3.50
Production Taxes	0.56	0.70	0.70	0.94
Ratios (Percent)				
Return on Investment[c]	4.4	14.1	9.3	12.8
Effective Tax Rate[d]	20.3	31.7	52.8	52.7

[a]Earnings of unconsolidated affiliates and gain (loss) on disposition of assets.
[b]COE = Crude oil equivalent. Dry natural gas was converted at 0.178 barrels of oil per thousand cubic feet.
[c]Net Income divided by net investment in place. (Net investment in place = net property, plant, and equipment plus investments and advances.)
[d]Income tax expense divided by pretax income.
NA = Not available.
-- = Not meaningful (less than $50 million).
DD&A = Depreciation, depletion, and amortization costs.
Note: Sum of components may not equal total due to independent rounding. Independent producers are publicly traded companies with oil and/or natural gas production whose primary industry code is Standard Industrial Classification 13 (oil and gas production and services).
Source: FRS Companies: Energy Information Administration, Form EIA-28, “Financial Reporting System.”

Table 13. Average Prices, Sales, and Production in Oil and Gas for FRS Companies, 1995-1996

Prices, Sales, and Production	1995	1996	Percent Change 1995-1996
Domestic Oil and Gas Production[a]			
Crude Oil and NGL (Million Barrels)	1,570.6	1,532.4	-2.4
Dry Natural Gas (Billion Cubic Feet)	8,055.2	8,191.6	1.7
Total (Million Barrels, COE)[b]	3,004.4	2,990.5	-0.5
Domestic Oil and Gas Sales Volumes			
Crude Oil and NGL (Million Barrels)	1,874.9	1,840.3	-1.8
Dry Natural Gas (Billion Cubic Feet)	12,107.8	12,020.0	-0.7
Total (Million Barrels, COE)[b]	4,030.1	3,979.9	-1.2
Domestic Production Segment Per Unit Sales Values			
Crude Oil and NGL (Dollars Per Barrel)	14.03	18.57	32.4
Dry Natural Gas (Dollars Per Thousand Cubic Feet)	1.54	2.16	39.9
Composite (Dollars Per Barrel COE)[b]	11.17	15.11	35.3
Foreign Oil and Gas Production[a]			
Crude Oil and NGL (Million Barrels)	1,434.9	1,459.1	1.7
Dry Natural Gas (Billion Cubic Feet)	4,431.2	4,703.6	6.1
Total (Million Barrels COE)[b]	2,223.7	2,224.8	3.3
Foreign Production Segment Per Unit Sales Values			
Crude Oil and NGL (Dollars Per Barrel)	16.12	19.31	19.8
Dry Natural Gas (Dollars Per Thousand Cubic Feet)	1.93	2.21	14.5
Canada	0.90	1.25	39.0
OECD Europe	2.57	2.63	2.4
Other Foreign	1.73	2.03	17.2
Composite (Dollars Per Barrel COE)[b]	14.16	17.02	20.2

[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.

they have in any year since 1991. Between 1991 and 1996, real domestic and foreign direct lifting costs have declined 36 percent and 35 percent, respectively (Figure 11), but the causes of the declines differed somewhat between the two areas. While direct lifting costs declined marginally, total lifting costs increased by 2 percent to $4.20 per barrel as production tax obligations, which tend to be tied to wellhead prices, rose along with prices. For the FRS companies, production taxes per BOE rose by the largest absolute amounts in two out of the three high tax regions, Africa ($0.35) and in the Other Western Hemisphere region ($0.33). In the U.S., total lifting costs averaged $4.12 per barrel, up 2 percent from 1995. Offshore lifting costs averaged $2.94 per barrel, well below both the onshore average of $4.57 per barrel and the average overseas.

Worldwide direct lifting costs per barrel (in constant dollars) for the FRS companies reached their peak in 1985 (Figure 11). Since 1991, they have declined every year, so that by 1996 worldwide direct lifting costs adjusted for inflation were one third less than in 1991. This average hides a lot of variance in direct lifting costs among different geographical regions. In the most extreme case, in 1996, direct lifting costs for OECD Europe (primarily the North Sea) were more than twice those of the Other Eastern Hemisphere (Table 14). However, average domestic and foreign direct lifting costs per barrel converged in 1991 and since then have not differed from each other by more than 8 percent (Figure 11).[44]

Direct lifting costs per barrel can be expressed as the product of direct lifting costs per well and the inverse of

Table 14. Lifting Costs by Region, FRS Companies and Independent Producers, 1995-1996
(Dollars Per Barrel of Oil Equivalent)

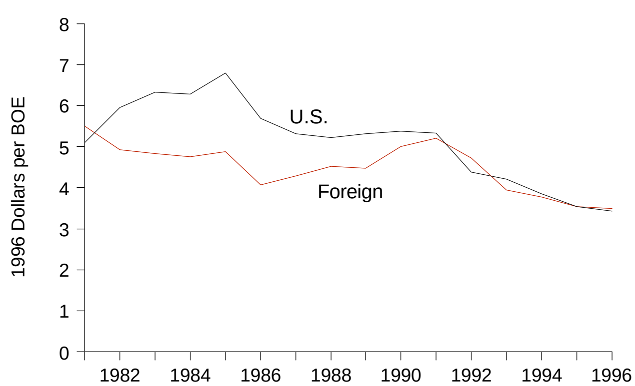
Region	Direct Lifting Costs			Production Taxes			Total		
	1995	1996	Percent Change	1995	1996	Percent Change	1995	1996	Percent Change
FRS Companies									
United States									
Onshore	--	--	--	--	--	--	4.45	4.57	2.8
Offshore	--	--	--	--	--	--	2.91	2.94	1.1
Total United States	3.47	3.42	-1.6	0.56	0.70	24.5	4.03	4.12	2.1
Foreign									
Canada	3.42	3.58	4.7	0.29	0.32	10.3	3.72	3.91	5.1
OECD Europe	4.72	4.41	-6.7	0.63	0.72	14.6	5.35	5.12	-4.2
Africa	2.49	2.95	18.3	1.27	1.62	27.9	3.76	4.57	21.6
Middle East	2.37	2.46	4.2	1.33	1.56	17.1	3.69	4.02	8.8
Other Eastern Hemisphere	2.13	2.16	1.5	0.77	1.01	31.4	2.89	3.17	9.4
Other Western Hemisphere	3.06	2.71	-11.5	0.92	1.25	35.9	3.98	3.96	-0.5
Total Foreign	3.48	3.39	-2.5	0.73	0.91	25.3	4.20	4.30	2.3
Worldwide Total	3.47	3.40	-2.0	0.63	0.79	25.2	4.11	4.20	2.2
Independent Producers									
United States	3.36	3.52	4.7	0.25	0.27	8.1	3.61	3.79	4.9
Foreign	3.82	3.52	-7.8	0.23	0.32	42.2	4.04	3.84	-5.0

-- = Data not available.

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

Source: **FRS companies**: Energy Information Administration, Form EIA-28, "Financial Reporting System." **Independent producers**: compiled from Arthur Andersen & Co., *Oil and Gas Reserves Disclosures Database*, 1992-1996 (Chicago, IL, 1997). Independent producers are publicly traded companies other than the FRS companies whose primary industry code is SIC 13.

Figure 11. Direct Oil and Gas Lifting Costs per BOE for FRS Companies, 1981-1996



BOE = Barrels of crude oil equivalent.

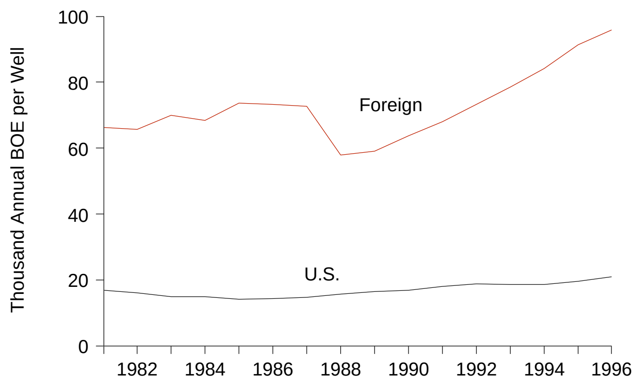
Source: Energy Information Administration, Form EIA-28, "Financial Reporting System."

oil and gas production per well. One way to examine the decline in direct lifting costs per barrel in recent years is to separate it into these two components.

Both domestic and foreign production of oil and gas per well have been generally increasing for many years (Figure 12); since 1991, domestic and foreign well productivities have increased 17 percent and 41 percent, respectively.[45] By themselves, these trends have resulted in lower direct lifting costs per barrel. The trend in foreign production per well in recent years has been largely fueled by OECD Europe, which has had the highest productivity per well of any region since 1991 and has had the highest total production of any foreign region since 1994.

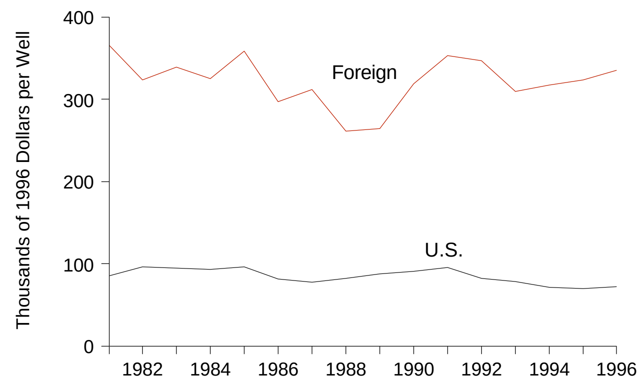
However, direct lifting costs per well have not behaved as consistently as has production per well. Domestic direct lifting costs per well (adjusted for inflation) have fallen 25 percent since 1991 (Figure 13), in part reflecting continued efforts to trim operating costs through consolidation and

Figure 12. Oil and Gas Production per Well for FRS Companies, 1981-1996



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

Figure 13. Direct Oil and Gas Lifting Costs per Well for FRS Companies, 1981-1996



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

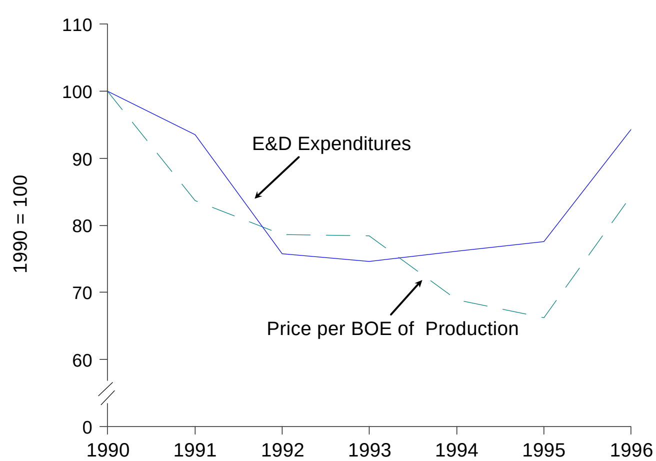
cost cutting. This change in direct lifting costs per well reinforces the effect of the increase in domestic production per well. In contrast, foreign direct lifting costs per well have not exhibited as clear a trend as have domestic direct lifting costs per well in the 1990's. While foreign direct lifting costs per well in 1996 were 5 percent below their peak in 1991, they have increased in each of the last 3 years. These increases have partially offset the effect of changing foreign productivity per well on direct lifting costs per barrel.

The net effect of the changes in production per well and direct lifting costs per well has been a reduction in both domestic and foreign direct lifting costs per barrel since 1991, but for somewhat different reasons. Domestic direct lifting costs per barrel have declined because of changes in both production per well and direct lifting costs per well, while foreign direct lifting costs per barrel have declined almost entirely because of changes in production per well.

Oil and Gas Investment

In a reversal of the general downward trend evident since the Persian Gulf War, the worldwide exploration and development expenditures of the FRS companies in 1996 were 24 percent higher than in 1995. While a portion of this increase can be attributed to the uptick in wellhead prices in 1996, factors other than price alone account for a portion of the higher spending (Figure 14). Among these other factors are the stimuli to exploration, development,

Figure 14. The Price of Oil and Gas and the FRS Companies' Worldwide Level of Exploration and Development Expenditures



BOE = Barrel of crude oil equivalent.
Note: Both series are deflated using the implicit chain weighted GDP deflator. Given data constraints, the price per barrel of oil equivalent production could only be calculated for domestic operations. It was calculated by dividing domestic FRS wellhead revenues from both oil and gas by the domestic FRS oil equivalent level of production. Natural gas was converted to its oil equivalent using the conversion factor of 0.178 barrels of oil per thousand cubic feet of gas.
Source: Energy Information Administration, Form EIA-28, "Financial Reporting System."

and production resulting from the cost-reducing effects of 3-D seismic, horizontal drilling, and the new production technologies in the offshore. Additional factors contributing to the increase are the opportunities associated with the more hospitable investment environment in countries such as Algeria, Venezuela, the countries of the Former Soviet Union, and even the United States.

Increased Focus on the U.S. Gulf of Mexico

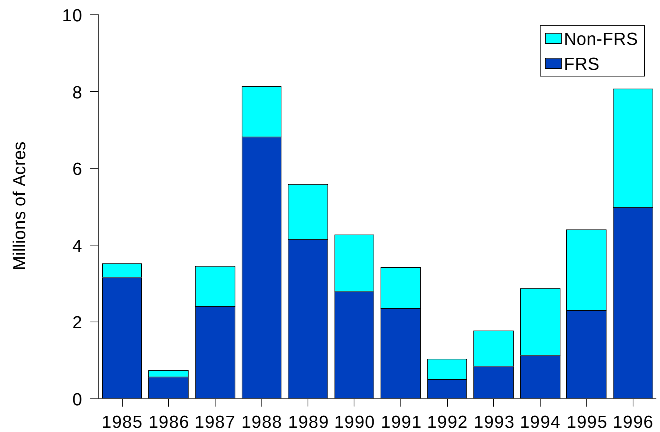
MMS Lease Sales Signal a New Era in the Offshore

In the early 1990's, expectations of diminished profitability in the offshore induced the FRS companies to scale back their stock of unproved offshore acreage, an indicator of future drilling levels, by 40 percent. However, the recently enacted Deepwater Relief Act, which enhanced the deepwater investment climate, and the demonstrated success of some of the recent deepwater projects, such as Auger and Mars, have convinced many industry participants that the prospects for profitable exploration, development, and production in the offshore are bright. As an indication that this might be true, the FRS companies were active participants in the Minerals Management Service (MMS) 1996 outer continental shelf (OCS) lease sales. In Lease Sale 157, its first Gulf of Mexico lease sale following the passage of the Deepwater Royalty Relief Act of 1995, the MMS received a record 1,381 bids on 924 tracts in the Central Gulf of Mexico. This topped the previous record set in 1971 by 32 percent and was almost double the average of the previous two years. Indicative of the focus on deepwater prospects, over half of the bids were for blocks having a water depth of 200 meters or more. This was in sharp contrast to just two years earlier when less than 20 percent of winning bids were for deepwater blocks.

Of particular note is the fact that over 43 percent of the bids in this lease sale were for blocks located in water depths in excess of 800 meters Later in 1996, another record was broken when the MMS conducted Lease Sale 161, which received 929 bids on 617 tracts for acreage in the Western Gulf. As in the earlier Central Gulf Lease sale, the focus was on deepwater blocks with over 50 percent of the bids representing blocks with a water depth greater than 800 meters as opposed to less than five percent in the 1994 Western Gulf Lease Sale.

Over the course of 1996, the MMS received over $1.2 billion in bids, more than what it received in 1993, 1994, and 1995 combined. In terms of acreage, the MMS awarded almost twice as much acreage in 1996 as in 1995 and more than seven times as much as in 1992 (Figure 15) and almost matched the record for the post-1986 era set in 1988.

Figure 15. Federal Outer Continental Shelf Acreage Awarded, 1985-1996



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

In the mid to late 1980's, over 80 percent of the new OCS acreage awarded was accounted for by the FRS companies. While the FRS companies were well represented among the winning companies at the recent lease sales, their share of the total acreage awarded in 1996 was 62 percent. This decline is consistent with the growing importance of independent producers in offshore exploration and production.[46] Indicative of this trend, two of the top five bidders at the 1996 Central Gulf Lease Sale were independent producers.

Expenditures on Exploration and Development in the Offshore Increase Sharply

Consistent with the record lease sales in the offshore, exploration and development expenditures of the FRS companies in the U.S. offshore increased by 42 percent, from $4.7 billion in 1995 to $6.7 billion in 1996 (Table 15). Expenditures for unproved acreage acquisitions accounted for over $250 million or approximately 13 percent of the total increase. Fifty-two percent of the increase was the direct result of increased drilling and equipping expenditures. Although some of the increase in drilling and equipping expenditures was a product of increased offshore well completions (Tables 16 and 17), a significant part of the increase in drilling and equipping expenditures was likely due to the increase in day rates for offshore rigs precipitated by the surge in offshore drilling activities. (See the box entitled "The Offshore Rig Squeeze".)

Additional evidence of the growing importance of the offshore Gulf of Mexico comes from the results of the 1996 Salomon Brothers, Inc.'s survey of the spending plans of 237 North American oil and gas producers and 103 producers based outside of the United States and Canada.

Table 15. Exploration and Development Expenditures by Region for FRS Companies, 1995-1996
(Million Dollars)

Region	1995	1996	Percent Change 1995-1996
United States			
Onshore	7,695	7,913	2.8
Offshore	4,739	6,719	41.8
Total United States	12,434	14,632	17.7
Foreign			
Canada	1,899	1,563	-17.7
OECD Europe	5,204	5,551	6.7
Former Soviet Union and Eastern Europe	359	461	28.4
Africa	2,043	2,798	37.0
Middle East	361	463	28.3
Other Eastern Hemisphere	2,430	4,625	90.3
Other Western Hemisphere	875	1,638	87.2
Total Foreign	13,171	17,099	29.8
Total FRS	25,605	31,731	23.9

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

Table 16. Exploratory Well Completions by Region for FRS Companies, 1994-1996

Region	Exploratory Oil Wells			Exploratory Gas Wells		
	1994	1995	1996	1994	1995	1996
United States						
Onshore	101	104	91	167	201	207
Offshore	13	32	36	47	53	87
Total United States	114	137	127	214	254	294
Foreign						
Canada	42	67	46	105	74	96
Europe[a]	10	21	14	11	11	11
Africa	13	11	16	W	W	W
Middle East	13	11	16	W	W	W
Other Eastern Hemisphere	12	13	22	15	44	46
Other Western Hemisphere	8	5	9	W	W	W
Total Foreign	89	120	111	133	130	160
Worldwide	202	256	238	347	384	453

[a]Europe includes OECD Europe, Eastern Europe, and the Former Soviet Union.
Note: Sum of components may not equal total due to independent rounding.
W = Data withheld to avoid disclosure of proprietary information.
Source: Energy Information Administration, Form EIA-28, "Financial Reporting System."

More than half (54 percent) of the respondents said the Gulf of Mexico was a high potential area and it was the most frequently mentioned as having the greatest exploration potential among all regions worldwide. Moreover, the Gulf of Mexico was cited by many companies as a major focus of their 1997 plans, especially exploration and development in deepwater and ultra-deepwater areas. Overall, the Gulf placed fourth in importance in the 1996 survey. The significance of this result is heightened by the fact that the Gulf was never mentioned in previous surveys.[47] (For more on this topic, see the box entitled "Deepwater in the Gulf of Mexico: A New Frontier.")

Onshore activity was buoyed by the joint application of 3D seismic and horizontal drilling technology in areas such as the Austin Chalk, where the reservoirs can be

Table 17. Development Well Completions by Region for FRS Companies, 1994-1996

Region	Oil Development Wells 1994	Oil Development Wells 1995	Oil Development Wells 1996	Gas Development Wells 1994	Gas Development Wells 1995	Gas Development Wells 1996
United States						
Onshore	1,980	1,908	2,095	1,865	2,156	2,049
Offshore	150	151	158	120	95	153
Total United States	2,130	2,059	2,253	1,985	2,252	2,202
Foreign						
Canada	174	570	560	417	190	234
Europe[a]	56	65	71	25	29	31
Africa	43	65	85	W	W	W
Middle East	63	45	49	W	W	W
Other Eastern Hemisphere	116	93	103	46	32	92
Other Western Hemisphere	86	121	123	W	W	W
Total Foreign	542	965	997	497	268	363
Worldwide	2,672	3,024	3,249	2,482	2,519	2,565

[a]Europe includes OECD Europe, Eastern Europe, and the Former Soviet Union.
Note: Sum of components may not equal total due to independent rounding.
W = Data withheld to avoid disclosure of proprietary information.
Source: Energy Information Administration, Form EIA-28, "Financial Reporting System."

problematic to exploit by using traditional techniques. Increased activity in Alaska also helped boost the onshore level of activity. (See the box entitled "A Renaissance of Activity in Alaska.")

Expenditures for Foreign Exploration and Development Increase

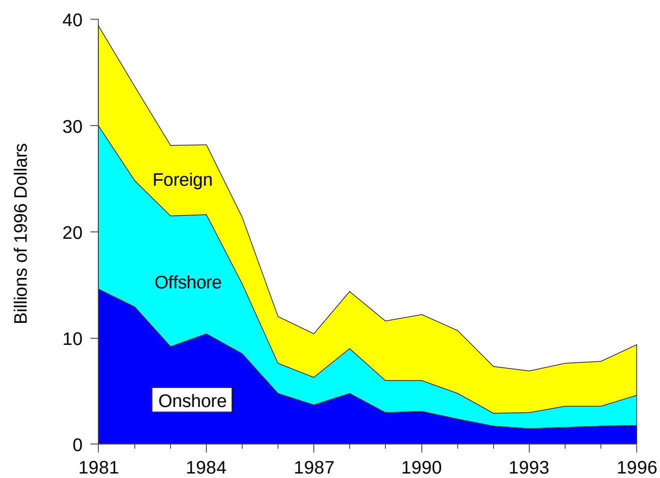
While FRS expenditures on exploration and development have declined significantly over the past 15 years, the share accounted for by foreign spending has increased (Figures 16 and 17). Consistent with this latter trend, while domestic exploration and development expenditures increased 18 percent between 1995 and 1996, foreign expenditures for the FRS companies registered an overall 30-percent increase between 1995 and 1996, rising from $13.2 billion in 1995 to $17.1 billion in 1996 (Table 15).

The $2.2-billion increase in exploration and development spending by the FRS companies in the Other Eastern Hemisphere was by far the largest component of the overall increase in foreign exploration and development activities. Mobil's $1.4 -billion acquisition of Ampolex (Australia) represented the major share of this increased spending in the region. Additional sources of increased activity included:

- **Unocal**. Increased its foreign exploration and development spending from $353 million to $509 million, in large part concentrating on exploration and development activities in Thailand, Indonesia, and Myanmar.[48]

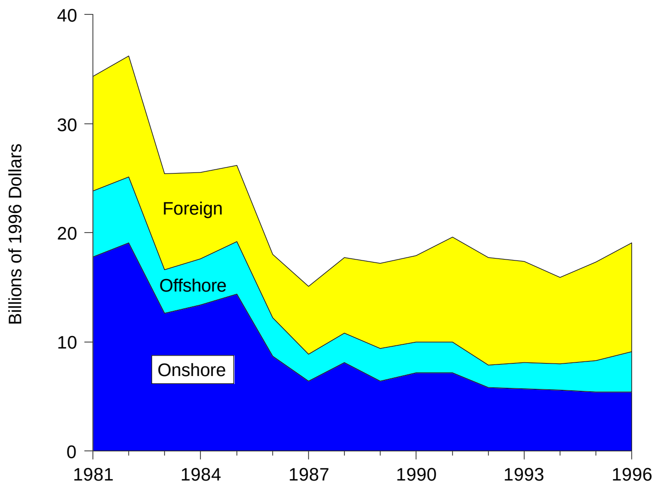
- **Texaco**. Continued its extensive drilling program in Southeast Asia with activities in the Gulf of Thailand and China's Bohai Bay.[49] The company also explored for natural gas on the Gorgon / Chrysaor trend in the Carnarvon Basin offshore Western Australia.

Figure 16. Exploration Expenditures for FRS Companies, 1981-1996



Note: Includes expenditures for unproved acreage.
Source: Energy Information Administration, Form EIA-28, "Financial Reporting System."

Figure 17. Development Expenditures for FRS Companies, 1981-1996



Note: Excludes expenditures for unproved acreage.
Source: Energy Information Administration, Form EIA-28, "Financial Reporting System."

- **Occidental Petroleum**. Moved ahead toward developing large natural gas fields in Malaysia containing an estimated 4.3 trillion cubic feet (tcf) of gross recoverable gas and in the Philippines with an estimated 3.3 tcf of gross recoverable gas. Together with ARCO, Occidental also made five new major natural gas discoveries in Indonesia.[50]

- **Mobil**. Continued to develop fields in North Sumatra (to offset the natural decline in production from the giant Arun field) and commenced development activity in North Sumatra's offshore "A" field.[51] The company is also active in the Griffin Area oil and gas fields northwest of Australia.[52]

The second largest component of the increase in foreign exploration and development expenditures was in the Other Western Hemisphere region, where the FRS companies increased spending by $763 million, an 87-percent increase over the 1995 level. Much of this increased expenditure represents the companies availing themselves of strategic opportunities in countries that were off limits to foreign investment until recently. In particular, Venezuela, which had nationalized the upstream properties of the FRS companies over two decades ago, recently changed its policy in light of its goal to increase its productive capacity along with the technical and economic challenges of developing its heavy crude oil resources.[53]

Recognizing the strategic importance of this regime change, the FRS companies have actively pursued investment opportunities in Venezuela. For example, during the historic 1996 Apertura (Light and Medium Oil Exploration Bid Round), DuPont's Conoco unit was awarded exploration rights to 100 percent of one block and 50 percent of a second block. More specifically, Conoco was awarded 100 percent exploration rights to the Gulf of Paria West, Block 7, located mostly offshore in the shallow water in the Gulf of Paria between Venezuela and Trinidad. The exploration agreement requires a four-year, $4-million commitment to drill two wells and obtain seismic data. Additionally, Conoco made a bonus payment to Petroleos de Venezuela (PDVSA) for Gulf of Paria West of $21.2 million. In its second successful bid, Conoco was awarded exploration rights to the Guanare block in western Venezuela in a 50-percent partnership with the French-based Elf Aquitaine. The terms of the exploration agreement require a five-year, $30-million investment to drill four wells and acquire seismic data. Conoco is also involved in a $2.2-billion joint venture with Maraven, a subsidiary of PDVSA, to produce and process extra heavy crude oil.[54]

Mobil, whose increased spending in the Other Western Hemisphere area accounts for a significant portion of the overall increase, is also re-establishing an upstream presence in Venezuela. In 1996, it was the successful bidder on the 445,000-acre La Ceiba exploration block located on the southeastern shore of Lake Maracaibo in western Venezuela. Estimated recoverable oil reserves are believed to be at least 400 million barrels. Also, Mobil, Lagoven (an affiliate of PDVSA), and Germany's Veba Oel entered into an agreement to produce and upgrade 120,000 barrels per day of extra heavy crude oil from Venezuela's Orinoco Tar Belt. Estimated recoverable reserves from this project are believed to be around 600 million barrels.[55]

Other FRS activities in the Other Western Hemisphere region contributing to the increased exploration and development spending included:

- **Texaco**. Accelerated its exploration program in Colombia through its inauguration of Chuchupa-B, the second offshore platform at the Chuchupa gas field offshore Colombia. Located 10 miles off Colombia's northeast coast, the Chuchupa field was discovered in 1973 and put on production in 1977. Estimated remaining recoverable gas reserves from this field and two others operated by Texaco are in excess of four trillion cubic feet.[56]

- **Conoco**. Acquired promising acreage in Colombia and Barbados.[57]

The Offshore Rig Squeeze

The passage of the Deepwater Royalty Relief Act, along with a combination of significant deepwater discoveries and innovative solutions to the challenges of producing in deep water, has been the driving force behind a surge in drilling activity in the Gulf of Mexico. This increased activity has, in turn, led to a significant tightening in the worldwide offshore rig market. For semisubmersibles, the utilization rate in the Gulf of Mexico in 1996 was close to 100 percent, while overall fleet utilization for rigs in the Gulf was around 90 percent. This "rig squeeze" precipitated a more-than-300-percent increase in the day rates for floating units over the rates charged just a few years ago. Additionally, day rates for premium jack up rigs in the Gulf of Mexico (i.e., 300-ft water depth cantilevered) reached $40,000-$45,000 per day bid levels in the fourth quarter of 1996, up from $20,000-$25,000 per day in the fourth quarter of 1995. The rig availability squeeze has also been aggravated by the recent history of depressed prices and the consequent dwindling ranks of drilling contractors and rig fleets. More specifically, over the 1986-1996 period, the total mobile offshore rig fleet declined from 687 to 548 total units and the number of drilling contractors, from 143 to 106. Over that same period, rig investment capital was allocated largely to the maintenance of existing units, leaving little capital for new rig construction.

To overcome the potential adverse impact of the offshore rig squeeze, operators in 1996 pursued strategies to lock in rigs so as to avoid delaying their drilling plans. For example, Texaco contracted with Diamond Offshore Drilling, Inc., to upgrade an existing semisubmersible rig, outfitting it for drilling in water depths up to 4,500 feet. The contract gave Texaco exclusive rights to the rig for three years. Similarly, British-Borneo, a non-FRS company, contracted with Atwood Oceanics for a 2,000-foot water depth semisubmersible rig for two years beginning in the summer of 1997 (at a day-rate of $88,400 with an option for a third year at an undisclosed defined price and an option for a fourth year based on market prices). Needless to say, with day rates at these levels, offshore rig upgrades and conversions were buoyant during 1996. Responding to the surge in offshore rig utilization, Amoco and Conoco made long-term commitments to enable the construction of newly designed, dynamically-positioned drillships, initially equipped to drill in 7,000 feet of water but eventually capable of drilling in as much as 10,000 feet of water.

For the foreseeable future, drilling activity in the deepwater and ultra-deepwater regions of the Gulf of Mexico is expected to continue at a rapid pace along with steady activity in the shallow and moderate depth regions. Petrodata Inc., Aberdeen, projects that overall demand for deepwater units worldwide will more than double by the year 2000, from the 1994-95 period. Matthew Simmons, President of Simmons & Company, International, suggests that "A rough estimate of deepwater rigs needed in the Gulf of Mexico alone indicates that the current supply needs to triple."[a]

[a] Richard Wheatley, "Gulf of Mexico action tightening worldwide off-shore rig squeeze," *Oil and Gas Journal*, Volume 94, Number 48 (November 25, 1996), p. 24.

- **Mobil**. Began engineering and feasibility studies in Peru to evaluate development of the 17-trillion-cubic-foot Camisea gas field. The field eventually could supply fuel for power to the Peruvian capital of Lima and pipeline gas for the fast-growing southern zone of South America.

Africa continued to attract more FRS exploration and development investment, with spending by the FRS companies rising by 37 percent. This was reflective of and consistent with an overall trend of increasing interest by international oil and gas companies in the continent's oil and gas opportunities.[58] Significant FRS activities in the region included:

- **Anadarko**. More than doubled its exploration and development spending in Algeria from $41 million in 1995 to $86 million in 1996.[59]

- **Mobil**. Initiated production in offshore Equatorial Guinea's Zafiro field. While field development can often take years to accomplish, the company was able to commence production 18 months after drilling the discovery well. The firm also reported two new discoveries near Zafiro and drilled the first wildcat well in a deepwater block in the Kwanza Basin in offshore Angola.[60]

Deepwater in the Gulf of Mexico: A New Frontier

While the FRS companies have explored for oil and gas in the deeper waters of the Gulf since the late 1970's, deepwater development was largely considered uneconomic given the fact that the costs of a fixed production platform exponentially increased with water depth. Indicative of this, in 1989 less than 3 percent of the oil produced in the Gulf of Mexico was from deepwater projects. Recently, however, a combination of significant new discoveries, legislated deepwater royalty relief, and advances in deepwater production systems have transformed the deepwater region of the Gulf into one of the hottest areas for exploration and development.

Helping foster this is the DeepStar Project, an industry cooperative effort whose goal is to identify economically viable methods of producing oil and gas from the deepwater tracts in the Gulf. As a result of this collective effort, as well as those of the individual firms, 17 percent of the total oil production in the Gulf of Mexico in 1996 was accounted for by projects operating in water depths exceeding 1,000 feet.[a]

The year 1996 also saw the commencement of production at the $1.2 billion Mars project, the largest discovery in the Gulf of Mexico over the last 25 years. Two FRS companies, Shell and BP America, are partners in the project. The project, with a water depth of 2,940 feet, broke the then existing record set by Shell's Auger project in 1994. Because the costs of installing a fixed platform are prohibitive at such a depth, a tension leg platform (TLP) was used to extract the oil and gas. Unlike a fixed platform, a tension leg platform is a floating structure that is held in place by tensioned tendons connected to the sea floor. The Mars project also employs another new important production technology, the subsea well. This technology extends the areal reach of a project by enabling the operator to place a satellite well on the sea floor and pipe the oil and gas back to the TLP or to other facilities. Oil production from the first well at the Mars project was a record-breaking 15,000 barrels of oil per day. Overall production from the project exceeds 100,000 barrels of oil per day. The oil is being transported to shore on the new $135-million Mars Pipe Line system. Suggestive of the project's potential, the pipeline has a capacity of 250,000 barrels of oil per day, with expansion plans to 500,000 barrels per day.[b]

Approximately 60 deepwater Gulf projects are in various stages of development. Among those scheduled for start-up in the next few years are Genesis, Gomez, Mensa, Neptune, Popeye, Petronius, Ram-Powell, Troika, and Ursa (Table 18). Reflecting the progress that has been made in controlling the costs of deepwater development in just the few short years since the 1994 start-up of Shell's Auger project, the development costs of these projects are expected to average $3.60 per barrel, 36 percent lower than Auger's development costs of $5.00 per barrel.

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[a] http://161.160.220.24/omm/gomr/homepg/offshore/deepwatr/dwprod96.html (November 25, 1997).
[b] http://ms.shellus.com/news/press080896.html (November 25, 1997).

- **Exxon**. Leads industry with 14 blocks of deepwater acreage in offshore Angola, Congo, and Nigeria; participated in the drilling of 6 wells and made a second discovery off Angola at Girassol; began work as the operator of 7 million acres in Niger.[61]

- **Amoco**. Continued natural gas exploration and development activities in Egypt's Nile Delta.[62]

- **Texaco**. Continued exploration activities in Namibia, Niger, and Angola.[63]

Of additional interest were the FRS companies' activities in Africa that concentrated on increasing reserves from already discovered fields by using enhanced oil recovery (EOR) technologies and horizontal and extended reach drilling technologies. These activities included:

- **ARCO**. Over thirty years ago, ARCO discovered the Rhourde el Baguel field only to lose it when their oil and gas properties in Algeria were nationalized. In part because of its technical expertise, the company was invited in the early 1990's to again operate the field under a production sharing agreement with the government. It is now using the EOR technology that it has learned from operating the Prudhoe Bay Field on the North Slope of Alaska (along with BP America) to significantly increase reserves from the 3-billion-barrel oil field. In 1996, the company was able to book 218 million barrels of net reserves with the expectation of booking 50 to 100 million barrels as the next increment in net reserves.[64]

- **Mobil**. In Nigeria, the company drilled horizontal and extended reach wells in the declining Ubit field

Table 18. Selected Deepwater Projects in the Gulf of Mexico

Project	Participating Companies	Water Depth	Start-up Year	Production System	Estimated Ultimate Recovery (million BOE)[a]	Project Cost (million dollars)[a]
Gensis	Chevron, Exxon, Fina	2,600	1996	SP	160+	750
Gomez	Union Pacific Resources	3,000	2000	NA	100-140	NA
Mars	Shell, BP America	2,940	1996	TLP	500	1,200
Mensa	Shell	5,300	1997	SS	128	280
Neptune	Oryx, CNG[b]	1,930	1997	SP	50-75	NA
Popeye	Shell, CNG[b], Mobil, BP America	2,000	1996	SS	67	110
Petronius	Texaco, Marathon	1,754	1999	CT	80-100	NA
Ram Powell	Shell, Amoco, Exxon	3,214	1997	TLP/SS	250	1,000
Troika	BP America, Marathon, Shell	2,800	1998	SS	200+	NA
Ursa	Shell, BP America, Conoco, Exxon	4,000	1999	TLP	400+	1,450

[a] These are unoffical estimates.
[b] A non-FRS company.
Note: CT–Compliant Tower; SS–Subsea System; TLP–Tension Leg Platform; SP–Spar Platform.
Sources: Press releases and Annual Reports.

to tap new reservoirs identified by advanced 3-D seismic and other technologies. In 1996, it added 400 million barrels in oil reserves and significantly increased its production from the field.[65]

- **Texaco**. By applying horizontal drilling technology on its Nigerian properties, the company was able to boost production by 27 percent to 69,000 barrels per day.[66]

The FRS companies were also active in the countries of the Former Soviet Union. In Russia, the Sakhalin I Production Sharing Agreement (PSA) became effective and the Sakhalin I Consortium, whose members include a subsidiary of Exxon, initiated a $200-$300 million resource appraisal program which included the collection of 3D seismic data on the high-potential Arkutun-Dagi field, offshore Sakhalin Island. Later in the year, the first well to be drilled under a PSA in Russia, the Dagi-5, was completed in this field by the Consortium.[67] Amoco has a 50-percent interest in the North Priobskoye License Area in Western Siberia and a 16-percent interest in the Varandey project in the Arctic Timan Pechora region. Both areas are believed to have billions of barrels of oil resources. However, both projects are dependent upon on the passage of acceptable production-sharing agreement (PSA) legislation by the Russian Parliament.[68] In contrast, development plans in the Caspian region are on track, with exports of oil to the West planned for late 1997. (See the box entitled "Resource Development in the Caspian Sea Region".)

Also noteworthy was the extraordinary increase in the FRS foreign expenditures for the acquisition of unproved acreage, an indicator of future exploratory and developmental activity. From 1995 to 1996, this category of exploration expenditures rose 248 percent to a total of $745 million (Table B21). This follows a clear trend since 1987 that shows a greater percentage of FRS unproved property acquisition budgets being allocated to the foreign sector. Exxon expanded its acreage position in China with the acquisition of additional blocks in the Tarim Basin and a new block in Liaodong Bay. The company now has exploration rights on 17 million acres in China, more than any other international company.[69] Phillips acquired new acreage in Norway, Denmark, and Greenland, where significant exploration activities are planned.[70] Again, such acquisitions should be expected to set the stage for significant future increases in the foreign exploration and development activities of the FRS companies. In fact, the 1997 capital spending plans for a number of the FRS companies indicate a continued focus on foreign exploration and development activities. For example, both Chevron and Unocal plan to increase their foreign exploration and development budgets by about 20 percent over 1996 levels, while well over one-half of Amoco's

A Renaissance of Activity in Alaska

Until recently, there was very little basis on which to be optimistic regarding the future of oil production in Alaska. Oil production from Prudhoe Bay was declining at approximately 10 percent per year and potential North Slope projects that could offset the decline were not as profitable as otherwise identical projects elsewhere because the ban on the exports of North Slope crude depressed the wellhead price of North Slope production. Also, the fiscal regime was anything but hospitable. Some State leases included provisions for a "net profits" tax, a tax on revenues after capital and operating cost are recovered, that was as high as 89 percent. Further, Alaska was perceived to be an expensive region in which to develop new reserves, the development costs of some of the newer proposed fields such as Northstar being estimated at an uneconomic $11 per barrel of reserves.[a]

This situation has improved significantly over the past two years. The repeal of the Export Ban has increased the wellhead price of Alaskan North Slope crude by approximately one dollar per barrel, an amount which, in turn, has increased the attractiveness of investing in Alaska.[b] Moreover, the State of Alaska has liberalized its fiscal regime by reducing its royalty take on new fields. Finally, the operators in Alaska have found ways to reduce the costs of developing new fields. For example, at Prudhoe Bay, ARCO has been able to reduce the cost of drilling a well by over 50 percent since the late 1980s. Moreover, using 3-D seismic and horizontal drilling technology, "fishhook" wells are now drilled that curve along with the oil-bearing strata to maximize the amount of the pipe that is in contact with the oil-bearing strata. As a result of these developments, it is now believed that the Northstar field, which was projected to cost $11 per barrel of potential reserves in 1991, will now be developed by BP America for less than $3.00 per barrel.[c]

These developments are having a major impact on resource development in Alaska. ARCO, BP America, and Exxon, the partners of the Prudhoe Bay field, have announced plans to expand the field's enhanced oil recovery project at a cost of $165 million.[d] This project is expected to increase production by 20,000 barrels per day. In addition, ARCO has announced plans to develop its Alpine field, which lies 30 miles west of Kuparuk. This field has potential reserves of over 300 million barrels, making it one of largest fields discovered in the United States over the past decade. The costs of developing the field are believed to be less than $2.50 per barrel. To minimize the impact of the field's development on the environment, ARCO will develop the field by using extended reach drilling technology from just two drill sites. Moreover, the field will operate much like an offshore platform in that there will not even be a road connecting it to the other North Slope infrastructure. ARCO also intends to develop the West Sak field. Phase I of the project calls for 50 wells and will add 50 MMB of reserves at a cost of $ 2.00 per barrel. Phase II of the project is expected to result in the drilling of an additional 500 wells and allow the recovery of 400 million barrels of reserves.

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[a] BP Exploration, *Northstar Fact Sheet* (May 1996).
[b] This is consistent both with the pattern of wellhead prices since the ban was repealed and prior projections of the lifting of the ban on wellhead values. See *Exporting Alaskan North Slope Crude Oil: Benefits & Costs*, U.S. Department of Energy, DOE/PO-0025 (Washington, DC, June 1994).
[c] BP Exploration, *Northstar Fact Sheet* (May 1996).
[d] http://www.arco.com/Corporate/reports/SAM97/upstrm9.htm (November 24, 1997).

planned $2.7-billion exploration and development budget for 1997 is allocated to projects outside the United States.[71]

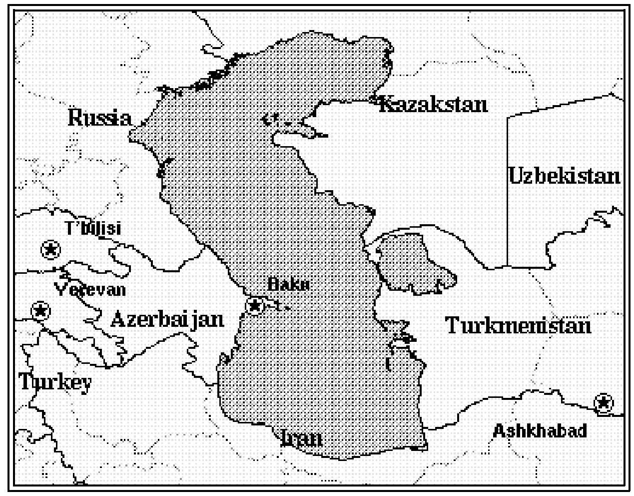
Expenditures on Proved Acreage Show Dramatic Rise, Foreign Sector Leads the Way

From 1991 to 1995, FRS companies' expenditures on proved acreage ranged between $1 billion and $2.3 billion, significantly below their 1990 level of $3.2 billion. In addition, over the 1991-95 period the share of foreign expenditures for worldwide proved acreage by the FRS companies ranged from a low of 13 percent in 1991 to a high of 40 percent in 1993. The share in 1990 was 57 percent.

It appears that, over the 1990-1995 period, the increasing globalization efforts of the FRS companies focused on ambitious drilling programs in a multitude of countries. For example, the number of foreign development wells drilled by the FRS companies increased by over 50 percent during this period.

In 1996, there was a dramatic turnaround. The FRS companies expenditures on proved acreage increased beyond the 1990 level to $3.4 billion. Moreover, the share of foreign to worldwide expenditures for proved acreage

Resource Development in the Caspian Sea Region



The Caspian Sea is a landlocked body of water whose coastal states include Azerbaijan, Iran, Kazakhstan, Russia, and Turkmenistan. Over 42 billion barrels of recoverable oil reserves are believed to lie beneath its waters. Some experts estimate that the Caspian Sea Basin may possess up to almost 200 billion barrels of reserves, which would make it the third largest depository of oil behind the Persian Gulf and Siberia.

Despite this untapped wealth, decision makers in the Former Soviet Union chose to invest their exploratory and developmental resources elsewhere. Thus, production in what is now the independent nation of Azerbaijan declined from 500,000 barrels per day (b/d) during World War II to less than 250,000 b/d in 1992. All of this changed with the breakup of Soviet Union. In September of 1994, a production-sharing agreement (PSA) that has come to be known as the “deal of the century” was signed between the Republic of Azerbaijan and an 11-company consortium known as the Azerbaijan International Operating Company (AIOC). The participating FRS companies include Amoco, Exxon, and Unocal. Under the PSA, the AIOC was required to drill a minimum of three appraisal wells on its contract area within 30 months from the agreement ratification date in December of 1994.

The FRS companies currently hold a 35-percent interest in the AIOC, with Amoco leading the way with 17.01 percent, followed by Unocal and Exxon, with interests of 10 percent and 8 percent, respectively. Total U.S. interest is 43.7 percent. The consortium is charged with developing the Azeri, Chirag, and deepwater Gunashli oil fields south of the Ashrafi/Dan Ulduzu area with estimated reserves of 4 billion barrels. AIOC expects to begin its own production from these fields in late 1997, with initial production estimated at about 115,000 barrels per day. The agreement stipulates that Azerbaijan is to receive 80 percent of the profits. In a separate agreement signed in December of 1996, another group of companies will hold exploration rights in the Ashrafi/Dan Ulduzu area of the Caspian Sea. Again, Amoco and Unocal are major participants, with interests of 30 percent and 25.5 percent, respectively. The contract area is located east of the Apsheron Peninsula and covers 453 square kilometers in water depths ranging from 75 to 200 meters.

The FRS companies are also active in Kazakstan. Mobil is a member of a consortium exploring for oil and gas in the Kazak sector of the sea. Onshore, Mobil and Chevron are participants in the Tengizchevoil joint venture, which operates the Tengiz oil field. Production from this field, one of the largest in the world with an estimated 3 to 10 billion barrels of oil, had been declining under Soviet managers. Under the joint venture, production has more than doubled to over 160,000 barrels per day by the end of 1996. While production from a field typically declines over time, the new managers of the field expect that annual production can be increased to almost 750,000 barrels per day by 2010.

Events in Turkmenistan provide further evidence of the important role that the FRS companies are playing in developing the oil and gas resources of the region. Recently, the Turkmenistan government decided to auction off oil and gas concessions in its sector of the Caspian Sea. Rather than holding the auction in Ashgabat, the capital of Turkmenistan, the oil officials are planning on conducting the auction in Houston, where many of the FRS companies have offices.

The major obstacle to developing the oil reserves of the Caspian Basin has been the problem of transporting the oil to Western markets. Currently, flows of oil from the region have been hampered by Russian interests which control all the export lines from the region. This problem is expected to ease somewhat upon the opening of a 870-mile pipeline that will transport the oil from Baku, the capital of Azerbaijan, via pipeline across Chechnya through Russia to the Black Sea port of Novorossisk. The oil will then be shipped to the West via tankers through the Turkish Straits into the Mediterranean. A second pipeline route is planned that would avoid Russian territory and Russian control altogether by transporting the oil west to the Turkish port of Ceyhan on Mediterranean. A decision on this route is expected in the fall of 1998.[a]

Resource Development in the Caspian Sea Region (continued)

The issue of who owns the undersea resources of the Caspian Basin could delay resource development. At issue is whether the Law of the Sea convention applies to the Caspian Sea. If so, then the maritime boundaries of the five states bordering the Caspian Sea could be established based upon the equidistant division of the sea and undersea resources into national sectors. If the Law were not applied, the Caspian Basin and its resources could be developed jointly. Arguing that the Law of the Sea does not apply in the Caspian Sea given that it is landlocked, Russia favors joint development of the Sea's resources. This position is supported by Iran. However, Iran's involvement in resource development could pose a major problem for the FRS companies in light of the Presidential Executive Orders which have imposed an embargo on trade and investment with Iran.

Despite this issue of whether resource development in the Caspian Sea will be governed by the Law of the Sea convention or not, there is every expectation that the Caspian Basin will be a major oil producing area in the future. As L. Richard Flury, Amoco's executive vice president for exploration and production, has said, "We've identified the Caspian Basin as a high priority area for growth and spending into the 21st century".[b]

[a] For more information on developments in the Caspian region, see http://www.eia.doe.gov/emeu/cabs/caspian.html.
[b] "Caspian Sea MODU Refurbished to Western Standards," *Oil and Gas Journal* (May 5, 1997), pp. 65-82.

skyrocketed to 73 percent. Contributing significantly to this development was Mobil's acquisition of Ampolex (Australia), which gives Mobil access to the vast liquefied natural gas potential of Australia's Northwest Shelf as well as oil and gas production and exploration acreage in both Australia and South America. This turn of events may signal a change in which the purchase of reserves outside North America is a more integral part of the overall reserve acquisition process of the FRS companies.

Drilling Activity in 1996

Natural Gas Well Completions Rise in the U.S. Offshore

Rising oil and gas prices from 1995 to 1996 led to an overall increase in total well completions by the FRS companies, though a regional disaggregation by fuel type (oil and gas) and well type (exploratory and developmental) shows that the increase was not across-the-board. In the United States, for example, onshore exploratory well completions by the FRS companies declined slightly. Offshore exploratory completions increased marginally for oil and dramatically for gas.

The increased interest in the offshore is reflected in the fact that offshore gas exploratory well completions by the FRS companies increased from 53 wells in 1995 to 87 wells in 1996 (Table 16). Gas development well completions by the FRS companies in the U.S. offshore increased substantially from 95 in 1995 to 151 in 1996 (Table 17), offering further evidence of the increasing attractiveness of the offshore to the FRS companies.

Gas Well Completions Surge in Canada and the Pacific Rim, Oil Drilling up in Africa.

Exploration. As in the United States, foreign exploratory well completions by the FRS companies overall favored natural gas. Completions for oil declined slightly while gas completions increased from 130 in 1995 to 160 in 1996 (Table 16). Both of these changes were driven largely by events in Canada, where oil exploratory well completions dropped significantly, almost returning to their 1994 level, and where gas exploratory well completions increased substantially after registering a sizable drop from 1994 to 1995. The fall in oil exploratory well completions may be due, in part, to the decline in drilling associated with the near completion of the Hibernia project off the east coast of Canada.

Development. Rising prices spurred increases in gas development well completions by the FRS companies in foreign regions. These increases were due almost entirely to increases in gas development well completions in Canada and in the countries of the Other Eastern Hemisphere. Africa registered the largest increase in oil development well completions by the FRS companies, where completions rose from 65 in 1995 to 85 in 1996 (Table 17). The increase in completions in Africa and in the Other Eastern Hemisphere are also reflective of the increasing FRS interest and activities in these regions.

Finding Costs and Finding Rates

Worldwide Finding Costs Stable from 1995 but Decline Dramatically from 1990 Through 1994

Finding costs are the costs of finding additional reserves of oil and gas. Finding costs are measured as the ratio of exploration and development expenditures, excluding expenditures on proved acreage, to reserve additions, excluding net purchases. Because of the likely lags between the time when the expenditures are incurred and the time when the associated reserve additions are booked, the finding costs reported here are calculated as three-year moving averages.

Although worldwide finding costs for the FRS companies remained fairly stable, registering a slight decrease of only 1 percent from $4.36 in the 1993-1995 period to $4.33 in the 1994-1996 period, differences across regions were pronounced (Table 19). The finding cost for the FRS companies in the United States showed an overall increase of 5 percent. This increase was clearly driven by a 22-percent rise in the finding cost for the U.S. offshore, a result consistent with the decline in the U.S. offshore reserve additions between 1995 and 1996 (Table 20). Longer reporting lags in the offshore, coupled with higher rig rates and more expenditures on unproved acreage, are the factors most likely responsible for the rise in offshore finding costs. Foreign finding costs for the FRS companies showed an overall decrease of 6 percent between 1993-1995 and 1994-1996, led by declines in the finding costs in the Middle East and the Other Western Hemisphere of 29 percent and 18 percent, respectively.

An important point to note and one that tends to get overlooked in examining period-to-period changes is the dramatic decline in the finding costs for the FRS companies over the entire 1990-1996 period. For example, though offshore finding costs increased by 22 percent from the most recent period, they have fallen by 32 percent since the 1990-92 period. An examination of the last column of Table 19 shows that for every region, except the Other Eastern Hemisphere, finding costs have dropped dramatically since 1990, with worldwide finding costs for the FRS companies declining by 29 percent. The exception is the Other Eastern Hemisphere region, where FRS finding costs have registered a substantial increase of over 51 percent since 1990.

Table 19. Finding Costs by Region, FRS Companies and Independent Producers, 1990-1996
(Dollars per Barrel of Oil Equivalent)

Region	1990-1992	1993-1995	1994-1996	Percent Change 1990/92-1994/96
FRS Companies				
United States				
Onshore	5.07	4.25	4.06	-19.9
Offshore	7.69	4.29	5.24	-31.9
Total United States	5.74	4.26	4.49	-25.8
Foreign				
Canada	10.91	5.95	5.75	-47.3
OECD Europe	7.94	4.92	4.51	-43.2
Africa	5.22	3.11	3.43	-34.3
Middle East	6.80	3.03	2.15	-68.4
Other Eastern Hemisphere	4.10	5.16	6.20	51.2
Other Western Hemisphere	5.07	2.49	2.04	-59.8
Total Foreign	6.42	4.46	4.19	-34.7
Worldwide Total	6.07	4.36	4.33	-28.7
Independent Producers				
United States	NA	5.29	5.39	NA
Foreign	NA	5.42	4.63	NA

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

Sources: **FRS companies**: Energy Information Administration, Form EIA-28, "Financial Reporting System"; **Independent producers**: compiled from Arthur Andersen & Co., *Oil and Gas Reserves Disclosures Database*, 1992-1996 (Chicago, IL, 1997). Independent producers are publicly traded companies other than the FRS companies whose primary industry code is SIC 13.

Table 20. Oil and Gas Reserves and Production for FRS Companies, 1995-1996

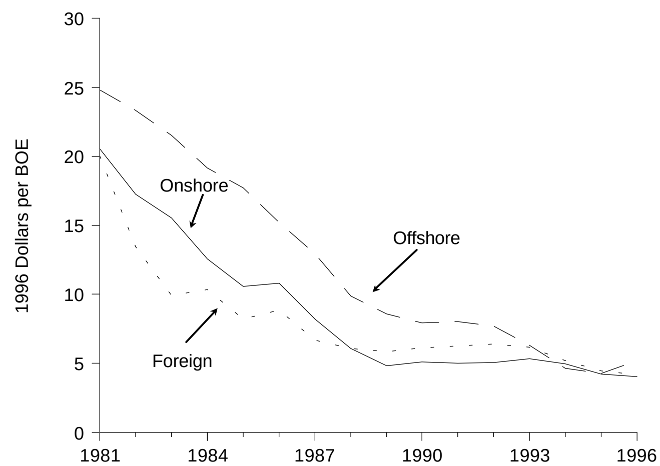
Reserves and Production	U.S. Onshore 1995	U.S. Onshore 1996	U.S. Offshore 1995	U.S. Offshore 1996	Foreign 1995	Foreign 1996
Oil (million barrels)						
Reserve Additions	940	1,053	571	417	1,983	2,069
Net Purchases	-228	-152	14	-56	-20	68
Production	1,242	1,198	329	334	1,435	1,458
Total Oil Reserves	13,655	13,376	3,085	3,085	13,887	14,563
Oil Reserve Additions[a]/Production (percent)	76	88	174	125	138	142
Natural Gas (billion cubic feet)						
Reserve Additions	6,155	3,686	2,862	2,283	5,618	7,419
Net Purchases	61	-843	90	-193	-910	-635
Production	5,365	5,380	2,690	2,811	4,431	4,703
Total Gas Reserves	58,337	55,761	20,976	20,292	59,749	61,829
Gas Reserve Additions[a]/Production (percent)	115	69	106	81	127	158

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

A most interesting pattern in finding costs over time is the convergence of finding costs for the U.S. onshore, U.S. offshore, and foreign regions. While offshore finding costs were much higher than both onshore and foreign finding costs in the 1980's, the cost differential was all but eliminated by the mid-1990's (Figure 18). This convergence can be attributed largely to the introduction and application of innovative geophysical and drilling technologies in exploring for new oil and gas reserves. Indicative of the importance of such innovations to the increased efficiency of offshore exploratory drilling is the increase in the offshore success rate, from 20 percent in 1977 to 59 percent in 1996. Additionally, the introduction of subsea well technologies, tension leg platforms, and production spars have opened up vast new and promising areas for exploration in the deepwater and ultra-deepwater areas of the offshore that previously had been inaccessible.[72]

Of additional interest is that, on average, finding costs for the independent producers remain significantly above those of the FRS companies, though the gap seems to be diminishing. The narrowing gap is likely due in part to independent producers having increasing access to technologies that were previously utilized by only the major oil and gas producers. For example, as noted in a recent article on applied geophysics, "Having started as a technology too expensive to be utilized except by major oil companies, 3D technology is now routinely used by independent operators in the U.S. and Canada."[73]

Figure 18. U.S. Onshore, U.S. Offshore, and Foreign Finding Costs for FRS Companies, 1981-1996



BOE = Barrel of crude oil equivalent.
Note: Finding costs are 3-year weighted averages of exploration and development expenditures, excluding expenditures for proved acreage, divided by reserve additions, excluding net purchases. Expenditures are deflated using the chain-weighted GDP deflator. Reserve additions exclude the downward revisions of the natural gas reserves located on the north slope of Alaska, which occurred in the mid-1980's upon realization that the gas was not currently marketable. Natural gas is converted to its oil equivalent using the conversion factor of 0.178 barrels of oil per thousand cubic feet of gas.
Source: Energy Information Administration, Form EIA-28, "Financial Reporting System."

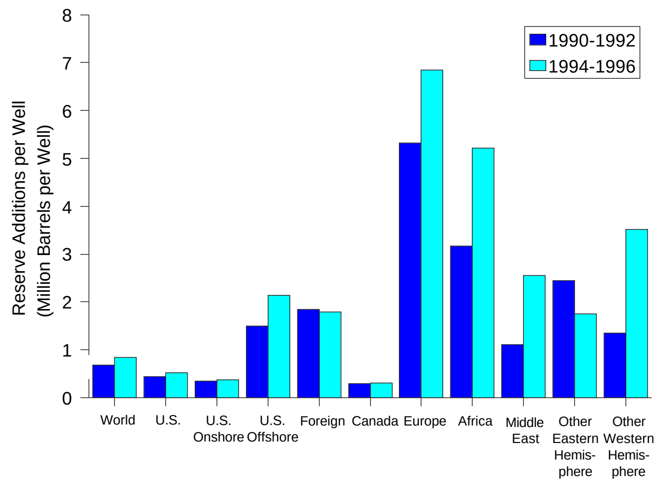
Worldwide Finding Rate Shows Slight Increase

The finding rate is a measure of the average productivity of exploration and development drilling. Fundamentally, it is the ratio of reserve additions, excluding net purchases, to the total number of exploratory and development wells drilled, including dry holes. The finding rate can change for a number of reasons. For example, for a given level of technology, finding rates are expected to decline over time due to the effects of resource depletion, i.e., larger fields are found first with subsequent drilling finding smaller and smaller fields as the resource is depleted. Of course, even with a given level of technology, finding rates in the short run could rise due to "prospect highgrading," i.e., drilling fewer wells but drilling them in the most promising prospects.[74] As geological, geophysical, and drilling technologies improve, however, finding rates can rise as the industry gets more efficient in identifying more promising prospects and adding the associated reserves by drilling fewer wells. In addition, technological advances can transform previously uneconomic prospects into economically viable ones. Because of the time lags between the drilling of wells and the reporting of the associated reserve additions, the finding rates reported here are calculated as three-year weighted averages of reserve additions (excluding net purchases), in barrels of oil equivalent (BOE), divided by total exploratory and development wells drilled (including dry holes).

The worldwide finding rate for the FRS companies increased from 687 thousand BOE in the 1990-1992 period to 840 thousand BOE in the 1994-1996 period (Figure 19). Large regional differences, however, were apparent. Domestically, the finding rate for the FRS companies increased from 434 thousand BOE in the 1990-1992 period to 523 thousand BOE in the 1994-1996 period. With the U.S. onshore finding rate only marginally higher from the earlier period, the increase was driven by the increase in the U.S. offshore finding rate from 1,500 thousand BOE to 2,144 thousand BOE.

The foreign finding rate for the FRS companies declined slightly from 1,848 thousand BOE in the 1990-1992 period to 1,792 thousand BOE in the 1994-1996 period. Significant increases were experienced in Europe, Africa, the Middle East, and in the Other Western Hemisphere regions. The likely explanation is that both improvements in technology plus greater access by the FRS companies to acreage with promising oil and gas opportunities led to the increase. The latter is probably the more important explanation for the increase in the finding rate in the Other

Figure 19. Finding Rates by Regions for FRS Companies, 1990-1992 and 1994-1996



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

Western Hemisphere region, given the recent events occurring in Venezuela and other South American countries.

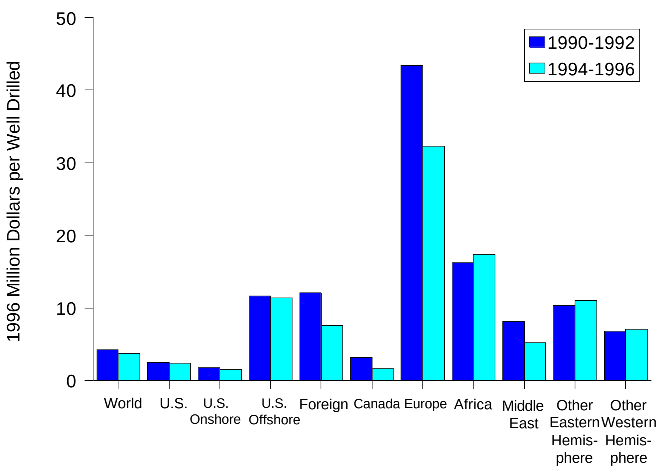
The most significant finding rate decline for the FRS companies in the foreign sector was experienced in the Other Eastern Hemisphere, where the finding rate declined to 1,750 thousand BOE per well in the 1994-1996 period from 2,451 thousand BOE per well in the 1990-1992 period. Part of this decline is explained by the fact that reserve additions were unusually high in 1991. Part of the decline might also be explained by Mobil's efforts to stem the productivity decline of the Arun field in Indonesia with the purposeful development of surrounding smaller fields.[75] In addition, though the FRS companies are increasing their presence in the Other Eastern Hemisphere, the amount of undeveloped acreage to which they have access is somewhat more limited than in other parts of the world.

Exploration and Development Costs per Well Decline, Large Regional Differences Remain

One measure of the cost of exploration and development activity is the ratio of exploration and development expenditures, excluding expenditures on proved acreage, to the number of wells drilled, including dry holes. Comprising the numerator of this ratio are expenditures for drilling and equipping wells, expenditures for unproved acreage, and expenditures for geological and geophysical data and data analysis.

As a result of cost-cutting efforts, worldwide exploration and development expenditures per well for the FRS companies declined from $4.2 million in the 1990-1992 period to $3.7 million in the 1994-1996 period (Figure 20). Large regional differences, however, are evident. In the U.S. onshore, expenditures per well declined 16 percent to $1.5 million in 1994-1996 from $1.8 million in the 1990-1992 period. In the U.S. offshore, expenditures per well declined marginally from $11.6 million in the 1990-1992 period to $11.4 million in the 1994-1996 period.

Figure 20. Exploration and Development Expenditures per Well by Regions for FRS Companies, 1990-1992 and 1994-1996



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

In contrast to these somewhat modest changes in domestic expenditures, foreign exploration and development expenditures per well for the FRS companies declined over 35 percent from $12.1 million in the 1990-1992 period to $7.6 million in the 1994-1996 period. Significant decreases were experienced in Canada, Europe, and the Middle East. In Canada, for example, the level of expenditures per well declined by over 45 percent. In Africa, the Other Western Hemisphere, and the Other Eastern Hemisphere, expenditures per well actually increased between the two periods. Factors accounting for these increases include the infrastructure investments that are required in these regions, the increased application of horizontal drilling technology (which tends to be costly on a per well basis) in Africa, and increased expenditures on unproved acreage.

The Components of the Change in Finding Costs

While finding costs in most regions have generally declined between 1990-1992 and the most recent three-year period, they have done so for different reasons. Changes in finding costs over time are explained by changes in drilling and other exploration and development expenditures per well and changes in the finding rate. Accordingly, the total change in finding costs between two time periods can be separated into an expenditure per well component and a finding rate component.

The results of this division indicate that almost 60 percent of the decline in worldwide finding costs between the periods 1990-1992 and 1994-1996 is explained by the increase in the finding rate between the two periods (Table 21).[76] However, for the U.S. onshore, 19 percent of the decline in onshore finding costs between the two periods can be explained by the increase in the onshore finding rate. In sharp contrast, over 95 percent of the decline in finding costs in the offshore between the two periods can be explained by the 43 percent increase in the offshore finding rate. In Canada, the finding rate barely increased between the two periods and, thus, it is not unexpected that the increase in the finding rate explains approximately 5 percent of the over $5.00 decline in finding costs between the two periods. In Africa and the Other Western Hemisphere, the change in the finding rate explains over 100 percent of the change in finding costs. In these regions, costs per well increased but finding costs declined as a result of large increases in the finding rate.

Production and Reserves

Reserve Replacement Rates Fall Domestically but Increase Abroad

The FRS companies replaced more oil reserves than were produced for all regions except the U.S. onshore, where the replacement rate, though showing an increase from the rate in 1995, remained below 100 percent (Table 20). For the U.S. offshore, the FRS rate of replacement of oil reserves declined but did stay above 100 percent. The FRS domestic replacement rates for natural gas declined considerably, falling below 100 percent for both the onshore and offshore regions. In contrast, the FRS companies replaced more of their foreign gas reserves than were produced, with the rate of replacement increasing from 127 percent in 1995 to 158 percent in 1996.

Table 21. The Components of the Change in Finding Costs Between the Periods 1990-1992 and 1994-1996 by Region for FRS Companies

Region	Change in Finding Costs	Percentage Change in Finding Costs	Percentage Change in Expenditures Per Well	Percentage Change in the Finding Rate	Percent of the Change in Finding Cost Accounted for by the Change in the Finding Rate
FRS Companies					
United States					
Onshore	-1.01	-19.9	-16.3	4.9	19.4
Offshore	-2.45	-31.9	-1.5	43.0	95.2
Total United States	-1.25	-25.8	-5.7	20.4	76.0
Foreign					
Canada	-5.16	-47.3	-46.2	3.1	4.8
OECD Europe	-3.43	-43.2	-25.4	28.7	46.3
Africa	-1.79	-34.3	7.5	64.4	117.3
Middle East	-4.65	-68.4	-36.2	129.6	64.0
Other Eastern Hemisphere	2.10	51.2	7.3	-28.7	82.7
Other Western Hemisphere	-3.03	-59.8	4.4	161.1	105.1
Total Foreign	-2.23	-34.7	-37.1	-3.0	-7.2
Worldwide Total	-1.74	-28.7	-12.9	22.2	59.2

Note: The above changes in finding costs are based on 3-year weighted averages of exploration and development expenditures, excluding expenditures for proved acreage, divided by reserve additions, excluding net purchases. Gas is converted to barrels of oil equivalent on the basis of 0.178 barrels of oil per thousand cubic feet of gas. The changes in costs per well are based on 3-year weighted averages of exploration and development expenditures, excluding expenditures for proved acreage, divided by wells drilled, including dry holes. The breakdown of the changes in finding costs into a cost component and a finding rate component makes use of the identity that finding costs equal expenditures per well divided by the finding rate.

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

Endnotes

[42] Unusual items are gains and charges recognized in a company's income statement that are of a non-recurring nature and generally unrelated to current operations. See endnote 7 in Chapter 2 for more explanation.

[43] For further information about Financial Accounting Standard 121, see Energy Information Administration, "New Accounting Standard Leads to Billions in Asset Writeoffs," *Performance Profiles of Major Energy Producers 1995*, DOE/EIA-0206(95) (Washington, DC, February 1997), p. 6.

[44] It is interesting to note that domestic and foreign finding costs converged in 1989.

[45] Both foreign and domestic production utilized a declining number of wells, but foreign production was increasing while domestic production was decreasing.

[46] Energy Information Administration, *Oil and Gas Development in the United States in the Early 1990's*, DOE/EIA-0600 (Washington, DC, October 1995).

[47] "Salomon: 1997 shaping up as strongest E&P in 9 years," *Oil and Gas Journal* (February 17, 1997), pp. 39-41.

[48] Unocal Corporation, *1996 Annual Report*, p. 22.

[49] Texaco Corporation, *1996 Annual Report*, p. 17.

[50] Occidental Petroleum, *1996 Annual Report*, p. 7.

[51] Mobil Corporation, *Fact Book 1996*, p. 37.

[52] http://www.mobil.com/world/asia-pacific/index.html

[53] See the box entitled "Upstream in Venezuela" in *Performance Profiles of Major Energy Producers 1995*, DOE/EIA-0206(95) (Washington, DC, February 1997), p. 31.

[54] http://www.conoco.com/about/venezuelanExploration.html (October 30, 1997).

[55] Mobil Corporation, *Fact Book 1996*, p. 14.

[56] Http://www.eia.doe.gov.emeu/cabs/colombia.pdf (December 22, 1997).

[57] E. I. DuPont de Nemours and Company, *1996 Annual Report*, p. 18.

[58] "Interest Grows In African Oil and Gas Opportunities," *Oil and Gas Journal* (May 12, 1997), pp. 41-59.

[59] Andarko Corporation, 1995 and 1996 *Annual Reports*.

[60] Mobil Corporation, *Fact Book 1996*, p. 33.

[61] Exxon Corporation, *1996 Annual Report*, p. 11.

[62] Amoco Corporation, *1996 Annual Report*, p. 13.

[63] Texaco Corporation, *1996 Annual Report*, p. 17.

[64] ARCO Corporation, *1996 Annual Report*, p. 9.

[65] Mobil Corporation, *1996 Annual Report*, p. 16.

[66] Texaco Corporation, *1996 Annual Report*, p. 16.

[67] http://www.exxon.com/exxoncorp/current_news/press_release11_21.html (November 21, 1996).

[68] http://www.amoco.com/what_we_do/ep/06_eurasia.html (November 18, 1997).

[69] Exxon Corporation, *1996 Annual Report*, p. 11.

[70] Phillips Corporation, *1996 Annual Report*, p. 13.

[71] "More E&P Focus of U.S. companies' budgets," *Oil and Gas Journal* (February 17, 1997), pp. 36-39.

[72] For a comprehensive discussion of the impact of offshore technologies and offshore potential, see "Subsea Technology Progress Buoys Gulf of Mexico Deepwater Action," *Oil and Gas Journal*, Vol. 94, No. 36 (September 2, 1996), p. 23; and "1997 OTC Highlights 50 Years of Offshore Technology and Progress," *Oil and Gas Journal*, Vol. 95, No. 19 (May 12, 1997), p. 22.

[73] "Parallel computing helps 3D depth imaging, processing," *Oil and Gas Journal* (October 28, 1996), p. 35.

[74] See *Performance Profiles of Major Energy Producers 1995* (Washington, DC, February 1997), p.32.

[75] Mobil Corporation, *Fact Book 1996*, p. 37.

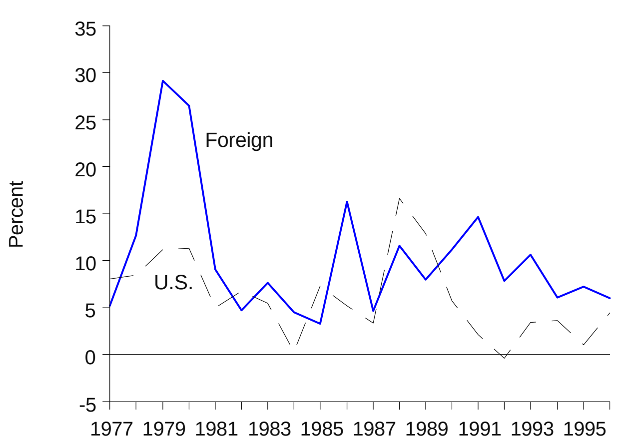
[76] This breakdown is not exact, given that expenditures per well and the finding rate have changed over time. However, one can calculate an upper and lower bound for each of the two factors. The numbers reported here are an average of the upper and lower bound.

4. Downstream Petroleum in 1996

The year 1996 could prove to be one of the best years for FRS domestic downstream operations during the 1990's. It also may have been the year that the trend of low earnings that persisted during the early 1990's reversed. After ranging between 3.6 percent and -0.4 percent between 1991 and 1995, the return on investment for domestic refining and marketing reached 4.4 percent during 1996 (Figure 21). Net income from U.S. refining and marketing operations, excluding unusual items,[77] doubled between 1995 and 1996 (Table 22). Among the reasons for the unusually good results in 1996 were increased margins on greater sales volumes. Additionally, refining investment, in order to comply with environmental legislation, fell dramatically during 1996, apparently because compliance had generally been achieved.

Foreign refining and marketing results continued to surpass those of domestic operations but declined during 1996, and the profitability of foreign refining and marketing operations reached a decade-low 6.0-percent return on investment. The continued decline of European margins and the maturity of retail markets was offset by FRS efforts to solidify their positions, or exit. By contrast, increasing margins and refined product demand growth in the Pacific Rim markets have attracted downstream investments by several of the FRS companies.

Figure 21. Return on Investment in Refining/ Marketing for FRS Companies, 1977-1996



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

U.S. Refining and Marketing

Gross Margins Increase for the First Time Since 1990

The domestic refined product revenues of the FRS companies increased by over $20 billion between 1995 and 1996 (Table 22), mainly because refined product prices overall were up 14 percent (Table 23). The volume of refined product sales increased by 3 percent, the largest annual increase registered by the FRS companies since 1986. Increased sales volume was partially achieved through more intensive use of refineries, as capacity utilization reached 94 percent during 1996 (Table 24).

For the first time since 1990, gross margins of FRS refiners increased in 1996. (The gross margin is refined product revenues less purchases of raw material inputs to refining and product purchases.) In 1996, price increases of refined products outstripped increases in the prices of raw material inputs to the production process and of refined products purchased (Table 23). The gross margin on all refined petroleum products increased by $1.00 per barrel from the decade low of $5.53 per barrel in 1995.

Most of the increase in the gross margin was attributable to distillate price increases. The winter of 1996 was unusually cold, particularly when compared to the winter of 1995.[78] Distillate prices realized by the FRS companies increased 20 percent during 1996, while gasoline prices increased by 12 percent (Table 23). Demand for heavier fuels also increased due to the frigid temperatures of early 1996. As natural gas consumption by electric utilities fell by 14 percent between 1995 and 1996[79] in response to a 33-percent increase in the price of natural gas (from $2.02 to $2.69 per thousand cubic feet),[80] utilities' use of residual fuel oil increased 11 percent. This shift in utility demand (from natural gas to residual fuel oil) was reflected in the 11-percent price increase that the FRS companies received for a group of "other" products, which included residual fuel oil.

Net margins are gross margins less out-of-pocket operating costs. The net margin is a measure of the (pretax) contribution to cash flow per barrel of refined product sold. Return on investment for refining / marketing operations is strongly linked to the net margin, with a correlation coefficient of 0.92.[81]

Table 22. Refining/Marketing Financial Items for FRS Companies, 1995-1996
(Million Dollars)

	United States		Foreign	
	1995	1996	1995	1996
Refined Product Revenues	120,698	141,525	124,615	133,476
plus Other Revenues[a]	11,146	11,480	4,737	4,574
minus Total Operating Expenses[a, b]	129,777	149,600	126,271	135,423
equals Operating Income[b]	2,067	3,405	3,081	2,627
Net Income, excluding unusual items	1,220	2,476	2,673	2,182
Unusual Items	-712	-225	-264	-198
Net Income	508	2,251	2,409	1,984

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

Table 23. Sales, Prices, and Margins in U.S. Refining/Marketing for FRS Companies, 1995-1996

Sales, Expenses, and Income	1995	1996	Percent Change 1995-1996
	(million barrels per day)		
Refined Product Sales	13.6	14.0	2.5
	(dollars per barrel)		
Average Sales Price			
Gasoline	27.13	30.27	11.6
Distillate	22.14	26.65	20.4
Other	20.77	23.00	10.7
All Refined Products	24.24	27.65	14.1
Raw Material Input and Product Purchases per Barrel	18.71	21.12	12.9
Average Sales Price Less Cost of Raw Materials and Product Purchases (Gross Margin)	5.53	6.53	18.1
Direct Operating Costs	5.04	5.66	12.3
Refined Product Margin[a]	0.49	0.87	77.6
Gasoline Marketing Margins			
Wholesaler/Reseller	5.61	4.40	-21.6
Retailer	2.48	2.65	6.9

[a]See Appendix B, Table B48, for the components to calculate the refined product margin.
Note: Sum of components may not equal total due to independent rounding. Percent changes were calculated from unrounded data.
Source: Energy Information Administration, Form EIA-28, "Financial Reporting System."

Although operating costs increased an average of $0.62 per barrel across all FRS companies, West Coast refiners' (ARCO, Chevron, Texaco, and Unocal) operating costs increased substantially more, by an average of almost $2.00 per barrel, than did the costs of the remaining companies, which increased by an average of only $0.14 per barrel. The increased costs of these companies is probably related to compliance with the standards of the California Air Resource Board (CARB) for reformulated gasoline (RFG)[82] and low-sulfur diesel, which are more stringent than the Federal standards of the Clean Air Act Amendments of 1990.

Table 24. Refining and Marketing Investment and Operating Data for FRS Companies, 1995-1996

Financial Items	1995	1996	Percent Change 1995-1996
	(billion dollars)		
Additions to Investment in Place			
United States			
Refining	3.6	2.1	-40.7
Marketing[a]	2.2	2.6	18.2
Total	5.8	4.7	-18.9
Foreign Refining and Marketing	3.0	3.5	18.9
Total	8.8	8.2	-6.8
	(thousand barrels per day)		
Refining Capacity			
United States	10,427	10,447	0.5
Foreign	4,450	4,346	-2.3
Total	14,877	14,823	-0.4
	(percent)		
Refinery Utilization Rate			
United States	91.8	93.5	--
Foreign	86.0	89.5	--

[a]Includes refining and marketing transport.

-- = 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."

One of the key targets of the cost-cutting by FRS refiners during the 1990's has been gasoline marketing networks. For example, between 1992 and 1995, FRS companies managed to reduce marketing costs by nearly one dollar per barrel sold (in 1996 dollars) (Table 25). However, in 1996, this trend leveled off, as marketing costs increased slightly (Table 26). This development was widespread, as all size categories of refiners registered higher marketing costs.

The increase in operating cost was substantially outweighed by the increase in the gross margin, resulting in an $0.87 per-barrel net margin on refined products, an increase of $0.38 per barrel from 1995.

Although the higher net margin was largely traceable to increased product prices and demand, particularly for distillate, the gains of 1996 may also have been at the expense of jobbers and other resellers of gasoline. The dealer margin is measured as the difference between the price that FRS companies received at the pump and the price for gasoline paid by dealers. The wholesaler margin is measured by the difference between the price paid by dealers to wholesalers for gasoline and the price paid by wholesalers to refiners.

In 1996, the wholesaler margin fell by $1.21 per barrel while the margin for company-operated outlets rose $0.17 per barrel (Table 23). That is, in the context of the often tight U.S. gasoline markets of 1996, the price paid to refiners for gasoline rose more than the price received by wholesalers / resellers.

Capital Expenditures

Refining

Since reaching a decade peak in 1992 of $5.2 billion, domestic refining capital expenditures by the FRS companies have fallen an average of 15 percent per year, reaching the decade's low point in 1996 at $2.1 billion. Refining investment in recent years has been driven largely by the environmental requirements of the Clean Air Act Amendments of 1990. Investment related to pollution abatement peaked in 1992 and has since declined, according to American Petroleum Institute information (Figure 22).

The decline in refining investment roughly parallels the decline in pollution abatement capital expenditures. For example, nearly two-thirds of the decline in FRS refining capital expenditures between 1995 and 1996 can be attributed to companies with a significant presence in California motor gasoline retail markets. ARCO, Chevron, Shell, and Texaco[83] all noted that substantial refinery investment to produce reformulated gasoline or low-

Table 25. FRS U.S. Refined Product Margins and Costs per Barrel Sold, Selected Years, 1979-1996
(1996 Dollars per Barrel)

	1979	1984	1988	1992	1995	1996
Gross Margin[a]	8.21	8.37	8.52	7.39	5.53	6.53
less						
Marketing Costs	1.95	2.63	1.96	2.90	1.75	1.86
Energy Costs	2.04	2.78	1.33	1.21	0.82	1.07
Other Operating Expense	2.75	2.95	3.02	2.88	2.47	2.73
equals						
FRS Refined Product Margin[b]	1.65	0.01	2.22	0.41	0.49	0.87
Refined Product Sales Volume (Mb/d)	14,868	12,055	14,075	13,053	13,641	13,985

[a]Refined product revenues less raw material and product purchases divided by refined product sales volume.
[b]Calculated from unrounded data.
Note: Years shown prior to 1995 are successive peak and trough years of U.S. refining/marketing profitability.
Mb/d = Thousand barrels per day.
Source: Energy Information Administration, Form EIA-28, "Financial Reporting System."

Table 26. Marketing Characteristics and Refined Product Margin for FRS Companies Ranked by Total Energy Assets, 1995-1996

Group	Average Outlet Volume (thousand gallons per month)		Refined Product Margin Per Barrel (dollars per barrel)		Marketing Expenses Per Barrel (dollars per barrel)	
	1995	1996	1995	1996	1995	1996
Top Four	84.0	81.1	0.40	0.83	1.85	1.92
Five Through Twelve	122.7	135.6	0.70	1.07	1.99	2.18
All Other	61.2	62.2	0.29	0.64	1.30	1.33
All FRS	90.3	94.1	0.49	0.87	1.75	1.86

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

sulfur diesel that comply with California requirements had been completed during 1996.[84]

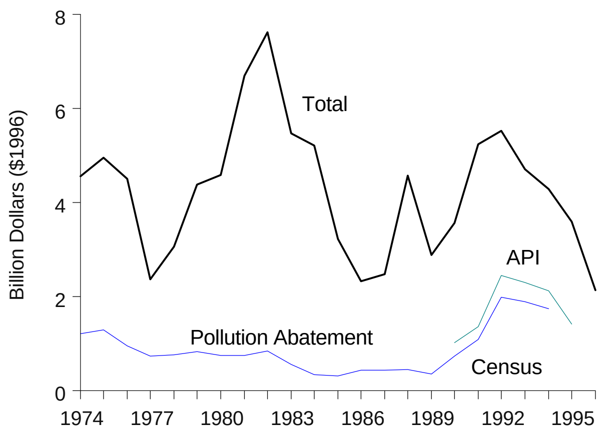
Pollution abatement capital expenditures are largely due to the Clean Air Act Amendments of 1990 (CAAA90). The CAAA90 required a phased reduction in vehicle emissions of regulated pollutants which were met primarily through the use of reformulated gasoline.[85] By November of 1992, refiners were required to produce oxygenated gasolines. Low-sulfur diesel fuel was required by October 1993. By January 1, 1995, reformulated gasoline (RFG) had to be available.[86] Thus, consistently through the first half of the 1990's, domestic refiners were faced with deadlines for new products requiring new capital investment.

Although data on the 1996 pollution abatement capital expenditures specifically for refining operations are not yet available, overall FRS environmentally-related capital expenditures fell by approximately 34 percent between 1995 and 1996. One would conclude from the company annual reports for 1996 that the major reason for the decline is that CAAA90-motivated investments have been completed. For example, ARCO, in its *1996 Annual Report*, notes that, "[i]n California ... modifications were completed in 1995 to meet the state's stringent requirements for cleaner gasoline,"[87] and Shell Oil Company noted that its reduction in oil products capital spending during 1996 was due to the completion of a 3-year, $1-billion upgrade of its Martinez, California, refinery in order to produce RFG, low-sulfur diesel, and jet fuel.[88]

Marketing

Capital expenditures for marketing in the 1990's tended to have two frequently complementary aims: to increase the value of outlet sites by adding nonfuel products and services and to increase the number of company-operated outlets.

Figure 22. U.S. Refining Capital Expenditures for FRS Companies, 1974-1996



Note: Excludes effects of intra-FRS mergers in 1982 and 1984.

Sources: Energy Information Administration, Form-EIA-28, "Financial Reporting System"; U.S. Department of Commerce, Bureau of the Census, *Pollution Abatement Costs and Expenditures,* (various issues) (Washington, DC); American Petroleum Institute, *Petroleum Industry Environmental Performance* (Washington, DC, May 1997)

Several ways of enhancing the value of their marketing operations have been undertaken by the FRS companies in the 1990's, generally in the form of enhancing sales of non-gasoline items. Toward that end the convenience-store format is becoming increasingly popular among FRS companies.[89] In addition, FRS companies' recent attempts to enhance the value of their outlets have included the introduction of several non-gasoline products, such as name-brand fast food outlets (known as multi-format stations),[90] in-store automatic teller machines, card readers in the gasoline pumps to reduce the amount of time required to purchase gasoline,[91] and a number of other innovations aimed at making marketing outlets "destinations" instead of merely a stop while traveling somewhere else.

One way of examining the success that FRS companies are having in their convenience store operations is to use revenue generated from non-gasoline sales on a per outlet basis. The FRS companies' annual revenue from convenience store gasoline outlets (as measured by "other refining and marketing revenue"[92] divided by company-owned outlets) increased by 3 percent between 1995 and 1996, rising from an average of $766 thousand to $788 thousand per outlet.

The increase in gross and net margins was accompanied by the first increase in FRS company-operated gasoline outlets during the 1990's.[93] The number of outlets increased by 4 percent, reaching 8,927 by the end of 1996 (Table 27). Although the increase in company-operated outlets generally occurred across all FRS companies, it was the most substantial among the largest and the smallest of the FRS companies (based on value of total energy assets). The number of outlets directly operated by the four largest companies increased by more than 11 percent between 1995 and 1996 (increasing from 2,012 to 2,235). Company-operated outlets of the smallest FRS companies increased by more than 4 percent, increasing from 2,601 to 2,714.

However, the number of dealer outlets of FRS companies continued its recent trend, declining by one percent during 1996. Dealer outlets sell motor fuel under the brand name of an FRS company under contract or through a lease agreement with the company, but they are not operated by the company.[94] The changes varied by size of FRS company. The group of smallest companies reported the largest reduction in branded dealers, falling by 3 percent, from 9,165 to 8,891. The group of largest companies reduced their branded dealers by 1 percent and the group of middle-sized dealers slightly increased the number of their branded dealers (increasing from 9,223 to 9,259). On balance, the total number of FRS-branded gasoline outlets fell by 0.1 percent.

Foreign Refining and Marketing

Margins Abysmal in Europe, Soaring in Pacific Rim

Unlike gross margins in the United States, gross margins in Europe (represented here by the Rotterdam/Brent refining margin) were low and falling in 1996. Most of the FRS companies with European operations spoke of "extremely competitive markets" as part of the reason for their particularly low revenues from downstream operations.[95] Relatively slow economic growth rates, coupled with many competitors for slowly expanding gasoline markets, led to gross margins that were negative for the second year in a row (Figure 23).

Conversely, the Pacific Rim (represented here by the Singapore/Dubai refining margin), particularly the developing countries such as China, had substantial growth rates in petroleum consumption during 1996, continuing several years of expansion and increasing gross margins. Although margins in the months of June through November 1997 were declining or low for both European and Pacific Rim refiners (Figure 23), the December margins were sharply higher in Singapore but were lower in Rotterdam.

Table 27. Gasoline Distribution by FRS Companies, 1995-1996

Distribution Category	1995	1996	Percent Change 1995-1996
	(million barrels)		
Wholesale Volume	1,117.3	1,145.1	2.5
Retail Volume			
Dealer Volume	680.3	662.6	-2.6
Company-Operated Volume	309.4	318.7	3.0
Total Retail Volume	989.8	981.4	-0.8
Direct Volume	303.5	350.0	15.3
Intersegment Volume	11.4	11.9	4.7
Total Volume	2,422.0	2,488.4	2.7
	(number of outlets)		
Dealer Outlets	29,811	29,398	-1.4
Company-Operated Outlets	8,549	8,927	4.4
Total Retail Outlets	38,360	38,325	-0.1
	(thousand gallons per month)		
Average Monthly Outlet Volume			
Dealers	79.9	78.9	-1.3
Company Operated	126.7	125.0	-1.3
All Retail	90.3	89.6	-0.8

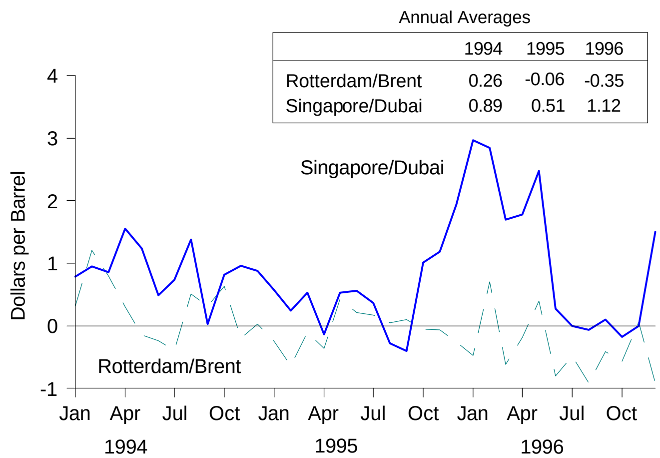
Note: Percent changes were calculated from unrounded data.
Source: Energy Information Administration, Form EIA-28, "Financial Reporting System."

Consistent with the year-to-year movement in margins were changes in the equity income earned by FRS companies from unconsolidated foreign refining and marketing operations, which are located chiefly in Asia.[96] Income from unconsolidated affiliates continued to increase,[97] rising from $887 million in 1995 to $1,005 million in 1996. In contrast, income from consolidated foreign refining and marketing operations (located chiefly in Europe[98]) continued to decline,[99] falling from $2.5 billion in 1995 to $1.9 billion in 1996.

Consolidation, Refocusing, and Joint Ventures Continue

Petroleum consumption increased an average of two percent per year, or less, in North America,[100] OECD Europe, Australasia, and Japan[101] between 1991 and 1996 (Figure 24). Slightly more growth (averaging about 3 percent annually) in petroleum consumption occurred in Latin America,[102] the Middle East, and Africa. At least temporarily dampening refiners' prospects was the substantial reduction (averaging almost 9 percent) in petroleum consumption over the same period in the countries of the Former Soviet Union and Eastern Europe, although the opening of these countries to foreign investment has attracted some downstream capital expenditures from FRS companies in recent years.[103] In contrast,

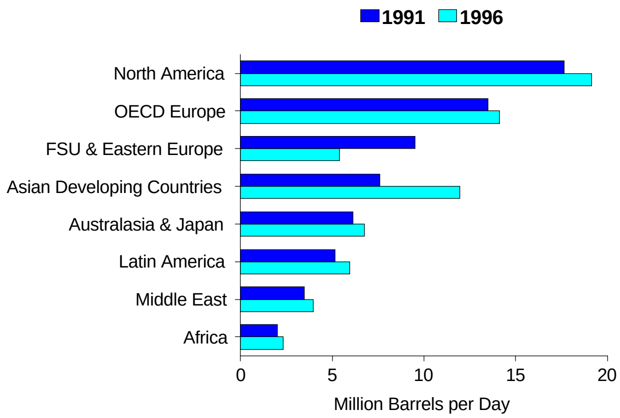
Figure 23. Foreign Refining Margins, 1994-1996



Note: Refining margin is defined as netback crude oil price less spot crude oil price. Netback price is calculated by multiplying the spot price of each refined product by its percentage share in the yield of a barrel of crude oil. Transport and out-of-pocket refining costs are then subtracted to arrive at netback price.

Sources: **1995:** *Petroleum Market Intelligence,* Vol. 9, No. 12, (January 4, 1996), p. 8; **1994:** *Petroleum Market Intelligence* Vol. 8, No. 12 (January 5, 1995), p 8; **1993:** *Petroleum Market Intelligence,* Vol. 7, No. 12 (January 6, 1994), p. 8.

Figure 24. Petroleum Consumption by Region, 1991 and 1996



Source: British Petroleum, *BP Statistical Review of World Energy 1997,* p. 10.

an area realizing a significant increase in the consumption of petroleum products between 1991 and 1996 was the developing countries of Asia (for example, China and Malaysia), where consumption increased an average of 11 percent over the period. With so little growth in petroleum consumption worldwide other than in the developing countries of Asia, the foreign downstream strategies of the FRS companies for the mature industrial regions are to consolidate and refocus operations through reducing costs or increasing value.

Examples of FRS consolidation and refocusing are numerous. Amoco recently announced that it will exit the Polish retailing market by selling its outlets to Texaco.[104] Exxon has announced that it will merge its refinery in Karlsruhe, Germany, with an adjacent refinery of Oberrheinische Mineraloelwerke GmbH (also known as OMW).[105] Mobil and British Petroleum completed much of their reorganization subsequent to their agreement to merge their European refining, marketing, and lubricants businesses.[106] As much as 90 percent (in terms of revenues) of the merger has been accomplished.[107]

Additionally, Mobil has noted that it is focusing on growth (in Asia, Latin America, and Africa) and efficiency and selective growth (in mature markets).[108] Texaco is expanding in the Baltic countries through its Scandinavian affiliate and has constructed three retail outlets in Poland.[109] Additionally, Texaco's and Chevron's Caltex joint venture sold its 50-percent interest in a major Japanese refinery, completed construction of a refinery in Thailand (64 percent ownership), and is expanding its retailing operations in Korea and the Philippines and its lubricants business in China, India, Indonesia, and Vietnam.[110]

Transportation

Natural Gas Pipelines Benefit from Higher Volumes

Most of the FRS companies are involved in liquids pipelines operations, while three companies' (Coastal, Enron, and Occidental) pipeline investments are in natural gas transmission. Nevertheless, natural gas pipeline revenues exceeded liquids pipelines revenues.

In 1996, FRS companies involved with operations in natural gas pipelines realized a 10-percent gain in overall revenue (Table 28) following a decline for two consecutive years. Revenues rebounded due mainly to higher transportation revenues, an improvement which reflected adjustment to Order 636. The FERC Order 636, first issued in April 1992, required pipelines to separate their previously bundled services, mainly gas sales, transportation, and storage, and offer these services separately.[111] The sale of natural gas to local distribution companies and end-users has shifted to producers and nonregulated marketing companies, including interstate pipeline company affiliates.[112] Interstate natural gas pipelines now provide primarily gas transportation and storage services to resellers of natural gas. The decline in 1994 coincided with the first full year that interstate natural gas pipelines operated under Federal Energy Regulatory Commission (FERC) Order 636. As FRS companies unbundled services during 1994 and 1995, revenue also declined, reflecting a further drop in sales volumes.[113]

Overall transportation revenue, which accounts for 71 percent of overall natural gas pipeline revenue, rose 8 percent as a result of higher transportation volumes in part traceable to imports of Canadian natural gas.[114] In 1996, Canada exported 2,883 billion cubic feet (Bcf) of natural gas into the United States, an amount which represented 13 percent of U.S. natural gas consumption. This level was a slight decline from the previous year's record (2,816 Bcf) that was nearly 10 percent above the 1994 level.[115] Canadian imports come through four regional areas of the United States: the Pacific Northwest, the West, the Midwest, and the Northeast.[116] Coastal's largest transporter of natural gas, ANR, operates in the midwestern region. Other FRS companies' natural gas pipelines also operate in the midwestern region as well as in California.[117]

Operating income declined 10 percent as higher operating expenses outpaced revenue growth (Table 28). Overall operating expenses of the FRS companies' natural gas pipelines increased as these companies started up new projects. The deregulation of the natural gas industry has provided incentives for interstate natural gas companies to build new pipelines, expansions, and extensions to relieve capacity constraints as well as gain entrance into new markets, particularly in the midwestern and eastern regions. Coastal's subsidiary, ANR, began the operation of the ANR Link that allows the company to operate in the Canadian market. The ANR Link connects the companies' existing pipeline in Michigan to an interconnection at the United States-Canada international boundary on the St. Clair River. It has an initial capacity of 150,000 cfp / d.[118] Occidental's subsidiary, MidCon, owner of the Natural Gas Pipeline Company of America, began the operation of the Fandango Pipeline. The pipeline transports 290,000 cf / pd from southern Texas to the Houston market.[119]

Overall capital expenditures for natural gas pipelines rose 42 percent between 1995 and 1996 (Table 28). The FRS companies' expenditures in 1996 focused on efforts to improve capacity in the Midwest as well as gain access to offshore projects through the development of new pipelines. For example, Enron reported a 45-percent increase in capital expenditures, up from $129 million.[120] Projects in 1996 noted by the companies included:

Enron

Enron's two subsidiaries increased gas supplies both on the West Coast and in midwestern markets. Northern Pipeline completed two expansion projects in 1996. One project added capacity in the Minnesota market and the other project increased capacity on its pipeline system in Iowa, Illinois, and Wisconsin.[121] Transwestern Pipeline expanded its San Juan lateral pipeline system to transport additional gas supplies from the San Juan Basin, New Mexico, to Texas and the midwestern markets.[122] Transwestern also purchased pipeline and compression facilities at La Plata, Colorado, which will give the company direct access to additional gas supplies in the San Juan Basin.[123]

Coastal

Coastal's subsidiary, Colorado Interstate Gas (CIG), began the expansion of its pipeline system in Wyoming. The Wind River Lateral project will accommodate the increased production of gas from the Wind River Basin,

Table 28. Financial Items for Transportation for FRS Companies, 1995-1996
(Million Dollars)

Financial Items	1995	1996	Percent Change 1995-1996
Natural Gas Pipelines[a]			
Revenues	5,322	5,870	10.3
Operating Expenses[b]	4,495	5,124	14.0
Operating Income[b]	827	746	-9.8
Additions to Investment in Place[c]	425	603	41.9
Liquids Pipelines[d]			
Revenues	4,535	3,790	-16.4
Operating Expenses[b]	2,445	2,291	-6.3
Operating Income[b]	2,090	1,532	-26.7
Additions to Investment in Place[c]	557	753	35.2
International Marine			
Revenues	2,150	2,263	5.3
Operating Expenses[b]	2,182	2,215	1.5
Operating Income[b]	-32	48	--
Additions to Investment in Place[c]	276	74	-73.2

[a]Data are for FRS companies with pipeline assets primarily in natural gas transmission.
[b]Excludes unusual items.
[c]Measured by additions to property, plant, and equipment, plus additions to investments and advances of all FRS companies.
[d]Data are for FRS companies with pipeline assets primarily in liquids pipelines.
-- = Not meaningful.
Source: Energy Information Administration, Form EIA-28, "Financial Reporting System."

Wyoming.[124] In September 1996, CIG completed the Parachute Creek Lateral project. The 37-mile pipeline connects to CIG's pipeline system and has an initial capacity of 37,000 cfp / d.[125] Wyoming Interstate Company, Coastal's affiliate, announced the expansion of its pipeline segment of the 800-mile Trailblazer Pipeline System to the eastern region. The project is expected to be completed in August 1997 and will increase capacity by an additional 193,000 cfp / d.[126]

Occidental Petroleum

Occidental's natural gas pipeline subsidiary, MidCon, completed and began the operation of its interconnector pipeline system in Chicago. The new facility connects the pipeline systems of MidCon and NIPSCO Industries and provides the companies with additional access to the Chicago and midwestern markets.[127]

The FRS companies' natural gas pipeline assets should grow in 1997 as the companies continue to increase pipeline capacity in the midwestern and eastern markets. (See the box entitled "Future Natural Gas Pipeline Projects.") Beyond the United States, all three companies indicate new opportunities in marketing and trading through LNG exports, particularly in the Far East. In addition, with the deregulation of the electricity industry, FRS companies can participate in this new market, possibly through mergers / partnerships.

Crude Oil Pipelines Income Declines with Tariff Rates and Throughput Volumes

The FRS companies' income from liquids pipelines declined 27 percent (Table 28) as tariff rates and throughput volumes in Alaska fell. In 1996, seven FRS companies jointly owned the Trans Alaskan Pipeline system (TAPS),[128] making its operations vital to the overall financial performance of FRS company liquids pipelines' operations. The TAPS transports crude oil and condensate from the Alaskan North Slope (ANS) to the port of Valdez, Alaska. In 1996, ANS production accounted for

Future Natural Gas Pipeline Projects

Enron. An Enron affiliate and a subsidiary both are pursing opportunities to expand capacity in the midwestern markets. Enron's affiliate, Northern Border Pipeline, and partners received preliminary approval from FERC for the expansion of Northern Border's main line from the Canadian border to Harper, Iowa. The company plans to build a pipeline from its existing main line in Harper, Iowa, to a point near Manhattan, Illinois. In addition, subject to FERC's approval of the Manhattan, Illinois, expansion, the company plans to construct another pipeline extension to transport gas directly to a major natural gas transmission and distribution company in the Chicago area. The estimated cost of the total expansion is estimated at $837 million, with operations to begin in November 1998, pending FERC approval.[a] An Enron subsidiary, Northern Natural Gas Company, sought FERC approval for a five-year expansion project, Peak Day 2000, to increase transportation services in the Midwest. The expansion will increase capacity by an additional 350,000 cf/pd in the Midwest.

Coastal. Coastal's subsidiary, ANR Pipeline, sought FERC approval for construction of a loop project, Michigan Leg South, to reduce capacity constraints in the Midwest. The project is expected to be completed in 1997 and will increase capacity by 135,000 cfp/d. In September 1997, CIG, Coastal's subsidiary, sought approval to construct Campo Lateral, a 115 mile pipeline, to combine the company's two existing pipelines located in Colorado. Campo Lateral will allow the company access to transport gas from the Raton Basin, Colorado.

Occidental Petroleum. MidCon received preliminary approval from FERC in August 1996 to expand its pipeline system between Chicago, Illinois, and Harper, Iowa (a proposal similar to Enron's expansion operations in the Midwest). The new facilities will provide for an additional 500,000 cfp/d of Canadian natural gas supplies. In addition, MidCon received permission from FERC and the Mexican Energy Regulatory Commission to develop a natural gas pipeline to transport gas into Mexico from Texas. The 100-mile natural gas pipeline will be constructed between the United States-Mexican border and Monterrey, Mexico.

[a]Enron Corporation, *1996 Annual Report*, pp. 8 and 38. Enron Corporation, 1996 Securities and Exchange Commisssion Form 10-K, p. 49. Occidental Petroleum Corporation, *1996 Annual Report* on Form 10-K , p. 10.
[b]Enron Corporation, 1996 Securities and Exchange Commisssion Form 10-K, p. 3.
[c]Coastal Corporation, *1996 Annual Report*, p. 17.
[d]Coastal's CIG Announces Southern Colorado Expansion, *PRNewswire*, p. 1.
[e]Occidental Petroleum Corporation, *1996 Annual Report on Form 10-K*, pp. 7 and 10.
[e]Occidental Petroleum Corporation, *1996 Annual Report*, pp. 16 and 17.

almost 20 percent of the United States' oil production. Prudhoe Bay is the largest oil field in the United States and accounts for the majority of TAPS throughput. Of the seven companies with an investment in TAPS, three companies (ARCO, BP America, and Exxon) account for 92 percent ownership of TAPS. These three companies accounted for 46 percent of the FRS companies' overall revenue from liquids pipelines in 1996.

The combined pipeline income of ARCO, BP America, and Exxon declined 66 percent compared to the income received during the prior year, due mainly to lower tariff rates received by TAPS operators and a reduction in throughput volumes.[129] Tariff rates declined 94 cents per barrel compared to the rates during the prior year, to $2.77 per barrel.[130] Throughput volumes dropped almost 6 percent, to 1.4 million barrels per day (bp/d) in 1996 from 1.5 million b/d in 1995. The decline in volumes reflects the continued drop in ANS production.[131]

The TAPS companies were able to reduce costs in 1996, but not by enough to offset lower volumes and lower tariffs. Cost-cutting features that have been implemented by the TAPS operator, Alyeska Pipeline Service Company, since 1991 include consolidation of field support services, reduction in maintenance shutdowns and repairs, prevention of pipeline corrosion,[132] and the decommission of two TAPS pump stations.[133] In an effort to further reduce operating costs, the TAPS operator restructured operations in Alaska. The company reduced personnel by 21 percent and announced the closure of two additional TAPS pump stations. Even with these cutbacks, TAPS will still have the needed capacity to transport ANS production.[134]

Other liquids pipelines companies registered modest declines in revenues and costs. On balance, operating income from pipelines for this group was down 4 percent.

Capital expenditures for all FRS liquids pipelines increased 35 percent, primarily due to expenditures by Shell. In 1996, Shell built four new crude oil pipelines in the Gulf of Mexico to gain access to its exploration and development operations.[135] In 1996, Amoco built a crude oil gathering pipeline system in the Gulf of Mexico and a liquefied petroleum gas pipeline system from Texas to Juarez, Mexico.[136] In addition, the company signed an agreement to purchase a Texaco pipeline system to transport crude oil supplies to its North Dakota refinery. Amoco also signed a joint venture with Conoco to construct a crude oil pipeline from Billings, Montana, to Elk Basin, Wyoming, to increase the capacity of Canadian crude oil that could be transported to Salt Lake City and Denver.[137] The pipeline was completed in 1997.[138] The increase in capital expenditures followed a sizable increase in capital expenditures in 1995. Expenditures in 1995 increased 72 percent compared to those in 1994, mostly due to ARCO's and Phillips Petroleum's expenditures on the new crude oil pipeline system, Seaway Pipeline Company. In 1996, Seaway Pipeline was converted from a natural gas pipeline system to a transporter of crude oil. Operations on the pipeline system began in 1996 and the pipeline has a capacity to transport 800,000 barrels per day.[139] The system operates from the U.S. Gulf Coast to Cushing, Oklahoma, and is the second largest crude oil system in the Lower 48.[140] The companies plan to convert a portion of the pipeline system to transport refined products. The completion date is scheduled for 1998.[141]

International Marine Benefits from Rise in Freight Rates

The financial performance of FRS companies' international marine operations improved in 1996. Overall revenue increased 5 percent compared to revenues in 1995 (Table 28). The gain in revenue was due almost entirely to a rise in freight rates. The average freight rate was $1.33 per barrel in 1996, up from $1.14 in 1995, and was the highest rate since 1973, with the exception of the 1990-91 freight rates.[142] During the Persian Gulf War of late 1990-early 1991, very large crude carriers (VLCCs) were used for floating storage and long-haul carriers of crude from the Middle East.[143] Freight rates in 1996 rose mainly as a result of higher transportation demand and a decline in surplus tonnage. Overall surplus tonnage declined 57 percent compared to tonnage in 1995 and was at its lowest level since 1974. There was no surplus tonnage for VLCCs, an occurrence that has not existed since the early 1970s.[144] Tankers sailing from the Middle East continued to decline, reflecting increased oil production from the North Sea and other non-OPEC producers and the continued effects of the United Nations' embargo imposed on Iraq in 1990 due to the invasion of Kuwait. However, after six years of international sanctions, Iraqi crude oil returned to international markets under the United Nations Resolution 986 in December 1996.[145]

The FRS companies reported income of $48 million from international marine operations in 1996 compared to losses of $32 million in 1995, reflecting the higher freight rates in 1996. Despite the sharp rise in income, capital expenditures declined 73 percent. However, capital expenditures in the prior year were especially high due to the purchase of two double-hull tankers in 1995 by Chevron.[146] In 1996, the company announced it would lease and operate two new double-hull tankers that are scheduled to be delivered in late 1998 and early 1999. Chevron operates the largest fleet among the majors and currently operates 12 double-hull tankers.[147] Mobil purchased a double-hull tanker in 1996[148] and purchased another double-hull tanker in 1997 to replace a phased-out 25-year-old single-hull tanker in December 1997.[149] The company has three double-hull tankers in service and has placed orders to purchase two additional tankers.[150]

Although ARCO does not report earnings in the international marine segment, the company transports some of its Alaska crude oil via tankers to West Coast markets. ARCO announced in 1997 its intentions to purchase two double-hull tankers to replace three phased-out 25-year-old tankers in 1998. These tankers will be ARCO's first double-hull tankers in the fleet and will transport Alaskan crude oil to West Coast markets. By the year 2000, five more of ARCO's eight crude tankers that are used to transport Alaskan crude oil to the West Coast will be 25 years old.[151]

The Oil Pollution Act of 1990 (OPA)was probably the most important legislation since the 1980's for the operation of the international marine industry. The OPA was enacted by Congress mainly in response to the Exxon Valdez spillage of almost 11 million gallons of oil in Prince William Sound, Alaska, in March of 1989. The requirements imposed by the OPA have had an impact on tanker operations in United States coastal waters as well as on the financial responsibilities required of tanker owners. At year end 1994, international marine operators were required to comply with two additional rules imposed by the OPA. (See the box entitled "The Oil Pollution Act of 1990.") With these new financial costs and liability statutes, some companies have decided not to continue in the international marine business. In 1996, Coastal discontinued its operations and now charters tankers to transport its crude.[152] In 1995, Texaco exited the marine business.[153] Amoco sold the remainder of its tankers to Norway's Bona shipping and charters three international marine tankers to reduce its liability risk.[154] Shell discontinued the transport of crude oil into U.S. waters, and decided to transport oil overseas.[155] The company combined the activities of its two companies, Shell International Trading Company and Shell International Shipping Company, into a single company.[156] BP chartered three new tankers to replace its aging fleet, recanting on an earlier decision to purchase the vessels.[157] Conversely, both Mobil and Chevron continued their international marine operations. The companies cited similar reasons for the commitment to own and operate their own vessels, in particular, the ability to avoid transportation risks, ensure cost-effective crude supplies, and maintain control over crude supplies.[158] Mobil and Chevron have made commitments to purchase additional double-hull tankers in the future in order to maintain high safety standards in international marine operations. Also, in 1997, ARCO's subsidiary, ARCO Marine, reconsidered its decision to exit marine operations.[159] However, the company merged their operations with ARCO Products Company in Los Angeles, California, and will provide additional transportation services to the chemical, coal, and international units.[160]

The Oil Pollution Act of 1990

The enactment of the Oil Pollution Act of 1990 (OPA) requires that all newly-built tankers sailing in United States' waters must have double-hulls by 1994 and bans all single-hull tankers from U.S. coastal waters by 2010. The Act also requires shippers plying United States' waters to present evidence that they have in place credible oil spill response programs. In addition, the maximum limit on oil-spill liability at the Federal level and the unlimited liabilities the States can seek went into effect on December 28, 1994.[a] Under the OPA, the tanker owner entering United States waters must possess a "Certificate of Financial Responsibility" which shows evidence of financial responsibility at a rate 10 times that of their prior rate, or a rate of $1,500 per gross register ton compared to $150 a ton in the past.[b]

[a]U.S. Department of Energy, *Transporting U.S. Oil Imports: The Impact of Oil Spill Legislation on the Tanker Market*, DOE/EP/79095t-H1 (Washington, DC, June 1992), p. 91.

[b]"Threat of Disruption in Oil Supply is Eased," *The New York Times* (December 22, 1994), p. D3.

Endnotes

[77] Gains and charges recognized in a company's income statement that are of a non-recurring nature and generally unrelated to current operations. See Endnote 7 in Chapter 2 of this report for more explanation.

[78] During the first quarter of 1996, the number of heating degree days were almost 6 percent greater than during the first quarter of 1995. Additionally, this trend continued over the entire year as the number of heating degree days was almost 5 percent higher during 1996 than during 1995 (Energy Information Administration, *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997), Table 1-8).

[79] Energy Information Administration, *Annual Energy Review*, 1996, DOE/EIA-0384(96) (Washington, DC, July 1997), Table 8.3.

[80] Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(97/10) (Washington, DC, October 1997).

[81] Energy Information Administration, *The Impact of Environmental Compliance Costs on U.S. Refining Profitability* (October 1997), http://www.eia.doe.gov/emeu/perfpro/ref_pi/keyfind.html.

[82] CARB's guidelines for RFG are stricter than those of the Environmental Protection Agency; consequently one may expect that refiners of motor gasoline for California will have higher production costs than other refiners. Close examination of the financial disclosures of these companies indicated that their opinions concerning the reason for the cost increase was compliance with Federal and State (California) mandated clean-burning gasoline (ARCO, *1996 Annual Report*, p. 21; and Chevron Corporation, *1996 Securities and Exchange Commission Form 10-K*, p. 2). Additionally, the annual report of Tosco Corporation was consulted because of Tosco's purchase of Unocal domestic downstream assets.

[83] Unocal also made such investments, but made no mention of them in its annual report, probably because they agreed in principle to sell their downstream operations to Tosco in late 1996. See Tosco Corporation, *1996 Annual Report*, p. 5.

[84] ARCO, *1996 Annual Report*, p. 15; Chevron Corporation, *1996 Annual Report*, p. 18; Shell Oil Company, *1996 Annual Report*, p. 41; Texaco, Inc., *1996 Annual Report*, p. 38; and Tosco Corporation, *1996 Annual Report*, p. 12.

[85] Energy Information Administration, *Annual Energy Outlook 1997*, http://www.eia.doe.gov/oiaf/aeo97/legreg.html (November 17, 1997).

[86] Energy Information Administration, *Performance Profiles of Major Energy Producers 1994*, http://www.eia.doe.gov/emeu/perfpro/pp94/ch4p1.html (November 17, 1997).

[87] ARCO, *1996 Annual Report*, p. 15.

[88] Shell Oil Company, *1996 Annual Report*, p. 70.

[89] The percentage of FRS gasoline outlets that have convenience stores increased from 27 percent in 1992 to 32 percent in 1995 for all companies with downstream operations. (See Energy Information Administration, *Performance Profiles of Major Energy Producers 1995*, DOE/EIA-0206(95) (Washington, DC, February 1997), pp. 43-44.) However, some of the companies failed to provide information to the *National Petroleum News* in time to be included in the survey of 1996 operations. For those companies providing information in both 1995 and 1996, the percentage of branded retail operations that are convenience stores fell by 1 percent during 1996. (See Kate Kenny and Don Smith, "Fast food drives search for incremental profits," *National Petroleum News*, Volume 89, Number 11 (October 1997), pp. S10-S19 and S26-S53.)

[90] See Energy Information Administration, *Performance Profiles of Major Energy Producers 1995*, DOE/EIA-0206(95) (Washington, DC, February 1997), p. 44.

[91] The number and types of innovations being introduced in gasoline pumps alone are numerous. See, for example, Angel Abcede, "Pump technology expands potential for sales, convenience," *National Petroleum News*, Volume 89, Number 9 (August 1997), pp. 30-38.

[92] Non-gasoline convenience store revenues are not directly collected from the FRS companies, but revenue from non-gasoline sales is collected. The category "other refining and marketing revenue" was originally intended to measure revenue from sales of tires, batteries, and accessories at traditional gasoline stations. It now tends to capture convenience store non-gasoline sales revenue with an occasional unusual item (e.g., a favorable legal judgement) included. Although not all company-operated retail outlets have convenience store formats, many do.

[93] In fact, the last time that the number of FRS company-operated stations increased was 1990, when the number of FRS company-operated outlets peaked at 11,177 and ended a 9-year expansion of company-operated outlets by FRS companies.

[94] Dealer outlets include both lessee dealers and open dealers. A lessee dealer leases the station and the property on which it is located and has use of the storage tanks, pumps, and other fixtures of the property. Lessee dealers have supply contracts with the FRS company and are directly supplied by the FRS company, or one of its affiliate or subsidiary companies. Lessee dealers pay dealer tankwagon prices for products it sells. Open dealers either own the station and property or lease them from a third party (i.e., someone other than the FRS company whose brand the open dealer displays). Open dealers buy petroleum products from the FRS company, one of its affiliates or subsidiaries, or from a wholesaler at prices below dealer tankwagon prices. See the Glossary of this report for more information.

[95] The companies indicating that European downstream markets were extremely competitive included Exxon, which said, "... competitive market conditions...depressed earnings," (Exxon Corporation, *1996 Annual Report*, http://www.exxon.com/exxon_corp/shareholder_info/annual_refining.html (November 17, 1997)) and Mobil, which said, "... mature markets like Japan and Australia where competitive pressures have intensified..." (Mobile Corporation, *1996 Annual Report*, http://www.mobil.com/this/financial/annual_report/opportunity.html (November 17, 1997)). See also Texaco Incorporated, *1996 Annual Report*, http://www.texaco.com/compinfo/1996ar/market.htm (November 17, 1997).

[96] As of 1995, approximately 10 percent of FRS European refining capacity was operated by unconsolidated affiliates. However, 45 percent of Asian capacity was operated by unconsolidated affiliates. See "Worldwide Refining Survey," *Oil and Gas Journal*, Volume 93, Number 51 (December 18, 1995), pp. 47-90, and company financial disclosures.

[97] FRS foreign refining and marketing earnings from unconsolidated affiliates increased 13 percent between 1995 and 1996. See Table B5 of this report and Energy Information Administration, *Performance Profiles of Major Energy Producers 1995*, DOE/EIA-0206(95) (Washington, DC, February 1997), Table B5.

[98] Forty percent of all FRS foreign refining capacity (and 52 percent of all consolidated foreign refining capacity) was located in Europe during 1995. See "Worldwide Refining Survey," *Oil and Gas Journal*, Volume 93, Number 51 (December 18, 1995), pp. 47-90; and company financial disclosures.

[99] FRS operating income from consolidated foreign refining and marketing operations fell 23 percent between 1995 and 1996. See Table B5 of this report and Energy Information Administration, *Performance Profiles of Major Energy Producers 1995*, DOE/EIA-0206(95) (Washington, DC, February 1997), Table B5.

[100] North America includes only Canada and the United States in this instance. Mexico is included in the category "Latin America."

[101] Australasia includes Australia and New Zealand.

[102] Mexico is included in the category "Latin America," and not in the category "North America" in this instance.

[103] For example, Texaco recently constructed its first three retail outlets in Poland and purchased Amoco's retailing network. See Texaco Incorporated, *1996 Annual Report*, http://www.texaco.com/compinfo/1996ar/market.htm (November 17, 1997) and "Amoco Spins off Central European Gasoline Stations," *Octane Week* (August 12, 1997).

[104] "Amoco Spins off Central European Gasoline Stations," *Octane Week* (August 12, 1997).

[105] Exxon Corporation, *1996 Annual Report*, http://www.exxon.com/exxoncorp/shareholder_info/annual_96/annual_refining.html (November 17, 1997).

[106] An overview of this merger was discussed in last year's report in the section entitled "A New Wave of Joint Ventures." See Energy Information Administration, *Performance Profiles of Major Energy Producers 1995*, DOE/EIA-0206(95) (Washington, DC, February 1997), p. 39.

[107] Although the alliance covers operations in 43 countries, formal agreements have been implemented in only 17 countries, yet this accounts for about 90 percent of the revenues from pre-alliance operations. See Mobil Corporation, http://www.mobil.com/world/europe/mobeurope.html (November 19, 1997).

[108] Mobil Corporation, *1996 Annual Report*, http://www.mobil.com/this/financial/annualreport/share_letter.html (November 17, 1997). Exxon noted similar intents in its *1996 Annual Report*, substituting eastern Europe for Africa and saying that it would "restrict refining investment in low growth areas." See Exxon Corporation, 1996 *Annual Report*, http://www.exxon.com/exxoncorp/shareholder_info/annual_96/annual_refining.html (November 17, 1997).

[109] Texaco Incorporated, *1996 Annual Report*, http://www.texaco.com/compinfo/1996ar/market.htm (November 17, 1997).

[110] Texaco Incorporated, *1996 Annual Report*, http://www.texaco.com/compinfo/1996ar/market.htm (November 17, 1997).

[111] The FERC believed that prior to Order 636, transportation services offered to non-sales customers were inferior to those services offered to customers who purchased gas, transportation, and storage from the same company. FERC Order Number 636, p. 31.

[112] "Beyond 2000: A Pipeline Odyssey," *Oil and Gas Investor* (June 1996), pp. 36-41.

[113] The Order also established a secondary market that allowed customers the option to sell their excess firm gas transportation capacity on a temporary basis, or relinquish their capacity when their contracts expired. Source: "Beyond 2000: A Pipeline Odyssey," *Oil and Gas Investor* (June 1996), pp. 36 - 41. Firm gas is defined as gas sold on a continuous basis and is generally on a long-term contract. Conversely, interruptible gas is gas sold to customers with a provision that permits the curtailment or cessation of service at the discretion of the distributing company. Source: Energy Information Administration, *Glossary of Energy and Energy-Related Terms and Definition, Second Edition*, DOE/EIA-0537(95) (Washington DC, May 1995), pp. 58 and 80.

[114] Enron Corporation, *1996 Annual Report*, p. 25, Coastal Corporation, *1996 Annual Report*, p. 23, and Occidental Corporation, *1996 Annual Report*, p. 23.

[115] Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(97/09) (Washington, DC, September 1997), Table 4.3.

[116] "Canada Supplies U.S. Record 2.8 tcf of Gas in 1995," *Oil and Gas Journal* (February 3, 1997), p. 24.

[117] One of Coastal's two wholly owned interstate pipelines, ANR, operates in the midwestern markets. The other pipeline, Colorado Interstate Gas, operates in the Rocky Mountain area. Coastal's five pipeline affiliates operate in various markets of the country and income from these companies are reported in " other income-net": Great Lakes Gas Transmission (50 percent ownership interest) in the midwestern and eastern Canada markets; Empire State Pipeline (50 percent ownership interest) in New York; High Island Offshore System (40 percent interest) and U-T Offshore System (33.75 percent ownership interest) both in the Gulf Coast; and Iroquois Gas Transmission System (16 percent ownership interest) in the northeastern market. Three of Enron's four interstate pipelines and affiliates, Transwestern Pipeline, Northern Natural Pipeline, and Northern Border Pipeline (13 percent ownership interest) operate in the saturated areas of California and in the Midwest area. Enron' other pipeline affiliate, Florida Gas Transmission (50 percent ownership interest) operates in the Florida peninsular and is the only pipeline that services this area. Occidental's subsidiary, Minion, owns Natural Gas Pipeline Company (NGPC). The NGPC operates in the Midwest area.

[118] Coastal Corporation, *1996 Annual Report*, pp. 16 and 17.

[119] Occidental Petroleum Corporation, *1996 Annual Report*, p. 16.

[120] Enron Corporation, 1996 *Securities and Exchange Commission Form 10-K*, p. 49.

[121] Enron Corporation, *1996 Annual Report*, p. 8.

[122] Enron Corporation, 1996 *Securities and Securities Commission Form 10-K*, p. 4.

[123] Enron Corporation, 1996 *Securities and Exchange Commission Form 10-K*, p. 4.

[124] Coastal Corporation, *Securities and Exchange Commission Form 10-K*, p. 6.

[125] Coastal Corporation, *1996 Annual Report*, pp. 16 and 17.

[126] Coastal Corporation, *Securities and Exchange Commission Form 10-K*, p. 6.

[127] Occidental Petroleum Corporation, *1996 Annual Report*, p. 16. Occidental Petroleum Corporation, *1996 Annual Report* on Form 10-K, p. 10.

[128] The following FRS companies together own 100 percent of the Trans Alaska Pipeline: Amerada Hess Corporation, Atlantic Richfield Corporation, BP America, Exxon Corporation, Mobil Corporation, Phillips Petroleum Company, and Unocal Corporation. However, of these seven ARCO, BP America, and Exxon account for 92 percent of TAPS ownership. Source: *Energy Alert* (April 3, 1992).

[129] Atlantic Richfield Company, *1996 Securities and Exchange Commission Form 10-K*, p. 30. Tariff rates based on weighted average tariff received by ARCO Transportation Alaska, BP America, Exxon and Mobil. Source: ARCO Transportation Alaska, Inc., *Historical Tariffs* (September 27, 1996), p. 1.

[130] ARCO Transportation Alaska, Inc., *Historical Tariffs* (September 27, 1996), p. 1.

[131] For a further discussion of the decline in the ANS production, see "The Survival of ANS Production" in Energy Information Administration, *Performance Profiles of Major Energy Producers 1995*, EIA/DOE-0206(95) (Washington, DC, February 1997), p. 49; and "Sustaining the Prudhoe Bay Field" in Energy Information Administration, *Performance Profiles of Major Energy Producers 1994*, EIA/DOE-0206(94) (Washington, DC, February 1996), p. 45.

[132] "North Slope producers. See Alaska Renaissance as TAPS Reaches 20," *Oil and Gas Journal* (June 16, 1997), pp. 22 - 26, and Atlantic Richfield Company, *1996 Securities and Exchange Commission Form 10-K*, p. 33.

[133] "Taps Reduced Flow to Reflect N. Slope Decline," *Oil and Gas Journal* (June 10, 1996), p. 30.

[134] "Alyeska to Close Two More TAPS Pump Stations," *Oil and Gas Journal* (May 5, 1997), p. 54.

[135] Shell Oil Company, *1996 Securities and Exchange Commission Form 10-K*, p. 14

[136] Amoco Corporation, *1996 Securities and Exchange Commission Form 10-K,* p. 13.

[137] Amoco Corporation, *1995 Securities and Exchange Commission Form 10-K,* p. 15.

[138] Amoco Corporation, *1996 Securities and Exchange Commission Form 10-K,* p. 13.

[139] Phillips Petroleum Corporation, *1996 Securities and Exchange Commission Form 10-K,* p. 15.

[140] Atlantic Richfield Company, *1995 Annual Report*, pp. 8 and 15; and Phillips Corporation, *1995 Securities and Exchange Commission Form 10-K*, pp. 13 and 14.

[141] Phillips Petroleum Corporation, *1996 Securities and Exchange Commission Form 10-K,* p. 15.

[142] Cambridge Energy Research Associates, *World Oil Trends*, 1997 Edition (Cambridge, MA, 1997), Table 36.

[143] Crude from the Middle East replaced Iraqi crude production

[144] Cambridge Energy Research Associates, *World Oil Trends*, 1997 Edition (Cambridge, MA, 1997), p. 81.

[145] The number of barrels of crude oil shipped per day is based on the Brent crude price in December 1996. "Focus-Iraq Eases Back into Oil Market," *Reuters Financial Service* (December 16, 1997), section: Money Report.

[146] Chevron Corporation, *1996 Supplement to the Chevron Corporation Annual Report*, p. 40.

[147] Chevron Corporation, *1996 Securities and Exchange Commission Form 10-K*, p. 21.

[148] "Double-Hull VLCCS Joins Fleet," *Oil and Gas Journal*, Vol. 94 (August 5, 1996), p. 36.

[149] "Mobil Christens Double-Hull Product Tanker," *Reuters*, (September 10, 1997), p. 1.

[150] "Mobil to Buy First Ship Built in US Yard that Meets OPA 90 Rules," *Business Times* (February 4, 1997), p. 1.

[151] "ARCO Marine designs Double-Hull Tankers to Carry Alaska Crude Oil," *Alaska Journal of Commerce* (January 6, 1997); and "Oil Companies Don't Deserve Praise," *The Seattle Times* (August 29, 1997), p. B5.

[152] Coastal Corporation, *Correspondence Letter* (November 11, 1997), p. 1.

[153] *The Oil Daily* (May 19, 1995), p. 1.

[154] Amoco Corporation, *1995 Securities and Exchange Commission Form 10-K*, p. 15.

[155] "A Legacy of Confusion," *1995 Asset Finance & Leasing Digest*, No. 219 (August 1995), pp. 24-27.

[156] Royal Dutch Shell Petroleum Company, *1995 Annual Report*, pp. 18 & 26.

[157] *Petroleum Intelligence Weekly* (November 6, 1995), p. 2.

[158] *Petroleum Intelligence Weekly* (November 6, 1995), p. 2; and *The Washington Post* (June 23, 1996), p. H1.

[159] "ARCO Marine designs Double-Hull Tankers to Carry Alaska Crude Oil," *Alaska Journal of Commerce* (January 6, 1997); and "Oil Companies Don't Deserve Praise," *The Seattle Times* (August 29, 1997), p. B5.

[160] "ARCO Marine designs Double-Hull Tankers to Carry Alaska Crude Oil," *Alaska Journal of Commerce* (January 6, 1997); and "Oil Companies Don't Deserve Praise," *The Seattle Times* (August 29, 1997), p. B5.

5. Coal and Alternative Energy

Coal

Domestic Coal Prices Decline Substantially Relative to Natural Gas

Domestic coal consumption jumped 5 percent in 1996, the largest annual increase since 1988.[161] In both years, the increase was accounted for mostly by increased coal consumption by the electric power industry.[162] In 1996, the increased burning of coal by electric utilities was not caused by an unusual increase in the amount of electricity produced as in 1988, but largely by a 27-percent decline in the price of coal delivered to U.S. electric utilities relative to the price of natural gas. The nominal price of coal delivered to electric utilities declined only 2 percent in 1996.[163] The decline in the price of coal continues a long-term trend. The price of bituminous coal and lignite in the United States, adjusted for inflation, has declined 64 percent since 1975.

Indications of the commitment of the FRS companies to domestic coal production were mixed in 1996. Production increased slightly, reversing four years of decline (Table 29). However, 1996 FRS domestic production was still only 59 percent of its high in 1991, in large part because six of the FRS companies completely exited the industry between 1989 and 1994.[164] Domestic coal reserves continued their long-term decline in 1996. At year-end, FRS reserves were down to 25 percent of their 1991 level. The decline in reserves occurred in all three coal-producing regions, but predominantly in the Midwest. Larger declines in Midwestern coal reserves are consistent with the declining sulfur content of coal consumed by electric utilities[165] (the major consumer of coal in the United States) and the relatively high sulfur content of much of the coal found in the Midwest.[166] For example, in 1996 Exxon ceased operating the Monterey No. 2 mine, which produced high-sulfur coal in Illinois.[167]

Worldwide revenues from coal sales by the FRS companies increased slightly in 1996 (Table 29). However, depreciation, depletion, and amortization (DD&A) expenses declined notably, largely because of a change in accounting standards implemented by many of the FRS companies in 1995. Financial Accounting Standard 121 (FAS 121) resulted in large writeoffs of assets for the FRS companies in 1995, when the companies that were significantly affected by the standard adopted it.[168] Since these writeoffs flow through the DD&A account, it was

Table 29. Coal Financial and Operating Indicators for the FRS Companies, 1995-1996
(Million Dollars)

Financial and Operating Indicators	1995	1996	Percent Change 1995-1996
Coal Financial Indicators			
Coal Revenues	3,508	3,524	0.5
General Operating Expenses (excluding taxes)	2,415	2,550	5.6
Coal Production Taxes	157	139	-11.5
Depreciation, Depletion, and Amortization	498	388	-22.1
General and Administrative	97	96	-1.0
Operating Income	341	351	2.9
Operating Income (excluding unusual items)[a]	561	354	-36.9
	(million tons)		
Coal Operating Indicators			
Coal Production	165	169	2.4
Coal Reserves	10,493	9,542	-9.1

[a]Unusual items totaled $220 million (pretax) in charges in 1995 and $3 million (pretax) in charges in 1996.
Sources: Energy Information Administration, Form EIA-28, “Financial Reporting System.”

unusually large in 1995, setting the stage for a large decline in DD&A in 1996, when FAS 121 had no significant effect on FRS companies' financial statements.

Excluding the effects of unusual items, which were almost entirely due to FAS 121 in 1995, operating income from the FRS companies' worldwide coal operations was down 37 percent between 1995 and 1996. This result reflects a 6-percent increase in general operating expenses (excluding taxes) which was not offset by revenues, which were hampered by lower coal prices and a slight 2-percent increase in production in the United States.

Other U.S. coal producers also registered lower income from coal production in 1996. For 12 non-FRS coal producers, accounting for 36 percent of U.S. production, operating income from coal operations, excluding unusual items,[169] was $654 million in 1996, down 5 percent from income in 1995.[170]

Other Energy

Revenues Reach a Record High

The FRS companies' financial performance in other energy businesses reached new highs in 1996. Revenues, at $2.4 billion, were at their highest level over the 1974 through 1996 period of FRS data collection and 70 percent above 1995 revenues (Table 30). Operating income also reached a new peak in 1996. Income has steadily grown from other energy activities in the 1990's, about doubling from 1990 to 1996. Prior to 1990, the other energy businesses of the FRS companies yielded 16 consecutive years of operating losses.

Other energy investments by FRS companies are in cogeneration and electric power generation, tar sands, geothermal, and reformulated fuels.[171] Four companies—Enron, ARCO, Coastal, and Texaco—were principally responsible for the FRS companies' investment in cogeneration and electric power generation facilities. Exxon accounts for FRS investments in oil production from Canadian tar sands. Unocal accounted primarily for the FRS companies' investment in geothermal production, while Kerr-McGee is involved in reformulated fuels.

Overall revenue from other energy operations increased 70 percent compared to those in 1995 (Table 30). Revenue and income benefited from the start-up of new independent power plants and positive operating results in tar sands operations, cogeneration,[172] and electric power generation.

The Asia-Pacific region is the fastest growing region for the development of electric power generation, and FRS companies have significant investments in these countries. The demand for electricity in Asia is projected to increase 5.2 percent annually between 1995 and 2015, with China having the largest growth projection.[173] Coastal began operations at two power plants in China and one in El Salvador (Table 31). The company reported a $44.2-million increase in revenue due primarily to operations at its El Salvador power plant that came on line in 1995. Equity income from partially-owned power plant investments also increased by $4 million.[174] Enron began operations at its new power plant in the Dominican Republic (Table 31).[175] The company also benefited from promotional activities at the Teesside cogeneration plant in the United Kingdom. Exxon has a long history in electric power operations, although the company does not report operations in the other energy segment. In 1996,

Table 30. Revenues, Income, and Investment in Other Energy for FRS Companies, 1995-1996
(Million Dollars)

Item	1995	1996	Percent Change 1995-1996
Revenues and Expenses			
Revenues	1,408	2,391	69.8
Operating Expenses[a]	1,214	2,085	71.7
Operating Income[a]	194	306	57.7
Additions to Investment in Place[b]			
United States	59	205	247.5
Foreign	327	351	7.3
Total	386	556	44.0

[a]Excludes unusual items, which were net pretax charges of $56 million in 1995 and $20 million in 1996.
[b]Additions to net property, plant, and equipment and advances to unconsolidated subsidiaries.
Source: Energy Information Administration, Form EIA-28, "Financial Reporting System."

Table 31. FRS Companies' Foreign Other Energy Projects in 1996

Company	Projects	Status in 1996
Enron Corporation	154-megawatt diesel/gas combined cycle power plant in Hainan Island, China[a]	Construction completed in 1/96
	First phase (826 megawatt) of the 2,450-megawatt gas-fired power plant in Dahbol, India[b]	Construction of phase I resumed in 12/96 with operation to began in 12/98
	185-megawatt barge-mounted combined cycle power plant in the Dominican Republic[c]	Operation began in 1/96
	551-megawatt combined-cycle oil gasification power plant on the island of Sardinia, Italy[d]	Construction in progress with operation expected in 2000
	478-megawatt gas-fired power plant in Marmara, Turkey[d]	Construction in progress with operation expected in 1999
	507-megawatt combined cycle power plant, and a liquefied natural gas terminal in Penuelas, Pureto Rico[d]	Construction will began in 1997
	500-megawatt gas-fired combined-cycle power plant in East Java, Indonesia[d]	Financial arrangements will be completed in 1997
	85-megawatt diesel power plant in Piti, Guam[e]	Construction began in 1997
Exxon Corporation	Four of the eight gas-fired power plants in Hong Kong (total capacity of 2,500-megawatts) [j]	Operation began in 1996
Coastal Corporation	140-megawatt combined cycle, natural gas-fired plant in Quetta, Pakistan[f]	Construction in progress with operation expected in late 1997
	53-megawatt expansion of the plant in Nejapa, El Salvador[g]	Operation in the second quarter of 1996
	24-megawatt heat recovery expansion at an existing 76-megawatt diesel-fired capacity power plant in Nanjing, China.[g]	Construction in progress with operation expected in the second quarter of 1997
	40-megawatt diesel-fired power plant in Wuxi City, China[g]	Operation began in first quarter of 1996
	40-megawatt expansion of the existing power plant in Wuxi City, China[g]	Operation expected in 1997
	76-megawatt power facility in Suzhou City, China[g]	Operation began in the fourth quarter of 1996
	24-megawatt cogeneration plant adjacent to Coastal's existing 76-megawatt power facility in Suzhou City, China[g]	Construction in progress with operation expected in 1998
	15-percent interest in a 60-90 megawatt, natural gas-fired cogeneration project in Bangchak, Thailand[h]	Purchased in 1996
Unocal Corporation	Three 55-megawatt electric power plants at the Salak field on the island of Java, Indonesia[i]	Construction in progress with operation expected in 1997

[a]Enron Corporation, *1996 Securities and Exchange Commission 10-K,* p. 12.

[b]Enron signed a Power Purchase Agreement on December 8, 1993, with the State of Maharashtra Electricity Board, India, to construct both phase I and II of a 2015 megawatt gas-fired power plant and related facilities, including a liquefied natural gas terminal. In March 1995, the company began the construction of phase I. However, almost 6 months later, construction came to a halt after a new governing coalition was elected in the State of Maharashtra. After months of negotiations, a preliminary agreement in February 1996 was reached between Dabhol Power Company (Enron's 80-percent owned subsidiary), the State government, and the Maharashtra State Electricity Board to go forward with an expanded project. However, phase I will now be built with a capacity of 826 megawatts and will burn naptha/ distillate as fuel instead of natural gas, which will be fueled by imported liquefied natural gas. The plant has the expansion capacity of 2,450 megawatts. Source: Enron Corporation, *1996 Securities and Exchange Commission Form 10-K*, p.11, and Enron Corporation, *1996 Securities and Exchange Commission Form 10-K*, p. 12.

[c]Enron Corporation, *1996 Securities and Exchange Commission Form 10-K*, p. 10.

[d]Enron Corporation, *1996 Securities and Exchange Commission Form 10-K*, p. 12.

[e]Enron Corporation, *1996 Securities and Exchange Commission Form 10-K*, pp. 12-13.

[f]Coastal Corporation, *1996 Annual Report*, p. 29.

[g]Coastal Corporation, *1996 Securities and Exchange Commission Form 10-K*, p. 19.

[h]Coastal Corporation, *1996 Annual Report*, p. 29.

[i]Unocal Company, *1996 Annual Report*, p. 27; and Unocal Company, *1995 Annual Report*, p. 12.

[j]Exxon Corporation, *1996 Annual Report*, p. 19.

Exxon began the operation of four gas-fired power plants that had a total capacity of 2,500-megawatts in Hong Kong.[176]

In 1996, Exxon's tar sands operations realized higher oil prices, although oil production from Syncrude Canada was slightly down, to 200,000 barrels per day (bp / d) compared to the record volume of 202,000 bp / d in 1995.[177] Conversely, Unocal reported a decline in revenue (excluding the $28-million gain from the sale of geothermal assets)[178] due to a contract dispute between its subsidiary, Philippine Geothermal, and the Philippine National Power Corporation. The decline in earnings was partially offset by increased steam generation from The Geysers plant in Northern California and the new expansion of the electric generation power plant in the Philippines.[179]

Operating expenses (excluding unusual items), were up 72 percent due primarily to new investments in international power generation plants by Coastal and Enron (Table 30 and Table 31). Coastal began operations in El Salvador and in China.[180] Enron began operations in the Dominican Republic.[181] Unocal also reported an increase in operating expenses due mostly to higher exploration expenses in Indonesia.[182] Nevertheless, revenue gains in other energy far outweighed operating expense increases, yielding a 58-percent increase in operating income, excluding unusual items.

Investment Commitments Continue to Grow

Overall capital expenditures increased 44 percent compared to expenses in 1995 (Table 30). Segmentally, investments in domestic operations were responsible for the increase, as growth in foreign investments slowed following an 85-percent increase in 1995. Domestic expenditures more than quadrupled due to Enron's $250-million investment in its limited partnership, Joint Energy Development Investments (JEDI) that was formed in 1993. The JEDI acquires and owns energy investments.[183] Foreign expenditures increased 7 percent due to the numerous power plant operations under construction in the Asia-Pacific region and in Latin America by Coastal, Enron, and Exxon (Table 31). In addition, Unocal's expenditures for geothermal development more than doubled, up from $51 million in 1995[184] due primarily to geothermal energy projects on two islands, Java and Sumatra, in Indonesia.[185] Unocal also secured financing for a 165-megawatt geothermal power plant on Java. The company will be responsible for the construction and operation of the plant and the development of geothermal resources.[186] Exxon's subsidiary, Imperial Oil Limited, completed its $175-million drilling expansion at its bitumen fields in Cold Lake in Alberta, Canada.[187]

Future projects in other energy disclosed by FRS companies include:

- **Exxon**. Exxon and its partners signed a memorandum of understanding (MOU) to develop a 1,050-megawatt gas-fired power facility in Shezhen, China. The company has also signed an MOU to develop, own, and operate other power projects in China.[188]

- **Coastal**. In 1996, Coastal announced its intentions to purchase a 46-percent interest in a 120-megawatt, coal-fired power plant in Puerto Quetzal, Guatemala. In addition, Coastal was selected by the Indian Aluminum Company to negotiate a power purchase agreement to construct and operate a 100-megawatt naphtha-fired power plant in Karnataka, India.[189] In 1997, Coastal completed negotiations to construct and operate a 114-megawatt capacity heavy-fuel oil power plant in Farouqabad, Pakistan. Operations are expected to began in late 1997.[190]

- **Enron**. Enron announced it intends to build a 500-megawatt gas-fired power plant in Jakarta, Indonesia, with construction to start in late 1997.[191]

- **Phillips Petroleum**. Phillips announced plans to build a cogeneration facility at each of its refinery plants with a completion date in 1998. The electricity and steam generated by the plants will be used at the facilities to lower operating expenses.[192]

Endnotes

[161] Energy Information Administration, *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997), Table 7.1.

[162] Energy Information Administration, *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997), Table 7.3.

[163] Energy Information Administration, *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997), Tables 6.9 and 7.8.

[164] Energy Information Administration, *Performance Profiles of Major Energy Producers 1994*, DOE/EIA-0206(94) (Washington, DC, February 1996), p. 54.

[165] Energy Information Administration, *Coal Data: A Reference*, DOE/EIA-0064(93) (Washington, DC, February 1995), p. 20.

[166] Energy Information Administration, *U.S. Coal Reserves: A Review and Update*, DOE/EIA-0529(95) (Washington, DC, August 1996), p. vii.

[167] Exxon Corporation, *1996 Annual Report*, p. 19.

[168] For further information about Standard 121, see Energy Information Administration, "New Accounting Standard Leads to Billions in Asset Writeoffs," *Performance Profiles of Major Energy Producers 1995*, DOE/EIA-0206(95) (Washington, DC, February 1997), p. 6.

[169] Unusual items are gains and charges recognized in a company's income statement that are of a nonrecurring nature and generally unrelated to current operations. See Endnote 7 in Chapter 2 of this report for more explanation.

[170] Compiled from information presented in *EPR Annual Review*, 1997 Report on Independent Petroleum and Coal Companies (Gaithersburg, MD, 1997), pp. 60, 72.

[171] Solar power earnings were not reported due to the joint venture between Amoco Corporation and Enron Corporation in January 1995. (Amoco Corporation, *1995 Securities and Exchange Commission Form 10-K*, p. 18). In addition to Texaco's investments in cogeneration, the company also has a patent on coal gasification. In 1996, Tampa Electricity Company in Florida began a 250-megawatt coal-based plant using Texaco gasification technology (Texaco Corporation, *1996 Annual Report*, p. 22).

[172] Cogeneration is the joint production of steam and electricity from a single fuel source.

[173] Energy Information Administration, *International Energy Outlook 1996 with Projections to 2015*, DOE/EIA-0484(97)(Washington, DC, April 1997), Table A8.

[174] Coastal Corporation, *1996 Annual Report*, p. 41.

[175] Enron Corporation, *1996 Securities and Exchange Commission Form 10-K*, p. 38.

[176] Exxon Corporation, *1996 Annual Report*, p. 19.

[177] Exxon Corporation, *1996 Securities and Exchange Commission Form 10-K*, p. 6; and Exxon Corporation, *1995 Annual Report*, p. 11.

[178] Unocal sold 80 percent of its interest in the subsidiary, NEC Acquisition Company, that owns a 25 percent interest in geothermal energy at The Geysers in Northern California (Unocal Corporation, *1996 Annual Report*, p.21).

[179] Unocal Corporation, *1996 Annual Report*, p. 20.

[180] Coastal Corporation, *1996 Annual Report*, pp. 11 and 12; and Coastal Corporation, *1996 Securities and Exchange Commission Form 10-K*, pp. 18 and 19.

[181] Enron Corporation, *1996 Securities and Exchange Commission Form 10-K*, pp. 11 and 12.

[182] Unocal Corporation, *1996 Annual Report*, p. 20.

[183] Enron Corporation, *1996 Annual Report*, p. 48.

[184] Unocal Corporation, *1996 Annual Report*, p. 20.

[185] Unocal Corporation, *1996 Annual Report*, p. 22.

[186] Unocal Corporation, *1996 Annual Report*, p. 15.

[187] Exxon Corporation, *1996 Securities and Exchange Commission 10-K*, p. 6; and Exxon Corporation, *Financial and Operating Review*, http://www.exxon.com/essoncorp/current%5Fnews/fo%Fupstream16.htm/ (December 17, 1997).

[188] Exxon Corporation, *1996 Annual Report*, p. 19.

[189] Coastal Corporation, *1996 Annual Report*, p. 29.

[190] Coastal Corporation, *1996 Securities and Exchange Commission, 10-K*, p. 20.

[191] Enron Corporation, *1996 Securities and Exchange Commission 10-K*, p. 12.

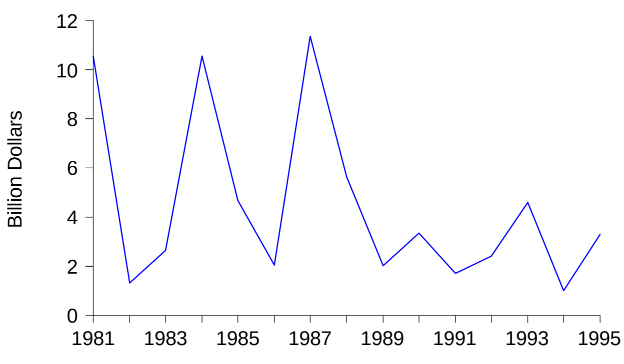
[192] Phillips Petroleum Corporation, *1996 Annual Report*, p. 21.

6. Foreign Direct Investment in U.S. Energy

Foreign Acquisitions and Divestitures of U.S. Energy Assets

Despite lackluster profitability, foreign direct investment in U.S. energy rose in 1995. In 1995,[193] acquisitions that affected the foreign direct investment position ("FDI-related" acquisitions) in U.S. petroleum and coal totaled $3.3 billion, up considerably from the previous year's level of $1.0 billion (Figure 25 and Table 32). This increase was largely the result of a few large transactions. Upstream, the acquisition of a large independent petroleum company by a recently-privatized Argentinean petroleum company accounted for most of the increase. (See the box entitled "Major FDI-Related Transactions in U.S. Energy 1995.") Downstream, there were two major transactions involving Canadian companies. In downstream petroleum, Clark USA, a wholly-owned subsidiary of Canada's Horsham Corp, purchased a major refinery from Chevron. In downstream natural gas, a Canadian natural gas transmission and service company purchased a U.S. natural gas transportation company, a reflection of the growing integration of the Canadian and U.S. natural gas markets.

Figure 25. Value of FDI-Related Acquisitions in U.S. Energy, 1981-1995



Source: Value of FDI-related acquisitions: Table A1, A2, and A3 in the Appendix of this report and Tables A1, A2, and A3 from previous editions of this report. Change in FDI: calculated as annual change in FDI position, based on latest consistent set of revisions, appearing in the August issues (1985-1996) of U.S. Department of Commerce, Bureau of Economic Analysis, Survey of Current Business.

A single divestiture, however, far outweighed the acquisitions. In 1995, Canada's Seagram Corporation sold its shares in E.I. de Nemours DuPont and Company (DuPont) back to DuPont in one of the largest stock repurchases on record. DuPont is the largest chemical company in the United States and owner of a major-U.S. integrated petroleum company, Conoco. About 39 percent of DuPont's fixed assets are allocated to petroleum.[194] Seagrams, in turn, used the dollars raised from the sale of DuPont to buy MCA Inc., a U.S. entertainment firm.

Additions to foreign direct investment in U.S. petroleum increased to $2.5 billion in 1995 and accounted for 6 percent of total foreign direct investment (Table 33).

Although FDI-related petroleum expenditures have risen over the past two years, FDI spending on non-petroleum assets has grown at a far faster rate. For most of the past decade, petroleum's share of total foreign direct investment dollars has fallen consistently from its peak in 1984 at 15 percent.

Domestic coal mining activities have for several years been a growing target of foreign direct investment in U.S. energy. However, in 1995, there were virtually no major acquisitions involving coal assets. Coal divestitures in 1995 totaled $110 million.

Increase in Foreign Ownership of Oil and Gas Dwarfed by 8-billion Dollar Sale

Seagrams Sells Stake in DuPont

The largest FDI-related transaction in 1995 involved the $8.8-billion sale by Canadian-held Seagram Corporation of their stake in DuPont. DuPont is the largest U.S. chemical manufacturer and owner of the major vertically-integrated petroleum company, Conoco. In 1981, in a bidding contest with the Seagram Corporation, DuPont acquired ownership of Conoco, whose assets included oil and gas production operations, refining and marketing operations, along with coal production. At the end of the process, Seagram acquired a 23-percent stake in DuPont, thus making DuPont a foreign-affiliated U.S. energy company.

Table 32. Value of FDI-Related Transactions in U.S. Energy, 1990-1995
(Million Dollars)

Acquisitions/Divestitures	1990	1991	1992	1993	1994	1995
Acquisitions						
Oil and Gas Production[a]	901	1,043	949	1,246	329	2,937
Petroleum Refining, Marketing and Transport	1,040	103	173	1,264	0	339
Coal	1,416	570	1,276	1,928	674	0
Other Energy	0	0	0	150	0	0
Total Acquisitions	3,357	1,716	2,398	4,588	1,013	3,276
Divestitures						
Oil and Gas Production[a]	474	736	461	938	663	866
Petroleum Refining, Marketing, and Transport	59	400	60	822	41	0
Coal[b]	841	155	869	438	768	110
Total Divestitures	1,374	1,291	1,390	2,198	1,472	976

[a]Includes drilling and drilling services.

[b]1990 includes Newmont Mining's sale of its 55-percent interest in Peabody Holding Company for $726 million, while 1992 includes Shell Oil's divestiture of its coal operations for $850 million.

Note: Divestitures do not include DuPont's $ 8.8 billion stock buyback.

Sources: **1995**: Based on Tables C1 and C2 in Appendix C. **1994**: Tables C1 and C2 in Energy Information Administration, *Performance Profiles of Major Energy Producers 1995*, DOE/EIA-0206(95) (Washington, DC, February 1997). **1993**: Based on Tables A1, A2, and A3 in Energy Information Administration, *Profiles of Foreign Direct Investment 1993*, DOE/EIA-0466(93) (Washington, DC, May 1995). **1992**: Based on Tables A1 and A2 in Energy Information Administration, *Profiles of Foreign Direct Investment in U.S. Energy 1992*, DOE/EIA-0466(92) (Washington, DC, May 1994). **1991**: Based on Tables A1 and A2 in Energy Information Administration, *Profiles of Foreign Direct Investment in U.S. Energy 1991*, DOE/EIA-0466(91) (Washington, DC, April 1993). **1990**: Based on Tables A1 and A2 in Energy Information Administration, *Profiles of Foreign Direct Investment in U.S. Energy 1990*, DOE/EIA-0466(90) (Washington, DC, April 1992).

The removal of DuPont's Conoco from the ranks of foreign-affiliated companies had a sizable effect on foreign affiliates' role in U.S. petroleum. Conoco ranked third among foreign-affiliated companies in oil and gas production and fourth in both refining and marketing. Since Conoco's U.S. coal production assets are jointly held with the German company Rheinbraun AG, the assets remained classified as foreign-affiliated.

YPF's Purchase of Maxus

In 1995, Yacimientos Petroliferos Fiscales (YPF), Argentina's largest petroleum company, acquired U.S.- based Maxus Energy Corp. YPF was until recently Argentina's state-owned and -operated national oil company. The earlier privatization of YPF in 1993 represented just one episode in the widespread energy (and non-energy) sector privatization that has occurred in Latin America in recent years. YPF is today the world's 13th largest publicly traded integrated oil company.[195] With its acquisition of U.S.-based Maxus, YPF entered the ranks of the major multinational petroleum companies. Maxus is a relatively large independent crude oil exploration and production company, with operations in the United States, Asia, and Latin America. Although YPF announced its takeover of Maxus in 1994, the transaction was concluded in June of 1995, for $1.8 billion, including cash and the assumption of $1 billion in liabilities. The purchase of Maxus represents the first major entry of Latin American petroleum companies into North American upstream operations. Venezuela's state-owned company, Petroleos de Venezuela (PDVSA), and Mexico's state-owned Pemex are the other Latin American countries with substantial investments in U.S. petroleum operations, although most of their assets are in refining and marketing. (See the box entitled "Latin America's Growing Role in U.S. Petroleum.")

Other Transactions

The second-largest, FDI-related upstream acquisition involved the merger of Blue Dolphin (which is in part German-held) and U.S.-based Petroport. The value of this transaction totaled $500 million. Blue Dolphin is a relatively small independent oil and gas producer. Blue Dolphin's purchase of Petroport is related to Petroport's planned development of a deepwater port in Freeport, Texas. As Latin American producers have gained an increasing share of U.S. oil imports, the need for greater Gulf of Mexico offshore port facilities has grown.

Table 33. Foreign Direct Investment in U.S. Petroleum and Coal, 1980-1995
(Billion Dollars)

	Foreign Direct Investment in U.S. Petroleum[a,b]	Foreign Direct Investment in U.S. Coal[a]	Total Foreign Direct Investment in the U.S.[a]	Petroleum as a Percent of Total	Coal as a Percent of Total
1980	12.2	0.5	83.0	14.7	0.6
1981	15.2	1.1	108.7	14.0	1.0
1982	17.7	1.2	124.7	14.2	1.0
1983	18.2	1.3	137.1	13.3	0.9
1984	25.4	2.6	164.6	15.4	1.6
1985	28.3	2.9	184.6	15.3	1.6
1986	29.1	3.5	220.4	13.2	1.6
1987	37.8	3.3	263.4	14.4	1.3
1988	36.0	5.3	314.8	11.4	1.7
1989	40.3	0.9	368.9	10.9	0.2
1990	42.9	0.8	394.9	10.9	0.2
1991	40.1	1.4	419.1	9.6	0.3
1992	37.6	1.1	427.6	8.8	0.3
1993	32.1	0.9	466.7	7.0	0.2
1994	33.1	0.6	502.4	6.6	0.1
1995	35.6	0.6	560.1	6.4	0.1

[a]Foreign direct investment (FDI) is the value of foreign parents' net equity in, and outstanding loans to, affiliates in the United States at the end of the year.

[b]The petroleum industry includes all phases of oil and gas exploration and production, petroleum refining, petroleum transport, and petroleum marketing.

Sources: **1993-1995**: U.S. Department of Commerce, Bureau of Economic Analysis, *Survey of Current Business* (Washington, DC, September 1996). **1991-1992**: U.S. Department of Commerce, Bureau of Economic Analysis, *Survey of Current Business* (Washington, DC, August 1995). **1987-1990**: U.S. Department of Commerce, Bureau of Economic Analysis, *Survey of Current Business* (Washington, DC, August 1993). **1985-1986**: U.S. Department of Commerce, Bureau of Economic Analysis, *Survey of Current Business* (Washington, DC, August 1990). **1981-1984**: U.S. Department of Commerce, Bureau of Economic Analysis, *Survey of Current Business* (Washington, DC, August 1986). **1980**: U.S. Department of Commerce, Bureau of Economic Analysis, *Survey of Current Business* (Washington, DC, October 1984).

There were a number of relatively small acquisitions in U.S. oil and gas production assets in 1995. The largest of these was Louis Dreyfus Natural Gas Corp.'s purchase of working oil and gas properties in Texas for $90 million from American Exploration. The second largest oil and gas transaction involved Forcenergy AB of Sweden, which paid $31 million to acquire producing properties in the Gulf of Mexico. All other FDI-related acquisitions involving oil and gas properties were under $30 million.

Compared to the DuPont stock buyback, other divestitures of crude oil and natural gas properties were relatively small in 1995. The largest purely upstream divestiture involved the sale of Hadson Corp., which was partly held by the Canadian-affiliated company Santa Fe Resources for $143 million to Louisiana Gas and Electric. Consol Coal Group, which is 50-percent owned by Rheinbraun AG, sold reserves of coalbed methane gas and assorted gathering lines to MCN Corp. for $83 million.

Kuwaiti-owned Santa Fe International largely exited the U.S. oil and gas business in 1995 although a portion of their U.S. assets were purchased by Canadian companies. As a consequence, the net impact on the FDI position of a portion of these transactions was nil. State-owned Kuwait Petroleum Corporation acquired Santa Fe International for $2.3 billion in 1981.[196] Santa Fe International is involved primarily in construction and, until 1995, oil and gas drilling and production. In 1995, Santa Fe International sold natural gas producing properties, gathering systems, and a gas processing plant to the U.S. company Cross Timbers Oil for $130 million and sold off all of their Gulf of Mexico properties to Chieftain International (a Canadian company) and to a joint venture between the U.S. company Enron Oil and Gas and Canada's Norcen for $110 million. Kuwait Petroleum also sold Santa Fe International's North Sea exploration and production unit for $1.2 billion in 1995.

Major FDI-Related Transactions in U.S. Energy 1995

Acquisitions

Argentina's YPF SA finalized its $1.8-billion takeover of Texas-based Maxus Energy Corp in June, in a merger consisting of cash and a billion dollars in assumed liabilities.

Blue Dolphin Energy, which is in part owned by UK and Norwegian interests, completed a merger valued at $500 million with Petroport L.L.C., holder of proprietary technology for offshore deepwater crude oil and products port facilities. The financial package included cash and contingent stock considerations.

Toronto-based Horsham's Clark Refining & Marketing unit acquired Chevron's Port Arthur refinery and related terminal facilities for $195 million in cash, with liabilities and contingent payments amounting to an additional $144 million.

For $167 million, Trident NGL Holdings signed a merger agreement with Natural Gas Clearinghouse and became part of NGC Corp., which is 25.7-percent owned by Canada's Nova Corp and 25.6 percent owned by British Gas.

Tejas Power Corp., 23-percent owned by Gaz de France, acquired 19 pipeline/gas-gathering systems located in the Gulf of Mexico for $155 million in cash from a group led by Seagull Energy Corp.

Divestitures

Hadson Corp, 41-percent owned by Canadian affiliated Santa Fe Resources, was acquired by LG&E Energy Corp for a reported sum of $143 million.

Santa Fe Minerals Inc.,a wholly owned entity of Kuwait Petroleum Corp., sold certain gas-producing properties, which also included a processing plant and gas-gathering system, to Cross Timbers Oil Co. for $130 million and sold their Gulf of Mexico properties to a joint venture between Enron Oil and Gas and Norcen and to Canada's Chieftain International for a total of $110 million.

MCN Corp. paid $120 million to CONSOL Coal Group, a joint venture 50-percent owned by Germany's Rheinbraun AG for interests in oil and gas acreage and reserves in mostly coalbed methane gas wells.

Germany's Saarbergwerke received proceeds of $110 million from the sale of 150 shares of its Ashland Coal convertible preferred stock holdings. Ashland Inc., the buyer, increased its equity position in Ashland Coal to 54 percent from 39 percent.

There were some notable mid-stream acquisitions in 1995 which highlight several recent trends evident in the natural gas industry, such as the integration of Canadian and U.S. natural gas markets, the natural gas industry's increased vertical integration, and the growing integration of U.S. natural gas and electricity markets. Reflecting the importance of gas marketing and the growing integration of the U.S. and Canadian natural gas markets, Natural Gas Clearinghouse (NGC), a U.S.-based gas marketer (whose owners include Canada's Nova Corp and British Gas), purchased Ozark Gas Transmission System for $45 million.

The largest oil and gas acquisition in 1994 also involved Canada's Nova Corp and NGC. Nova purchased an interest in Natural Gas Clearinghouse, the largest independent gas marketing company in the United States. Gas marketing has become increasingly important, along with the services of natural gas brokers and providers of various transportation services, following implementation of the Federal Energy Regulatory Commission (FERC) Order 636, which required an unbundling of various natural gas pipeline services, which, in turn, encouraged the growth of a natural gas marketing industry. According to a recent EIA report on natural gas, "Today marketing companies play a significant role in the aggregating of supplies and in the selling of services that had previously been provided by pipeline companies."[197] This has been due largely to the deregulation of the U.S. natural gas industry and the growing integration of U.S.

Latin America's Growing Role in U.S. Petroleum

Over the last decade, the national petroleum companies of Venezuela and Mexico have made substantial commitments to U.S. petroleum. Most recently, Argentina's former national petroleum company (which was only recently privatized) has also invested heavily in U.S. petroleum operations.

Since first entering the U.S. refined product market in 1986, Venezuela's state petroleum company, Petroleos de Venezuela, S.A. (PDVSA), has increased its asset base in the United States to over $6 billion. Through its U.S. subsidiaries, PDVSA accounts for roughly 5 percent of U.S. refinery capacity and 7 percent of U.S. retail gasoline outlets. In 1995, PDV America, PDVSA's U.S. affiliate, was the sixth largest U.S. petroleum refiner and the second largest foreign-held refiner after Shell Oil Company.

PDVSA's U.S. operations consist of one wholly-owned subsidiary (CITGO) and two affiliates (UNO-VEN, and Lyondell-CITGO). The UNO-VEN Company is a 50/50 joint venture between PDV America and Unocal. CITGO also carries a ten percent interest in a 265,000 b/d refinery jointly held with the ARCO subsidiary, Lyondell.

CITGO owns and operates four refineries in the United States, with a total distillation capacity of 503,000 b/d and markets gasoline and lubricants through more than 13,000 U.S. outlets—the largest number of branded gasoline stations served by an individual company. UNO-VEN, a downstream joint venture created in 1989 by PDVSA and Unocal, refines petroleum products in one jointly-owned refinery and markets gasoline and other products to consumers. UNO-VEN supplies approximately 2,700 "76" branded outlets[i] in sixteen states, chiefly in the midwest.

Neither CITGO nor UNO-VEN owns any U.S. crude oil reserves. Instead, both rely on crude oil purchases to supply their refineries. CITGO has long-term contracts with PDVSA and one-year renewable contracts with Petroleos Mexicanos (PEMEX), the state-oil company of Mexico, both of which produce heavy, sour crude oil. The contract with PDVSA serves as an outlet for Venezuelan crude oils.

PEMEX's U.S. operation consists of a joint venture with Shell Oil. Similar to PDVSA's U.S. investments, part of PEMEX's motivation lay in its attempt to find a secure outlet for its crude oil. In 1992, PEMEX and Shell agreed to form a joint refining venture involving Shell's 225,000 b/d refinery in Deer Park, Texas. The aggrement called for the refinery to process 100,000 b/d of Mayan crude and to provide PEMEX with 45,000 b/d of gasoline.

In contrast to PDVSA's and PEMEX's U.S. petroleum investments, Yacimientos Petroleferos Fiscales' (YPF, the recently privatized national petroleum company of Argentina) foray into U.S. petroleum was an upstream venture. In 1995, YPF purchased Maxus, a large independent producer of crude oil and natural gas, with operations in Indonesia and Latin America as well as the United States.

and Canadian natural gas markets. Over the past ten years, imports of natural gas from Canada have grown 376 percent and, in 1995, U.S. imports of Canadian natural gas accounted for 13 percent of U.S. consumption. In 1995, Canada directed one-half of its natural gas production to the U.S. market.

In recent years, there have been several notable mergers and acquisitions between electric power producers and natural gas pipeline companies. One such transaction in 1995 also involved NGC Corp. In 1995, NGC Corp. merged with Trident NGL (North America's largest natural gas liquids operator). In addition to further increasing NGC's role in U.S. natural gas transmission and marketing, the merger also represented a foray into electricity markets by NGC Corp through the acquisition of Trident's electricity generation assets. Several other natural gas pipeline and electricity company mergers have taken place. One other midstream acquisition in 1995 involved horizontal integration: Tejas Power purchased a gas gathering system and a related gas processing plant for $155 million which had been jointly owned by Seagull Corp, Amoco Corp, Enron Corp and Panhandle Eastern Corp.

Gulf of Mexico Becomes Investment Focus

For those companies with foreign affiliations during both 1994 and 1995, outlays for exploration and development (E&D) in the United States rose slightly (Table 34). Much of this new investment was for exploring and developing properties in the Gulf of Mexico. Of the eleven companies maintaining FDI status in both 1994 and 1995, nine

Table 34. U.S. Capital and Exploratory Expenditures of Foreign-Affiliated Petroleum and Natural Gas Companies, 1993-1995
(Million Dollars)

Company	Upstream[a]			Company	Downstream[b]		
	1993	1994	1995		1993	1994	1995
Shell Oil	901	1,296	1,642	Shell Oil	704	1,087	1,065
BP America	790	826	875	Lyondell Petrochemical	54	210	505
YPF	NF	NF	647	Citgo Petroleum	345	350	314
DuPont	379	357	NF	Castle Energy	36	218	NF
Anadarko Petroleum	208	352	225	Total Petroleum, Ltd.	234	95	245
Santa Fe Energy Resources	143	107	186	Uno-Ven	206	217	232
Louis Dreyfus Natural Gas	219	109	185	BP America	359	226	210
BHP Petroleum (Americas)	43	67	140	DuPont	213	191	NF
Canadian Occidental	41	47	95	Star Enterprise	147	152	148
Chieftain Development International	21	22	87	Clark USA	68	100	42
Fina	47	64	83	Fina	86	49	42
Norcen Energy Resources	141	43	48	Tesoro Petroleum	7	NF	NF
Presidio Oil	21	35	18				
Coho Energy	24	NF	NF				
Total	**2,978**	**3,325**	**4,231**	**Total**	**2,410**	**2,906**	**2,803**

[a]Oil and gas exploration, development, and production.
[b]Petroleum refining, marketing, and pipelines.
NF = Not foreign-affiliated in the year shown.
Sources: Company annual reports.

reported higher U.S. E&D spending and most cited the Gulf of Mexico as a growing target of investment and production. The Gulf is rapidly becoming the focus of overall U.S. exploration and development activities. The Gulf of Mexico today accounts for 21 percent of U.S. crude oil production and 26 percent of U.S. natural gas production.[198] In contrast to Alaska and the onshore lower-48 States, production from the Gulf of Mexico has risen steadily in recent years and is expected to continue to do so in the future. Since 1990, total additions to U.S. offshore U.S. reserves of crude oil and natural gas have increased by 32 percent, while onshore additions have remained unchanged.[199] In 1995, crude oil production increases from the Gulf of Mexico almost offset production declines from Alaska and the lower 48 States. Furthermore, offshore Gulf of Mexico production is expected to increase at a 1-percent annual rate through the year 2015[200] and is expected to continue to offset declines in Alaskan and onshore lower 48 State production.

Foreign-affiliated companies have been increasingly involved in Gulf of Mexico exploration and development activities. Since 1987, the number of foreign-affiliated producers in the Gulf of Mexico has more than doubled (Table 35). As a consequence, the foreign affiliates' share of crude oil production has risen from 25 percent of total Gulf of Mexico production in 1987 to 35 percent in 1994. Over the same period, however, the foreign affiliates' share of natural gas production declined from 20 percent to 17 percent. This decline was largely the result of Shell Oil's reduced natural gas production. Between 1987 and 1993, Shell's Gulf of Mexico natural gas extensions and discoveries failed to keep pace with production, downward reserve revisions, and reserve sales. In contrast, other foreign affiliates, in total, reported an increase in natural gas production from the Gulf of Mexico between 1987 and 1994.

Shell Oil is the second largest producer of U.S. crude oil among foreign-affiliated companies and fourth largest among all companies. Among all companies, Shell ranked first among offshore U.S. producers[201] and first in exploration and development spending among the foreign-affiliated companies. A large and increasingly greater portion of Shell's U.S. upstream activity has been focused on the Gulf of Mexico. In 1995, Shell reported spending $346 million more than in the prior year for U.S. exploration and development activity after reporting increased spending of $395 million in 1994 (Table 34). Shell reported that these higher levels of expenditures were due to "spending for production drilling and development in the Gulf of Mexico,"[202] and that, " the

Table 35. Foreign Affiliates' Share of Gulf of Mexico Oil and Gas Production, 1987 and 1994
(Percent)

	1987	1994
Crude Oil Production[a,b]		
Number of Foreign-Affiliated Producers	9	21
Foreign Affiliates' Share	25.0	35.0
Natural Gas Production[a,c]		
Number of Foreign-Affiliated Producers	10	21
Foreign Affilates' Share	19.6	17.0
Excluding Shell Oil	7.3	10.4

[a]Operated basis.
[b]Includes condensate.
[c]Includes casing-head gas.
Source: U.S. Department of Interior, Minerals Management Service, *Federal Offshore Statistics: 1987* and *1994* (Herndon, VA.)

higher level of capital spending is expected to continue through the decade as Shell Oil develops the Gulf of Mexico projects."[203]

Part of Shell's success in the Gulf of Mexico was due to the adoption of deep sea drilling technology. In 1994, Shell began production from the Auger platform in the Gulf. The Auger platform, which cost about $1 billion to construct,[204] established a record for water depth in the United States at 2,860 feet.[205] Another Gulf of Mexico prospect, the Mars field, began production in late 1996. It is estimated that the Mars field holds as much as 600 million barrels of crude oil. In order to develop the field, Shell installed an innovative tension leg platform at a depth of 2,933 feet. Shell holds a 71-percent interest in Mars, with BP America, another foreign affiliate, owning the remaining 29 percent.

BP America also reported increased spending in 1995 and pointed to the Gulf of Mexico as an area of future production gains. BP America, which is Shell's partner in a number of major Gulf of Mexico exploration and development projects, is the largest foreign-affiliated producer of crude oil in the United States. Over 80 percent of BP's U.S. oil production, however, comes from Alaska, an area of declining production.

Foreign Investment in U.S. Refining Declines

The largest acquisition of a purely downstream operation in 1995 involved Clark's purchase of Chevron's Port Arthur, Texas, refinery in a transaction valued at $339 million. The Port Arthur purchase more than doubled Clark's refining capacity and made Clark the seventeenth largest U.S. refiner. However, the divestiture of Seagram's ownership of DuPont (which thereby reclassified DuPont's four refineries and 448 thousand barrels- per-day of refining capacity out of the foreign-affiliated group of petroleum companies) more than offset the addition to U.S. capacity of foreign affiliates due to the Clark purchase and resulted in a reduced overall presence for the foreign-affiliated companies involved in U.S. refining. For example, the foreign-affiliated companies' share of U.S. refining capacity fell from 29 percent in 1994 to 27 percent in 1995.

Major Refinery Upgrade Lifts Refining Capital Expenditures

Largely due to higher expenditures by one FDI company, capital expenditures for those foreign-affiliated companies continuing to be involved in U.S. refining rose 12 percent in 1995 (Table 34). Of the nine foreign-affiliated refiners, seven reported reduced downstream capital expenditures in 1995, and one a slight gain. Virtually all of the increase in downstream capital expenditures is traceable to Lyondell Petrochemical. Lyondell's refinery is partially-owned by Petroleos de Venezuela. Lyondell reported downstream capital spending of $505 million in 1995, up from $210 million in 1994 and $54 million in 1993.[206] Lyondell is undergoing a major upgrade of its Houston, Texas, refining operation to process heavy crude oil from Venezuela. The upgrade is expected to be completed in 1997.

Overall Foreign Direct Investment

U.S. Economy More Attractive to Foreign Investment

The FDI position is the cumulative net flow of funds between foreign-affiliated U.S.-based companies and their foreign owners. The U.S. Department of Commerce measures FDI position as the book value of foreign direct investors' equity in and net outstanding loans to their U.S. affiliates. Total additions to the FDI position in all U.S. industries in 1995 were $57.7 billion (Table 36), up from $35.7 billion in 1994. Over the past three years, additions to FDI have grown considerably from a low point of $8.5 billion in 1992, its lowest level since 1972, when poor world economic conditions discouraged such investments.

According to the U.S. Department of Commerce, "... the strong increase in the [FDI] position in 1995, as well as the increase in 1994, reflected a number of factors. Continued economic expansion in a number of major investor countries, such as the United Kingdom, may have increased the ability of parent companies in those countries to make new acquisitions and to contribute additional capital to their existing U.S. affiliates, while reducing the need to draw funds from the affiliates. The continued strength of the U.S. economy enhanced the profit potential of new acquisitions, and the depreciation of the dollar against several European currencies and the Japanese yen reduced the costs of acquisitions in foreign currency terms .... Industry specific factors also contributed to the increase in position. One such factor ... was the world-wide consolidation of the health-care industry, which led to foreign acquisitions of U.S. pharmaceutical and biotechnology companies." [207]

The main U.S. industries targeted by foreign investors in 1995 were pharmaceuticals and chemicals, food and beverages, motion pictures, and banking and finance.

Table 36. Geographic Sources of Foreign Direct Investment in U.S. Industry, 1993-1995
(Billion Dollars)

Region	Foreign Direct Investment Position			Net Additions	
	1993	1994	1995	1994	1995
All Countries	466.7	502.4	560.1	35.7	57.7
Canada	40.5	42.1	46.0	1.6	3.9
Europe					
United Kingdom	103.3	111.1	132.3	7.8	21.2
Netherlands	71.9	68.2	67.7	-3.7	-0.5
Germany	35.1	40.3	47.9	5.2	7.6
France	30.6	34.1	38.2	3.5	4.1
Switzerland	22.3	25.3	33.1	3.0	7.7
Other Europe	24.8	30.4	41.6	5.6	11.3
Latin America[a]					
Netherlands Antilles	7.5	8.3	7.2	0.8	-1.1
Panama	4.1	3.8	4.1	-0.3	0.3
Venezuela	-0.3	-0.3	-0.2	0.0	0.1
Other Latin America	8.5	13.2	11.7	4.7	-1.5
Australia	7.0	7.9	7.8	0.9	-0.1
Other OPEC[b]	3.1	3.2	2.8	0.1	-0.4
Japan	100.3	104.5	108.6	4.2	4.1
Other Countries	5.0	6.9	8.2	1.9	1.3

[a]Latin America includes South America, Central America, and the Caribbean (outside of U.S. possessions and territories).
[b]OPEC is the Organization of Petroleum Exporting Countries. Its members are Algeria, Ecuador, Gabon, Indonesia, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
Note: Sum of components may not equal total due to independent rounding.
Source: U.S. Department of Commerce, Bureau of Economic Analysis, *Survey of Current Business* (Washington, DC, September 1996).

Acquisitions with a value of $1 billion or more by foreign investors in 1995 included:

- **Chemicals and pharmaceuticals.** Hoechst AG of Germany purchased Dow Chemical's 71-percent stake in Marion Merril Dow for $7.1 billion. Ciba-Geigy AG of Switzerland gained a 28-percent share of Chiron Corp. for $1.4 billion.

- **Entertainment.** In the second largest FDI-related acquisition in 1995, Canada's Seagram Co. Ltd. acquired an 80-percent interest in MCA Inc. for $5.7 billion from Japan's Matsushita Electric Industrial Co.

- **Food and beverages**. Grand Metropolitan of the United Kingdom acquired Pet Inc. for $2.6 billion and Cadbury-Schweppes, also of the United Kingdom, acquired Dr. Pepper/Seven Up Companies for $2.4 billion.

- **Banking and Finance**. Germany's Deutsche Bank AG purchased ITT Commercial Finance from ITT Corp. for $2.6 billion and National Australia Bank Ltd. acquired Michigan National, a diversified financial services corporation, for $1.5 billion.

- **Other.** Luxotica Group of Italy, an eyeglass maker, acquired U.S. Shoe Corp., which owns the LensCrafter eyecare chain, for $1.3 billion.

Heightened Gulf Prospects and Refinery Upgrades Draw Investors

The FDI position in petroleum also grew in 1995, to $35.6 billion, 8 percent above the 1994 level. Nevertheless, the FDI position in petroleum still remained below its peak value of $42.9 billion attained in 1990 (Table 33).

The attraction of oil and gas prospects in the Gulf of Mexico and the need for periodic refinery upgrades have been the main factors in the rise in FDI in U.S. petroleum, rather than the recent financial performance of U.S. petroleum operations. Upstream profitability, which crashed following the oil price collapse of late 1985-early 1986, subsequently recovered and attained a post-collapse peak in the context of 1990's oil price run up. Since then, U.S. upstream profitability fell and stabilized at a low level (Figure 4 in Chapter 2). In downstream operations, rates of return in U.S. refining and marketing peaked in the late 1980's following a massive consolidation of industry capacity. In subsequent years, profitability has declined sharply due to a combination of weak growth in petroleum product demand, additional light product capacity, and added operating costs stemming from environmental requirements, particularly those related to the Clean Air Act Amendments of 1990.

Petroleum FDI is largely traceable to investors based in the Netherlands and the United Kingdom. Royal Dutch/Shell is owned largely by investors from the United Kingdom, the United States, and the Netherlands. (See the box entitled "The Historic Role of the European Majors and U.S. Petroleum Companies.") Petroleum FDI from investors in the United Kingdom and the Netherlands has held steady over the past few years. Much of the balance of European-based investment in U.S. petroleum reflects U.S. operations of France's two largest petroleum companies, Elf Aquitaine and Total, along with Belgium's Petrofina. Although Japan and Germany rank second and fifth, respectively, in terms of total FDI in the United States (Table 36), investors from these nations account for only a fraction of a percent of FDI in U.S. petroleum (Table 37).

Canadian investors' interest in U.S. petroleum and natural gas has shown a resurgence in the 1990's. The Canadian share of petroleum-related FDI was 15 percent in 1980 but steadily declined to 3 percent in 1990. By 1995, Canada's share of total FDI in U.S. petroleum had climbed to 8 percent. A number of Canadian policies encouraged Canadians to invest in their own energy resources in the 1980's, apparently at the expense of U.S. energy investments. Policies included the favoring of Canadian ownership of energy resources located in Canada, elimination of most energy price controls, and relaxation of restrictions on the export of Canadian natural gas. However, as the impacts of these measures receded, U.S. petroleum and natural gas became more attractive as targets of Canadian investors.

Latin American investment in U.S. petroleum has grown over the past few years due largely to a flow of funds from PDVSA, PEMEX, and, most recently, YPF. However, the U.S. Department of Commerce data for Latin America as a whole includes transactions originating in such offshore investment havens as the Netherlands Antilles, thus, perhaps, overstating the actual Latin American position in petroleum FDI in the United States.

Foreign-Affiliated Companies' Role in U.S. Energy Operations

Transactions data and information drawn from the U.S. Department of Commerce's international investment surveys are useful in discerning the overall investment targets of foreign investors and the changing emphasis of their interest in U.S. energy. However, these data yield no

Table 37. Geographic Sources of Foreign Direct Investment in U.S. Petroleum, 1993-1995
(Million Dollars)

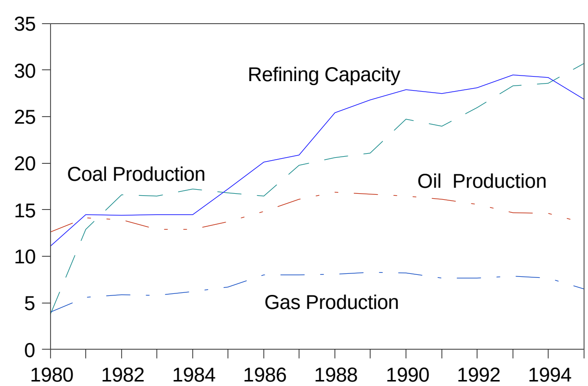
Source	Foreign Direct Investment			Net Additions	
	1993	1994	1995	1994	1995
All Countries	32,057	33,103	35,636	1,046	2,533
Canada	2,331	2,842	2,949	511	107
Europe					
United Kingdom	9,903	10,398	10,398	495	600
Netherlands	12,006	12,019	12,962	13	943
Germany	(b)	79	-65	(b)	-144
Other Europe	2,312	2,478	2,936	166	458
Latin America[a]					
Netherlands Antilles	1,612	1,689	2,061	77	372
Venezuela	(b)	-572	-514	(b)	58
Other Latin America	(b)	54	223	(b)	169
Australia	2,168	(b)	3,280	(b)	(b)
Other OPEC[c]	(b)	1,590	1,244	(b)	-346
Japan	344	97	29	-247	-68
Other Countries	(b)	(b)	-512	(b)	(b)

[a]Latin America includes South America, Central America, and the Caribbean (outside of U.S. possessions and territories).
[b]Data withheld by the U.S. Department of Commerce to prevent disclosure.
[c]OPEC is the Organization of Petroleum Exporting Countries. Its members are Algeria, Ecuador, Gabon, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
Source: U.S. Department of Commerce, Bureau of Economic Analysis, *Survey of Current Business* (Washington, DC, August 1996).

information on the operational role of foreign-affiliated enterprises in U.S. energy activities in 1995 or over time.

In this section, the involvement of foreign-affiliated companies in the areas of upstream and downstream petroleum operations (including natural gas production), coal production, and uranium exploration and development are reviewed. Due largely to the DuPont stock buyback, foreign affiliates' share of U.S. crude oil and natural gas production declined (Figure 26). The same was true of petroleum refining. The foreign affiliates' share of U.S. coal production rose in 1995 largely due to increased production by Peabody, the U.S. coal-producing subsidiary of Hanson PLC of the United Kingdom.

Figure 26. Foreign Affiliates' Share of U.S. Production of Oil, Gas, and Coal, and of U.S. Refining Capacity, 1980-1995



Sources: Tables of this report. U.S. Department of Energy, *Annual Report to Congress*, DOE/S-0010(84) (Washington, DC, September 1984); Energy Information Administration, *Profiles of Foreign Direct Investment in U.S. Energy, 1983-1992*, DOE/EIA-0466 (Washington, DC, 1984-1994).

Foreign-Affiliated Natural Gas Production and Gasoline Marketing Expand

Even excluding the DuPont buyback, the U.S. petroleum producers which were foreign-affiliated in both 1994 and 1995 reported a 1-percent decline in crude oil production

The Historic Role of the European Majors and U.S. Petroleum Companies

Major European petroleum companies have long played an important role in U.S. energy. Royal/Dutch Shell and British Petroleum are far and away the largest of these companies. Royal/Dutch Shell has been active in the United States since at least World War I, while British Petroleum became a major participant in U.S. petroleum activity when BP purchased Standard Oil of Ohio through a series of transactions beginning in the early 1970's and ending in 1987, when BP gained 100-percent ownership and renamed the company BP America. France's formerly state-owned petroleum companies, Elf Acquitaine and TOTAL, also have substantial U.S. petroleum operations as does the Belgian Corporation, Petrofina, through its U.S. subsidiary, Fina.

In many ways these major European petroleum companies are the most direct competitors of the major U.S. petroleum companies in the United States, in Europe, and around the globe. This is due in part to the close interconnectedness of the European and North American petroleum industries. Through mergers and joint ventures this interconnectedness has grown significantly in recent years. British Petroleum, for instance, is the largest producer of crude oil in the United States. British Petroleum is also the sixth largest U.S. refiner and among the top ten branded marketers of gasoline in the United States. Shell Oil is the fourth largest U.S. oil and gas producer, the fifth largest U.S. petroleum refiner, and first in gasoline marketing. Companies based in the United States play a similar role in the European petroleum industry. Roughly 90 percent of European crude oil production comes from Norwegian and British territories in the North Sea.[a] Companies based in the United States account for roughly one-fourth of North Sea production--the remainder being produced almost entirely by the European majors. The European presence of U.S. companies in downstream petroleum is also very strong. Exxon and Mobil alone account for one-fourth of Western European refining capacity. Chevron, DuPont, and Texaco also have a major presence in European downstream.

Until recently, much of Europe's petroleum industry was, to varying degrees, state owned. Recent privatizations may have encouraged still greater integration of the European and U.S. petroleum companies through joint ventures both here and in Europe. The largest of these to date involves British Petroleum and Mobil, which announced early in 1996 an intent to merge their European downstream operations. As a result of the merger, over 9,000 European service stations will be combined and the combined operations will account for a 12-percent share of the European retail fuel market.

Several other, although much smaller, joint ventures involving U.S. and European majors have recently been implemented or announced. In 1994,Texaco and Norsk Hydro, a Norwegian integrated petroleum company, created a marketing-only joint venture, which now holds the largest motor gasoline market share in the Scandinavian countries. In 1996, Exxon and DuPont's Conoco announced a joint refining venture with their Karlsruhe German refineries, but stated that they would continue as competitors in marketing.

Another development involving major European petroleum companies is greater ownership by U.S. investors. Increasingly, the European majors have solicited foreign investment capital, particularly from investors in the United States—the largest capital market in the world. British Petroleum is currently 17-percent held by U.S. investors, up from 6-percent ownership as recently as 1991. Investors from the United States are now the largest owners of BP's shares, after investors from the United Kingdom, who have a 70-percent share. The share of ownership in Royal Dutch/Shell by U.S. investors has exceeded the share of investors from the Netherlands and has been second only to investors from the United Kingdom.

In recent years, the French government has undertaken an effort to privatize Elf Acquitaine and TOTAL. As with British Petroleum and Royal Dutch/Shell, foreign investors—particularly those based in the United States—have increased their ownership of the French majors considerably. Foreign investors held 35 percent of Elf's shares in 1995 versus 21 percent in 1992. Foreign interests in TOTAL (particularly from the United States and the United Kingdom) accounted for 44 percent of TOTAL's outstanding shares versus 23 percent in 1990. In 1995, Petrofina reported that 56 percent of the company's debt was denominated in U.S. dollars.

[a] Energy Information Administration, *International Energy Review 1993*, DOE/EIA-02219(93)(Washington DC, May 1995), p. 22.

in 1995 (Table 38). Most of the decline registered by foreign affiliates was traceable to a drop in BP America's production from Prudhoe Bay of 54 thousand barrels per day.[208] Prudhoe Bay, located in Alaska's North Slope, is a mature field with declining production. Recently, however, the rate of decline has been somewhat offset by natural gas reinjection projects.[209] Nearly offsetting BP America's decline was Shell Oil's increase in oil production in 1995. Shell attributed the increase to higher production from the company's Gulf of Mexico fields, particularly from the deepwater Gulf.[210]

In contrast to oil production, U.S. natural gas production rose 6 percent in 1995 for those foreign affiliates who reported natural gas production in both 1994 and 1995. The increase was due almost entirely to Shell Oil's ambitious efforts to exploit natural gas reserves in the Gulf of Mexico.

Due primarily to gains in reserves located in the Gulf of Mexico by several of the smaller foreign affiliates, the foreign affiliates' share of total crude oil and natural gas reserves rose slightly in 1995 (Table 39). Anadarko (which is held partly by Algeria's state oil company, Sonatrach) added the most reserves in 1995, largely due to its Gulf of Mexico fields. Two other foreign-affiliated companies reported adding substantial reserves in 1995, Sweden's Forcenergy Gas and Australia's Broken Hill Proprietary (BHP). Both companies' U.S. oil and gas production operations are heavily concentrated in the Gulf of Mexico.

Table 38. Net Production of Petroleum and Dry Natural Gas in the United States by Foreign-Affiliated U.S. Companies, 1994-1995

Company	Crude Oil and Natural Gas Liquids (thousand barrels per day)		Dry Natural Gas (billion cubic feet)	
	1994	1995	1994	1995
BP America	604.9	572.6	[b]25.2	[b]23.0
Shell Oil Co	413.7	441.1	570.0	644.0
DuPont	90.4	NF	318.0	NF
Santa Fe Energy Resources	57.5	58.4	49.8	50.3
Anadarko Petroleum	31.0	30.1	173.0	172.0
Fina	12.5	10.3	52.9	52.1
Canadian Occidental Ltd.	9.3	9.6	20.0	16.0
BHP Petroleum (Americas)	5.7	8.5	31.0	38.5
YPF S.A.	0.0	8.2	0.0	36.0
Total Minatome Corp	7.7	7.7	28.2	28.2
Forcenergy Gas Exploration	4.8	6.4	17.1	21.1
Norcen Energy Resources	4.7	4.9	32.5	40.5
Louis Dreyfus Natural Gas Co.	5.1	4.6	43.1	51.3
Elf Aquitaine Inc.	4.1	3.9	22.6	21.6
Presidio Oil Co.	3.1	NF	17.2	NF
Saba Petroleum Co.	1.8	1.9	1.0	0.9
Chieftain Development International	1.9	1.6	12.6	10.1
Cairn Energy USA	0.3	1.2	3.9	10.4
Other Companies	2.8	1.4	21.1	10.1
Total Foreign-Affiliated•	1,265.6	1,172.4	1,439.2	1,226.1
Total United States	8,642.5	8,626.0	18,747.0	18,804.0
Percent Foreign-Affiliated•	14.6	13.6	7.7	6.5

[a]Unless otherwise noted, company production is net ownership interest production.
[b]Excludes natural gas consumed in Alaskan operations.
NF = No foreign affiliation during this period.
Note: Totals may not equal sum of components due to independent rounding.
Sources: Company data: Form 10-K reports to the U.S. Securities and Exchange Commission and Annual Reports to Shareholders. United States totals: Energy Information Administration, January 1997, *Monthly Energy Review*, DOE/EIA-0035(97/01) (Washington, DC, January 1997).

Table 39. Domestic Oil and Dry Natural Gas Proved Reserves and Production for Foreign-Affiliated U.S. Companies, 1994 and 1995

Fuel Type	Foreign-Affiliated Companies[a]	U.S. Total	Foreign-Affiliated Share of U.S. Total (percent)
Crude Oil and Natural Gas			
Liquids Proved Reserves	(million barrels)		
December 31, 1994	5,149	29,627	17.4
December 31, 1995	5,203	29,750	17.5
1995 Production	428	3,004	14.2
1995 Gross Reserve Additions[b]	482	3,127	15.4
1995 Ratio of Gross Reserve Additions to Production	1.13	1.04	NM
	(billion cubic feet)		
Dry Natural Gas Proved Reserves			
December 31,1994	13,381	163,837	8.2
December 31, 1995	13,653	165,416	8.3
1995 Production	1,226	17,966	6.8
1995 Gross Reserve Additions[b]	1,498	19,575	7.7
1995 Ratio of Gross Reserve Additions to Production	1.22	1.09	NM

[a]Reserves and production are on a net ownership interest basis. The reserves and production data under each fuel type are for companies identified as foreign affiliated and reporting oil and/or natural gas production during 1995.
[b]Gross reserve additions = annual change in reserves + annual production.
NM = Not meaningful.
Sources: **Foreign-affiliated data**: Companies' Form 10-Ks filed with the U.S. Securities and Exchange Commission and annual reports to shareholders. **U.S. totals**: Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1995 Annual Report*, DOE/EIA-0216(95) (Washington, DC, November 1996).

Foreign-affiliated companies' share of U.S. crude distillation capacity, at 27 percent in 1995, was down 2 percentage points from that of the previous year (Table 40). The exit of DuPont from the ranks of foreign affiliates along with the company's 435 thousand barrels per day of refining capacity, accounted for much of the decline in the foreign affiliates' share of U.S. refining activity. Further, two relatively small foreign-affiliated independent refiners either sold or shut down operations in 1995, further reducing the foreign presence in U.S. downstream activity by another 180,000 barrels per day. In July of 1995, Castle Energy, a then U.S. subsidiary of the German company Metallgeselschaft ceased operations at one refinery and sold the other. Pacific Refining, a joint venture between China's Sinochem and U.S.-based Coastal, also shut down its refinery. Partly offsetting these losses was Clark's purchase of Chevron's large 185,000 barrels-per-day refinery in Port Arthur, Texas. Clark is owned by Canada's Horsham Corp, a company with interests in U.S. minerals and real estate, in addition to its U.S. petroleum holdings.

The role of foreign affiliates in U.S. gasoline marketing, as measured by their share of retail outlets selling gasoline, fell from 27 percent in 1994 to 26 percent in 1995. (Table 41). Again, the decline was due largely to the departure of DuPont from the ranks of foreign-affiliated companies. Excluding DuPont, the share of marketing outlets owned by foreign affiliates rose. Of the eleven foreign affiliates reporting U.S. marketing operations in both 1994 and 1995, only one reported a reduction in the number of outlets. Over the last five years, while the number of total branded retail gasoline outlets in the United States has declined roughly 10 percent, the number of foreign-affiliated outlets has grown. In large measure, Citgo's expansion of its gasoline marketing network has been responsible for the overall steady growth in the foreign-affiliated presence in U.S. gasoline marketing. In 1995,

Table 40. U.S. Refinery Operations of Foreign-Affiliated U.S. Companies, 1994-1995

Company	Number of Refineries[a]		Total Crude Distillation Capacity[a] (thousand barrels per day)	
	1994	1995	1994	1995
Shell Oil Co.	5	5	748	756
BP America	4	4	705	694
Star Enterprise	3	3	600	605
Petroleos de Venezuela	4	4	545	545
DuPont	4	NF	435	NF
Clark USA	2	3	124	309
Lyondell Petrochemical.	1	1	265	265
Shell Oil/PMI Holdings	1	1	216	265
Fina	2	2	220	234
Total Petroleum, North America.	4	4	198	198
Uno-Ven	1	1	145	145
Castle Energy	2	(b)	120	(b)
BHP-Petroleum Americas Refining Inc.	1	1	95	95
Pacific Refining	1	(c)	50	(c)
Transworld Oil USA	1	1	13	13
Total Foreign-Affiliated	36	30	4,479	4,124
Total United States	173	169	15,318	15,354
Percent Foreign-Affiliated	20.8	17.8	29.2	26.9

[a]Refineries operable as of January 1st of following year.
[b]Castle Energy sold one refinery in September 1995 and shut down their other refinery in October 1995.
[c] Pacific Refining shut down their Hercules, CA., refinery.
NF = No foreign affiliation during this period.
Sources*: Oil and Gas Journal* (December 19, 1994) and *Oil and Gas Journal* (December 18, 1995).

Citgo added over 900 service stations to its marketing network. Also, excluding DuPont, foreign affiliates' gasoline sales volumes rose in 1995, largely reflecting Citgo's expansion in gasoline marketing.

Foreign Affiliates' Mining Activity Little Changed

Foreign affiliates increased their share of the U.S. coal market in 1995 due largely to the actions of one company. Peabody Holding Company, a subsidiary of the UK conglomerate Hanson PLC, is the largest producer of coal in the United States. In 1994, Peabody purchased two Powder River, Wyoming, mines from Exxon, allowing Peabody to increase sales by 27 million tons in 1995.[211] In contrast to previous years, the year 1995 is noteworthy for the fact that there were no major purchases of U.S. coal assets by foreign investors.

Beginning in 1981, foreign investors have steadily increased their presence in U.S. coal mining (Figure 27). The share of U.S. coal production accounted for by foreign-affiliated operations equaled 31 percent of the U.S. total, up from 29 percent in 1994 (Table 42). Although foreign affiliates made no notable coal acquisitions in 1995, there was one divestiture in U.S. coal in 1995. Ashland bought back 15 percent of Ashland Coal's stock held by Germany's Saarbergwerke for $110 million. This transaction reduced Saarbergwerke's stake in Ashland Coal to under 1 percent.[212] Ashland Coal, however, remains a foreign-affiliated company due to the continued ownership of Ashland Coal, held by Spain's Carboex International Ltd.

The U.S. uranium industry remained in a depressed state in 1995 because of the availability of cheap uranium imports along with the stagnation of the nuclear power industry. For the years 1992-1995, U.S. uranium

Table 41. Branded Retail Outlets and Total Gasoline Supplied by Foreign-Affiliated U.S. Companies, 1994-1995

Company	1994	1995
Citgo Petroleum[a]	13,116	14,054
Star Enterprise	9,262	9,378
Shell Oil Co.	8,609	8,767
BP America	6,750	6,800
DuPont	5,196	NF
Fina	2,631	2,631
Circle K	2,505	2,505
Uno-Ven	2,549	2,395
Total Petroleum North America	1,757	1,991
Clark USA	839	842
Hawaiian Independent Refinery	28	28
Total for Foreign-Affiliated Companies	53,242	49,391
U.S. Total[b]	195,455	190,246
Foreign-Affiliated Companies as Percent of U.S. Total	27.2	26.0
	Total Gasoline Supplied[c] (thousand barrels per day)	
Total for Foreign-Affiliated Companies[d]	2,346	2,204
U.S. Total[e]	7,601	7,588
Foreign-Affiliated Companies as Percent of U.S. Total	30.9	29.0

[a]Jobber-supplied outlets. Citgo is 100-percent owned by Petroleos de Venezuela.
[b]The total includes all establishments selling gasoline at retail.
[c]Gasoline Supplied refers to average daily gasoline shipments.
[d]Disaggregated company numbers are considered proprietary by the Energy Information Administration.
[e]Total gasoline supplied.
NF = No foreign affiliation during this period.

Sources: **Company station counts and total branded outlets**: *National Petroleum News' Market Facts 1995* (mid-July 1995). **Company gasoline volumes**: Energy Information Administration, Form EIA-782c. **Total gasoline supplied**: Energy Information Administration, *Monthly Energy Review November 1996*, DOE/EIA-0035(96/11) (Washington, DC, November 1996).

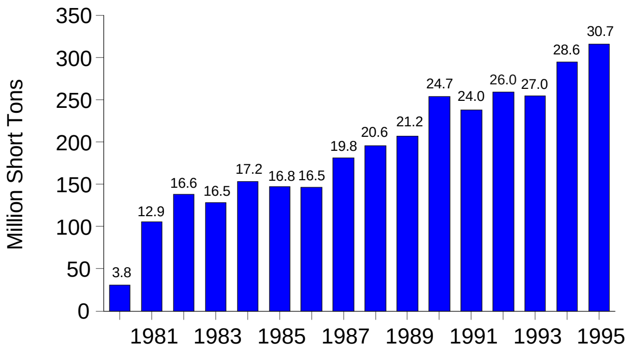
production averaged only a quarter of the level of the prior three-year period.[213] Accordingly, activity and expenditures for uranium exploration and development, although higher in 1995 than in 1994, were a small fraction of the spending levels seen as recently as in the mid 1980's (Table 43). Foreign affiliates' expenditures also rose in 1995, although they also remained significantly below spending levels seen in the mid 1980's. Still, foreign affiliates accounted for 35 percent of total U.S. uranium exploration and development.

Financial Performance of Foreign-Affiliated Energy Companies

Developments in U.S. petroleum and natural gas markets had mixed effects on the financial results of U.S. energy companies in 1995. On an annual basis, the price of crude oil at the U.S. wellhead was up $1.43 per barrel in 1995 compared to the price in 1994.[214] However, largely due to the effects of a relatively warm winter in early 1995, the wellhead natural gas price was down $1.63 per barrel on a crude oil equivalent basis. Consequently, the financial results for U.S. oil and gas producers in 1995 were strongly influenced by the proportion to which oil or natural gas contributed to revenue.

The relatively mild weather and difficulties surrounding the introduction of reformulated gasoline (RFG) in the first quarter of 1995 drove refiners' gross margins (average wholesale product price minus raw material input costs) to a six-year low. As a result, U.S. refining operations registered another year of poor financial performance in 1995. However, refiners with chemical manufacturing operations were buoyed by a second

Figure 27. Production and Share of U.S. Total Bituminous Coal and Lignite for Foreign-Affiliated U.S. Companies, 1980-1995



Note: Percentage values appearing above bars indicate foreign-affiliates' share of U.S. production.

Sources: **1981**: Energy Information Administration, *Profiles of Foreign Direct Investment in U.S. Energy 1983*, DOE/EIA-0466 (Washington, DC, February 1985). **1982-1989**: *Keystone Coal Industry Manual, 1983-1990* Editions. 1990: *1992 Coal Mine Directory* (Chicago, IL,: Maclean Hunter Publishing Co., January 1993). **1992**: *1994 Coal Mine Directory* (Chicago, IL,: Maclean Hunter Publishing Co., January 1994). **1993**: *1995 Coal Mine Directory* (Chicago, IL,: Maclean Hunter Publishing Co., January 1995). **U.S. Totals**: Energy Information Administration, *Coal Industry Annual 1993*, DOE/EIA-0584(93) (Washington, DC, December 1994).

consecutive year of earnings growth from these operations.

The year-to-year results of foreign-affiliated U.S. energy companies (Table 44) are strongly affected by the absence of DuPont in 1995. DuPont, which is a major energy company as well as the largest U.S.-based chemical manufacturer, exited the ranks of foreign affiliates after buying Seagram's minority ownership interest for $8.8 billion in 1995. Excluding DuPont from the 1994 results allows for a clearer assessment of the financial performance of ongoing foreign-affiliated energy companies.

Revenues of this latter group were up 14 percent due largely to increases in excess of a billion dollars registered by Circle K, Citgo Petroleum, Lyondell Petrochemical, and Shell Oil. The foreign affiliates' 71-percent increase in net income reflected mainly a $1-billion increase in Shell Oil's bottom line. Shell reported that over half of the income gain came from their chemical operations with income from U.S. oil and gas production also contributing significantly. Fina and Lyondell Petrochemical also attributed their earnings improvements almost entirely to their chemical operations.[215] Specialized oil and gas producers among the foreign affiliates, as a group, reported a turnaround from net losses of $15 million in 1994 to net income of $194 million in 1995.

Foreign affiliates, overall, appeared to outperform the rest of the U.S. energy industry in 1995 by registering steeper year-over-year gains in revenues, net income, and cash flow. The foreign affiliates' profitability in 1995, measured by return on shareholders' equity, was 10.4 percent versus 9.5 percent for the U.S. energy industry comparison group. Accordingly, foreign affiliates registered a sharper rise in capital expenditures: 27 percent compared to 12 percent for the comparison group. Most of the heightened spending reflected the attractiveness of U.S. oil and gas (Table 34) and chemical manufacture. About 77 percent of the $1.6-billion rise in foreign affiliates' capital expenditures was traceable to Shell Oil and Lyondell Petrochemical. Nearly 90 percent of Shell's increased spending was allocated to U.S. oil and gas production—-particularly to exploration and development in the Gulf of Mexico. Lyondell's step-up in capital expenditures was split 60/40 between chemicals and refining, respectively.

Outward Investment in Petroleum

Petroleum investment flows out of as well as into the United States. Direct Investment Abroad (DIA) in petroleum has grown steadily in the 1990's (Table 45). While the overall value of petroleum-related DIA has grown considerably over the last few years, the composition of petroleum-related DIA across different geographical regions has changed markedly. Shifts in the composition of DIA thus far can be seen by comparing patterns in 1989 with 1995 patterns.

Europe Continues as Area of Largest Investment

The exception was Europe, the largest target of U.S. petroleum DIA (Figure 28), which saw roughly the same share of DIA in 1995 as in 1989 (38 percent in 1989 versus 39 percent in 1995). U.S. petroleum DIA in Europe encompasses North Sea oil and gas production, petroleum transportation operations, and refining and marketing throughout the continent. Norway and the UK (Western Europe's two major crude oil producers) account for two-thirds of all U.S. petroleum DIA in Europe, indicating that European DIA expenditures are mainly for exploration and production in the North Sea. Companies based in the United States account for one-fourth of all North Sea oil production.

Table 42. Bituminous Coal and Lignite Production and Source of Ownership of Foreign-Affiliated Companies in the United States, 1994-1995
(Thousand Short Tons)

Controlling Company (Foreign-Ownership Interest)	1994	1995
Peabody Holding Co. (Hanson plc)	119,309	139,048
Consol Coal Group (DuPont) (Rheinbraun AG)	70,547	69,144
Kennecott Energy Co. (RTZ plc)	44,813	53,211
Ashland Coal Co. (Carborex)	14,887	15,399
Utah Minerals International, Inc. (Broken Hill Proprietary Co.)	13,903	14,631
Costain Coal Co., (Costain Group)	11,298	10,421
Westmoreland Coal Co. (Vebra Kohle International)	10,701	7,628
Andalex Resources, Inc. (Andalex Resources, Inc.)	4,450	4,967
Great Western Resources, Inc.	3,480	728
Agip Coal, Inc. (Ente Nazionale Idrocarburi)	671	43
Carter-Roag Coal Co. (Marquard and Bahls Coal Co.)	496	481
Total Foreign-Affiliated	**294,555**	**315,701**
Total United States	**1,028,883**	**1,028,263**
Percent Foreign-Affiliated	**28.6**	**30.7**

[a]Coal production refers to bituminous coal, subbituminous coal, and lignite coal production only.
NF = No foreign affiliation during this period.
Source: Energy Information Administration, *Coal Industry Annual 1994*, DOE/EIA-0584(94) (Washington, DC, October 1995) and Energy Information Administration, *Coal Industry Annual 1995*, DOE/EIA-0584(95) (Washington, DC, October 1996).

Table 43. Foreign Participation in U.S. Uranium Exploration and Development, 1976-1995
(Million Dollars)

	Exploration and Development Expenditures by Foreign Companies	Total U.S. Exploration and Development Expenditures	Foreign Expenditures as a Percent of U.S. Total	Number of Foreign-Affiliated Companies
1976	13.2	170.7	8	15
1977	21.7	258.1	8	17
1978	39.3	314.3	13	31
1979	34.1	315.9	11	28
1980	37.6	267.0	14	28
1981	24.6	144.8	17	25
1982	14.6	73.6	20	14
1983	4.8	36.9	13	9
1984	6.6	26.5	25	9
1985	5.6	20.1	28	6
1986	12.0	22.1	54	8
1987	11.9	19.7	60	11
1988	8.9	20.1	44	11
1989	6.1	14.8	41	7
1990	2.5	17.1	15	9
1991	3.5	17.8	19	6
1992	8.0	14.5	55	6
1993	8.5	11.3	76	7
1994	1.9	3.7	51	8
1995	2.1	6.0	35	NA

Source: Energy Information Administration, *Uranium Industry Annual 1995*, DOE/EIA-0478(95) (Washington, DC, May 1996), p. 5.

Table 44. Selected Financial Information for Foreign-Affiliated U.S. Energy Companies, 1994-1995
(Billion Dollars)

	Foreign-Affiliated U.S. Energy Companies[a]			Foreign-Affiliated U.S. Energy Companies (excluding DuPont)[b]			U.S. Energy Industry Comparison Group[c]		
	1994	1995	Percent Change	1994	1995	Percent Change	1994	1995	Percent Change
Financial Items									
Revenues	97.5	66.5	-31.9	58.2	66.5	14.2	379.0	411.9	8.7
Net Income	4.5	3.0	-33.3	1.8	3.0	70.5	12.7	15.3	20.0
Cash Flow[d]	11.2	6.9	-38.4	5.5	6.9	24.7	41.1	49.3	19.9
Capital Expenditures .	9.2	7.5	-17.8	5.9	7.5	27.2	37.9	42.4	11.8
Cash Dividends	3.2	2.0	-37.0	2.0	2.0	3.0	11.8	13.8	17.2
Total Assets	97.1	63.7	-34.4	60.2	63.7	5.8	402.8	409.7	1.7
	(percent)								
Financial Ratios									
Return on Equity[e]	11.1	10.4		6.4	10.4		8.2	9.5	
Dividends/Net Income	71.7	67.8		112.2	67.8		92.8	90.7	
Dividends/Cash Flow .	28.7	29.3		35.5	29.3		28.7	28.1	
Debt/Equity[f]	39.0	31.4		33.9	31.4		54.6	50.9	

[a]Includes incorporated U.S. energy companies that are foreign affiliated and for which publicly reported financial information is available. Also included are foreign parent companies for which data for U.S. operations were not separately disclosed. For 1994 these companies were: Anadarko Petroleum Corp., Arabian Shield Development Co., Arakis Energy Corp., Ashland Coal Inc., Bellwether Exploration Co., Blue Dolphin Energy Co., Cairn Energy USA Inc., Canadian Occidental Petroleum Ltd., Caspen Oil Inc., Castle Energy Corp., Chieftain International Inc., Circle K. Corp., Citgo Petroleum, DI Industries, Inc., Global Marine Inc., Daleco Resources Corp., E.I. du Pont de Nemours and Company, Fina Inc., Forcenergy Gas Exploration Inc., Georesources Inc., Harken Energy Corp., Hondo Oil and Gas Co., Horsham Corp., Louis Dreyfus Natural Gas Corp., Lyondell Petrochemical Co., MSR Exploration, Magellan Petroleum Corp., NGC Corp., Norcen Energy Resources Ltd., Oceanic Exploration Co., Penn Virginia Corp., Powerhouse Resources Inc., Presidio Oil Co., Ranger Oil Ltd., Rio Algom Ltd., Saba Petroleum Co., Santa Fe Energy Resources Inc., Schlumberger Ltd., Shell Oil Co., Sunlite Inc., Taurus Petroleum Inc., Total Petroleum (North America), Westmoreland Coal Co., and XCL Ltd. The following companies were no longer foreign-affiliated in 1995: Bellwether Exploration Co., Castle Energy Corp., E.I. du Pont de Nemours and Company, Global Marine Inc., Harken Energy Corp., and. Presidio Oil Co.

[b]Year-to-year comparisons are strongly affected by DuPont, which was foreign affiliated in 1994 but not in 1995.

[c]The comparison group is derived from aggregates available from Standard and Poor's Compustat II Industrial File for the following four-digit (SIC) industries: 1220 (bituminous coal, lignite mining), 1221 (bituminous coal, lignite surface mining), 1311 (crude petroleum and natural gas production), 1381 (oil and gas well drilling), 1382 (oil and gas field exploration), 1389 (oil and gas field services not elsewhere classified), and 2911 (petroleum refining). To obtain comparison group aggregates, the Compustat aggregates were adjusted by subtracting out data for companies which have been identified as foreign-affiliated, or whose operations are foreign based, or foreign-based companies whose U.S. operations are already included in U.S. companies identified as foreign-affiliated.

[d]Measured as cash flow from operations.

[e]Defined as net income divided by year-end stockholders' equity.

[f]Defined as year-end long-term debt divided by year-end stockholders' equity.

NM = Not meaningful.

Note: Percent changes were calculated from unrounded data.

Source: Compiled from Compustat II Industrial File and company annual reports.

Downstream, U.S. companies still play a major role in European refining, and Europe remains the largest area of refining activity for U.S. petroleum companies outside of the United States (Table 46). In 1995, Exxon and Mobil alone accounted for one-fourth of Western European refining capacity. Chevron, DuPont, and Texaco also have a major downstream presence in Europe. However, in Western Europe, U.S. petroleum companies operate in a downstream market that has been declining. Little in the way of refinery expansion is expected to take place in

Table 45. U.S. Direct Investment in Foreign Petroleum, 1980-1995
(Billion Dollars)

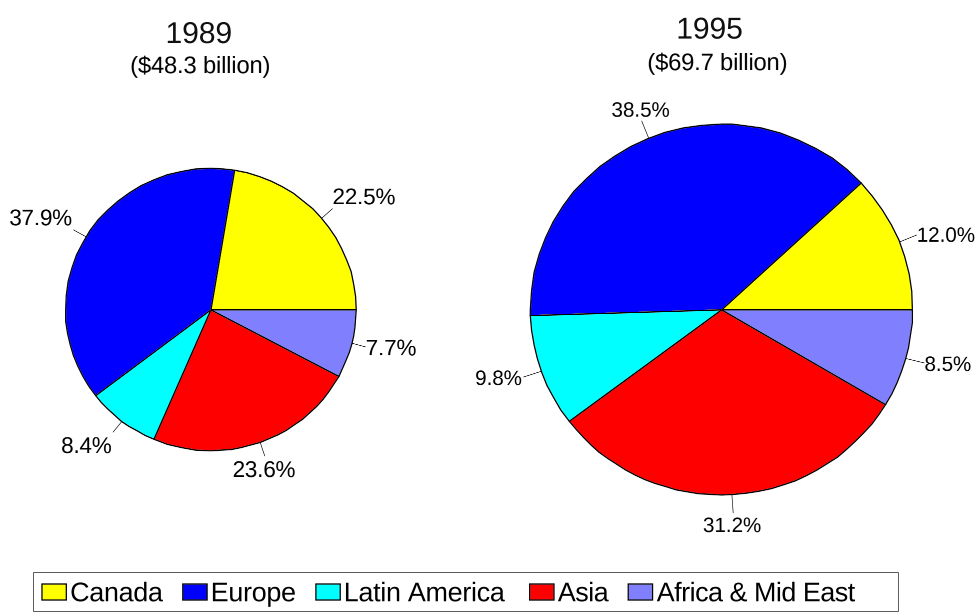
	U.S. Direct Investment in Foreign Petroleum[a,b]	Total U.S. Direct Investment Abroad[a]	Petroleum as a Percent of Total
1980	47.6	215.4	22.1
1981	53.2	228.3	23.3
1982	57.8	207.8	27.8
1983	57.6	207.2	27.8
1984	58.1	211.5	27.5
1985	57.7	230.2	25.1
1986	58.5	259.8	22.5
1987	59.8	314.3	19.0
1988	57.8	335.9	17.2
1989	48.3	381.8	12.7
1990	52.8	430.5	12.3
1991	57.7	467.8	12.3
1992	58.5	502.0	11.7
1993	64.2	564.3	11.4
1994	66.3	621.0	10.7
1995	69.7	711.6	9.8

[a]Direct Investment Abroad is the value of U.S. parents' net equity in, and outstanding loans to, affiliates outside the United States.

[b]The petroleum industry includes all phases of oil and gas exploration and production, petroleum refining, petroleum transport, and petroleum marketing.

Sources: **1993-1995**: U.S. Department of Commerce, Bureau of Economic Analysis, *Survey of Current Business* (Washington, DC, September 1996). **1989-1992**: U.S. Department of Commerce, Bureau of Economic Analysis, *Survey of Current Business* (Washington, DC, August 1995). **1987-1988**: U.S. Department of Commerce, Bureau of Economic Analysis, *Survey of Current Business* (Washington, DC, August 1993). **1985-1986**: U.S. Department of Commerce, Bureau of Economic Analysis, *Survey of Current Business* (Washington, DC, August 1990). **1982-1984**: U.S. Department of Commerce, Bureau of Economic Analysis, *Survey of Current Business* (Washington, DC, August 1987). **1980-1981**: U.S. Department of Commerce, Bureau of Economic Analysis, *Survey of Current Business* (Washington, DC, August 1985).

Figure 28. Share of U.S. Petroleum Industry Direct Investment Abroad, 1989 and 1995



Note: The relative size of the two year's pie charts reflects the difference in the level of investment between the years 1989 and 1995.

Table 46. Refinery Capacity Outside the United States for FRS Companies, 1995
(Thousand Barrels per Day)

Region	Crude Distillation Capacity[a]	Percent Distribution
Europe	2,691	44.1
Asia	2,190	35.9
Latin America	416	6.8
Canada	393	6.4
Other	408	6.9
Total	6,097	100.0

[a]Includes ownership shares in investees' refineries.

Source: Company filings of Securities and Exchange Commission Form 10-K, Company annual reports, and supplements to annual reports.

Western Europe in the near future. As a consequence, U.S. companies have been reducing the scale of their Western European operations for several years. In 1995, Mobil closed its Woerth, Germany, refinery and announced that the company would integrate operations at its 70,000 barrels per day (b/d) Gravenechon, France, refinery and its 200,000 b/d Corytown, UK, refinery.

One means the U.S. majors have employed to adapt to a weak European product market has been to engage in joint ventures. The largest of these to date involves British Petroleum and Mobil, which announced early in 1996 an intent to merge their European downstream operations. The book value of the assets in this latter proposed merger is estimated at $5 billion. BP and Mobil together sell approximately 1,375,000 b/d of product in Europe. As a result of the merger, over 9,000 European service stations will be combined, accounting for 12 percent of the European retail fuel market.

Several other, although much smaller, downstream joint ventures involving U.S. and European majors have recently been implemented or announced. In 1994,Texaco and Norsk Hydro, a Norwegian integrated petroleum company, created a marketing-only joint venture, with the largest share of motor gasoline market in Scandinavia. In 1996, Exxon and Conoco announced a joint refining venture with their Karlsruhe, Germany, refineries but stated that they would continue as competitors in marketing.

Investment in Asia Approaches European Level

In 1989, Asia accounted for 24 percent of total U.S. petroleum DIA, which was significantly less than Europe's 38-percent share. Subsequently, Asia has been gaining ground on Europe. In 1995, although Asia was still the second-largest target of U.S. petroleum DIA, Asia's 1995 share had climbed to 31 percent of the total (Figure 28). A large portion of the growth in Asia DIA was accounted for by downstream petroleum investment in Japan, led by U.S. majors and their affiliates. The major U.S. petroleum companies are heavily involved in Japan's refining and marketing operations. Caltex (the Chevron /Texaco joint venture), Exxon, and Mobil account for one-fifth of Japan's refining capacity. These companies are also major gasoline retailers in Japan. Mobil alone accounts for almost 7 percent of Japan's gasoline market.[216] However, Japan is a relatively mature market and most of Asia's demand growth is occurring in the more rapidly expanding Asian economies. Moreover, Japan has begun to loosen trade and price restrictions which had supported high levels of refining profitability. An indication of the relatively decreased attractiveness of Japan's downstream prospects was Caltex's announcement in 1995 of the sale of two of its Japanese refineries, which took place in 1996.

Indonesia ranks second as a target of U.S. petroleum DIA in Asia. Indonesia is both a large producer of crude oil and natural gas as well as being a large petroleum product refiner. Most U.S. petroleum investment in Indonesia is conducted by the major petroleum companies and is directed to upstream activity. Companies based in the United States, by themselves or through joint ventures, account for over four-fifths of Indonesia's crude oil production.[217] Most of Indonesia's oil exports are destined for Japanese refineries, including those of U.S. majors and their affiliates. Indonesia's crude oil production peaked in 1991 and is expected to continue to decline in future years.[218] However, Indonesia, the world's largest exporter of liquefied natural gas (LNG), is attempting to add considerably to its natural gas export capacity. Currently, Mobil operates Indonesia's Arun natural gas field (12 trillion cubic feet in reserves), which supplies 47 percent of Indonesia's natural gas production.[219]

For the future, Indonesia is attempting to develop its huge Natuna gas project (with estimated reserves of 46 trillion cubic feet), which is expected to reach completion in 2003. Exxon, Mobil, and Indonesia's state-owned petroleum company, Pertamina, are developing the Natuna field. Other major natural gas projects include the development of the Irian field, a venture in which ARCO is involved. ARCO's Indonesia operations currently produce 270 million cubic feet of gas per day in 1995, well up from 25 million cubic feet in 1993.[220] Indonesia has also entered into a number of LNG supply contracts with other Asian countries in order to acquire secure outlets for future increases in natural gas export capacity.

Australia and Singapore are also major targets of petroleum-related DIA in Asia. However, while Australia is both a target for upstream and downstream DIA, Singapore is purely a downstream investment. Singapore has realized substantial increases in investment largely due to the activity of a handful of U.S. majors who have been upgrading and expanding their Singapore refineries. Two U.S. companies (Exxon and Mobil) account for 42 percent of Singapore's refining capacity. Royal/Dutch Shell, the parent of U.S.-based Shell Oil, accounts for 35 percent. In 1995, Exxon completed a $190-million hydro processing unit.[221] Mobil expanded its capacity at its Singapore refinery by 10 percent in 1995. Over the last few years, Mobil has spent over $800 million to upgrade its Singapore refinery.

In Australia, among U.S.-based companies, Exxon is far and away the largest producer of crude oil, accounting for 28 percent of Australia's total output. In refining, Caltex and Mobil operate four Australian refineries with a total capacity of 246 thousand barrels per day, or 34 percent of Australia's total capacity.

China, South Korea, Malaysia, and Thailand have been rapidly growing targets of U.S. petroleum DIA, although accounting for a relatively small share of current U.S. petroleum DIA in Asia. With the exception of South Korea, (where U.S. petroleum DIA is entirely downstream) these countries have seen U.S. petroleum DIA flow into oil and gas production operations as well as into refining and marketing operations. Having achieved some of the highest rates of economic growth around the globe in recent years, these countries are expected to continue to be targets of U.S. petroleum DIA in the future.

Canadian Investment Share Declines Dramatically

Canada has shown a general decline in U.S. petroleum DIA since peaking in 1989. In 1989, U.S. petroleum DIA in Canada accounted for 23 percent of total U.S. petroleum DIA. Among the FRS companies, exploration and development expenditures for Canada peaked in 1989 at $6.2 billion, reflecting drilling and exploratory activity as well as Exxon's $4-billion acquisition of Texaco Canada. Since then, annual exploration and development spending has ranged from $1.1 billion to $1.9 billion. By 1995, Canada's share of DIA had fallen to 12 percent. Most of this decline is the result of lower exploration and development spending, although some disinvestment of U.S.-owned assets has occurred.

Latin America accounted for roughly 10 percent of U.S. petroleum DIA in 1995, up a bit from an 8-percent share in 1989. Most Latin American DIA is directed toward upstream activities. Over the last ten years, Latin American crude oil production has risen more than 50 percent. Companies based in the United States have played an increasingly important role in the development of Latin America's petroleum resources, particularly as the move to privatize petroleum assets in Latin America has opened up previously off-limit areas to exploration activity. The FRS companies, for instance, have increased their exploration and development expenditures in Latin America by 44 percent since 1989.

In Africa, U.S. petroleum companies' investment is largely directed upstream and concentrated in Nigeria and Angola. Middle East activity is much smaller and is scattered across several countries in the region. Nigeria is Africa's largest producer of crude oil and is expected to show significant production gains in future years.[222] In North Africa, FRS companies have growing investments in Algeria and Egypt. In 1995, Amoco produced 121 thousand barrels per day in Egypt and has signed an agreement with the Egyptian government to enter the natural gas transportation business.[223] USX also has upstream investments in Egypt although its current production level is quite small. In Algeria, Anadarko entered into a production sharing contract with Sonatrach in 1989.

Although Anadarko reported $41 million in capital spending in Algeria in 1995, Anadarko's Algerian operations are in the exploratory and pre-production phase.[224]

Outward Investment in Electricity

Privatization and the deregulation of utilities overseas has presented U.S. companies with unprecedented opportunities to invest in electric power generation, transmission, and distribution overseas. (These developments recently have been addressed in depth in a new EIA report entitled *Electricity Reform Abroad and U.S. Investment*.[225] Virtually all regions of the globe have seen openings of domestic power industries to foreign investment. A veritable boom in foreign investment in electricity assets has resulted. U.S. utilities have been among the most noticeable of investors in foreign electric power assets, although petroleum companies have also been major participants. Some U.S. utilities have purchased overseas electricity assets in several continents, thereby giving rise to a new phenomenon, the multinational electricity company. The Department of Commerce publishes time series data on overseas investment in electric power facilities by U.S.-based companies. Although the series includes gas pipeline and sanitary service investment, it is dominated by transactions involving electric power assets. The value of U.S. DIA in electric, gas, and sanitary services rose sharply from $1.6 billion in 1993 to $2.4 billion in 1994, before leaping to $8.4 billion in 1995.

Some of the most ambitious efforts at power privatization and deregulation have occurred in Australia and the United Kingdom. In its *Survey of Current Business*, the U.S. Department of Commerce noted that, “Equity capital outflows primarily financed the boom in large mergers and acquisitions involving large U.S. multinational corporations in 1995 …. U.S. electric utilities, responding to opportunities created by recent privatizations, acquired several energy providers in Australia and the United Kingdom.”[226]

In the United Kingdom, what was once largely a publicly-owned electric power industry has been transformed into two major power generators, a major transmission company, and twelve regional power producers, all of which have been privatized.[227] Nuclear power plants have been privatized as well, under the firm British Energy. Companies based in the United States have purchased several electric power companies in England. Of the twelve privatized regional electric distribution companies, seven have been purchased by U.S. utilities thus far. Upon settlement, the value of these transactions will exceed $15 billion.

Companies based in the United States have also been major investors in independent power projects and in several recently privatized natural gas distribution companies in the United Kingdom.

Similarly, in Australia, privatization and the opening up of electricity assets to foreign investment have led to a surge in U.S. energy company investments in power generation, transmission, and regional distribution companies. Most of this activity has occurred in Victoria, Australia’s second most populous state. Victoria sold five regional distribution companies, all of which were, at least in part, purchased by U.S.-based companies.[228]

Endnotes

[193] The focus year for foreign direct investment is 1995, not 1996, due to the fact that financial performance data (covered in the preceding chapters of this report) were not available for foreign direct investment.

[194] DuPont *1995 Annual Report,* p. 55.

[195] *Petroleum Economist,* June 1995, p. 6.

[196] U.S. Department of Energy, *Secretary's Annual Report to Congress*, DOE/S-0010(83) (Washington, DC, September 1983), pp. 132-134.

[197] Energy Information Administration, *Natural Gas 1995: Issues and Trends*, DOE/EIA-0560(95) (Washington, DC, October 1995), p. 1.

[198] Energy Information Administration, *Annual Energy Review 1995*, DOE/EIA-0384(95) (Washington, DC, July 1996), pp. 143 and 195.

[199] Energy Information Administration, Form EIA-28, "Financial Reporting System."

[200] Energy Information Administration, *Annual Energy Outlook 1997,* DOE/EIA-0383(97) (Washington, DC, December 1995), p. 64.

[201] *PR Newswire* (May 25, 1996).

[202] Shell Oil Company, *Annual Report 1995,* p. 37.

[203] Shell Oil Company, *Annual Report 1995,* p. 37.

[204] "Shell to Raise Gas Output by Going Deeper in Gulf of Mexico," *The New York Times* (May 26, 1995), p. D18.

[205] Shell Oil Co., *1994 Annual Report*, p. 11.

[206] Lyondell Petrochemical Company, *1995 Annual Report*, p. 41.

[207] U.S. Department of Commerce, *Survey of Current Business,* (Washington, DC, July 1996) p. 49.

[208] British Petroleum Company p.l.c., *BP Financial and Operating Information 1990-1994,* p. 34.

[209] Energy Information Administration, *Performance Profiles of Major Energy Producers 1994*, DOE/EIA-0206(94) (Washington, DC, February 1996), p. 45.

[210] Shell Oil Company *1995 Annual Report*, p.36.

[211] Hanson PLC, *1995 Annual Report*, p. 14.

[212] Ashland Coal, Inc. *1995 Annual Report,* pp.41, 42, and 59.

[213] Energy Information Administration, *Uranium Industry Annual 1994*, DOE/EIA-0478(94)(Washington, DC, July 1995), p. xviii.

[214] Oil and gas price data are from Energy Information Administration, *Monthly Energy Review December 1996*, Tables 9.1 and 9.11.

[215] Shell Oil Co. *Annual Report 1995*, Lyondell Petrochemical Co. *1995 Annual Report*; and Fina Inc, *Annual Report 1995.*

[216] Mobil Corp., *Mobil Fact Book 1995*, p. 54.

[217] *Oil and Gas Journal*, December 30, 1996, pp. 59-61.

[218] Energy Information Administration, *International Energy Annual 1995*, DOE/EIA-0219(95) (Washington, DC, December 1996), p. 26.

[219] Energy Information Administration, *Country Analysis Briefs: 1994*, DOE/EIA-0595 (Washington, DC, May 1995), p.37.

[220] ARCO *1995 Annual Report*, p. 46.

[221] Exxon Corp., *Exxon 1995 Financial and Operating Review*, p. 52.

[222] Energy Information Administration, *International Energy Outlook 1996*, DOE/EIA-048(96) (Washington, DC, May 1996), p. 124.

[223] Amoco Corporation, *Financial and Statistical Supplement to the 1995 Annual Report*, pp. 19 and 20.

[224] Anadarko Petroleum Corporation, *1995 Annual Report*, pp. 9 and 61.

[225] Energy Information Administration, *Electricity Reform Abroad and U.S. Investment*, DOE/EIA-0616 (Washington, DC, October 1997).

[226] Energy Information Administration, *Privatization and the Globalization of Energy Markets*, DOE/EIA-0609 (Washington, DC, October 1996), pp. 44-48.

[227] For a more detailed account of privatization and foreign investment in U.K. electricity operations, see the Energy Information Administration's report *Privatization and the Globalization of Energy Markets*, DOE/EIA-0609 (Washington, DC, October 1996) and *Electricity Reform Abroad and U.S. Investment*, DOE/EIA-0616 (Washington, DC, October 1997).

[228] Energy Information Administration, *Privatization and the Globalization of Energy Markets*, DOE/EIA-0609 (Washington, DC, October 1996), pp. 47 and 48.

Appendix A

Structure of the Financial Reporting System—Form EIA-28

Appendix A

Structure of the Financial Reporting System - Form EIA-28

Reporting Format

The FRS data system is designed to permit review of the functional performance of major energy-producing companies in total, as well as by specific functions and geographic areas of operation. The financial reporting schedules obtain data on revenues, costs, and profits, thereby indicating financial flows and performance characteristics. In addition, Form EIA-28 is used to collect balance sheet data (e.g., accumulated property, plant, and equipment), along with data on new investment in these accounts. To complement the financial data, statistical schedules are included to trace physical activity patterns and to evaluate several physical and financial relationships.

In greater detail, the structure of the reporting package is as follows:

1. Financial Reporting

   a. The reporting begins with the three basic financial statements required by the Securities and Exchange Commission (SEC) Form 10-K:

      i. Consolidating Statement of Income (Schedule 5110)
      ii. Selected Consolidating Financial Data (Balance Sheets) (Schedule 5120)
      iii. Consolidated Statement of Cash Flows (Schedule 5131)

   b. Company-wide financial information is first disaggregated by functional lines (segments) on Schedules 5110 and 5120 as follows:

      i. Petroleum
      ii. Coal
      iii. Other Energy (includes Nuclear)
      iv. Nonenergy (includes Chemicals)

   c. Nonenergy data are collected to characterize corporate resource investment strategies and to allow aggregation of the FRS detailed schedules into the consolidated company amounts.

2. Operating and Statistical Information

   a. For each type of energy activity, complementary operating information is obtained through the following schedules:

      i. Petroleum (Schedule 5211-Schedule 5246)
      ii. Coal (Schedule 5341)

   b. The schedules are designed to correspond to the financial information so that the level of effort in the financial sense can be compared to physical results.

3. Complementary Schedules

   a. Examine corporate research and development funding priorities (Schedule 5111)

   b. Reveal impact of tax policy on financial results of reporting companies (Schedule 5112)

   c. Monitor raw materials acquisition and refined product disposition strategies of FRS companies (Schedule 5211 and Schedule 5212)

   d. Trace changes in reserves for petroleum (including natural gas) (Schedule 5246) and coal (Schedule 5341)

Petroleum Segment Overview

The petroleum line of business is further disaggregated into segments.[229] These segments are presented as though each were a separate entity, with certain limitations, entering into transactions with other segments and third parties.

The following lists each segment within the petroleum line of business, along with a brief description of that segment's principal revenue-generating product or service. (Further detail on the FRS petroleum segments can be found in the section on *FRS Petroleum Supply and Trading Function* and *FRS Income Taxes*.)

1. *U.S. Production* – produces and sells U.S. crude oil, natural gas, and natural gas liquids. For FRS purposes, sales of U.S. crude oil must be made to the U.S. refining / marketing segment. Natural gas and natural gas liquids can be purchased from or sold directly to U.S. or foreign third parties, unconsolidated affiliates, and other U.S. or foreign segments.

2. *U.S. Refining/Marketing* – purchases raw materials from the U.S. production segment, the foreign refining / marketing segment, and third parties for refining or sale to third parties. The segment also purchases directly from the foreign production segment for those companies that do not have foreign refining / marketing and import all foreign production and purchases.

3. *U.S. Pipelines* – transport crude oil, natural gas, and natural gas liquids through Federal-or State-regulated pipeline operations.

4. *Foreign Production* – produces and sells foreign crude oil, natural gas, and natural gas liquids. Crude oil sales are made to the foreign refining / marketing segment unless the company does not have foreign refinery operations and imports all foreign crude oil gained through production or purchases. Companies that meet these criteria may sell directly to the U.S. refining / marketing segment.

5. *Foreign Refining/Marketing* – purchases raw materials from foreign production segments and U.S. refining / marketing segments, refines, and sells to third parties and refining / marketing segments.

6. *International Marine* – provides marine transportation of foreign and U.S. source crude oil.

Selection of FRS Reporting Companies

Twenty-seven companies were initially notified of a requirement to file Form EIA-28. This group was chosen initially from the top 50 publicly-owned U.S. crude oil producers, who, in 1976, had at least 1 percent of either production or reserves of oil, gas, coal, or uranium in the United States or 1 percent of refining capacity or petroleum product sales in the United States.

Mergers, acquisitions, and spinoffs, together with the selection criteria applied to 1991 data, resulted in the list of companies shown in Table A1 on the following page.

Data Quality Assurance Program

The data quality assurance program encompasses EIA's efforts to ensure the quality and integrity of FRS data. These efforts are evidenced by the design of the form and by the procedures applied to verify the data, including computer programmed checks and desk review procedures.

Forms Design

The Securities and Exchange Commission (SEC) Form 10-K contains financial statements audited by independent certified public accountants. These financial statements and the entire text of the annual report and Form 10-K are reviewed by the SEC staff to provide the investing public with assurances that data filed on Form 10-K are accurate and are in accordance with generally accepted accounting principles and SEC Regulations.

The FRS Form EIA-28 is designed in a multi-tier structure to take advantage of the SEC review and audit by independent certified public accountants. This structure presents both the Form 10-K figures and statistics and the more detailed data required by the FRS system. The top FRS tier corresponds to Form 10-K; the second tier is the first tier disaggregated into the different sources of energy (e.g., petroleum, coal); and the third tier is the second tier disaggregated into the specific functional line-of-business segments within petroleum. (See the Petroleum Segment Overview section at the beginning of this appendix which describes the FRS segments in detail.) The fourth tier provides further detail within the individual segments—for example, the details of petroleum raw materials purchased and sold. Therefore, the lower tiers can be aggregated to each successively higher tier until the consolidated Form 10-K figures are reached. In this way, the more detailed FRS data is tied to the aggregated figures already reported publicly to the SEC and to company shareholders.

Review Procedures

Detailed computer editing and desk review procedures have been established for the incoming FRS data. The result of each review is the issuance of a letter to the reporting company containing questions regarding data elements. The reporting companies respond to each question, either by explaining the item or by amending any incorrect schedule. Amended schedules are reprocessed like the original, with the full range of desk and computer checks. The result of this process is an internally

Table A1. Companies Reporting to the Financial Reporting System, 1974-1996

Company	1974-81	1982	1983-84	1985-86	1987	1988	1989-90	1991	1992-93	1994-96
Amerada Hess Corporation	X	X	X	X	X	X	X	X	X	X
American Petrofina, Inc.[a]	X	X	X	X	X	X	X			
Amoco Corporation[b]	X	X	X	X	X	X	X	X	X	X
Anadarko Petroleum, Inc.									X	X
Ashland Inc.	X	X	X	X	X	X	X	X	X	X
Atlantic Richfield Co. (ARCO)	X	X	X	X	X	X	X	X	X	X
BP America, Inc.[c]					X	X	X	X	X	X
Burlington Northern Inc.[d]	X	X	X	X	X					
Burlington Resources Inc.[d]						X	X	X	X	X
Chevron Corporation[e f]	X	X	X	X	X	X	X	X	X	X
Cities Service[g]	X	X								
Coastal Corporation	X	X	X	X	X	X	X	X	X	X
Conoco[h]	X									
E.I. du Pont de Nemours and Co.[h]		X	X	X	X	X	X	X	X	X
Enron Corporation									X	X
Exxon Corporation	X	X	X	X	X	X	X	X	X	X
Fina, Inc.[a]								X	X	X
Getty Oil[i]	X	X	X							
Gulf Oil[f]	X	X	X							
Kerr-McGee Corporation	X	X	X	X	X	X	X	X	X	X
Marathon[j]	X									
Mobil Corporation[k]	X	X	X	X	X	X	X	X	X	X
Nerco, Inc.[l]									X	
Occidental Petroleum Corporation[g]	X	X	X	X	X	X	X	X	X	X
Oryx Energy Company[m]						X	X	X	X	X
Phillips Petroleum Company	X	X	X	X	X	X	X	X	X	X
Shell Oil Company	X	X	X	X	X	X	X	X	X	X
Standard Oil Co. (Ohio) (SOHIO)[c]	X	X	X	X						
Sun Company, Inc.[m]	X	X	X	X	X	X	X	X	X	X
Superior Oil[k]	X	X	X							
Tenneco Inc.[n]	X	X	X	X	X	X				
Texaco Inc.[i]	X	X	X	X	X	X	X	X	X	X
Total Petroleum (North America) Ltd.[o]							X	X		
Union Pacific Resources Group, Inc.[p]	X	X	X	X	X	X	X	X	X	X
Unocal Corporation	X	X	X	X	X	X	X	X	X	X
USX Corporation[j]	X	X	X	X	X	X	X	X	X	

[a]American Petrofina, Inc. changed its name to Fina, Inc., effective April 17, 1991.
[b]Formerly Standard Oil Company (Indiana).
[c]In 1987, British Petroleum acquired all shares in Standard Oil Company (Ohio) that it did not already control and renamed its U.S. affiliate, BP America.
[d]Burlington Resources was added to the FRS system and Burlington Northern was dropped for 1988. Data for Burlington Resources covers the full year 1988 even though that company was not created until May of that year.
[e]Formerly Standard Oil Company of California.
[f]Chevron acquired Gulf Oil in 1984, but separate data for Gulf continued to be available for the full 1984 year.
[g]Occidental acquired Cities Service in 1982. Separate financial reports were available for 1982, so each company continued to be treated separately until 1983.
[h]DuPont acquired Conoco in 1981. Separate data for Conoco were available for 1981; DuPont was included in the FRS system in 1982.
[i]Texaco acquired Getty in 1984; however, Getty was treated as a separate FRS company for that year.
[j]U.S. Steel (now USX) acquired Marathon in 1982.
[k]Mobil acquired Superior in 1984, but both companies were treated separately for that year.
[l]RTZ America acquired the common stock of Nerco, Inc., on Feb. 17, 1994. In Sept. 1993, Nerco, Inc. sold Nerco Oil & Gas, Inc., its subsidiary. Nerco's 1993 submission includes operations of Nerco Oil & Gas, Inc., through Sept. 28, 1993.
[m]Sun Company spun off Sun Exploration and Development Company (later renamed Oryx Energy Company) during 1988. Both companies were included in the FRS system for 1988; therefore, some degree of duplication exists for that year.
[n]Tenneco sold its worldwide oil and gas assets and its refining and marketing assets in 1988. Other FRS companies purchased approximately 70 percent of Tenneco's assets.
[o]Effective June 1, 1991, Total's exploration, production, and marketing operations in Canada were spun off to Total Oil & Gas, a new public entity.
[p]Effective October 15, 1996, Union Pacific Corporation distributed its ownership in the Union Pacific Resources Group, Inc. to its shareholders. Prior to 1996, the FRS system included Union Pacific Corporation. The FRS system includes only Union Pacific Resources Group, Inc. for 1996.
"X" indicates that the company was included in the FRS system for the year indicated.
Source: Energy Information Administration, Form EIA-28, "Financial Reporting System."

consistent database that has been reconciled to the Form 10-K and from which the output reports can be compiled.

The FRS review procedures include:

- Computer programmed checks for mathematical accuracy (e.g., addition and subtraction)
- Computer programmed checks to insure that corresponding schedules are correctly cross-referenced
- Desk reviews comparing reported FRS data to information from each company's Form 10-K and annual report
- Desk reviews comparing reported data (e.g., average cost per foot drilled) for an individual FRS company to the average for all FRS reporting companies and to prior year information of the individual company
- Desk reviews comparing reported data to other related data series to ascertain any unusual variance
- Statistical disclosure avoidance procedures.

Computer Programmed Checks

There are 803 computer programmed checks for mathematical accuracy which ensure that each horizontal and vertical total equals the sum of the amounts within each line or column. There are also 50 computer programmed cross-reference checks which ascertain that the amounts within a certain section of a schedule equal the amounts of the same description within a different schedule. The cross-reference checks are performed to ensure accuracy and consistency between different schedules. For example, the amount reported on Schedule 5210 for the U.S. production segment charges for depreciation, depletion, and amortization is cross-referenced to ensure the same amount is reported on Schedule 5120. Since the number and type of errors noted during these checks is an indicator of respondent understanding of the form, existing and potential problems are identified. The FRS review staff can then focus most of their attention on specific companies and areas where data accuracy may be of a greater concern.

Desk Review Procedures

Desk review procedures encompass a detailed comparison of the data submitted to information contained in the Form 10-K and the annual report to company shareholders, as well as other publicly available information.

As stated previously, the Form 10-K and the annual report contain financial information audited by independent certified public accountants. This financial information, along with textual and statistical information, has also been reviewed by the SEC staff, which includes not only accountants, lawyers, and financial analysts, but also petroleum and mineral resource engineers. Hence, the data contained in these documents is considered a valuable reference in connection with the quality of FRS data.

The data contained in each respondent's submission is compared to the data on Form 10-K and the annual report material by use of a detailed review program. Each review program step is performed by trained auditors supervised by CPAs with experience in auditing medium-to-large public companies.

These comparisons involve checking elements in both the financial and physical information areas (e.g., production, reserves, refinery statistics, etc.). Direct comparisons are made of specific data elements from the FRS form with corresponding items on Form 10-K or in the annual report. Indirect comparisons deal with information that is mentioned in Form 10-K and the annual report, but which is not quantified sufficiently for direct matching with FRS data. For example, if a respondent's annual report discussed an investment in coal, appropriate entries would be expected on the FRS schedule for coal.

The FRS desk review procedures also include two other types of comparisons. The first type of comparison is made against prior year FRS data of the reporting company as well as the average data for all FRS reporting companies. These procedures ensure consistency and reasonableness across reporting years.

The second procedure involves comparing data to other related data series. Information contained in the FRS system is compared to data available from other DOE systems and published data, such as state mining surveys.

The FRS desk review procedures described above often lead to the formulation of a set of questions that are issued to the reporting companies each year. Response to these questions generates substantial interchange between the energy company staffs and the FRS staff. From this interchange the company personnel acquire a better understanding of the unique aspects of the FRS system. The FRS staff learns more about each reporting company, the industry, and how each company's accounting and reporting practices might affect the published FRS aggregate data.

Statistical Disclosure Avoidance Procedures

Procedures to prevent the disclosure of "individually identifiable energy information" have been applied to each table in this report. These tables provide summary rather than company-specific information. In most cases, the level of summarization applies to all FRS companies. In certain cases, subcategories have been established that break the reports into size or other descriptive classes. Each table has been screened to ensure that no statistical disclosure will occur.

A large number of summary computer reports, generated from a single selected database, provide the basis for these tables. In conjunction with the summary reports, a parallel set of cell count reports were produced that tabulate for each report cell the number of nonzero values that were aggregated to produce the summary value. The cell count reports were then reviewed to identify whether potential disclosure problems would result from having an insufficient number of reporters or from having values that represent primarily dominant companies in a particular energy sector or activity.

If potential disclosure problems are identified, the tables are restructured to combine values or groups of individual cells in the tables so that the resulting tables are essentially disclosure free.

Financial Analysis Guide

Indicators of Financial Performance

To depict the activities of the FRS companies classified by the various energy industries, several indicators have been selected to show the amounts and geographic distribution of production, profits, cash generated, accumulated investment, and annual new investment. These indicators are compared across segments, across functions within segments, and geographically. They are the same as, or similar, to indicators that have been in regular use by financial analysts and economists for many years. However, to avoid potential misunderstandings, the measures used, their significance, and their limitations are described below.

All of these measures are based upon the existing framework of financial reporting now used by industry, which relies on Generally Accepted Accounting Principles (GAAP). GAAP is the set of accounting principles by which industry reflects the financial results of operations, cash flows, and financial positions of individual business enterprises. The two primary issues one must contend with in using present GAAP-based data is that not all companies use the same GAAP accounting methods (e.g., full cost versus successful efforts in petroleum) and GAAP is based upon historical cost accounting principles (inflationary distortions and market values are not reflected). Both of these can cause a degree of noncomparability of reported data across companies in the case of accounting methods and through time in the case of historical cost accounting. In spite of these problems, the data are regarded as meaningful, especially for trend analysis. (For a further discussion of these two problems, see the Accounting Practices section of this appendix.)

The financial measure of the production and distribution of raw materials and refined products is operating revenues, or sales. Under GAAP, this measure is based on arm's-length transactions with third parties. However, in the FRS system, the concept of sales has been extended to include sales from one segment to another. By use of such an approach, one segment's sales become another segment's costs, which must be eliminated in consolidation. The establishment of the FRS segments, the definition of sales (trading function), and the nontraceable and eliminations categories are discussed more fully in the Accounting Practices section of this appendix.

Profits are the measure of financial return for company activities. In the FRS system, profits are expressed in terms of net income, operating income, and contribution to net income. The first term applies only to the consolidated company profits and represents income after the provision for income tax expense. Operating income applies both to the segments and to the consolidated company and is the net of operating revenues and operating expenses. Excluded from this figure are such items as income taxes, interest income, and interest expense, which are not allocated to the segments because they are "corporate-level" items for FRS system purposes. (This is explained more fully in the Accounting Practices section of this appendix.) Contribution to net income is meant to be the equivalent of net income for individual segments and excludes several corporate-level items which are not allocated to the segment level.

"Cash flow from operations" is presented for the consolidated company. It generally follows the indirect or reconciliation method of reporting cash flow from operations allowed by Statement of Financial Accounting Standards No. 95. The indirect method adjusts net income to remove the effects of changes in receivables, payables, and inventory during the year. The indirect method also adjusts for the effects of depreciation, depletion, and amortization, gains or losses on disposition of property, plant, and equipment, and other items. "Cash flow from operations" represents the cash effects of producing and delivering the company's products and services. This presentation is useful in analyzing the ability to generate future positive cash flow, adequacy of cash flow in relation to current obligations, and the relationship of net income to cash flow.

Accumulated investment is expressed by: (1) total assets; (2) net property, plant, and equipment (PP&E); (3) investments and advances to unconsolidated affiliates; and (4) net investment in place.

Total assets are used in the context of the consolidated company figures and are the total of the left-hand, or asset side, of the balance sheet.

Net PP&E is frequently used as a measure of resources committed by an enterprise to an industry or segment. In the energy industry, net PP&E accounts for the bulk of the consolidated assets.

Investments and advances to unconsolidated affiliates are of interest because many energy companies extend the range of their activities through subsidiaries of which they own less than 50 percent.

Finally, net investment in place is the total of: (1) net PP&E and (2) investments and advances to unconsolidated affiliates.

Annual new investment is the measure of newly committed resources during any given year. In the FRS system, this is expressed in terms of: (1) additions to PP&E; (2) current capitalized exploration and development (E&D) expenditures; (3) current expenditures on E&D; (4) additions to investment in unconsolidated affiliates; and (5) additions to net investment in place. The key words are: *current*, which means simply a current commitment of resources; and *capitalized*, which refers to expenditures that are classified as an addition to the PP&E account in the balance sheet rather than as an expense of the current year in the income statement. Being capitalized indicates that the expenditure benefits future years and will be amortized to expense in the years benefitted. Being expensed means the cost does not directly benefit a future period; therefore, the cost should be shown as an expense of the current year. The capitalization concept is at the heart of the difference between the successful efforts versus full cost accounting methods (discussed in the Accounting Practices section of this appendix). Therefore, in the FRS system, total expenditures that are both expensed and capitalized are used as a measure of activity to standardize the measurement of resources invested.

Foreign Reserve Interests

This category includes all three types of foreign reserves collected on Form EIA-28: (1) net ownership interest reserves; (2) proportionate interest in investee reserves; and (3) foreign access reserves. These three foreign categories are added together for purposes of comparison with U.S. net working interest reserves because of the different nature of company interests in foreign production as compared to U.S. production.

Foreign petroleum reserve statistics are not strictly comparable to those of U.S. petroleum reserves because of the more complex and varying arrangements whereby U.S. companies obtain foreign crude oil. In addition, such arrangements have been known to be changed suddenly by those governments, thereby imposing a degree of uncertainty about what a reporting company can describe as its equity reserves. Foreign reserve statistics may be used as an indicator of the rate and magnitude of industry activity, but the fact that their character is distinct from those of U.S. reserves must be recognized.

Accounting Practices

Relation of FRS to Generally Accepted Accounting Principles

In completing Form EIA-28, with one exception noted below, companies use the same generally accepted accounting principles that they use in their financial statements filed with the SEC and in their annual reports to shareholders. Therefore, the amount and timing of income recognized and the capitalization policies will be the same. Net income in the FRS system will agree in total with that reported in each company's financial statements.

However, in the FRS system the presentation of the details of financial and statistical data will usually differ somewhat from that presented by most individual companies because current reporting standards do not require standardized business segments with standardized financial statement line items. In the FRS system, such standardization is necessary because of the need to aggregate a large number of companies (see Sec. 205(h), P.L. 95-91).

FRS Petroleum Supply and Trading Function

In establishing the FRS functional lines of business for reporting the activities of vertically integrated enterprises, it was necessary to define a set of trading rules. Each segment can engage in activities as defined by the rules. Otherwise, the segment data would be inconsistent between companies.

FRS defines the following segments within petroleum; they are the main components of the 5200 series schedules:

- U.S. Production
- U.S. Refining / Marketing
- U.S. Pipelines
- Foreign Production
- Foreign Refining / Marketing
- International Marine (Transportation).

A few of the more noteworthy rules, intended to make the trading activities of each FRS reporting company comparable to those of the other companies, are as follows:

1. Transfers (sales) between segments of the same company are recorded at arm's-length market prices. Where there are no comparable arm's-length transactions, field posted prices may be used. If third party realizations for specific raw material streams are below posted prices, the same lower prices should be used to value internal transfers of those raw materials.

2. All crude oil produced is recorded as a sale by the respective foreign or U.S. production segments to the corresponding foreign or U.S. refining / marketing segments. The production segments are not permitted to sell crude oil directly to third parties, but instead must transfer it to the company's refining / marketing segments which sell, in turn, to the third parties. Companies that do not have foreign refining and import all foreign purchases may deviate from this practice and sell directly to U.S. refining / marketing.

3. Crude oil purchased from third parties is reflected as a purchase by the appropriate refining / marketing segment: foreign refining / marketing for foreign source crude oil and U.S. refining / marketing for U.S. source crude oil. Foreign source crude oil destined for a U.S. refining segment is then recorded as a sale by the foreign refining / marketing segment to the U.S. refining / marketing segment.

4. Although production segments are neither sellers nor purchasers of crude oil from third parties, by FRS system convention, natural gas may be both purchased and sold by production segments.

5. All transportation costs are incurred by the purchasing segment. Therefore, when U.S. refining / marketing segments purchase crude oil from foreign refining / marketing segments, the U.S. refining / marketing segment incurs the transportation cost.

6. With regard to sales to third parties, an export sale is a sale shipped free on board (f.o.b.) to a foreign location. In contrast, if a sale is made f.o.b. to a U.S. location, it is considered a U.S. sale even though the goods may ultimately be shipped overseas by a third party who purchased the goods.

7. A U.S. purchase is a purchase made from U.S. sources, even though, in the case of goods purchased from third parties, the materials purchased may be of foreign origin. In the FRS system, the point of purchase and not the country of production is the determining factor.

Nontraceables and Eliminations

One of the objectives of the FRS system is to allow economic and financial analysis of the energy industry to be performed by individual functions. These functions, referred to in the FRS system as segments, are presented as separate entities with their own income statements. They reflect sales and purchases not only to and from unaffiliated parties, but also to and from other segments. Because the segments are not separate entities, but are part of an integrated firm, two special classifications are defined which allow reconciliation of consolidated company figures with those of the segments.

The first is the nontraceable classification, which covers those items included in the consolidated financial statements but not allocated to the segments. The second is the eliminations classification, which prevents double counting of intersegment transactions when the segments are consolidated into total company figures.

The nontraceable classification captures assets, liabilities, revenues, and expense items that cannot be attributed to the activities of a segment. In the FRS data, this classification reflects general overhead for the consolidated firm, as well as financial activities which represent corporate-level activities.

While the financial transactions may play a key role in the firm's ability to do business, such transactions are not allocated to activities in an individual segment. Cash, corporate investments, interest income, and interest expense are examples of nontraceable items. The accompanying example illustrates a nontraceable item, interest expense of $20, and the $10 corresponding tax effect (see “FRS Segment Tax Allocation Rules” in this appendix for further explanation).

The need for the eliminations classification arises when the product of one segment is sold to a second segment, which, in turn, sells the product again. In the example illustrated in Table A2, $80 of crude oil is sold by the U.S. production segment to the refining / marketing segment. The refining / marketing segment records $80 of purchases of crude oil and, after processing, reflects sales of $160 of refined product. If the segment figures were simply added to arrive at the consolidated total, the consolidated sales figure of $240 ($80 + $160) would be too high because of double counting. Thus, the eliminations classification subtracts $80 of sales and $80 of costs, leaving consolidated sales of $160, the appropriate measure of the firm's consolidated transactions.

The nontraceables and eliminations classifications are treated as if they are segments for purposes of aggregating segment data to the consolidated level.

FRS Income Taxes

FRS Segment Tax Allocation Rules. In the FRS system, the tax allocated to each segment reflects a pro-rata share of consolidated income taxes. Where the consolidated company reports income and pays a tax, but an individual segment incurs a loss, the segment with a loss reflects a tax benefit. This treatment is an FRS rule whose purpose is to reflect, at the segment level, the effect of the segment's operations on the consolidated income taxes. The tax benefit reflected at the segment level is limited to the extent it offsets taxes in other segments on a consolidated basis. In comparing an FRS company's segment to a specialized (nonintegrated) company in the same line of business, one must consider the effect of the above described rule. The current tax effect may be different, since a specialized company cannot report tax benefits for operating losses incurred in that year. It must carry the loss forward, or backward, against profits of other years, while a segment of an otherwise profitable consolidated firm can show a tax benefit by FRS conventions because a segment's loss can offset profits in other segments on a consolidated basis.

FRS Reporting Companies, Segments, and Tax-Paying Entities. FRS reporting companies and their segments differ from the entities which actually pay income taxes. The FRS system reports energy activities on a consolidated company basis, disaggregated into various energy lines of business. Accordingly, income tax expense, current and deferred, is reflected on a line-of-business basis. However, under the tax laws, taxes are not necessarily based upon FRS reporting company consolidated earnings of the FRS line-of-business segments.

The tax-paying entities of an FRS reporting company are its subsidiaries. Some are incorporated in the United States and some in foreign countries, and each may operate in the United States, foreign countries, or both. Income tax expense in the FRS system consists of both U.S. and foreign income taxes incurred by these subsidiaries. Taxes reflected by the consolidated company and each individual segment are allocated from taxes paid and deferred by the actual tax-paying entities.

The United States taxes only income of foreign corporations earned in the United States or paid into the United States as dividends to a U.S. parent corporation

Table A2. Example of Nontraceables and Eliminations

Financial Items	Consolidated	Elimination	Nontraceable	Refining/ Marketing	Production
Revenues	160	(80)	-	160	80
Less Expenses:					
General and Administrative .	10	-	2	5	3
Other Operations	10	-	-	5	5
Crude	-	(80)	-	80	-
Operating Income	140	-	(2)	70	72
Less Interest Expense	20	-	20	-	-
Less Income Taxes	60	-	(11)	35	36
Net Income	60	-	(11)	35	36

Note: Numbers in parentheses are negative.

(owner). All income subject to U.S. tax, whether the entity is a foreign or U.S. corporation, is given the benefit of the foreign income tax credit (up to the statutory rate) to avoid double taxation. Each U.S. incorporated subsidiary of a U.S. corporation elects either to be included in a consolidated U.S. tax return or to file a separate return, depending on which election is most likely to minimize the aggregate U.S. and foreign taxes. In the FRS system, corporate organization and relationships are not purely a function of line-of-business financial reporting. This fact requires that allocations be made of taxes incurred so that they can be classified according to the FRS segment format. These allocations are required when a subsidiary is involved in both U.S. and foreign operations and / or in more than one line of energy business. For example, the FRS system has separate segments for the foreign and U.S. petroleum production business, and for the foreign and U.S. refining / marketing business. Therefore, if an FRS reporting company has a foreign subsidiary involved in both petroleum production and refining / marketing of petroleum, a disaggregation of that subsidiary's activities, including income taxes, must be made.

The disaggregation is further complicated by the existence of nontraceable items, such as interest expense, interest income, minority interest, and foreign currency gains and losses. The nontraceable column must be treated as a separate segment when the tax allocation is made.

Deferred Taxes

The Financial Accounting Standards Board (FASB) began working on a project to reexamine the generally accepted accounting procedure for income taxes in September 1982. Accounting Principles Board Opinion 11 ("APB 11"), issued in 1967, faced criticism and concerns about the inconsistencies in its amendments and interpretations. In addition, problems created by new tax depreciation methods and changes in accounting for income taxes in other countries were making APB 11 outdated. In 1988, the FASB issued Statement of Financial Accounting Standards No. 96, "Accounting for Income Taxes" ("SFAS 96"), to address the increased complexity and significance of deferred taxes in the balance sheet. However, because of its complex scheduling process and conservative tax asset provisions, SFAS 96 soon became a source of controversy among businesses, CPA firms, professional organizations, and industry trade groups. In response to the criticism, the FASB deferred the required implementation date of SFAS 96 three times (SFAS 100, 103, and 108) and began developing a new standard which would address not only criticism of APB Opinion 11 but also the controversy surrounding SFAS 96. The new standard, SFAS 109, "Accounting for Income Taxes," became effective for periods beginning after December 15, 1992.

The objective of accounting for income taxes is the recognition and presentation in the financial statements of the following:

- Taxes currently payable or refundable
- Deferred tax assets and liabilities for the future tax consequences of events that have been recognized in the financial statements or tax returns.

Deferred taxes reflect the future tax consequences of events already recognized in either the financial statements or tax returns. SFAS 109 uses the balance sheet approach, also referred to as the liability method, to determine deferred taxes. This method, first introduced in SFAS 96, differs from APB 11, which used the income statement approach. SFAS 109 also requires a deferred tax asset to be recognized for deductible temporary differences and operating loss and tax credit carryforwards using the applicable tax rate.

The income statement approach recognizes deferred taxes on the temporary timing differences between pretax accounting income and taxable income each year. Temporary differences are those differences between accounting and taxable income that will ultimately reverse. For example, intangible drilling costs for a successful well are expensed when paid for tax purposes but capitalized and depreciated for accounting purposes. If we assume the intangible drilling cost of $100,000 was the sole timing difference, and this cost was depreciated $20,000 per year for accounting purposes, there would be an $80,000 temporary timing difference in year one, as taxable income would be less than accounting income. This timing difference would reverse $20,000 each year as the intangible drilling cost is depreciated for accounting purposes with no deduction for tax purposes. At the end of the fifth year, the timing difference would be completely reversed.

The liability approach recognizes deferred taxes on the temporary differences between the financial and tax bases of assets and liabilities. Both the deferred tax liability and the deferred tax asset must be measured by use of the applicable tax rate. The applicable tax rate is the enacted tax rate to be applied to the last dollar of taxable income for the year when the liability is expected to be settled or the assets recovered. A single flat tax rate may be used for companies for which graduated rates are not a significant factor. A deferred tax asset is recognized for existing alternative minimum tax credit carryforwards for tax purposes. When computing deferred tax assets and / or liabilities, if there is a change in the tax rate or tax law, the deferred tax assets and / or liabilities should be adjusted in the period that includes the enactment date. To the extent deferred tax balances are adjusted for the effects of such changes, income tax expense or benefit from continuing operations is charged or credited. Using the example from the preceding paragraph, the financial statement basis of the intangible drilling cost in year one would be $80,000 ($100,000 less $20,000 depreciation), while there would be no basis for tax purposes because the costs were totally deducted. Deferred taxes would be provided for the $80,000 difference by use of enacted tax rates. Deferred taxes would be adjusted each year until the difference between the financial accounting and tax bases was fully eliminated at the end of year five.

Once deferred tax assets and liabilities relating to the future tax consequences of temporary differences and carryforwards have been measured, the deferred tax provision or benefit is based on the net change in a deferred tax balance during the year. The income tax expense or benefit for the period is derived from the total tax currently payable or refundable and the deferred tax expense or benefit.

As stated earlier, SFAS 109 became effective for fiscal years beginning after December 15, 1992. There were two transition options available when adopting SFAS 109: prospective or retroactive application. A company could elect to restate the financial statements for any number of consecutive prior years (retroactive application) or report a cumulative effect adjustment below “income from continuing operations” (prospective application).

For 1993 through 1996, all FRS companies have reported taxes in accordance with SFAS 109. For 1992, seventeen FRS reporting companies had adopted the provisions of SFAS 109, which resulted in a net $163 million benefit to their 1992 reported earnings. The remaining eight FRS reporting companies adopted SFAS 109 in the first quarter of 1993, resulting in a $671 million benefit to 1993 reported earnings. Of the eight companies which had not adopted SFAS 109 in 1992, five reported under APB 11 and three reported in accordance with SFAS 96.

Corporate Acquisitions

Under FRS reporting rules, no acquisitions are accounted for under the pooling of interest method. This is because, under the pooling method, the financial statements do not reflect such transactions as new investment, since the historical financial statements are restated. One of the objectives of the FRS is to track new investment activities.

For FRS reporting purposes, acquisitions accounted for as pooling for annual report purposes must be reflected in the FRS filing under a modified purchase method. All purchase accounting rules are followed, except that the assets of the acquired company are not revalued but are recorded at their book values as stated on the acquired company's books.

Full Cost and Successful Efforts Accounting Methods

FRS reporting companies are permitted to choose between two accounting methods, “full cost” and “successful efforts,” to account for their exploration and production activities. All but two of the FRS companies use the successful efforts method. The main difference between the two methods is the treatment of dry exploratory well cost.

Under full cost, the cost of a dry exploratory well is capitalized and then amortized to the income statement over the productive life of successful wells. Thus, the costs of both dry and successful wells are capitalized and reflected in the balance sheet as part of producing properties.

Under successful efforts, the cost of a dry exploratory well is written off to expense in the year in which drilling is determined to be unsuccessful. There is no capitalized cost of such dry exploratory wells carried on the balance sheet.

In comparison to the successful efforts method, the full cost method will: (1) show less volatility of earnings, since the cost of unsuccessful wells is amortized over many years; (2) show a higher balance in accumulated property, plant, and equipment (PP&E), since the account contains the costs of all wells drilled, including dry exploratory wells; (3) usually show higher earnings during years of intense exploratory activity when a number of dry wells are encountered; and (4) show the same cumulative earnings over a long period of years, since eventually all costs will be amortized to the income statement. These effects are minimized if the firm is large, since the exploratory activities of a large firm are usually smaller, relative to total production operations, than they are in a small production firm.

Usually, the precise effect of using one method over the other cannot be determined. However, one large firm switched from full cost to successful efforts in 1975 and restated 1973 and 1974 data to the successful efforts method. Thus, we have available the impact of this conversion on their comparative net income, net PP&E, and return on net PP&E for 1973 and 1974 (see Table A3). Since twenty-two of the FRS companies presently use successful efforts accounting, comparability problems are inconsequential.

Inventory Accounting — LIFO Versus FIFO

The Last In-First Out (LIFO) and the First In-First Out (FIFO) inventory methods are used most often in the preparation of financial statements of industrial enterprises.

Under FIFO, the balance sheet valuation of inventory is based upon the most recent prices paid for the physical units on hand at year's end, and the income statement reflects the cost of units sold at the oldest unit cost. In periods of rapidly rising prices, the income statement reflects higher profits than would be reflected if the units sold were priced at current replacement cost or under the LIFO method.

Under LIFO, the balance sheet valuation of inventory is based on the prices paid for the first units of each major type of inventory ever purchased. For example, crude oil could be carried at $10 per barrel, an amount which vastly understates the value of the inventory in terms of its replacement cost. The income statement reflects the cost of units sold at the most recent prices paid for the number of units sold. Thus, cost of goods sold reflects nearly a replacement cost amount, and profits are lower than under the FIFO method.

Since either method is permitted under the Federal tax laws, most companies use LIFO for operations subject to U.S. taxation because earnings and, hence, taxes are lower under this method. By 1979, most FRS reporting companies were using primarily the LIFO inventory method. Most analysts probably would agree that LIFO is the preferable method, since the income statement is more realistic than with FIFO. However, its disadvantage is that the balance sheet's inventory figure is understated, and, hence, the stockholders' equity amount is correspondingly understated.

In 1996, two FRS companies reported liquidation profits or losses. The 1996 aggregate liquidation profits increased the reporting companies' operating income by $46 million, an amount which represented 0.1 percent of their aggregate operating income. This compares to a $163 million increase in 1995 and a $23.4 million increase in 1994, amounts that represented 0.5 and 0.1 percent, respectively, of aggregate operating income for those years.

Foreign Currency Translations

In December 1981, the Financial Accounting Standards Board (FASB) issued Statement No. 52, "Foreign Currency Translations," which superseded FASB-8, "Accounting for the Translation of Foreign Currency Transactions and Foreign Currency Financial Statements." FASB-52 covers the translation of foreign currency financial statements for the purposes of the consolidation, combination, or reporting by the equity method and the translation of foreign currency transactions. The new statement required that assets, liabilities, and operations of an entity be stated in the currency of the primary economic environment in which the entity operates (termed the "functional currency"). If a foreign entity has not kept its financial records in the functional currency, remeasurement is required prior to translation. Any gain or loss on remeasurement is recognized in current net income. The assets and liabilities of the foreign entity are translated from its functional currency to the reporting currency at the current rate of exchange.

Under FASB-52, gain or loss on the translation of foreign currency financial statements is shown as a separate component of stockholders' equity, whereas, under FASB-8, all non-monetary balance sheet items were translated at the historical rate of exchange. Thus, the change to FASB-52, which uses the current rate of exchange, had the most significant impact on inventories and fixed assets. With respect to the income statement, FASB-52 requires that only gains or losses from foreign currency transactions be included.

Table A3. A Comparison Between Full Cost and Successful Efforts Accounting Methods

Years	Full Cost	Successful Efforts
1973		
Net Income (dollars)	1,292,400	1,243,300
Net PP&E (dollars)	8,476,700	7,511,300
Net Income/PP&E (percent)	15.25	16.70
1974		
Net Income (dollars)	1,586,400	1,544,700
Net PP&E (dollars)	9,593,300	8,563,500
Net Income/PP&E (percent)	16.54	17.98

Source: Texaco, Inc., 1974 and 1977 *Annual Report* and *Statistical Supplements.*

As Table A4 indicates, foreign currency translation gains decreased stockholders' equity by 0.2 percent, while foreign currency transaction losses decreased pretax income by 0.1 percent in 1996.

FRS Database History

The Form EIA-28, "Financial Reporting System (FRS)," database has existed in three formats during its 22-year history. In addition, there have been minor, periodic adjustments since 1987. The most noteworthy was the change from a Statement of Sources and Uses of Funds to a Statement of Cash Flows, effective in the 1986 reporting year. The first version of the Form EIA-28 and its database covered years 1974-1980. The second version covered years 1981-1986. The third covered years 1987-1992. The fourth version begins with the 1993 reporting year and is approved through the 1999 reporting year.

The current version was changed by the addition of the former Soviet Union and Eastern Europe as a new geographical reporting area.

The first full reporting year for the first version of the form was 1977. It consisted of 47 separate schedules containing 8,775 data elements and was 136 pages long.[230] This version of the database contained a significant amount of detail at the consolidated level, in each line of business and in the breadth of operating statistics. However, not all of the collected data were loaded into the database. About 1,000 elements were not unique to individual companies—such as joint venture information—and were maintained only in their hard copy format.

In 1982 (for the 1981 reporting year), the form was shortened by 72 percent, to 2,468 elements. The format was still the same, with data collected at the consolidated level, four energy lines of business (petroleum, coal, nuclear, and other energy) and nonenergy. The 1981-1986 form consisted of 19 schedules and was 35 pages long. Although data were still collected by each line of business, most of the decline was at the line-of-business level, where more than 81 percent of the form was eliminated, compared with a 58-percent decline at the consolidated level.

In 1988 (for the 1987 reporting year), the form was shortened by another 33 percent, to 1,650 elements. The consolidated level was shortened by 32 percent, primarily by combining other energy with nuclear energy. Petroleum data declined by 10 percent, coal by 74 percent, and separate income statement schedules for the remaining lines of business (coal, nuclear and other energy, and nonenergy) were eliminated altogether (although income statements for each of these lines of business were incorporated into Schedule 5110, Consolidating Statement of Income). The form currently has 14 schedules and is 27 pages long.

Table A4. The Impact of FASB-52, Foreign Currency Translations, on Stockholders' Equity and Pretax Income, 1982-1996

Year	Translation Gains/Losses	Stockholders' Equity	Percent of Stockholders' Equity	Transaction Gains/Losses	Pretax Income	Percent of Pretax Income
	(million dollars)			(million dollars)		
1982	-1,764	183,933	-1.0	-111	45,157	-0.2
1983	-1,253	192,509	-0.7	35	47,420	0.1
1984	-1,683	176,461	-1.0	-44	47,609	-0.1
1985	399	165,457	0.2	176	43,573	0.4
1986	1,786	164,601	1.1	543	20,564	2.6
1987	3,425	165,458	2.1	176	25,006	0.7
1988	-495	164,832	-0.3	89	34,285	0.3
1989	-465	160,638	-0.3	142	32,281	0.4
1990	1,918	167,060	1.1	135	37,489	0.4
1991	101	167,574	0.1	-25	25,120	-0.1
1992	-3,341	157,295	-2.1	375	22,542	1.7
1993	-637	161,769	-0.4	170	24,777	0.7
1994	1,912	165,689	1.2	280	29,592	1.0
1995	701	166,689	0.4	-48	34,233	-0.1
1996	-368	179,917	-0.2	-22	52,808	-0.1

Source: Energy Information Administration, Form EIA-28, “Financial Reporting System.”

Endnotes

[229] The other lines of business (Coal, Other Energy, and Nonenergy) were also disaggregated into segments, but only through 1986.

[230] In order to extend the range of the data back through 1974, an abbreviated version of the form was collected for the years 1974 through 1976. Almost 2,900 data elements (one-third of the total) were collected for each of these years, and consisted primarily of summary data from 26 of the 47 schedules.

Appendix B

Detailed Statistical Tables

Table B1. Selected U.S. Operating Statistics for FRS Companies and U.S. Industry, 1995 and 1996

Operating Statistics	FRS Companies			U.S. Industry [1]			FRS as a Percent of U.S. Industry	
	1995	1996	Percent Change	1995	1996	Percent Change	1995	1996
Petroleum								
Net Production								
Crude Oil and Natural Gas Liquids (million barrels)	1,570.6	1,532.4	-2.4	3,004.0	3,023.0	0.6	52.3	50.7
Natural Gas (billion cubic feet)	8,055.3	8,191.6	1.7	17,966.0	18,861.0	5.0	44.8	43.4
Net Imports								
Crude Oil and Natural Gas Liquids (million barrels)	612.1	565.7	-7.6	2,810.0	2,946.6	4.9	21.8	19.2
Refinery Capacity (thousand barrels per day)	10,427.0	10,477.0	0.5	15,981.0	16,031.8	0.3	65.2	65.4
Refinery Output[2] (thousand barrels per day)	10,652.0	10,954.0	2.8	16,534.7	16,800.7	1.6	64.4	65.2
Bituminous Coal and Lignite Production (million tons)	165.4	169.4	2.4	1,028.3	1,059.1	3.0	16.1	16.0

[1] U.S. area is defined to include the 50 States, District of Columbia, U.S. Virgin Islands, and Puerto Rico.
[2] For FRS companies, includes refinery output at own refineries for own account and at others' refineries for own account.

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 1996 Annual Report* (November 1997). 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 3,150.2 million barrels in 1996 and 3,148.5 million barrels in 1995. (See Energy Information Administration, *Petroleum Supply Annual 1996,* Volume 1 (June 1997), p. 2.) For dry natural gas production, the official Energy Information Administration U.S. totals are 19,022 billion cubic feet in 1996 and 18,599 billion cubic feet in 1995. (See Energy Information Administration, *Natural Gas Monthly, September 1997,* p. 8.)

Sources: Industry data - Petroleum net production: Energy Information Administration, Form EIA-23; see *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1996 Annual Report* (November 1997). 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*, 1995 and 1996. Coal production: Energy Information Administration, Form EIA-7A (Coal Production Report); see *Coal Industry Annual 1996* (October 1997).

Table B2. Selected U.S. Operating Statistics for FRS Companies and U.S. Industry, 1990-1996

Operating Statistics	1990	1991	1992	1993	1994	1995	1996
Petroleum							
Net Production							
Crude Oil and Natural Gas Liquids (million barrels)							
FRS companies	1,814.0	1,818.1	1,750.2	1,632.5	1,593.8	1,570.6	1,532.4
U.S. Industry[1]	3,237.0	3,266.0	3,219.0	3,127.0	3,059.0	3,004.0	3,023.0
FRS as a percent of U.S. Industry	56.0	55.7	54.4	52.2	52.1	52.3	50.7
Natural Gas (billion cubic feet)							
FRS companies	7,578.2	7,509.5	7,877.7	7,651.1	7,998.4	8,055.3	8,191.6
U.S. Industry[1]	17,233.0	17,202.0	17,423.0	17,789.0	18,322.0	17,966.0	18,861.0
FRS as a percent of U.S. Industry	44.0	43.7	45.2	43.0	43.7	44.8	43.4
Net Imports							
Crude Oil and Natural Gas Liquids (million barrels)							
FRS companies	975.2	917.9	868.8	757.5	754.1	612.1	565.7
U.S. Industry[1]	2,324.7	2,243.7	2,383.0	2,640.9	2,788.7	2,810.0	2,946.6
FRS as a percent of U.S. Industry	41.9	40.9	36.5	28.7	27.0	21.8	19.2
Refinery Capacity (thousand barrels per day)							
FRS companies	11,372.0	11,203.0	10,952.0	10,714.0	10,642.0	10,427.0	10,477.0
U.S. Industry[1]	16,430.4	16,452.6	15,804.4	15,718.0	16,069.3	15,981.0	16,031.8
FRS as a percent of U.S. Industry	69.2	68.1	69.3	68.2	66.2	65.2	65.4
Refinery Output[2] (thousand barrels per day)							
FRS companies	11,312.0	11,122.0	10,994.0	10,822.0	10,812.0	10,652.0	10,954.0
U.S. Industry[1]	15,911.2	15,872.2	15,932.0	16,341.2	16,341.1	16,534.7	16,800.7
FRS as a percent of U.S. Industry	71.1	70.1	69.0	66.2	66.2	64.4	65.2
Bituminous Coal and Lignite Production (million tons)							
FRS companies	282.0	289.6	251.9	197.3	179.7	165.4	169.4
U.S. Industry[1]	1,029.1	996.0	994.1	941.1	1,028.9	1,028.3	1,059.1
FRS as a percent of U.S. Industry	27.4	29.1	25.3	21.0	17.5	16.1	16.0

[1] U.S. area is defined to include the 50 States, District of Columbia, U.S. Virgin Islands, and Puerto Rico.
[2] For FRS companies, includes refinery output at own refineries for own account and at others' refineries for own account.

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 1996 Annual Report* (November 1997). 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 3,150.2 million barrels in 1996 and 3,148.5 million barrels in 1995. (See Energy Information Administration, *Petroleum Supply Annual 1996,* Volume 1 (June 1997), p. 2.) For dry natural gas production, the official Energy Information Administration U.S. totals are 19,022 billion cubic feet in 1996 and 18,599 billion cubic feet in 1995. (See Energy Information Administration, *Natural Gas Monthly, September 1997,* p. 8.)

Sources: Industry data - Petroleum net production: Energy Information Administration, Form EIA-23; see *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1996 Annual Report* (November 1997). 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*, 1995 and 1996. Coal production: Energy Information Administration, Form EIA-7A (Coal Production Report); see *Coal Industry Annual 1996* (October 1997).

Table B3. A Comparison of Selected Financial Items for FRS Companies and the S&P Industrials, 1996 and Percent Change from 1995

Selected Financial Items	FRS Companies		S&P Industrials	
	1996 (billion dollars)	Percent Change from 1995	1996 (billion dollars)	Percent Change from 1995
Income Statement				
Operating Revenues	541.4	12.4	3,586.5	6.1
Operating Expenses	-492.7	9.7	-3,192.1	6.1
Operating Income	48.7	49.6	394.4	6.8
Other Income[1]	3.4	148.9	-52.7	-35.6
Income Taxes	-20.0	56.9	-122.9	13.8
Net Income	32.0	51.6	218.9	22.0
Cash Flows from Operations[2]				
Net Income	32.0	51.6	218.9	22.0
Other Items, Net[3]	32.2	-13.9	195.8	1.7
Net Cash Flow from Operations	64.2	9.7	414.7	12.4
Cash Flows from Investing Activities[2]				
Additions to PP&E	-44.2	-0.8	-272.9	11.3
Other Investment Activities, Net[4]	6.8	-32.1	-63.3	-13.8
Net Cash Flow from Investing Activities	-37.4	8.2	-336.2	5.5
Cash Flows from Financing Activities[2]				
Proceeds from Long-Term Debt	10.7	-46.3	255.7	8.7
Proceeds from Equity Security Offerings	1.2	-66.3	35.5	62.4
Dividends to Shareholders	-15.6	2.3	-79.0	2.8
Reductions in Long-Term Debt	-18.9	1.2	-218.8	38.5
Stock Repurchases	-1.3	-87.1	-66.9	16.2
Other Financing Activities, Net	-0.6	-75.4	14.0	([5])
Net Cash Flow from Financing Activities	-24.5	6.9	-59.5	63.5
Effect of Exchange Rate Changes on Cash	0.0	-78.6	-1.5	([5])
Increase (Decrease) in Cash and Cash Equivalents	2.3	([5])	17.9	([5])

[1] "Other Income" includes other revenue and expense, discontinued operations, extraordinary items, and accounting changes.
[2] Items that add to cash are positive, and items that use cash are shown as negative values.
[3] "Other Items, Net" includes: DD&A, deferred taxes, dry hole expense, minority interest, recognized undistributed earnings/(losses) of unconsolidated affiliates, (gain)/loss on disposition of PP&E, changes in operating assets and liabilities, and other noncash items, excluding net change in short-term debt; other cash items, net.
[4] "Other Investment Activities, Net" includes additions to investments and advances and proceeds from disposals of PP&E.
[5] Not meaningful.

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

Table B4. Consolidating Statement of Income for FRS Companies, 1996

(Million Dollars)

Income Statement Items	Consolidated	Eliminations & Non-Traceable	Petroleum	Coal	Nuclear & Other Energy	Non-Energy
Operating Revenues	541,388	-11,945	464,845	3,524	2,391	82,573
Operating Expenses						
General Operating Expenses	453,811	-11,164	393,739	2,689	1,900	66,647
DD&A	29,331	415	24,301	388	133	4,094
General & Administrative	9,562	1,957	5,597	96	72	1,840
Total Operating Expenses	492,704	-8,792	423,637	3,173	2,105	72,581
Operating Income	48,684	-3,153	41,208	351	286	9,992
Other Revenue & (Expense)						
Earnings of Unconsolidated Affiliates	4,916	35	3,404	98	164	1,215
Other Dividend & Interest Income	2,452	2,452	–	–	–	–
Gain/Loss on Disposition of PP&E	1,940	-67	1,517	227	-90	353
Interest Expenses & Financial Charges	-6,938	-6,938	–	–	–	–
Minority Interest in Income	-845	-845	–	–	–	–
Foreign Currency Translation Effects	-22	-22	–	–	–	–
Other Revenue & (Expense)	2,621	2,621	–	–	–	–
Total Other Revenue & (Expense)	4,124	-2,764	4,921	325	74	1,568
Pretax Income	52,808	-5,917	46,129	676	360	11,560
Income Tax Expense	20,005	-2,681	18,795	218	145	3,528
Discontinued Operations	W	W	W	0	0	0
Extraordinary Items and Cumulative Effect of Accounting Changes	W	W	W	0	0	0
Net Income	32,029	-3,583	26,907	458	215	8,032

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

Table B5. Consolidating Statement of Income for FRS Companies, U.S. and Foreign Petroleum Segments, 1996

(Million Dollars)

Income Statement Items	U.S. Petroleum				Foreign Petroleum			
	Consoli-dated	Production	Refining/ Marketing	Pipelines	Consoli-dated	Production	Refining/ Marketing	Int'l Marine
Operating Revenues								
Raw Material Sales	114,537	59,788	86,551	W	73,128	47,752	58,502	0
Refined Products Sales	141,334	W	141,525	W	133,393	W	133,476	0
Transportation Revenues	6,882	W	3,522	7,847	2,078	171	W	2,250
Management And Processing Fees	1,051	355	749	41	1,248	W	W	W
Other	9,723	839	7,209	348	4,056	818	3,246	W
Total Operating Revenues	273,527	61,102	239,556	9,660	213,903	49,447	196,552	2,263
Operating Expenses								
General Operating Expenses	232,639	33,030	230,305	6,094	183,680	24,260	191,604	2,083
DD&A	15,229	10,499	3,847	883	9,072	7,237	1,736	99
General & Administrative	3,557	1,203	1,917	438	2,045	785	1,319	33
Total Operating Expenses	251,425	44,732	236,069	7,415	194,797	32,282	194,659	2,215
Operating Income	22,102	16,370	3,487	2,245	19,106	17,165	1,893	48
Other Revenue & (Expense)								
Earnings of Unconsolidated Affiliates	622	130	70	422	2,782	1,770	1,005	W
Gain(Loss) On Disposition of PP&E	990	790	81	119	527	487	40	W
Total Other Revenue & (Expense)	1,612	920	151	541	3,309	2,257	1,045	7
Pretax Income	23,714	17,290	3,638	2,786	22,415	19,422	2,938	55
Income Tax Expense	7,585	5,474	1,135	976	11,210	10,232	954	24
Discontinued Operations	W	W	W	W	0	0	0	0
Extraordinary Items and Cumulative Effect of Accounting Changes	W	W	W	W	0	0	0	0
Contribution To Net Income	15,702	11,816	2,251	1,635	11,205	9,190	1,984	31

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

Table B6. Profit Rates for Lines of Business and Petroleum Segments for FRS Companies, 1990-1996
(Percent)

Line of Business	1990	1991	1992	1993	1994	1995	1996
Consolidated	6.8	4.5	0.5	4.7	4.9	6.2	9.5
Petroleum	9.5	7.0	5.6	6.4	5.6	5.7	10.1
U.S. Petroleum	7.9	4.9	4.4	4.9	5.2	4.0	9.9
Oil and Gas Production	8.5	5.1	5.9	5.3	5.5	4.4	14.1
Refining/Marketing	5.1	2.0	-0.4	3.4	3.6	1.0	4.4
Pipelines	11.2	10.7	8.4	6.4	7.6	9.1	6.9
Foreign Petroleum	12.5	11.0	7.9	9.2	6.2	8.4	10.6
Oil and Gas Production	13.1	9.1	8.2	8.6	6.5	9.3	12.8
Refining/Marketing	11.2	14.6	7.8	10.6	6.1	7.2	6.0
International Marine	11.7	15.6	-1.2	1.2	-2.0	-2.5	2.2
Coal	3.3	8.7	-9.3	7.6	4.0	6.9	9.9
Nuclear and Other Energy	2.6	2.8	1.8	4.1	4.8	6.1	7.9
Nonenergy	7.8	2.9	2.1	4.7	10.5	19.4	15.0

Note: Profit rate measured as contribution to net income/net investment in place.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B7. Profit Rates for Petroleum Segments for FRS Companies Ranked by Total Energy Assets, 1994-1996

(Percent)

Petroleum Segments	Top Four			Five Through Twelve			All Other		
	1994	1995	1996	1994	1995	1996	1994	1995	1996
Petroleum	6.5	6.6	11.1	5.0	5.7	9.9	4.1	3.4	8.0
U.S. Petroleum	5.0	3.1	11.8	5.5	5.8	10.1	4.8	1.5	6.7
Oil and Gas Production	5.9	3.2	18.0	5.4	5.8	12.8	4.9	3.3	11.1
Refining/Marketing	2.1	0.8	2.6	5.4	4.8	8.1	3.0	-4.6	1.2
Pipelines	17.1	20.0	16.6	5.9	7.2	5.9	8.6	9.9	5.7
Foreign Petroleum	7.7	9.1	10.6	3.4	5.1	9.4	1.6	11.2	13.2
Oil and Gas Production	9.9	11.4	14.1	2.4	4.8	9.9	1.1	10.1	13.6
Refining/Marketing	5.8	6.7	6.0	10.6	9.7	5.9	5.5	25.5	8.9
International Marine	-3.7	-0.9	4.0	181.3	-141.7	W	-6.5	-50.0	W

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

Table B8. A Comparison of Balance Sheet Items for FRS Companies and the S&P Industrials, 1996 and Percent Change from 1995

Balance Sheet Items	FRS Companies		S&P Industrials	
	1996 (billion dollars)	Percent Change from 1995	1996 (billion dollars)	Percent Change from 1995
Assets				
Current Assets	108.2	9.8	1,016.3	5.7
Noncurrent Assets				
Property, Plant, and Equipment				
Gross	635.0	-0.8	2,504.2	5.6
Accumulated DD&A	-331.6	0.5	-1,160.1	4.0
Net	303.4	-2.3	1,344.1	7.1
Investments and Advances	32.3	11.2	104.5	6.3
Other Noncurrent Assets	26.8	1.0	1,417.8	12.8
Subtotal Noncurrent Assets	362.4	-1.0	1,836.1	9.7
Total Assets	470.6	1.3	3,882.7	8.7
Liabilities and Stockholders' Equity				
Liabilities				
Current Liabilities	110.1	6.0	880.8	6.0
Long-Term Debt	70.9	-16.2	778.6	6.3
Other Long-Term Items	105.3	1.7	930.1	7.4
Minority Interest	6.6	12.2	49.8	20.3
Subtotal Liabilities and Other Items	292.9	-1.7	2,639.2	6.8
Stockholders' Equity				
Retained Earnings	156.3	3.2	928.7	10.8
Other Equity	21.4	40.6	314.8	19.8
Subtotal Stockholders' Equity	177.8	6.6	1,243.5	12.9
Total Liabilities and Stockholders' Equity	470.6	1.3	3,882.7	8.7

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

Table B9. Consolidated Balance Sheet for FRS Companies, 1990-1996

(Billion Dollars)

Balance Sheet Items	1990	1991	1992	1993	1994	1995	1996
Assets							
Current Assets							
Cash & Marketable Securities	14.9	12.4	12.1	14.1	13.2	12.2	13.4
Trade Accounts and Notes Receivable	56.6	47.2	44.6	41.7	45.8	48.8	56.2
Inventories							
Raw Materials & Products	28.0	27.0	26.2	23.7	22.9	22.6	22.7
Materials & Supplies	5.3	5.2	4.6	4.3	4.4	4.1	3.8
Other Current Assets	10.5	9.2	10.4	9.6	10.2	10.9	12.1
Total Current Assets	115.4	101.0	97.9	93.5	96.6	98.6	108.2
Non-current Assets							
Property, Plant & Equipment							
Gross	565.0	581.4	599.9	607.9	624.1	640.2	635.0
Accumulated DD&A	262.5	275.9	290.2	300.0	315.4	329.8	331.6
Net	302.5	305.5	309.7	307.9	308.7	310.5	303.4
Investments & Advances to Unconsolidated Affiliates	17.2	20.1	21.9	23.6	25.9	29.0	32.3
Other Non-current Assets	22.2	20.6	24.2	26.3	26.2	26.5	26.8
Total Non-current Assets	341.8	346.2	355.7	357.8	360.8	366.0	362.4
Total Assets	457.2	447.1	453.6	451.3	457.4	464.6	470.6
Liabilities & Stockholder's Equity							
Liabilities							
Current Liabilities							
Trade Accounts & Notes Payable	64.6	56.5	53.1	49.1	51.5	53.1	61.4
Other Current Liabilities	50.2	47.6	48.7	47.0	45.8	50.8	48.8
Long Term Debt	88.5	90.9	93.5	89.4	88.1	84.6	70.9
Deferred Income Tax Credits	50.3	47.0	44.7	45.5	45.0	45.5	45.5
Other Deferred Credits	12.3	12.2	16.5	15.9	16.8	17.3	19.2
Other Long Term Items	19.8	21.1	34.9	37.7	39.3	40.7	40.6
Minority Interest in Consolidated Affiliates	4.4	4.2	4.8	5.0	5.1	5.8	6.6
Total Liabilities	290.1	279.6	296.3	289.6	291.7	297.9	292.9
Stockholders' Equity							
Retained Earnings	148.7	148.9	139.2	142.0	145.0	151.4	156.3
Other Equity	18.4	18.6	18.1	19.8	20.7	15.3	21.4
Total Stockholders' Equity	167.1	167.6	157.3	161.8	165.7	166.7	177.8
Total Liabilities & Stockholders' Equity	457.2	447.1	453.6	451.3	457.4	464.6	470.6
Memo:							
Foreign Currency Translation Adjustment Cumulative at Year End	-3.3	-3.2	-6.6	-7.3	0.7	1.5	1.2
Foreign Currency Translation Adjustment for the Current Year	1.9	0.1	-3.3	-0.6	1.9	0.7	-0.4

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

Table B10. Distribution of Net Investment in Place for FRS Companies, United States and Foreign, 1996

Fixed Investment	Consolidated Company	United States	Foreign	Nontraceable[1]
Net Investment in Place				
(billion dollars)				
Net Property, Plant, and Equipment	303.4	188.9	107.1	7.3
Investments and Advances to Unconsolidated Affiliates	32.3	9.6	20.4	2.2
Total Net Investment in Place	335.6	198.5	127.5	9.6
Net Investment in Place				
(percent distribution)				
Net Property, Plant, and Equipment	100.0	62.3	35.3	2.4
Investments and Advances to Unconsolidated Affiliates	100.0	29.8	63.2	6.9
Total Net Investment in Place	100.0	59.2	38.0	2.9
Additions to Investment in Place				
(billion dollars)				
Property, Plant, and Equipment	44.2	24.3	18.9	0.9
Investments and Advances to Unconsolidated Affiliates	5.8	2.4	2.7	0.7
Total Additions to Investment in Place	50.0	26.7	21.6	1.6
Additions to Investment in Place				
(percent distribution)				
Property, Plant, and Equipment	100.0	55.1	42.8	2.1
Investments and Advances to Unconsolidated Affiliates	100.0	41.9	46.2	12.0
Total Additions to Investment in Place	100.0	53.5	43.2	3.3

[1] Includes items in consolidated balance sheet that cannot be allocated to segments (nontraceables). In this table, this column is derived as a residual.

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

Table B11. Net Property, Plant and Equipment (PP&E), Additions to PP&E, Investments and Advances, and Depreciation, Depletion and Amortization (DD&A), by Lines of Business for FRS Companies, 1996

(Million Dollars)

Line of Business	Year End Balance		Activity During Year		
	Net PP&E	Investments and Advances	Additions to PP&E	Additions to Investments and Advances	DD&A
Nonenergy					
Foreign Chemicals	9,446	3,930	1,586	741	929
U.S. Chemicals	28,028	1,955	4,883	201	2,502
Foreign Other Nonenergy	5,020	57	W	35	W
U.S. Other Nonenergy	4,209	929	W	90	W
Total Nonenergy	46,703	6,871	7,522	1,067	4,094
Nuclear and Other Energy					
Foreign	1,060	W	W	W	110
United States	954	W	W	W	23
Total Nuclear and Other Energy	2,014	701	183	373	133
Coal					
Foreign	W	W	W	W	W
United States	W	W	W	W	W
Total Coal	3,602	1,027	278	418	388
Petroleum					
United States					
Production	82,227	1,640	13,077	1,026	10,499
Refining/Marketing					
Refining	29,790	940	2,094	42	2,171
Marketing	15,932	625	1,964	87	1,396
Refining/Marketing Transport					
Pipelines	1,580	494	223	103	99
Marine	1,151	W	29	0	103
Other	1,032	W	140	0	78
Total U.S. Refining/Marketing	49,485	2,134	4,450	232	3,847
Rate Regulated Pipelines					
Refined Products	1,284	174	125	W	58
Natural Gas	14,967	976	565	W	489
Crude Oil and Liquids	5,610	698	397	235	336
Total Rate Regulated Pipelines	21,861	1,848	1,087	269	883
Total U.S. Petroleum	153,573	5,622	18,614	1,527	15,229
Foreign					
Production	64,989	6,747	13,411	1,335	7,237
Refining/Marketing	23,827	9,000	3,178	W	1,736
International Marine	1,336	66	21	W	99
Total Foreign Petroleum	90,152	15,813	16,610	1,721	9,072
Total Petroleum	243,725	21,435	35,224	3,248	24,301
Nontraceable	7,328	2,243	946	693	415
Consolidated	303,372	32,277	44,153	5,799	29,331

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

Table B12. Income and Investment Patterns in Worldwide Petroleum for FRS Companies Ranked by Total Energy Assets, 1996, and Percent Change from 1995

Income and Investment	Worldwide	United States	Foreign
		(million dollars)	
1996			
Contribution to Net Income			
Top Four	13,563.0	5,648.0	7,915.0
Five Through Twelve	9,784.0	7,675.0	2,109.0
All Other	3,560.0	2,379.0	1,181.0
Net Investment in Place[1]			
Top Four	122,383.0	47,875.0	74,508.0
Five Through Twelve	98,507.0	76,024.0	22,483.0
All Other	44,270.0	35,296.0	8,974.0
Additions to Investment in Place			
Top Four	17,290.0	5,419.0	11,871.0
Five Through Twelve	13,826.0	9,329.0	4,497.0
All Other	7,356.0	5,393.0	1,963.0
		(percent)	
Distribution, 1996			
Contribution to Net Income			
Top Four	100.0	41.6	58.4
Five Through Twelve	100.0	78.4	21.6
All Other	100.0	66.8	33.2
Net Investment in Place[1]			
Top Four	100.0	39.1	60.9
Five Through Twelve	100.0	77.2	22.8
All Other	100.0	79.7	20.3
Additions to Investment in Place			
Top Four	100.0	31.3	68.7
Five Through Twelve	100.0	67.5	32.5
All Other	100.0	73.3	26.7
Change from 1995			
Contribution to Net Income			
Top Four	74.3	277.8	25.9
Five Through Twelve	80.5	75.9	99.3
All Other	139.7	361.9	21.8
Net Investment in Place[1]			
Top Four	3.8	-1.4	7.3
Five Through Twelve	3.1	1.7	8.1
All Other	1.9	1.5	3.6
Additions to Investment in Place			
Top Four	19.5	5.5	27.3
Five Through Twelve	24.5	15.5	48.2
All Other	11.5	8.1	21.9

[1] Measured as net property, plant, and equipment plus investments and advances.

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 B13. Income and Investment Patterns by Petroleum Segments for FRS Companies Ranked by Total Energy Assets, 1996, and Percent Change from 1995

Income and Investment	United States				Foreign			
	Consolidated	Production	Refining/ Marketing	Pipelines	Consolidated	Production	Refining/ Marketing	International Marine
	(million dollars)							
1996								
Contribution to Net Income								
Top Four	5,648.0	4,773.0	497.0	378.0	7,915.0	6,063.0	1,796.0	56.0
Five Through Twelve	7,675.0	5,111.0	1,605.0	959.0	2,109.0	2,000.0	128.0	W
All Other	2,379.0	1,932.0	149.0	298.0	1,181.0	1,127.0	60.0	W
Net Investment in Place[1]								
Top Four	47,875.0	26,464.0	19,138.0	2,273.0	74,508.0	43,144.0	29,979.0	1,385.0
Five Through Twelve	76,024.0	39,942.0	19,898.0	16,184.0	22,483.0	20,299.0	W	W
All Other	35,296.0	17,461.0	12,583.0	5,252.0	8,974.0	8,293.0	W	W
Additions to PP&E[2]								
Top Four	4,954.0	3,424.0	1,337.0	193.0	10,670.0	7,830.0	2,820.0	20.0
Five Through Twelve	8,628.0	6,077.0	1,901.0	650.0	4,064.0	3,750.0	313.0	1.0
All Other	5,032.0	3,576.0	1,212.0	244.0	1,876.0	1,831.0	45.0	0.0
	(percent)							
Distribution, 1996								
Contribution to Net Income								
Top Four	100.0	84.5	8.8	6.7	100.0	76.6	22.7	0.7
Five Through Twelve	100.0	66.6	20.9	12.5	100.0	94.8	6.1	W
All Other	100.0	81.2	6.3	12.5	100.0	95.4	5.1	W
Net Investment in Place[1]								
Top Four	100.0	55.3	40.0	4.7	100.0	57.9	40.2	1.9
Five Through Twelve	100.0	52.5	26.2	21.3	100.0	90.3	W	W
All Other	100.0	49.5	35.6	14.9	100.0	92.4	W	W
Additions to PP&E[2]								
Top Four	100.0	69.1	27.0	3.9	100.0	73.4	26.4	0.2
Five Through Twelve	100.0	70.4	22.0	7.5	100.0	92.3	7.7	0.0
All Other	100.0	71.1	24.1	4.8	100.0	97.6	2.4	0.0
Change from 1995								
Contribution to Net Income								
Top Four	277.8	450.5	240.4	-21.6	25.9	43.6	-13.5	-500.0
Five Through Twelve	75.9	126.4	71.8	-18.1	99.3	119.5	-22.0	11.8
All Other	361.9	237.2	-126.0	-42.0	21.8	39.5	-64.5	-14.3
Net Investment in Place[1]								
Top Four	-1.4	-1.2	-1.0	-5.5	7.3	16.6	-3.0	-7.4
Five Through Twelve	1.7	2.1	2.8	-0.6	8.1	6.3	W	W
All Other	1.5	1.2	1.9	1.3	3.6	3.8	W	W
Additions to PP&E[2]								
Top Four	-2.5	15.2	-32.3	45.1	20.2	28.5	12.4	-92.7
Five Through Twelve	8.7	19.8	-17.8	17.3	33.3	34.4	22.3	0.0
All Other	3.9	9.7	-15.6	67.1	18.4	20.6	-31.8	-100.0

[1] Measured as net property, plant, and equipment plus investments and advances.
[2] Property, plant, and equipment.
W = Data withheld to avoid disclosure.
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 B14. Size Distribution of Income and Investment Within Worldwide Petroleum for FRS Companies Ranked by Total Energy Assets, 1994-1996

(Percent)

Patterns Across Size Groups	Worldwide			United States			Foreign		
	1994	1995	1996	1994	1995	1996	1994	1995	1996
Contribution to Net Income									
All FRS	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Top Four	53.5	53.0	50.4	30.7	23.5	36.0	86.0	75.6	70.6
Five Through Twelve	33.6	36.9	36.4	49.1	68.5	48.9	11.5	12.7	18.8
All Other	12.9	10.1	13.2	20.1	8.1	15.2	2.5	11.7	10.5
Net Investment in Place[1]									
All FRS	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Top Four	45.4	45.9	46.2	31.6	30.7	30.1	69.0	70.2	70.3
Five Through Twelve	37.1	37.2	37.2	46.5	47.3	47.8	21.1	21.0	21.2
All Other	17.5	16.9	16.7	21.9	22.0	22.2	9.9	8.8	8.5
Additions to Investment in Place									
All FRS	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Top Four	41.6	45.0	44.9	26.7	28.2	26.9	62.1	66.8	64.8
Five Through Twelve	34.9	34.5	35.9	40.5	44.4	46.3	27.1	21.7	24.5
All Other	23.5	20.5	19.1	32.7	27.4	26.8	10.8	11.5	10.7

[1] Measured as net property, plant, and equipment plus investments and advances.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B15. Consolidated Statement of Cash Flows for FRS Companies, 1990-1996

(Million Dollars)

Cash Flows[1]	1990	1991	1992	1993	1994	1995	1996
Cash Flows From Operations							
Net Income	21,608	14,679	1,757	15,488	16,547	21,131	32,029
Minority Interest in Income	408	235	344	397	513	731	845
Noncash Items							
DD&A	30,739	30,017	31,033	30,355	30,667	36,698	29,331
Dry Hole Expense, This Year	2,796	2,841	1,986	1,673	1,805	1,510	1,812
Deferred Income Taxes	-39	-2,062	-3,929	-990	509	-327	2,863
Recognized Undistributed (Earnings)/Losses of Unconsolidated Affiliates	-777	-829	-350	-137	-372	-845	-226
(Gain)/Loss on Disposition of PP&E	-795	-1,808	-1,294	-941	-570	-2,445	-1,940
Changes in Operating Assets and Liabilities and Other Noncash Items	3,525	2,923	3,284	2,646	-1,884	-763	-365
Other Cash Items, Net	-2,572	1,823	11,927	1,705	1,084	2,808	-165
Net Cash Flow From Operations	54,893	47,819	44,758	50,196	48,299	58,498	64,184
Cash Flows From Investing Activities							
Additions to PP&E:							
Due to Mergers and Acquisitions	-3,467	-1,075	-874	-306	-2,271	-4,137	-2,281
Other	-41,122	-43,812	-39,604	-37,755	-35,217	-40,356	-41,872
Total Additions to PP&E	-44,589	-44,887	-40,478	-38,061	-37,488	-44,493	-44,153
Additions to Investments and Advances	-886	-1,520	-1,483	-2,318	-1,588	-3,208	-5,799
Proceeds From Disposals of PP&E	7,143	9,359	7,268	11,757	6,447	9,063	10,942
Other Investment Activities, Net	327	-103	-1,584	-2,242	-2,363	4,086	1,608
Cash Flow From Investing Activities	-38,005	-37,151	-36,277	-30,864	-34,992	-34,552	-37,402
Cash Flows From Financing Activities							
Proceeds From Long-Term Debt	15,759	22,120	24,745	18,982	12,500	19,929	10,708
Proceeds From Equity Security Offerings	1,501	491	3,438	2,146	2,614	3,471	1,171
Reductions in Long-Term Debt	-17,223	-18,411	-25,284	-20,886	-13,760	-18,657	-18,883
Purchase of Treasury Stock	-5,435	-1,973	-824	-514	-1,010	-10,035	-1,299
Dividends to Shareholders	-13,300	-13,497	-13,521	-13,563	-14,906	-15,238	-15,585
Other Financing Activities, Including Net Change in Short-Term Debt	243	-978	2,308	-4,102	-1,091	-2,350	-578
Cash Flow From Financing Activities	-18,455	-12,248	-9,138	-17,937	-15,653	-22,880	-24,466
Effect of Exchange Rate on Cash	74	-138	-359	-198	131	14	3
Net Increase/(Decrease) in Cash and Cash Equivalents	-1,493	-1,718	-1,016	1,197	-2,215	1,080	2,319

[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 B16. A Comparison of Key Financial Indicators, Selected Performance Measures, and Patterns of Finance for FRS Companies and for the S&P Industrials, 1994-1996

(Percent)

Financial Indicators	FRS Companies			S&P Industrials		
	1994	1995	1996	1994	1995	1996
Profitability Measures						
Net Income to Total Assets	3.6	4.5	6.8	4.9	5.0	5.6
Net Income to Stockholders' Equity	10.0	12.7	18.0	16.1	16.3	17.6
Net Income Plus Interest to Total Invested Capital	9.7	11.7	15.7	13.5	13.8	14.5
Cash Flow from Operations and Uses of Cash						
Net Cash Flow from Operations to Total Assets	10.6	12.6	13.6	9.7	10.3	10.7
Additions to PP&E to Net Cash Flow from Operations	77.6	76.1	68.8	66.0	66.5	65.8
Dividends to Net Cash Flow from Operations	30.9	26.0	24.3	22.0	20.8	19.1
Liquidity and Leverage Measures						
Long-Term Debt to Stockholders' Equity	53.1	50.7	39.9	66.5	66.5	62.6
Long-Term Debt to Total Assets	19.3	18.2	15.1	20.2	20.5	20.1
Current Assets to Current Liabilities	99.2	94.9	98.3	113.6	115.7	115.4

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

Table B17. Worldwide Income Taxes for FRS Companies, 1995 and 1996

Taxes by Geographic Sector	Billion Dollars		Percent Change from 1995	Income Taxes as a Percent of Pretax Income	
	1995	1996		1995	1996
Pretax Income[1]	34.2	52.8	54.3	100.0	100.0
Income Taxes					
U.S. Federal	3.6	7.5	108.1	10.5	14.1
U.S. State and Local	0.6	0.8	29.4	1.8	1.5
Foreign	8.5	11.7	37.4	25.0	22.2
Total Income Taxes	12.8	20.0	56.9	37.2	37.9
Current Income Taxes					
U.S. Federal	4.5	5.7	26.7	13.1	10.7
U.S. State and Local	0.6	0.7	14.8	1.9	1.4
Foreign					
Canada	0.6	0.7	17.5	1.9	1.4
Europe and Former Soviet Union[2]	2.8	3.9	40.3	8.0	7.3
Africa	1.2	2.0	62.5	3.5	3.7
Middle East	1.0	1.3	29.5	3.0	2.5
Other Eastern Hemisphere	1.9	2.2	16.6	5.5	4.2
Other Western Hemisphere	0.5	0.7	41.8	1.5	1.4
Subtotal	8.0	10.8	35.0	23.4	20.5
Total Current Income Taxes	13.1	17.2	31.2	38.4	32.6
Deferred Income Taxes					
U.S. Federal	-0.9	1.8	([3])	-2.6	3.4
U.S. State and Local	0.0	0.1	([3])	-0.1	0.1
Foreign	0.5	0.9	73.2	1.6	1.8
Total Deferred Income Taxes	-0.4	2.8	([3])	-1.1	5.3

[1] Excludes discontinued operations, extraordinary items, and cumulative effect of accounting changes.
[2] 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.
[3] Not meaningful.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B18. U.S. Federal Income Taxes for FRS Companies, 1995 and 1996

U.S. Tax Determination	Billion Dollars		Percent Change from 1995	Percent of Net Income Before Taxes	
	1995	1996		1995	1996
Pretax Income[1] (worldwide)	34.2	52.8	54.3	100.0	100.0
Adjustments to Income					
Income Not Subject to U.S. Taxes	-4.0	-6.2	54.3	-11.8	-11.8
Deductions for Income Taxes Paid in Other Jurisdictions	-0.8	-1.3	63.5	-2.4	-2.5
Taxable Income	29.4	45.2	54.0	85.8	85.7
Expected Tax Computed at U.S. Statutory Rate	10.3	15.8	54.0	30.0	30.0
Cause of Increase or Decrease in Taxes					
Statutory Depletion	-0.1	-0.1	-22.9	-0.2	-0.1
Foreign Tax Credits	-5.7	-6.9	22.3	-16.5	-13.1
Alternative Minimum Tax	0.0	0.0	0.0	0.0	0.0
Investment Tax Credits	-0.1	-0.1	26.8	-0.3	-0.2
Other	-0.9	-1.3	46.7	-2.5	-2.4
U.S. Federal Income Tax Expense on U.S. Taxable Income	3.6	7.5	108.1	10.5	14.1
Current	4.5	5.7	26.7	13.1	10.7
Deferred	-0.9	1.8	([2])	-2.6	3.4

[1] Excludes discontinued operations, extraordinary items, and cumulative effect of accounting changes.
[2] Not meaningful.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B19. Analysis of Income Taxes for FRS Companies, 1990-1996

(Million Dollars)

Income Taxes	1990	1991	1992	1993	1994	1995	1996
Income Taxes (as per Financial Statements)							
Current Paid or Accrued							
U.S. Federal, before Investment Tax Credit & Alternative Minimum Tax	5,008	3,543	2,355	2,584	1,907	4,486	6,141
U.S. Federal Investment Tax Credit	-75	-52	-41	-76	0	-162	-146
Effect of Alternative Minimum Tax	534	412	450	-158	30	151	-325
U.S. State & Local Income Taxes	901	695	759	462	528	649	745
Foreign Income Taxes							
Canada	901	119	558	660	705	634	745
Europe and Former Soviet Union[1]	2,864	2,710	2,066	1,947	2,300	2,752	3,862
Africa	2,110	1,563	1,509	1,256	1,127	1,204	1,956
Middle East	1,310	1,088	1,275	893	835	1,024	1,326
Other Eastern Hemisphere	2,261	2,248	2,180	2,075	2,085	1,882	2,195
Other Western Hemisphere	862	380	420	440	464	514	729
Total Foreign	10,308	8,108	8,008	7,271	7,516	8,010	10,813
Total Current	16,676	12,706	11,531	10,083	9,981	13,134	17,228
Deferred							
U.S. Federal, before Investment Tax Credit	420	-1,846	-1,723	-549	691	-793	1,410
U.S. Federal Investment Tax Credit	55	2	-43	-32	26	61	69
Effect of Alternative Minimum Tax	-474	-558	-564	117	-51	-158	312
U.S. State & Local Income Taxes	24	-69	20	-19	-56	-30	56
Foreign	-178	385	-594	-456	43	537	930
Total Deferred	-153	-2,086	-2,904	-939	653	-383	2,777
Total Income Tax Expense	16,523	10,620	8,627	9,144	10,634	12,751	20,005
Reconciliation of Accrued U.S. Federal Income Tax Expense To Statutory Rate							
Consolidated Pretax Income/(Loss)	37,489	25,120	22,542	24,777	29,592	34,233	52,808
Less: Foreign Source Income not Subject to U.S. Tax	3,836	3,671	2,753	3,233	3,575	4,038	6,230
Equals: Income Subject to U.S. Tax	33,653	21,449	19,789	21,544	26,017	30,195	46,578
Less: U.S. State & Local Income Taxes	634	757	748	509	438	440	782
Less: Applicable Foreign Income Taxes Deducted	1,174	907	1,121	638	327	377	554
Equals: Pretax Income Subject to U.S. Tax	31,845	19,785	17,920	20,397	25,252	29,378	45,242
Tax Provision Based on Previous Line	10,821	6,717	6,082	7,138	8,842	10,281	15,834
Increase/(Decrease) in Taxes Due To							
Foreign Tax Credits Recognized	-6,031	-5,263	-4,596	-4,754	-4,831	-5,661	-6,926
U.S. Federal Investment Tax Credit Recognized	-42	-67	-83	-108	-34	-97	-123
Statutory Depletion	-116	-86	-66	-39	-52	-70	-54
Effect of Alternative Minimum Tax	34	-3	-87	-1	-14	0	1
Other	802	87	-826	-352	-1,314	-868	-1,273
Actual U.S. Federal Tax Provision (Refund)	5,468	1,385	424	1,884	2,597	3,585	7,459

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

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

Table B20. U.S. Taxes Other Than Income Taxes for FRS Companies, 1996, and Percent Change from 1995

U.S. Taxes Other than Income Taxes	Total United States		Petroleum		Coal		Other[1]	
	1996 (million dollars)	Percent Change from 1995	1996 (million dollars)	Percent Change from 1995	1996 (million dollars)	Percent Change from 1995	1996 (million dollars)	Percent Change from 1995
Production Taxes								
Windfall Profit Tax	W	W	W	W	0.0	--	0.0	--
Severance Taxes	1,982.0	24.2	1,928.0	25.9	54.0	-5.3	0.0	-100.0
Other Direct Production Taxes	W	W	W	W	85.0	-15.0	1.0	-66.7
Total Production Taxes	2,238.0	20.3	2,098.0	23.9	139.0	-11.5	1.0	-90.9
Superfund	14.0	-95.2	20.0	-91.1	0.0	--	-6.0	-108.8
Import Duties	260.0	150.0	–	–	–	–	–	–
Sales, Use, and Property	2,516.0	-12.8	–	–	–	–	–	–
Payroll	1,531.0	-17.0	–	–	–	–	–	–
Other Taxes	514.0	-9.2	–	–	–	–	–	–
Total Taxes Paid (Other Than Income Taxes)	7,073.0	-6.4	–	–	–	–	–	–
Excise Taxes Collected	32,426.0	5.2	–	–	–	–	–	–

[1] Nuclear, Other Energy, and Nonenergy.
W = Data withheld to avoid disclosure.
– = Not available.
-- = Not applicable.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B21. Petroleum Exploration and Development Expenditures for FRS Companies, United States and Foreign, 1996, and Percent Change from 1995

Exploration and Development Expenditures	Worldwide Expenditures	U.S. Expenditures			Foreign Expenditures		
	FRS Companies (million dollars) 1996	FRS Companies (million dollars) 1996	Percent Change from 1995	U.S. FRS as a Percent of Total FRS 1996	FRS Companies (million dollars) 1996	Percent Change from 1995	FRS Foreign as a Percent of Total FRS 1996
Exploration							
Acquisition of Unproved Acreage	1,742.0	997.0	67.6	57.2	745.0	248.1	42.8
Geological and Geophysical	1,494.0	625.0	28.6	41.8	869.0	3.1	58.2
Drilling and Equipping[1]	4,615.0	2,338.0	27.6	50.7	2,277.0	7.7	49.3
Other	1,612.0	693.0	16.3	43.0	919.0	-7.1	57.0
Total Exploration	9,463.0	4,653.0	32.6	49.2	4,810.0	15.6	50.8
Development							
Acquisition of Proved Acreage	3,360.0	922.0	-5.9	27.4	2,438.0	557.1	72.6
Lease Equipment	3,677.0	1,613.0	13.2	43.9	2,064.0	34.3	56.1
Drilling and Equipping[1]	11,432.0	6,154.0	13.3	53.8	5,278.0	16.4	46.2
Other[2]	3,799.0	1,290.0	18.8	34.0	2,509.0	-2.3	66.0
Total Development	22,268.0	9,979.0	11.8	44.8	12,289.0	36.4	55.2
Total Exploration and Development	31,731.0	14,632.0	17.7	46.1	17,099.0	29.8	53.9

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 B22. U.S. and Foreign Exploration and Development Expenditures and Production (Lifting) Costs for FRS Companies, 1996

(Million Dollars)

Expenditures	Worldwide	United States			Foreign
		Total	Onshore	Offshore	
Exploration and Development Expenditures					
Exploration Expenditures					
Unproved Acreage	1,742	997	463	534	745
Drilling and Equipping					
Dry Holes (Cumulative)	–	877	340	537	–
Oil Wells (Cumulative)	–	295	102	193	–
Gas Wells (Cumulative)	–	730	221	509	–
Work-in-progress Adjustment	–	436	149	287	–
Total Drilling and Equipping	4,615	2,338	812	1,526	2,277
Geological and Geophysical	1,494	625	254	371	869
Other, Including Direct Overhead	1,612	693	297	396	919
Total Exploration Expenditures	9,463	4,653	1,826	2,827	4,810
Development Expenditures					
Proved Acreage (Including Mergers and Acquisitions)	3,360	922	630	292	2,438
Drilling and Equipping					
Dry Holes (Cumulative)	–	261	171	90	–
Oil Wells (Cumulative)	–	1,946	1,129	817	–
Gas Wells (Cumulative)	–	2,071	1,451	620	–
Work-in-progress Adjustment	–	1,876	828	1,048	–
Total Drilling and Equipping	11,432	6,154	3,579	2,575	5,278
Lease Equipment	3,677	1,613	875	738	2,064
Other Development					
Support Equipment	628	218	188	30	410
Other, Including Direct Overhead	3,171	1,072	815	257	2,099
Total Development Expenditures	22,268	9,979	6,087	3,892	12,289
Total Exploration and Development Expenditures	31,731	14,632	7,913	6,719	17,099
Production (Lifting) Costs					
Windfall Profit Tax	W	W	–	–	0
Other Severance and Production Taxes	W	W	–	–	1,196
Other Production Expenses	18,902	10,221	–	–	8,681
Total Production (Lifting) Costs	22,196	12,319	9,855	2,464	9,877
Total Expenditures and Costs Incurred	53,927	26,951	17,768	9,183	26,976

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

Table B23. Total Exploratory and Development Wells Drilled in the United States for FRS Companies and U.S. Industry, 1995 and 1996

Wells Drilled	U.S. Industry		FRS		All Other	
	1995	1996	1995	1996	1995	1996
Exploratory						
Dry	1,977	2,106	304	358	1,673	1,748
Successful	1,580	1,815	391	420	1,189	1,395
Oil	746	848	137	127	609	721
Gas	834	967	255	293	580	674
Subtotal	3,557	3,921	695	778	2,862	3,143
Percent Successful	44.4	46.3	56.3	54.0	41.5	44.4
Development						
Dry	2,502	3,136	280	342	2,222	2,794
Successful	12,505	15,633	4,311	4,454	8,194	11,179
Oil	6,120	7,333	2,059	2,253	4,061	5,080
Gas	6,385	8,300	2,252	2,202	4,133	6,099
Subtotal	15,007	18,769	4,591	4,797	10,417	13,972
Percent Successful	83.3	83.3	93.9	92.9	78.7	80.0
Total Wells Drilled	18,563	22,690	5,286	5,574	13,278	17,116

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 Administration. Totals are based on data which appeared in the Energy Information Administration's *Monthly Energy Review, September 1997,* p. 83. FRS companies data - Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B24. Completed Well Costs, Oil, Gas, and Dry, for FRS Companies and U.S. Industry, 1995 and 1996

Drilling and Equipping Measures	FRS Companies			U.S. Industry			FRS as a Percent of U.S. Industry	
	1995	1996	Percent Change	1995	1996	Percent Change	1995	1996
Exploration								
Oil Wells								
Drilling and Equipping Costs[1]	236.0	295.0	25.0	–	–	–	–	–
Wells Completed	136.6	126.6	-7.3	746.0	848.0	13.7	18.3	14.9
Cost per Well (thousand dollars)	1,728	2,330	34.9	–	–	–	([2])	([2])
Average Depth (thousand feet)	9.1	9.0	-1.1	6.8	7.2	5.8	([2])	([2])
Cost per Foot (dollars)	189.71	258.77	36.4	–	–	–	([2])	([2])
Gas Wells								
Drilling and Equipping Costs[1]	447.0	730.0	63.3	–	–	–	–	–
Wells Completed	254.5	293.4	15.3	834.0	967.0	15.9	30.5	30.3
Cost per Well (thousand dollars)	1,756	2,488	41.7	–	–	–	([2])	([2])
Average Depth (thousand feet)	8.5	12.6	48.1	6.4	6.3	-1.7	([2])	([2])
Cost per Foot (dollars)	207.14	198.15	-4.3	–	–	–	([2])	([2])
Dry Holes								
Drilling and Equipping Costs[1]	675.0	877.0	29.9	–	–	–	–	–
Wells Completed	303.9	357.8	17.7	1,977.0	2,106.0	6.5	15.4	17.0
Cost per Well (thousand dollars)	2,221	2,451	10.4	–	–	–	([2])	([2])
Average Depth (thousand feet)	8.9	8.8	-0.8	6.0	6.3	5.7	([2])	([2])
Cost per Foot (dollars)	250.93	279.03	11.2	–	–	–	([2])	([2])
Development								
Oil Wells								
Drilling and Equipping Costs[1]	1,643.0	1,946.0	18.4	–	–	–	–	–
Wells Completed	2,059.2	2,252.8	9.4	6,120.0	7,333.0	19.8	33.6	30.7
Cost per Well (thousand dollars)	798	864	8.3	–	–	–	([2])	([2])
Average Depth (thousand feet)	5.7	5.6	-0.6	5.2	5.2	-0.1	([2])	([2])
Cost per Foot (dollars)	141.14	153.71	8.9	–	–	–	([2])	([2])
Gas Wells								
Drilling and Equipping Costs[1]	1,703.0	2,071.0	21.6	–	–	–	–	–
Wells Completed	2,251.6	2,201.5	-2.2	6,385.0	8,300.0	30.0	35.3	26.5
Cost per Well (thousand dollars)	756	941	24.4	–	–	–	([2])	([2])
Average Depth (thousand feet)	6.9	7.2	4.7	6.4	6.6	2.0	([2])	([2])
Cost per Foot (dollars)	110.02	130.73	18.8	–	–	–	([2])	([2])
Dry Holes								
Drilling and Equipping Costs[1]	197.0	261.0	32.5	–	–	–	–	–
Wells Completed	279.7	342.3	22.4	2,502.0	3,136.0	25.3	11.2	10.9
Cost per Well (thousand dollars)	704	762	8.3	–	–	–	([2])	([2])
Average Depth (thousand feet)	6.1	7.2	18.3	5.4	5.7	5.5	([2])	([2])
Cost per Foot (dollars)	115.54	105.75	-8.5	–	–	–	([2])	([2])

[1] Million Dollars.
[2] Not meaningful.
– = Not available.

Sources: Industry data - 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 1997,* p. 83. FRS companies data - Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B25. Completed Well Costs, Oil, Gas, and Dry, Onshore and Offshore, for FRS Companies, 1995 and 1996

Drilling and Equipping Measures	Total United States			U.S. Onshore			U.S. Offshore		
	1995	1996	Percent Change	1995	1996	Percent Change	1995	1996	Percent Change
Exploration									
Oil Wells									
Drilling and Equipping Costs[1]	236.0	295.0	25.0	77.0	102.0	32.5	159.0	193.0	21.4
Wells Completed	136.6	126.6	-7.3	104.4	91.1	-12.7	32.2	35.5	10.2
Cost per Well (thousand dollars)	1,728	2,330	34.9	738	1,120	51.8	4,938	5,437	10.1
Average Depth (thousand feet)	9.1	9.0	-1.1	8.0	8.0	0.3	12.7	11.5	-9.3
Cost per Foot (dollars)	189.71	258.77	36.4	92.11	139.34	51.3	389.71	473.04	21.4
Gas Wells									
Drilling and Equipping Costs[1]	447.0	730.0	63.3	194.0	221.0	13.9	253.0	509.0	101.2
Wells Completed	254.5	293.4	15.3	201.4	206.5	2.5	53.1	86.9	63.7
Cost per Well (thousand dollars)	1,756	2,488	41.7	963	1,070	11.1	4,765	5,857	22.9
Average Depth (thousand feet)	8.5	12.6	48.1	7.2	9.0	24.6	13.2	21.0	58.8
Cost per Foot (dollars)	207.14	198.15	-4.3	133.24	118.82	-10.8	360.40	279.06	-22.6
Dry Holes									
Drilling and Equipping Costs[1]	675.0	877.0	29.9	307.0	340.0	10.7	368.0	537.0	45.9
Wells Completed	303.9	357.8	17.7	231.9	274.0	18.2	72.0	83.8	16.4
Cost per Well (thousand dollars)	2,221	2,451	10.4	1,324	1,241	-6.3	5,111	6,408	25.4
Average Depth (thousand feet)	8.9	8.8	-0.8	7.8	7.5	-3.5	12.4	13.0	5.2
Cost per Foot (dollars)	250.93	279.03	11.2	170.65	165.69	-2.9	413.02	492.21	19.2
Development									
Oil Wells									
Drilling and Equipping Costs[1]	1,643.0	1,946.0	18.4	1,063.0	1,129.0	6.2	580.0	817.0	40.9
Wells Completed	2,059.2	2,252.8	9.4	1,907.8	2,094.8	9.8	151.4	158.0	4.4
Cost per Well (thousand dollars)	798	864	8.3	557	539	-3.3	3,831	5,171	35.0
Average Depth (thousand feet)	5.7	5.6	-0.6	5.3	5.2	-0.7	10.5	10.8	2.8
Cost per Foot (dollars)	141.14	153.71	8.9	105.74	103.05	-2.5	365.24	479.46	31.3
Gas Wells									
Drilling and Equipping Costs[1]	1,703.0	2,071.0	21.6	1,332.0	1,451.0	8.9	371.0	620.0	67.1
Wells Completed	2,251.6	2,201.5	-2.2	2,156.2	2,049.0	-5.0	95.4	152.5	59.9
Cost per Well (thousand dollars)	756	941	24.4	618	708	14.6	3,889	4,066	4.5
Average Depth (thousand feet)	6.9	7.2	4.7	6.7	7.0	4.0	10.6	10.1	-4.8
Cost per Foot (dollars)	110.02	130.73	18.8	92.07	101.44	10.2	366.96	403.12	9.9
Dry Holes									
Drilling and Equipping Costs[1]	197.0	261.0	32.5	118.0	171.0	44.9	79.0	90.0	13.9
Wells Completed	279.7	342.3	22.4	261.8	319.2	21.9	17.9	23.1	29.1
Cost per Well (thousand dollars)	704	762	8.3	451	536	18.9	4,413	3,896	-11.7
Average Depth (thousand feet)	6.1	7.2	18.3	5.9	7.0	17.7	8.7	10.6	22.0
Cost per Foot (dollars)	115.54	105.75	-8.5	76.13	76.89	1.0	509.68	368.85	-27.6

[1] Million Dollars.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B26. U.S. Net Wells Completed, and Net In-Progress Wells for FRS Companies, 1990-1996

Wells	1990	1991	1992	1993	1994	1995	1996
Number of Net Wells Completed During Year							
Onshore							
Net Exploratory Wells							
Dry Holes	411	297	294	231	175	232	274
Oil Wells	132	155	112	108	101	104	91
Gas Wells	490	283	127	127	167	201	207
Total Exploratory Wells	1,033	735	533	466	443	538	572
Net Development Wells							
Dry Holes	260	326	193	236	203	262	319
Oil Wells	3,337	2,738	1,664	1,966	1,980	1,908	2,095
Gas Wells	1,681	1,354	1,582	1,664	1,865	2,156	2,049
Total Development Wells	5,277	4,418	3,439	3,865	4,048	4,326	4,463
Offshore							
Net Exploratory Wells							
Dry Holes	114	92	50	69	78	72	84
Oil Wells	31	41	21	22	13	32	36
Gas Wells	76	55	25	42	47	53	87
Total Exploratory Wells	222	189	95	133	138	157	206
Net Development Wells							
Dry Holes	32	20	19	13	17	18	23
Oil Wells	143	128	111	125	150	151	158
Gas Wells	146	81	46	98	120	95	153
Total Development Wells	321	228	176	236	287	265	334
Total United States							
Net Exploratory Wells							
Dry Holes	525	390	344	300	253	304	358
Oil Wells	163	196	132	130	114	137	127
Gas Wells	566	338	151	169	214	255	293
Total Exploratory Wells	1,254	924	627	599	581	695	778
Net Development Wells							
Dry Holes	293	345	212	249	220	280	342
Oil Wells	3,479	2,866	1,775	2,091	2,130	2,059	2,253
Gas Wells	1,826	1,435	1,628	1,761	1,985	2,252	2,202
Total Development Wells	5,598	4,646	3,615	4,101	4,335	4,591	4,797
Number of Net In-Progress Wells At Year End							
Onshore							
Exploratory Wells	275	125	97	106	90	135	133
Development Wells	1,100	650	795	709	524	541	675
Total In-Progress Wells	1,375	775	892	815	614	676	808
Offshore							
Exploratory Wells	72	49	39	35	46	46	45
Development Wells	64	36	57	68	91	57	93
Total In-Progress Wells	137	85	96	103	137	103	138
Total United States							
Exploratory Wells	347	174	136	141	136	181	178
Development Wells	1,164	686	852	777	615	598	768
Total In-Progress Wells	1,512	860	988	918	751	779	946

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

Table B27. Exploration and Development Net Drilling Footage for FRS Companies, 1990-1996

(Thousand Feet)

Exploration, Development, and Production Statistics	1990	1991	1992	1993	1994	1995	1996
Onshore							
Exploratory Well Footage							
Dry Hole Footage	3,660	2,611	2,623	2,341	1,699	1,799	2,052
Oil Well Footage	1,069	1,208	964	974	796	836	732
Gas Well Footage	2,126	1,711	1,035	1,072	1,464	1,456	1,860
Total Exploratory Footage	6,855	5,530	4,622	4,387	3,959	4,091	4,644
Development Well Footage							
Dry Hole Footage	1,758	1,130	1,270	1,429	1,177	1,550	2,224
Oil Well Footage	14,442	12,928	9,192	11,407	10,269	10,053	10,956
Gas Well Footage	10,593	7,388	10,589	11,558	12,955	14,468	14,304
Total Development Footage	26,793	21,446	21,051	24,394	24,401	26,071	27,484
Offshore							
Exploratory Well Footage							
Dry Hole Footage	1,268	1,087	755	710	911	891	1,091
Oil Well Footage	400	487	275	304	132	408	408
Gas Well Footage	809	647	321	488	568	702	1,824
Total Exploratory Footage	2,477	2,221	1,351	1,502	1,611	2,001	3,323
Development Well Footage							
Dry Hole Footage	201	202	172	158	124	155	244
Oil Well Footage	1,247	1,086	871	1,267	1,597	1,588	1,704
Gas Well Footage	1,074	711	466	975	1,025	1,011	1,538
Total Development Footage	2,522	1,999	1,509	2,400	2,746	2,754	3,486

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

Table B28. U.S. Net Producing Wells and U.S. Acreage for FRS Companies, 1990-1996

Wells and Acreage	1990	1991	1992	1993	1994	1995	1996
Number of Net Producing Wells							
Onshore							
Oil Wells	133,889	123,426	112,782	106,760	105,679	94,867	87,461
Gas Wells	43,124	43,591	46,308	46,535	49,237	50,388	48,779
Total Producing Wells	177,013	167,017	159,089	153,295	154,916	145,256	136,240
Offshore							
Oil Wells	5,795	5,337	5,021	4,274	4,179	4,180	3,552
Gas Wells	3,150	2,887	2,709	2,643	2,895	3,042	2,556
Total Producing Wells	8,944	8,224	7,730	6,917	7,074	7,221	6,108
Total United States							
Oil Wells	139,684	128,763	117,803	111,034	109,858	99,047	91,013
Gas Wells	46,274	46,478	49,016	49,178	52,132	53,430	51,335
Total Producing Wells	185,958	175,241	166,819	160,212	161,990	152,477	142,348
	(thousand acres)						
Net Acreage							
Onshore							
Developed	31,345	31,043	29,590	28,856	28,744	27,429	26,733
Undeveloped	59,085	53,923	44,433	42,196	35,698	38,792	31,659
Offshore							
Developed	6,089	5,237	5,202	4,799	4,818	6,154	5,470
Undeveloped	23,095	22,993	20,837	16,175	13,925	14,334	16,880
Gross Acreage							
Onshore							
Developed	62,908	61,178	53,389	50,640	51,846	50,016	46,887
Undeveloped	92,037	84,382	68,413	65,051	57,865	61,651	53,775
Offshore							
Developed	10,829	10,673	10,602	9,753	10,112	11,291	9,668
Undeveloped	35,584	35,126	26,692	20,233	19,128	18,595	21,786

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

Table B29. U.S. Net Petroleum Acreage for FRS Companies, Ranked by Total Energy Assets, 1996 and Percent Change from 1995

Petroleum Acreage	Undeveloped Acreage		Developed Acreage		Total Acreage	
	Thousand Acres	Percent Change from 1995	Thousand Acres	Percent Change from 1995	Thousand Acres	Percent Change from 1995
Onshore						
Top Four	10,285	3.5	8,936	0.3	19,221	2.0
Five Through Twelve	13,269	2.3	9,058	5.1	22,327	3.4
All Other	8,105	-49.0	8,739	-11.8	16,844	-34.7
All FRS	31,659	-18.4	26,733	-2.5	58,392	-11.8
Offshore						
Top Four	3,879	22.1	1,787	-16.4	5,666	6.6
Five Through Twelve	10,520	26.1	2,372	-12.5	12,892	16.6
All Other	2,481	-12.0	1,311	0.5	3,792	-8.0
All FRS	16,880	17.8	5,470	-11.1	22,350	9.1
Total						
Top Four	14,164	8.0	10,723	-2.9	24,887	3.0
Percent Onshore	72.6	--	83.3	--	77.2	--
Five Through Twelve	23,789	11.6	11,430	0.9	35,219	7.9
Percent Onshore	55.8	--	79.2	--	63.4	--
All Other	10,586	-43.4	10,050	-10.3	20,636	-31.0
Percent Onshore	76.6	--	87.0	--	81.6	--
All FRS	48,539	-8.6	32,203	-4.1	80,742	-6.9
Percent Onshore	65.2	--	83.0	--	72.3	--

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

Table B30. U.S. Net Ownership Interest Petroleum Reserves and Production for FRS Companies and U.S. Industry, 1996

Reserves and Production	Crude Oil and Natural Gas Liquids (billion barrels)		Natural Gas (trillion cubic feet)	
	FRS Companies	U.S. Industry	FRS Companies	U.S. Industry
Onshore				
Beginning Reserves	13.7	25.6	58.3	134.8
Ending Reserves	13.4	25.6	55.8	136.3
Percent Change	-2.2	-0.1	-4.4	1.1
Production	1.2	2.5	5.4	13.6
Percent Change from 1995	-3.5	-0.2	0.3	3.8
Offshore				
Beginning Reserves	3.1	4.1	21.0	30.4
Ending Reserves	3.1	4.2	20.3	30.2
Percent Change	0.6	2.9	-3.4	-0.7
Production	0.3	0.5	2.8	5.3
Percent Change from 1995	1.6	5.0	4.5	8.2
Total				
Beginning Reserves	16.7	29.8	79.3	165.1
Ending Reserves	16.5	29.8	76.1	166.5
Percent Change	-1.7	0.3	-4.1	0.8
Production	1.5	3.0	8.2	18.9
Percent Change from 1995	-2.4	0.6	1.7	5.0

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*, 1995 and 1996 (November 1996 and November 1997). FRS companies data - Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B31. Proved Petroleum Reserves for FRS Companies, United States and Foreign, 1996

Reserves Statistics	Worldwide Total	United States			Foreign		
		Total	Onshore	Offshore	Total	Canada	Other
	(million barrels)						
Crude Oil and Natural Gas Liquids							
Net Ownership Interest Reserves:							
Beginning of Period	30,626	16,741	13,673	3,068	13,885	2,010	11,875
Revisions of Previous Estimates	944	312	278	34	632	-2	634
Improved Recovery	550	334	311	24	216	36	180
Purchases of Minerals-in-Place	514	144	125	19	370	5	365
Extensions & Discoveries	2,046	824	464	359	1,222	143	1,080
Production	-2,991	-1,532	-1,198	-334	-1,459	-133	-1,327
Sales of Minerals-in-Place	-663	-361	-277	-84	-303	-125	-178
End of period	31,025	16,462	13,376	3,085	14,563	1,934	12,630
Proportionate Interest in Investee Reserves and Foreign Access Reserves	1,815	--	--	--	1,815	W	W
	(billion cubic feet)						
Natural Gas							
Net Ownership Interest Reserves:							
Beginning of Period	139,062	79,313	58,299	21,014	59,749	8,952	50,797
Revisions of Previous Estimates	-258	-467	-526	60	208	-377	585
Improved Recovery	528	382	365	18	146	65	82
Purchases of Minerals-in-Place	1,554	958	685	274	596	159	437
Extensions & Discoveries	13,118	6,053	3,848	2,206	7,064	465	6,599
Production	-12,895	-8,192	-5,380	-2,811	-4,704	-812	-3,892
Sales of Minerals-in-Place	-3,225	-1,995	-1,528	-467	-1,230	-1,055	-175
End of Period	137,883	76,053	55,761	20,292	61,830	7,397	54,433

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

Table B32. U.S. Reserve Additions, Exploration and Development Expenditures, and Expenditures per Barrel of Reserve Additions for FRS Companies Ranked by Total Energy Assets and for U.S. Industry, 1994-1996

Reserve Additions, Expenditures, and Wells	1994			1995			1996		
	Onshore	Offshore	Total	Onshore	Offshore	Total	Onshore	Offshore	Total
	(million barrels)								
Reserve Additions[1]									
Top Four	447.6	464.7	912.4	648.5	433.6	1,082.1	526.3	305.9	832.2
Five Through Twelve	724.6	424.3	1,148.9	885.8	457.3	1,343.1	681.3	466.5	1,147.7
All Other	353.2	177.2	530.4	496.9	186.8	683.7	498.6	49.0	547.5
All FRS	1,525.4	1,066.3	2,591.7	2,031.2	1,077.8	3,109.0	1,706.1	821.3	2,527.5
U.S. Industry	4,423.3	1,598.2	6,021.4	4,741.8	1,816.2	6,558.0	3,129.2	1,017.2	4,147.8
	(million dollars)								
Exploration and Development Expenditures									
Top Four	1,850.0	1,120.0	2,970.0	1,903.0	1,493.0	3,396.0	1,914.0	1,985.0	3,899.0
Five Through Twelve	2,829.0	1,914.0	4,743.0	3,031.0	2,036.0	5,067.0	3,273.0	3,116.0	6,389.0
All Other	2,140.0	1,159.0	3,299.0	1,948.0	1,043.0	2,991.0	2,096.0	1,326.0	3,422.0
All FRS	6,819.0	4,193.0	11,012.0	6,882.0	4,572.0	11,454.0	7,283.0	6,427.0	13,710.0
U.S. Industry	–	–	–	–	–	–	–	–	–
	(number of wells)								
Wells Completed									
Top Four	1,211.9	125.0	1,336.9	1,425.6	146.6	1,572.2	1,603.0	193.3	1,796.3
Five Through Twelve	1,878.5	186.7	2,065.2	1,835.2	146.9	1,982.1	2,055.7	196.9	2,252.6
All Other	1,400.0	113.3	1,513.3	1,602.7	128.5	1,731.2	1,375.9	149.6	1,525.5
All FRS	4,490.4	425.0	4,915.4	4,863.5	422.0	5,285.5	5,034.6	539.8	5,574.4
U.S. Industry	20,256.0	784.0	21,041.0	17,978.0	586.0	18,563.0	22,193.0	497.0	22,690.0
	(dollars per barrel)								
Exploration and Development Expenditures per Barrel of Reserve Additions									
Top Four	4.13	2.41	3.26	2.93	3.44	3.14	3.64	6.49	4.69
Five Through Twelve	3.90	4.51	4.13	3.42	4.45	3.77	4.80	6.68	5.57
All Other	6.06	6.54	6.22	3.92	5.58	4.37	4.20	27.07	6.25
All FRS	4.47	3.93	4.25	3.39	4.24	3.68	4.27	7.83	5.42
U.S. Industry	–	–	–	–	–	–	–	–	–
	(thousand barrels)								
Reserve Additions per Well Completed									
Top Four	369.4	3,717.9	682.5	454.9	2,958.0	688.3	328.3	1,582.4	463.3
Five Through Twelve	385.7	2,272.7	556.3	482.7	3,113.1	677.6	331.4	2,369.0	509.5
All Other	252.3	1,564.4	350.5	310.0	1,454.0	394.9	362.4	327.4	358.9
All FRS	339.7	2,508.9	527.3	417.6	2,554.0	588.2	338.9	1,521.5	453.4
U.S. Industry	218.4	2,038.5	286.2	263.8	3,099.3	353.3	141.0	2,046.7	182.8

[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 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.

Sources: Reserve additions - 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*, 1994, 1995, and 1996 Annual Reports. Wells completed - special compilation provided by the Office of Oil and Gas, Energy Information Administration. Totals are based on data which appeared in the Energy Information's *Monthly Energy Review, September 1997,* p. 83. FRS companies data - Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B33. Foreign Petroleum Exploration, Development, Reserves, and Production Statistics by Geographic Area for FRS Companies and Foreign Industry, 1996, and Percent Change from 1995

Foreign Petroleum Activities	Total Foreign	Canada	Europe and Former Soviet Union[1]	Africa	Middle East	Other Eastern Hemisphere	Other Western Hemisphere
Crude Oil and NGL Production[2] (million barrels)							
FRS Companies	1,448.8	132.5	565.4	271.3	119.2	263.9	96.5
Percent Change	-6.5	-13.1	-4.4	-18.4	8.8	-0.4	-2.8
Foreign Industry[3]	22,193.0	890.0	5,125.0	2,775.0	7,428.0	1,605.0	4,370.0
Percent Change	-16.5	2.2	2.7	5.9	0.6	1.8	35.7
Wells Completed							
FRS Companies	1,908.9	1,069.5	189.2	128.1	59.9	309.0	153.2
Percent Change	8.0	1.9	6.5	24.5	1.4	33.5	4.2
Foreign Industry	23,829.0	13,182.0	4,791.0	704.0	679.0	1,466.0	3,007.0
Percent Change	9.9	20.5	-8.7	15.6	4.3	27.4	-2.4
Success Rate[4]							
FRS Companies	85.4	87.4	71.1	82.4	90.0	85.0	90.6
Foreign Industry	83.3	77.9	93.6	82.1	94.3	76.9	91.5
Exploration and Development Expenditures (million dollars)							
FRS Companies	17,099.0	1,563.0	6,012.0	2,798.0	463.0	4,625.0	1,638.0
Percent Change	29.8	-17.7	8.1	37.0	28.3	90.3	87.2
Crude Oil and NGL Reserve Interests[5] (million barrels)							
FRS Companies	16,378.2	1,944.3	6,427.3	3,199.3	1,786.6	2,169.2	851.4
Percent Change	6.4	-3.6	10.7	13.2	-0.8	2.3	2.8

[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.
[2] Crude oil plus natural gas liquids. Includes ownership interest production and foreign access production.
[3] Foreign Industry levels defined as total activity outside of the United States except the People's Republic of China.
[4] Success Rate defined as the total number of successful well completions during the period divided by the total number of wells drilled.
[5] Includes net ownership interest reserves (88.9 percent) and "Other Access" reserves (11.1 percent). "Other Access" reserves include proportional interest in investee reserves and foreign access reserves.

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

Sources: FRS Companies - Energy Information Administration, Form EIA-28 (Financial Reporting System). Industry data - *World Oil*, August 1997, and Energy Information Administration, *International Energy Annual*, 1996.

Table B34. Foreign Exploration and Development Expenditures by Region for FRS Companies, 1990-1996

(Million Dollars)

Foreign Expenditures by Region	1990	1991	1992	1993	1994	1995	1996
Exploration Expenditures							
Canada	753	661	336	403	573	493	355
OECD Europe	2,233	2,192	1,544	1,313	1,063	1,242	1,345
Former Soviet Union and E. Europe	0	0	0	163	204	181	194
Africa	618	680	738	599	678	707	779
Middle East	302	258	273	225	104	90	45
Other Eastern Hemisphere	1,017	1,028	869	736	888	1,016	1,462
Other Western Hemisphere	327	435	283	240	320	431	630
Total Foreign Exploration Expenditures	5,250	5,254	4,043	3,679	3,830	4,160	4,810
Development Expenditures							
Canada	1,065	1,070	770	1,156	1,262	1,406	1,208
OECD Europe	4,383	4,643	5,252	4,169	3,376	3,962	4,206
Former Soviet Union and E. Europe	0	0	0	100	93	178	267
Africa	807	845	655	873	714	1,336	2,019
Middle East	296	233	285	460	341	271	418
Other Eastern Hemisphere	1,416	1,359	1,540	1,733	1,870	1,414	3,163
Other Western Hemisphere	343	300	364	376	423	444	1,008
Total Foreign Development Expenditures	8,310	8,450	8,866	8,867	8,079	9,011	12,289
Total Exploration and Development Expenditures							
Canada	1,818	1,731	1,106	1,559	1,835	1,899	1,563
OECD Europe	6,616	6,835	6,796	5,482	4,439	5,204	5,551
Former Soviet Union and E. Europe	0	0	0	263	297	359	461
Africa	1,425	1,525	1,393	1,472	1,392	2,043	2,798
Middle East	598	491	558	685	445	361	463
Other Eastern Hemisphere	2,433	2,387	2,409	2,469	2,758	2,430	4,625
Other Western Hemisphere	670	735	647	616	743	875	1,638
Total Foreign Exploration and Development Expenditures	13,560	13,704	12,909	12,546	11,909	13,171	17,099

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

Table B35. Distribution of Foreign Exploration and Development Expenditures for FRS Companies Ranked by Total Energy Assets, 1996, and Percent Change from 1995

Exploration and Development Expenditures	Total Foreign	Canada	Europe and Former Soviet Union[1]	Africa and Mideast	Other Eastern Hemisphere	Other Western Hemisphere
	(million dollars)					
1996						
All FRS	17,099.0	1,563.0	6,012.0	3,261.0	4,625.0	1,638.0
Top Four	10,120.0	967.0	3,320.0	1,722.0	3,242.0	869.0
Five Through Twelve	4,474.0	496.0	1,321.0	1,348.0	583.0	726.0
All Other	2,505.0	100.0	1,371.0	191.0	800.0	43.0
	(percent)					
Distribution 1996						
All FRS	100.0	9.1	35.2	19.1	27.0	9.6
Top Four	100.0	9.6	32.8	17.0	32.0	8.6
Five Through Twelve	100.0	11.1	29.5	30.1	13.0	16.2
All Other	100.0	4.0	54.7	7.6	31.9	1.7
Change from 1995						
All FRS	29.8	-17.7	8.1	35.6	90.3	87.2
Top Four	36.4	-15.2	5.2	10.3	145.6	259.1
Five Through Twelve	18.8	-5.7	-0.6	93.7	-7.9	24.5
All Other	26.2	-56.9	27.1	29.9	67.7	-14.0

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

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

Table B36. Number of Net Wells Completed, Net In-Progress Wells, and Net Producing Wells in Foreign Areas for FRS Companies, 1990-1996

Number of Wells	1990	1991	1992	1993	1994	1995	1996
Canada							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	104.9	101.3	65.1	71.7	111.2	107.5	86.2
Oil Wells	61.7	38.2	19.7	47.9	42.0	66.6	46.0
Gas Wells	48.3	54.0	29.6	46.8	105.1	74.0	96.1
Total Exploratory Wells	214.9	193.5	114.4	166.4	258.3	248.1	228.3
Development Wells							
Dry Holes	47.2	32.3	29.3	47.4	59.6	42.7	48.1
Oil Wells	225.7	169.6	211.1	334.6	174.2	569.5	559.4
Gas Wells	97.1	97.0	39.4	292.9	416.6	189.6	233.7
Total Development Wells	370.0	298.9	279.8	674.9	650.4	801.8	841.2
Net In-Progress Wells at Year End	63.9	29.3	31.7	65.3	57.6	43.1	17.2
Net Producing Wells							
Oil Wells	15,044.9	13,996.6	12,597.5	11,704.3	11,268.5	9,793.9	8,719.5
Gas Wells	6,635.8	6,094.0	5,927.2	5,740.2	5,953.3	5,998.6	5,784.8
Total Producing Wells	21,680.7	20,090.6	18,524.7	17,444.5	17,221.8	15,792.5	14,504.3
Europe and Former Soviet Union[1]							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	74.9	77.6	47.4	33.4	33.7	42.1	49.4
Oil Wells	16.1	8.2	16.2	11.8	13.3	21.4	14.5
Gas Wells	15.9	15.0	11.8	14.6	11.2	10.6	11.4
Total Exploratory Wells	106.9	100.8	75.4	59.8	58.2	74.1	75.3
Development Wells							
Dry Holes	3.7	5.4	2.6	3.6	1.5	2.2	5.3
Oil Wells	54.4	52.0	38.2	59.9	60.4	72.4	77.6
Gas Wells	22.5	26.5	25.8	28.8	24.5	29.0	31.0
Total Development Wells	80.6	83.9	66.6	92.3	86.4	103.6	113.9
Net In-Progress Wells at Year End	78.4	77.0	70.5	76.3	74.5	73.0	68.7
Net Producing Wells							
Oil Wells	1,475.8	1,462.0	1,459.3	1,479.3	1,430.2	1,359.4	1,445.5
Gas Wells	643.6	645.4	647.5	687.0	720.7	741.9	765.2
Total Producing Wells	2,119.4	2,107.4	2,106.8	2,166.3	2,150.9	2,101.3	2,210.7
Africa and Middle East							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	51.4	54.5	65.3	37.9	32.0	28.4	19.8
Oil Wells	W	W	W	W	W	W	W
Gas Wells	W	W	W	W	W	W	W
Total Exploratory Wells	67.5	73.9	84.8	52.8	47.9	42.8	44.0
Development Wells							
Dry Holes	6.6	W	W	W	W	W	W
Oil Wells	77.5	82.7	91.1	72.2	105.7	109.7	133.0
Gas Wells	2.0	W	W	W	W	W	W
Total Development Wells	86.1	94.1	103.5	81.8	117.7	119.2	144.0
Net In-Progress Wells at Year End	29.0	44.0	34.4	21.3	45.1	41.9	36.9
Net Producing Wells							
Oil Wells	1,240.7	1,294.2	1,374.1	1,322.9	1,442.2	1,509.0	1,688.9
Gas Wells	20.0	20.6	26.8	25.8	34.4	41.9	49.9
Total Producing Wells	1,260.7	1,314.8	1,400.9	1,348.7	1,476.6	1,550.9	1,738.8

See footnotes at end of table.

Table B36. Number of Net Wells Completed, Net In-Progress Wells, and Net Producing Wells in Foreign Areas for FRS Companies, 1990-1996 (Continued)

Number of Wells	1990	1991	1992	1993	1994	1995	1996
Other Eastern Hemisphere							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	57.4	60.5	47.6	43.9	47.4	47.4	42.6
Oil Wells	18.0	21.1	22.9	8.3	11.6	13.1	21.6
Gas Wells	11.0	11.4	10.0	16.4	14.5	44.4	46.3
Total Exploratory Wells	86.4	93.0	80.5	68.6	73.5	104.9	110.5
Development Wells							
Dry Holes	4.5	14.5	11.0	8.7	5.2	1.5	3.7
Oil Wells	124.6	106.4	106.7	124.9	115.7	92.7	103.1
Gas Wells	47.2	48.6	71.9	62.7	45.9	32.4	91.7
Total Development Wells	176.3	169.5	189.6	196.3	166.8	126.6	198.5
Net In-Progress Wells at Year End	85.5	89.4	71.5	83.8	71.9	92.5	72.4
Net Producing Wells							
Oil Wells	1,632.9	1,532.1	1,650.2	1,666.0	1,714.9	1,476.2	1,622.0
Gas Wells	324.8	321.1	373.2	393.9	437.9	401.4	561.2
Total Producing Wells	1,957.7	1,853.2	2,023.4	2,059.9	2,152.8	1,877.6	2,183.2
Other Western Hemisphere							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	19.7	15.1	6.9	8.1	7.5	9.2	12.4
Oil Wells	W	W	W	W	W	W	W
Gas Wells	W	W	W	W	W	W	W
Total Exploratory Wells	22.7	25.6	12.0	19.8	15.5	13.9	23.4
Development Wells							
Dry Holes	2.5	W	W	W	W	W	W
Oil Wells	87.4	87.4	87.0	78.8	85.6	120.5	123.3
Gas Wells	0.0	W	W	W	W	W	W
Total Development Wells	89.9	93.4	89.0	87.2	94.3	133.1	129.8
Net In-Progress Wells at Year End	15.1	9.6	7.4	15.6	14.8	20.2	16.1
Net Producing Wells							
Oil Wells	3,102.0	3,145.5	2,938.3	3,032.6	2,939.6	2,980.6	2,478.9
Gas Wells	48.4	44.5	42.0	65.4	48.7	57.6	77.3
Total Producing Wells	3,150.4	3,190.0	2,980.3	3,098.0	2,988.3	3,038.2	2,556.2
Total Foreign							
Net Wells Completed During Year							
Exploratory Wells							
Dry Holes	308.3	309.0	232.3	195.0	231.8	234.6	210.4
Oil Wells	112.7	95.5	81.0	93.0	88.5	119.7	110.9
Gas Wells	77.4	82.3	53.8	79.4	133.1	129.5	160.2
Total Exploratory Wells	498.4	486.8	367.1	367.4	453.4	483.8	481.5
Development Wells							
Dry Holes	64.5	61.3	52.2	71.1	77.2	51.9	67.9
Oil Wells	569.6	498.1	534.1	670.4	541.6	964.8	996.4
Gas Wells	168.8	180.4	142.2	391.0	496.8	267.6	363.1
Total Development Wells	802.9	739.8	728.5	1,132.5	1,115.6	1,284.3	1,427.4
Net In-Progress Wells at Year End	271.9	249.3	215.5	262.3	263.9	270.7	211.3
Net Producing Wells							
Oil Wells	22,496.3	21,430.4	20,019.4	19,205.1	18,795.4	17,119.1	15,954.8
Gas Wells	7,672.6	7,125.6	7,016.7	6,912.3	7,195.0	7,241.4	7,238.4
Total Producing Wells	30,168.9	28,556.0	27,036.1	26,117.4	25,990.4	24,360.5	23,193.2

[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.

W = Data withheld to avoid disclosure.

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

Table B37. Foreign Proved Oil and Gas Reserves for FRS Companies, 1996

Reserves Statistics	Foreign					
	Total Foreign	Canada	Europe and Former Soviet Union[1]	Africa and Mideast	Other Eastern Hemisphere	Other Western Hemisphere
	(million barrels)					
Crude Oil and Natural Gas Liquids						
Net Ownership Interest Reserves:						
Beginning of Period	13,885	2,010	5,704	3,664	1,683	824
Revisions of Previous Estimates & Improved Recovery	848	34	306	360	W	W
Net Purchases of Minerals-in-Place	68	-120	9	138	W	W
Extensions & Discoveries	1,222	143	581	279	123	96
Production	-1,459	-133	-591	-375	-264	-96
End of Period	14,563	1,934	6,009	4,067	1,706	849
	(billion cubic feet)					
Natural Gas						
Net Ownership Interest Reserves:						
Beginning of Period	59,749	8,952	24,866	806	20,794	4,331
Revisions of Previous Estimates & Improved Recovery	355	-312	476	W	-227	W
Net Purchases of Minerals-in-Place	-634	-896	-52	W	80	W
Extensions & Discoveries	7,064	465	1,661	226	1,720	2,992
Production	-4,704	-812	-1,973	-108	-1,545	-265
End of Period	61,830	7,397	24,978	1,184	20,821	7,450

[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.

W = Data withheld to avoid disclosure.

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

Table B38. Foreign Production (Lifting) Costs for FRS Companies, 1990-1996

(Million Dollars)

Production Costs by Region	1990	1991	1992	1993	1994	1995	1996
Canada							
Royalty Expenses	W	W	W	19	W	W	W
Taxes other than Income Taxes	W	W	W	56	W	W	W
Other Costs	1,736	1,797	1,388	1,210	1,141	1,082	993
Total Production Costs	1,814	1,893	1,464	1,285	1,234	1,174	1,082
OECD Europe							
Royalty Expenses	544	495	465	305	206	235	251
Taxes other than Income Taxes	270	229	257	214	274	311	400
Other Costs	3,692	4,353	4,199	3,617	4,128	4,116	3,996
Total Production Costs	4,506	5,077	4,921	4,136	4,608	4,662	4,647
Former Soviet Union and E. Europe							
Royalty Expenses	0	0	0	0	0	0	0
Taxes other than Income Taxes	0	0	0	0	1	W	W
Other Costs	0	0	0	54	64	W	W
Total Production Costs	0	0	0	54	65	128	134
Africa							
Royalty Expenses	317	295	282	W	W	W	W
Taxes other than Income Taxes	9	14	21	W	W	W	W
Other Costs	625	680	776	821	740	607	812
Total Production Costs	951	989	1,079	1,122	1,011	916	1,259
Middle East							
Royalty Expenses	W	W	62	W	W	W	W
Taxes other than Income Taxes	W	W	292	W	W	W	W
Other Costs	305	217	324	313	340	258	296
Total Production Costs	468	316	678	424	435	403	483
Other Eastern Hemisphere							
Royalty Expenses and Taxes other than Income Taxes	687	730	685	630	433	400	542
Other Costs	1,318	1,420	1,400	1,173	1,132	1,110	1,161
Total Production Costs	2,005	2,150	2,085	1,803	1,565	1,510	1,703
Other Western Hemisphere							
Royalty Expenses and Taxes other than Income Taxes	312	230	137	122	83	129	180
Other Costs	530	481	450	374	346	428	389
Total Production Costs	842	711	587	496	429	557	569
Total Foreign							
Royalty Expenses	1,107	968	991	789	613	680	901
Taxes other than Income Taxes	1,273	1,220	1,286	969	843	942	1,196
Other Costs	8,206	8,948	8,537	7,562	7,891	7,728	7,780
Total Production Costs	10,586	11,136	10,814	9,320	9,347	9,350	9,877

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

Table B39. U.S. Refining/Marketing Dispositions of Refined Products by Channel of Distribution for FRS Companies, 1990-1996

U.S. Dispositions	1990	1991	1992	1993	1994	1995	1996
	Values (million dollars)						
Motor Gasoline							
Intersegment Sales	247	568	231	196	268	365	400
U.S. Third-Party Sales							
Wholesale-Resellers	33,255	28,854	26,641	24,954	24,923	27,386	32,500
Company Operated Automotive Outlets	14,238	13,059	12,049	11,018	9,694	10,088	11,293
Company Lessee and Open Automotive Outlets	25,373	22,459	23,061	21,917	20,948	20,494	21,725
Other (Industrial, Commercial and Other Retail)	4,576	4,043	5,713	5,391	5,199	7,368	9,412
Total Third-Party Sales	77,442	68,415	67,464	63,280	60,764	65,336	74,930
Total Motor Gasoline Sales	77,689	68,983	67,695	63,476	61,032	65,701	75,330
Distillate Fuels							
Intersegment Sales	473	483	550	440	211	219	291
Third-Party Sales	40,222	35,052	33,370	32,624	30,357	30,201	41,327
Total Distillate Fuels Sales	40,695	35,535	33,920	33,064	30,568	30,420	41,618
Other Refined Products							
Intersegment Sales	5,093	4,435	4,671	4,213	3,824	3,952	4,124
Third-Party Sales	20,945	19,032	17,854	16,894	19,366	20,625	20,453
Total Other Refined Products Sales	26,038	23,467	22,525	21,107	23,190	24,577	24,577
Total U.S. Refined Products							
Intersegment Sales	5,813	5,486	5,452	4,849	4,303	4,536	4,815
Third-Party Sales	138,609	122,499	118,688	112,798	110,487	116,162	136,710
Total U.S. Refined Products Sales	144,422	127,985	124,140	117,647	114,790	120,698	141,525
	Volumes (million barrels)						
Motor Gasoline							
Intersegment Sales	8	18	9	9	9	11	12
U.S. Third-Party Sales							
Wholesale-Resellers	1,072	996	972	1,012	1,064	1,117	1,145
Company Operated Automotive Outlets	384	367	350	342	308	309	319
Company Lessee and Open Automotive Outlets	719	734	740	731	736	680	663
Other (Industrial, Commercial and Other Retail)	163	151	216	233	229	304	350
Total Third-Party Sales	2,338	2,248	2,277	2,318	2,338	2,411	2,476
Total Motor Gasoline Sales	2,346	2,267	2,286	2,327	2,347	2,422	2,488
Distillate Fuels							
Intersegment Sales	16	19	24	20	11	11	12
Third-Party Sales	1,356	1,328	1,340	1,380	1,381	1,363	1,550
Total Distillate Fuels Sales	1,372	1,347	1,364	1,400	1,392	1,374	1,562
Other Refined Products							
Intersegment Sales	230	212	232	240	226	222	209
Third-Party Sales	879	925	896	843	946	961	860
Total Other Refined Products Sales	1,108	1,137	1,128	1,082	1,172	1,183	1,069
Total U.S. Refined Products							
Intersegment Sales	253	249	264	269	246	245	232
Third-Party Sales	4,573	4,502	4,513	4,541	4,665	4,734	4,886
Total U.S. Refined Products Sales	4,826	4,751	4,778	4,810	4,911	4,979	5,119

See footnote at end of table.

Table B39. U.S. Refining/Marketing Dispositions of Refined Products by Channel of Distribution for FRS Companies, 1990-1996 (Continued)

U.S. Dispositions	1990	1991	1992	1993	1994	1995	1996
	Number of Automotive Outlets						
Number of Active Automobile Outlets at Year End							
Company Operated	11,177	10,745	9,935	9,021	8,755	8,549	8,927
Lessee Dealers	20,376	19,891	19,334	18,588	16,385	15,861	15,247
Open Dealers	19,532	17,969	17,297	16,088	15,320	13,950	14,151
Total Outlets	51,085	48,605	46,566	43,697	40,460	38,360	38,325

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

Table B40. Sales of U.S. Refined Products, by Volume and Price, for FRS Companies Ranked by Total Energy Assets, 1995 and 1996

(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								
1996	11.9	33.50	10.5	33.88	0.4	31.91	1.0	30.19
1995	11.4	32.00	11.3	32.05	0.1	20.00	([1])	([2])
Percent Change	4.7	4.7	-7.0	5.7	652.0	59.6	3,441.4	-12.5
Wholesale/Resellers								
1996	1,145.1	28.38	396.0	29.20	460.9	28.25	288.2	27.48
1995	1,117.3	24.51	400.0	24.83	452.0	24.68	265.3	23.75
Percent Change	2.5	15.8	-1.0	17.6	2.0	14.5	8.6	15.7
Dealer-Operated Outlets								
1996	662.6	32.79	232.4	31.78	307.9	33.71	122.4	32.35
1995	680.3	30.12	247.7	30.76	308.3	30.15	124.3	28.78
Percent Change	-2.6	8.8	-6.2	3.3	-0.1	11.8	-1.6	12.4
Company-Operated Outlets								
1996	318.7	35.43	79.9	36.78	154.9	34.46	83.9	35.94
1995	309.4	32.60	74.8	34.08	153.1	31.02	81.6	34.22
Percent Change	3.0	8.7	6.9	7.9	1.2	11.1	2.9	5.0
Other[3]								
1996	350.0	26.89	124.6	32.42	127.1	22.39	98.3	25.70
1995	303.5	24.27	80.5	29.71	122.5	23.35	100.6	21.05
Percent Change	15.3	10.8	54.9	9.1	3.8	-4.1	-2.3	22.1
Total Gasoline								
1996	2,488.4	30.27	843.5	31.16	1,051.1	30.06	593.8	29.39
1995	2,422.0	27.13	814.3	28.06	1,035.9	27.09	571.8	25.86
Percent Change	2.7	11.6	3.6	11.0	1.5	11.0	3.8	13.6
Distillate								
1996	1,561.5	26.65	554.5	26.71	586.0	26.80	421.0	26.36
1995	1,373.7	22.14	483.2	22.22	537.8	22.18	352.7	21.98
Percent Change	13.7	20.4	14.8	20.2	8.9	20.8	19.4	19.9
All Other Products								
1996	1,068.7	23.00	339.8	23.59	369.1	21.97	359.8	23.49
1995	1,183.1	20.77	315.3	24.44	422.9	18.42	445.0	20.41
Percent Change	-9.7	10.7	7.8	-3.5	-12.7	19.2	-19.1	15.1
Total Refined Products								
1996	5,118.6	27.65	1,737.8	28.26	2,006.2	27.62	1,374.7	26.92
1995	4,978.8	24.24	1,612.8	25.61	1,996.6	23.93	1,369.5	23.09
Percent Change	2.8	14.1	7.8	10.4	0.5	15.4	0.4	16.6

[1] Less than 50,000 barrels.
[2] Not meaningful.
[3] Includes direct sales to industrial and commercial customers and sales to unconsolidated affiliates.
Note: Sum of components may not equal total due to independent rounding.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B41. U.S. Petroleum Refining/Marketing, General Operating Expenses for FRS Companies, 1990-1996
(Billion Dollars)

General Operating Expenses	1990	1991	1992	1993	1994	1995	1996
Raw Material Supply							
Raw Material Purchases	151.8	135.9	134.9	125.5	120.3	125.2	156.7
Other Raw Material Supply Expense	4.1	4.8	4.3	5.1	5.0	4.7	4.1
Total Raw Material Supply Expense	155.8	140.7	139.2	130.6	125.3	129.9	160.8
Less: Cost of Raw Materials Input To Refining	83.4	72.5	69.1	61.0	59.3	64.1	75.9
Net Raw Material Supply	72.4	68.2	70.1	69.6	66.0	65.8	84.9
Refining							
Raw Materials Input to Refining	83.4	72.5	69.1	61.0	59.3	64.1	75.9
Less: Raw Material Used as Refinery Fuel	3.9	3.6	3.4	3.6	2.9	2.6	3.9
Refinery Process Energy Expense	5.5	5.5	5.4	5.6	4.7	4.1	5.5
Other Refining Operating Expenses	9.8	9.9	9.9	9.8	9.7	9.6	10.6
Refined Product Purchases	31.4	27.0	27.7	26.9	27.4	31.0	38.0
Other Refined Product Supply Expenses	4.6	4.1	3.7	4.2	3.4	3.4	4.1
Total Refining	130.8	115.5	112.4	103.9	101.6	109.6	130.1
Marketing							
Cost of Other Products Sold	4.8	5.8	4.6	4.7	4.1	4.4	5.4
Other Marketing Expenses	9.8	11.4	12.9	10.5	8.8	8.7	9.3
Subtotal	14.6	17.2	17.5	15.2	12.9	13.1	14.8
Expense of Transport Services for Others	0.6	0.5	1.1	1.0	1.1	0.6	0.5
Total Marketing	15.3	17.7	18.6	16.1	14.0	13.7	15.3
Total U.S. Refining/Marketing Segment General Operating Expenses	218.5	201.4	201.1	189.7	181.7	189.1	230.3

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

Table B42. U.S. Petroleum Segments Purchases and Sales of Raw Materials and Refined Products for FRS Companies, 1990-1996

Purchases and Sales	1990	1991	1992	1993	1994	1995	1996
	Values (million dollars)						
Purchases							
U.S. Refining/Marketing Segment							
Raw Materials							
Crude Oil and NGL	144,973	129,380	124,868	111,654	104,471	111,556	138,397
Natural Gas	3,935	4,367	7,504	10,678	12,360	9,747	15,651
Other Raw Materials	2,848	2,195	2,496	3,196	3,498	3,892	2,697
Total Raw Materials	151,756	135,942	134,868	125,528	120,329	125,195	156,745
Refined Products							
Motor Gasoline	13,927	12,106	12,403	11,831	12,430	14,131	18,078
Distillate Fuels	7,006	5,738	6,008	6,629	6,626	6,773	9,634
Other Refined Products	10,497	9,136	9,261	8,467	8,389	10,114	10,246
Total Refined Products	31,430	26,980	27,672	26,927	27,445	31,018	37,958
U.S. Production Segment							
Crude Oil and NGL	2,702	4,186	2,816	2,458	2,660	3,353	5,163
Natural Gas	3,167	3,223	4,192	5,042	5,950	6,981	10,715
Total Raw Materials	5,869	7,409	7,008	7,500	8,610	10,334	15,878
Sales							
U.S. Refining/Marketing Segment							
Raw Materials							
Crude Oil and NGL	69,037	64,948	63,564	56,612	49,752	53,544	69,485
Natural Gas	3,226	3,873	7,406	10,527	12,432	9,295	15,790
Other Raw Materials	1,271	929	1,175	1,720	2,201	2,325	1,276
Total Raw Materials	73,534	69,750	72,145	68,859	64,385	65,164	86,551
Refined Products							
Motor Gasoline	77,689	68,983	67,695	63,476	61,032	65,701	75,330
Distillate Fuels	40,695	35,535	33,920	33,064	30,568	30,420	41,618
Other Refined Products	26,038	23,467	22,525	21,107	23,190	24,577	24,577
Total Refined Products	144,422	127,985	124,140	117,647	114,790	120,698	141,525
U.S. Production Segment							
Crude Oil and NGL	38,088	32,372	29,585	25,734	23,468	26,303	32,948
Natural Gas	15,999	14,071	16,905	20,238	19,757	18,696	26,840
Total Raw Materials	54,087	46,443	46,490	45,972	43,225	44,999	59,788

See footnotes at end of table.

Table B42. U.S. Petroleum Segments Purchases and Sales of Raw Materials and Refined Products for FRS Companies, 1990-1996 (Continued)

Purchases and Sales	1990	1991	1992	1993	1994	1995	1996
	Volumes						
Purchases							
U.S. Refining/Marketing Segment							
Raw Materials							
Crude Oil and NGL (million barrels)	6,991	6,985	7,176	7,032	7,090	6,802	7,112
Natural Gas (billion cubic feet)	2,276	2,884	4,593	6,022	7,479	6,543	7,506
Refined Products (million barrels)							
Motor Gasoline	454	427	467	487	563	588	677
Distillate Fuels	242	226	253	288	322	321	380
Other Refined Products	399	407	410	378	345	422	363
Total Refined Products	1,094	1,059	1,129	1,153	1,230	1,330	1,420
U.S. Production Segment							
Crude Oil and NGL (million barrels)	177	222	206	178	201	237	300
Natural Gas (billion cubic feet)	1,875	2,067	2,408	2,569	3,276	4,395	4,723
Sales							
U.S. Refining/Marketing Segment							
Raw Materials							
Crude Oil and NGL (million barrels)	3,286	3,359	3,572	3,436	3,406	3,213	3,528
Natural Gas (billion cubic feet)	1,851	2,457	4,198	5,416	6,960	6,089	7,195
Refined Products (million barrels)							
Motor Gasoline	2,346	2,267	2,286	2,327	2,347	2,422	2,488
Distillate Fuels	1,372	1,347	1,364	1,400	1,392	1,374	1,562
Other Refined Products	1,108	1,137	1,128	1,082	1,172	1,183	1,069
Total Refined Products	4,826	4,751	4,778	4,810	4,911	4,979	5,119
U.S. Production Segment							
Crude Oil and NGL (million barrels)	2,088	2,078	2,044	1,898	1,889	1,875	1,933
Natural Gas (billion cubic feet)	8,979	8,761	9,712	9,801	10,810	12,108	12,281

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

Table B43. U.S. and Foreign Refining/Marketing Segment, Sources and Dispositions of Crude Oil and Natural Gas Liquids for FRS Companies, 1990-1996

(Million Barrels)

Sources and Dispositions	1990	1991	1992	1993	1994	1995	1996
U.S. Refining/Marketing							
Sources							
Acquisitions from U.S. Production Segment ..	1,788	1,753	1,745	1,743	2,014	1,658	1,599
Purchases from Other U.S. Segments	308	309	567	552	339	365	397
Purchases from Third Parties and Unconsolidated Affiliates	3,920	4,005	3,995	3,979	3,983	4,167	4,549
Net Transfers from Foreign Refining/Marketing Segment	975	918	869	757	754	612	566
Total Sources	6,991	6,985	7,176	7,032	7,090	6,802	7,112
Dispositions							
Net Change in Inventories	28	-32	-8	31	48	23	21
Input to Refineries	3,678	3,658	3,611	3,565	3,636	3,565	3,563
Sales to:							
Unaffiliated Third Parties	2,957	3,040	3,171	3,261	3,235	2,961	3,291
Other Segments Excluding Foreign Refining/Marketing	329	320	401	175	172	252	237
Total Dispositions	6,991	6,985	7,176	7,032	7,090	6,802	7,112
Foreign Refining/Marketing							
Sources							
Acquisitions from Foreign Production Segment	1,246	1,241	1,150	1,163	1,335	1,249	1,371
Purchases							
Other Foreign Segments	28	61	77	85	95	93	88
Unconsolidated Affiliates	246	311	79	2	63	89	89
Unaffiliated Third Parties							
Foreign Access	178	131	111	114	120	107	145
Foreign Governments (Open Market)	690	580	774	725	726	621	844
Other Unaffiliated Third Parties	1,903	1,972	1,885	2,653	2,147	2,063	1,819
Net Transfers to U.S. Refining/ Marketing Segment	-975	-918	-869	-757	-754	-612	-566
Total Sources	3,315	3,379	3,207	3,986	3,731	3,610	3,790
Dispositions							
Net Change in Inventories	12	-4	-8	-1	0	1	38
Input to Refineries	1,361	1,508	1,367	1,530	1,535	1,520	1,605
Sales	1,942	1,874	1,849	2,456	2,195	2,090	2,147
Total Dispositions	3,315	3,379	3,207	3,986	3,731	3,610	3,790

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

Table B44. U.S. and Foreign Oil Raw Materials Balance for FRS Companies Ranked by Total Energy Assets, 1994-1996

(Million Barrels)

Geographical Sector	Raw Material Acquisitions: Direct Oil Access[1]	Net Oil Purchases[2]	Net Oil Imports	Oil Stock Changes[3]	Total Refinery Input
United States					
All FRS					
1996	2,025.6	992.4	565.7	-20.7	3,562.9
1995	2,023.7	952.3	612.1	-23.3	3,564.9
1994	2,367.4	562.0	754.1	-47.7	3,635.7
Top Four					
1996	588.5	394.8	225.7	-21.5	1,187.4
1995	577.2	360.2	274.6	-28.7	1,183.3
1994	639.9	307.3	350.9	-43.4	1,254.6
Five Through Twelve					
1996	1,086.2	175.4	141.1	-0.9	1,401.9
1995	1,054.3	222.6	148.0	-5.7	1,419.2
1994	1,346.9	-98.8	150.3	5.6	1,403.9
All Other					
1996	350.8	422.1	198.9	1.7	973.6
1995	392.2	369.5	189.5	11.1	962.4
1994	380.6	353.5	252.9	-9.9	977.1
Foreign					
All FRS					
1996	1,268.2	940.6	-565.7	-38.4	1,604.7
1995	1,165.8	967.2	-612.1	-1.2	1,519.7
1994	1,130.4	1,159.2	-754.1	-0.4	1,535.2
Top Four					
1996	800.0	917.7	-225.7	-37.5	1,454.6
1995	592.7	1,056.9	-274.6	0.2	1,375.1
1994	579.2	1,150.6	-350.9	-7.6	1,371.2
All Other[4]					
1996	468.2	22.8	-340.1	-0.9	150.1
1995	573.2	-89.7	-337.5	-1.4	144.5
1994	551.3	8.7	-403.2	7.3	164.0

[1] Ownership interest production plus purchases from other company segments and from unconsolidated affiliates of crude oil and natural gas liquids (domestic and foreign areas) plus foreign access oil (foreign area only). Foreign access represents acquisitions from foreign entities, for which reporting firms act as producers under long-term contract.

[2] Purchases of crude and natural gas liquids (except imports) on the open market or from unaffiliated third parties less oil sales to unaffiliated third parties.

[3] Positive number indicates stock withdrawal (addition to supply).

[4] The "Five Through Twelve" and "All Other" groups combined into foreign "All Other" to prevent disclosure.

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

Table B45. U.S. Refinery Output and Refinery Capacity Statistics for FRS Companies, Ranked by Total Energy Assets, and for U.S. Industry, 1995 and 1996

(Thousand Barrels per Day)

Refined Product Statistics[1]	FRS Companies				U.S. Industry	FRS Percent of Industry
	All FRS	Top Four	Five Through Twelve	All Other		
1996						
Refinery Output Volume[2]	10,954	3,932	4,243	2,779	16,801	65.2
Percent Gasoline	44.5	43.5	47.6	41.3	46.1	63.0
Percent Distillate	30.3	31.3	29.8	29.8	30.1	65.7
Percent Other	25.1	25.2	22.7	28.9	23.8	68.8
Refinery Capacity						
Year's Change (Net)	50	63	-40	27	51	98.4
At Year End	10,477	3,455	4,018	3,004	16,032	65.3
Utilization Rate[3]	93.5	95.3	94.6	90.1	91.5	([4])
1995						
Refinery Output Volume[2]	10,652	3,703	4,253	2,696	16,535	64.4
Percent Gasoline	45.5	45.3	49.0	40.4	46.2	63.5
Percent Distillate	27.2	25.1	28.5	28.1	28.8	60.9
Percent Other	27.2	29.6	22.5	31.5	25.0	70.2
Refinery Capacity						
Year's Change (Net)	-215	-113	42	-144	-88	243.5
At Year End	10,427	3,392	4,058	2,977	15,981	65.2
Utilization Rate[3]	91.8	93.3	95.2	85.6	89.9	([4])

[1] U.S. FRS and U.S. industry data include operations in Puerto Rico and the U.S. Virgin Islands.
[2] For FRS companies, includes refinery output at own refineries for own account and at others' refineries for own account.
[3] Defined as average daily crude runs at own refineries, for own account, and for account of others, divided by average daily crude distillation capacity.
[4] Not meaningful.

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

Sources: Industry data - Refinery output and refinery capacity: Energy Information Administration, Forms EIA-820 (Annual Refinery Report) and EIA-810 (Monthly Refinery Report); see *Petroleum Supply Annual*, 1995 and 1996. FRS companies data - Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B46. Foreign Refinery Output and Refinery Capacity Statistics for FRS Companies, Ranked by Total Energy Assets, and for Foreign Industry, 1995 and 1996

(Thousand Barrels per Day)

Refined Product Statistics[1]	FRS Companies All FRS	FRS Companies Top Four	FRS Companies All Other[2]	Foreign Industry	FRS Percent of Industry
1996					
Refinery Output Volume[3]	4,648	4,159	489	–	(4)
Percent Gasoline	27.5	27.5	28.0	–	(4)
Percent Distillate	41.4	41.5	40.9	–	(4)
Percent Other	31.1	31.1	31.1	–	(4)
Refinery Capacity					
Year's Change (net)	-104	-135	31	1,528	-6.8
At Year End	4,346	3,947	399	57,017	7.6
Utilization Rate[5]	89.5	86.9	116.3	–	(4)
1995					
Refinery Output Volume[3]	4,343	3,861	482	–	–
Percent Gasoline	28.7	28.3	31.7	–	–
Percent Distillate	41.5	40.8	46.9	–	–
Percent Other	29.8	30.9	21.4	–	–
Refinery Capacity					
Year's Change (net)	-316	-266	-50	0	0.0
At Year End	4,450	4,082	368	0	0.0
Utilization Rate[5]	86.0	83.7	110.9	–	(4)

1 Foreign FRS and foreign industry data exclude operations in Puerto Rico and the U.S. Virgin Islands, as well as China.
2 "Five through Twelve" and "All Other" groups 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 Not meaningful.
5 Defined as average daily crude runs at own refineries, for own account, and for account of others, divided by average daily crude distillation capacity.
– = Not available.
Note: Sum of components may not equal total due to independent rounding.
Sources: Industry data - Energy Information Administration, *International Energy Annual*, 1995 and 1996. FRS companies data - Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B47. U.S. and Foreign Petroleum Refining Statistics for FRS Companies, 1990-1996

Refining Statistics	1990	1991	1992	1993	1994	1995	1996
	(thousand barrels per calendar day)						
U.S. Refining							
Runs to Stills							
At Own Refineries	9,922	9,847	9,736	9,676	9,809	9,669	9,777
By Refineries of Others	4	5	5	5	5	5	5
Total Runs to Stills	9,926	9,852	9,741	9,681	9,814	9,674	9,782
Refinery Output at Own Refineries and Refineries of Others							
Reformulated Motor Gasoline	–	–	–	–	–	–	1,302
Oxygenated Motor Gasoline	–	–	–	–	–	–	165
Other Motor Gasoline	–	–	–	–	–	–	3,410
Total Motor Gasoline	5,010	5,055	4,968	4,953	4,936	4,849	4,877
Distillate Fuels	2,866	2,954	2,931	2,916	3,030	2,901	3,323
Other Refined Products	3,436	3,113	3,095	2,953	2,846	2,902	2,754
Total Refinery Output	11,312	11,122	10,994	10,822	10,812	10,652	10,954
Refinery Capacity at End of Year	11,372	11,203	10,952	10,714	10,642	10,427	10,477
	(number of refineries)						
Number of Wholly Owned Refineries	89	88	82	75	74	69	69
	(thousand barrels per calendar day)						
Foreign Refining							
Runs to Stills							
At Own Refineries	3,575	3,667	3,706	3,823	3,829	3,962	3,936
By Refineries of Others	717	632	749	312	304	323	506
Total Runs to Stills	4,292	4,299	4,455	4,135	4,133	4,285	4,442
Refinery Output at Own Refineries							
Motor Gasoline	1,084	1,097	1,098	1,114	1,122	1,175	1,172
Distillate Fuels	1,431	1,534	1,553	1,634	1,674	1,662	1,690
Other Refined Products	1,075	1,009	1,064	1,148	1,102	1,183	1,280
Total Refinery Output at Own Refineries	3,590	3,640	3,715	3,896	3,898	4,020	4,142
Refinery Output at Refineries of Others							
Motor Gasoline	208	188	199	85	85	70	107
Distillate Fuels	315	303	359	136	140	140	234
Other Refined Products	199	199	192	88	82	113	165
Total Refinery Output at Refineries of Others	722	690	750	309	307	323	506
Total Refinery Output	4,312	4,330	4,465	4,205	4,205	4,343	4,648
Refinery Capacity at End of Year	4,504	4,622	4,648	4,692	4,766	4,450	4,346
	(number of refineries)						
Number of Wholly Owned Refineries	25	27	27	26	26	24	20
Number of Partially Owned Refineries	17	15	14	14	14	13	12

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

Table B48. U.S. Refining/Marketing Revenues and Costs for FRS Companies, 1994-1996

Revenues and Costs	Million Dollars			Percent of Product Revenues		
	1994	1995	1996	1994	1995	1996
Refined Product Revenues	114,790.0	120,698.0	141,525.0	100.0	100.0	100.0
Refined Product Costs						
Raw Materials Processed[1]	58,025.0	62,142.0	70,339.0	50.5	51.5	49.7
Refinery Energy Expense	4,702.0	4,101.0	5,480.0	4.1	3.4	3.9
Other Refinery Expense	8,854.0	8,854.0	9,882.0	7.7	7.3	7.0
Product Purchases	27,445.0	31,018.0	37,958.0	23.9	25.7	26.8
Other Product Supply Expense	3,432.0	3,432.0	4,072.0	3.0	2.8	2.9
Marketing Expense[2]	8,822.0	8,709.0	9,318.0	7.7	7.2	6.6
Total Refined Product Costs	111,280.0	118,256.0	137,049.0	96.9	98.0	96.8
Refined Product Margin	3,510.0	2,442.0	4,476.0	3.1	2.0	3.2
Dollars per Barrel Margin[3]	0.71	0.49	0.87	--	--	--
Other Refining/Marketing Revenues[4]	10,586.0	10,449.0	10,731.0	--	--	--
Other Refining/Marketing Expenses						
DD&A	3,780.0	4,732.0	3,847.0	--	--	--
Other[5]	7,454.0	7,166.0	7,873.0	--	--	--
Total Other Expenses	11,234.0	11,898.0	11,720.0	--	--	--
Refining/Marketing Operating Income	2,862.0	993.0	3,487.0	--	--	--
Miscellaneous Revenue & Expense[6]	289.0	-107.0	-101.0	--	--	--
Less Income Taxes	1,306.0	371.0	1,135.0	--	--	--
Refining/Marketing Net Income	1,845.0	508.0	2,251.0	--	--	--

[1] Represents reported cost of raw materials processed at refineries, less any profit from raw material trades or exchanges by refining/marketing.
[2] Excludes cost of marketing 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 not included in raw material costs, and expenses for TBA.
[6] Includes other revenue and expense items, extraordinary items, and cumulative effect of accounting changes.
-- = Not applicable.
Source: Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B49. Sources of U.S. Bituminous Coal and Lignite Production, by Region and Mining Method, for FRS Companies and U.S. Industry, 1996, and Percent Change From 1995

Production	Total	Region			Mining Method	
		East	Midwest	West	Underground	Surface
	(million tons)					
1996						
FRS Companies	169.4	44.5	18.3	106.7	59.0	110.4
U.S. Industry	1,059.1	447.1	111.8	500.2	409.4	649.7
	(percent)					
Distribution by Region, 1996						
FRS Companies	100.0	26.2	10.8	62.9	--	--
U.S. Industry	100.0	42.2	10.6	47.2	--	--
Distribution by Mining Method, 1996						
FRS Companies	100.0	--	--	--	34.8	65.2
U.S. Industry	100.0	--	--	--	38.7	61.3
FRS Companies as a Percent of U.S. Industry	16.0	9.9	16.4	21.3	14.4	17.0
Change from 1995						
FRS Companies	2.4	-2.6	6.5	4.0	-5.5	7.3
U.S. Industry Total	3.0	3.9	2.2	2.4	3.4	2.7

-- = Not applicable.

Sources: Industry data - Energy Information Administration Form EIA-7A, see *Coal Industry Annual 1996* (October 1997). FRS companies data - Energy Information Administration, Form EIA-28 (Financial Reporting System).

Table B50. U.S. Coal Reserves Balance for FRS Companies, 1990-1996

(Million Tons)

Reserves Balance	1990	1991	1992	1993	1994	1995	1996
Changes to U.S. Coal Reserves							
Beginning of Period	49,200	44,949	39,026	18,593	16,142	13,395	10,493
Changes due to:							
Leases/Purchases of Minerals-in-Place	654	-107	571	145	W	W	W
Corporate Mergers and Acquisitions	W	W	W	0	W	W	W
Other Reserve Changes	W	W	W	-325	-61	-699	8
Production	-282	-290	-252	-197	-180	-165	-169
Dispositions of Minerals-in-Place	-4,002	-7,824	-18,576	-2,074	-2,591	-2,128	-1,150
End of Period Reserves	44,948	38,219	20,787	16,142	13,381	10,493	9,542
Weighted Average Annual Production Capacity	320	327	291	236	201	184	192

W = Data withheld to avoid disclosure.

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

Table B51. U.S. Coal Reserves (End of Year) and Production Statistics for FRS Companies, 1990-1996

(Million Tons)

Reserves and Production Statistics	U.S. Total	Region			Mining Method	
		East	Midwest	West	Underground	Surface
1990						
U.S. Coal Reserves	44,948.5	8,864.7	6,812.0	29,271.9	14,865.6	30,082.9
U.S. Coal Production	282.0	118.8	25.5	137.8	119.4	162.7
1991						
U.S. Coal Reserves	38,218.9	4,802.1	5,653.1	27,763.7	10,136.4	28,082.5
U.S. Coal Production	289.6	114.1	26.2	149.4	122.8	166.8
1992						
U.S. Coal Reserves	20,787.2	4,190.0	4,733.3	11,863.9	8,127.0	12,660.3
U.S. Coal Production	251.9	75.4	22.8	153.7	83.8	168.1
1993						
U.S. Coal Reserves	16,142.0	2,946.0	3,673.4	9,522.6	6,068.1	10,074.0
U.S. Coal Production	197.3	40.7	13.5	143.0	52.8	144.5
1994						
U.S. Coal Reserves	13,381.3	2,833.2	3,212.5	7,335.7	5,479.1	7,902.2
U.S. Coal Production	179.7	46.2	15.9	117.7	58.5	121.2
1995						
U.S. Coal Reserves	10,493.2	2,763.1	3,206.0	4,524.1	5,336.9	5,156.3
U.S. Coal Production	165.4	45.6	17.2	102.6	62.5	102.9
1996						
U.S. Coal Reserves	9,541.7	2,675.3	2,466.5	4,399.8	4,571.4	4,970.3
U.S. Coal Production	169.4	44.5	18.3	106.7	59.0	110.4

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

Table B52. Research and Development Expenditures for FRS Companies, 1990-1996

(Million Dollars)

Research and Development Expenditures	1990	1991	1992	1993	1994	1995	1996
Sources of R&D Funds							
Federal Government	11	14	22	16	15	W	W
Internal Company	3,843	3,832	3,603	3,308	2,985	2,817	2,675
Other Sources	49	56	60	26	50	W	W
Total Sources	3,903	3,902	3,685	3,350	3,050	2,861	2,717
Breakdown of R&D Expenditures							
Oil & Gas Recovery	727	794	781	671	572	494	482
Other Petroleum	615	678	652	569	531	461	432
Coal Gasification/Liquefaction	38	39	W	W	W	W	W
Other Coal	15	17	W	W	W	W	W
Nuclear and Other Energy	116	95	80	121	116	50	51
Nonenergy	2,274	2,159	2,041	1,902	1,741	1,744	1,617
Unassigned	118	120	117	77	71	100	127
Total Expenditures	3,903	3,902	3,685	3,350	3,050	2,861	2,717

W = Data withheld to avoid disclosure.

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

Appendix C

Completed Foreign Direct Investment Transactions, 1995

Appendix C

Completed Foreign Direct Investment Transactions

Table C1. Completed Transactions by Size in the Petroleum Industry from January 1995 Through December 1995 – Acquisitions and Divestitures

Acquiring Company	Acquiring Company Activity	Affected Company	Affected Company Activity	Type of Transaction	Size of Transaction (million dollars)	Date of Transaction
		Acquisitions				
YPF (Argentina)	Integrated petroleum operations	Maxus Energy Corp.	Oil and gas exploration and production	Merger	1,844	June
Investa AS (Norway) Blue Dolphin Energy	Oil and gas exploration and production	Petroport L.C.	Oil and gas exploration and production	Merger	500	March
Horsham Corp (Canada) Clark Refining & Marketing Inc.	Petroleum Refining & Marketing	Chevron Corp.	Integrated petroleum operations	Asset acquisition	339	February
Nova Corp (Canada) Natural Gas Clearinghouse	Gas marketing	Trident NGL Holding Inc.	Natural gas liquids operations	Merger	167	March
Gaz de France (France) Tejas Power Corp	Natural gas gathering & marketing	Seagull Energy Corp.	Gas transmission & marketing	Asset acquisition	154.8	September
Louis Dreyfus et Cie (France) Louis Dreyfus Natural Gas Corp.	Oil and gas exploration and production	American Exploration Co.	Oil and gas exploration and production	Property Acquisition	90	July
Chieftain International Inc. (Canada)	Oil and gas exploration and production	Santa Fe Minerals	Oil and gas exploration and production	Property acquisition	55	August
Forcenergy AB (Sweden) Forcenergy Inc.	Oil and gas exploration and production	NA	NA	Property acquisition	31	March
Interkohle (Germany) Penn Virginia Corp	Leases mineral rights, oil & gas exploration and development	United Meridian Corp	Oil and gas exploration and production	Property acquisition	17	February

Table C1. Completed Transactions by Size in the Petroleum Industry from January 1995 Through December 1995 – Acquisitions and Divestitures (Continued)

Acquiring Company	Acquiring Company Activity	Affected Company	Affected Company Activity	Type of Transaction	Size of Transaction (million dollars)	Date of Transaction
			Acquisitions (continued)			
Nova Corp (Canada) NGC Liquids Marketing Inc.	Natural gas marketing	LPG Services Group	Natural gas transmission	Merger	8.3	October
Louis Dreyfus et Cie (France) Louis Dreyfus Natural Gas Corp.	Oil and gas exploration and production	Mitchell Energy & Development	Gas transmission, oil and gas exploration & development	Asset acquisition	7	September
Nova Corp (Canada) NGC Liquids Marketing Inc.	Gas marketing	Sheffield Exploration Co.	Oil and gas exploration and production	Asset acquisition	5.5	October
United Energy Corp. (United Kingdom) Ambrit Energy Corp.	Oil and gas exploration and production	Woodbine Petroleum Inc.	Oil and gas exploration and production	Asset acquisition	4.3	March
MSR Exploration Ltd. (Canada)	Oil and gas exploration and production	Hanson Production Co.	NA	Property acquisition	3.9	September
Forcenergy AB (Sweden) Forcenergy Inc.	Oil and gas exploration and production	NA	NA	Property acquisition	3.9	December
Forcenergy AB (Sweden) Forcenergy Inc.	Oil and gas exploration and production	NA	NA	Property acquisition	NA	December
Louis Dreyfus et Cie Louis Dreyfus Natural Gas Corp.	Oil and gas exploration and production	Bogart Oil	Oil and gas exploration and production	Property acquisition	NA	December
Nova Corp (Canada) NGC Corp.	Natural gas transmission, marketing	ONEOK Inc	Natural gas transmission & distribution	Asset acquisition	NA	December
Nova Corp (Canada) NGC Corp.	Natural gas transmission, marketing	Kerr-McGee Corp.	Oil and gas exploration and production	Asset acquisition	NA	August
MSR Exploration Inc. (Canada)	Oil and gas exploration and production	NA	NA	Property acquisition	NA	February
			Divestitures			
Natural Gas Clearinghouse	Gas marketing	**Nova Corp** (Canada) Trident NGL Holding Inc.	Natural gas liquids operations	Merger	167	March
LG&E Energy Corp.	Electricity generation, gas transmission & distribution	**Andrew Soros** (Canada) Hadson Corp.	Oil and gas exploration and production	Merger	143	May

Table C1. Completed Transactions by Size in the Petroleum Industry from January 1995 Through December 1995 – Acquisitions and Divestitures (Continued)

Acquiring Company	Acquiring Company Activity	Affected Company	Affected Company Activity	Type of Transaction	Size of Transaction (million dollars)	Date of Transaction
		Divestitures (continued)				
Cross Timbers Oil Company	Oil and gas exploration and production	**Kuwait Petroleum Corp**. (Kuwait) Santa Fe Minerals Inc.	Oil and gas exploration and production	Property acquisition	130	August
MCN Corp.	Gas transmission and distribution	**Rheinbraun AG** (Germany) CONSOL Coal Group	Coal mining	Property acquisition	120	December
Enron Oil & Gas/ Chieftain International U.S. Inc.	Oil and gas exploration and production	**Kuwait Petroleum Corp**. (Kuwait) Santa Fe Minerals Inc.	Oil and gas exploration and production	Property acquisition	110	April
Titan Resources LP	Oil and gas exploration and production	**Sonatrach** (Algeria) Anadarko Petroleum Corp	Oil and gas exploration and production	Property acquisition	42.3	December
Seneca Resources Corp		**Royal Dutch/ Shell Group** (Netherlands) Shell Offshore Inc.	Oil and gas exploration and production	Property acquisition	31.75	September
NA	NA	**Costain PLC** (United Kingdom) Costain Holdings Inc.	Diversified holdings	Asset acquisition	24	January
NA	NA	**Norcen Energy Resources Ltd** (Canada)	Oil and gas exploration and production	Property acquisition	16	February
Panaco Inc.	Oil and gas exploration and production	**Royal Dutch/ Shell Group** (Netherlands) Shell Oil Co.	Integrated petroleum operations	Property acquisition	10.5	December
CoEnergy Offshore Pipeline & Processing Co.	Natural gas transmission and distribution	**Investa AS** (Norway) Blue Dolphin Energy Co.	Oil and gas exploration and production	Asset acquisition	10	August
Fortune Petroleum	Oil and gas exploration and production	**Petrofina S.A.** (France) Fina Inc.	Integrated petroleum operations	Property acquisition	2.9	December
Hampton Resources Corp	Oil and gas exploration and production	**Andrew Soros** (Canada) Santa Fe Energy Resources Inc.	Oil and gas exploration and production	Property acquisition	2.2	January

Table C1. Completed Transactions by Size in the Petroleum Industry from January 1995 Through December 1995 – Acquisitions and Divestitures (Continued)

Acquiring Company	Acquiring Company Activity	Affected Company	Affected Company Activity	Type of Transaction	Size of Transaction (million dollars)	Date of Transaction
		Divestitures (continued)				
Newfield Exploration Co.	Oil and gas exploration and production	**Nippon Oil Co.** (Japan) Nippon Oil Exploration	Oil and gas exploration and production	Property acquisition	1.75	December
Aquila Energy Resources	Oil and gas exploration and production	**Petrofina S.A.** (France) Fina Oil and Chemical	Integrated petroleum operations	Property acquisition	NA	July
Energy Resource Technology	NA	**Total SA** (France) Total Minatome	Oil and gas exploration and production	Property acquisition	NA	October

NA = Not available.
Sources: See page 173.

Table C2. Completed Transactions by Size in the Coal Industry from January 1995 Through December 1995 – Acquisitions and Divestitures

Acquiring Company	Acquiring Company Activity	Affected Company	Affected Company Activity	Type of Transaction	Size of Transaction (million dollars)	Date of Transaction
			Divestitures			
Ashland Inc.	Petroleum operations, chemicals, coal	**Saarbergwerke** (Germany) Ashland Coal	Coal Mining	Equity acquisition	110	February

Sources: See page 173.

Sources

Informational material used in compiling Tables C1 and C2:

- *The Wall Street Journal*, various issues, 1995 and 1996.
- *Business Week*, various issues.
- Company financial reports: annual reports to stockholders, annual reports on Securities and Exchange Commission (SEC) Form 10-K, and filings on SEC Schedule 13-D.
- *Oil and Gas Journal*, various issues, 1995 and 1996. Pennwell Publishing Company, Tulsa, OK.
- *The Merger Yearbook U.S./International Edition* 1996. Securities Data Company, New York, NY.
- *Oil and Gas Investor*, September 1995 and April 1996. Hart Publications, Inc., Denver, CO.
- *U.S. Oil Week*, various issues, 1995 and 1996. Capital Publishing Group, Alexandria, VA.
- *Coal*, various issues, 1995 and 1996. Maclean Hunter Publishing Co., Chicago, IL.
- Company press releases.

Glossary

Acquisition Costs: Direct costs and indirect costs incurred to acquire legal rights to deplete natural resources. Direct costs include costs incurred to obtain options to lease or purchase mineral rights and costs incurred for the actual leasing (e.g., lease bonuses) or purchasing of the rights. Indirect costs include such costs as: brokers' commissions and expenses; abstract and recording fees; filing and patenting fees; and costs of legal examination of title and documents.

Acreage: An area, measured in acres, that is subject to ownership or control by those holding total or fractional shares of working interests. Acreage is considered developed when development has been completed. (See definition for Working Interest.) A distinction may be made between “gross” acreage and “net” acreage:

- **Gross.** All acreage covered by any working interest, regardless of the percentage of ownership in the interest.
- **Net.** Gross acreage adjusted to reflect the percentage of ownership in the working interest in the acreage.

Affiliate: An “affiliate” of, or a person “affiliated” with, a specific person is a person that directly, or indirectly through one or more intermediaries, controls, or is controlled by, or is under common control with, the person specified. The term “affiliate” includes any subsidiary or parent of the person specified.

Amortization: The depreciation, depletion, or charge-off to expense of intangible and tangible assets over a period of time. In the extractive industries, the term is most frequently applied to mean either (1) the periodic charge-off to expense of the costs associated with nonproducing mineral properties incurred prior to the time when they are developed and entered into production or (2) the systematic charge-off to expense of those costs of productive mineral properties (including tangible and intangible costs of prospecting, acquisition, exploration, and development) that had been initially capitalized (or deferred) prior to the time the properties entered into production, and thereafter are charged off as minerals are produced.

Branded Product: A refined petroleum product sold by a refiner with the understanding that the purchaser has the right to resell the product under a trademark, trade name, service mark, or other identifying symbol or names owned by such refiner.

Christmas Tree: The valves and fittings installed at the top of a gas or oil well to control and direct the flow of well fluids.

Coal Gasification: The process of converting coal into gas. The basic process involves crushing coal to a powder, which is then heated in the presence of steam and oxygen to produce a gas. The gas is then refined to reduce sulfur and other impurities. The gas can be used as a fuel or processed further and concentrated into chemical or liquid fuel.

Coal Liquefaction: A chemical process that converts coal into clean-burning liquid hydrocarbons, such as synthetic crude oil and methanol.

Coal Regions: The following regional definitions are used to report domestic coal reserves, production, and other operating statistics.

- **Eastern Region.** Consists of the Northern Appalachian Coal Basin. The following States comprise the Eastern Region: Alabama, Georgia, Ohio, Maryland, Mississippi, Pennsylvania, Virginia, Tennessee, North Carolina, West Virginia, and Eastern Kentucky.
- **Midwest Region.** Consists of the Illinois and Michigan Coal Basins. The following States comprise the Midwest Region: Illinois, Indiana, Michigan, and Western Kentucky.
- **Western Region.** Consists of the Northern Rocky, Southern Rocky, Western Interior, and West Coast Coal Basins. The following States comprise the Central Western Region: Alaska, Arizona, Arkansas, California, Colorado, Idaho, Iowa, Kansas, Louisiana, Missouri, Montana, New Mexico, North Dakota, Oklahoma, Oregon, Texas, South Dakota, Utah, Washington, and Wyoming.

Company Automotive (Retail) Outlet: Any retail outlet selling motor fuel under a reporting company brand name. (See definition for Branded Product.)

- **Company Operated.** A company retail outlet which is operated by salaried or commission personnel paid by the reporting company.

- **Lessee.** An independent marketer who leases the station and land and has use of tanks, pumps, signs, etc. A lessee dealer typically has a supply agreement with a refiner or a distributor and purchases products at dealer tank wagon prices. The term "lessee dealer" is limited to those dealers who are supplied directly by a refiner or any affiliate or subsidiary company of a refiner. "Direct supply" includes use of commission agent or common carrier delivery.

- **Open.** An independent marketer who owns or leases (from a third party who is not a refiner) the station or land of a retail outlet and has use of tanks, pumps, signs, etc. An open dealer typically has a supply agreement with a refiner or a distributor and purchases products at or below dealer tank wagon prices.

Contribution to Net Income: The FRS segment equivalent of net income. However, many consolidated items of revenue and expense are not allocated to the segments, and therefore they are not equivalent in a strict sense. The largest item not allocated to the segments is interest expense since this is regarded as a corporate-level item for FRS purposes.

Crude Oil: A mixture of hydrocarbons that exists in liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities. For FRS reporting, volumes reported as crude include:

- Liquids technically defined as crude oil.

- Small amounts of hydrocarbons that exist in the gaseous phase in natural underground reservoirs but are liquid at atmospheric pressure after being recovered from oil well (casinghead) gas in lease separators and are commingled with the crude stream without being separately measured.

- Small amounts of nonhydrocarbons produced with the oil.

Statistical data pertaining to crude oil production and reserves are reported as liquid equivalents at the surface (excluding base sediment and water) measured in terms of stock tank barrels of 42 U.S. gallons at atmospheric pressure, corrected to 60 degrees Fahrenheit.

Where a State regulatory agency specifies a definition of crude oil which differs from that set forth above for statistical purposes, the State definition should be followed.

DD&A: Abbreviation for depreciation, depletion and amortization.

Deferred Taxes: Taxes accrued and reflected as an expense in a company's income statement, but not payable to the taxing authority in that time period. These taxes are accrued to compensate for an understatement of income tax expense which would occur if only the tax currently due to the taxing authority were reflected as the total income tax expense.

Depletion: A term for either (1) a periodic assignment to expense of recorded amounts or (2) an allowable income tax deduction that is related to the exhaustion of mineral reserves. Depletion is included as one of the elements of amortization. When used in that manner, depletion refers only to book depletion (see definition for Amortization).

- **Book.** The portion of the carrying value (other than the portion associated with tangible assets) prorated in each accounting period, for financial reporting purposes, to the extracted portion of an economic interest in a wasting natural resource.

- **Tax-cost.** A deduction (allowance) under U.S. Federal Income taxation normally calculated under a formula whereby the adjusted basis of the mineral property is multiplied by a fraction, the numerator of which is the number of units of minerals sold during the tax year and the denominator of which is the estimated number of units of unextracted minerals remaining at the end of the tax year plus the number of units of minerals sold during the tax year.

- **Tax-percentage (or Statutory).** A deduction (allowance) allowed to certain mineral producers under U.S. Federal income taxation calculated on the basis of a specified percentage of gross revenue from the sale of minerals from each mineral property not to exceed the lesser of 50 percent of the taxable income from the property computed without allowance for depletion. (There are also other limits on percentage depletion on oil and gas production.) The taxpayer is entitled to a deduction representing the amount of tax-cost depletion or percentage (statutory) depletion, whichever is higher.

- **Excess Statutory Depletion.** The excess of estimated statutory depletion allowable as an income tax deduction over the amount of cost depletion otherwise allowable as a tax deduction, determined on a total enterprise basis.

Depreciation: See definition for Amortization.

Development: The preparation of a specific mineral deposit for commercial production; this preparation includes construction of access to the deposit and of facilities to extract the minerals. The development process is sometimes further distinguished between a preproduction stage and a current stage, with the distinction being made on the basis of whether the development work is performed before or after production from the mineral deposit has commenced on a commercial scale.

Development Costs: Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering, and storing the oil and gas. More specifically, development costs, and also depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

- Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves;

- Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly;

- Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and utility waste disposal systems; and

- Provide improved recovery systems.

Distillate: A general classification for one of the petroleum fractions produced in conventional distillation operations. Included are kerosene and products known as heating oils and diesel fuels, specifically: No. 1, No. 2, and No. 4 Fuel Oils and No. 1, No. 2, and No. 4 Diesel Fuels.

Domestic Operations: Domestic operations are those operations located in the United States.

- The United States is defined as the 50 States, including their offshore territorial waters, the District of Columbia, U.S. commonwealth territories, and protectorates.

Drilling: The act of boring a hole (1) to determine whether minerals are present in commercially recoverable quantities and (2) to accomplish production of the minerals (including drilling to inject fluids).

- **Exploratory.** Drilling to locate probable mineral deposits or to establish the nature of geological structures; such wells may not be capable of production if minerals are discovered.

- **Developmental.** Drilling to delineate the boundaries of a known mineral deposit to enhance the productive capacity of the producing mineral property.

- **Directional.** Drilling that is deliberately made to depart significantly from the vertical.

Drilling and Equipping of Wells: The drilling and equipping of wells through completion of the "christmas tree."

Dry-Hole Charge: The charge-off to expense of a previously capitalized cost upon the conclusion of an unsuccessful drilling effort.

Equity in Earnings of Unconsolidated Affiliates: A company's proportional share (based on ownership) of the net earnings or losses of an unconsolidated affiliate.

Exploration: The identification of areas that may warrant examination and to examine specific areas that are considered to have prospects of containing oil and gas reserves, including drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property.

Exploration Costs: Costs, including depreciation and applicable operating costs, of support equipment and facilities and other costs directly identifiable with exploration activities, such as:

- Costs of topographical, geological, and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these costs are sometimes referred to as geological and geophysical, or "G&G" costs.

- Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on the properties, legal costs for title defense, and the maintenance of land and lease records.

- Dry hole contributions and bottom hole contributions. Costs of drilling and equipping exploratory wells.

- Costs of drilling exploratory-type stratigraphic test wells.

Extraordinary Item: Income and expense items associated with events and transactions that possess a high degree of abnormality and are of a type that would not reasonably be expected to recur in the foreseeable future.

Field: An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both.

Footage Drilled: Total footage for wells in various categories, as reported for any specified period, includes (1) the deepest total depth (length of well bores) of all wells drilled from the surface, (2) the total of all bypassed footage drilled in connection with reported wells, and (3) all new footage drilled for directional "sidetrack" wells. Footage reported for directional "sidetrack" wells does not include footage in the common bore, which is reported as footage for the original well. In the case of old wells drilled deeper, the reported footage is that which was drilled below the total depth of the old well.

- **Deepest Total Depth.** The deepest total depth of a given well is the distance from a surface reference point (usually the Kelly bushing) to the point of deepest penetration measured along the well bore. If a well is drilled from a platform or barge over water, the depth of the water is included in the total length of the well bore.

- **Sidetrack Drilling.** This is a remedial operation that results in the creation of a new section of well bore for the purpose of (1) detouring around junk, (2) redrilling lost hole, or (3) straightening key seats and crooked holes. Directional "sidetrack" wells do not include footage in the common bore which is reported as footage for the original well.

Foreign Access: Refers to proved reserves of crude (including lease condensate) and natural gas liquids applicable to long-term supply agreements with foreign governments or authorities in which the company acts as producer.

Foreign Operations: These are operations that are located outside the United States. Determination of whether an enterprise's mobile assets, such as offshore drilling rigs or ocean-going vessels, constitute foreign operations should depend on whether such assets are normally identified with operations located outside the United States.

Foreign operations are segregated into the following areas for FRS reporting purposes:

- **OECD Europe.** Includes Austria, Belgium, Denmark, Finland, France, the Federal Republic of Germany, Greece, Iceland, Ireland, Italy, Luxembourg, the Netherlands, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, and the United Kingdom.

- **Former Soviet Union (FSU) and East Europe.** The Baltic States of Estonia, Latvia, and Lithuania, as well as Armenia, Azerbaijan, Belarus, Georgia, Kazakhstan, Kyrgystan, Moldova, Russia, Tajikstan, Turkmenistan, Ukraine, Uzbekistan, Albania, Bulgaria, Czech Republic, Hungary, Poland, Romania, Slovakia, and Yugoslavia.

- **Middle East.** Includes Saudi Arabia, the United Arab Emirates, Iraq, Iran, Kuwait, the Iraq-Saudi Arabia Neutral Zone, Qatar, Dubai, Bahrain, Oman, Yemen, Syria, Jordan, and Israel.

- **Canada.**

- **Africa** (the African continent).

- **Other Eastern Hemisphere.** Areas eastward of the Greenwich prime meridian to 180 degrees longitude and not included in other specified domestic or foreign classifications.

- **Other Western Hemisphere.** Areas westward of the Greenwich prime meridian to 180 degrees longitude not included in other domestic or foreign classifications.

Funds From Operations: Calculated by adding noncash charges back to net income or contribution to net income. Deferred taxes and depreciation, depletion, and amortization (DD&A) are the largest noncash charges.

Funds, Total Sources of: The total source of funds including net income plus noncash charges such as DD&A and deferred taxes, issuances of stocks and bonds, and proceeds from the sale or property, plant, and equipment. The concept is similar to cash flow generated, but does not attempt to account for changes in working capital items. Thus, for example, an inventory buildup or drawdown would not be accounted for under the "funds" concept since both cash and inventory are items of working capital.

Geological and Geophysical (G&G) Costs: Costs incurred in making geological and geophysical studies, including, but not limited to, costs incurred for salaries, equipment, obtaining rights of access, and supplies for scouts, geologists, and geophysical crews.

Hydrocarbon: An organic chemical compound of hydrogen and carbon in either the gaseous, liquid, or solid phase. The molecular structure of hydrocarbon compounds varies from the simplest (e.g., methane, a constituent of natural gas) to the very heavy and very complex.

Improved Recovery: The operation whereby crude oil or natural gas is recovered using any method other than those that rely primarily on the use of natural reservoir pressure, gas lift, or a pump.

Intangible Drilling and Development Costs (IDC): Costs incurred in preparing well locations, drilling and deepening wells, and preparing wells for initial production up through the point of installing control valves. None of these functions, because of their nature, have salvage value. Such costs would include labor, transportation, consumable supplies, drilling tool rentals, site clearance, and similar costs.

Investment and Advances to Unconsolidated Affiliates: The balance sheet account representing the cost of investments and advances to unconsolidated affiliates. Generally, affiliates which are less than 50 percent owned by a company may not be consolidated into the company's financial statements.

Lease Bonus: An amount paid by a lessee to a lessor as consideration for granting a lease, usually as a lump sum; this payment is in addition to any rental or royalty payments.

Lease Equipment: All equipment located on the lease except the well and the complete christmas tree installation.

Lifting Costs: The costs associated with the extraction of a mineral reserve from a producing property. (See definition for Production Cost.)

Mineral: Any of the various naturally occurring substances (such as coal, crude oil, metals, natural gas, salt, sand, stone, sulfur, and water) usually obtained from the earth. The term is used to include all wasting, i.e., nonregenerative, inorganic substances that are extracted from the earth.

Mineral Interests in Properties (hereinafter referred to as Properties): These include fee ownership or a lease, concession, or other contractual interest representing the right to extract minerals subject to such terms as may be imposed by the conveyance of those interests. Properties also include royalty interests, production payments payable in oil or gas, and other nonoperating interests in properties operated by others. Properties include those agreements with foreign governments or authorities under which an enterprise participates in the operation of the related properties or otherwise serves as "producer" of the underlying reserves, but properties do not include other supply agreements or contracts that represent the right to purchase (as opposed to extract) oil and gas.

Mineral Lease: An agreement wherein a mineral interest owner (lessor) conveys to another party (lessee) the rights to explore for, develop, and produce specified minerals. The lessee acquires a working interest and the lessor retains a nonoperating interest in the property, referred to as the royalty interest, each in proportions agreed upon.

Mineral Rights: The ownership of the minerals beneath the earth's surface with the right to remove them. Mineral rights may be conveyed separately from surface rights.

Mining: Any activity directed to the extraction of ore and associated rock. Included are open pit work, quarrying, augering, alluvial dredging, and combined operations, including surface and underground operations.

Minority Interest in Income: The proportional share of the minority ownership's interest (less than 50 percent) in the earnings or losses of the consolidated subsidiary.

Subsidiaries are generally fully consolidated when a share of ownership between 51 percent and 100 percent is held by the parent. In consolidation, 100 percent of revenues, expenses, assets, etc. are included in the financial statements even though, for example, the subsidiary is only 80 percent owned by the parent company. In such cases, the consolidated balance sheet must have a caption on the right-hand side titled something like "minority interests in consolidated affiliates," and the income statement must have a similar line to reduce net income to the pro rata (80 percent in this example) share of the consolidated subsidiary's net income.

Motor Gasoline (Finished): A complex mixture of relatively volatile hydrocarbons, with or without small quantities of additives, that has been blended to form a fuel suitable for use in spark-ignition engines. Motor gasoline, as given in ASTM Specification D439 or Federal Specification VV-G-l690B, includes a range in distillation temperatures from 122 to 158 degrees Fahrenheit at the 10-percent recovery point and from 365 to 374 degrees Fahrenheit at the 90-percent recovery point. Motor gasoline includes reformulated motor gasoline, oxygenated motor gasoline, and other finished motor gasoline. Blendstock is excluded until blending has been completed.

- **Reformulated Motor Gasoline.** Gasoline reformulated for use in motor vehicles, the composition and properties of which meet the requirements of the reformulated gasoline regulations promulgated by the U.S. Environmental Protection Agency under Section 211K of the Clean Air Act.

- **Oxygenated Gasoline.** Gasoline formulated for use in motor vehicles that has an oxygen content of 1.8 percent or higher, by weight. Includes gasohol.

- **Other Finished Gasoline.** Motor Gasoline not included in the oxygenated or reformulated gasoline categories.

Motor Gasoline, Finished Gasohol: A blend of finished motor gasoline (leaded or unleaded) and alcohol (generally ethanol but sometimes methanol), limited to 10 percent by volume of alcohol.

Motor Gasoline, Finished Leaded: Contains more than 0.05 gram of lead per gallon or more than 0.005 gram of phosphorus per gallon. Premium and regular grades are included, depending on the octane rating. Includes leaded gasohol. Blendstock is excluded until blending has been completed. Alcohol that is to be used in the blending of gasoline is excluded.

Motor Gasoline, Finished Unleaded: Contains not more than 0.05 gram of lead per gallon and not more than 0.005 gram of phosphorus per gallons. Premium and regular grades are included, depending on the octane rating. Includes unleaded gasohol. Blendstock is excluded until blending has been completed. Alcohol that is to be used in the blending of gasohol is also excluded.

MTBE (Methyl tertiary butyl ether) (CH3)3C)CH: An ether intended for motor gasoline blending. (See definition for Oxygenates.)

Natural Gas: A mixture of hydrocarbon compounds and small quantities of various nonhydrocarbons existing in the gaseous phase or in solution with crude oil in natural underground reservoirs at reservoir conditions. The principal hydrocarbons usually contained in the mixture are methane, ethane, propane, butanes, and pentanes. Typical nonhydrocarbon bases which may be present in reservoir natural gas are carbon dioxide, helium, hydrogen sulfide, and nitrogen. Under reservoir conditions, natural gas and the liquefiable portions thereof occur either in a single gaseous phase in the reservoir or in solution with crude oil and are not distinguishable at that time as separate substances.

Natural gas, based on the type of occurrence in the reservoir, is classified by two categories, as follows:

- **Non-Associated Gas** is natural gas that is not in contact with significant quantities of crude oil in the reservoir.

- **Associated/Dissolved Gas** is the combined volume of natural gas which occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved).

Associated gas is free natural gas, commonly known as gas cap gas, which overlies and is in contact with crude oil in the reservoir. Dissolved gas is natural gas that is in solution with crude oil in the reservoir at reservoir conditions.

Statistical data pertaining to natural gas production and reserves are reported in units of 1,000,000 cubic feet (i.e., MMCF) at 14.73 pounds per square inch absolute and 60 degrees Fahrenheit for FRS purposes.

Natural Gas Liquids (NGL): Natural gas liquids are those portions of reservoir gas which are liquefied at the surface in lease separators, field facilities, or gas processing plants. Natural gas liquids include but are not limited to: ethane, propane, butanes, pentanes, natural gasoline, and condensate.

Net Investment in Place: The sum of net property, plant, and equipment (PP&E) plus investment and advances to unconsolidated affiliates.

Nonbranded Product: Any refined petroleum product that is not a branded product.

Nuclear Fuel Operations: All nuclear fuel operations, excluding reactor and reactor component manufacturing or containment construction. Includes exploration and development; mining; milling; conversion; enrichment; fabrication; reprocessing; and spent fuel storage.

Offshore: That geographic area that lies seaward of the coastline. In general, the coastline is the line of ordinary low water along with that portion of the coast that is in direct contact with the open sea or the line marking the seaward limit of inland water.

If a State agency uses a different basis for classifying onshore and offshore areas, the State classification should be used. (Cook Inlet in Alaska is classified as offshore.)

Oil Shale: A sedimentary rock containing kerogen, a solid organic material.

Operating Expenses: Segment expenses related both to revenue from sales to unaffiliated customers and revenue from intersegment sales or transfers, excluding loss on disposition of property, plant, and equipment; interest expenses and financial charges; foreign currency translation effects; minority interest; and income taxes.

Operating Income: Operating revenues less operating expenses. Excludes items of other revenue and expense, such as equity in earnings of unconsolidated affiliates, dividends, interest income and expense, income taxes, extraordinary items, and cumulative effect of accounting changes.

Operating Revenues: Segment revenues both from sales to unaffiliated customers (i.e., revenue from customers outside the enterprise as reported in the company's consolidated income statement) and from intersegment sales or transfers, if any, of product and services similar to those sold to unaffiliated customers, excluding equity in earnings of unconsolidated affiliates; dividend and interest income; gain on disposition of property, plant, and equipment; and foreign currency translation effects.

Other Energy Operations: Energy operations not included in Petroleum or Coal. Other Energy includes nuclear, oil shale, tar sands, coal liquefaction and gasification, geothermal, solar, and other forms of non-conventional energy.

Oxygenates: Any substance which, when added to gasoline, increases the amount of oxygen in that gasoline blend. Through a series of waivers and interpretive rules, the Environment Protection Agency (EPA) has determined the allowable limits for oxygenates in unleaded gasoline. The "Substantially Similar" Interpretive Rules (56 FR (February 11, 1991)) allows blends of aliphatic alcohols other than methanol and aliphatic ethers, provided the oxygen content does not exceed 2.7 percent by weight. The "Substantially Similar" Interpretive Rules also provide for blends of methanol up to 0.3 percent by volume exclusive of other oxygenates, and butanol or alcohols of a higher molecular weight up to 2.75 percent by weight. Individual waiver pertaining to the use of oxygenates in unleaded gasoline have been issued by the EPA. They include:

- **Fuel Ethanol.** Blends of up to 10 percent by volume anhydrous ethanol (200 proof) (commonly referred to as the "gasohol waiver").

- **Methanol.** Blends of methanol and gasoline-grade tertiary butyl alcohol (GTBA) such that the total oxygen content does not exceed 3.5 percent by weight and the ratio of methanol to GTBA is less than or equal to 1. It is also specified that this blended fuel must meet American Society for Testing and Materials (ASTM) volatility specifications (commonly referred to as the "ARCO" waiver).

  Blends of up to 5.0 percent by volume methanol with a minimum of 3.5 percent by volume cosolvent alcohols having a carbon number of 4 or less (i.e., ethanol, propanol, butanol, and / or GTBA). The total oxygen must not exceed 3.7 percent by weight, and the blend must meet ASTM volatility specifications as well as phase separation and purity specifications (commonly referred to as the "DuPont" waiver).

- **MTBE (Methyl tertiary butyl ether).** Blends up to 15.0 percent by volume MTBE which must meet the ASTM D4814 specifications. Blenders must take precautions that the blends are not used as base gasolines for other oxygenated blends (commonly referred to as the "Sun" waiver).

PP&E, Additions to: The current year's expenditures on property, plant, and equipment (PP&E). The amount is predicated upon each reporting company's accounting practice. That is, accounting practices with regard to capitalization of certain items may differ across companies, and therefore this figure in FRS will be a function of each reporting company's policy.

PP&E, Net: The original cost of property, plant, and equipment (PP&E), less accumulated depreciation.

Petroleum: Hydrocarbon mixtures broadly defined to include crude oil, lease condensate, natural gas, products of natural gas processing plants (plant products), refined products, and semifinished products and blending materials.

Pipelines, Rate Regulated: FRS establishes three pipeline segments: crude / liquid (raw materials); natural gas; and refined products. The pipelines included in these segments are all Federally or State rate-regulated pipeline operations, which are included in the reporting company's consolidated financial statements. However, at the reporting company's option, intrastate pipeline operations may be included in the U.S. Refining / Marketing Segment **if:** they would comprise less than 5 percent of U.S. Refining / Marketing Segment net PP&E, revenues, and earnings in the aggregate; and if the inclusion of such pipelines in the consolidated financial statements adds less than $100 million to the net PP&E reported for the U.S. Refining / Market Segment.

Primary Recovery: The crude oil or natural gas recovered by any method that may be employed to produce them where the fluid enters the well bore by the action of natural reservoir pressure (energy or gravity).

Primary Transportation: Conveyance of large shipments of petroleum raw materials and refined products usually by pipeline, barge, or ocean-going vessel. All crude oil transportation is primary, including the small amounts moved by truck. All refined product transportation by pipeline, barge, or ocean-going vessel is primary transportation.

Producing Property: A term often used in reference to a property, well, or mine that produces wasting natural resources. The term means a property that produces in paying quantities (that is, one for which proceeds from production exceed operating expenses).

Production, Natural Gas Liquids: Production of natural gas liquids is classified as follows:

- **Contract Production.** Natural gas liquids accruing to a company because of its ownership of liquids extraction facilities that it uses to extract liquids from gas belonging to others, thereby earning a portion of the resultant liquids.

- **Leasehold Production.** Natural gas liquids produced, extracted, and credited to a company's interest.

- **Contract Reserves.** Natural gas liquid reserves corresponding to the contract production defined above.

- **Leasehold Reserves.** Natural gas liquid reserves corresponding to the leasehold production defined above.

Production, Oil and Gas: The lifting of the oil and gas to the surface and gathering, treating, field processing (as in the case of processing gas to extract liquid hydrocarbons), and field storage. The production function shall normally be regarded as terminating at the outlet valve on the lease or field production storage tank; if unusual physical or operational circumstances exist, it may be more appropriate to regard the production function as terminating at the first point at which oil, gas, or gas liquids are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal.

- **Gross Company-Operated Production.** Total production from all company-operated properties, including all working and nonworking interests.

- **Net Working Interest Production.** Total production accruing to the reporting company's working interests less royalty oil and volumes due others.

Production Costs: Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. The following are examples of production costs (sometimes called lifting costs):

- Costs of labor to operate the wells and related equipment and facilities.

- Repair and maintenance costs.

- The costs of materials, supplies, and fuel consumed and services utilized in operating the wells and related equipment and facilities.

- The costs of property taxes and insurance applicable to proved properties and wells and related equipment and facilities.

- The costs of severance taxes.

Depreciation, depletion, and amortization (DD&A) of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

Production costs include the following subcategories of costs:

- Well operations and maintenance

- Well workovers

- Operating fluid injection and improved recovery programs

- Operating gas processing plants
- *Ad valorem* taxes
- Production or severance taxes
- Other, including overhead.

Research and Development: Basic and applied research in the sciences and engineering and the design and development of prototypes and processes, excluding quality control, routine product testing, market research, sales promotion, sales service, research in the social sciences or psychology, and other non-technological activities or technical services.

Reserves, Change in: For FRS reporting, the following definitions should be used for changes in reserves.

- **Revisions of Previous Estimates.** Changes in previous estimates of proved reserves, either upward or downward, resulting from new information normally obtained from development drilling and production history or resulting from a change in economic factors. Revisions do not include changes in reserve estimates resulting from increases in proved acreage or from improved recovery techniques.

- **Improved Recovery.** Changes in reserve estimates resulting from application of improved recovery techniques shall be separately shown, if significant. If not significant, such changes shall be included in revisions of previous estimates.

- **Purchases or Sales of Minerals-in-Place.** Increase or decrease in the estimated quantity of reserves resulting from the purchase or sale of mineral rights in land with known proved reserves.

- **Extensions, Discoveries, and Other Additions.** Additions to an enterprise's proved reserves that result from (1) extension of the proved acreage of previously discovered (old) reservoirs through additional drilling in periods subsequent to discovery and (2) discovery of new fields with proved reserves or of new reservoirs of proved reserves in old fields.

Reserves (Coal): Coal reserve estimates comprising the demonstrated coal reserve base include only proved (measured) and probable (indicated).

- **Proved (Measured) Reserves.** Reserves or resources for which tonnage is computed from dimensions revealed in outcrops, trenches, workings, and drill holes and for which the grade is computed from the results of detailed sampling. The sites for inspection, sampling, and measurement are spaced so closely and the geologic character is so well defined that size, shape, and mineral content are well established. The computed tonnage and grade are judged to be accurate within limits which are stated, and no such limit is judged to be different from the computed tonnage or grade by more than 20 percent.

- **Probable (Indicated) Reserves.** Reserves or resources for which tonnage and grade are computed partly from specific measurements, samples, or production data and partly from projection for a reasonable distance on geologic evidence. The sites available are too widely or otherwise inappropriately spaced to permit the mineral bodies to be outlined completely or the grade established throughout.

Reserves, Net: Includes all proved reserves associated with the company's net working interests. (See definition for Working Interest.)

Reserves, Proved (Oil and Gas): The estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Reservoirs are considered proved if economic producibility is supported by one or more of: actual production; conclusive formation test; core analysis; and / or electric or other log interpretations. The area of a reservoir considered proved includes (1) that portion delineated by drilling and defined by gas-oil and / or oil-water contacts, if any; and (2) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limited of the reservoir.

Volumes of oil and gas placed in underground storage are not to be considered proved reserves; but should be classified as inventory.

Reserves that can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

Estimates of proved reserves do not include the following: (1) oil that may become available from known reservoirs but is classified separately as “indicated additional reserves;” (2) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (3) crude oil, natural gas, and natural gas liquids that may occur in undrilled prospects; and (4) crude oil, natural gas, and natural gas liquids that may be recovered from oil shales, coal, gilsonite and other such sources.

It is not necessary that production, gathering, or transportation facilities be installed or operative for a reservoir to be considered proved.

For natural gas, an appropriate reduction in the reservoir gas volume is made to cover the removal of the liquefiable portions of the gas and the exclusion of nonhydrocarbon gases where they occur in sufficient quantity to render the gas unmarketable. If the liquefiable portions of the gas are not separately estimated, they need not be separately stated for FRS reporting purposes.

Reservoir: A porous and permeable underground formation containing an individual and separate accumulation of producible hydrocarbons (oil and/or gas) that is confined by impermeable rock or water barriers and is characterized by a single natural pressure system.

Residual Fuel Oil: The heavier oils that remain after the distillate fuel oils and lighter hydrocarbons are distilled away in refinery operations and that conform to ASTM Specifications D396 and 975. Included are No. 5, a residual fuel oil of medium viscosity; Navy Special, for use in steam-powered vessels in government service and in shore power plants; No. 6, which includes Bunker C fuel oil, and is used for commercial and industrial heating, electricity generation, and to power ships.

Royalty: A contractual arrangement providing a mineral interest that gives the owner a right to a fractional share of production or proceeds therefrom, that does not contain rights and obligations of operating a mineral property, and that is normally free and clear of exploration, developmental, and operating costs, except production taxes.

Short Ton: A unit of weight that equals 2,000 pounds.

Support Equipment and Facilities: These include, but are not limited to, seismic equipment, drilling equipment, construction and grading equipment, vehicles, repair shops, warehouses, supply points, camps, and division, district, or field offices.

Tangible Development Costs: Cost incurred during the development stage for access, mineral-handling, and support facilities having a physical nature. In mining, such costs would include tracks, lighting equipment, ventilation equipment, other equipment installed in the mine to facilitate the extraction of minerals, and supporting facilities for housing and care of work forces. In the oil and gas industry, tangible development costs would include well equipment (such as casing, tubing, pumping equipment, and well heads), as well as field storage tanks and gathering systems.

Tar Sands: Naturally occurring bitumen-impregnated sands that yield mixtures of liquid hydrocarbon and that require further processing other than mechanical blending before becoming finished petroleum products.

Timing Differences: Differences between the periods in which transactions affect taxable income and the periods in which they enter into the determination of pretax accounting income. Timing differences originate in one period and reverse or “turn around” in one or more subsequent periods. Some timing differences reduce income taxes that would otherwise be payable currently; others increase income taxes that would otherwise be payable currently.

Transfer Price: The monetary value assigned to products, services, or rights conveyed or exchanged between related parties, including those occurring between units of a consolidated entity.

Uncompleted Wells, Equipment, and Facilities Costs: The costs incurred to (1) drill and equip wells that are not yet completed, and (2) acquire or construct equipment and facilities that are not yet completed and installed.

Undeveloped Property: Refers to a mineral property on which development wells or mines have not been drilled or completed to a point that would permit the production of commercial quantities of mineral reserves.

Uranium Oxide: A yellow or brown powder produced from naturally occurring uranium minerals as a result of milling uranium ore or processing uranium-bearing solutions. Synonymous with “yellowcake,” U_3O_8, or uranium concentrate.

Well: A hole drilled in the earth for the purpose of (1) finding or producing crude oil or natural gas; or (2) providing services related to the production of crude oil or natural gas.

Wells are classified as (1) oil wells; (2) gas wells; (3) dry holes; (4) stratigraphic test wells; or (5) service wells. The latter two types of wells are not counted for FRS reporting.

Oil wells, gas wells, and dry holes are classified as exploratory wells or development wells. Exploratory wells are subclassified as (1) new-pool wildcats; (2) deeper-pool tests; (3) shallow-pool test; and (4) outpost (extension) tests. Well classifications reflect the status of wells after drilling has been completed.

- **Completion.** The term refers to the installation of permanent equipment for the production of oil or gas.

- **Development Well.** A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

- **Dry Hole.** An exploratory or development well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

- **Exploratory Well.** A well that is not a development well, a service well, nor a stratigraphic test as those items are defined elsewhere.

- **Oil Well.** A well completed for the production of crude oil from at least one oil zone or reservoir.

Wellhead Price: The value at the mouth of the well. In general, the wellhead price is considered to be the sales price obtainable from a third party in an arm's length transaction. Posted prices, requested prices, or prices as defined by lease agreements, contracts, or tax regulations should be used where applicable.

Working Interest: An interest in a mineral property that entitles the owner of that interest to all of a share of mineral production from the property, usually subject to a royalty.

A working interest permits the owner to explore, develop, and operate the property. The working interest owner bears the costs of exploration, development, and operation of the property and, in return, is entitled to a share of the mineral production from the property or to a share of the proceeds therefrom. It may be assigned to another party in whole or in part, or it may be divided into other special property interests.

- **Gross Working Interest.** The reporting company's working interest plus the proportionate share of any basic royalty interest or overriding royalty interest related to the working interest.

- **Net Working Interest.** The reporting company's working interest not including any basic royalty or overriding royalty interests.