2. Financial Developments in 2002

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

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

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

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

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

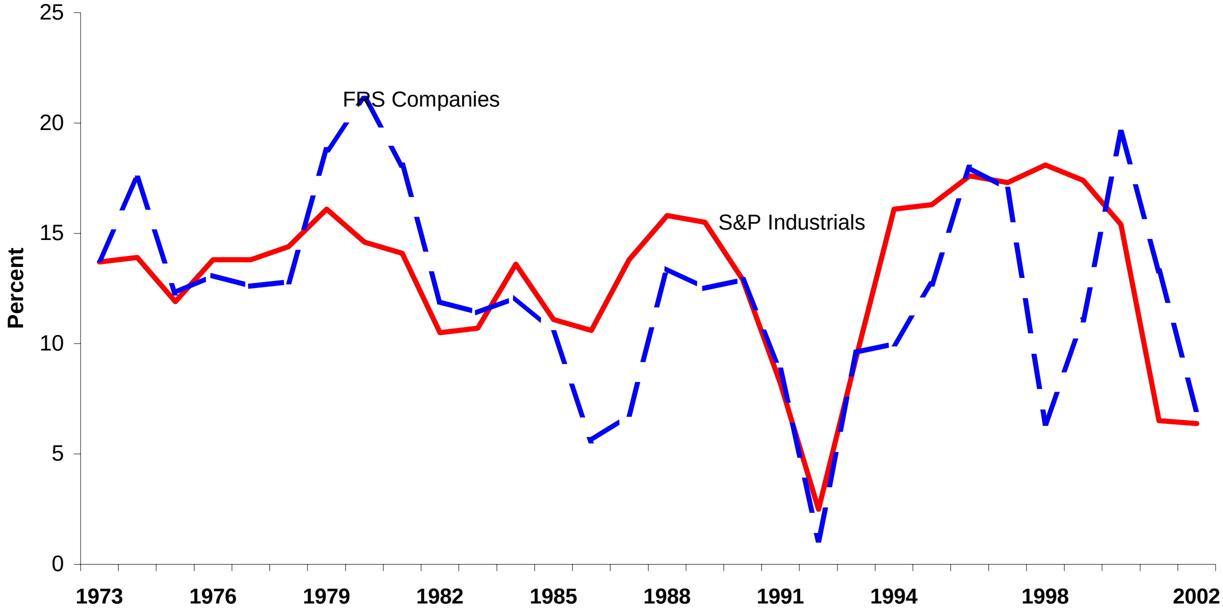
NA= not available.

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

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

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

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



Note: Time Warner and Qwest Communications data have been excluded from S&P Industrials data in 2001 and 2002 due to anomalies in the data for both companies in 2002, which, when included, greatly distorted the numbers for the group as a whole.
Sources: **FRS Companies**: Energy Information Administration, Form EIA-28 (Financial Reporting System). **S&P Industrials**: Compustat PC Plus, a service of Standard and Poor's.

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

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

Income and Cash Flow

Downstream Petroleum Performance Hit A New Low in 2002

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

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

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

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

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

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

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

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

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

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

FRS Companies’ Pipeline Earnings

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

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

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

Low Natural Gas Prices Hurt Upstream Profits

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

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

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

Other Energy Plagued by Energy Trading Collapse

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

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

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

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

Chemical Operations Yield Rare Gains in Earnings

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

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

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

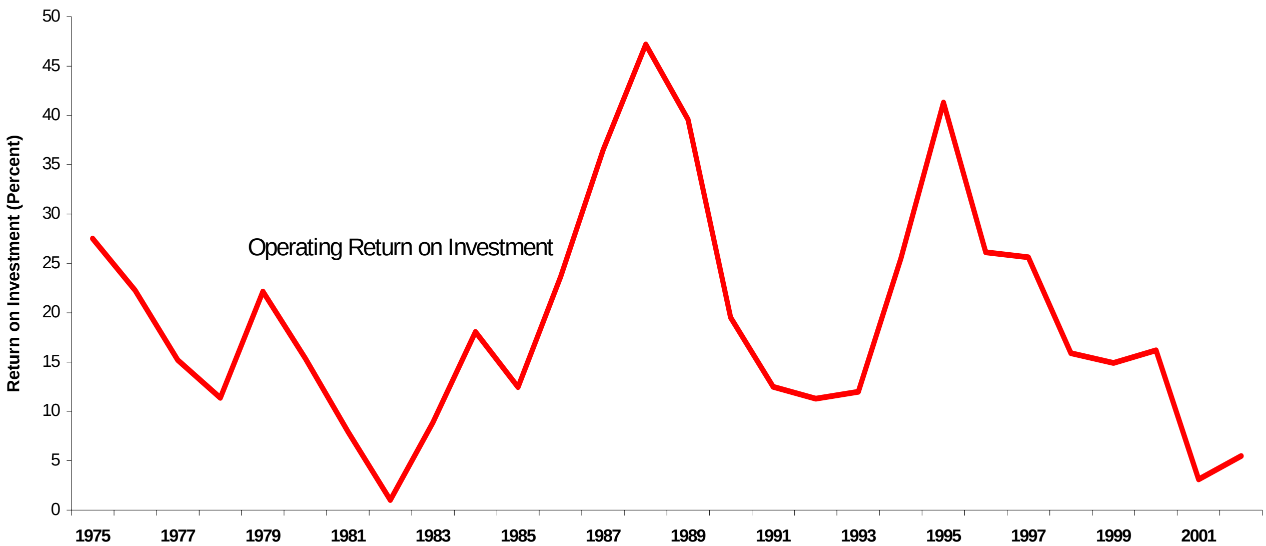
Table 3. Operating Income in Chemicals and Other Nonenergy Segments for FRS Companies, 2001-2002
(Million Dollars)

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

-- = not meaningful

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

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



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

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

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

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

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

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

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

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

Targets of Investment

FRS Companies Increase Upstream Focus on OECD Europe, North Sea

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

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

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

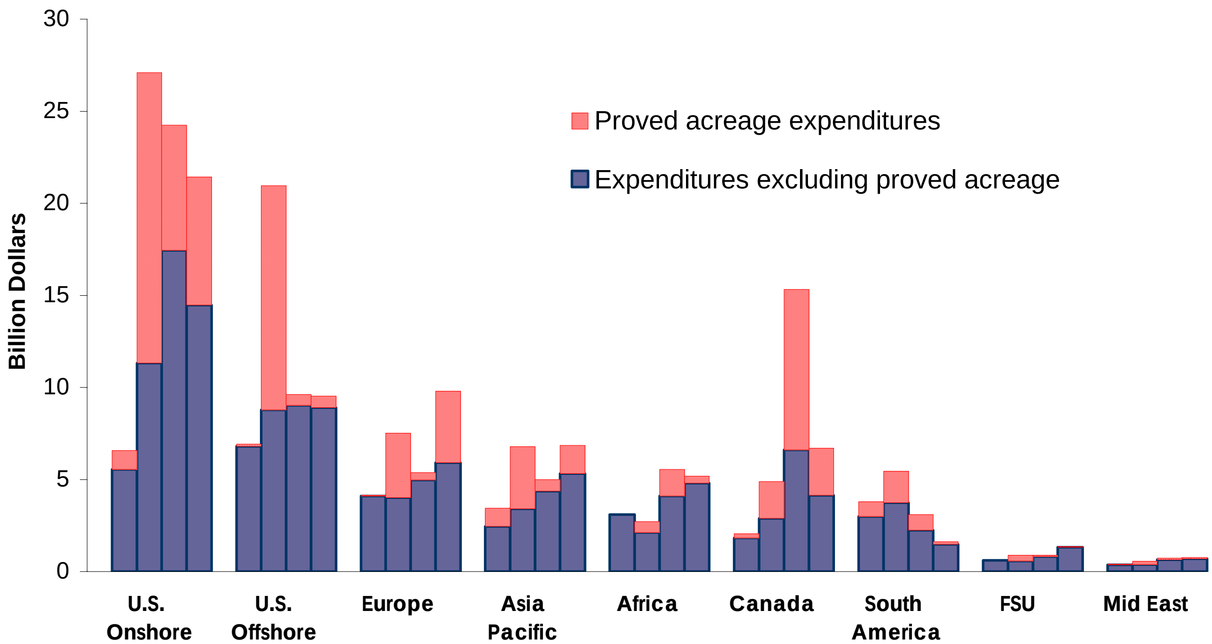
Table 5. Additions to Investment in Place by Line of Business for FRS Companies, 2001-2002
(Billion Dollars)

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

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

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

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



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

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

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

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

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

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

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

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

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

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

Upstream Merger Wave Ebbs

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

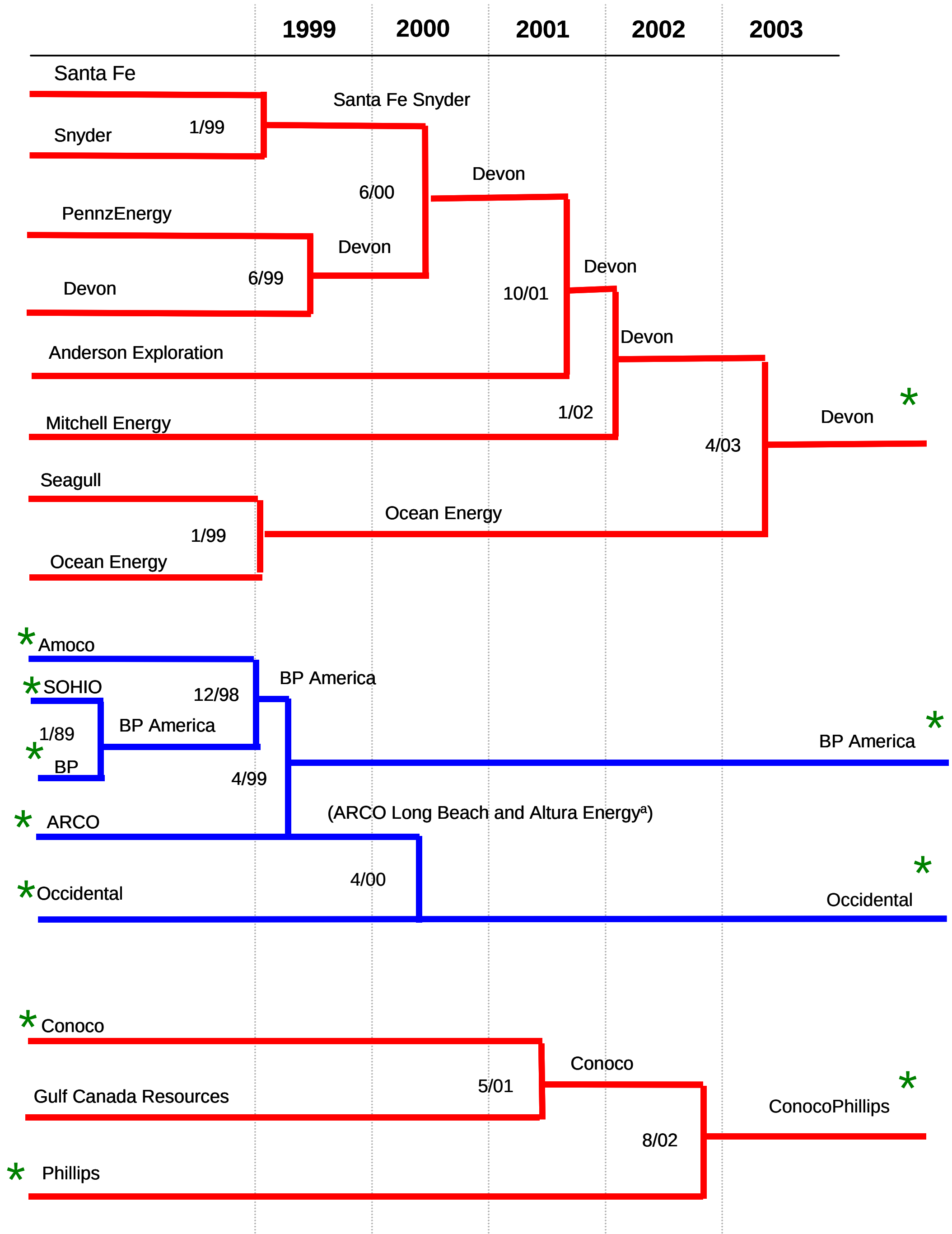
Some of the companies previously involved in significant upstream merger activity (other than ConocoPhillips and Devon) may have ceased their merger activity in order to address problems on their balance sheets. For example, some companies may have not wanted to further increase their level of debt or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

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

Mergers Drive Increase in Refining/Marketing Capital Expenditures

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

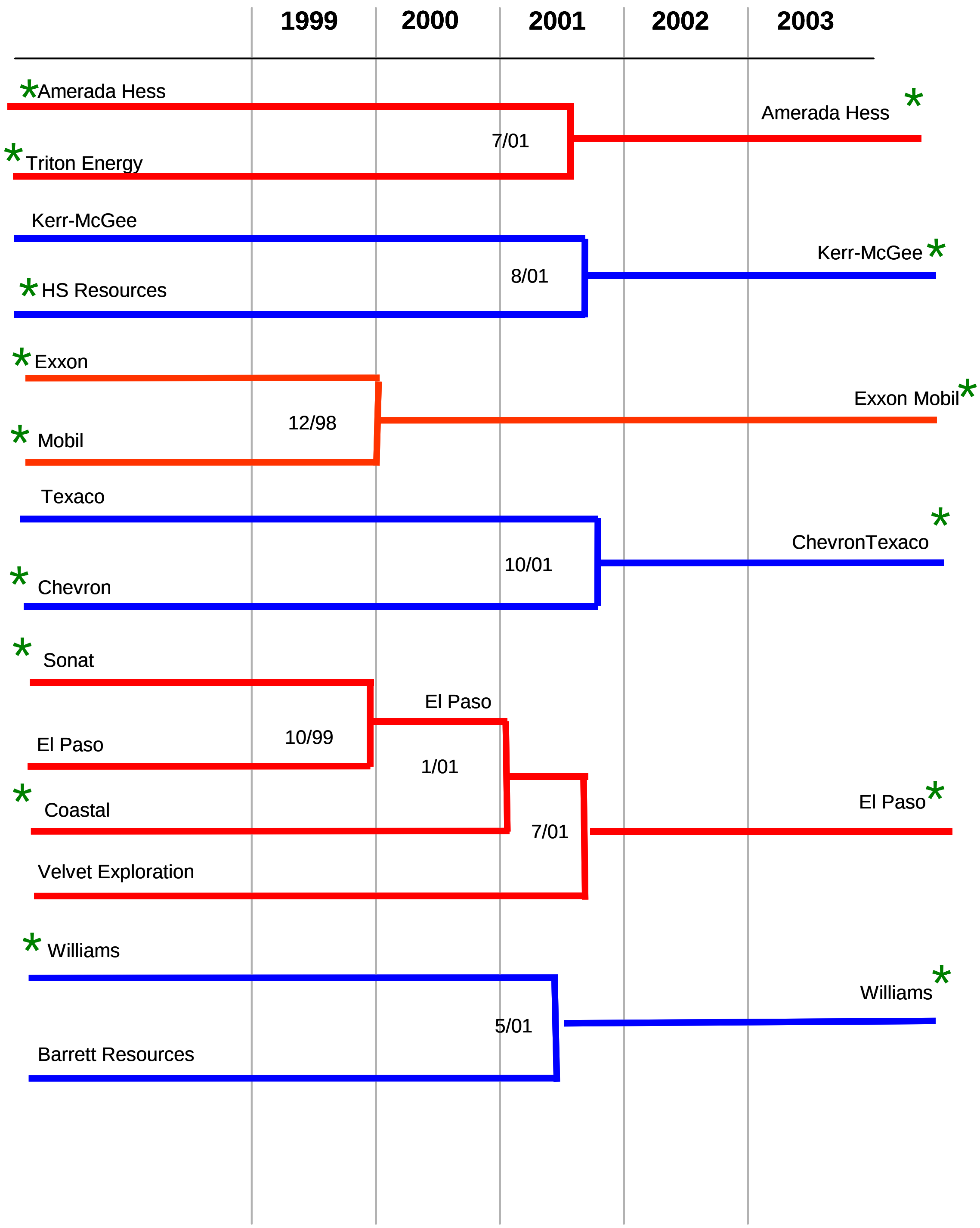
Figure 6. Recent Mergers Affecting FRS Oil and Gas Producers



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

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

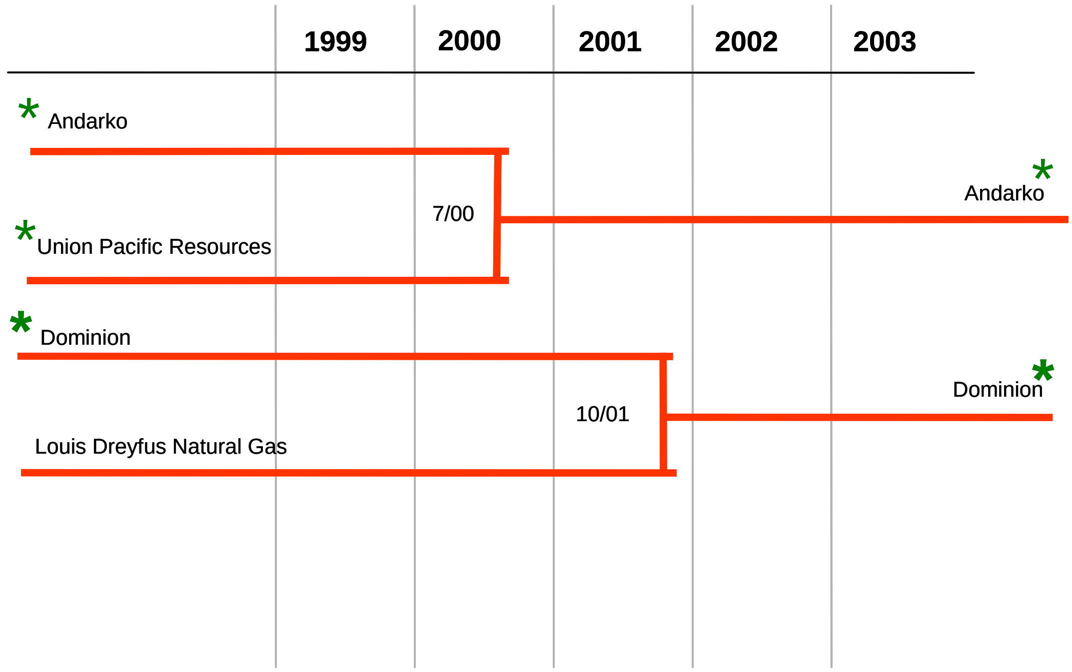
Figure 6. Recent Mergers Affecting FRS Oil and Gas Producers (continued)



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

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

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



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

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

Sources: Company news releases and other public disclosures.

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

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

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

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

Sources: Company annual reports to shareholders and press releases.

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

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

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

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

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

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

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

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

Other Energy No Longer a Source of Corporate Growth

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

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

Sources and Uses of Cash

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

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

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

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

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

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

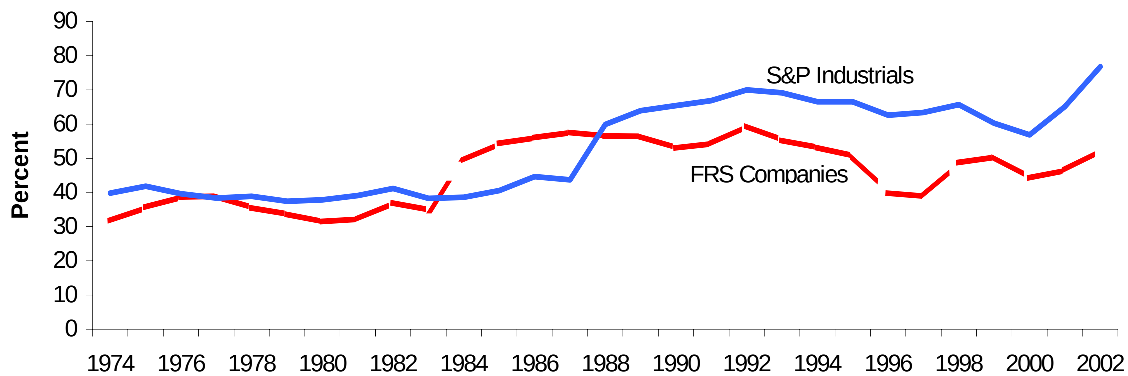
Other outlays subject to cuts were expenditures to reduce long-term debt, down 19 percent between 2001 and 2002, and purchases of treasury stock, down 37 percent. The only outlay that was not cut was cash dividends to shareholders. Dividend payouts typically show modest year-to-year increases. Also,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

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

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

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

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



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

Endnotes

[10]For a list of the FRS companies in 2002, see the box entitled, “The FRS Companies in 2002,” in Chapter 1.
[11]Return on equity, a frequently used measure of corporate profitability, is measured by the ratio of net income to stockholders’ equity.
[12]The Standard and Poor's (S&P) Industrials is a well-recognized database that includes nearly 400 of the largest U.S. industrial companies. Financial statistics for the S&P Industrials were obtained by accessing Compustat PC Plus, a service of Standard & Poor's, Inc.
[13]Energy Information Administration, *Performance Profiles of Major Energy Producers 2001*, DOE/EIA-0206(01) (Washington, DC, January 2002), p. 53.
[14]Line-of-business profit measures should be distinguished from measures that reflect company-wide results because the former reflect only allocated income, expense, and asset items. Two measures of income are presented: *operating income* and *contribution to net income*. Operating income by line of business is similar in concept to the operating income measure for total company operations. It is the net of operating revenues and operating expenses (including depreciation, depletion, and amortization) for a line of business. Contribution to net income equals operating income plus income from unconsolidated affiliates and gains on disposals of property, plant, and equipment less income taxes imputed to the line of business and excludes certain non-allocable items, primarily interest expense. Interest expense is the principal source of difference between a company-wide net income figure and line-of-business contributions to net income (see Appendix A for further discussion).
[15]Return on investment is net income divided by net investment in place, which is net property, plant, and equipment plus year-end balance for investments and advances to unconsolidated affiliates.
[16]Energy Information Administration, *Monthly Energy Review*, (DOE/EIA-0035 (2003/11)) (Washington, DC, November 2003), Table 9-11.
[17]ChevronTexaco Corporation 2002 *Annual Report*, pp. 36-37.
[18]El Paso Coporation 2002 Securities and Exchange Commission Form 10-K, pp. 61-65.
[19]For FRS purposes, separate reporting of income for chemical and other nonenergy segments was discontinued beginning with the 1987 reporting year. However, the disclosures of chemical segment revenues and operating income made by the FRS companies in their annual reports to shareholders closely track, in the aggregate, comparable disclosures in the Form EIA-28 from 1974 through 1986, when income statement items were collected for chemical businesses by the FRS. Thus, the public disclosures of chemical segment revenue and operating income were utilized for 1987 through 2002. Revenues and operating income for the other nonenergy segment after the 1986 reporting year were obtained by subtracting the publicly disclosed chemical segment values from the nonenergy line-of-business values reported on Form EIA-28.
[20]Exxon Mobil Corporation 2002 Securities and Exchange Commission Form 10-K, p. 29.
[21]Exxon Mobil Corporation, 2002 *Financial and Operating Review*, p. 77.
[22]Energy Information Administration, *Performance Profiles of Major Energy Producers 2001*, DOE/EIA-0206(2001) (Washington, DC, January 2003), p. 81.
[23]Exxon Mobil Corporation, press release (November 13, 2002).
[24]The largest of these non-cash items is the cost of depreciation, depletion, and amortization. Also, outlays (receipts) of cash that were recognized as non-cash items in previous income statements (e.g., provisions for a legal settlement taken as a charge against income in a previous year but not actually paid until the current year) are subtracted from (added to) net income in computing cash flow. Lastly, changes in working capital (excluding cash) due to operations are subtracted.
[25]To the extent possible, capital expenditures are measured by *additions to investment in place*, which is defined as additions to property, plant, and equipment (PP&E) plus additions to investments and advances. In 2002, additions to PP&E accounted for 92 percent of capital expenditures so measured.
[26]Devon Energy Corporation 2002 *Annual Report*, p. 14.
[27]Devon Energy Corporation, press release (January 24, 2002).
[28]Royal Dutch/Shell, press release (October 31, 2002).
[29]BP, press release (August 2, 2002).
[30]ConocoPhillips 2002 *Annual Report*, pp. 13-15.
[31]Devon Energy Corporation 2002 Securities and Exchange Commission Form 10-K, p.19.
[32]Devon Energy Corporation 2002 Securities and Exchange Commission Form 10-K, p.47.
[33]Anadarko Petroleum Corporation 2002 Securities and Exchange Commission Form 10-K, p.14.
[34]Apache Corporation 2002 Securities and Exchange Commission Form 10-K, p. 4, F16.
[35]BP November 2003 discussion on: Upstream Build Projects.” Web address: http://www.eia.doe.gov/perfpro/ref_pi/fig5.gif.
[36] Two other trains that were approved earlier have yet to begin full operations, although one began deliveries in August 2002. Atlantic LNG, Company Website (at Hhttp://www.atlanticlng.comH) train2_3.php3 (as of 1/14/2004).

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