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BP and the Consolidation of the Oil Industry, 1998–2002

As the board of directors meeting ended on November 29, 2001, Lord Browne, BP's group chief executive, reflected on the changes that had occurred within the oil and gas industry since BP announced its merger with Amoco Corporation in August 1998. Lord Browne believed as early as 1995 that the then-current industry structure could not persist, given its inability to deliver returns comparable to other industries; however, merger discussions began only in 1998, when a belief that oil prices would continue to trend down toward $10 to $15 per barrel forced companies to take dramatic action. BP's first-mover advantage was the opportunity to pick its partners.[1] Browne outlined the rationale for the mergers:

> The starting point was the desire to move BP on from its middle ranked position in the oil sector. We had put in place the financial and organizational discipline required to secure short-term performance improvement, but we were acutely aware that there were a number of missing pieces, which we needed to find to be a real competitor with the best in the sector. We called these the strategic gaps. The most important of these gaps were inadequate natural gas reserves, poor returns and weak competitive positions in the United States and Europe, insufficient access to growth markets, too narrow a portfolio in chemicals, limited exposure in the Far East, and limited hydrocarbon renewal options beyond 2005. Overall, we also realized the need for greater scale—to be a truly global player.[2]

The board had just finished debating the merits of competing options for continued growth. Most of the likely acquisition candidates had found partners, and competition authorities worldwide worried that the leaders of the consolidating industry might enjoy considerable market power. Was it now time for BP to focus on efficiency and internal growth? BP still participated in all aspects of oil and gas operations, including exploration, production, refining, and marketing of hydrocarbons, but was this level of vertical integration necessary to be competitive? Many regional and segment specialty companies were challenging that assumption. As Browne headed back to his office, he knew the company still had some challenging decisions to make.

Professor Forest Reinhardt, Assistant Professor Ramon Casadesus-Masanell, and Research Associate David J. Hanson prepared this case. HBS cases are developed solely as the basis for class discussion. Cases are not intended to serve as endorsements, sources of primary data, or illustrations of effective or ineffective management.

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Oil and Gas Industry

The modern petroleum industry is said to have started in 1859, when Colonel Edwin Drake struck oil in Western Pennsylvania at a depth of 70 feet. Incomplete markets, transportation shortages, and unstable relationships between firms gave oil companies the incentive to integrate vertically, matching the capacities of their production, refining, and marketing operations. The largest of these integrated firms was John D. Rockefeller's Standard Oil Trust. It seized such a large market share that in 1911 the U.S. Supreme Court declared it a monopoly and broke it into 34 separate companies. (Over the remainder of the twentieth century, those companies slowly reunited. In 2001, Standard Oil was only three deals away from being re-formed. If ExxonMobil, BP, ChevronTexaco, and USX-Marathon were to merge, Standard Oil would be fully reassembled, although this seemed highly unlikely due to regulatory concerns.[3])

The oil industry began in the United States, but the country's share of world crude oil production declined from 60% in 1934 to 10.6% in 2000.[4] By the end of the twentieth century, oil had been discovered in more than 80 countries. The majority of these finds had occurred in the Middle East, the former Soviet Union, South America, North Africa, Alaska, the Gulf of Mexico, and the North Sea. Originally, private companies in partnership with host nation governments developed the majority of oil production. In the second half of the twentieth century, most nations with significant reserves nationalized production and confiscated private company assets, often with little or no compensation. At the end of the century, the state-owned petroleum companies remained some of the largest in the world (see **Exhibit 1**), but many of the oil fields were still operated by partnerships between governments and private companies. Governments valued the management skills, access to capital, and technological expertise the private companies offered, and the firms' skills became more important as oil and gas fields became more challenging to access and to develop efficiently. Depending on the country, private companies were allowed to participate as shareholders of the state-run company or as independent operators. Private companies were usually charged a fixed per barrel royalty, a regular corporate income tax, and an additional oil profits tax; the structure of the oil profits tax varied by country, but marginal tax rates often fell in the 50% to 90% range.

Supply and Demand

In 2000, global oil consumption averaged 75.6 million barrels per day.[a]

The key determinants of demand for petroleum products, used mainly for heat, transportation, and electricity generation, were economic activity and the weather. Increases in economic activity led to growth in housing starts, commercial floor space, and disposable income, all of which tended to increase energy consumption.[5] Similarly, sustained economic growth increased demand as businesses expanded production and developed new products that consumed energy. The weather had an especially large effect on residential consumer demand.[6] Unseasonably hot or cold temperatures led to increased demand for oil and gas to heat homes or to generate electrical power for air-conditioning units. Unexpected events like the September 11, 2001, terrorist attacks in the United States also affected demand.

The determinants of supply included real exploration and production costs, technological advances, and the regulatory environment. Improved technology could make production economically viable for a greater number of reserve discoveries. Regulatory effects included

[a] In the business press, "demand" is often used as a synonym for consumption.

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governmental restrictions on access to reserves and government rules that required a variety of fuel blends to reduce air pollution in various locations.

Supply could also be affected by price uncertainty. During the 1990s, efforts to cut costs by managing inventory levels more tightly intensified volatility in petroleum prices: between 1998 and 2002, oil prices ranged from below $12 per barrel to more than $30 per barrel. Downturns in prices could trigger significant cutbacks in spending on exploration and development. These cutbacks slowed construction of drilling rigs and other infrastructure needed to support future production.

Suppliers could not respond immediately to rising prices. In 2000, for example, the number of new gas well completions increased by almost 45%, but gas production increased by only 3.8%. The production lag reflected, in part, the 16 to 18 months required to acquire necessary investment funds, install production equipment, and construct gathering lines and pipelines needed for transportation.[7]

Because oil and gas investments typically had long payback periods, executives were willing to make them only when they thought that price levels were representative of long-term market conditions. Assets in place were difficult to retire immediately if prices softened. Anticipating these difficulties, managers did not automatically increase their investments in response to price upturns.

Over the long term, businesses and consumers could react to higher prices by increasing conservation, switching to alternative fuels as they became economically viable, or using technology to develop more energy efficient products and processes. Some power-generating facilities and factories could utilize oil or gas depending on relative cost.[8] (**Exhibit 2** shows the relative prices of oil and natural gas since 1997. The spike in natural gas prices at the beginning of 2001 was caused by an unusually cold winter, low inventory levels, and constrained supply due to an extended period of low investment.[9])

Industry Structure

World oil consumption grew each year during the 1990s by approximately 1 million barrels per day, reaching 75.6 million barrels per day in 2000.[b] (**Exhibit 3** shows the world supply and consumption balance, and **Exhibit 4** compares world GDP growth with growth in world oil consumption.)

Members of the Organization of the Petroleum Exporting Countries (OPEC) held an estimated 70% of the world's 1.03 trillion barrels of proven reserves. (**Exhibits 5a** and **5b** rank the top 20 countries according to crude oil and natural gas reserves, respectively.) OPEC members included Algeria, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela. In 2001, they produced approximately 30 million barrels per day. Collectively, they were estimated to have 7 million barrels per day of excess capacity, down from 15 million in the mid-1980s, whereas non-OPEC countries produced at or near capacity.

OPEC was formed in Baghdad in September 1960 to unify and coordinate member countries' petroleum policies. Government representatives met regularly to discuss prices and to set members' production quotas. Historically, OPEC had collected pricing data on a "basket" of seven crude oils

[b] Because oil and natural gas were substitutes in some markets, natural gas stocks and flows were often measured in barrels of oil equivalent (BOE). One BOE equaled 42 U.S. gallons of oil or approximately 6,000 cubic feet of natural gas.

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containing both light, sweet crude oil and heavier sour crudes;[c] it had then set production quotas designed to keep this basket price between $22 and $28 per barrel. After September 2001, however, it suspended its focus on the price band in response to the sustained weakness in markets. Enforcement of negotiated quotas was a chronic problem for OPEC. Like nonmember countries, its members could benefit if they sold additional production, and OPEC lacked a formal enforcement mechanism.

After a long period of stability between World War II and 1970, oil prices fluctuated substantially over the ensuing three decades. (See **Exhibit 6** for a chronology of world oil market and price events.) OPEC engineered its first dramatic increase in oil price in 1973 by nationalizing production and beginning an embargo. Prices rose sharply again in 1979 during the Iranian revolution. The resulting investment surge in non-OPEC nations, coupled with a new focus on substitution and conservation in consuming countries, led to falling prices in the early to mid-1980s. Prices spiked again in 1990–1991 during the Persian Gulf War. Oil prices fell sharply in 1997 as Iraq was allowed by the United Nations to begin exporting oil, resulting in the largest increase in world oil supply in a decade. Prices continued to decline in 1998 due to the economic crisis in Asia and two unusually warm winters. From their 1998 low, oil prices tripled by September 2000 as OPEC decreased production, world demand recovered, and winter temperatures returned to normal.

Publicly traded oil companies in industrialized nations varied widely in size and organizational structure. They ranged from completely integrated firms to specialists in refining, marketing, exploration and production, or energy services. In the late 1990s, a wave of merger and acquisition activity created a new breed of firm termed "supermajors." The largest of these firms, ExxonMobil, had total assets of more than $150 billion.

The vertically integrated firms' share of U.S. oil industry assets declined from 97% in the 1970s to 70% in 1999. Conversely, independent refiners in the United States increased their market share from 7% in 1990 to 38% in 1999; two-thirds of this increase came from acquisitions of assets sold by vertically integrated and formerly integrated firms.[10] (**Exhibit 7** shows the changing structure of companies from 1979 to 1999.)

At the turn of the century, the industry's capital stock was aging, for three related reasons. First, publicly traded companies had shifted their focus from production growth toward maximizing return on capital. Second, the price decline in 1998 caused most firms to curtail their capital spending budgets. Finally, access to low-cost reserves was limited by geology and politics.[11]

Business Segments

Upstream The processes of exploring for oil and gas, developing reserves, and bringing them to the surface with production wells were collectively known as "upstream operations."

Upstream companies tracked the ratio of reserves to production, which showed how long proven reserves would last at current annual production rates. In 2001, the ratio was 15 for non-OPEC countries, whereas OPEC could continue current production levels from proven reserves for another 80 years.[12] (Note that the ratio did not reliably indicate when the oil would "run out." Consumption tended to increase over time; meanwhile, technological innovations and new discoveries continued to increase recoverable reserves.)

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[c] "Sweet" and "sour" refer to the sulfur content in oil. Sweet crudes are less sulfurous. A light oil requires less refining before being used in internal combustion or gas turbine engines, whereas a heavy oil requires additional refining. A light, sweet oil usually commands the highest prices.

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The higher prices that resulted from OPEC's supply restrictions in the 1970s and early 1980s provided companies with the funds and the economic incentive to increase reserves by focusing exploration attention on higher cost areas. At the same time, OPEC's actions underscored the macroeconomic and security implications of dependence on risks to oil supplies. Technological progress enabled firms to reduce the cost of exploration and extraction and thereby increase the amount of reserves.

Three major technological advances included horizontal drilling, measurement while drilling, and three-dimensional seismic analysis. Horizontal drilling involved drilling a well vertically and then slanting the drill bit or even turning it horizontally. This technique allowed a single well to penetrate several reservoirs, producing up to seven times as much oil and gas as a vertical well. Measurement while drilling entailed the placement of sensors on the end of the drill bit that transmitted information on the bit's location and direction, the geology at the bottom of the hole, and the presence of hydrocarbons, all while drilling continued.

The third innovation, three-dimensional seismic imaging, used acoustic signals to create an image of a site's geological makeup. This image facilitated the identification of areas with a high probability of successful drilling, increasing the likelihood that developmental wells would become economically viable. An even newer technology, four-dimensional imaging, took measurements at two different locations over time. Although expensive, typically adding one dollar per barrel to costs, this technology enabled operators to detect fluid movement between wells and locate bypassed reserves.[13]

Downstream The refining and marketing of petroleum products were known as "downstream operations." Crude oil was a complex mixture of hydrocarbons that was distilled into component parts according to molecular weights to form a variety of refined products. The most common products included gasoline, kerosene, jet fuel, diesel fuel, and home heating oil. (**Exhibit 8** shows the overall product mix of U.S. refineries in 2000.)

Profitability in refining was measured by both gross margins (refined product revenues minus raw material and product purchases divided by refined product sales volume) and net refined product margin (petroleum product revenues minus all out-of-pocket refining and marketing expenses divided by refined product sales volume). Refining margins were typically low. (See **Exhibit 9** for more detail on refining margins and **Exhibit 10** for return on investment information.)

In an attempt to increase margins, many refiners moved to a "just-in-time" principle that, along with industry consolidation, caused inventories to reach historical lows relative to production. Refiners also updated existing refineries to accommodate heavier and more sulfurous crude. This allowed them to make lighter refined products such as gasoline that historically provided higher margins than lower quality residual fuel oils. Advances in technology and reductions in refinery bottlenecks created the equivalent of three new refineries each year.[14]

As of January 2001, 72.8 million of the world's 81 million barrels per day of refinery capacity was located in non-OPEC countries. (**Exhibit 11** shows world refinery capacity information.) The United States had more refinery capacity than any other country. In 2001, its 152 plants refined about 16.6 million barrels per day of crude oil.[15] In 1987, by contrast, 219 refineries had operated in the United States, but produced only 15.5 million barrels per day.[16] During the 1990s, many integrated firms selectively divested refining assets, thus facilitating an increase in market share for the independent refiners. (See **Exhibit 12** for U.S. refinery ownership data.)

Once refined, products were sold both to businesses (e.g., airlines) and to households. In each of these markets, sellers sought to use quality, service, convenience, and location to differentiate their

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offerings. Between 1990 to 1997, the major U.S. oil companies decreased their number of branded marketing outlets by 34% and refocused their operations on the regions in which they had the most success, that is, the greatest profitability or the greatest market share. In contrast, independent refining and marketing companies expanded their scope of operations by acquiring refineries, marketing outlets, or both.[17] Some OPEC-based firms entered this business as well.

Other Many petroleum firms were also involved in a variety of other businesses. Historically, most major oil companies had had divisions that produced chemicals. Large-scale chemical manufacturing plants were often colocated with refineries. Their outputs were used in a variety of industries, including aerospace, agriculture, automotive, and construction. More recently, several oil companies had entered renewable energy businesses (wind and solar power, for example); the investments in renewables reflected the belief that the world would continue moving toward cleaner fuels and eventually move away from hydrocarbons as its primary source of energy. Finally, a growing number of companies participated in an area known as energy services. Some primary activities of these companies included power generation, hydrocarbon and power transportation, and market making in energy futures.

BP

History[18]

BP began its organizational life as the Anglo-Persian Oil Company, which floated its first shares in 1909 to finance oil production under a concession agreement signed by Muzaffar al-Din Shah of Persia. In its early years the company managed to preserve its independence because the British government, realizing that oil was indispensable to effective modern warfare, insisted that it was critical to maintain other commercial sources to offset the dominance of Royal Dutch Shell.

Shah Reza Pahlavi renegotiated Anglo-Persian's concession in 1932, increasing the fraction of the profits that went to the government. When the Shah renamed his country Iran in 1935, Anglo-Persian changed its name, too, to Anglo-Iranian. In 1951, Iranian Prime Minister Mohammad Mossadiq nationalized the Iranian oil industry, expelling Anglo-Iranian without any compensation. After Mossadiq was overthrown in a 1953 coup engineered by the U.S. Central Intelligence Agency, the Western oil companies were invited to return. The Iranian government now required a 50% share of the profits from production and refining in Iran, and further insisted that it would do business only with a consortium of companies, not with a single entity. Anglo-Iranian received a 40% share in the consortium, called Iranian Oil Partners, but its profits from Iranian oil were severely curtailed under this new agreement.

During its exile from Iran, the company expanded its production base into Kuwait, Iraq, and Qatar. In 1954, Anglo-Iranian changed its name again, to British Petroleum; it had been using "British Petroleum," "British Petrol," and "BP" at retail stations and in advertisements since 1917. The name change coincided with a change in strategic focus; rattled by the events in Iran, the company set out to reduce its dependence on crude oil sources in the Middle East.

These plans bore substantial fruit in the late 1960s and early 1970s with the discovery of enormous reserves in the Prudhoe Bay region of Alaska and in the North Sea. BP quickly established a major presence in both areas. BP's Forties field in the North Sea, discovered in 1970, was the first of a long series of BP finds in that region. BP was also one of the biggest backers of the Alaska pipeline, which carried crude from Prudhoe Bay in northern Alaska to the port of Valdez on Prince William Sound

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800 miles to the south. Despite the passionate opposition of the environmental community, the pipeline was completed in 1977.

To make the most of its Alaskan oil, BP executives decided that the company needed to establish a network of retail marketing outlets in the United States. In 1968, BP purchased 8,500 New England service stations from Sinclair Oil. In 1970, it traded these stations, along with most of its Alaskan holdings, to Standard Oil of Ohio (Sohio), one of the remnants of Standard Oil; in return, Sohio offered to BP an initial 25% of its share capital followed by an additional 29% when Sohio production at Prudhoe Bay topped 600,000 barrels per day. In the 1980s, the BP-Sohio partnership turned sour as the American company sank billions of dollars in unprofitable nonpetroleum investments and pursued an expensive yet largely unsuccessful exploration program. Asserting that they "could no longer stand by and watch," BP executives called for the resignation of Sohio's president and chairman in 1986. The following year, BP purchased the remaining 45% of Sohio's shares for $7.6 billion; the former Sohio and BP's existing U.S. businesses combined to form BP America, Inc., a significant competitor in the U.S. petroleum industry.

Merger Activity

BP triggered a wave of oil industry mergers and acquisitions with its announcement in August 1998 of a $53 billion merger with Amoco. Based in Chicago, Amoco was the United States' fifth largest oil company, with 1997 revenues of $36 billion and 9,300 gasoline retail outlets, mainly in the Midwest and in eastern, and southeastern states. Other significant assets included natural gas discoveries off of Trinidad and several large oil discoveries in the Gulf of Mexico, the North Sea, and Colombia. In the deal announcement, Lord Browne declared:

> This merger is a superb alliance of equals with complementary strategic and geographical strengths, which effectively creates a new super-major that can better serve our millions of customers worldwide. We are uniting two excellent portfolios of assets and people to create a group that will have the financial resources, scale and global reach to compete effectively in the 21st century. International competition in the industry is already fierce and will grow more acute as new players emerge. In such a climate the best investment opportunities will go increasingly to companies that have the size and financial strength to take on those large-scale projects that offer a truly distinctive return.[19]

Synergies of at least $2 billion were projected to come from reductions in staff ($1B), more focused exploration ($300MM), streamlining of businesses ($200MM), improved procurement ($250MM), and rationalization of operations ($250MM).[20] In 1996, Browne had entered into a refining and marketing joint venture with Mobil in Europe that quickly exceeded cost reduction expectations, so analysts expected the $2B in savings to be achievable.

A strategic assessment made of BP's main challenges prior to the merger identified several issues. It had a weak retailing position in the United States, it needed to enlarge its chemical business, and it was underexposed in natural gas (i.e., BP's ratio of gas production to oil production was low relative to its competitors). At the time, this underexposure was hurting results, because natural gas sales were more profitable than oil sales. Amoco was almost exclusively concentrated in the United States and was having difficulty finding new reserves to replace dwindling U.S. supplies despite spending $10 billion in exploration. Its chemicals business had accounted for 25% of earnings in 1997.[21] BP had the stronger position in exploration and production, whereas Amoco's strengths were in its petrochemicals business and U.S. refining and marketing.

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The merged company became the largest producer of petroleum and natural gas in the United States. Besides creating the world's third largest publicly traded petroleum company, with combined revenues of $108 billion, the merger created a major petrochemicals operation with revenues of $13 billion. Through its 16,350 U.S. gas stations, BP Amoco was the leading marketer in 20 of the 36 states in which it operated, and it had a 15% share of the U.S. gasoline market.[22]

The merger occurred when oil and chemical prices were extremely low, the most accessible cost-cutting measures had been taken, and companies were searching for additional ways to grow and increase profitability. Browne believed that "being at the top of the second division is fine, but there are limits to what you can do. The whole point of this deal is that it allows us to do more."[23] The companies believed the revenues of the combined firm would enable it to finance more development projects itself, hold down costs, and potentially win more reserve auctions. BP Chief Economist Peter Davies thought that the governments of oil-producing nations might prefer to work with large companies that had the means to follow through with commitments than with consortia of smaller companies.[24] More generally, as BP Policy Advisor Nick Butler pointed out, "[A] broad mix of activities diversifies our risk and generates opportunities for learning across boundaries. We can understand change in all parts of the markets, and we have the skills to manage that change."[25]

The deal was completed on December 31, 1998, after the companies agreed to divest 134 gas stations in eight U.S. markets and nine light-petroleum storage terminals. Additionally, up to 1,600 independent retailers in 30 markets would be allowed to switch brands if desired. U.S. Federal Trade Commission (FTC) Chairman Robert Pitofsky stated:

> Although the merger of BP and Amoco involves companies of enormous size, and there is a significant trend toward concentration in the petroleum industry, the operations of these two companies rarely overlap in a way that threatens competition. Where they do overlap, mainly in wholesale and retail sale of gasoline in local markets in this country, the Commission with the cooperation of the companies has achieved substantial divestitures and other relief that makes it likely that consumers will enjoy the benefits of competition.[26]

ExxonMobil

Industry reaction to BP's bid for Amoco was swift. On December 1, 1998, Exxon announced its intention to purchase Mobil for approximately $79 billion. The combined company held a 14% share of the U.S. gasoline market, 21 billion BOE of proven reserves, refining capacity of 6 million barrels per day, and over 40,000 service stations marketed under the Exxon, Mobil, and Esso brand names in more than 118 countries. Total cost savings were expected to be about $2.8 billion.

Most analysts and industry observers had a positive response to the acquisition, citing similar arguments to those used in the BP Amoco deal. Because of Exxon's already large size, some saw the merger as a defensive move against a continued long-term depression in oil prices: the company could increase profitability through cost cutting instead of relying on an increase in oil prices. Most concerns were about gaining regulatory approval. Even though a 14% national market share was far less than the 90% share that led to the breakup of Standard Oil, regulators were interested in the state-by-state and even city-by-city evaluation of competition. Exxon and Mobil had considerable overlap in several areas. A George Washington University law professor said that the deal never would have cleared regulatory hurdles 20 years ago, but noted that antitrust philosophy had changed. "It turned in the direction of believing you can have a lot of competition even if you don't have a lot of companies. There is awareness that global competition is a very powerful force and that American firms should have flexibility to make adjustments that allow them to better compete overseas."[27]

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Others questioned the financial merits of the merger. One analyst wrote, "This deal would face far more regulatory hurdles than BP-Amoco, which would eat into the logic of the merger. Exxon would have to pay a premium but the lack of value-creating opportunities and the forced divestments could wash away any benefits it did get from the deal."[28] Other skeptics feared that the point of the merger was to prop up prices, although Exxon and Mobil would argue that the efficiencies resulting from the merger would allow both increased profits for the firms and lower retail prices for consumers.

The ARCO Deal

Only four months after completing the Amoco acquisition and partially in response to the announcement of the merger between Exxon and Mobil, BP Amoco again looked to grow by acquisition. On April 1, 1999, the company announced a $26.8 billion deal to purchase Atlantic Richfield Company (ARCO). ARCO was a Los Angeles–based integrated oil company with 1999 revenues of $13 billion and operations in 29 countries. Post-merger market capitalization would be $190 billion, and the company would be the world's largest public oil producer. Annual pretax synergies of at least $1 billion were expected. In the deal announcement, Browne said:

> For BP Amoco, the strategic rationale for this deal is the immense potential it offers for future growth. In Alaska in particular, the synergies we can achieve from combining our operations will greatly increase the competitiveness of the state in the face of uncertain oil prices and provide a strong incentive for significant investment in existing and future fields. The addition of ARCO's international assets powerfully strengthens our global portfolio. Most significantly, it gives us a major platform for upstream growth in Asia where we will have world-class gas reserves ready to supply Japan, Korea, and other key markets when recovery comes to the region, which it undoubtedly will.[29]

ARCO was to add 2.8 billion BOE of proven reserves, mainly in Alaska, to BP's portfolio. ARCO would also provide undeveloped natural gas reserves of up to 25 trillion cubic feet, located in Indonesia, the Gulf of Mexico, and the North Sea. In addition, two highly efficient refineries and a strong retail network of 1,700 gas stations on the U.S. West Coast would complete BP Amoco's nationwide downstream business. In Alaska, the combined company would hold leases to 860,000 acres of state-owned land, and would be the only oil company operating in the North Slope oil fields. Alaska would account for about 30% of BP's total oil production.

The shareholders of both companies and the European Commission approved the deal, but the FTC and several states sued to halt the acquisition. An already tense relationship among BP, the FTC, Alaska, and several Western states was made worse after the discovery of a 1995 e-mail exchange between BP managers that discussed "shorting the West Coast market" to achieve "West Coast price uplift scenarios." The e-mail described shipping Alaskan oil to the Far East for less net revenue than could be achieved by shipping it to the lower 48 states. The expected result was higher West Coast gasoline prices.[30]

On April 13, 2000, the FTC finally approved the BP Amoco-ARCO deal, but only after the companies agreed to sell all of ARCO's Alaskan operations to Phillips Petroleum for $6.5 billion. The FTC was mainly concerned that the merged company would control approximately 75% of Alaskan North Slope crude oil output and more than 70% of the Trans-Alaska Pipeline System, potentially hurting consumers on the U.S. West Coast. BP Amoco also agreed to sell some pipeline and oil storage holdings in Cushing, Oklahoma.[31] Approximately $210 million of the projected $1 billion of synergies had been expected to come from streamlining Alaskan operations.

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Post-Merger Operations

In 2001, BP operated in all major industry segments, with 130 business units in more than 100 countries and approximately 100,000 employees. The company continued to expand its asset portfolio: it bought Burmah Castrol for $5 billion in July 2000 to enhance its lubricant business, and also picked up the remaining 18% of Vastar Resources, an exploration and development company with deepwater experience, that it did not already own. BP made significant investments in Angola, Indonesia, Russia, and China. It had two large gas marketing joint ventures with PetroChina and Sinopec (China Petroleum & Chemical Corporation), two of Asia's largest oil and gas producers.

As of 2001, the energy content of the reserve mix was split evenly between oil and natural gas, with production at 60% oil and 40% natural gas. Total upstream production in 2000 was 1.1 billion BOE, of which 69% came from the United States and the United Kingdom. BP felt confident in its ability to reach target cost reductions of $5.8 billion from 1998 levels by the end of 2001. Upstream operations were the most profitable. Downstream margins were improving, and chemicals continued to be the most challenging business. (**Exhibits 13, 14, 15,** and **16** contain information on BP's worldwide assets, historical financial data, stock price performance, and pre- and post-merger selected financial figures, respectively.)

BP's managers believed its post-merger size and portfolio of assets would provide it with the stability, risk management capability, and global reach to offer a range of services to governments that would help it gain access to significant new reserves and increase profitability. Some new upstream investments required $15 billion to $20 billion, and BP believed it could pursue these opportunities without risking significant financial distress. In addition, it could participate in a range of investments instead of being forced to choose only one.

Browne had believed, back in 1998, that oil companies were international, but not global in nature. BP felt this needed to change, and developed a concept called "reach" to become more competitive in a truly global environment:

> The benefits are in both physical and intellectual economies of scale. The intellectual economies stem from a deep process of learning. With a lot of experiences, it's more likely that you have the best experience somewhere within the company. Applying this best experience everywhere in the company will provide benefit above a company with only a single experience. Even with expansion, productivity and returns must never go down, otherwise people will believe that scale is more important than value.[32]

BP's performance goals are shown in **Exhibit 17.** BP wanted to accomplish profitable growth through the quality of its assets and operational efficiency. Investments were approved only if they could return their cost of capital if the Brent crude oil price (a benchmark price for North Sea production) was $11 per barrel, and deliver a return of roughly 15% at a Brent price of $16. BP planned to divest the weakest 10% of its assets each year.[33] In describing the company's ongoing strategy, Chief Financial Officer John Buchanan stated, "We want to be more than the best investment opportunity in our sector. We want to be seen as a great company, not just a great oil company."[34]

Lord Browne summarized the overall strategy as follows:

> We intend to focus on natural gas for our low carbon world, and we continue to upgrade our refinery portfolio, concentrating investment in locations where we can develop uniquely advantaged sites—linking supplies, processing and market demand. Two key factors run through every element of BP's strategy. First, we believe in the principle of mutual advantage

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as the foundation of secure and successful relationships. Secondly, the growth potential of our business arises from our ability to apply innovative technology.[35]

The company's degree of vertical integration was also significant. Lord Browne stated:

> We don't really believe in vertical integration and haven't for a very long time, but there are some benefits. The right refineries in the right geographic areas may provide a benefit. Also, shareholders invest in the agency of the management to more easily participate in portions of the industry than they can do themselves. It's easier to invest in BP than obtain a private equity stake in China.[36]

Buchanan addressed the company's integrated nature by saying, "Some advantages of vertical integration come from unpredictable regulated markets. You never know where the rent will show up. Markets aren't yet perfect, and there is not contestability at each point in the value chain."[37] BP Policy Advisor Nick Butler, commenting on the company's vertical integration, emphasized that capacities of upstream and downstream assets were unequal, that there were no requirements for BP businesses to buy from or sell to each other, and that all businesses were forced to compete independently. Butler added, "Our structure, which evolved over the past ten years, has been used to expose interbusiness subsidies, and to force businesses to perform more competitively."[38] Buchanan described this structure as "virtual integration."[39]

Knowing that the company's size could lead to an increase in bureaucracy, BP made the business unit the most important entity within the company. Each of about 130 business unit leaders negotiated a "performance contract" with his or her group vice president each year. Attainment of the cash flow, net income, and new investment targets specified in the contract was an important determinant of compensation and a critical factor in defining the long-term career prospects of business unit leaders. Additionally, business units were organized into peer groups whose managers met periodically to critique each other's performance against a list of key performance indicators that they themselves drew up. The top quartile performers were responsible for the bottom quartile's improvement. This encouraged information to move freely among business units without having to flow through corporate headquarters.[40]

BP was also aware that a company of its size would attract social and political scrutiny. BP's stated desire was to focus on long-term relationships and mutuality of interests in its business dealings. A positive track record and reputation were deemed essential. Knowing that some people believe that oil companies simply wanted to exploit people and the environment for profits, Buchanan declared, "We don't want to be seen as a global corporate beast, but as normal people with families and concerns about others and the environment."[41] Toward this goal, BP planned to unilaterally cut its emissions of greenhouse gases by 10% from a 1990 baseline by 2003. Buchanan noted that the emissions goals had proved to be a stimulus for innovation. He said that managers had been forced to rethink their approach to business, and argued that the emissions reduction would pay for itself through the productivity increases that were driven by the new standards.[42]

Browne was also cognizant of the public's trepidation about BP's potential to exercise market power:

> BP is one of the world's largest companies and it would be wrong to suggest that a degree of power does not accompany scale. But wherever or whoever you are there are counter-balances to that apparent power . . . whether it be from Non-Governmental Organizations, whose role in national and international affairs has become increasingly prominent over the last decade; from governments who, although we may request them to take account of the effects of any legislation on our operations or our employees, ultimately wield the real power

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to determine what we can and cannot do; from national and supra-national regulators who review the competition, health, safety, environmental and other aspects of our businesses; or lastly from the opinion of our employees, customers, shareholders and the communities in which we work. I believe strongly that to continue to be successful, our reputation with all these constituencies must be maintained or enhanced. It is not possible—nor should it be—to run a business in isolation from the effect of that business on the rest of the natural and human world and the views of the many people who represent that world.[43]

Major Competitors in 2001

The merger of BP and Amoco set off a wave of consolidation in the industry. Other large public energy companies reached merger agreements and created a new group of supermajor firms. The four other firms in this category included ExxonMobil, Royal Dutch Shell, ChevronTexaco, and TotalFinaElf. One motivation behind the mergers was a belief in the advantages of spreading the risk of new exploration and production projects over a larger base. The supermajors were awarded higher valuation multiples than their smaller rivals, possibly implying that the supermajors were better positioned to generate higher and more stable earnings.[44] **Exhibits 18** and **19** compare the financial performance of the supermajor firms, and **Exhibit 20** breaks out performance by major business segment.

ExxonMobil Corporation The world's largest publicly traded petroleum company was formed in 1999 by the $79 billion merger between two former pieces of John D. Rockefeller's Standard Oil. Exxon was the descendant of Standard Oil of New Jersey, whereas Mobil was born by the merger of Standard Oil of New York and Vacuum Oil in 1931. In response to Federal Trade Commission and European Commission antitrust concerns, Exxon ended its gasoline and lubricants joint venture with BP and divested $4 billion in assets, including 2,400 U.S. gas stations and a refinery in California. Mobil's European and natural gas trading and marketing businesses were also sold.[45] ExxonMobil had $232 billion in revenue and $17.7 billion of earnings in 2000.

During 2000, ExxonMobil claimed $2.5 billion of pretax savings from merger synergies. Future gains in capital productivity were expected to originate from investment selectivity, aggressive asset management, reduced working capital requirements, and continuous refinement of the capital structure. The company also planned to cut 12% of its workforce (14,000 jobs) by 2002.[46]

The company maintained leading positions in most major exploration and production areas in the world, including the Gulf of Mexico, offshore West Africa, and the Caspian Sea. Total production for 2000 was 1.4 billion BOE, of which 74% came from North America and Europe. Meanwhile, the downstream marketing business focused on building its customer base through features such as the Speedpass system and an upgraded convenience store offering. The company also invested heavily in its chemicals unit, increasing capacity of four high-volume products by more than 75% over a five-year period. ExxonMobil was also developing online e-commerce activities.[47]

Royal Dutch/Shell Group Royal Dutch was formed in 1890 and Shell Transport and Trading was formed in 1897 to develop oil finds in the Far East. In 1907, the companies formed the parent holding company of Royal Dutch Shell, with 60% and 40% ownership stakes, respectively. Royal Dutch Shell operated in more than 135 countries and had year 2000 earnings of $12.7 billion on $149.1 billion of revenue. In the late 1990s, it refrained from participating in large merger activity and focused instead on internal efficiencies and consolidating smaller independent energy companies. To become more focused and efficient, Royal Dutch Shell cut costs, closed several country offices, sold its coal operations, and reduced its chemicals business by 40%. Total upstream production in 2000

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was 1.2 billion BOE, of which 77% came from Europe and the Eastern Hemisphere. As of 2002, the company had 46,000 service stations and wanted to expand its marketing presence.[48] In October 2001, it purchased Texaco's interests in the U.S. refining joint ventures Equilon and Motiva. Besides these initiatives, Shell's future strategic plans involved focusing on gas, becoming a major player in independent power generation, and developing sources of alternative energy.

Shell sought to have an extensive portfolio of opportunities, a strong brand, and a global reach. It planned to offer customers new products, services, and e-business options while staying competitive in hydrocarbons. In addition, Shell's executives asserted that meeting society's expectations was the key to long-term success, and that the company "must deliver on the economic, social and environmental requirements of sustainable development."[49]

ChevronTexaco Corporation Chevron's $38 billion acquisition of Texaco, completed in October 2001, formed the world's number four petroleum company. In 2000, Chevron generated 66% of its revenues and 48% of its net income in the United States, and Texaco generated 34% of its revenues and 75% of its profits in the United States. However, the combined firm planned to compete aggressively worldwide. It operated in more than 180 countries, and its assets included proved reserves of 11.5 billion BOE with 2.7 million BOE of daily production.[50] Fifty-two percent of upstream production in 2000 came from the United States, the highest percentage of all the supermajors.

Chevron and Texaco began their courtship in 1999, but were unable to reach an agreement until 2000 because of valuation and antitrust concerns. Texaco was forced to divest its 44% stake in the refining and marketing joint venture Equilon and its 36% stake in Motiva to Royal Dutch Shell. The firm's management stated that ChevronTexaco "is highly competitive across all energy sectors, is projected to achieve at least $1.8 billion in annual savings and is well positioned for growth. We share common values, including protecting the environment, partnering with the communities where we operate, and promoting diversity and opportunity in our work force."[51]

The company's strategy included increasing capital expenditures on exploration and production, growing the commercial power generation business, and emphasizing social responsibility. ChevronTexaco owned 36% of the energy services firm Dynegy, and its managers asserted that developing the next generation of energy technologies was a fundamental part of the company's overall strategy. In addition, the company stated, "Success cannot be measured by financial value alone. We believe that our commitment to diversity has made us a better, stronger, smarter enterprise. We also appreciate that involvement in the energy industry means being involved in the communities where we operate. We take very seriously our responsibility as a trustee of our planet's resources, of our environment and of the health of our employees, our neighbors and our customers."[52]

TotalFinaElf The Paris-based company was originally formed as a consortium in 1924 to develop an oil industry for France and operated under the name Compagnie Francaise des Petroles (CFP). CFP changed its name to Total in 1991, merged with Belgium's PetroFina in 1999, and completed a takeover of Elf Aquitaine in 2000 to form the current company. In 2000, TotalFinaElf earned $6.5 billion on revenues of $108 billion. The company operated more than 17,600 service stations in Europe and Africa, had proved reserves of 10.8 billion BOE, and ran refineries with a production capacity of 2.6 billion barrels per day.[53] The majority of its upstream production was in Europe and Africa.

In upstream operations, the synergies from the merger along with increased production and productivity added 1.2 billion euros to operating income in 2000. Goals included production growth of 6% per year to 2005 and savings of 4.4 billion euros by 2003. The group's stated priority was to grow its upstream business by developing large, low-cost oil and gas projects, and to pursue selective

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growth of downstream operations in Africa and Asia. Upstream expenditures were "expected to account for half of TotalFinaElf's capital employed in 2005. This investment choice reflects the Group's confidence that oil and natural gas will continue to play a central role in meeting the planet's growing energy needs over the next two decades. It is anticipated that the transportation industries will account for an increasing share of oil consumption, while power generation will spur gas demand."[54]

Challenges and Potential Limits to Growth

After the industry consolidation, executives at the major petroleum companies continued to evaluate their prospects for future growth. It was not clear whether continued merger activity was a viable path for future success. Although post-merger cost cutting and consolidation of redundant activities provided a significant short-term benefit, one industry economist cautioned that the size of the companies could cause other problems:

> This merger activity makes sense from a cost-saving perspective in a depressed market, but it is difficult to manage a company with this many assets. In the long run, this should lead to inefficiencies including inertia, bureaucracy, and number of people. It could cause the company to react slowly and lose opportunities. A counter argument is that a manager's span of control is increased because of today's speed of information flow, communications methods, and computing power. But, even if you can get the information, it still comes down to a few guys making the final decisions. It gets more complicated as the number of places in which you conduct business increases. Analysis still has to be done and a smaller, more nimble company can beat you. Of course, the increased size could lead to more delegation but that has always been the case, and management talent is at a premium.[55]

In addition, the industry was tightly regulated by federal and state governments. Antitrust concerns might preclude any other major merger activity. Governments also controlled access to many of the most interesting remaining reserves. In the United States, for example, some believed that significant reserves underlay the Arctic National Wildlife Refuge (ANWR); a federal government proposal to allow exploration and development in ANWR, bitterly opposed by some environmentalists, was the subject of intense political debate.

Other governments, including Iran and Saudi Arabia, needed billions of dollars of investment for infrastructure and development.[56] The major oil companies competed for the rights to invest in these areas and manage the political risk inherent to the region. Governments were reluctant to grant sole production rights to any single producer. Additionally, U.S. firms were still prohibited from investing in countries that were under sanctions from the federal government or the United Nations.

After the terrorist attacks on September 11, 2001, attention was refocused on the political stability of the Middle East and on the ultimate allocation of the rents from the oil produced there. The resultant concerns could lead to new exploration in areas formerly deemed uneconomical or politically unavailable. As the number of countries in which a given company had significant operations increased, however, relationships with host governments became more complicated.

Government regulations on refining activity, including tighter emissions standards, requirements for cleaner burning gasolines, and rules for underground storage tanks, had a significant impact on firms' downstream operations. For environmental and political reasons, it seemed unlikely that new "greenfield" refineries would be built in the United States. Capacity increases would have to come from expansion of existing refineries, efficiency gains, and technological advances. A potential ban on

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MBTE, the prevailing fuel additive used to increase octane and oxygen content in gasoline, could also lead to increased costs.[57]

Society struggled with competing demands for energy security, environmental quality, and inexpensive heat, light, and mobility. As of 2001, it seemed clear that hydrocarbons would remain the mainstay of energy production for at least 20 to 30 years. As Royal Dutch Shell stated, "… a major challenge facing society today is posed by three inextricably linked issues: the world's increasing demand for energy, the need for economic and social development of a growing population, and the need to assure a viable world for future generations. This threefold challenge has serious implications for the energy business, and concerns over climate change are at the heart of it."[58]

The Future

Lord Browne continued to contemplate BP's alternatives for continued growth. The immediate options fell into four main categories: acquisition, internal growth, divestiture, and business diversification. Each path seemed promising, but also presented challenges. BP had some experience integrating acquisitions and creating efficiencies, but competition authorities and a lack of quality opportunities might prevent profitable growth. Browne noted, "In theory, you can go and 'hoover up' all kinds of companies, but the question is, so what? We were focused on costs, but we're now moving on to productivity and producing profitable organic growth."[59] CFO John Buchanan acknowledged, "The oil and gas industry is rarely thought of as a growth industry. In some ways, the low growth, steady income, and high dividend payments of industry stocks actually mimic bonds."[60]

Lord Browne couldn't be sure that the markets would warm to the idea of BP as a growth stock. He felt the company had strong managerial talent and the internal knowledge to succeed in all aspects of the business, but was it possible to become more profitable or be rewarded with higher multiples by divesting some businesses and focusing on a particular segment? Finally, he considered expanding BP's energy services, power generation, and trading offerings, but was left wondering if those areas were outside BP's main competencies:

> When planning for the future, we think about four main areas. First, who is going to use our products and when? How is the changing nature of these products going to produce value? We believe people want to drive cars and not leave any mess behind. We must work towards that end. Second, what will be the effect of technologies? It should lead to increasing productivity, then to updating our products, and finally creating new products. Third, what will the source be for our raw materials? We must be aware of the political nature of the world and that changes are likely in existing regimes. How will this affect us, and what do we do about it. Finally, we must observe our competitors. Do they have any new ideas, and if so, what do we do about it?[61]

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Exhibit 1 World's Top 20 Oil Companies—2000

				Reserves		Annual Output		Refinery	Product
PIW Index[a]	Company	Country	Ownership	Liquids (mil. bbl)	Gas (mil. BOE)	Liquids (mil. bbl)	Gas (mil. BOE)	Capacity (000 b/d)	Sales (000 b/d)
100.0	Saudi Aramco	Saudi Arabia	State	259,200	35,550	8,044	550	1,992	2,650
98.8	ExxonMobil	USA	Public	11,260	9,466	2,444	1,896	6,400	8,887
98.8	PDVSA	Venezuela	State	76,852	24,453	2,950	667	3,096	2,500
98.0	NIOC	Iran	State	87,993	136,147	3,620	859	1,534	1,342
97.4	Royal Dutch / Shell	UK/Netherlands	Public	9,775	9,757	2,268	1,370	3,212	6,795
92.1	BP	UK	Public	7,572	5,921	2,061	1,011	2,801	5,002
91.8	Pemex	Mexico	State	28,400	5,001	3,343	799	1,528	1,650
85.4	Pertamina	Indonesia	State	7,860	19,784	973	1,050	1,050	1,190
84.5	TotalFinaElf	France	Public	6,869	2,231	1,468	529	2,586	3,168
81.6	KPC	Kuwait	State	96,500	13,783	2,025	156	1,075	1,165
80.2	Sonatrach	Algeria	State	8,830	22,717	1,480	1,265	485	750
79.9	PetroChina	China	State	10,999	4,101	2,124	112	2,066	1,376
77.8	Petrobras	Brazil	State	8,100	1,777	1,191	206	1,953	1,818
77.0	Chevron	USA	Public	4,784	1,509	1,127	419	1,524	2,384
73.2	Texaco	USA	Public	3,480	1,351	885	333	1,417	3,221
70.3	Adnoc	UAE	State	50,710	32,683	1,240	531	234	455
67.1	ENI	Italy	Public	3,137	2,278	666	390	824	940
63.0	Repsol YPF	Spain	Public	2,150	2,385	451	216	1,206	920
62.7	INOC	Iraq	State	112,500	18,300	2,528	53	348	520
59.5	Libya INOC	Libya	State	23,600	7,707	1,211	100	380	400
59.5	Petronas	Malaysia	State	2,952	10,745	636	850	290	425

Source: "Oil and Gas: Production & Marketing," Standard & Poor's Industry Surveys, October 18, 2001, p. 11.

[a]*Petroleum Intelligence Weekly*'s ranking based on reserves, output, capacity, and sales.

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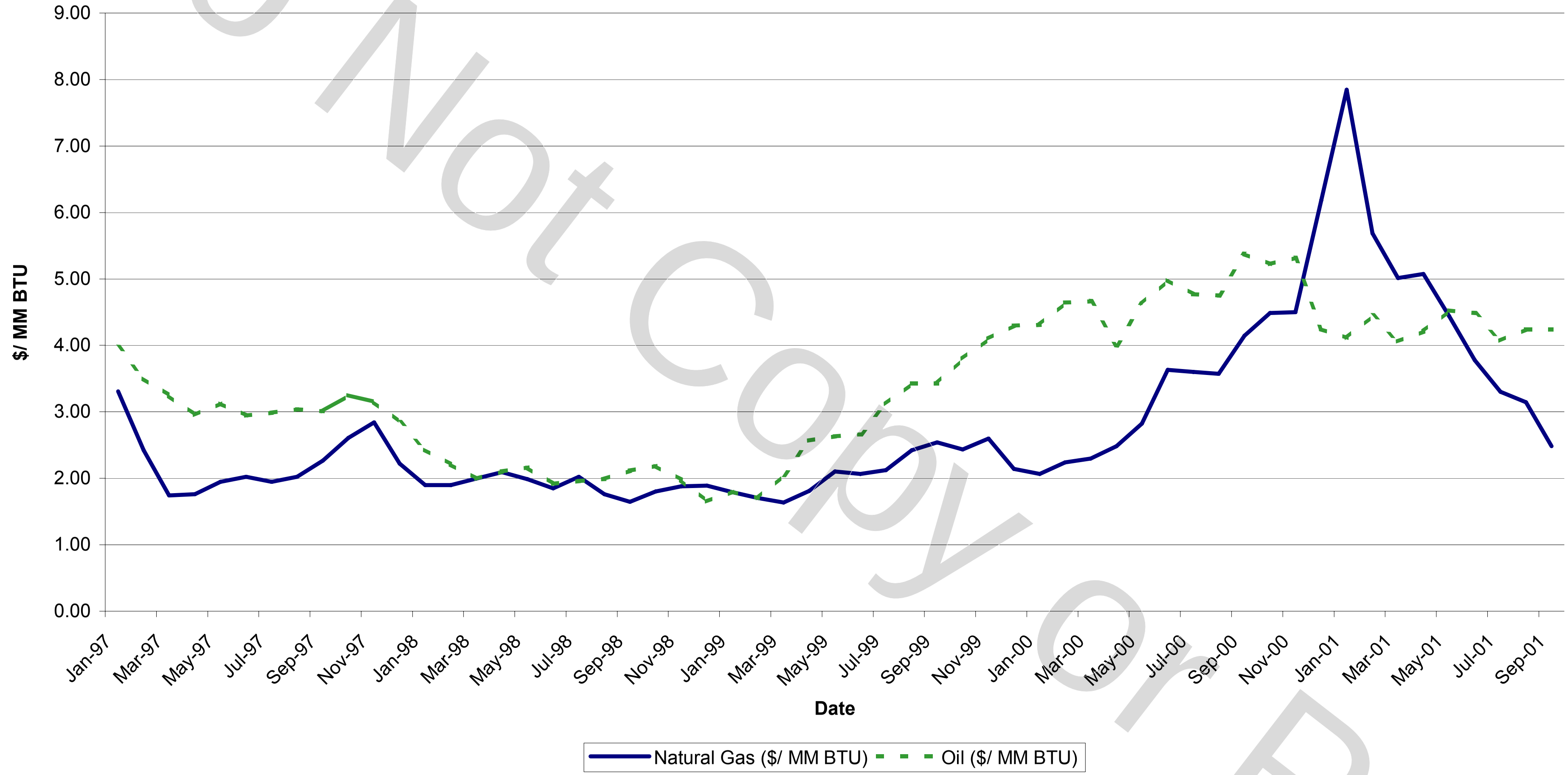
Exhibit 2 Oil and Natural Gas Relative Prices



Source: *Natural gas data:* Energy Information Administration, http://www.eia.doe.gov/oil_gas/natural_gas/data_publications/natural_gas_weekly_market_update/ngwmu.html, accessed November 2001. *Oil prices*: Energy Information Administration, http://www.eia.doe.gov/neic/historic/hpetroleum.htm, accessed November 2001.

Note: The oil price is based on West Texas intermediate crude. Natural gas prices are taken from the Henry Hub in Louisiana—a benchmark for upstream spot prices in the United States.

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Exhibit 3 International Petroleum Supply and Consumption Balance (million barrels per day)

	1988	1989	1990	1991	1992	1993	1994	1996	1997	1998	1999	2000	2001	2002
Consumption OECD														
U.S. (50 states)	17.3	17.3	17.0	16.7	17.0	17.2	17.7	18.3	18.6	18.9	19.5	19.7	19.8	20.1
Europe	12.4	12.5	12.6	13.4	13.6	13.5	13.6	14.3	14.4	14.7	14.5	14.4	14.3	14.3
Japan	4.8	5.0	5.1	5.3	5.4	5.4	5.7	5.9	5.7	5.5	5.6	5.5	5.5	5.5
Other OECD	2.6	2.7	2.7	2.7	2.7	2.8	2.9	3.0	3.1	3.1	3.2	3.3	3.4	3.4
Total OECD	**37.1**	**37.6**	**37.5**	**38.1**	**38.8**	**39.0**	**39.9**	**41.4**	**41.8**	**42.3**	**42.8**	**42.9**	**43.0**	**43.4**
Non-OECD														
Former Soviet Union	8.9	8.7	8.4	8.4	6.8	5.6	4.8	4.0	3.9	3.8	3.7	3.7	3.7	3.7
Europe	2.2	2.1	1.7	1.4	1.3	1.3	1.3	1.4	1.5	1.5	1.5	1.5	1.6	1.6
China	2.3	2.4	2.3	2.5	2.7	3.0	3.2	3.6	3.9	4.1	4.3	4.6	4.8	4.9
Other Asia	4.4	4.9	5.3	5.7	6.2	6.8	7.3	8.5	9.0	8.7	9.0	9.0	9.1	9.2
Other Non-OECD	10.0	10.3	10.5	10.6	11.0	11.4	11.8	12.4	12.9	13.3	13.6	13.9	14.0	14.1
Total Non-OECD	**27.7**	**28.3**	**28.2**	**28.5**	**28.0**	**28.0**	**28.4**	**30.0**	**31.2**	**31.4**	**32.1**	**32.7**	**33.1**	**33.6**
TOTAL WORLD CONSUMPTION	**64.8**	**65.9**	**65.7**	**66.6**	**66.8**	**67.0**	**68.3**	**71.4**	**73.0**	**73.6**	**74.9**	**75.6**	**76.1**	**77.0**
Supply OECD														
U.S. (50 states)	10.5	9.9	9.7	9.9	9.8	9.6	9.4	9.4	9.5	9.3	9.0	9.1	9.0	9.0
Canada	2.0	2.0	2.0	2.0	2.1	2.2	2.3	2.5	2.6	2.7	2.6	2.7	2.8	2.9
North Sea	3.8	3.7	3.9	4.1	4.5	4.8	5.5	6.3	6.2	6.2	6.3	6.0	5.9	6.0
Other OECD	1.5	1.4	1.5	1.5	1.4	1.4	1.5	1.5	1.6	1.6	1.5	2.0	2.0	1.9
Total OECD	**17.8**	**17.1**	**17.1**	**17.5**	**17.9**	**18.0**	**18.7**	**19.7**	**19.9**	**19.7**	**19.4**	**19.8**	**19.6**	**19.8**
Non-OECD														
OPEC	21.5	23.3	24.5	24.6	25.8	26.6	27.0	28.3	29.9	30.4	29.3	30.9	30.3	29.6
Former Soviet Union	12.5	12.1	11.4	10.4	8.9	8.0	7.3	7.1	7.1	7.2	7.6	8.1	8.8	9.1
China	2.7	2.8	2.8	2.8	2.8	2.9	2.9	3.1	3.2	3.2	3.2	3.2	3.3	3.3
Mexico	2.9	2.9	3.0	3.2	3.2	3.2	3.2	3.3	3.4	3.5	3.4	3.5	3.6	3.7
Other Non-OECD	7.3	12.0	8.0	8.1	8.4	8.7	9.2	10.2	10.5	10.8	11.3	11.3	11.4	12.0
Total Non-OECD	**47.0**	**48.9**	**49.7**	**49.1**	**49.1**	**49.4**	**49.6**	**52.0**	**54.2**	**55.2**	**54.8**	**57.0**	**57.3**	**57.6**
TOTAL WORLD SUPPLY	**64.8**	**65.9**	**66.8**	**66.7**	**67.0**	**67.4**	**68.3**	**71.8**	**74.1**	**74.9**	**74.2**	**76.8**	**76.9**	**77.4**

Source: "Short-Term Energy Outlook—October 2001," Energy Information Administration.

Note: ***OECD***: Organization for Economic Cooperation and Development: Australia, Austria, Belgium, Canada, Denmark, Finland, France, Germany, Greece, Iceland, Ireland, Italy, Japan, Luxembourg, the Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom, and the United States. The Czech Republic, Hungary, Mexico, Poland, and South Korea are all members of OECD, but are not yet included in our OECD estimates.

OPEC: Organization of the Petroleum Exporting Countries: Algeria, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.

Former Soviet Union: Armenia, Azerbaijan, Belarus, Estonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Moldova, Russia, Tajikistan, Turkmenistan, Ukraine, and Uzbekistan.

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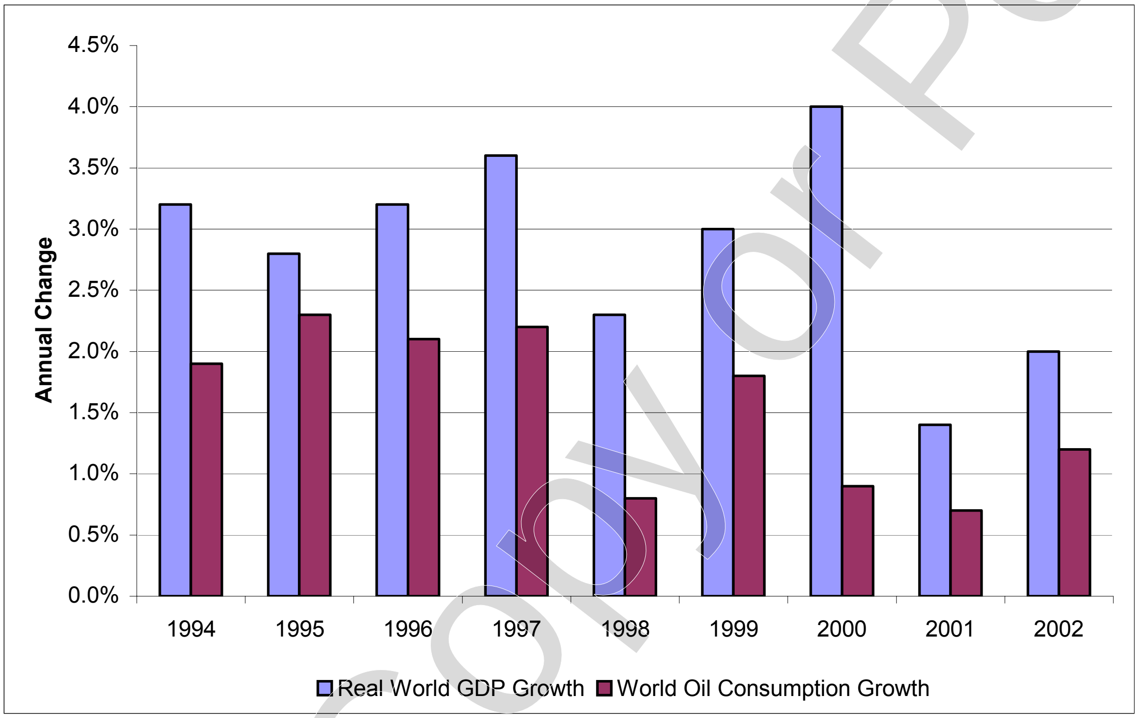
Exhibit 4 World Economic and Oil Consumption Growth, 1994–2002[a]



Source: Energy Information Administration.

[a]Data for 2001 and 2002 are estimates.

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Exhibit 5a Crude Oil Reserves in 20 Leading Nations
(million barrels)

	Oil	
	Total	% of World
Total World	***1,028,458***	***100.0%***
Saudi Arabia[a]	259,200	25.2%
Iraq[a]	112,500	10.9%
United Arab Emirates[a]	97,800	9.5%
Kuwait[a]	94,000	9.1%
Iran[a]	89,700	8.7%
Venezuela[a]	76,862	7.5%
F.S.U./ C.I.S.	57,000	5.5%
Libya[a]	29,500	2.9%
Mexico	28,260	2.7%
China	24,000	2.3%
Nigeria[a]	22,500	2.2%
United States	21,765	2.1%
Norway	9,447	0.9%
Algeria[a]	9,200	0.9%
Brazil	8,100	0.8%
Oman	5,506	0.5%
Angola	5,412	0.5%
United Kingdom	5,003	0.5%
Neutral Zone (Asia)	5,000	0.5%
Indonesia[a]	4,980	0.5%
Top 20 Total	965,735	93.7%

Exhibit 5b Natural Gas Reserves in 20 Leading Nations
(million barrels)

	Natural Gas	
	Total	% of World
Total World	***1,028,458***	***100.0%***
F.S.U./C.I.S.	381,656	37.8%
Iran[a]	154,751	15.3%
Qatar[a]	75,050	7.4%
Saudi Arabia[a]	40,746	4.0%
U.A.E.[a]	40,422	4.0%
U.S.	31,827	3.1%
Algeria[a]	30,436	3.0%
Venezuela[a]	27,977	2.8%
Nigeria[a]	23,632	2.3%
Iraq[a]	20,926	2.1%
Malaysia	15,570	1.5%
Indonesia[a]	13,779	1.4%
Netherlands	11,911	1.2%
Canada	11,625	1.2%
Kuwait[a]	10,044	1.0%
China	9,205	0.9%
Libya[a]	8,843	0.9%
Australia	8,500	0.8%
Norway	8,386	0.8%
Egypt	6,708	0.7%
Top 20 Total	931,993	92.2%

Source: *Oil (2001):* Adapted from *NPN Market Facts Supplement*, July 15, 2001, p. 70. *Natural gas (2000):* "BP Statistical Review of World Energy," June 2001, p. 20.

[a] Member of OPEC.

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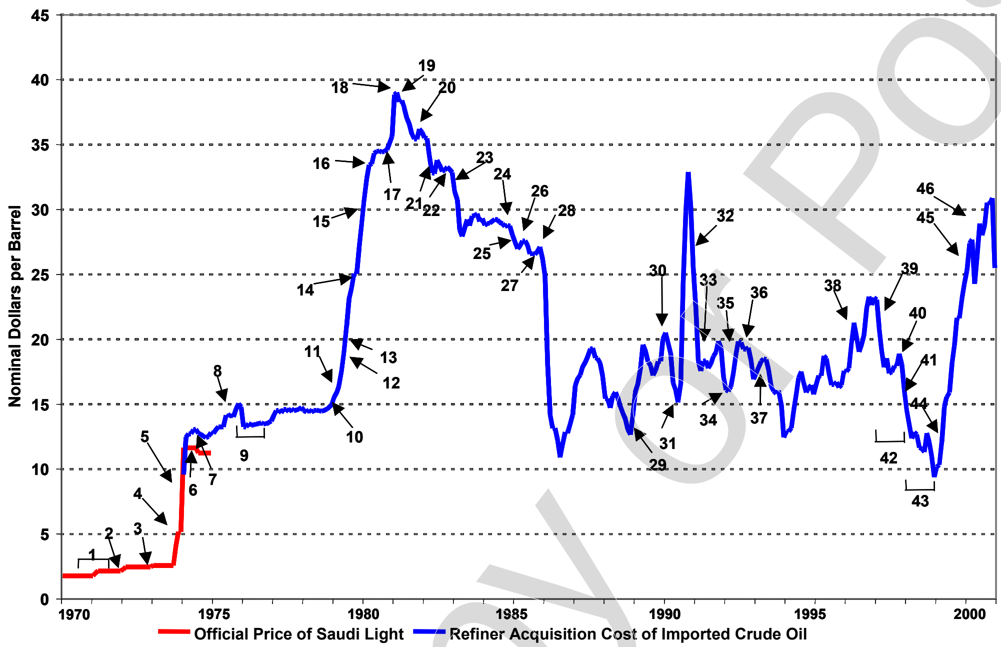
Exhibit 6 Historical Oil Prices, 1970–2001



1. OPEC begins to assert power; raises tax rate & posted prices.
2. OPEC begins nationalization process; raises prices in response to falling U.S. dollar.
3. Negotiations for gradual transfer of ownership of Western assets in OPEC countries.
4. Oil embargo begins (October 19–20, 1973).
5. OPEC freezes posted prices; U.S. begins mandatory oil allocation.
6. Oil embargo ends (March 18, 1974).
7. Saudis increase tax rates and royalties.
8. OPEC announces 15% revenue increase effective October 1, 1975.
9. Official Saudi Light price held constant for 1976.
10. Iranian revolution; Shah deposed.
11. OPEC raises prices 14.5% on April 1, 1979.
12. U.S. phased price decontrol begins.
13. OPEC raises prices 15%.
14. Iran takes hostages; President Carter halts imports from Iran; Iran cancels U.S. contracts; non-OPEC output hits 17.0 million b/d.
15. Saudis raise marker crude price from $19/bbl to $26/bbl.
16. Kuwait, Iran, and Libya production cuts drop OPEC oil production to 27 million b/d.
17. Saudi Light raised to $34/bbl.
18. First major fighting in Iran-Iraq War.
19. President Reagan abolishes remaining price and allocation controls.
20. Spot prices dominate official OPEC prices.
21. U.S. boycotts Libyan crude; OPEC plans 18 million b/d output.
22. Libya initiates discounts; non-OPEC output reaches 20 million b/d; OPEC output is 15 million b/d.
23. OPEC cuts prices by $5/bbl and agrees to 17.5 million b/d output.
24. Norway, United Kingdom, and Nigeria cut prices.
25. OPEC accord cuts Saudi Light price to $28/bbl.
26. OPEC output falls to 13.7 million b/d.
27. Saudis link to spot price and begin to raise output.
28. OPEC output reaches 18 million b/d.
29. Exxon's *Valdez* tanker spills 11 million gallons of crude oil.
30. OPEC raises production ceiling to 19.5 million b/d.
31. Iraq invades Kuwait.
32. Operation Desert Storm begins; 17.3 million barrels of Strategic Petroleum Reserve (SPR) crude oil sales is awarded.
33. Persian Gulf War ends.
34. Dissolution of Soviet Union; Last Kuwaiti oil fire is extinguished on November 6, 1991.
35. Saudi Arabia agrees to support OPEC price increase.
36. OPEC production reaches 25.3 million b/d, the highest in over a decade.
37. Kuwait boosts production by 560,000 b/d in defiance of OPEC quota.
38. Extremely cold weather in the U.S. and Europe.
39. Iraq begins exporting oil under United Nations Security Council Resolution 986.
40. Prices rise as Iraq's refusal to allow United Nations weapons inspectors into "sensitive" sites raises tensions in the oil-rich Middle East.
41. OPEC raises its production ceiling by 2.5 million barrels per day to 27.5 million barrels per day. This is the first increase in 4 years.
42. World oil supply increases by 2.25 million barrels per day in 1997, the largest annual increase since 1988.
43. Oil prices continue to plummet as increased production from Iraq coincides with no growth in Asian oil demand due to the Asian economic crisis and increases in world oil inventories following two unusually warm winters.
44. OPEC pledges additional production cuts for the third time since March 1998. Total pledged cuts amount to about 4.3 million barrels per day.
45. Oil prices triple between January 1999 and September 2000 due to strong world oil demand, OPEC oil production cutbacks, and other factors, including weather and low oil stock levels.
46. President Clinton authorizes the release of 30 million barrels of oil from the SPR over 30 days to bolster oil supplies, particularly heating oil in the Northeast.

Source: Energy Information Administration, http://www.eia.doe.gov/emeu/cabs/chron.html, January 2001, accessed January 2002.

Note: Chart shows official price of Saudi light crude 1970–1975 and refiner acquisition cost of imported crude 1975–2000.

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Exhibit 7 Companies in the U.S. Department of Energy Financial Reporting System[a]

1979	1990	1999
Vertically Integrated[b]	***Vertically Integrated***	***Vertically Integrated***
Exxon	Exxon	ExxonMobil
Mobil	Mobil	BP Amoco
Texaco	DuPont (Conoco)	Chevron
Chevron	Chevron	Texaco
Amoco	Amoco	Shell Oil
Gulf Oil	Shell Oil	Atlantic Richfield
Shell Oil	Texaco	USX (Marathon)
Atlantic Richfield	Atlantic Richfield	Conoco
Tenneco	BP America	Phillips Petroleum
BP America	USX (Marathon)	Amerada Hess
Conoco	Phillips Petroleum	Coastal
Sunoco	Unocal	Fina
Phillips Petroleum	Coastal	
Getty Oil	Amerada Hess	***Nonintegrated Producers***
Unocal	Sunoco	Occidental Petroleum
Occidental Petroleum	Ashland Oil	Union Pacific Resources
Union Pacific Resources	Kerr-McGee	Unocal
Amerada Hess	Fina	Burlington Resources
Cities Service	Total Petroleum (N. America)	Kerr-McGee
Marathon		Anadarko Petroleum
Coastal	***Nonintegrated Producers***	
Ashland Oil	Occidental Petroleum	***Nonintegrated Refiners***[d]
Kerr-McGee	Union Pacific Resources	Equilon Enterprises
Fina	Burlington Resources	Motiva Enterprises
	Oryx Energy	Tosco
Nonintegrated Producers[c]		Ultramar Diamond Shamrock
Burlington Resources		CITGO Petroleum
Superior Oil		Sunoco
		Valero Energy
		Lyondell-CITGO Refining
		Clark Refining and Marketing
		Tesoro Petroleum
		Energy Services[e]
		Enron
		Williams Companies
		El Paso Energy

Source: "Performance Profiles of Major Energy Producers," Energy Information Administration, 1999, p. 54.

[a]Companies included in the financial reporting system own at least 1% of U.S. reserves or production of oil or natural gas or 1% of U.S. refining capacity or refined product sales.

[b]Vertically integrated firms' operations encompass the functions of oil and natural gas production, transport, petroleum refining, and marketing of refined petroleum products.

[c]Nonintegrated producers are primarily involved in oil and gas production, but do not own petroleum refining and marketing operations.

[d]Nonintegrated refiners are primarily involved in petroleum refining and marketing, but do not own oil and gas production operations.

[e]Energy services firms typically provide natural gas transmission and distribution; electricity generation and distribution; trading, wholesaling, and marketing of natural gas and electricity; and associated customer services such as risk management.

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Exhibit 8 U.S. Refiner Product Volumes and Customers (year 2000, million gallons per day)

			Total	
	End Users[a]	Wholesalers[b]	Volume	Production %
Motor gasoline	60.9	304.4	365.3	56.7%
No. 2 distillate[c]	25.4	122.1	147.5	22.9%
Kero-jet[d]	49.3	15.7	65	10.1%
Residual fuel oil[e]	13.1	10.5	23.6	3.7%
Propane	2.9	34.8	37.7	5.8%
Other	1.0	4.6	5.6	0.9%
Total	152.6	492.1	644.7	100.0%

Source: EIA/Petroleum Marketing Annual 2000, published August 2001.

[a]Sales made directly to the product's consumer. Includes bulk consumers such as utilities, as well as residential and commercial consumers.

[b]Sales of products to purchasers who are other-than-ultimate consumers.

[c]No. 2 distillate can be used as diesel fuel or as heating and fuel oil.

[d]Kero-jet is used for military and commercial turbojet and turboprop aircraft engines.

[e]Residual fuel oil includes the heavier oils that remain after lighter hydrocarbons are distilled away in refining. They are used in steam-powered ships, for the production of electricity, and for various industrial purposes.

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Exhibit 9 Refining Margins, Production Costs, and Product Sales of U.S. Majors, 1990–1999

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
					(Nominal Dollars per Barrel)					
Petroleum Product Gross Refining Margin	7.11	7.01	6.78	6.66	5.86	5.41	6.33	6.61	5.97	5.47
– Petroleum Product Marketing Costs	2.02	2.38	2.66	2.14	1.76	1.71	1.77	1.71	1.40	1.42
– Petroleum Product Energy Costs	1.12	1.16	1.11	1.15	0.94	0.81	1.04	1.00	0.73	0.82
– Petroleum Product Other Operating Costs	2.80	2.74	2.64	2.67	2.45	2.41	2.66	2.45	2.36	2.13
= Petroleum Product Net Refining Margin	1.17	0.73	0.37	0.70	0.70	0.48	0.85	1.44	1.50	1.10
					(Real Dollars per Barrel)					
Petroleum Product Gross Refining Margin	8.22	7.81	7.39	7.09	6.10	5.51	6.33	6.49	5.78	5.22
– Petroleum Product Marketing Costs	2.34	2.65	2.90	2.28	1.83	1.74	1.77	1.68	1.36	1.36
– Petroleum Product Energy Costs	1.29	1.29	1.21	1.22	0.98	0.83	1.04	0.98	0.71	0.78
– Petroleum Product Other Operating Costs	3.24	3.05	2.88	2.84	2.55	2.46	2.66	2.40	2.29	2.03
= Petroleum Product Net Refining Margin	1.35	0.81	0.40	0.74	0.73	0.49	0.85	1.41	1.45	1.05
					(Thousand Barrels per Day)					
Refined Product Sales*	13,222	13,015	13,089	13,178	13,455	13,641	14,024	13,294	20,061	21,416
GDP Deflator	86.5	89.7	91.8	94	96	98.1	100	101.9	103.2	104.7

Sources: Energy Information Administration, http://www.eia.doe.gov/emeu/finance/usi&to/downstream/update/table5.html, accessed November 2001. *Costs, margins, and sales:* Energy Information Administration, Form EIA-28 (Financial Reporting System). *GDP deflator:* U.S. Department of Commerce, Bureau of Economic Analysis, August 28, 2001.

*Due to definitional changes, 1998–1999 data are not comparable to earlier figures.

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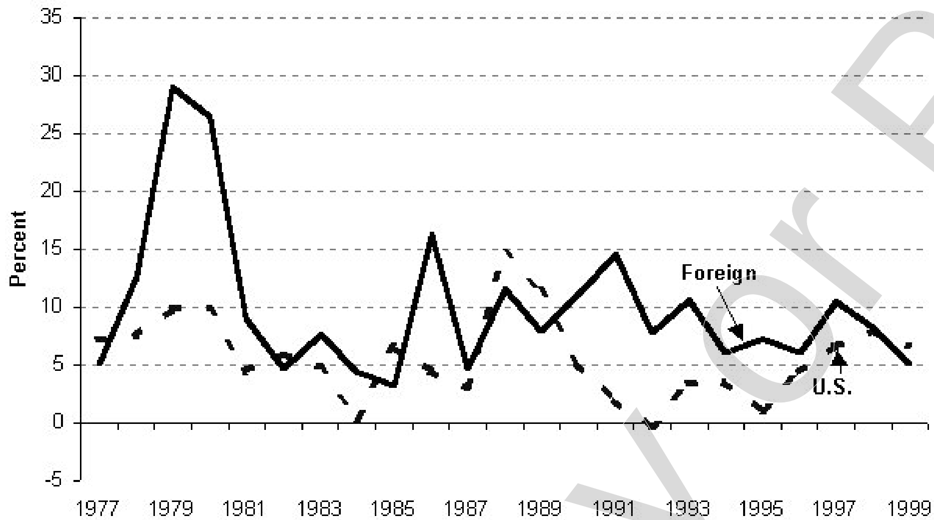
Exhibit 10 Return on Investment in Refining/Marketing for U.S. Majors



Source: Financial Analysis Team, Office of Energy Markets and End Use, Energy Information Administration, Form EIA-28 (Financial Reporting System), http://www.eia.doe.gov/emeu/finance/usi&to/downstream/update/figure1.jpg.

Exhibit 11 World Crude Oil Refining Capacity (thousand barrels per day)

	1990		2000			
Region/Country	**Capacity**	**Throughput**	**Capacity**	**Throughput**	**% of World Capacity**	**Number of Refineries**
North America	19,195	16,485	19,935	18,215	24.3%	186
Central & South America	5,985	4,670	6,490	5,525	7.9%	73
Europe	16,425	13,920	16,390	14,880	20.0%	115
Former Soviet Union	12,310	9,150	9,000	4,560	11.0%	93
Middle East	4,950	4,390	6,355	5,800	7.8%	45
Africa	2,690	2,270	2,965	2,445	3.6%	46
Asia Pacific	13,280	11,190	20,840	18,085	25.4%	203
World Total	74,835	62,075	81,975	69,510	100.0%	761

Sources: "International Energy Annual," Energy Information Administration 1999; "BP Statistical Review of World Energy," June 2001.

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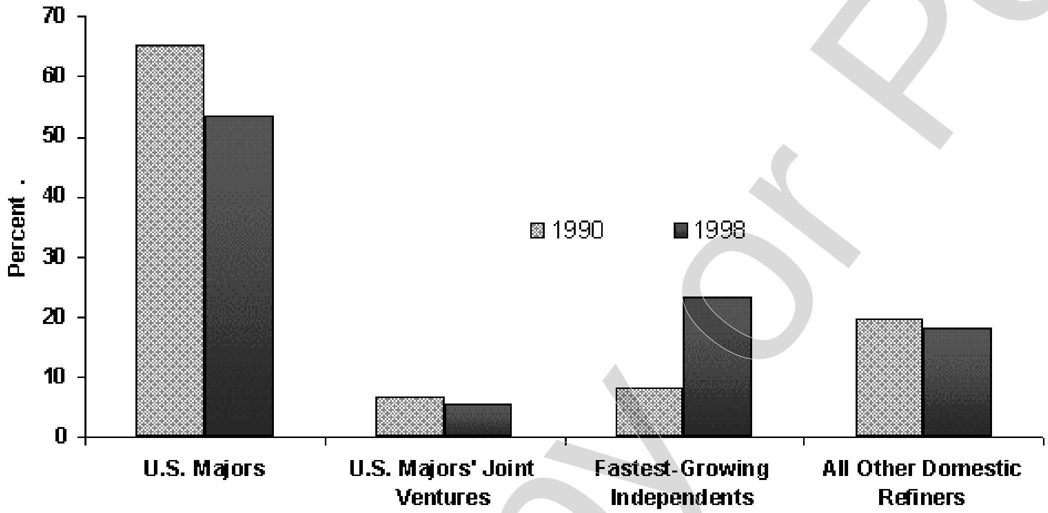
Exhibit 12 U.S. Refining Capacity by Ownership Category, 1990 and 1998



Sources: *Petroleum Supply Annual 1990, Volume 1*, DOE/EIA-0340(90)/1 (Washington, DC: Energy Information Administration, May 1991), Table 39; *Petroleum Supply Annual 1996, Volume 1*, DOE/EIA-0340(96)/1 (Washington, DC: Energy Information Administration, June 1997), Table 40; *Petroleum Supply Annual 1997, Volume 1*, DOE/EIA-0340(90)/1 (Washington, DC: Energy Information Administration, June 1998), Tables 37 and 38; and various news sources.

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Exhibit 13 BP Worldwide Assets

Exploration and Production Interests

Oil and Natural Gas Production (net of royalty), (000 BOE per day)	**1998**	**1999**	**2000**
United Kingdom	735	804	819
Rest of Europe	139	128	113
United States	1,255	1,213	1,256
Rest of World	921	962	1,052
Total	3,050	3,107	3,240
Number and Location of Service Stations (at 12/31)			
Europe	8,400	8,200	7,900
United States (company owned)	4,400	4,300	5,400
United States (franchises)	11,900	12,000	11,900
Rest of World	3,600	3,700	3,800
Total	28,300	28,200	29,000
Refinery Throughputs and Utilization (000 bbl per day)			
United Kingdom	296	271	324
Rest of Europe	551	540	602
United States	1,489	1,340	1,625
Rest of World	362	371	365
Total	2,698	2,522	2,916
Utilization	**94%**	**95%**	**95%**

Source: BP financial and operating information, 1996–2000.

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Exhibit 14 Summarized Group Financial Statements ($ millions)

	1996	1997	1998	1999	2000
Summarized Group Income Statements					
Turnover	102,064	108,564	83,732	101,180	**161,826**
Less: joint ventures	–	16,804	15,428	17,614	**13,764**
Group turnover	102,064	91,760	68,304	83,566	**148,062**
Replacement cost operating profit					
Exploration and production	7,602	7,287	3,081	6,983	**14,012**
Gas and power	161	98	150	211	**186**
Refining and marketing	1,708	2,292	2,564	1,840	**3,908**
Chemicals	1,654	1,530	1,100	686	**760**
Other businesses and corporate	(491)	(524)	(374)	(826)	**(1,110)**
Total replacement cost operating profit	10,634	10,683	6,521	8,894	**17,756**
Exceptional items	(462)	128	850	(2,280)	**220**
Replacement cost profit before interest and tax	10,172	10,811	7,371	6,614	**17,976**
Stock holding gains (losses)	1,172	(939)	(1,391)	1,728	**728**
Historical cost profit before interest and tax	11,344	9,872	5,980	8,342	**18,704**
Interest expense	1,131	1,035	1,177	1,316	**1,770**
Profit before taxation	10,213	8,837	4,803	7,026	**16,934**
Taxation	2,783	3,013	1,520	1,880	**4,972**
Profit after taxation	7,430	5,824	3,283	5,146	**11,962**
Minority shareholders' interest (MSI)	13	151	63	138	**92**
Profit for the year	7,417	5,673	3,220	5,008	**11,870**
Distribution to shareholders	3,007	3,452	4,121	3,884	**4,625**
Retained profit (deficit) for the year	4,410	2,221	(901)	1,124	**7,245**
Earnings per ordinary share—cents					
Basic	38.79	29.56	16.77	25.82	**54.85**
Diluted	38.63	29.41	16.70	25.68	**54.48**
Dividends per ordinary share—cents	15.50	18.00	19.75	20.00	**20.50**
Replacement cost results					
Historical cost profit	7,417	5,673	3,220	5,008	**11,870**
Stock holding (gains) losses	(1,172)	939	1,391	(1,728)	**(728)**
Replacement cost profit for the year	6,245	6,612	4,611	3,280	**11,142**
Summarized Group Balance Sheets					
Fixed assets	61,937	65,553	67,689	66,084	**103,819**
Stocks and debtors	25,134	19,304	16,351	21,926	**38,288**
Cash and liquid resources	1,580	1,422	875	1,551	**1,831**
Total assets	88,651	86,279	84,915	89,561	**143,938**
Creditors and provisions excluding finance debt	33,360	29,799	27,587	30,675	**48,747**
Total assets minus creditors and provisions excluding finance debt	55,291	56,480	57,328	58,886	**95,191**
Financed by:					
Finance debt	12,848	12,877	13,755	14,544	**21,190**
Minority shareholders' interest	313	1,100	1,072	1,061	**585**
BP shareholders' interest	42,130	42,503	42,501	43,281	**73,416**
	55,291	56,480	57,328	58,886	**95,191**
Summarized Group Cash Flow Statements					
Net cash inflow from operating activities	13,679	15,558	9,586	10,290	**20,416**
Dividends from joint ventures	–	190	544	949	**645**
Dividends from associated undertakings	476	551	422	219	**394**
Net cash outflow from servicing of finance and returns on investments	(880)	(655)	(825)	(1,003)	**(892)**
Tax paid	(2,431)	(2,273)	(1,705)	(1,260)	**(6,198)**
Net cash outflow for capital expenditure and financial investment	(7,965)	(7,432)	(7,298)	(5,385)	**(7,072)**
Net cash inflow (outflow) for acquisitions and disposals	(91)	(2,624)	778	243	**865**
Equity dividends paid	(2,411)	(2,437)	(2,408)	(4,135)	**(4,415)**
Net cash inflow (outflow)	377	878	(906)	(82)	**3,743**
Financing	828	1,012	(377)	(954)	**3,413**
Management of liquid resources	(147)	(167)	(596)	(93)	**452**
Increase (decrease) in cash	(304)	33	67	965	**(122)**
	377	878	(906)	(82)	**3,743**

Source: BP.

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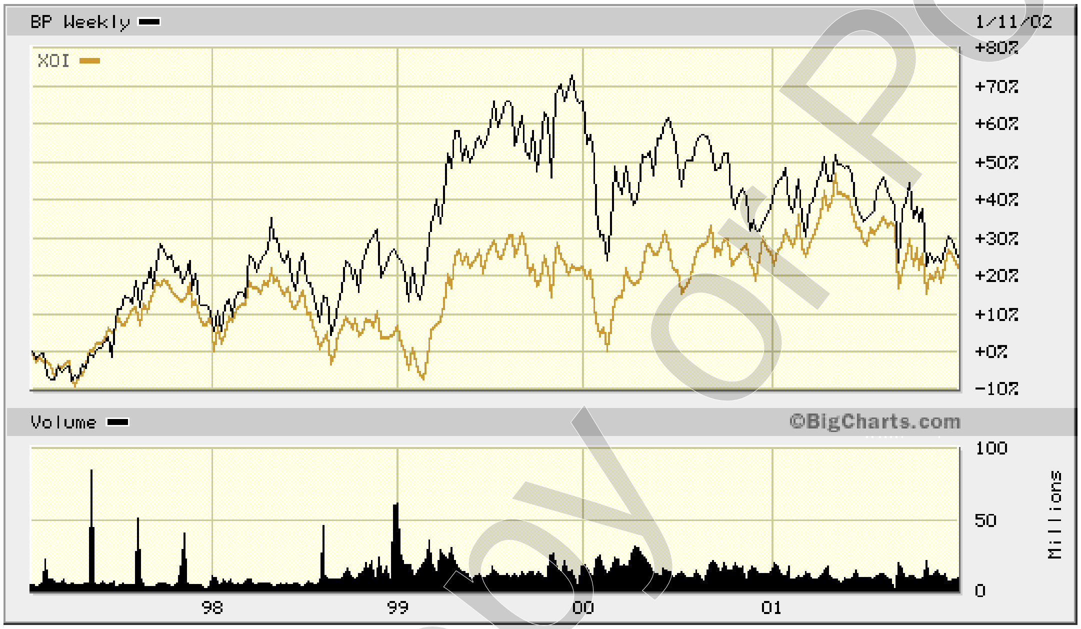
Exhibit 15 BP Stock Price History vs. AMEX Oil Index, 1997–2001



Source: 2002 Marketwatch.com Inc.

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Exhibit 16 Pre- and Post-Merger Selected Financials ($ millions)

	Pre-Merger	Post-Merger		Pre-Merger	Post-Merger	
	Amoco 1997	BP 1997	BP Amoco 1998	ARCO 1999	BP AMOCO 1999	BP Amoco + ARCO, 2000
Revenue	36,287	108,564	83,732	13,055	101,180	161,826
Operating expenses	5,009			2,386		
Replacement cost of sales[a]		73,828	56,270		68,615	121,516
Selling, general, and administrative expense	2,172			607		
Distribution and administration expense[b]		6,742	6,044		6,064	8,535
Depletion, depreciation, amortization	2,373	5,117	5,301	1,785	5,049	7,449
Income before taxes	3,776	8,837	4,803	1,916	7,026	16,934
Net Income	2,720	5,673	3,220	1,422	5,008	11,870
Net property, plant, and equipment	22,543	52,595	54,880	18,466	52,631	75,173
Total assets	32,489	86,279	84,915	26,272	89,561	143,938
Equity	16,319	42,503	42,501	8,686	43,281	73,416

Source: Company financial statements.

[a]Operating expenses for Amoco and ARCO.

[b]Selling, general, and administrative expenses for Amoco and ARCO.

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Exhibit 17 BP Business Objectives

	2000–2001	Medium Term
Group performance improvement potential[a]	$2.0B	$1.4B per year
Upstream		
volume growth of	5.5%	5.5% per year with upside to 7%
unit cost reduction	6.0%	6.0% per year
Downstream		
unit cost reduction	2.5%	1.5% per year
Chemicals		
volume growth of	2000 kte	2000 kte per year
unit cost reduction	4.0%	4.0% per year
Earnings		Double-digit earnings growth at midcycle[b]
Gearing (ratio of net debt to capital employed)		Maintain 20%–30% via CAPEX and share repurchase
Dividend policy		Pay out 50% of midcycle income

Source: BP, http://www.bp.com/corp_reporting/objectives/bus_objectives_01.asp, accessed December 2001.

[a]Pretax costs and volumes.

[b]Midcycle is based on a Brent crude price of $16 per barrel.

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Exhibit 18 Comparisons of Major Oil Firms in 2000 ($ million)

	BP	ExxonMobil	Royal Dutch Shell	ChevronTexaco	TotalFinaElf
Revenue	161,826	232,748	191,511	118,676	105,667
Assets	143,938	149,000	115,660	72,131	82,400
Net income	11,870	17,720	12,719	7,511	6,368
Shareholders' equity	73,416	70,757	57,086	33,369	30,421
Return on sales	7.3%	7.6%	6.6%	6.3%	6.0%
Sales/assets	1.1	1.6	1.7	1.6	1.3
Assets/equity	2.0	2.1	2.0	2.2	2.7
Return on equity	16.2%	25.0%	22.3%	22.5%	20.9%
Return on capital employed	25.0%	20.6%	19.5%	17.6%	19.6%
Reserves:					
Oil (mil. BOE)	6.5	11.6	8.4	8.5	7.0
Gas (mil. BOE)	6.9	9.3	5.4	3.0	3.8
Total	13.4	20.9	13.8	11.5	10.8
Share of world production	3.3%	3.4%	3.2%	2.8%	2.0%
Capital and exploration expense	11,600	9,953	8,500	9,387	7,693
— as % of sales	7.17%	4.28%	4.44%	7.91%	7.28%
Retail outlets	28,300	45,000	46,000	25,000	17,700

Source: Adapted from company annual reports and SEC 10Ks. *Production sources: Petroleum Intelligence Weekly* (December 18, 2000); Energy Information Administration, Form EIA-28 (Financial Reporting System); and *International Energy Annual 1999,* DOE/EIA-0219(99), (Washington, DC: Energy Information Administration, February 2001).

Notes: Production is reported on a net ownership basis. Crude oil includes natural gas liquids and condensates. Shares are based on pro forma 1999 production by companies as configured in January 2001.

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Exhibit 19 Selected BP Operating Statistics

	1996	1997	1998	1999	2000
Exploration and Production					
Finding and Development Costs ($/BOE)					
BP	4.02	4.22	4.7	3.21	3.29
Range of other oil majors					
Maximum	6.66	5.39	12.84	9.87	n/a
Minimum	1.9	3.08	3.17	3.23	n/a
Cost of Supply ($/BOE)					
BP	7.3	7.5	7.8	6.4	7.5
Range of other oil majors					
Maximum	7.8	8.2	8.5	8.5	n/a
Minimum	6.5	7.1	7.4	7.3	n/a
Net Income per BOE					
BP	4.43	4.25	2.17	4.11	8.48
Range of other oil majors					
Maximum	4.28	4.13	2.35	3.67	7.82
Minimum	3.61	3.33	1.1	2.34	6.93
Reserve Replacement					
BP	154%	160%	132%	112%	163%
Range of other oil majors					
Maximum	208%	180%	190%	149%	n/a
Minimum	61%	77%	61%	45%	n/a
Refining and Marketing					
Return on Fixed Assets					
BP	7.5%	11.6%	12.8%	9.4%	21.6%
Range of other oil majors					
Maximum	10.4%	13.4%	12.2%	7.8%	n/a
Minimum	3.8%	7.6%	7.2%	3.8%	n/a
Chemicals					
Return on Sales					
BP	12.1%	11.4%	10.4%	8.6%	7.9%
Range of 15 competitors					
Maximum	11.3%	13.8%	11.4%	8.5%	10.8%
Minimum	5.2%	6.0%	3.7%	3.6%	1.4%

Source: BP financial and operating information, 1996–2000.

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Exhibit 20 Revenue, Income, and Assets by Business Unit[a] ($ millions)

	2000			1999			1998		
	Revenue	Income	Assets	Revenue	Income	Assets	Revenue	Income	Assets
ExxonMobil									
Upstream	41,004	12,369	45,731	28,221	5,886	48,100	25,473	3,352	46,900
Downstream	164,510	3,418	26,730	134,846	1,227	28,974	120,841	3,474	29,412
Chemicals	17,501	1,161	9,935	13,777	1,354	9,969	13,589	1,394	9,501
Total	**223,015**	**16,948**	**82,396**	**176,844**	**8,467**	**87,043**	**159,903**	**8,220**	**85,813**
BP									
Upstream	30,942	14,012	46,751	19,133	6,983	34,442	16,080	3,173	36,511
Downstream	128,896	4,094	18,941	68,216	2,051	9,587	48,437	2,622	9,743
Chemicals	11,247	760	8,360	9,392	686	7,780	9,691	1,100	7,743
Total	**171,085**	**18,866**	**74,052**	**96,741**	**9,720**	**51,809**	**74,208**	**6,895**	**53,997**
Royal Dutch Shell Group									
Upstream	27,794	9,880	36,155	18,323	4,519	36,717	15,519	(247)	37,619
Downstream	122,769	1,965	59,627	84,044	2,963	51,946	74,602	1,128	50,133
Chemicals	16,307	819	12,989	13,634	885	17,737	13,121	(718)	17,082
Total	**166,870**	**12,664**	**108,771**	**116,001**	**8,367**	**106,400**	**103,242**	**163**	**104,834**
ChevronTexaco[b]									
Upstream	27,508	7,086	34,846	17,514	2,587	32,992	13,748	1,467	29,864
Downstream	82,587	1,004	27,246	56,878	995	25,340	49,834	1,137	25,042
Chemicals	2,921	40	3,070	3,737	109	4,226	3,216	122	3,873
Total	**113,016**	**8,130**	**65,162**	**78,129**	**3,691**	**62,558**	**66,798**	**2,726**	**58,779**
TotalFinaElf									
Upstream	23,991	9,304	21,586	13,044	3,789	19,774	11,119	1,920	15,985
Downstream	77,871	2,892	7,208	48,002	962	7,640	36,802	1,157	7,629
Chemicals	19,546	1,497	5,574	16,102	1,094	5,187	15,030	1,243	4,811
Total	**121,408**	**13,693**	**34,368**	**77,148**	**5,846**	**32,601**	**62,951**	**4,320**	**28,424**

Source: Company annual reports.

[a]For comparability, gas, power, and energy services information is contained in the downstream numbers. Nonoperating, corporate, and miscellaneous business financials are not included. ExxonMobil, BP, and TotalFinaElf report net fixed assets by business segment. Royal Dutch Shell and ChevronTexaco report total segment assets. BP and TotalFinaElf report operating income by business unit. All others are net income. Revenue numbers include sales between businesses. TotalFinaElf reports in euros. Numbers were converted to U.S. dollars.

[b]ChevronTexaco numbers sum totals from individual company annual reports.

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