CONOCOPHILLIPS
Form 10-K
March 02, 2004

2003

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

(Mark One)	
[x]	ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended **December 31, 2003**

OR

[ ]	TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from ____________ to ____________

Commission file number 000-49987

ConocoPhillips

(Exact name of registrant as specified in its charter)

Delaware	**01-0562944**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*

600 North Dairy Ashford
Houston, TX 77079
(Address of principal executive offices)

Registrant s telephone number, including area code: **281-293-1000**

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	**Name of each exchange on which registered**
Common Stock, $.01 Par Value	New York Stock Exchange
Preferred Share Purchase Rights Expiring June 30, 2012	New York Stock Exchange
6.375% Notes due 2009	New York Stock Exchange
6.65% Debentures due July 15, 2018	New York Stock Exchange
7% Debentures due 2029	New York Stock Exchange
7.125% Debentures due March 15, 2028	New York Stock Exchange
9 3/8% Notes due 2011	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes _X_ No ___

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [X]

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). Yes _X_ No ___

The aggregate market value of common stock held by non-affiliates of the registrant on June 30, 2003, the last business day of the registrant s most recently completed second fiscal quarter, based on the closing price on that date of $54.80, was $37.2 billion. The registrant, solely for the purpose of this required presentation, had deemed its Board of Directors and the Compensation and Benefits Trust to be affiliates, and deducted their stockholdings of 369,905 and 26,035,094 shares, respectively, in determining the aggregate market value.

The registrant had 684,182,093 shares of common stock outstanding at January 31, 2004.

Documents incorporated by reference:
Portions of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 5, 2004 (Part III)

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PART I

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PART I

Unless otherwise indicated, the company, we, our, us, and ConocoPhillips are used in this report to refer to the businesses of ConocoPhillips and its consolidated subsidiaries. Conoco and Phillips are used in this report to refer to the individual companies prior to the merger date of August 30, 2002. Items 1 and 2, Business and Properties, contain forward-looking statements including, without limitation, statements relating to the company s plans, strategies, objectives, expectations, intentions, and resources, that are made pursuant to the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. The words forecasts, intends, believes, expects, plans, scheduled, anticipates, estimates, and similar expressions identify forward-looking statements. The company does not undertake to update, revise or correct any of the forward-looking information. Readers are cautioned that such forward-looking statements should be read in conjunction with the company s disclosures under the heading: CAUTIONARY STATEMENT FOR THE PURPOSES OF THE SAFE HARBOR PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995, beginning on page 83.

Items 1 and 2. BUSINESS AND PROPERTIES

CORPORATE STRUCTURE

ConocoPhillips is a major, integrated, global energy company. ConocoPhillips was incorporated in the state of Delaware on November 16, 2001, in connection with, and in anticipation of, the merger between Conoco Inc. (Conoco) and Phillips Petroleum Company (Phillips). The merger between Conoco and Phillips (the merger) was consummated on August 30, 2002, at which time Conoco and Phillips combined their businesses by merging with separate acquisition subsidiaries of ConocoPhillips. As a result of the merger, Conoco and Phillips each became wholly owned subsidiaries of ConocoPhillips. For accounting purposes, Phillips was designated as the acquirer of Conoco and ConocoPhillips was treated as the successor of Phillips. Accordingly, Phillips operations and results are presented in this Form 10-K for all periods prior to the close of the merger. From the merger date forward, the operations and results of ConocoPhillips reflect the combined operations of the two companies. Subsequent to the merger, Conoco was renamed ConocoPhillips Holding Company, and Phillips was renamed ConocoPhillips Company, but for ease of reference, those companies will be referred to respectively in this document as Conoco and Phillips.

Our business is organized into five operating segments:

1) Exploration and Production (E&P) This segment primarily explores for and produces crude oil, natural gas, and natural gas liquids on a worldwide basis.

2) Midstream Through both consolidated and equity interests, this segment gathers and processes natural gas produced by ConocoPhillips and others, and fractionates and markets natural gas liquids, primarily in the United States, Canada and Trinidad. The Midstream segment includes our 30.3 percent equity investment in Duke Energy Field Services, LLC, a joint venture with Duke Energy.

3) Refining and Marketing (R&M) This segment refines, markets and transports crude oil and petroleum products, mainly in the United States, Europe and Asia.

4) Chemicals This segment manufactures and markets petrochemicals and plastics on a worldwide basis. The Chemicals segment consists of our 50 percent equity investment in Chevron Phillips Chemical Company LLC, a joint venture with ChevronTexaco Corporation.

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5) Emerging Businesses This segment encompasses the development of new businesses beyond our traditional operations. Emerging Businesses includes new technologies related to natural gas conversion into clean fuels and related products (gas-to-liquids), technology solutions, power generation, and emerging technologies.

At December 31, 2003, ConocoPhillips employed approximately 39,000 people.

SEGMENT AND GEOGRAPHIC INFORMATION

For operating segment information and geographic information, see Note 28 Segment Disclosures and Related Information in the Notes to Consolidated Financial Statements, which is incorporated herein by reference.

EXPLORATION AND PRODUCTION (E&P)

This segment explores for and produces crude oil, natural gas, and natural gas liquids on a worldwide basis. It also mines deposits of oil sands in Canada to extract the bitumen and upgrade it into a synthetic crude oil. At December 31, 2003, our E&P operations were producing in the United States, the Norwegian and U.K. sectors of the North Sea, Canada, Nigeria, Venezuela, offshore Timor Lesté in the Timor Sea, offshore Australia, offshore China, offshore the United Arab Emirates, offshore Vietnam, Russia, and Indonesia.

The information listed below appears in the supplemental oil and gas operations disclosures on pages 154 through 172 and is incorporated herein by reference:

- Proved worldwide crude oil, natural gas and natural gas liquids reserves;
- Net production of crude oil, natural gas and natural gas liquids;
- Average sales prices of crude oil, natural gas and natural gas liquids;
- Average production costs per barrel-of-oil-equivalent;
- Net wells completed, wells in progress, and productive wells; and
- Developed and undeveloped acreage.

In 2003, our worldwide production, including our share of equity affiliates production, averaged 1,590,000 barrels-of-oil-equivalent (BOE) per day, a 49 percent increase from 1,069,000 BOE per day in 2002. During 2003, 674,000 BOE per day were produced in the United States, a 15 percent increase from 587,000 BOE per day in 2002. Production from our international E&P operations averaged 916,000 BOE per day in 2003, up 90 percent from 482,000 BOE per day in 2002. In addition, our Canadian Syncrude mining operations had net production of 19,000 barrels per day in 2003, compared with 8,000 barrels per day in 2002. The increased production mainly reflects the impact of the merger. We convert our natural gas production to BOE based on a 6:1 ratio: six thousand cubic feet of natural gas equals one barrel-of-oil-equivalent.

Our worldwide annual average crude oil sales price increased 14 percent in 2003, from $24.07 per barrel to $27.47 per barrel. Our annual average worldwide natural gas sales price also increased, going from $2.77 per thousand cubic feet in 2002 to $4.07 per thousand cubic feet in 2003.

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Finding and development costs in 2003 were $5.35 per barrel-of-oil-equivalent, compared with $5.57 in 2002. Over the last five years, our finding and development costs averaged $4.29 per barrel-of-oil-equivalent. Finding and development costs per barrel-of-oil-equivalent is calculated by dividing the net reserve change for the period (excluding production and sales) into the costs incurred for the period, as reported in the Costs Incurred disclosure required by Statement of Financial Accounting Standards No. 69, Disclosures about Oil and Gas Producing Activities.

At December 31, 2003, ConocoPhillips, including its share of equity affiliates, held a combined 52.6 million net developed and undeveloped acres, compared with 101.9 million net acres at year-end 2002. The decrease in acreage primarily reflects the removal of acreage in Somalia, where operations had been suspended by declarations of force majeure. At year-end 2003, we held acreage in 25 countries.

E&P U.S. OPERATIONS

In 2003, U.S. E&P operations contributed 43 percent of our worldwide liquids production and 42 percent of our worldwide natural gas production. Our U.S. E&P operations are managed in two divisions: Alaska and the Lower 48 States.

Alaska

We are a major producer of crude oil on Alaska s North Slope, and we produce natural gas in the Cook Inlet. A brief summary of our major Alaska producing fields, transportation infrastructure, and exploration activities follows.

Greater Prudhoe Area

The Greater Prudhoe Area is comprised of the Prudhoe Bay field and satellites, as well as the Greater Point McIntyre Area fields. We have a 36.1 percent interest in all fields within the Greater Prudhoe Area, all of which are operated by BP p.l.c. (BP).

The Prudhoe Bay field is the largest oil field on Alaska s North Slope. It is the site of a large waterflood and enhanced oil recovery project, as well as a gas processing plant that processes and reinjects natural gas back into the reservoir. Our net crude oil production from the Prudhoe Bay field averaged 121,500 barrels per day in 2003, compared with 130,800 barrels per day in 2002, while natural gas liquids production averaged 23,000 barrels per day in 2003, compared with 24,100 barrels per day in 2002. Normal field declines were the main cause of the lower production rates in 2003.

Prudhoe Bay satellite fields Aurora, Borealis, Polaris, Midnight Sun, and Orion produced 16,200 net barrels per day of crude oil in 2003, compared with 12,700 net barrels per day in 2002. Borealis contributed the biggest share in 2003, producing 10,300 net barrels per day. All Prudhoe Bay satellite fields are produced through Prudhoe Bay production facilities. Development options and plans are being studied for other potential Prudhoe Bay satellites.

The Greater Point McIntyre Area (GPMA) is made up of the Point McIntyre, Niakuk, Lisburne, West Beach, and North Prudhoe Bay State fields. The fields within the GPMA are generally produced through the Lisburne Production Center. Net crude oil production for GPMA averaged 18,200 barrels per day in 2003, compared with 19,800 barrels per day in 2002. The bulk of this production came from the Point McIntyre field, which is approximately seven miles north of the Prudhoe Bay field and extends into the Beaufort Sea.

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Greater Kuparuk Area
We operate the Greater Kuparuk Area, which is comprised of the Kuparuk field and four satellite fields: Tarn, Tabasco, Meltwater, and West Sak. Our ownership interest is 55.2 percent in the Kuparuk field, which is located about 40 miles west of Prudhoe Bay. Field installations include three central production facilities that separate oil, natural gas and water. The natural gas is either used for fuel or compressed for reinjection. Our net crude oil production from the Kuparuk field averaged 78,600 barrels per day in 2003, compared with 79,000 barrels per day in 2002. Natural production declines from Kuparuk were offset by an average of 8,000 barrels per day of production from the Palm discovery that extended the Kuparuk field to the west about three miles. Development of the Palm discovery included the construction of a new drill site and the drilling of 17 wells. Palm production began in November 2002.

Other fields in the Greater Kuparuk Area produced 21,800 net barrels per day of crude oil in 2003, primarily from the Tarn, Tabasco, and Meltwater satellites. We have a 55.3 percent interest in Tarn and Tabasco and a 55.4 percent interest in Meltwater.

The Greater Kuparuk Area also includes the West Sak heavy-oil field. Annual production rates increased from 3,300 net barrels per day in 2002 to 3,800 net barrels per day in 2003. Progress was made in 2003 towards proving concepts necessary for full-scale development of this field. Eight wells were drilled during the year, increasing production from 3,300 net barrels per day in the month of December 2002 to 5,000 net barrels per day in the month of December 2003. We have a 55.3 percent interest in this field.

Western North Slope
The Alpine field, located west of the Kuparuk field, began production in November 2000. In 2003, the field produced at a net rate of 64,500 barrels of oil per day, compared with 63,400 barrels per day in 2002. We are the operator and hold a 78 percent interest in Alpine.

In May 2003, we announced plans to increase produced water and natural gas handling capacities at our Alpine production facilities. Although we inject seawater into the Alpine reservoir as a means of enhanced oil recovery, most production has been almost 100 percent oil. Eventually, the injected water and natural gas will start to break through into the producing wells, requiring an increase in the amount of produced water and natural gas that needs to be handled. The increase in water and natural gas handling capacities should allow crude oil production to remain at or slightly above current production rates for a longer period of time than could otherwise have been achieved. Startup of the expanded facilities is planned to commence by the end of 2004.

In January 2003, ConocoPhillips and the U.S. Department of Interior Bureau of Land Management signed a Memorandum of Understanding that provides for completion of an Environmental Impact Statement (EIS) for five prospective Alpine satellites: Fiord, Nanuq, Lookout, Spark, and Alpine West, as well as future potential developments in the northeast corner of the National Petroleum Reserve-Alaska (NPR-A) and near the Alpine oil field. A final decision to move forward on these projects will be made after the EIS is completed, currently expected in second half of 2004, and the appropriate permits have been granted.

Cook Inlet
Our assets in Alaska include the North Cook Inlet field, the Beluga River natural gas field, and the Kenai liquefied natural gas facility.

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We have a 100 percent interest in the North Cook Inlet field. Net production in 2003 averaged 112 million cubic feet per day, compared with 125 million cubic feet per day in 2002. All of the production from the North Cook Inlet field is used to supply our share of gas to the Kenai liquefied natural gas plant. The decline in production in 2003 was the result of well problems. Well work completed in late 2003 and planned for 2004 is expected to improve production.

Our interest in the Beluga River field is 33 percent. Net production averaged 63 million cubic feet per day in 2003, compared with 41 million cubic feet per day in 2002. Gas from the Beluga River field is sold to local utilities, industrial consumers, and used as back-up supply to the Kenai liquefied natural gas plant.

We have a 70 percent interest in the Kenai liquefied natural gas plant, which supplies liquefied natural gas to two utility companies in Japan. Utilizing two ships, the company transports the liquefied natural gas to Japan, where it is reconverted to dry gas at the receiving terminal. We sold 44.0 billion cubic feet of liquefied natural gas to Japan in 2003, compared with 44.4 billion cubic feet in 2002.

Exploration

We drilled or participated in three exploratory wells during 2003, on locations near Alpine, the NPR-A and the Cook Inlet. Two of these wells are pending further appraisal, and one was a dry hole. We plan to drill or participate in four exploration wells in Alaska during 2004.

Transportation

We transport the petroleum liquids we produce on the North Slope to market through the Trans-Alaska Pipeline System (TAPS), an 800-mile pipeline, marine terminal, spill response and escort vessel system that ties the North Slope of Alaska to the port of Valdez in south-central Alaska.

In 2001, ConocoPhillips and the five other owners of TAPS completed and filed state and federal applications for renewal of the pipeline s right-of-way permit through 2034. The State of Alaska approved the 30-year right-of-way renewal in November 2002 and U.S. federal approval was received in January 2003.

Regulatory approval was received in early 2003 for us to purchase an additional 1.5 percent interest in TAPS from Amerada Hess Corporation, thereby increasing our ownership in TAPS to 28.3 percent. The purchase was effective January 24, 2003. We also have ownership interests in the Alpine, Kuparuk and Oliktok pipelines on the North Slope.

We continue to evaluate a gas pipeline project to deliver natural gas from Alaska s North Slope to the Lower 48. Given the size of the project and risk associated with it, we continue to believe that risk mitigation mechanisms and improvements in project economics are necessary before this project can proceed. Activities in 2003 included promoting state and federal legislation that would lower the economic risk of the project.

Our wholly owned subsidiary, Polar Tankers Inc., manages the marine transportation of our Alaska North Slope production. Polar Tankers is based in Long Beach, California, and operates six ships in the Alaskan trade, chartering additional third-party-operated vessels as necessary. In 2001, Polar Tankers brought the *Polar Endeavour* into service; the *Polar Resolution* was brought into service in 2002; and the *Polar Discovery* was brought into service in 2003. These 125,000 deadweight-ton, double-hulled crude oil tankers are the first three of five Endeavour Class tankers that we plan to add to our Alaska-trade fleet. The fourth and fifth tankers are scheduled to enter the fleet in 2004 and 2005, respectively.

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Lower 48 States

Our operations in the Lower 48 States are principally located in the following areas:

Offshore: Gulf of Mexico

Onshore: various trends in Texas, New Mexico, Oklahoma, Louisiana, Utah, Colorado, and Wyoming

Gulf of Mexico

Our current portfolio of producing properties in the Gulf of Mexico includes three fields operated by us and six fields operated by other companies. The number of fields declined in 2003 with the divestiture of properties as part of our portfolio rationalization program. At December 31, 2003, we had 22 leases in production or under development in the deepwater Gulf of Mexico.

We hold a 16 percent interest in the co-venturer-operated Ursa field. The Ursa tension-leg platform was installed in late 1998 in approximately 3,900 feet of water, with first production occurring in March 1999. Our net production in 2003 averaged 13,300 barrels per day of liquids and 13 million cubic feet per day of natural gas.

The Princess field is a northern, subsalt extension of the Ursa field. It was discovered in 2000, with first production beginning in late 2002 from an extended-reach well from the Ursa platform. A three-well subsea tieback to the Ursa platform was completed in 2003. Our net production in 2003 averaged 2,600 barrels per day of liquids and 7.3 million cubic feet per day of natural gas. We hold a 16 percent interest in Princess.

We operate and hold a 75 percent interest in the Garden Banks 783 and 784 leases which contain the Magnolia field discovered in 1999. Installation of a tension-leg platform, to be located in almost 4,700 feet of water, is expected in mid-2004, with first oil scheduled for late 2004. Peak production of 49,000 net barrels-of-oil-equivalent per day is expected in 2005 from proved reserves.

We have a 16.8 percent interest in the K2 discovery. K2, located in Green Canyon Block 562, was discovered in 1999, with appraisal drilling continuing in 2003. A development option under consideration would utilize a subsea tieback to a nearby third-party platform. Project sanctioning is expected in the first quarter of 2004.

In July 2003, we announced a discovery with the Lorien well in Green Canyon Block 199. The well was drilled in 2,177 feet of water and encountered more than 120 feet of hydrocarbons. The well has been suspended pending further appraisal of the hydrocarbon zone. We are the operator with a 65 percent interest.

During 2003, two deepwater exploratory wells did not encounter commercial quantities of hydrocarbons: the Voss well in Keathley Canyon Block 511 and the Yorick well in Green Canyon Block 435.

Onshore

Our onshore Lower 48 production is primarily natural gas, with the majority of the production located in the Lobo Trend in south Texas, the San Juan Basin of New Mexico, and the Guymon-Hugoton Trend in the panhandles of Texas and Oklahoma. We also have oil and natural gas production from the Permian Basin in West Texas and Southeast New Mexico. Other positions and production are maintained in other parts of Texas and Oklahoma, the Arkansas/Louisiana/Texas area, and onshore Gulf Coast area. In addition, we hold coalbed methane acreage positions in the Powder River Basin in Wyoming, the Uinta Basin in Utah, and the Black Warrior Basin in Alabama.

Activities in 2003 primarily were centered on continued optimization and development of these mature assets. Combined production from Lower 48 onshore fields in 2003 averaged a net 1,237 million cubic feet per day of natural gas and 57,000 barrels per day of liquids.

E&P NORTHWEST EUROPE

In 2003, E&P operations in Northwest Europe contributed 30 percent of our worldwide liquids production and 34 percent of our worldwide natural gas production. Our Northwest Europe assets are principally located in the Norwegian and U.K. sectors of the North Sea.

Norway

The Ekofisk Area is located approximately 200 miles offshore Norway in the center of the North Sea. The Ekofisk Area is comprised of four producing fields: Ekofisk, Eldfisk, Embla, and Tor. Ekofisk serves as a hub for petroleum operations in the area, with surrounding developments utilizing the Ekofisk infrastructure. Net production in 2003 from the Ekofisk Area was 126,500 barrels of liquids per day and 127 million cubic feet of natural gas per day, compared with 127,000 barrels of liquids per day and 133 million cubic feet of natural gas per day in 2002. We are operator and hold a 35.1 percent interest in Ekofisk.

In 2003, we and our co-venturers approved a plan for further development of the Ekofisk Area. The project consists of two interrelated components. A new platform, Ekofisk 2/4M, is anticipated to have 30 well slots, a high-pressure separator and equipment for produced water treatment. The project also includes modification on the existing Ekofisk Complex to increase process capacity. Construction began in 2003 and production from the new platform is projected to begin in the fall of 2005.

We also have ownership interests in other producing fields in the Norwegian North Sea, including a 24.3 percent interest in the Heidrun field, a 10.3 percent interest in the Statfjord field, a 23.3 percent interest in the Huldra field, a 1.6 percent interest in the Troll field, a 9.1 percent interest in the Visund field, and a 2.4 percent interest in the Oseberg area. Production from these and other fields in the Norwegian sector of the North Sea and the Norwegian Sea averaged a net 93,300 barrels of liquids per day and 149 million cubic feet of natural gas per day in 2003.

In September 2003, production began from the Grane field, in which we have a 6.4 percent interest. Peak production from this field is expected in 2005, and is anticipated to be approximately 14,000 net barrels per day from proved reserves.

We also have interests in certain of the transportation and processing infrastructure of the Norwegian North Sea, including a 35.1 percent interest in the Norpipe Oil Pipeline System, a 2.3 percent interest in Gassled, which owns most of the Norwegian gas transportation system, and a 1.6 percent interest in the southern part of the planned Langeled gas pipeline.

United Kingdom

We are the largest owner in, and the joint operator of, the Britannia natural gas/condensate field, in which we have a 58.7 percent interest. Our net production from Britannia averaged 391 million cubic feet of natural gas per day and 14,500 barrels of liquids per day in 2003. Oil and gas production from Britannia is delivered by pipeline to Scotland. Development drilling on Britannia is expected to continue into the year 2006.

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In December 2003, we approved a plan for the development of the Callanish and Brodgar fields. These new Britannia satellite development projects will be tied back to the Britannia facility, with first production targeted for 2007. The development plan has been submitted for government approval. We have a 75 percent interest in the Brodgar field and an 83.5 percent interest in the Callanish field.

We operate and hold a 36.5 percent interest in the Judy/Joanne fields, which together comprise J-Block. Additionally, the Jade field began production in the first quarter of 2002 from a wellhead platform and pipeline tied to the J-Block facilities. We are the operator of and hold a 32.5 percent interest in Jade. Together, these fields produced a net 18,100 barrels of liquids per day and 118 million cubic feet of natural gas per day in 2003.

ConocoPhillips continues to supply gas from J-Block to Enron Capital and Trade Resources Limited (Enron Capital), which was placed in Administration in the United Kingdom on November 29, 2001. ConocoPhillips has been paid all amounts currently due and payable by Enron Capital in respect of the J-Block gas sales agreement, including outstanding amounts due for the period prior to the appointment of the Administrator. We believe that Enron Capital will continue to pay the amounts due for gas supplied by us in accordance with the terms of the gas sales agreement. We do not currently expect that we will have to curtail sales of gas under the gas sales agreement or shut in production as a result of the Administration of Enron Capital. However, in the event that the arrangements for the processing of Enron Capital s gas are terminated or Enron Capital goes into liquidation, there may be additional risk of production being reduced or shut-in.

We have various ownership interests in 13 producing gas fields in the southern North Sea, in the Rotliegendes and Carboniferous areas. These fields mostly feed into the ConocoPhillips-operated Theddlethorpe gas processing facility through three ConocoPhillips-operated pipeline systems. Net production in 2003 averaged 371 million cubic feet per day of natural gas and 2,000 barrels of liquids per day.

During 2003 we continued the development of the CMS3 area in the southern sector of the U.K. North Sea, which consists of five natural gas reservoirs currently being developed by us as a single, unitized project. The McAdam and Watt fields were brought onstream in 2003, following the Hawksley and Murdoch K fields in 2002. Drilling operations on the final reservoir, Boulton H, are ongoing into 2004. Collectively, these fields are known as CMS3 due to their utilization of the production and transportation facilities of the ConocoPhillips-operated Caister Murdoch System (CMS). We are the operator of CMS3 and hold a 59.5 percent interest.

We also have ownership interests in several other producing fields in the U.K. North Sea, including a 23.4 percent interest in the Alba field, a 40 percent interest in the MacCulloch field, an 11.5 percent interest in the Armada field, and a 4.8 percent interest in the Statfjord field. Production from these and the other remaining fields in the U.K. sector of the North Sea averaged a net 44,500 barrels of liquids per day and 61 million cubic feet of natural gas per day in 2003.

We have a 24 percent interest in the Clair field development in the Atlantic Margin. The Clair development is comprised of a conventional steel jacket structure with minimum manned facilities topside. First production from Clair is targeted for late 2004.

The Interconnector pipeline, which connects the United Kingdom and Belgium, facilitates the marketing throughout Europe of the natural gas we produce in the United Kingdom. Our 10 percent equity share of the Interconnector pipeline allows us to ship approximately 200 million cubic feet of natural gas per day to markets in continental Europe. We have multi-year contracts to supply natural gas to Gasunie in the Netherlands and Wingas in Germany.

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Exploration

In Norway, we drilled or participated in six exploratory and appraisal wells during 2003 in the deepwater Voring and More basins, the South Viking Graben and the Central Graben. Of the six wells, three are moving forward with development plans or pending further evaluation, and three were considered non-commercial discoveries or dry holes. Four partner-operated exploration wells are planned for 2004. One is a deepwater prospect in PL 283, and the other three are near-field exploration wells in the Heidrun and Visund licenses.

In the U.K. sector of the North Sea, we drilled or participated in four exploratory and appraisal wells during 2003 in the southern North Sea, the central North Sea near the Jade and Britannia fields, and the West of Shetland deepwater area. Of the four wells, two are moving forward with development plans and two were dry holes. We plan to participate in three exploratory wells in 2004, including two wells in the southern North Sea and one on a structure adjacent to the Callanish field.

E&P CANADA

In 2003, E&P operations in Canada contributed 5 percent of our worldwide liquids production and 13 percent of our worldwide natural gas production, excluding Syncrude production.

Conventional Oil and Gas Operations

Operations in western Canada encompass properties in Alberta, northeastern British Columbia and southwestern Saskatchewan. We separate our holdings in western Canada into four geographic regions. The north region contains a mix of oil and natural gas, and primarily is winter access. The central and west regions produce mainly natural gas. The south region has shallow gas and medium-to-heavy oil. Production from conventional oil and gas operations in western Canada averaged a net 40,500 barrels per day of liquids and 435 million cubic feet per day of natural gas in 2003.

We are working with three other energy companies, as members of the Mackenzie Delta Producers Group (Group), on the development of the Mackenzie Valley pipeline, which is proposed to transport onshore gas production from the Mackenzie Delta in northern Canada to existing markets. Initial design capacity for the Mackenzie Valley pipeline is proposed to be 1,200 million cubic feet per day, but capacity would be expandable with additional compression. We would hold a 16 percent interest in the pipeline and a 75 percent interest in the development of the Parsons Lake gas field. The Parsons Lake gas field would be one of the three primary fields in the Mackenzie Delta that would anchor the pipeline development. Conceptual engineering commenced in April 2002. Regulatory applications for the project are expected to be submitted in mid-2004 and first gas production is currently targeted for late 2009.

We owned a 46.7 percent interest in Petrovera, a joint venture that combined a substantial portion of our Canadian heavy-oil assets and certain associated natural gas assets. The asset base of the joint venture was located mainly in southwestern Saskatchewan. Net production in 2003 was 15,300 barrels of petroleum liquids per day, and was included in equity affiliate production. On February 18, 2004, we sold our interest in the joint venture.

Exploration

We hold exploration acreage in three areas of Canada: offshore eastern Canada, the foothills of western Alberta, and the Mackenzie Delta/Beaufort Sea. In eastern Canada, we hold a 20 percent interest in deepwater Nova Scotia, EL 2359. After participating in the Newburn well in 2002, we are waiting on the results from drilling in adjacent blocks. In deepwater Newfoundland, we are working to convert our large Laurentian permit into specific exploration licenses. We hope to complete this in 2004 and expect to

acquire seismic in 2005. In the foothills, two out of three exploratory wells drilled in 2003 were successful. In the Mackenzie Delta/Beaufort Sea, we began drilling a well in early 2004.

Other Canadian Operations
We have two oil sands projects in Canada: Syncrude Canada Ltd. and Surmont.

Syncrude Canada Ltd.
We own a 9.03 percent undivided interest in Syncrude Canada Ltd., a joint venture created by a number of energy companies for the purpose of mining shallow deposits of oil sands, extracting the bitumen, and upgrading it into a light sweet crude oil called Syncrude. The primary plant and facilities are located at Mildred Lake, about 25 miles north of Fort McMurray, Alberta, together with an auxiliary mining and extraction facility approximately 20 miles from the Mildred Lake plant. Syncrude Canada Ltd. holds eight oil sands leases and the associated surface rights, of which our share is approximately 23,000 net acres. Our net share of production averaged 19,000 barrels per day in 2003.

We continued with development of the Stage III expansion-mining project in 2003, which is expected to increase our Syncrude production. The Aurora Train 2 project (the new mine) was completed and started up in the fourth quarter of 2003. The expansion project is expected to bring various units onstream during 2004, while the completion of a new coker to service the expanded project is anticipated in the second half of 2005.

The U.S. Securities and Exchange Commission s regulations define this project as mining-related and not part of conventional oil and gas operations. As such, Syncrude operations are not included in our proved oil and gas reserves or production as reported in the supplemental oil and gas information.

Surmont
The Surmont lease is located about 35 miles south of Fort McMurray, Alberta. We own a 43.5 percent interest and are the operator. The project will use a method called steam assisted gravity drainage, that involves the injection of steam deep into the oil sands, effectively melting the bitumen, which is then recovered and pumped to the surface for further processing. In May 2003, we received regulatory approval to develop the oil sands from the Alberta Energy and Utilities Board, and in late 2003 our Board of Directors approved the project. Construction of the facilities is expected to begin in early 2004, with first oil production scheduled for 2006.

E&P SOUTH AMERICA

In 2003, E&P operations in South America were comprised of interests in Venezuela, Ecuador and Brazil. South American operations contributed 8 percent of our worldwide liquids production in 2003.

Venezuela

We operate and have an interest in two heavy-oil projects in Venezuela: Petrozuata and Hamaca. We also have an interest in and operate in the Gulf of Paria, which contains the Corocoro conventional oil and gas discovery as well as exploration opportunities. In addition, we have an interest in Plataforma Deltana Block 2, a large natural gas discovery.

In December of 2002, civil unrest in Venezuela caused economic and other disruptions that shut down most oil and gas operations in Venezuela, including the company s Petrozuata and Hamaca operations. Production from these operations resumed in the first quarter of 2003.

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Petrozuata

Petrozuata is a Venezuelan Corporation formed under a 35-year Association Agreement between a wholly owned subsidiary of ConocoPhillips that has a 50.1 percent non-controlling equity interest and PDVSA Petroleo, a subsidiary of Petroleos de Venezuela S.A. (PDVSA), the national oil company of Venezuela.

The project is an integrated operation that produces extra-heavy crude oil from reserves in the Zuata region of the Orinoco Oil Belt, transports it to the Jose industrial complex on the north coast of Venezuela, and upgrades it into medium-grade crude oil. Associated by-products produced are liquefied petroleum gas, sulfur, petroleum coke and heavy gas oil. The medium-grade crude oil produced by Petrozuata is used as a feedstock for our Lake Charles, Louisiana, refinery and the Cardon refinery in Venezuela operated by PDVSA. Our net production was 51,600 barrels of heavy crude oil per day in 2003, and is included in equity affiliate production.

We entered into an agreement to purchase up to 104,000 barrels per day of the Petrozuata upgraded crude oil for a market-based formula price over the term of the joint venture in the event that Petrozuata is unable to sell the production for higher prices. All upgraded crude oil sales are denominated in U.S. dollars. By-products produced by the upgrading facility are sold to a variety of domestic and foreign purchasers. The loading facilities at Jose transfer crude oil and some of the by-products to ocean vessels for export.

Hamaca

The Hamaca project also involves the development of heavy-oil reserves from the Orinoco Oil Belt. ConocoPhillips owns a 40 percent interest in the Hamaca project, which is operated by Petrolera Ameriven on behalf of the owners. The other participants in Hamaca are PDVSA and ChevronTexaco Corporation. Our interest is held through a joint limited liability company, Hamaca Holding LLC, for which we use the equity method of accounting.

Net production averaged 22,100 barrels per day of heavy crude oil in 2003, and is included in equity affiliate production. The joint-venture agreement has a 35-year term.

Construction of the heavy-oil upgrader, pipelines and associated production facilities at the Jose industrial complex began in 2000. The upgrader is expected to begin producing commercial quantities of medium-grade crude oil by the end of 2004, at which time our net production from the Hamaca field is expected to increase to approximately 71,000 barrels per day from proved reserves.

Gulf of Paria

In 1999 the Corocoro discovery in the Gulf of Paria West Block was made and later confirmed with appraisal drilling in 2001 and 2002. In 2003, Venezuelan authorities approved Phase I of the development plan for the Corocoro field. We operate the field with a 32.2 percent interest. In accordance with the profit sharing agreement that governs the block, a subsidiary of PDVSA elected to acquire a 35 percent interest in the development, lowering our interest from 50 percent to 32.5 percent. In September 2003, we acquired a 37.5 percent interest in the adjoining Gulf of Paria East Block, onto which a portion of the Corocoro discovery extends.

Plataforma Deltana Block 2

We acquired a 40 percent interest in Plataforma Deltana Block 2 in 2003. The block is co-venturer-operated and holds a gas discovery made by PDVSA in 1983. Appraisal wells are planned in 2004. Contingent on the results of the appraisal wells, development of the field may include a well platform in approximately 300 feet of water, a 170-mile pipeline to shore, and a liquefied natural gas plant. The liquefied natural gas would be shipped to the U.S. market.

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Brazil
We have concession agreements on two deepwater exploration blocks (BM-ES-11 and BM-PAMA-3) offshore Brazil. These blocks were acquired in Brazil s third bid round held in June 2001. We entered into joint ventures on both blocks in late 2002, reducing our interest to 70 percent in BM-ES-11 and 65 percent in BM-PAMA-3. In 2003, further evaluation led to the write-off of our leasehold investment in BM-ES-11, and we initiated the process to exit the block. Further evaluation of BM-PAMA-3 is planned for 2004.

Ecuador
We sold our 14 percent, non-operator interest in Block 16 and the associated fields on December 5, 2003, with an effective date of January 1, 2003. We have no other assets in Ecuador, and have exited the country.

E&P ASIA PACIFIC

In 2003, E&P operations in the Asia Pacific area contributed 6 percent of our worldwide liquids production and 9 percent of our worldwide natural gas production.

China
Our combined net production of crude oil from the Xijiang facilities averaged 10,900 barrels per day in 2003. The Xijiang development consists of three fields located approximately 80 miles from Hong Kong in the South China Sea. The facilities include two manned platforms and a floating production, storage and offloading facility.

Production from Phase I development of the Peng Lai 19-3 field in Bohai Bay Block 11-05 began in late December 2002. In 2003, the field produced 14,800 net barrels of oil per day. We have a 49 percent interest, with the remainder held by the China National Offshore Oil Corporation. The Phase I development utilizes one wellhead platform and a floating production, storage and offloading facility.

We continue to move forward with the design for Phase II of the Peng Lai 19-3 development. Phase II would include multiple wellhead platforms, and a larger floating production, storage and offloading facility. The Peng Lai 25-6 field, discovered in 2000 and located three miles east of Peng Lai 19-3, will be developed in conjunction with Phase II of the Peng Lai 19-3 development project.

Exploration activity continued in 2003 in Block 11-05, with two successful wells announced. The Peng Lai 19-9-1 well, located about two miles east of the Peng Lai 19-3 field, discovered the Peng Lai 19-9 field that will be part of the Phase II development. Drilling of the Peng Lai 13-1-1 well, located about 18 miles north of the Peng Lai 19-3 field, was completed in March 2003.

Indonesia
We operate nine Production Sharing Contracts (PSCs) in Indonesia and have a non-operator interest in four others. Our assets are concentrated in two core areas: the West Natuna Sea and South Sumatra; with a potentially emerging area offshore East Java. We are a party to five long-term U.S. dollar pipeline gas contracts that have been signed in Indonesia. Production of natural gas from Indonesia averaged a net 255 million cubic feet per day in 2003, while production of crude oil averaged a net 16,000 barrels per day.

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Offshore Assets
We operate three offshore PSCs: 1) South Natuna Sea Block B, 2) Nila, and 3) Ketapang. We also hold a non-operator interest in the Pangkah PSC offshore East Java. We participate in various natural gas marketing arrangements in connection with these assets, including being a co-venturer in the West Natuna Gas Supply Group (WNG). The WNG jointly markets natural gas from certain fields in three South Natuna Sea PSCs to Singapore.

The Kakap PSC, adjacent to the South Natuna Sea Block B, was sold in September 2003. The property was selected for disposition because of its high operating cost structure and limited further exploration potential. In addition, during 2003 we relinquished the Tobong PSC and sold the Sebuku PSC after concluding that neither PSC had significant remaining exploration potential.

The South Natuna Sea Block B PSC has two currently producing mature oil fields and 15 gas fields (some with recoverable oil volumes) in various phases of development. The largest current development in Block B is the Belanak oil and gas field, in which a floating production, storage and offloading vessel is under construction. The vessel is expected to be completed, and oil production to commence, in the first half of 2005. Two additional developments that would produce into the Belanak infrastructure are scheduled for startup in 2006 and 2008.

We also have an active exploration program in both the Natuna Sea and East Java. During 2003, two unsuccessful exploratory wells were drilled in the Natuna Sea Nila Block. An additional well in the Nila Block is planned for 2004. During 2003, in the East Java offshore Ketapang Block, two appraisal wells were drilled on the Bukit Tua oil field discovery, one of which was successful, and one of which was unsuccessful. An additional appraisal well and an exploration well are planned for 2004.

Onshore Assets
We operate six onshore PSCs: 1) Corridor TAC, 2) Corridor PSC, 3) South Jambi B , 4) Sakakemang JOB (jointly operated with a co-venturer), 5) Block A PSC in Aceh, and 6) Warim. We also hold non-operator interests in the Banyumas PSC in Java and the Bentu and Korinci-Baru PSCs in Sumatra. The Tungkal PSC was sold in December 2003. As with our offshore properties, we participate in various gas marketing arrangements in connection with these fields. Exploration efforts focus on locating additional natural gas reserves.

We announced in March 2003 the successful test of the Suban-8 delineation well on the southwest flank of the Suban gas field, located in the Corridor PSC of South Sumatra. In December 2003, we began an exploratory well in the Corridor Block to test a gas prospect located close to other producing fields. We continue to appraise and develop the Suban gas field. In addition, we completed the successful test of the North Sumpal-1 well in the Sakakemang Block located in South Sumatra, and continued on the construction of the South Jambi gas project in the South Jambi B Block also located in South Sumatra.

We are a 35 percent owner of TransAsia Pipeline Company Pvt. Ltd., a consortium company, which has a 40 percent ownership in PT Transportasi Gas Indonesia, an Indonesian limited liability company, which owns and operates the Grissik to Duri gas pipeline.

Vietnam
We have a 23.25 percent interest in Block 15-1 in the Cuu Long Basin in the South China Sea. In 2001, the co-venturers in Block 15-1 declared the southwest portion of the Su Tu Den (Black Lion) field commercial after a successful appraisal program. In addition, an appraisal well in the northeast portion of Su Tu Den was successfully drilled in 2002. The Su Tu Den Phase I development project was approved in December 2001. Production from Su Tu Den Phase I began in the fourth quarter of 2003. The initial net

production rate was approximately 16,000 barrels of oil per day from seven wells located in the Phase I area. The oil is being processed and stored in a new floating production, storage and offloading vessel, which has a 1 million barrel storage capacity and can initially process up to 65,000 gross barrels per day.

An exploration discovery was also made on the nearby Su Tu Vang (Golden Lion) prospect in the third quarter of 2001. The potential commerciality of Su Tu Vang and the northeast portion of Su Tu Den are being evaluated. In addition, in the fourth quarter of 2003, a successful exploration well was drilled in the Su Tu Trang (White Lion) area (southeast area of the block).

We have a 36 percent interest in the Rang Dong field in Block 15-2 in the Cuu Long Basin. In the third quarter of 2002, production began from two new wellhead platforms in the Rang Dong field. During late 2003, field facilities were upgraded to include a utilities/living quarters platform, and a central processing platform with facilities to enable gas lift, gas export and water injection. With the completion of these facilities, water injection became possible on all three wellhead platforms and gas lift became possible on two of the wellhead platforms. A successful appraisal step-out well, Rang Dong-12X, was drilled in the central part of the field in late 2001, and a development plan for this area of the field is being evaluated.

We also own interests in offshore Blocks 16-2, 5-3, 133 and 134, as well as a 16.33 percent interest in the Nam Con Son gas pipeline.

Timor Sea and Australia

Bayu-Undan

The unitized Bayu-Undan field, located in the Timor Sea, is being developed in two phases. Phase I is a gas-recycle project, where condensate and natural gas liquids will be separated and removed and the dry gas reinjected back into the reservoir. This phase began production in February 2004, and is expected to average a net rate of 23,000 barrels of liquids per day from proved reserves in 2004.

In June 2003, we announced that the Gas Development Plan for the field had received approval from the Timor Sea Designated Authority. This final approval allowed Phase II, the development of the natural gas reserves, to proceed. Phase II will involve a natural gas pipeline from the field to Darwin, and a liquefied natural gas (LNG) facility located at Wickham Point, Darwin. In March 2002, we announced that we had signed a Heads of Agreement (LNG HOA) with The Tokyo Electric Power Company, Incorporated (TEPCO) and Tokyo Gas Co., Ltd. (Tokyo Gas). Under the LNG HOA, TEPCO and Tokyo Gas would purchase 3 million tons per year in total of LNG for a period of 17 years, utilizing natural gas from the Bayu-Undan field. The approval of the Gas Development Plan by the Timor Sea Designated Authority satisfied the remaining condition precedent necessary for the LNG HOA to have a binding effect and for the project to proceed. As a result of project approvals, we added 1.36 trillion cubic feet of net proved natural gas reserves in 2003. The first LNG cargo is scheduled for delivery in early 2006. We have a 56.7 percent controlling interest in the integrated project.

Greater Sunrise

We and our co-venturers continue to evaluate commercial development options and LNG markets in the Asia Pacific region and the North American west coast for the natural gas and condensate from the Greater Sunrise field. The development options under consideration consist of an offshore floating LNG facility and an onshore LNG facility located in Darwin, Australia. Efforts are under way to market LNG into both the Asian and North American west coast markets. Further engineering studies relating to design and development concepts also continue. We have a 30 percent, non-operator interest in Greater Sunrise.

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E&P AFRICA AND THE MIDDLE EAST

Nigeria
Our crude oil production from five leases in Nigeria averaged a net 36,900 barrels per day in 2003, while net natural gas production averaged 63 million cubic feet per day. These five leases include four onshore Oil Mining Leases (OML) and a shallow-water offshore OML. Continued development and exploratory drilling is planned for 2004 on the onshore leases.

We also have production sharing contracts on deepwater Nigeria Oil Prospecting Leases (OPLs), including OPL 318 with a 50 percent interest where we are the operator, OPL 214 with a 20 percent interest and OPL 248 with a 40 percent interest. We are planning to drill the first exploration well on OPL 248 in 2004.

We have a 20 percent interest in a 480-megawatt gas-fired power plant being constructed to supply electricity to Nigeria s national electricity supplier. When operational, the plant will consume 68 million cubic feet per day of natural gas sourced from within our Nigerian proved natural gas reserves. The plant is expected to become operational in 2005.

In October 2003, ConocoPhillips, the Nigerian National Petroleum Corporation (NNPC), Eni and ChevronTexaco signed a Heads of Agreement (HOA) to conduct front-end engineering and design work for a new LNG facility that would be constructed in Nigeria s central Niger Delta. The co-venturers have agreed to form an incorporated joint venture, to be known as Brass LNG Limited to undertake the project. The front-end engineering and design work will be for two trains, each nominally sized at 5 million metric tons per year. Natural gas supplies for the facility would come from natural gas reserves within oil and gas fields already operated by existing Nigerian Agip Oil Company and ChevronTexaco joint ventures. The front-end studies are expected to be completed in 2005, and the LNG facility is targeted to be operational in 2009.

Angola
We have a 20 percent interest in exploratory activity in deepwater Block 34, offshore Angola. The first exploration well, completed in 2002, did not encounter commercial quantities of hydrocarbons, which led to a substantial financial impairment of our investment in the block. The second exploration well, drilled in late 2003, was also unsuccessful, leading to a write-off of our remaining investment in the block.

Cameroon
In December 2002, we announced a successful test of an exploratory well offshore Cameroon. The well, located in exploration permit PH 77, offshore in the Douala Basin, obtained a maximum flow rate of 3,000 barrels of oil per day and 1.8 million cubic feet of natural gas per day during the test. Contractor interests in the permit are held 50 percent by ConocoPhillips and 50 percent by a subsidiary of Petronas Carigali (Petronas). We serve as the operator of the consortium. We are currently analyzing well results, and developing plans to evaluate the discovery and other identified exploration prospects.

Dubai
In Dubai, United Arab Emirates, we are using horizontal drilling techniques and advanced reservoir drainage technology to enhance the efficiency of the offshore production operations and improve recovery rates from four fields that we operate.

Saudi Arabia
We had a 15 percent interest in Core Venture 1 and a 30 percent interest in Core Venture 3 of the Kingdom of Saudi Arabia s natural gas initiative. Agreement could not be reached during the negotiation of the implementation agreement, leading to the termination of both projects.

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E&P RUSSIA AND CASPIAN SEA REGION

Russia

We have a 50 percent ownership interest in Polar Lights Company, a Russian limited liability company established in January 1992 to develop the Ardalin field in the Timan-Pechora basin in Northern Russia. We account for our interest using the equity method. Polar Lights started producing oil in August 1994 from the Ardalin field. In June 2002, production commenced from the Oshkotyn field, the first of three satellite fields under development. In 2003, production began from the other two satellite fields: East Kolva and Dyusushev.

Our net production from Polar Lights averaged 13,600 barrels of petroleum liquids per day in 2003, and is included in equity affiliate production.

Caspian Sea

In the North Caspian Sea, we have an 8.33 percent interest in the Republic of Kazakhstan s North Caspian Sea Production Sharing Agreement (NCPSA), which includes the Kashagan field. During 2003, we, along with four of the remaining five co-venturers, exercised our pre-emptive rights to acquire a proportionate share of BG International s sale of their 16.67 percent interest in the project. Upon Republic of Kazakhstan approval of the transaction, our interest in the NCPSA will increase to 10.19 percent.

The exploration area consists of 10.5 blocks, totaling nearly 2,000 square miles. The initial production phase of the contract is for 20 years, with options to extend the agreement an additional 20 years. In June 2002, we and the other contracting companies, in conjunction with KazMunayGas, which represents the Government of the Republic of Kazakhstan, declared the Kashagan discovery commercial. In February 2004, the Kashagan Development Plan was approved by the Republic of Kazakhstan.

The contracting companies plan to continue to explore other structures within the North Caspian Sea license. In October 2002, we and our co-venturers announced a new hydrocarbon discovery on the Kalamkas More prospect located approximately 40 miles southwest of the Kashagan field. Exploratory drilling continued in 2003 with three additional wells drilled. The Aktote #1 and the Kashagan Southwest #1 were announced as discoveries in November 2003. Operations on the Kairan #1 well were suspended for the winter period and will resume in the spring of 2004.

In the South Caspian Sea offshore Azerbaijan, we have a 20 percent interest in the Zafar Mashal prospect. The first exploratory well began in late 2003 and is planned for completion in 2004.

E&P OTHER

In July 2003, we signed a Heads of Agreement with Qatar Petroleum for the development of Qatargas 3, a large-scale liquefied natural gas (LNG) project located in Qatar and servicing the U.S. natural gas markets. The agreement provided the framework for the necessary project agreements and the completion of feasibility studies. Qatargas 3 is planned as an integrated project, jointly owned by ConocoPhillips (30 percent) and Qatar Petroleum. It would consist of the facilities to produce gas from Qatar s offshore North Field, yielding approximately 7.5 million gross tons per year of LNG from a new facility located in Ras Laffan Industrial City. The LNG would be shipped from Qatar to the United States in a fleet of new LNG carriers. We would purchase the LNG and be responsible for regasification and marketing within the United States. The project could result in sales of natural gas up to 1 billion cubic feet per day. Startup of the Qatargas 3 project is estimated to be in the 2009 timeframe.

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In December 2003, we signed a Statement of Intent with Qatar Petroleum regarding the construction of a gas-to-liquids (GTL) plant in Ras Laffan, Qatar. The agreement initiates the detailed technical and commercial pre-front-end engineering and design studies and established principles for negotiating a Heads of Agreement for an integrated reservoir-to-market GTL project.

In late 2003, we signed an agreement with Freeport LNG Development, L.P. to participate in its proposed LNG receiving terminal in Quintana, Texas. This agreement gives us 1 billion cubic feet per day of regasification capacity in the terminal and a 50 percent interest in the general partnership managing the venture. The terminal will be designed with a storage capacity of 6.9 billion cubic feet and a send-out capacity of 1.5 billion cubic feet per day. Pending government approvals, construction is scheduled to begin in the second half of 2004, with commercial startup in mid-2007.

We are continuing with plans to develop a project to build a liquefied natural gas import terminal in northern Baja California to provide access to gas markets in that region. Although we wrote-off our investment in the proposed Rosarito LNG terminal, we continue working with federal, state, and local officials in Mexico to evaluate various other alternatives, which includes offshore options.

E&P RESERVES

The company has not filed any information with any other federal authority or agency with respect to its estimated total proved reserves at December 31, 2003. No difference exists between the company s estimated total proved reserves for year-end 2002 and year-end 2001, which are shown in this filing, and estimates of these reserves shown in a filing with another federal agency in 2003.

DELIVERY COMMITMENTS

The Commercial organization optimizes the commodity flows of our E&P segment. This group markets our crude oil and natural gas production, with commodity buyers, traders and marketers in offices in Houston, London, Singapore and Calgary.

We sell crude oil and natural gas from our E&P producing operations under a variety of contractual arrangements, some of which specify the delivery of a fixed and determinable quantity. Our Commercial organization also enters into natural gas sales contracts where the source of the natural gas used to fulfill the contract can be the spot market, or a combination of our reserves and the spot market. Worldwide, we are contractually committed to deliver approximately 4.8 trillion cubic feet of natural gas and 270 million barrels of crude oil in the future, including the minority interests of consolidated subsidiaries. These contracts have various expiration dates through the year 2025. The crude oil commitment and approximately 4.3 trillion cubic feet of the natural gas commitment are expected to come from proved reserves in the United States, the Timor Sea, Nigeria, and the United Kingdom. The remainder of the natural gas commitment will be purchased in the spot market.

MIDSTREAM

Our Midstream business is conducted through owned and operated assets as well as through our 30.3 percent equity investment in Duke Energy Field Services, LLC (DEFS). The Midstream businesses purchase raw natural gas from producers and gather natural gas through extensive pipeline gathering systems. The gathered natural gas is then processed to extract natural gas liquids from the raw gas stream. The remaining

residue gas is marketed to electrical utilities, industrial users, and gas marketing companies. Most of the natural gas liquids are fractionated-separated into individual components like ethane, butane and propane and marketed as chemical feedstock, fuel, or blendstock. Total natural gas liquids extracted in 2003, including our share of DEFS, was 219,000 barrels per day, with 167,000 barrels per day of natural gas liquids fractionated.

DEFS markets a substantial portion of its natural gas liquids to ConocoPhillips and Chevron Phillips Chemical Company LLC (a joint venture between ConocoPhillips and ChevronTexaco) under a supply agreement that continues until December 31, 2014. This purchase commitment is on an if-produced, will-purchase basis and so it has no fixed production schedule, but has had, and is expected over the remaining term of the contract to have, a relatively stable purchase pattern. Under this agreement, natural gas liquids are purchased at various published market index prices, less transportation and fractionation fees. DEFS also purchases raw natural gas from our E&P operations in the United States.

DEFS is headquartered in Denver, Colorado. At December 31, 2003, DEFS owned and operated 56 natural gas liquids extraction plants, and owned an equity interest in another 10. Also at year end, DEFS gathering and transmission systems included approximately 58,000 miles of pipeline. In 2003, DEFS raw natural gas throughput averaged 6.7 billion cubic feet per day, and natural gas liquids extraction averaged 365,000 barrels per day. DEFS assets are primarily located in the Gulf Coast area, West Texas, Oklahoma, the Texas Panhandle, the Rocky Mountain area, and western Canada.

Outside of DEFS, our U.S. Midstream assets are located primarily in New Mexico, Texas and Louisiana. At December 31, 2003, these assets included seven fully owned and operated natural gas liquids extraction plants, plus two additional plants that we operate and in which we own a 95 percent and a 50 percent interest. These nine plants have a combined natural gas net plant inlet capacity of 762 million cubic feet per day. One of the plants in Louisiana also includes a 10,500 barrel-per-day liquids fractionator. We also have minor interests in two other natural gas liquids extraction plants, and we own underground natural gas liquids storage facilities in Texas and Louisiana.

We own a 25,000 barrel-per-day capacity liquids fractionation plant in Gallup, New Mexico; a 22.5 percent equity interest in Gulf Coast Fractionators, which owns a natural gas liquids fractionating plant in Mt. Belvieu, Texas (with our net share of capacity at 25,000 barrels per day); and a 40 percent interest in a fractionation plant in Conway, Kansas (with our share of capacity at 42,000 barrels per day). We own a 700-mile intrastate natural gas and liquids pipeline system in Louisiana and gas gathering and natural gas liquids pipelines in several states.

Our Canadian natural gas liquids business includes the following assets:

- A 92 percent operating interest in the 2.4 billion-cubic-feet-per-day Empress natural gas processing and fractionation facilities near Medicine Hat, Alberta, with natural gas liquids production capacity of 50,000 barrels per day;

- A 580-mile Petroleum Transmission Company pipeline from Empress to Winnipeg and six related pipeline terminals;

- Two underground natural gas liquids storage facilities, comprised of the Richardson caverns with a one million barrel capacity and the Dewdney caverns with a three million barrel capacity along with 0.6 billion cubic feet of natural gas storage capacity; and

- A 10 percent interest in the 1,902-mile Cochin liquefied petroleum gas pipeline, originating in Edmonton, Alberta, and ending in Sarnia, Ontario, and a terminal storage system that transports propane, ethane and ethylene.

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Canadian natural gas liquids extracted averaged 45,000 barrels per day in 2003.

We also own a 39 percent equity interest in Phoenix Park Gas Processors Limited, a joint venture with the National Gas Company of Trinidad and Tobago Limited, which processes gas in Trinidad and markets natural gas liquids throughout the Caribbean and into the U.S. Gulf Coast. Phoenix Park s facilities include a gas processing plant and a natural gas liquids fractionator. Our share of natural gas liquids extracted averaged 11,100 barrels per day in 2003.

In early 2004, we approved the disposal of some of our non-DEFS Midstream assets located in the Lower 48 states that are not associated with our E&P operations.

REFINING AND MARKETING (R&M)

R&M operations encompass refining crude oil and other feedstocks into petroleum products (such as gasoline, distillates and aviation fuels), buying, selling and transporting crude oil, and buying, transporting, distributing and marketing petroleum products. R&M has operations in the United States, Europe and Asia Pacific.

The Commercial organization optimizes the commodity flows of our R&M segment. This organization selects and procures feedstocks for R&M s refineries. Commercial also supplies the gas and power needs of the R&M facilities. Commercial has buyers, traders and marketers in offices in Houston, London, Singapore and Calgary.

As a condition to the merger, the U.S. Federal Trade Commission (FTC) required that we divest specified Conoco and Phillips assets, the most significant of which were Phillips Woods Cross, Utah, refinery and associated motor fuel marketing operations; Conoco s Commerce City, Colorado, refinery and related crude oil pipelines; and Phillips Colorado motor fuel marketing operations. All FTC-mandated dispositions were completed in late-2002 or during 2003.

In addition, in December 2002, we committed to and initiated a plan to sell approximately 3,200 marketing sites that did not fit into our long-range plans. In the third quarter of 2003, we concluded the sale of all of the Exxon-branded marketing assets in New York and New England, including contracts with independent dealers and marketers. Approximately 230 of the 3,200 sites were included in this package. In the fourth quarter of 2003, we concluded the sale of our Circle K subsidiary, representing approximately 1,660 sites, as well as the assignment of the franchise relationship with more than 350 franchised and licensed stores. Other, smaller dispositions also occurred during 2003. In January 2004, we signed agreements to sell our Mobil-branded marketing assets on the East Coast in two separate transactions. Assets in the packages include 104 company-owned and operated sites, and 352 dealer sites. Each of the transactions is expected to close in the second quarter of 2004. Discussions are under way with potential buyers for the remaining sites, and we expect to complete the sales of these assets during 2004.

Both the FTC-required dispositions and the retail site dispositions were classified as discontinued operations for financial reporting purposes, and are included in Corporate and Other. Accordingly, they are excluded from the descriptions of R&M s continuing operations contained in this section. See Note 4 Discontinued Operations, in the Notes to Consolidated Financial Statements, for additional information.

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UNITED STATES

Refining

At December 31, 2003, we owned and operated 12 crude oil refineries in the United States, having an aggregate rated crude oil refining capacity at year-end 2003 of 2,168,000 barrels per day. The average purchase cost of a barrel of crude delivered to our U.S. refineries in 2003 was $29.10, compared to $24.92 in 2002.

East Coast Region
Bayway Refinery
Located on the New York Harbor in Linden, New Jersey, Bayway has a crude oil processing capacity of 250,000 barrels per day and processes mainly light low-sulfur crudes. Crude oil is supplied to the refinery by tanker, primarily from the North Sea and West Africa. The refinery produces a high percentage of transportation fuels such as gasoline, diesel, and jet fuel along with home heating oil. Other products include petrochemical feedstocks (propylene) and residual fuel oil. The facility distributes its refined products to East Coast customers through pipelines, barges, railcars and trucks. The mix of products produced changes to meet seasonal demand. Gasoline is in higher demand during the summer, while in winter, the refinery optimizes operations to increase heating oil production. A 775 million-pound-per-year polypropylene plant became operational in March 2003.

Trainer Refinery
The Trainer refinery is located in Trainer, Pennsylvania, about 10 miles southwest of the Philadelphia airport on the Delaware River. The refinery has a crude oil processing capacity of 180,000 barrels per day and processes mainly light low-sulfur crudes. The Bayway and Trainer refineries are operated in coordination with each other by sharing crude oil cargoes, moving feedstocks between the facilities, and sharing certain personnel. Trainer receives crude oil from the North Sea and West Africa. The refinery produces a high percentage of transportation fuels such as gasoline, diesel, and jet fuel along with home heating oil. Other products include residual fuel oil and liquefied petroleum gas. Refined products are distributed to customers in Pennsylvania, New York and New Jersey via pipeline, barge, railcar and truck.

Gulf Coast Region
Alliance Refinery
The Alliance refinery, located in Belle Chasse, Louisiana, on the Mississippi River, is about 25 miles south of New Orleans and 63 miles north of the Gulf of Mexico. The refinery has a crude oil processing capacity of 250,000 barrels per day and processes mainly light low-sulfur crudes. Alliance receives domestic crude oil via pipeline, and crude oil from the North Sea and West Africa via pipeline connected to the Louisiana Offshore Oil Port. The refinery produces a high percentage of transportation fuels such as gasoline, diesel, and jet fuel along with home heating oil. Other products include petrochemical feedstocks (benzene) and anode petroleum coke. The majority of the refined products are distributed to customers through the Colonial and Plantation pipeline systems.

Lake Charles Refinery
The Lake Charles refinery is located in Westlake, Louisiana. The refinery has a crude oil processing capacity of 252,000 barrels per day. The refinery receives domestic and international crude oil and processes heavy, high-sulfur, low-sulfur and acidic crude oil. While the sources of international crude oil can vary, the majority is Venezuelan and Mexican heavy crudes delivered via tanker. The refinery produces a high percentage of transportation fuels such as gasoline, off-road diesel, and jet fuel along with heating oil. The majority of the refined products are distributed to customers by truck, railcar or major common-carrier pipelines. In addition, refined products can be sold into export markets through the refinery s marine terminal.

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The Lake Charles facilities also include a specialty coker and calciner that manufactures graphite and anode petroleum cokes supplied to the steel and aluminum industries, and provides a substantial increase in light oils production by breaking down the heaviest part of the crude barrel to allow additional production of diesel fuel and gasoline.

The Lake Charles refinery supplies feedstocks to Excel Paralubes, Penreco and Venture Coke Company (Venco), all joint ventures that are part of our Specialty Businesses function within R&M.

Sweeny Refinery

The Sweeny refinery is located in Old Ocean, Texas, about 65 miles southwest of Houston. The refinery has a crude oil processing capacity of 215,000 barrels per day. The refinery primarily receives crude oil through 100 percent owned and jointly owned terminals on the Gulf Coast, including a deepwater terminal at Freeport, Texas. The refinery produces a high percentage of transportation fuels such as gasoline, diesel, and jet fuel along with home heating oil. Other products include petrochemical feedstocks (benzene) and petroleum (fuel) coke. Refined products are distributed throughout the Midwest and southeastern United States through pipeline, barge and railcar.

ConocoPhillips has a 50 percent interest in Merey Sweeny, L.P., a limited partnership that owns a 58,000 barrel-per-day delayed coker and related facilities at the Sweeny refinery. PDVSA, which owns the remaining 50 percent interest, supplies the refinery with up to 165,000 barrels per day of Venezuelan Merey, or equivalent, crude oil. We are the operating partner.

Central Region

Wood River Refinery

The Wood River refinery is located in Roxana, Illinois, about 15 miles north of St. Louis, Missouri, on the east side of the Mississippi River. It is our largest refinery, with a crude oil processing capacity of 286,000 barrels per day. The refinery can process a mix of both light low-sulfur and heavy high-sulfur crudes, which it receives from domestic and foreign sources by pipeline. The refinery produces a high percentage of transportation fuels such as gasoline, diesel, and jet fuel along with home heating oil. Other products include petrochemical feedstocks (benzene) and asphalt. Through an off-take agreement, a significant portion of its gasoline, diesel and jet fuel is sold to a third party at the refinery for delivery via pipelines into the upper Midwest, including the Chicago, Illinois, and Milwaukee, Wisconsin, metropolitan areas. Remaining refined products are distributed to customers in the Midwest by pipeline, truck, barge and railcar.

During 2003, we purchased certain assets at Premcor s Hartford, Ill., refinery. The purchase included the coker, crude unit, catalytic cracker, alkylation unit, isomerization unit, a portion of the site utilities and a portion of the storage tanks at the Premcor facility. The overall production of the Wood River refinery will only increase slightly, but the purchase will enable the refinery to process heavier, lower cost crude oil.

Ponca City Refinery

Our refinery located in Ponca City, Oklahoma, has a crude oil processing capacity of 194,000 barrels per day. Both foreign and domestic crudes are delivered by pipeline from the Gulf of Mexico, Oklahoma, Kansas, Texas and Canada. The refinery s facilities include fluid catalytic cracking, delayed coking and hydrodesulfurization units, which enable it to produce high ratios of gasoline and diesel fuel from crude oil. Finished petroleum products are shipped by truck, railcar and company-owned and common-carrier pipelines to markets throughout the Midcontinent region.

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Borger Refinery

The Borger refinery is located in Borger, Texas, in the Texas Panhandle about 50 miles north of Amarillo. It includes a natural gas liquids fractionation facility. The crude oil processing capacity is 148,000 barrels per day, and the natural gas liquids fractionation capacity is 95,000 barrels per day. The refinery processes mainly heavy high-sulfur crudes. The refinery receives crude oil and natural gas liquids feedstocks through our pipelines from west Texas, the Texas Panhandle and Wyoming. The Borger refinery can also receive foreign crude oil via our pipeline systems. The refinery produces a high percentage of transportation fuels such as gasoline, diesel, and jet fuel along with a variety of natural gas liquids and solvents. Pipelines move refined products from the refinery to west Texas, New Mexico, Arizona, Colorado, and the Midcontinent region.

Billings Refinery

The Billings refinery is located in Billings, Montana, and has a crude oil processing capacity of 60,000 barrels per day, processing a mixture of about 95 percent Canadian heavy high-sulfur crude plus domestic high-sulfur and low-sulfur crudes, all delivered by pipeline. A delayed coker converts heavy high-sulfur residue into higher value light oils. The refinery produces a high percentage of transportation fuels such as gasoline, jet fuel, and diesel, as well as fuel grade petroleum coke. Finished petroleum products from the refinery are delivered via company-owned pipelines, railcars, and trucks. Pipelines transport most of the refined products to markets in Montana, Wyoming, Utah, and Washington.

West Coast Region

Los Angeles Refinery

The Los Angeles refinery is composed of two linked facilities located about five miles apart in Carson and Wilmington, California, about 15 miles southeast of the Los Angeles International airport. Carson serves as the front-end of the refinery by processing crude oil, and Wilmington serves as the back-end by upgrading products. The refinery has a crude oil processing capacity of 132,000 barrels per day and processes mainly heavy high-sulfur crudes. The refinery receives domestic crude oil via pipeline from California and foreign and domestic crude oil by tanker through company-owned and third-party terminals in the Port of Los Angeles. The refinery produces a high percentage of transportation fuels such as gasoline, diesel, and jet fuel. Other products include fuel-grade petroleum coke. The refinery produces California Air Resources Board (CARB) gasoline using ethanol, which we use to replace methyl tertiary-butyl ether (MTBE) to meet federally mandated oxygenate requirements. Refined products are distributed to customers in southern California, Nevada and Arizona by pipeline and truck.

San Francisco Area Refinery

The San Francisco Area refinery is composed of two linked facilities located about 200 miles apart. The Santa Maria facility is located in Arroyo Grande, California, about 200 miles south of San Francisco, while the Rodeo facility is in the San Francisco Bay area. The refinery s crude oil processing capacity is 109,000 barrels per day of mainly heavy high-sulfur crudes. Both the Santa Maria and Rodeo facilities have calciners to upgrade the value of the coke that is produced. The refinery receives crude oil from central California, including the Elk Hills oil field, and foreign crude oil by tanker. Semi-refined liquid products from the Santa Maria facility are sent by pipeline to the Rodeo facility for upgrading to finished petroleum products. The refinery produces transportation fuels such as gasoline, diesel, and jet fuel. Other products include calcine and fuel grade petroleum coke. The refinery produces CARB gasoline using ethanol, which we use to replace MTBE to meet federally mandated oxygenate requirements. Refined products are distributed by pipeline, railcar, truck and barge.

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Ferndale Refinery
The Ferndale refinery in Ferndale, Washington, is about 20 miles south of the United States-Canada border on Puget Sound. The refinery has a crude oil processing capacity of 92,000 barrels per day. The refinery primarily receives crude oil from the Alaskan North Slope, with secondary sources supplied by Canada or the Far East. Ferndale operates a deepwater dock that is capable of taking in full tankers bringing North Slope crude oil from Valdez, Alaska. The refinery is also connected to the Terasen crude oil pipeline that originates in Canada. The refinery produces transportation fuels such as gasoline, diesel, and jet fuel. Other products include residual fuel oil supplying the northwest marine transportation market. Construction of a new fluidized catalytic cracking unit to increase the yield of transportation fuel, and a new S Zorb unit that reduces the sulfur in gasoline, both became fully operational in 2003. Most refined products are distributed by pipeline and barge to major markets in the northwest United States.

Marketing

In the United States, we market gasoline, diesel fuel, and aviation fuel through approximately 14,300 outlets in 44 states. The majority of these sites utilize the Conoco, Phillips 66 or 76 brands.

Wholesale
In our wholesale operations, we utilize a network of marketers and dealers operating approximately 13,300 outlets. We place a strong emphasis on the wholesale channel of trade because of its lower capital requirements and higher return on capital. Our refineries and transportation systems provide strategic support to these operations. We also buy and sell petroleum products in spot markets. Our refined products are marketed on both a branded and unbranded basis.

In addition to automotive gasoline and diesel fuel, we produce and market aviation gasoline, which is used by smaller, piston-engine aircraft. Aviation gasoline and jet fuel are sold through independent marketers at approximately 570 Phillips 66 branded locations in the United States.

Retail
In our retail operations, we own and operate approximately 330 sites under the Phillips 66, Conoco and 76 brands. Company-operated retail operations are focused in 10 states, mainly in the Midcontinent, Rocky Mountains, and West Coast regions. Most of these outlets market merchandise through the Kicks 66, Breakplace, or Circle K brand convenience stores.

At December 31, 2003, CFJ Properties, our 50/50 joint venture with Flying J, owned and operated 97 truck travel plazas that carry the Conoco and/or Flying J brands. The merger of Conoco and Phillips triggered change of control provisions in the joint venture agreement, giving Flying J the option to purchase our interest in CFJ Properties at fair value. A third party is determining the fair value of the joint venture. Once that binding appraised value is determined, Flying J will have 30 days to exercise their purchase option. Assuming Flying J does not exercise its purchase option, we plan to continue as a co-venturer in CFJ Properties.

Transportation

Pipelines and Terminals
At December 31, 2003, we had approximately 32,800 miles of common-carrier crude oil, raw natural gas liquids and products pipeline systems in the United States, including those partially owned and/or operated by affiliates. We also owned and/or operated 76 finished product terminals, eight liquefied petroleum gas terminals, 11 crude oil terminals and one coke exporting facility.

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Tankers
At December 31, 2003, we had under charter 13 double-hulled crude oil tankers, with capacities ranging in size from 650,000 to 1,100,000 barrels. These tankers are utilized to transport feedstocks to certain of our U.S. refineries. We also had an ocean-going barge under charter, as well as a domestic fleet of both owned and chartered boats and barges providing inland waterway transportation. The information above excludes the operations of the company s subsidiary, Polar Tankers Inc., which is discussed in the E&P section, as well as an owned tanker on lease to a third party for use in the North Sea.

Specialty Businesses

We manufacture and sell a variety of lubricants and specialty products including petroleum cokes, lubes (such as automotive and industrial lubricants), solvents, and pipeline flow improvers to commercial, industrial and wholesale accounts worldwide.

Lubricants are marketed under the Conoco, Phillips 66, 76 Lubricants and Kendall Motor Oil brands. The distribution network consists of over 900 outlets, including mass merchandise stores, fast lubes, tire stores, automotive dealers, and convenience stores. Lubricants are also sold to industrial customers in many markets.

Excel Paralubes is a joint-venture hydrocracked lubricant base oil manufacturing facility, located adjacent to our Lake Charles refinery, and is 50 percent owned by us. Excel Paralubes lube oil facility produces approximately 20,000 barrels per day of high-quality, clear hydrocracked base oils. Hydrocracked base oils are second in quality only to synthetic base oils, but are produced at a much lower cost. The Lake Charles refinery supplies Excel Paralubes with gas-oil feedstocks. We purchase 50 percent of the joint venture s output, and market it to third parties.

We have a 50 percent interest in Penreco, a fully integrated specialties company, which manufactures and markets highly refined specialty petroleum products, including solvents, waxes, petrolatums and white oils, for global markets.

We manufacture high-quality graphite and anode-grade cokes in the United States and Europe, for use in the global steel and aluminum industries. Venco is a coke calcining joint venture in which we have a 50 percent interest. Base green petroleum coke volumes are supplied to Venco s Lake Charles calcining facility from our Alliance, Lake Charles, and Ponca City refineries.

INTERNATIONAL

Refining

At December 31, 2003, we owned or had an interest in six refineries outside the United States with an aggregate rated crude oil capacity of 442,000 net barrels per day. The average purchase cost of crude oil delivered to the company s international refineries in 2003 was $28.94 per barrel, compared with $24.55 per barrel in 2002.

Humber Refinery
Our wholly owned Humber refinery is located in North Lincolnshire, United Kingdom. The refinery s crude oil processing capacity is 234,000 barrels per day. Crude oil processed at the refinery is supplied primarily from the North Sea and includes lower-cost, acidic crudes. The refinery also processes other

intermediate feedstocks, mostly vacuum gas oils and residual fuel oil. The refinery s location on the east coast of England provides for cost-effective North Sea crude imports and product exports to European and world markets.

The Humber refinery is a fully integrated refinery that produces a full slate of light products and minimal fuel oil. The refinery also has two coking units with associated calcining plants, which upgrade the heavy bottoms and imported feedstocks into light-oil products and high-value graphite and anode petroleum cokes. Approximately 60 percent of the light oils produced in the refinery are marketed in the United Kingdom, while the other products are exported to the rest of Europe and the United States.

Whitegate Refinery
The Whitegate refinery is located in Cork, Ireland, and in 2003 had a crude oil processing capacity of 72,000 barrels per day. Effective January 1, 2004, the rated processing capacity was increased to 75,000 barrels per day due to incremental debottlenecking. Crude oil processed by the refinery is light sweet crude sourced mostly from the North Sea. The refinery primarily produces transportation fuels and fuel oil, which are distributed to the inland market via truck and sea, as well as being exported to the European market. We also operate a deepwater crude oil and products storage complex with a 7.5 million barrel capacity in Bantry Bay, Cork, Ireland.

MiRO Refinery
The Mineraloel Raffinerie Oberrhein GmbH (MiRO) refinery in Karlsruhe, Germany, is a joint-venture refinery with a crude oil processing capacity of 283,000 barrels per day. We have an 18.75 percent interest in MiRO, giving us a net capacity share of 53,000 barrels per day. Approximately 60 percent of the refinery s crude oil feedstock is low-cost, high-sulfur crude. The MiRO complex is a fully integrated refinery producing gasoline, middle distillates, and specialty products along with a small amount of residual fuel oil. The refinery has a high capacity to convert lower-cost feedstocks into higher value products, primarily with a fluid catalytic cracker and delayed coker. The refinery produces both fuel grade and specialty calcined cokes. The refinery processes crude and other feedstocks supplied by each of the partners in proportion to their respective ownership interests.

Czech Republic Refineries
Through our participation in Ceská rafinérská, a.s. (CRC), we have a 16.33 percent ownership in two refineries in the Czech Republic, giving us a net capacity share of 27,000 barrels per day. Effective January 1, 2004, the rated crude oil processing capacity was increased to 28,000 barrels per day for our share, due to incremental debottlenecking. The refinery at Litvinov has a crude oil processing capacity of 109,200 barrels per day and processes low cost Russian export blend crude oil delivered from Russia by pipeline. Litvinov includes both hydrocracking and visbreaking, producing a high yield of transport fuels and petrochemical feedstocks and only a small amount of fuel oil. The Kralupy refinery has a crude oil processing capacity of 60,800 barrels per day and processes low sulfur crude, mostly from the Mediterranean. Kralupy has a new fluidized catalytic cracking unit, which gives the refinery a high yield of transport fuels. The two refineries complement each other and are run on an overall optimized basis, with certain intermediate streams moving between the two plants. CRC processes crude and other feedstocks supplied by ConocoPhillips and the other partners, with each partner receiving their proportionate share of the resulting products. We market our share of these finished products in both the Czech Republic and in neighboring markets.

Melaka Refinery
The refinery in Melaka, Malaysia, is a joint venture with Petronas, the Malaysian state oil company. We own a 47 percent interest in the joint venture. In 2003, the refinery had a rated crude oil processing capacity of 120,000 barrels per day, of which our share was 56,000 barrels per day. Effective January 1,

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2004, our share of the rated crude oil processing capacity was increased to 57,500 barrels per day due to incremental debottlenecking. Crude oil processed by the refinery is sourced mostly from the Middle East. The refinery produces a full range of refined petroleum products. The refinery capitalizes on our proprietary coking technology to upgrade low-cost feedstocks to higher-margin products. Our share of refined products is distributed by truck to the company s ProJET retail sites in Malaysia, or transported by sea primarily to Asian markets.

Marketing

We have marketing operations in 15 European countries. Our European marketing strategy is to sell primarily through owned, leased or joint-venture retail sites using a low-cost, high-volume, low-price strategy. We also market aviation fuels, liquid petroleum gases, heating oils, transportation fuels and marine bunkers to commercial customers and into the bulk or spot market.

We use the JET brand name to market retail and wholesale products in our wholly owned operations in Austria, Belgium, the Czech Republic, Denmark, Finland, Germany, Hungary, Luxembourg, Norway, Poland, Slovakia, Sweden and the United Kingdom. In addition, various joint ventures in which we have an equity interest market products in Switzerland and Turkey under the Coop and Tabas or Turkpetrol brand names, respectively.

As of December 31, 2003, we had approximately 2,100 marketing outlets in our European operations, of which about 1,200 were company-owned, and 900 were dealer-owned. Through our joint venture operations in Turkey and Switzerland, we also have interests in approximately 800 additional sites.

The company s largest branded site networks are in Germany and the United Kingdom, which account for approximately 60 percent of our total European branded units.

As of December 31, 2003, we had approximately 140 marketing outlets in our wholly owned Thailand operations in Asia. In addition, through a joint venture in Malaysia with Sime Darby Bhd., a company that has a major presence in the Malaysian business sector, we also have an interest in another approximately 40 retail sites. In Thailand and Malaysia, retail products are marketed under the JET and ProJET brands, respectively.

CHEMICALS

On July 1, 2000, ConocoPhillips and ChevronTexaco combined their worldwide chemicals businesses, excluding ChevronTexaco s Oronite business, into a new company, Chevron Phillips Chemical Company LLC (CPChem). In addition to contributing the assets and operations included in our Chemicals segment, we also contributed the natural gas liquids business associated with our Sweeny, Texas, complex. ConocoPhillips and ChevronTexaco each own 50 percent of CPChem. We use the equity method of accounting for our investment in CPChem.

CPChem, headquartered in The Woodlands, Texas, has 32 production facilities and six research and technology centers. CPChem uses natural gas liquids and other feedstocks to produce petrochemicals such as ethylene, propylene, styrene, benzene and paraxylene. These products are then marketed and sold, or used as feedstocks to produce plastics and commodity chemicals, such as polyethylene, polystyrene, and cyclohexane.

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CPChem s domestic production facilities are located at Baytown, Borger, Conroe, La Porte, Orange, Pasadena, Port Arthur and Old Ocean, Texas; St. James, Louisiana; Pascagoula, Mississippi; Marietta, Ohio; and Guayama, Puerto Rico. CPChem also has nine plastic pipe plants and one pipe fittings plant in eight states.

Major international production facilities are located in Belgium, China, Saudi Arabia, Singapore, South Korea and Qatar. There is one plastic pipe plant in Mexico.

CPChem has research facilities in Oklahoma, Ohio and Texas, as well as in Singapore and Belgium.

Construction of a major olefins and polyolefins complex in Mesaieed, Qatar, named Q-Chem I, was completed in 2003. The facility, which is operating and in the final stages of performance testing, has an annual capacity of approximately 1.1 billion pounds of ethylene, 1 billion pounds of polyethylene and 100 million pounds of 1-hexene. CPChem has a 49 percent interest, with a Qatar state firm owning the remaining 51 percent interest.

CPChem has also signed an agreement for the development of a second complex to be built in Mesaieed, Qatar, named Q-Chem II. The facility will be designed to produce polyethylene and normal alpha olefins, on a site adjacent to the newly-constructed Q-Chem I complex. CPChem and Qatar Petroleum, through the Q-Chem II joint venture, entered into a separate agreement with Atofina and Qatar Petrochemical Company to jointly develop an ethane cracker in northern Qatar at Ras Laffan Industrial City. Final approval of the Q-Chem II projects by CPChem s Board of Directors is expected to be requested in 2005, with startup expected in 2008.

CPChem announced plans in 2002 for a 50 percent-owned joint venture project in Al Jubail, Saudi Arabia. The project includes the construction of an integrated olefins, ethyl benzene and styrene monomer facility on a site adjacent to the existing aromatics complex owned by Saudi Chevron Phillips Company, a 50 percent-owned CPChem joint venture. The project also includes the expansion of Saudi Chevron Phillips Company s benzene facility. This additional benzene capacity will be used to provide feedstock for the new facility. Final approval of the project by CPChem s Board of Directors is expected to be requested in 2004, with operational startup expected in 2007.

A brief description of CPChem s major product lines follows.

Olefins and Polyolefins

Ethylene: Ethylene is a basic building block for plastics and also a raw material for chemicals used to make paints, detergents and antifreeze. Ethylene is produced at Old Ocean, Port Arthur and Baytown, Texas, as well as in Qatar. CPChem s net annual capacity at December 31, 2003, was approximately 8.1 billion pounds.

Polyethylene: Polyethylene is used to make a wide variety of plastic products, including various containers, shopping and trash bags, and plastic films. Polyethylene is produced at Pasadena, Baytown, and Orange, Texas, as well as in China, Singapore and Qatar. CPChem s net annual capacity at December 31, 2003, was approximately 5.9 billion pounds.

Plastic Pipe: Polyethylene plastic pipe is produced at nine plants in the United States and one plant in Mexico. Pipe fittings are produced at one plant in the United States. CPChem s net annual capacity at December 31, 2003, was approximately 564 million pounds.

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Normal Alpha Olefins: Normal alpha olefins can be custom blended for special applications and are used extensively as polyethylene comonomers and are also used in synthetic lubricants and additives. Normal alpha olefins are produced at Baytown, Texas and in Qatar. CPChem s net annual capacity at December 31, 2003, was approximately 1.5 billion pounds.

Aromatics and Styrenics
Styrene: Styrene, produced from benzene and ethylene, is used as a feedstock for polystyrene and is also used to produce a variety of polymers with end-uses that include packaging, rubber products, automotive and other applications. Styrene is produced at St. James, Louisiana. CPChem s net annual capacity at December 31, 2003, was approximately 2.1 billion pounds.

Polystyrene: Polystyrene is a thermoplastic polymer used to make packing materials, cups, toys, furniture, and housewares. It is produced at Marietta, Ohio, and in China. CPChem s net annual capacity at December 31, 2003, was approximately 990 million pounds.

Benzene: Benzene is a building block chemical used in the production of ethylbenzene, cumene, and cyclohexane. Benzene is produced at Pascagoula, Mississippi and in Saudi Arabia. CPChem s net annual capacity at December 31, 2003, was approximately 2.1 billion pounds.

Cyclohexane: Cyclohexane is a derivative of benzene that is predominantly used in intermediates for the manufacture of nylon. It is produced at Port Arthur, Texas, and in Saudi Arabia. CPChem s net annual capacity at December 31, 2003, was approximately 1.2 billion pounds. This includes the capacity of a new plant in Port Arthur that commenced operations in February 2004, and excludes the capacity of a plant, also in Port Arthur, that was shut down. In addition, CPChem markets cyclohexane production from ConocoPhillips Sweeny and Borger complexes.

K-Resin®: K-Resin® is a styrene-butadiene copolymer used to produce a clear, shatter-resistant resin. It is produced at Pasadena, Texas, and in South Korea. CPChem s net annual capacity at December 31, 2003, was approximately 269 million pounds.

Paraxylene: Paraxylene is an aromatic used as a feedstock for polyester and certain plastics. It is currently produced at Pascagoula, Mississippi. The Pascagoula plant s annual capacity at December 31, 2003, was approximately 1.0 billion pounds. A plant in Guayama, Puerto Rico, with an annual capacity at December 31, 2003, of approximately 715 million pounds, was reconfigured in 2003 and is currently idled. Operations at the Puerto Rico plant could resume when market conditions improve.

Specialty Products
Specialty Chemicals: CPChem manufactures, markets and distributes organosulfur, paraffinic, olefinic and aromatic specialty chemicals as well as a complete line of natural gas odorants, specialty catalysts, specialty fuels, mining chemicals and oilfield drilling additives, enhancers and cements. These products are manufactured and processed in Borger and Conroe, Texas, and Tessenderlo, Belgium.

Ryton® Polyphenylene Sulfide: CPChem produces high-performance polyphenylene sulfide polymers (PPS) sold under the trademark Ryton®, which is produced at Borger, Texas. CPChem s annual capacity of Ryton PPS at December 31, 2003, was 22 million pounds. Ryton PPS compounds are produced at La Porte, Texas, as well as in Belgium and Singapore. These facilities have a net annual capacity of approximately 44 million pounds of Ryton PPS compounds in the aggregate.

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EMERGING BUSINESSES

Emerging Businesses encompass the development of new businesses beyond our traditional operations. As a result of market, operating and technological uncertainties, we terminated our carbon fibers project during 2003.

GAS-TO-LIQUIDS (GTL)

The GTL process refines natural gas into a wide range of transportable products. Our GTL research facility is located in Ponca City, Oklahoma, and includes laboratories, pilot plants, and a demonstration plant to facilitate technology advancements. The 400 barrel-per-day demonstration plant, designed to produce clean fuels from natural gas, was completed in April 2003. The plant has been commissioned and operations started, with thorough testing scheduled throughout 2004.

TECHNOLOGY SOLUTIONS

Our Technology Solutions businesses provide technologies and services that can be used in our operations or licensed to third parties. Downstream, major product lines include sulfur removal technologies (S Zorb), alkylation technologies (ReVAP), and delayed coking technologies. For upstream and downstream, Technology Solutions offers analytical services, pilot plant, and industrial hygiene services.

POWER GENERATION

The focus of our power business is on developing integrated projects in support of the company s E&P and R&M strategies and business objectives. The projects that enable these strategies are included within the respective E&P and R&M segments. The projects and assets that have a significant merchant component are included in the Emerging Businesses segment.

The power business is developing a 730-megawatt gas-fired combined heat and power plant in North Lincolnshire, United Kingdom. The facility will provide steam and electricity to the Humber refinery and steam to a neighboring refinery, as well as market power into the U.K. market. Construction began in 2002, with commercial operation anticipated in 2004.

We also own or have an interest in gas-fired cogeneration plants in Orange and Corpus Christi, Texas, and a petroleum coke-fired plant in Lake Charles, Louisiana.

EMERGING TECHNOLOGY

Emerging Technology focuses on developing new business opportunities designed to provide growth options for ConocoPhillips well into the future. Example areas of interest include renewable energy, advanced hydrocarbon processes, energy conversion technologies and new petroleum-based products.

COMPETITION

We compete with private, public and state-owned companies in all facets of the petroleum and chemicals businesses. Some of our competitors are larger and have greater resources. Each of the segments in which we operate is highly competitive. No single competitor, or small group of competitors, dominates any of our business lines.

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Upstream, our E&P segment competes with numerous other companies in the industry to locate and obtain new sources of supply, and to produce oil and natural gas in an efficient, cost-effective manner. Based on reserves statistics published in the September 15, 2003, issue of the *Oil and Gas Journal*, we had the eighth-largest total of worldwide reserves of non-government-controlled companies. We deliver our oil and natural gas production into the worldwide oil and natural gas commodity markets. The principal methods of competing include geological, geophysical and engineering research and technology; experience and expertise; and economic analysis in connection with property acquisitions.

The Midstream segment, through our equity investment in DEFS and our consolidated operations, competes with numerous other integrated petroleum companies, as well as natural gas transmission and distribution companies, to deliver the components of natural gas to end users in the commodity natural gas markets. DEFS is one of the largest producers of natural gas liquids in the United States, based on the November 17, 2003, *Gas Processors Report*. DEFS principle methods of competing include economically securing the right to purchase raw natural gas into its gathering systems, managing the pressure of those systems, operating efficient natural gas liquids processing plants, and securing markets for the products produced.

Downstream, our R&M segment competes primarily in the United States, Europe and the Asia Pacific region. Based on the statistics published in the December 22, 2003, issue of the *Oil and Gas Journal*, we had the largest U.S. refining capacity of about 15 large refiners of petroleum products. Worldwide, we ranked fourth among non-government-controlled companies. In the Chemicals segment, through our equity investment, CPChem generally ranks within the top 10 producers of its major product lines, based on average 2003 production capacity, as published by Chemical Market Associates Inc. Petroleum products, petrochemicals and plastics are delivered into the worldwide commodity markets. Elements of downstream competition include product improvement, new product development, low-cost structures, and manufacturing and distribution systems. In the marketing portion of the business, competitive factors include product properties and processibility, reliability of supply, customer service, price and credit terms, advertising and sales promotion, and development of customer loyalty to ConocoPhillips or CPChem s branded products.

GENERAL

At the end of 2003, we held a total of 1,918 active patents in 68 countries worldwide, including 733 active U.S. patents. During 2003, we received 57 patents in the United States and 136 foreign patents. Our products and processes generated licensing revenues of $35 million in 2003. The overall profitability of any business segment is not dependent on any single patent, trademark, license, franchise or concession.

Company-sponsored research and development activities charged against earnings were $136 million, $355 million and $44 million in 2003, 2002 and 2001, respectively.

The environmental information contained in Management s Discussion and Analysis on pages 72 through 75 under the caption, Environmental is incorporated herein by reference. It includes information on expensed and capitalized environmental costs for 2003 and those expected for 2004 and 2005.

Like all major international oil companies, we have for many years operated in countries that are subject to U.S. government restrictions or prohibitions on business activities by U.S. companies. In some cases, business is permitted if we have received a license from the Office of Foreign Assets Control (OFAC). The regulations implementing the restrictions are complicated and subject to interpretation by OFAC. We have programs designed to ensure compliance with the restrictions and believe that our present operations comply with applicable laws and regulations.

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In view of recent political, diplomatic and military developments in the Middle East, and throughout the world, we have reexamined our policies and procedures in order to prevent any actions that would violate the letter, or even the spirit of the restrictions. These developments may affect prices, production levels, allocation and distribution of raw materials and products, including their import, export and ownership; the amount of tax and timing of payment; and the cost of compliance with environmental regulations.

Following the events of September 11, 2001, a number of institutional investors and state governmental agencies have questioned the appropriateness of U.S. companies transacting business in or with any country that has reportedly been linked to terrorism, even if the country is not subject to legal restrictions. We have reexamined our policies and business ventures to ensure that our activities in or with certain countries are consistent with the U.S. government s policy, interests and objectives in such countries.

Web Site Access to SEC Reports

Our Internet Web site address is *http://www.conocophillips.com*. Information contained on our Internet Web site is not part of this report on Form 10-K.

Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and any amendments to these reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are available on our Web site, free of charge, as soon as reasonably practicable after such reports are filed with, or furnished to, the SEC. Alternatively, you may access these reports at the SEC s Internet Web site at *http://www.sec.gov*.

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Item 3. LEGAL PROCEEDINGS

The following is a description of reportable legal proceedings including those involving governmental authorities under federal, state and local laws regulating the discharge of materials into the environment for this reporting period. The following proceedings include those matters that arose during the fourth quarter of 2003 and those matters previously reported in ConocoPhillips 2002 Form 10-K and our first-, second- and third-quarter 2003 Forms 10-Q that have not been resolved. While it is not possible to accurately predict the final outcome of these pending proceedings, if any one or more of such proceeding was decided adversely to ConocoPhillips, there would be no material effect on our consolidated financial position. Nevertheless, such proceedings are reported pursuant to the United States Securities and Exchange Commission s regulations.

In December 2003, we entered into an Administrative Consent Order and Notice of Noncompliance with the Massachusetts Department of Environmental Protection for alleged violations of State II and Hazardous Waste requirements at various retail gasoline outlets formerly owned by us. This Consent Agreement provides for the payment of a civil administrative penalty in the amount of $106,250.

In November 2003, the U.S. Environmental Protection Agency (EPA) issued us a notice of violation for alleged violations of the gasoline Reid Vapor Pressure rules in 1999, 2000 and 2001 at our Wood River and Billings refineries. The notice of violation seeks a proposed penalty of $127,000. We are currently working with EPA toward a negotiated resolution of this matter.

On September 17, 2003, U.S. EPA Region 10 notified ConocoPhillips of its intent to assess civil penalties for alleged National Pollution Discharge Elimination System (NPDES) permit violations at our Tyonek offshore platform located near Cook Inlet, Alaska. The alleged violations arise from our July 2003 NPDES self-disclosure report to EPA Region 10. On February 10, 2004, EPA Region 10 issued to us a proposed Complaint for Civil Penalties and a proposed Consent Decree for the alleged permit violations. The proposed consent decree provides for the payment of a $450,000 civil penalty. We are currently working with the EPA and the U.S. Department of Justice (DOJ) on the terms of the agreements and expect the matter to be finalized by the end of the second quarter of 2004.

On August 24, 2003, the Contra Costa County District Attorney s Office in California issued a demand letter to ConocoPhillips seeking civil penalties in the amount of $524,000 for 31 alleged violations of the Bay Area Air Quality Management District regulations at our Rodeo facility of the San Francisco area refinery. The demand has been reduced to $361,000. These alleged violations cover the period from mid-2001 through August 2003. We are currently working with the Contra Costa County District Attorney s Office toward a negotiated resolution of this matter.

In August of 2003, EPA Region 6 issued a Show Cause Order alleging violations of the Clean Water Act at the Borger refinery. The alleged violations relate primarily to discharges of selenium and reported exceedances of permit limits for whole effluent toxicity. We met with EPA staff on October 29, 2003, to discuss the allegations. We believe the EPA staff is evaluating the information presented at the meeting. The EPA has not yet proposed a penalty amount.

On December 31, 2002, we received a Revised Proposed Agreed Order, which amended the June 24, 2002, Proposed Agreed Order, from the Texas Commission on Environmental Quality (TCEQ), proposing a penalty of $458,163 in connection with alleged air emission violations at our Borger refinery as a result of an inspection conducted by the TCEQ in October 2000. On March 19, 2003, the TCEQ issued a recalculation of the proposed penalty in the amount of $467,834. We are currently working with TCEQ toward a negotiated resolution of this matter.

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On December 17, 2002, the DOJ notified ConocoPhillips of various alleged violations of the NPDES permit for the Sweeny refinery. DOJ asserts that these alleged violations occurred at various times during the period beginning January 1997 through July 2002. We have reached a tentative agreement with the DOJ that will require us to pay a civil penalty and/or perform certain work valued at $700,000.

In December 2002, the Louisiana Department of Environmental Quality (LDEQ) notified ConocoPhillips of its intent to assess civil penalties for over 120 alleged regulatory violations at various Circle K stores in the Baton Rouge, Louisiana area. On October 6, 2003, the LDEQ notified ConocoPhillips that the civil penalty assessment for these alleged violations is $189,659. This matter was settled in November 2003.

On November 14, 2002, the TCEQ issued a proposed agreed Findings Order to resolve alleged water discharge violations of the Texas Water Code and Commission Rules at the Sweeny refinery for the period beginning March 2000 through July 2002. The proposed order assesses a penalty in the amount of $488,125. We have agreed with the TCEQ to settlement terms that are expected to be finalized during the first quarter of 2004.

On July 15, 2002, the United States filed a Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) cost recovery action against ConocoPhillips alleging that the United States has incurred unreimbursed oversight costs at the Lowry Superfund Site located in Arapahoe County, Colorado. The United States seeks recovery of approximately $12.3 million in past oversight costs and a declaratory judgment for future CERCLA response cost liability. Pursuant to the terms of a prior settlement agreement between us, Waste Management, Inc. and others, Waste Management has assumed our defense for this matter and it is our position that Waste Management should indemnify us for any liability arising from this action.

We have responded to information requests from EPA regarding New Source Review compliance at our Alliance, Bayway, Borger, Ferndale, Los Angeles, Sweeny, Trainer, and Wood River refineries; and the Rodeo and Santa Maria units of our San Francisco refinery. Although we have not been notified of any formal findings or violations arising from these information requests, we have been informed that the EPA is contemplating the filing of a civil proceeding against us for alleged violations of the Clean Air Act. We are currently seeking a negotiated resolution of these matters, which will likely result in increased environmental capital expenditures and governmental monetary sanctions.

All significant litigation arising from the March 27, 2000, explosion and fire that occurred in an out-of-service butadiene storage tank at the K-Resin® styrene-butadiene copolymer plant has now been resolved.

In June of 1997, we experienced pipeline spills on our Seminole pipeline at Banner, Wyoming, and Lodge Grass, Montana. In response to these spills, the DOJ advised us in August 2000 that the United States is contemplating a legal proceeding under the Clean Water Act against us. We and DOJ have reached a tentative agreement that will require us to pay a $465,000 civil penalty.

Additionally, we are subject to various lawsuits and claims including, but not limited to: actions challenging oil and gas royalty and severance tax payments; actions related to gas measurement and valuation methods; actions related to joint interest billings to operating agreement partners; and claims for damages resulting from leaking underground storage tanks or other accidental releases, with related toxic tort claims. As a result of Conoco s separation agreement with DuPont in October 1998, we also have assumed responsibility for current and future claims related to certain discontinued chemicals and agricultural chemicals businesses operated by Conoco in the past. In general, the effect on future financial results is not subject to reasonable estimation because considerable uncertainty exists. The ultimate liabilities resulting from such lawsuits and claims may be material to results of operations in the period in which they are recognized.

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Item 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None.

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EXECUTIVE OFFICERS OF THE REGISTRANT

Name	Position Held	Age*
Rand C. Berney	Vice President and Controller	48
William B. Berry	Executive Vice President, Exploration and Production	51
John A. Carrig	Executive Vice President, Finance, and Chief Financial Officer	52
Archie W. Dunham	Chairman of the Board of Directors	65
Philip L. Frederickson	Executive Vice President, Commercial	47
Stephen F. Gates	Senior Vice President, Legal, and General Counsel	57
John E. Lowe	Executive Vice President, Planning, Strategy and Corporate Affairs	45
J. J. Mulva	President and Chief Executive Officer	57
J. W. Nokes	Executive Vice President, Refining, Marketing, Supply and Transportation	57

**On March 1, 2004.*

There is no family relationship among the officers named above. Each officer of the company is elected by the Board of Directors at its first meeting after the Annual Meeting of Stockholders and thereafter as appropriate. Each officer of the company holds office from date of election until the first meeting of the directors held after the next Annual Meeting of Stockholders or until a successor is elected. The date of the next annual meeting is May 5, 2004. Set forth below is information concerning the executive officers.

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Rand C. Berney was appointed Vice President and Controller of ConocoPhillips upon completion of the merger. Prior to the merger, he was Phillips Vice President and Controller since 1997.

William B. Berry was appointed Executive Vice President, Exploration and Production of ConocoPhillips on January 1, 2003, having previously served as President of ConocoPhillips Asia Pacific operations since completion of the merger. Prior to the merger, he was Phillips Senior Vice President E&P Eurasia-Middle East operations since 2001; and Phillips Vice President E&P Eurasia operations since 1998.

John A. Carrig was appointed Executive Vice President, Finance, and Chief Financial Officer of ConocoPhillips upon completion of the merger. Prior to the merger, he was Phillips Senior Vice President and Chief Financial Officer since 2001; Phillips Senior Vice President, Treasurer and Chief Financial Officer since 2000; and Phillips Vice President and Treasurer since 1996.

Archie W. Dunham was appointed Chairman of the Board of Directors of ConocoPhillips upon completion of the merger. Prior to the merger, he was Conoco s Chairman of the Board, President and Chief Executive Officer since 1999; and Conoco s President and Chief Executive Officer since 1996.

Philip L. Frederickson was appointed Executive Vice President, Commercial of ConocoPhillips upon completion of the merger. Prior to the merger, he was Conoco s Senior Vice President of Corporate Strategy and Business Development since 2001; and Conoco s Vice President of Business Development since 1998.

Stephen F. Gates was appointed Senior Vice President, Legal, and General Counsel of ConocoPhillips effective May 1, 2003. Prior to joining ConocoPhillips, he was a partner at Mayer, Brown, Rowe & Maw. Previously, he served as senior vice president and general counsel of FMC Corporation in 2000 and 2001. Prior to that, he served at BP Amoco (now BP plc) where he was executive vice president and group chief of staff after serving as vice president and general counsel of Amoco.

John E. Lowe was appointed Executive Vice President, Planning, Strategy and Corporate Affairs of ConocoPhillips upon completion of the merger. Prior to the merger, he was Phillips Senior Vice President, Corporate Strategy and Development since 2001; Phillips Senior Vice President of Planning and Strategic Transactions since 2000; Phillips Vice President of Planning and Strategic Transactions since 1999; and Phillips Manager of Strategic Growth Projects since earlier in 1999.

J. J. Mulva was appointed President and Chief Executive Officer of ConocoPhillips upon completion of the merger. Prior to the merger, he was Phillips Chairman of the Board of Directors and Chief Executive Officer since 1999; and Phillips Vice Chairman of the Board of Directors, President, and Chief Executive Officer since earlier in 1999.

J. W. Nokes was appointed Executive Vice President, Refining, Marketing, Supply and Transportation of ConocoPhillips upon completion of the merger. Prior to the merger, he was Conoco s Executive Vice President, Worldwide Refining, Marketing, Supply and Transportation since 1999.

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PART II

Item 5. MARKET FOR REGISTRANT S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

Quarterly Common Stock Prices and Cash Dividends Per Share

ConocoPhillips common stock began trading on September 3, 2002, the first trading day after the effective date of the merger. ConocoPhillips common stock is traded on the New York Stock Exchange, under the symbol COP.

	Stock Price		
	High	Low	Dividends
2003			
First	**$ 53.85**	**45.14**	**.40**
Second	**55.95**	**49.67**	**.40**
Third	**57.53**	**51.29**	**.40**
Fourth	**66.04**	**54.29**	**.43**
2002			
Third (from September 3)	$ 53.20	45.87	.36
Fourth	50.75	44.03	.40

Phillips Petroleum Company s (predecessor to ConocoPhillips) stock was traded primarily on the New York, Pacific and Toronto stock exchanges. On August 30, 2002, it ceased trading.

	Stock Price		
Phillips Petroleum Company (predecessor to ConocoPhillips)	High	Low	Dividends
2002			
First	$ 63.80	55.30	.36
Second	64.10	54.53	.36
Third (through August 30)	59.21	44.75	N/A

Closing Stock Price at December 31, 2003	$ 65.57
Closing Stock Price at January 31, 2004	$ 65.88
Number of Stockholders of Record at January 31, 2004*	59,165

* *In determining the number of stockholders, we consider clearing agencies and security position listings as one stockholder for each agency or listing.*

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Item 6. SELECTED FINANCIAL DATA

	Millions of Dollars Except Per Share Amounts				
	2003	2002*	2001*	2000	1999
Sales and other operating revenues	**$ 104,196**	56,748	24,892	22,155	14,988
Income from continuing operations	**4,593**	698	1,601	1,848	604
Per common share					
Basic	**6.75**	1.45	5.46	7.26	2.39
Diluted	**6.70**	1.44	5.43	7.21	2.37
Net income (loss)	**4,735**	(295)	1,661	1,862	609
Per common share					
Basic	**6.96**	(.61)	5.67	7.32	2.41
Diluted	**6.91**	(.61)	5.63	7.26	2.39
Total assets	**82,455**	76,836	35,217	20,509	15,201
Long-term debt	**16,340**	18,917	8,610	6,622	4,271
Mandatorily redeemable other minority interests and preferred securities	**141**	491	650	650	650
Cash dividends declared per common share	**1.63**	1.48	1.40	1.36	1.36

* *Income from continuing operations, including related per share amounts, have been restated to reflect the adoption of Statement of Financial Accounting Standards No. 145, Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections, as it relates to the classification of premiums paid on the early retirement of debt.*

See Management s Discussion and Analysis of Financial Condition and Results of Operations for a discussion of factors that will enhance an understanding of this data. The following transactions affect the comparability of the amounts included in the table above:

The merger of Conoco and Phillips in 2002;

The classification of a substantial portion of our retail marketing operations as discontinued operations in late 2002;

The acquisition of Tosco Corporation in 2001;

The acquisition of Atlantic Richfield Company s Alaskan operations in 2000; and

The contribution of a significant portion of the company s midstream and chemicals businesses into joint ventures accounted for using equity-method accounting in 2000.

Also, see Note 2 Changes in Accounting Principles, in the Notes to Consolidated Financial Statements, for information on changes in accounting principles that affect the comparability of the amounts included in the table above.

Item 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

February 25, 2004

Management s Discussion and Analysis is the company s analysis of its financial performance and of significant trends that may affect future performance. It should be read in conjunction with the financial statements and notes, and supplemental oil and gas disclosures. It contains forward-looking statements including, without limitation, statements relating to the company s plans, strategies, objectives, expectations, intentions, and resources that are made pursuant to the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. The words intends, believes, expects, plans, scheduled, anticipates, estimates, and similar expressions identify forward-looking statements. T company does not undertake to update, revise or correct any of the forward-looking information unless required to do so under the federal securities laws. Readers are cautioned that such forward-looking statements should be read in conjunction with the company s disclosures under the heading: CAUTIONARY STATEMENT FOR THE PURPOSES OF THE SAFE HARBOR PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995, beginning on page 83.

RESULTS OF OPERATIONS

Merger of Conoco and Phillips

On August 30, 2002, Conoco Inc. (Conoco) and Phillips Petroleum Company (Phillips) combined their businesses by merging with wholly owned subsidiaries of a new company named ConocoPhillips (the merger). The merger was accounted for using the purchase method of accounting, with Phillips designated as the acquirer for accounting purposes. Because Phillips was designated as the acquirer, its operations and results are presented in this annual report for all periods prior to the close of the merger. From the merger date forward, the operations and results of ConocoPhillips reflect the combined operations of the two companies.

Business Environment and Executive Summary

Our overall earnings depend primarily upon the profitability of our Exploration and Production (E&P) and Refining and Marketing (R&M) segments. Our earnings normally are less impacted by results from the Midstream, Chemicals and Emerging Businesses segments.

Crude oil and natural gas prices, along with refining margins, play the most significant roles in our profitability. These prices and margins are driven by market factors over which we have no control. However, from a competitive perspective, there are other important factors that we must manage well to be successful, including:

- Operating our producing properties and refining and marketing operations safely, consistently and in an environmentally sound manner. Safety is our first priority and we are committed to protecting the health and safety of everyone who has a role in our operations. Consistently high utilization rates at our refineries, minimizing downtime in producing fields, and maximizing the development of our reserves all enable us to capture the value the market gives us in terms of prices and margins. Finally, our operations are conducted in a manner that emphasizes our environmental stewardship.

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Controlling costs and expenses. Since we cannot control the prices of the commodity products we sell, keeping our operating and overhead costs low, within the context of our commitment to safety and environmental stewardship, is a top priority. We monitor these costs using various methodologies that are reported to senior management monthly, on both an absolute-dollar basis and a per-unit basis. Low operating and overhead costs are critical to maintaining competitive positions in our industries, as such, cost control is a component of our variable compensation programs.

Selecting the appropriate projects in which to invest our capital dollars. We participate in capital-intensive industries. As a result, we must often invest significant capital dollars to explore for new oil and gas fields, develop newly discovered fields, maintain existing fields, or continue to maintain and improve our refinery complexes. We invest in those projects that are expected to provide an adequate financial return on invested dollars. However, there are often long lead times from the time we make an investment to the time that investment is operational and begins generating financial returns. Our capital spending in 2003 totaled $6.2 billion, and we anticipate capital spending to be approximately $6.9 billion in 2004.

Evaluating our asset portfolio. We continue to evaluate opportunities to acquire assets that will contribute to future growth at competitive prices. We also continually assess our assets to determine if any no longer fit our growth strategy and should be sold or otherwise disposed. This management of our asset portfolio is important to ensuring our long-term growth and maintaining adequate financial returns.

Hiring, developing and retaining a talented workforce. We want to attract, train, develop and retain individuals with the knowledge and skills to implement our business strategy and who support our values and ethics.

Many of our key performance indicators are shown in the statistical tables provided at the beginning of our operating segment sections that follow. These include crude oil and natural gas prices and production, natural gas liquids prices, refining capacity utilization, and refinery output. We also use the return on capital employed measure.

Other significant factors that can and/or do affect our profitability include:

Property and leasehold impairments. As mentioned above, we participate in capital intensive industries. At times, these investments become impaired when our reserve estimates are revised downward, when crude oil or natural gas prices decline significantly for long periods of time, or when a decision to dispose of an asset leads to a write-down to fair market value. Also, at times we invest large amounts of money in exploration blocks which, if exploratory drilling proves unsuccessful, could lead to material impairment of leasehold values.

Goodwill. As a result of recent mergers and acquisitions, we have a significant amount of goodwill on our balance sheet. Although our latest tests indicate that no goodwill impairment is currently required, future deterioration in market conditions could lead to goodwill impairments that would have a substantial negative affect on the company s profitability.

Tax jurisdictions. As a global company, our operations are located in countries with different tax rates and fiscal structures. Accordingly, our overall effective tax rate can vary significantly between periods based on the mix of earnings within our global operations.

Segment Analysis

The E&P segment s results are most closely linked to crude oil and natural gas prices. These are commodity products, the prices of which are subject to factors external to our company and over which we have no control. We benefited from favorable crude oil prices in 2003, which contributed significantly to what we view as strong results from this segment in 2003. For a discussion of factors impacting crude oil and natural gas prices in 2003, as well as our view of the potential movement of these prices into 2004, see the Outlook section. At year-end 2003, we estimated that a $1 per barrel change in crude oil prices would have an estimated $170 million annual impact on net income. For natural gas, the corresponding impact is approximately $40 million for a 10 cent per thousand cubic feet price change.

The Midstream segment s results are most closely linked to natural gas liquids prices. The most important factor on the profitability of this segment is the results from our 30.3 percent equity investment in Duke Energy Field Services, LLC (DEFS). Higher natural gas liquids prices improved results from this segment in 2003. In early 2004, we approved the disposal of some of our non-DEFS Midstream assets located in the Lower 48 states that are not associated with our E&P operations.

Refining margins, refinery utilization, cost control, and marketing margins primarily drive the R&M segment s results. Refining margins are subject to movements in the cost of crude oil and other feedstocks, and the sales prices for refined products, which are subject to market factors over which we have no control. Refining margins in 2003 were much improved over 2002, resulting in improved R&M profitability. See the Outlook section for further discussion of refining margins in 2003 and our view of their potential movement into 2004. At year-end 2003, we estimated that a 25 cent per barrel change in refining margins would have an estimated $125 million annual impact on net income. For wholesale marketing margins, the corresponding impact is approximately $100 million for a 1 cent per gallon margin change. Our refineries operated at 94 percent of rated capacity in 2003, and our goal in 2004 is to operate at about the same level.

The Chemicals segment consists of our 50 percent interest in Chevron Phillips Chemical Company LLC (CPChem). The chemicals and plastics industry is mainly a commodity-based industry where the margins for key products are based on market factors over which CPChem has little or no control. The chemicals and plastics industry has been in a cyclical downturn for the last several years. In this difficult market environment, CPChem has placed great emphasis on safety, cost control and managing its capacity utilization. In addition, CPChem is investing in feedstock-advantaged areas in the Middle East with access to large, growing markets, such as Asia. With its low cost structure, we feel CPChem is well positioned to benefit from improved margins when the chemicals industry emerges from its downturn.

The Emerging Businesses segment represents our investment in new technologies or businesses outside our normal scope of operations. We do not expect the results from this segment to be material to our consolidated results. However, the businesses in this segment allow us to support our primary segments by staying current on new technologies that could become important drivers of profitability in future years.

At December 31, 2003, we had a debt-to-capital ratio of 34 percent. We have made a priority of using funds available after paying dividends and capital spending to reduce debt. We reduced our debt by $4.8 billion in 2003. We feel that by lowering our debt-to-capital ratio over the next several years to about 30 percent, we can improve our cost of capital and further position ourselves for growth opportunities in the future.

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Consolidated Results

	Millions of Dollars		
Years Ended December 31	**2003**	2002	2001
Income from continuing operations	$ **4,593**	698	1,601
Income (loss) from discontinued operations	**237**	(993)	32
Cumulative effect of accounting changes	**(95)***		28
Net income (loss)	$ **4,735**	(295)	1,661

* *Includes a $107 million charge related to discontinued operations.*

A summary of the company s net income (loss) by business segment follows:

	Millions of Dollars		
Years Ended December 31	**2003**	2002	2001
Exploration and Production (E&P)	$ **4,302**	1,749	1,699
Midstream	**130**	55	120
Refining and Marketing (R&M)	**1,272**	143	397
Chemicals	**7**	(14)	(128)
Emerging Businesses	**(99)**	(310)	(12)
Corporate and Other*	**(877)**	(1,918)	(415)
Net income (loss)	$ **4,735**	(295)	1,661

* *Includes income (loss) from discontinued operations.*

2003 vs. 2002

Net income was $4,735 million in 2003, compared with a net loss of $295 million in 2002. The improved results in 2003 were primarily due to:

- Increased E&P and R&M production volumes as a result of the merger;
- Higher crude oil, natural gas, and natural gas liquids prices in our E&P segment;
- Improved refining and marketing margins in our R&M segment;

Lower impairments and lease loss accruals related to discontinued operations; and

Lower merger-related expenses in 2003, compared with 2002.

See the Segment Results section for additional information on our E&P and R&M results, as well as our other reporting segments.

2002 vs. 2001

We incurred a net loss of $295 million in 2002, compared with net income of $1,661 million in 2001. The decrease was primarily attributable to recognizing impairments and loss accruals totaling $1,077 million after-tax associated with our retail and wholesale marketing operations that were classified as discontinued operations in late 2002, as well as merger-related costs totaling $557 million after-tax. Also negatively impacting results for 2002 were other asset impairments totaling $192 million after-tax, lower refining margins, lower natural gas sales prices, decreased equity earnings from Duke Energy Field Services, LLC (DEFS), and higher interest expense. These factors were partially offset by improved results from Chemicals and higher production volumes in E&P after the merger.

Income Statement Analysis

2003 vs. 2002

The merger affects the comparability of the 2003 and 2002 periods. 2003 includes a full year of ConocoPhillips operations, while 2002 includes only four months of combined operations. Prior to August 30, 2002, our results reflect Phillips operations only. Accordingly, the merger significantly increased:

- Sales revenues and purchase costs due to higher volumes of products being bought and sold;
- Equity earnings due to an increased number of equity affiliates;
- Production and operating expenses and selling, general and administrative expenses due to the increased size and scope of operations following the merger, partially offset by lower merger-related costs in 2003;
- Depreciation, depletion and amortization due to the increased depreciable asset base;
- Taxes other than income taxes due to higher gasoline sales, production volumes and property and payroll taxes; and
- Interest and debt expense due to higher debt levels following the merger.

In addition to the merger impact, sales and other operating revenues and purchase costs increased because of higher prices for key products such as crude oil, natural gas, automotive gasoline and distillates. These are commodity products and their price levels are determined by market factors.

Our share of earnings from affiliates acquired in the merger accounted for the majority of the increase in the equity earnings. Of these, the E&P joint ventures in Canada (Petrovera) and Venezuela (Petrozuata), along with CFJ Properties in our R&M segment, provided the largest equity earnings. On February 18, 2004, we sold our interest in the Petrovera joint venture. Of the equity affiliates held prior to the merger, our equity earnings from DEFS improved on higher natural gas liquids prices, and our earnings from Hamaca, an E&P heavy-oil joint venture in Venezuela, increased due to higher crude oil production.

A higher net gain on asset sales was primarily responsible for the increase in other income in 2003. During 2003 we sold several E&P operations that did not fit into our long-term growth strategy. In addition, 2003 included gains attributable to insurance demutualization benefits. See the Corporate and Other section of Segment Results for additional information on these insurance benefits.

Selling, general and administrative expenses in 2002 included a $246 million charge for the write-off of in-process research and development costs acquired in the merger. The absence of such a significant charge in the 2003 period reduced the impact of the merger on this line item.

Property impairments increased by $75 million in 2003, compared with 2002. The 2003 impairments were recorded as a result of asset status changes from held-for-use to held-for-sale, producing properties that failed to meet recoverability tests, and tax law changes in Norway affecting asset removal costs. During 2002, property impairments were triggered by asset dispositions and the impairment of tradenames. See Note 12 Property Impairments, in the

Notes to Financial Statements, for additional information.

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Accretion on discounted liabilities increased $123 million in 2003, reflecting accretion expense on environmental liabilities assumed in the merger and discounted obligations associated with the retirement and removal of long-lived assets that became effective January 1, 2003, with the adoption of Statement of Financial Accounting Standards (SFAS) No. 143, Accounting for Asset Retirement Obligations. See Note 2 Changes in Accounting Principles, in the Notes to Financial Statements, for additional information on SFAS No. 143.

In addition to the merger impact, interest and debt expense also increased in 2003 because of the adoption of Financial Accounting Standards Board (FASB) Interpretation No. 46, Consolidation of Variable Interest Entities, (FIN 46). The adoption of FIN 46 for variable interest entities involving synthetic leases and certain other financing structures, effective January 1, 2003, resulted in increased balance sheet debt, which resulted in higher interest expense in 2003. See Note 2 Changes in Accounting Principles, and Note 14 Debt, in the Notes to Consolidated Financial Statements, for additional information.

During 2003, we recognized a $28 million gain on subsidiary equity transactions related to our E&P Bayu-Undan development in the Timor Sea. See Note 7 Subsidiary Equity Transactions, in the Notes to Consolidated Financial Statements, for additional information.

Our effective tax rate in 2003 was 45 percent, compared with 67 percent in 2002. The lower effective tax rate in 2003 primarily was the result of a higher proportion of income in lower-tax-rate jurisdictions and the one-time impact of tax law changes in certain international jurisdictions. Contributing to the higher effective tax rate in 2002 was a write-off of in-process research and development costs, as well as the partial impairment of an exploration prospect, both without corresponding tax benefits in 2002.

Our discontinued operations had income of $237 million in 2003, compared with a net loss of $993 million in 2002. The net loss in 2002 reflected charges totaling $1,008 million after-tax related to the impairment of properties, plants and equipment; goodwill; intangible assets; and provisions for losses associated with various operating lease commitments. For additional information about our discontinued operations, see Note 4 Discontinued Operations, in the Notes to Consolidated Financial Statements.

We adopted SFAS No. 143 effective January 1, 2003, resulting in the recognition of a benefit of $145 million for the cumulative effect of this accounting change. Also effective January 1, 2003, we adopted FIN 46 for variable interest entities involving synthetic leases and certain other financing structures created prior to February 1, 2003. This resulted in a charge of $240 million for the cumulative effect of this accounting change. Together, these resulted in a net charge of $95 million. For additional information on these accounting changes, see Note 2 Changes in Accounting Principles, in the Notes to Consolidated Financial Statements.

2002 vs. 2001

In addition to the merger of Conoco and Phillips on August 30, 2002, ConocoPhillips closed on the $7 billion acquisition of Tosco Corporation on September 14, 2001. Together, these transactions significantly increased operating revenues; equity earnings; other income; purchase costs; operating expenses; selling, general and administrative expenses; depreciation, depletion and amortization; taxes other than income taxes; accretion on discounted liabilities; and interest and debt expense in 2002, compared with 2001.

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Restructuring Accruals

As a result of the merger, we began a restructuring program in September 2002 to capture the benefits of combining Conoco and Phillips by eliminating redundancies, consolidating assets, and sharing common services and functions across regions. We expect the restructuring program to be completed by the end of the first quarter of 2004. From September 2002 through December 31, 2003, approximately 3,900 positions worldwide had been identified for elimination. Of this total, approximately 3,000 employees had been terminated by December 31, 2003. The information in Note 5 Restructuring, in the Notes to Consolidated Financial Statements, is incorporated herein by reference.

Segment Results

E&P

	2003	2002	2001
	Millions of Dollars		
Net Income			
Alaska	$ **1,445**	870	866
Lower 48	**929**	286	476
United States	**2,374**	1,156	1,342
International	**1,928**	593	357
	$ **4,302**	1,749	1,699

	2003	2002	2001
	Dollars Per Unit		
Average Sales Prices			
Crude oil (per barrel)			
United States	$ **28.85**	23.83	23.57
International	**28.27**	25.14	24.16
Total consolidated	**28.54**	24.38	23.77
Equity affiliates	**18.58**	18.41	12.36
Worldwide	**27.47**	24.07	23.74
Natural gas lease (per thousand cubic feet)			
United States	**4.62**	2.75	3.56
International	**3.71**	2.79	2.60
Total consolidated	**4.07**	2.77	3.23
Equity affiliates	**4.44**	2.71	
Worldwide	**4.07**	2.77	3.23

Average Production Costs Per Barrel of Oil Equivalent				
United States	$	**5.89**	5.66	5.52
International		**4.25**	3.99	2.70
Total consolidated		**5.00**	4.94	4.60
Equity affiliates		**4.72**	4.38	2.74
Worldwide		**4.98**	4.92	4.60

Finding and Development Costs Per Barrel of Oil Equivalent*				
United States	$	**9.30**	7.46	5.15
International		**4.54**	5.09	6.80
Worldwide		**5.35**	5.57	5.97

* *Includes our share of equity affiliates.*

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	2003	2002	2001
	Millions of Dollars		
Worldwide Exploration Expenses			
General administrative; geological and geophysical; and lease rentals	$ **301**	285	207
Leasehold impairment	**133**	146	51
Dry holes	**167**	161	48
	$ **601**	592	306

	Thousands of Barrels Daily		
Operating Statistics			
Crude oil produced			
Alaska	**325**	331	339
Lower 48	**54**	40	34
United States	**379**	371	373
European North Sea	**290**	196	136
Asia Pacific	**61**	24	17
Canada	**30**	13	1
Other areas	**72**	43	34
Total consolidated	**832**	647	561
Equity affiliates	**102**	35	2
	934	682	563
Natural gas liquids produced			
Alaska	**23**	24	25
Lower 48	**25**	8	1
United States	**48**	32	26
European North Sea	**9**	8	7
Canada	**10**	4	
Other areas	**2**	2	2

	69	46	35

	Millions of Cubic Feet Daily		
Natural gas produced*			
Alaska	**184**	175	177
Lower 48	**1,295**	928	740
United States	**1,479**	1,103	917
European North Sea	**1,215**	595	308
Asia Pacific	**318**	137	51
Canada	**435**	165	18
Other areas	**63**	43	41
Total consolidated	**3,510**	2,043	1,335
Equity affiliates	**12**	4	
	3,522	2,047	1,335

* *Represents quantities available for sale. Excludes gas equivalent of natural gas liquids shown above.*

	Thousands of Barrels Daily		
Mining operations			
Syncrude produced	**19**	8	

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2003 vs. 2002

The E&P segment explores for and produces crude oil, natural gas, and natural gas liquids on a worldwide basis. It also mines deposits of oil sands in Canada to extract the bitumen and upgrade it into a synthetic crude oil. At December 31, 2003, our E&P operations were producing in the United States, the Norwegian and U.K. sectors of the North Sea, Canada, Nigeria, Venezuela, offshore Timor Lesté in the Timor Sea, offshore Australia, offshore China, offshore the United Arab Emirates, offshore Vietnam, Russia, and Indonesia.

Net income from the E&P segment increased 146 percent in 2003, compared with 2002. The improvement reflects higher production volumes, primarily due to the merger; higher crude oil and natural gas prices; and an increased net gain on asset sales. These items were partially offset by higher production and operating expenses; depreciation, depletion and amortization; and taxes other than income taxes, all the result of the larger size and scope of our operations following the merger.

In addition, 2003 included benefits of $233 million in our international E&P operations from changes in income tax and site restoration laws, as well as an equity realignment of certain Australian operations. Also, the cumulative effect of the adoption of SFAS No. 143 and the adoption of FIN 46 for variable interest entities involving synthetic leases and certain other financing structures increased E&P s net income by $142 million in 2003.

Our average worldwide crude oil sales price was $27.47 per barrel in 2003, compared with $24.07 in 2002. We also benefited from higher natural gas prices in 2003, with our average worldwide price increasing from $2.77 per thousand cubic feet in 2002 to $4.07 in 2003. If crude oil and natural gas prices in 2004 do not remain at the historically strong levels experienced in 2003, E&P s earnings will be negatively impacted in 2004. See the Outlook section for additional discussion of crude oil and natural gas prices.

ConocoPhillips proved reserves at year-end 2003 were 7.85 billion barrels of oil equivalent, a slight increase over 7.81 billion barrels at year-end 2002. Our Canadian Syncrude mining operations had an additional 265 million barrels of proved oil sands reserves at the end of 2003, compared with 272 million barrels at year-end 2002.

2002 vs. 2001

Net income from the E&P segment increased 3 percent in 2002, compared with 2001. Although E&P benefited from four months of increased production volumes in 2002 following the merger, this increase was mostly offset by lower natural gas sales prices, higher exploration expenses, and the unfavorable $24 million impact of a tax law change in the United Kingdom. Our average worldwide crude oil sales price was $24.07 per barrel in 2002, a 1 percent increase over $23.74 in 2001. Our average worldwide natural gas price in 2002 was $2.77 per thousand cubic feet, a 14 percent decrease from $3.23 in 2001.

Our proved reserves at year-end 2002 were 7.81 billion barrels of oil equivalent, a 52 percent increase over year-end 2001 s 5.13 billion barrels of oil equivalent. The increase was attributable to the merger.

U.S. E&P

2003 vs. 2002

Net income from our U.S. E&P operations increased 105 percent in 2003, compared with 2002. Net income from our Alaskan operations increased $575 million in 2003. The improvement in Alaska reflects higher crude oil prices, and a net $143 million benefit from the cumulative effect of adopting SFAS No. 143 and FIN 46, partially offset by slightly lower crude oil production volumes. The West Coast price of our Alaskan crude oil production increased 22 percent in 2003, from $23.75 per barrel in 2002 to $28.87 per barrel in 2003. Normal field declines and some operating interruptions in 2003 were mostly offset by increased production from the Borealis satellite field, the new Kuparuk Palm drill site, and Alpine, which enabled us to experience only a slight decrease in our Alaska crude oil production rate in 2003.

Our E&P Lower 48 net income increased $643 million in 2003, primarily because of increased natural gas production and sales prices, as well as, to a lesser extent, higher crude oil production and prices. U.S. Lower 48 natural gas prices increased 71 percent in 2003. Our increased production volumes in the Lower 48 mainly were the result of the merger, partially offset by the impact of asset dispositions. We continued our Lower 48/Gulf of Mexico asset rationalization program in 2003, which resulted in the sale of properties that did not fit into our long-term growth strategy. As planned, we are exiting the shallow water areas of the Gulf of Mexico. The Lower 48 operations recognized a net $1 million charge from the cumulative effect of adopting SFAS No. 143 and FIN 46 effective January 1, 2003.

2002 vs. 2001

Net income from U.S. E&P operations decreased 14 percent in 2002, compared with 2001. Although net income for 2002 benefited from four months of increased production volumes following the merger, this increase was more than offset by lower natural gas prices, lower production volumes in Alaska, and higher dry hole costs. Our U.S. average natural gas price in 2002 was 23 percent lower than in 2001.

Our U.S. crude oil production decreased slightly in 2002, while natural gas production increased 20 percent. The increase in natural gas production was mainly due to four months of production from fields acquired in the merger. The merger impact on total crude oil production was offset by lower production in Alaska, which experienced normal field declines, along with operating interruptions at the Prudhoe Bay field.

International E&P

2003 vs. 2002

Net income from our international E&P operations increased 225 percent in 2003, compared with 2002. Increased production volumes following the merger accounted for the majority of the earnings improvement. Higher crude oil and natural gas prices contributed to the remaining increase.

International E&P s production on a barrel-of-oil-equivalent basis averaged 916,000 barrels per day in 2003, compared with 482,000 barrels per day in 2002. In addition, our Syncrude mining operations produced 19,000 barrels per day in 2003, compared with 8,000 barrels per day in 2002. Although the merger was the primary reason for the production increase, other items impacting our production rate in 2003 were:

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The startup of the Grane field in the Norwegian North Sea in September 2003;

A full year s production from Phase I of the development of the Peng Lai 19-3 field in China s Bohai Bay; and

The startup of production from the Phase I development of the Su Tu Den project in Vietnam late in the fourth quarter of 2003.

Included in international E&P s net income in 2003 was a net foreign currency transaction loss of $50 million, compared with a net loss of $34 million in 2002.

International E&P s net income in 2003 also was favorably impacted by the following items:

In Norway, the Norway Removal Grant Act (1986) was repealed in the second quarter of 2003. Prior to its repeal, this Act required the Norwegian government to contribute to the cost of removing offshore oil and gas production facilities. Now, the co-venturers in the facilities must fund all removal costs, but can deduct the removal costs, as incurred, under the Petroleum Tax Act, at the marginal tax rate in effect at the time of removal. These changes required us: to recognize an additional liability for the government s share, prior to repeal of the Act, of the future removal costs, with a corresponding increase in properties, plants and equipment (PP&E); and to establish a net deferred tax asset for the temporary differences between the financial basis and tax basis of all of our Norwegian removal assets and liabilities. Some of the increases in PP&E were on shut-in fields, which led to immediate impairments of those properties. The overall impact on 2003 results was a net after-tax benefit of $87 million.

In the Timor Sea region, ConocoPhillips and its co-venturers received final approvals from authorities to proceed with the natural gas development phase of the Bayu-Undan project in the second quarter of 2003. This approval allowed a broad ownership interest re-alignment among the co-venturers to proceed, which included our sale of a 10 percent interest in the project and the issuance of equity by previously wholly owned subsidiaries. In addition, the ratification of the Australia/Timor Lesté treaty lowered the company s deferred tax liability position. The net result of these events was an after-tax benefit of $51 million in 2003. See Note 7 Subsidiary Equity Transactions, in the Notes to Consolidated Financial Statements, for additional information.

In November 2003, the Canadian Parliament enacted federal tax rate reductions for oil and gas producers. As a result we recognized a $95 million benefit upon revaluation of our deferred tax liability in the fourth quarter.

2002 vs. 2001

Net income from international E&P operations increased 66 percent in 2002. The improvement reflects four months of increased production volumes following the merger. However, 2002 net income included a $24 million deferred tax charge related to tax law changes in the United Kingdom. Net income in 2002 also included a $77 million leasehold impairment of deepwater Block 34, offshore Angola, due to an unsuccessful exploratory well in the block, along with higher dry hole charges.

Our international crude oil production increased 64 percent in 2002, while natural gas production increased 126 percent. The increases were mainly due to the addition of four months of production from fields acquired in the merger.

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Midstream

		2003	2002	2001
		Millions of Dollars		
Net Income*	$	**130**	55	120
**Includes DEFS related net income:*	$	***72***	*23*	*101*
		Dollars Per Barrel		
Average Sales Prices				
U.S. natural gas liquids*				
Consolidated	$	**22.67**	19.07	
Equity		**22.12**	15.92	18.77

	Thousands of Barrels Daily		
Operating Statistics			
Natural gas liquids extracted**	**219**	156	120
Natural gas liquids fractionated	**167**	133	108

**Based on index prices from the Mont Belvieu and Conway market hubs that are weighted by natural gas liquids component and location mix.*
***Includes our share of equity affiliates.*

2003 vs. 2002

The Midstream segment purchases raw natural gas from producers and gathers natural gas through extensive pipeline gathering systems. The natural gas is then processed to extract natural gas liquids from the raw gas stream. The remaining residue gas is marketed to electrical utilities, industrial users, and gas marketing companies. Most of the natural gas liquids are fractionated separated into individual components like ethane, butane and propane and marketed as chemical feedstock, fuel, or blendstock.

Our Midstream segment consists of a 30.3 percent interest in Duke Energy Field Services, LLC (DEFS), as well as our other natural gas gathering and processing operations, and natural gas liquids fractionation and marketing businesses, primarily in the United States, Canada and Trinidad.

Net income from the Midstream segment increased 136 percent in 2003, compared with 2002. The increase primarily was attributable to improved results from DEFS and the addition of midstream operations following the merger. DEFS results mainly increased because of higher natural gas liquids prices in 2003. In addition, DEFS results in 2002 included higher costs for gas imbalance adjustment accruals.

Included in the Midstream segment s 2003 net income was a basis-difference benefit of $36 million, compared with $35 million in 2002, representing the amortization of the excess amount of our 30.3 percent equity interest in the net assets of DEFS over the book value of our investment in DEFS.

2002 vs. 2001

Net income from the Midstream segment decreased 54 percent in 2002, compared with 2001. The decrease was primarily due to lower results from DEFS, which experienced a decline in natural gas liquids prices, increased costs for gas imbalance accruals and other adjustments, and higher operating expenses.

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These items were partially offset by the benefit of four months   results from operations acquired in the merger.

Included in the Midstream segment   s net income in 2002 was a benefit of $35 million, representing the amortization of the basis difference between the book value of ConocoPhillips   contribution to DEFS and our 30.3 percent equity interest in DEFS. The corresponding amount for 2001 was $36 million.

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R&M

	2003	2002	2001
	Millions of Dollars		
Net Income			
United States	$ **990**	138	395
International	**282**	5	2
	$ **1,272**	143	397

	Dollars Per Gallon		
U.S. Average Sales Prices*			
Automotive gasoline			
Wholesale	$ **1.05**	.96	.83
Retail	**1.35**	1.03	1.01
Distillates wholesale	**.92**	.77	.78

** Excludes excise taxes.*

	Thousands of Barrels Daily		
Operating Statistics			
Refining operations*			
United States			
Rated crude oil capacity**	**2,168**	1,829	732
Crude oil runs	**2,074**	1,661	686
Capacity utilization (percent)	**96%**	91	94
Refinery production	**2,301**	1,847	795
International			
Rated crude oil capacity**	**442**	195	22
Crude oil runs	**385**	152	20
Capacity utilization (percent)	**87%**	78	91
Refinery production	**412**	164	19
Worldwide			
Rated crude oil capacity**	**2,610**	2,024	754
Crude oil runs	**2,459**	1,813	706
Capacity utilization (percent)	**94%**	90	94
Refinery production	**2,713**	2,011	814

Petroleum products sales volumes			
United States			
Automotive gasoline	**1,369**	1,230	537
Distillates	**575**	502	225
Aviation fuels	**180**	185	78
Other products	**492**	372	220
	2,616	2,289	1,060
International	**430**	162	10
	3,046	2,451	1,070

**Includes our share of equity affiliates.*

***Weighted-average crude oil capacity for the period, including the refineries acquired in the Tosco acquisition in September 2001 and the refineries acquired as a result of the merger. Actual capacity at year-end 2002 and 2001 was 2,166,000 and 1,656,000 barrels per day, respectively, in the United States and 440,000 and 72,000 barrels per day, respectively, internationally.*

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2003 vs. 2002

The R&M segment s operations encompass refining crude oil and other feedstocks into petroleum products (such as gasoline, distillates and aviation fuels), buying and selling crude oil and refined products, and transporting, distributing and marketing petroleum products. R&M has operations in the United States, Europe and Asia Pacific.

Net income from our R&M segment increased substantially in 2003, compared with 2002. The improved results primarily were due to significantly higher U.S. refining margins. The addition of refining and marketing assets in the merger also contributed to the higher 2003 earnings, as did increased wholesale gasoline margins. Partially offsetting the improvements was a net charge of $125 million for the cumulative effect of the adoption of FIN 46 for variable interest entities involving synthetic leases and certain other financing structures.

Our refineries produced 2.7 million barrels per day of petroleum products in 2003, compared with 2.0 million barrels per day in 2002. The increase reflects the addition of production from refineries acquired in the merger.

2002 vs. 2001

Net income from the R&M segment declined 64 percent in 2002, compared with 2001, reflecting lower refining margins, along with an $84 million after-tax impairment of a tradename and leasehold improvements of certain retail sites. R&M earnings for 2002 included four months results from operations acquired in the merger, as well as the impact of a full year s results from Tosco operations, while the 2001 results included Tosco operations for only the last three and one-half months of 2001.

Worldwide crude oil refining capacity utilization was 90 percent in 2002, compared with 94 percent in 2001. Our refineries produced 2.0 million barrels per day of petroleum products in 2002, compared with 814,000 barrels per day in 2001. The increase reflects a full year of operations for refineries acquired in the Tosco acquisition and four months of operations for the refineries acquired in the merger.

U.S. R&M

2003 vs. 2002

Net income from our U.S. R&M operations increased significantly in 2003, compared with 2002. The improved results mainly were due to significantly higher refining margins, particularly during the third quarter of 2003. Industry U.S. refining margins were strong in the third quarter of 2003 due to increased gasoline demand in August and an unusual number of refined product supply disruptions, including refinery outages in the Midwest caused by a major power blackout in August 2003. See the Outlook section for additional discussion of refining margins. We capitalized on the strong refining margins in the third quarter by running our U.S. refineries at a utilization rate of 96 percent during the quarter. However, this rate was negatively impacted by a fire at our Ponca City, Oklahoma, refinery during July that resulted in portions of the facility being shut down. The Ponca City refinery s throughput was restored in the fourth quarter of 2003 to levels achieved before the fire.

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The addition of refining and marketing assets in the merger also contributed to the higher 2003 earnings, as did increased wholesale gasoline margins. Partially offsetting the margin improvements in 2003 was a net charge of $125 million for the cumulative effect of the adoption of FIN 46 for variable interest entities involving synthetic leases and certain other financing structures, along with higher utility costs.

For the full year of 2003, our U.S. refineries ran at a crude oil capacity utilization rate of 96 percent, compared with 91 percent in 2002. The rate in 2002 was lowered by higher maintenance turnaround activity, the impact of tropical storms on our Gulf Coast refineries, and the loss of Venezuelan crude oil supply in the fourth quarter due to the economic and political instability in that country during the quarter.

2002 vs. 2001

Net income from U.S. R&M operations declined 65 percent in 2002, compared with 2001. The decrease was primarily due to lower refining margins, particularly in the Midcontinent and Gulf Coast regions, along with an $84 million after-tax impairment of a tradename and leasehold improvements of certain retail sites. These items were partially offset by increased production and sales volumes as a result of the Tosco acquisition and the merger. Net income for 2002 included four months of operations acquired in the merger, and a full year of Tosco operations, while the 2001 results included Tosco operations for only three and one-half months. Effective January 1, 2001, we changed our method of accounting for the costs of major maintenance turnarounds from the accrue-in-advance method to the expense-as-incurred method. The cumulative effect of this change in accounting principle increased R&M net income by $26 million. Also included in 2001 was a $27 million write-down of inventories to market value.

International R&M

2003 vs. 2002

Net income from our international R&M operations increased substantially in 2003, compared with 2002. The improvement was due to the larger size and scope of our international refining and marketing operations following the merger, along with higher international refining margins. Prior to the merger, our international R&M operations consisted only of our Whitegate refinery in Ireland with a rated crude oil capacity of 72,000 barrels per day. The merger added one wholly owned and four joint-venture refineries, with a rated crude oil capacity of 370,000 barrels per day. In addition, the merger added an extensive marketing network throughout Europe and Asia. Included in international R&M s net income in 2003 was a net foreign currency gain of $18 million, compared with a net gain of $9 million in 2002.

Our international crude oil capacity utilization rate was 87 percent in 2003, compared with 78 percent in 2002. The lower utilization rate in 2002 primarily was the result of the Humber refinery in the United Kingdom being shut down for an extended period of time in the fourth quarter due to a power outage and subsequent downtime.

2002 vs. 2001

Net income from international R&M operations increased $3 million in 2002, compared with 2001, reflecting the impact of the merger. The Humber refinery was shut down for an extended period of time during the fourth quarter of 2002, which negatively impacted international R&M s 2002 results.

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Chemicals

	Millions of Dollars		
	2003	2002	2001
Net Income (Loss)	**$ 7**	(14)	(128)

2003 vs. 2002

The Chemicals segment consists of our 50 percent interest in Chevron Phillips Chemical Company LLC (CPChem), which we account for using the equity method of accounting. CPChem uses natural gas liquids and other feedstocks to produce petrochemicals such as ethylene, propylene, styrene, benzene, and paraxylene. These products are then marketed and sold, or used as feedstocks to produce plastics and commodity chemicals, such as polyethylene, polystyrene and cyclohexane.

As the results in both years indicate, the chemicals industry continues to be challenged to effectively utilize capacity, manage costs and improve margins in a difficult economic environment. The worldwide chemicals industry experienced an economic downturn beginning in the second half of 2000, and the downturn continued through 2003. The downturn has led to excess production capacity in the industry and pressured margins on key products. The chemicals industry has also been impacted by high energy prices, which negatively impacts both utility and feedstock costs.

2002 vs. 2001

The Chemicals segment incurred a net loss of $14 million in 2002, compared with a net loss of $128 million in 2001. Higher margins in 2002 contributed to the improvement in results. Lower operating expenses, feedstock costs and energy prices in 2002 were partially offset by decreased sales prices.

Due to depressed economic conditions in the chemicals industry, asset retirements and impairments totaling $84 million after-tax were recognized by CPChem in 2001. A developmental reactor at the Pasadena Plastics Complex in Pasadena, Texas, was retired; accelerated depreciation was recognized by CPChem on two polyethylene reactors at the Orange chemical plant in Orange, Texas; an ethylene unit was retired at the Sweeny complex in Old Ocean, Texas; an equity affiliate of CPChem recorded a property impairment related to a polypropylene facility; property impairments were taken on the manufacturing facility in Puerto Rico; and the benzene and cyclohexane units at the Puerto Rico facility were retired. In addition, the valuation allowance on the Puerto Rico facility s deferred tax asset related to its net operating losses was increased in 2001 so that the deferred tax assets were fully offset by valuation allowances. Partially offsetting these impairments and retirements was a business interruption insurance settlement recognized by CPChem, and a favorable deferred tax adjustment recorded by ConocoPhillips related to the Puerto Rico facility, together totaling $57 million after-tax.

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Emerging Businesses

		Millions of Dollars		
		2003	2002	2001
Net Loss				
Technology solutions	$	**(20)**	(16)	(12)
Gas-to-liquids		**(50)**	(273)	
Power		**(5)**	(3)	
Other		**(24)**	(18)	
	$	**(99)**	(310)	(12)

2003 vs. 2002

The Emerging Businesses segment includes the development of new businesses outside our traditional operations. Emerging Businesses incurred a net loss of $99 million in 2003, compared with a net loss of $310 million in 2002. The net loss in 2003 was less than that in 2002 as a result of a $246 million write-off of purchased in-process research and development costs in the third quarter of 2002 related to Conoco s natural gas-to-liquids and other technologies. In accordance with FASB Interpretation No. 4, Applicability of FASB Statement No. 2 to Business Combinations Accounted for by the Purchase Method, value assigned to research and development activities in the purchase price allocation that have no alternative future use are required to be charged to expense at the date of the consummation of the combination. The $246 million charge was the same on both a before-tax and after-tax basis, because there was no tax basis in the assigned value prior to its write-off.

2002 vs. 2001

The Emerging Businesses segment posted a net loss of $310 million in 2002, compared with a net loss of $12 million in 2001. Results for 2002 included a $246 million write-off of acquired in-process research and development costs described above. The increased number of developing businesses after the merger also contributed to the larger losses in 2002.

Corporate and Other

		Millions of Dollars		
		2003	2002	2001
Net Loss				
Net interest	$	**(632)**	(412)	(262)

Corporate general and administrative expenses	**(173)**	(173)	(114)
Discontinued operations	**237**	(993)	32
Merger-related costs	**(223)**	(307)	
Cumulative effect of accounting changes	**(112)***		
Other	**26**	(33)	(71)
	$ (877)	(1,918)	(415)

** Includes a $107 million charge related to discontinued operations.*

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2003 vs. 2002

Net interest after-tax represents interest expense, net of interest income and capitalized interest, as well as premiums incurred on the early retirement of debt. Net interest increased 53 percent in 2003, compared with 2002. The increase in 2003 mainly was due to our higher debt levels following the merger, the impact of the adoption of FIN 46 for variable interest entities involving synthetic leases and certain other financing structures, and increased premiums on the early retirement of debt. The adoption of FIN 46 at January 1, 2003, increased debt, which resulted in higher interest expense. See Note 2 Changes in Accounting Principles, in the Notes to Consolidated Financial Statements, for additional information.

After-tax corporate general and administrative expenses were the same in 2003 as in 2002. Expenses in 2003 were impacted by the merger, as well as the expensing of stock options. Beginning in 2003, on a prospective basis, we elected to use the fair-value accounting method provided for under SFAS No. 123, Accounting for Stock-Based Compensation. Offsetting these items were increased allocations of certain staff costs to the operating segments in 2003. The increased corporate allocations did not have a material impact on the operating segments results.

Income from discontinued operations was $237 million in 2003, compared with a loss of $993 million in 2002. The net loss in 2002 reflects charges totaling $1,008 million after-tax related to the impairment of properties, plants and equipment; goodwill; intangible assets; and provisions for losses associated with various operating lease commitments. For additional information about our discontinued operations, see Note 4 Discontinued Operations, in the Notes to Consolidated Financial Statements.

On an after-tax basis, merger-related costs were $223 million in 2003, compared with $307 million in 2002. Included in these costs were employee relocation expenses, transition labor costs, and other charges directly associated with the merger.

The category Other consists primarily of items not directly associated with the operating segments on a stand-alone basis, including certain foreign currency transaction gains and losses, and environmental costs associated with sites no longer in operation. Results from Other were improved in 2003 because of higher foreign currency transaction gains and an after-tax gain of $34 million in the first quarter of 2003, representing beneficial interests we had in certain insurance companies as a result of the conversion of those companies from mutual companies to stock companies, a process known as demutualization. These beneficial interests arose from our prior purchase and ownership of various insurance policies and contracts issued by the mutual companies. Prior to the demutualizations, our mutual ownership interests in these insurance companies were not recognized because the ownership interests in the mutual companies were neither capable of valuation nor marketable. Included in Other in 2003 was a net foreign currency transaction gain of $67 million, after-tax, compared with a net gain of $21 million in 2002.

2002 vs. 2001

Corporate and Other s net loss was $1,918 million in 2002, compared with $415 million in 2001. The increased net loss in 2002 reflects losses from discontinued operations, primarily due to impairments, and merger-related costs. Net interest expense and corporate general and administrative costs were also higher in 2002 due to the merger.

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CAPITAL RESOURCES AND LIQUIDITY

Financial Indicators

	Millions of Dollars Except as Indicated		
	2003	2002	2001
Current ratio	**.8**	.9	1.3
Net cash provided by operating activities	**$ 9,356**	4,978	3,559
Total debt repayment obligations due within one year	**$ 1,440**	849	44
Total debt*	**$ 17,780**	19,766	8,654
Mandatorily redeemable preferred securities of trust subsidiaries*	**$**	350	650
Other minority interests	**$ 842**	651	5
Common stockholders equity	**$ 34,366**	29,517	14,340
Percent of total debt to capital**	**34%**	39	37
Percent of floating-rate debt to total debt	**17%**	12	20

* *With the adoption of Financial Accounting Standards Board Interpretation No. 46, Consolidation of Variable Interest Entities, effective January 1, 2003, the mandatorily redeemable preferred securities were removed from our balance sheet and effectively replaced with debt.*

** *Capital includes total debt, mandatorily redeemable preferred securities, other minority interests and common stockholders equity.*

To meet our liquidity requirements, including funding our capital program, paying dividends and repaying debt, we look to a variety of funding sources, primarily cash generated from operating activities. During 2003, available cash was used to support the company s ongoing capital expenditures program, repay debt and pay dividends. In October 2003, our Board of Directors (Board) declared a dividend of $.43 per share, payable December 1, 2003, which represented a 7.5 percent increase from the previous quarter s dividend rate. Total dividends paid on our common stock in 2003 was $1.1 billion. During 2003, cash and cash equivalents increased $183 million to $490 million.

Significant Sources of Capital

Operating Activities

During 2003, cash of $9,356 million was provided by operating activities, an increase of $4,378 million from 2002. The increase in cash provided by operating activities was primarily due to:

- Higher crude oil, natural gas and natural gas liquids prices;
- Increased production as a result of the inclusion of Conoco activity for the full year; and
- Higher refining and marketing margins.

In addition, working capital changes increased cash flow from operating activities $589 million in 2003, compared with an increase of $982 million in 2002. Cash from operating activities provided by discontinued operations amounted to $189 million, compared with $202 million in 2002.

Asset Sales

Following the merger, we initiated an asset disposition program to sell approximately $3 billion to $4 billion of assets by the end of 2004. Through year-end 2003, we had sold approximately $3.4 billion of assets and raised our target to $4.5 billion by year-end 2004. In February 2004, we sold our 46.7 percent interest in Petrovera Resources Limited, which primarily produced conventional heavy oil in Western Canada. Additional assets expected to be sold in 2004 are primarily related to our marketing

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business. In addition, we are proceeding with plans to dispose of some of our non-DEFS Midstream assets. During 2003, $2.7 billion was received from the sale of various assets, including the remaining assets required to be sold by the Federal Trade Commission as a result of the merger, a substantial portion of our U.S. retail marketing sites, and non-strategic E&P properties. Proceeds from these asset sales have been, and will be, used primarily to pay off debt.

Commercial Paper and Credit Facilities

While the stability of our cash flows from operating activities benefits from geographic diversity and the effects of upstream and downstream integration, our operating cash flows remain exposed to the volatility of commodity crude oil and natural gas prices and refining and marketing margins, as well as periodic cash needs to finance tax payments and crude oil, natural gas and petroleum product purchases. Our primary funding source for short-term working capital needs is a $4 billion commercial paper program, a portion of which may be denominated in other currencies (limited to euro 3 billion equivalent). Commercial paper maturities are generally limited to 90 days. At December 31, 2003, we had $709 million of commercial paper outstanding, compared with $1,517 million of commercial paper outstanding at December 31, 2002, of which $206 million was denominated in foreign currencies.

Effective October 14, 2003, we entered into two new revolving credit facilities to replace our previously existing $2 billion 364-day facility that expired on that same date. The new revolving credit facilities consist of a $1.5 billion 364-day facility and a $500 million five-year facility. We also have two revolving credit facilities totaling $2 billion expiring in October 2006. There were no outstanding borrowings under these facilities at December 31, 2003. These credit facilities support the company s $4 billion commercial paper program. In addition, one of our Norwegian subsidiaries has two $300 million revolving credit facilities that expire in June 2004, under which no borrowings were outstanding at December 31, 2003.

Moody s Investor Service has maintained a rating of A3 on our senior long-term debt; and Standard and Poors Rating Service and Fitch have maintained ratings of A-. We do not have any ratings triggers on any of our corporate debt that would cause an automatic event of default in the event of a downgrade of our credit rating and thereby impact our access to liquidity. In the event that our credit rating deteriorated to a level that would prohibit us from accessing the commercial paper market, we would still be able to access funds under our $4.6 billion revolving credit facilities. Based on our year-end commercial paper balance of $709 million, we had access to $3.9 billion in borrowing capacity as of December 31, 2003, which provides ample liquidity to cover daily operations.

Shelf Registration

In late 2002, we filed a universal shelf registration statement with the U.S. Securities and Exchange Commission for various types of debt and equity securities. As a result, we have available to issue and sell a total of $5 billion of various types of securities under the universal shelf registration statement.

Minority Interests

At December 31, 2003, we had outstanding $842 million of equity held by minority interest owners, including a net minority interest of $496 million in Ashford Energy Capital S.A. and a $141 million net minority interest in Conoco Corporate Holdings L.P.

In December 2001, in order to raise funds for general corporate purposes, Conoco and Cold Spring Finance S.a.r.l. formed Ashford Energy Capital S.A. through the contribution of a $1 billion Conoco subsidiary promissory note and $500 million cash by Cold Spring. Through its initial $500 million investment, Cold Spring is entitled to a cumulative annual preferred return based on three-month LIBOR rates, plus 1.27 percent. The preferred return at December 31, 2003, was 2.48 percent. In 2008, and at each 10-year anniversary thereafter, Cold Spring may elect to

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remarket their investment in Ashford, and if unsuccessful, could require ConocoPhillips to provide a letter of credit in support of Cold Spring s investment, or in the event that such letter of credit is not provided, then cause the redemption of their investment in Ashford. Should ConocoPhillips credit rating fall below investment grade, Ashford would require a letter of credit to support $475 million of the term loans, as of December 31, 2003, made by Ashford to other ConocoPhillips subsidiaries. If the letter of credit is not obtained within 60 days, Cold Spring could cause Ashford to sell the ConocoPhillips subsidiary notes. At December 31, 2003, Ashford held $1.6 billion of ConocoPhillips subsidiary notes and $25 million in investments unrelated to ConocoPhillips. We report Cold Spring s investment as a minority interest because it is not mandatorily redeemable and the entity does not have a specified liquidation date. Other than the obligation to make payment on the subsidiary notes described above, Cold Spring does not have recourse to our general credit.

In 1999, in order to raise funds for general corporate purposes, Conoco formed Conoco Corporate Holdings L.P., contributing an office building and four aircraft to the partnership. Conoco Corporate Holdings L.P. is a limited-life entity that must be liquidated in 2019. The limited partner interest was sold to Highlander Investors L.L.C. for $141 million, which represented an initial net 47 percent interest. Highlander s current investment in Conoco Corporate Holdings L.P. is 24.4 percent. Highlander is entitled to a cumulative annual priority return on its investment of 7.86 percent. The net minority interest in Conoco Corporate Holdings L.P. was $141 million at December 31, 2003 and 2002, and is callable without penalty beginning in the fourth quarter of 2004.

Receivables Factoring

At December 31, 2003 and 2002, we also had sold $226 million and $264 million, respectively, of receivables under factoring arrangements. We retained servicing responsibility for these sold receivables, which gives us certain benefits, the fair value of which approximates the fair value of the liability incurred for continuing to service the receivables. See Note 15 Sales of Receivables, in the Notes to Consolidated Financial Statements, for additional information.

Off-Balance Sheet Arrangements

Receivables Monetization

At December 31, 2002, certain credit card and trade receivables had been sold to two Qualifying Special Purpose Entities (QSPEs) in revolving-period securitization arrangements. These arrangements provided for us to sell, and the QSPEs to purchase, certain receivables and for the QSPEs to then issue beneficial interests of up to $1.5 billion to five bank-sponsored entities. All five bank-sponsored entities are multi-seller conduits with access to the commercial paper market and purchase interests in similar receivables from numerous other companies unrelated to us. We have no ownership interests, nor any variable interests, in any of the bank-sponsored entities. As a result, we do not consolidate any of these entities. Furthermore, we do not consolidate the QSPEs because they meet the requirements of SFAS No. 140, Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities, to be excluded from the consolidated financial statements of ConocoPhillips.

During 2003, we purchased from the bank-sponsored entities the senior interests of one of our two existing QSPEs and discontinued selling receivables to it. We have consolidated this QSPE since acquiring the senior interests. Also during 2003, the third-party beneficial interest holders approved amendments to the other QSPE to increase the amount of third-party beneficial interests that can be issued to $1.2 billion. These changes resulted in a net reduction of the maximum level of senior beneficial interests that can be issued to third-party beneficial interest holders from $1.5 billion to $1.2 billion. At December 31, 2003 and 2002, we had sold accounts receivable of $1.2 billion and $1.3 billion, respectively. The receivables transferred to the QSPE meets the isolation requirements and other requirements of SFAS No. 140 to be accounted for as sales. Accordingly, receivables transferred to the QSPEs were accounted for as sales.

We retain beneficial interests in this QSPE that are subordinate to the beneficial interests issued to the bank-sponsored entities. These retained interests, which are reported on the balance sheet in accounts and notes receivable related parties, were $1.3 billion at both December 31, 2003 and 2002. We also retain servicing responsibility related to the sold receivables, which gives us certain benefits, the fair value of which approximates the fair value of the liability incurred for continuing to service the receivables. The carrying value of the subordinated beneficial interests approximates fair market value due to the short term of the underlying assets, which makes stress testing unnecessary.

Preferred Stock
During 1996 and 1997, we formed two statutory business trusts, Phillips 66 Capital I (Trust I) and Phillips 66 Capital II (Trust II), with ConocoPhillips owning all of the common securities of the trusts. The sole purpose of the trusts was to issue preferred securities to outside investors, investing the proceeds thereof in an equivalent amount of subordinated debt securities of ConocoPhillips. The two trusts were established to raise funds for general corporate purposes. On May 31, 2002, we redeemed all of the outstanding subordinated debt securities held by Trust I, which triggered the redemption of the $300 million of trust preferred securities of Trust I at par value, $25 per share. The redemption was funded by the issuance of commercial paper.

At December 31, 2003, Trust II had $350 million of mandatorily redeemable preferred securities outstanding, whose sole asset was $361 million of ConocoPhillips subordinated debt securities, which bear interest at 8 percent. Distributions on the trust preferred securities are paid by the trust with funds from interest payments made by ConocoPhillips on the subordinated debt securities. We made interest payments in 2003 totaling $29 million. In addition, we have guaranteed the payment obligations of the trust on the trust preferred securities to the extent we have made interest payments on the subordinated debt securities. Prior to January 1, 2003, we consolidated Trust II and the mandatorily redeemable preferred securities were presented in the mezzanine section of the balance sheet. The subordinated debt securities and related income statement effects were eliminated in our consolidated financial statements. However, with the adoption of the provisions of FIN 46, effective January 1, 2003, we were required to deconsolidate Trust II, which had the effect of increasing debt by $361 million since the subordinated debt securities were no longer eliminated in consolidation, and removing the mandatorily redeemable preferred securities from our balance sheet. When we redeem the subordinated debt securities, Trust II is required to apply all the redemption proceeds to the immediate redemption of the preferred securities. See Note 2 Changes in Accounting Principles and Note 19 Preferred Stock and Other Minority Interests, in the Notes to Consolidated Financial Statements, for additional information.

Affiliated Companies
As part of our normal ongoing business operations and consistent with normal industry practice, we invest in, and enter into, numerous agreements with other parties to pursue business opportunities, which share costs and apportion risks among the parties as governed by the agreements. At December 31, 2003, we were liable for certain contingent obligations under various contractual arrangements as described below.

> *Hamaca:* The Hamaca project involves the development of heavy-oil reserves from the Orinoco Oil Belt. We own a 40 percent interest in the Hamaca project, which is operated by Petrolera Ameriven on behalf of the owners. The other participants in Hamaca are Petroleos de Venezuela S.A. (PDVSA) and ChevronTexaco Corporation. Our interest is held through a jointly owned

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limited liability company, Hamaca Holding LLC, for which we use the equity method of accounting. Hamaca Holding LLC revenues for 2003 were approximately $284 million, expenses were approximately $143 million and cash provided by operating activities was approximately $143 million. We have a 57.1 percent non-controlling ownership interest in Hamaca Holding LLC. In the second quarter of 2001, we, along with our co-venturers in the Hamaca project, secured approximately $1.1 billion in a joint debt financing for our heavy-crude oil project in Venezuela. The Export-Import Bank of the United States provided a guarantee supporting a 17-year-term $628 million bank facility. The joint venture also arranged a $470 million 14-year-term commercial bank facility for the project. Total debt of $969 million was outstanding under these credit facilities at December 31, 2003. Of this amount, $388 million is recourse to ConocoPhillips. The proceeds of these joint financings are being used to primarily fund a heavy-oil upgrader. The remaining necessary funding will be provided by capital contributions from the co-venturers on a pro rata basis to the extent necessary to successfully complete construction. Once completion certification is achieved (required by October 1, 2005), the joint project financings will become non-recourse with respect to the co-venturers and the lenders under those facilities can then look only to the Hamaca project s cash flows for payment.

Merey Sweeny L.P. (MSLP): MSLP is a limited partnership in which we and PDVSA each own an indirect 50 percent interest. During 1999, MSLP issued $350 million of 8.85 percent bonds due 2019 that we, along with PDVSA, are jointly-and-severally liable for under a construction completion guarantee. The bond proceeds were used to fund construction of a coker, vacuum unit and related facilities at our Sweeny, Texas, refinery, plus certain improvements to existing facilities at the same location. MSLP owns the coker and vacuum unit and, in the third quarter of 2000, began processing long residue produced from the Venezuelan Merey crude oil delivered under a supply agreement that we have with PDVSA. MSLP charges us a fee, which totaled approximately $145 million in 2003, to process the long residue through the vacuum unit and coker. This is the partnership s primary source of revenue. MSLP revenues for 2003 were approximately $162 million, expenses were approximately $140 million and cash provided by operating activities was approximately $31 million. If completion certification is not attained by June 18, 2004, the 8.85 percent bonds could be called and the bondholders would look to the two MSLP partners for repayment. MSLP is currently awaiting receipt of a permit for a new waste water pipeline and working to resolve issues in placing its insurance program, after which we expect to achieve completion certification in the second quarter of 2004. Upon completion certification, the 8.85 percent bonds become non-recourse to the two MSLP partners and the bondholders can then look only to MSLP cash flows for payment.

We purchased the improvements to existing facilities from MSLP for a price equal to the cost of construction, and MSLP provided seller financing. Terms of financing provide for 240 monthly payments of principal and interest commencing September 2000 with interest accruing at a 7 percent annual rate. The principal balance due on the seller financing was $131 million at December 31, 2003, and is included as long-term debt in our balance sheet. MSLP pays a monthly access fee to us, which totaled approximately $20 million in 2003, for the use of the improvements to the refinery. The access fee equals the monthly principal and interest paid by us to purchase the improvements from MSLP. To the extent the access fee is not paid by MSLP, we are not obligated to make payments for the improvements.

During the first quarter of 2002, MSLP issued $25 million of tax-exempt bonds due 2021. This issuance, combined with similar bonds MSLP issued in 1998, 2000, and 2001, bring the total outstanding to $100 million. As a result of the company s support as a primary obligor of a 50 percent share of these MSLP financings, $50 million of long-term debt is included in our balance sheet at December 31, 2003 and 2002, respectively.

Other: At December 31, 2003, we had guarantees of approximately $340 million outstanding for our portion of other joint-venture debt obligations, which have terms of up to 22 years. Included in these outstanding guarantees was $158 million associated with the Polar Lights Company joint venture in Russia. Payment will be required if a joint venture defaults on its debt obligations.

Capital Requirements

For information about our capital expenditures and investments, see Capital Spending below.

Our balance sheet debt at December 31, 2003, was $17.8 billion. This reflects debt reductions of approximately $4.8 billion during 2003, including accounting changes that increased balance sheet debt approximately $2.8 billion as a result of the adoption of FIN 46. See Note 2 Changes in Accounting Principles and Note 14 Debt, in the Notes to Consolidated Financial Statements, for additional information.

During 2003, we reduced our commercial paper balance outstanding from $1.5 billion at December 31, 2002, to $709 million at December 31, 2003. In 2003, we paid off the following notes and debt facilities as they were called or matured and funded the payments with cash from operating activities and proceeds from asset dispositions:

$250 million 8.49% Notes due 2023, at 104.245 percent;

$150 million 8.25% Mortgage Bonds due May 15, 2003;

$250 million 7.92% Notes due in 2023, at 103.96 percent;

$250 million 7.20% Notes due 2023, at 103.60 percent;

$100 million 6.65% Notes that matured on March 1, 2003;

$180 million SRW Cogeneration Limited Partnership note;

$500 million Floating Rate Notes due April 15, 2003;

$90 million Tosco Trust 2000-E 8.78% Senior Secured Notes due 2010;

$245 million Tosco Trust 2000-E 8.58% Senior Secured Notes due 2010;

$199 million Arctic Funding, Limited Partnership 6.85% Senior Secured Note due 2011;

$100 million of floating rate aviation equipment lease obligations having a final maturity in 2004;

$489 million of fixed and floating rate ocean vessel lease obligations having final maturities from 2004 to 2005; and

$1,130 million of floating rate marketing lease obligations having maturities from 2003 to 2006.

In October and November 2003, we executed certain interest rate swaps that had the effect of converting $1.5 billion of debt from fixed to floating rate. These swaps qualify for hedge accounting under SFAS 133, Accounting for Derivative Instruments and Hedging Activities.

Also during 2003, we issued $79.5 million of tax-exempt bonds and assumed an additional amount of $20 million.

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Contractual Obligations

The following table summarizes our aggregate contractual fixed and variable obligations as of December 31, 2003:

	Millions of Dollars				
	Payments Due by Period				
At December 31, 2003	Total	Up to 1 Year	1-3 Years	3-5 Years	After 5 Years
Debt obligations*	$ 17,720	1,434	3,110	1,202	11,974
Capital lease obligations	60	6	12	38	4
Total debt	17,780	1,440	3,122	1,240	11,978
Operating lease obligations	3,073	471	810	619	1,173
Purchase obligations**	58,231	19,972	4,869	3,915	29,475
Other long-term liabilities***					
Asset retirement obligations	2,685	61	242	364	2,018
Accrued environmental costs	1,119	140	304	138	537
Total	$ 82,888	22,084	9,347	6,276	45,181

**Total debt excluding capital lease obligations. Includes net unamortized premiums and discounts.*

***Represents any agreement to purchase goods or services that is enforceable and legally binding and that specifies all significant terms. The majority of the purchase obligations are market-based contracts. Includes: (1) our commercial activities of $23.0 billion, of which $11.1 billion are primarily related to the supply of crude oil to our refineries and the optimization of the supply chain, $5.6 billion primarily related to the supply of unfractionated NGLs to fractionators, optimization of NGL assets, and for resale to customers, $4.4 billion primarily related to natural gas for resale to customers, $1.7 billion of futures, and $217 million related to the purchase side of exchange agreements; (2) $23.3 billion of purchase commitments for products, mostly natural gas and natural gas liquids, from CPChem over the remaining term of 97 years; and (3) purchase commitments for jointly owned fields and facilities where we are the operator, of which some of the obligations will be reimbursed by our co-owners in these properties. Does not include: (1) purchase commitments for jointly owned fields and facilities where we are not the operator; (2) our agreement to purchase up to 104,000 barrels per day of Petrozuata crude oil for a market-based formula price over the term of the Petrozuata joint venture (about 35 years) in the event that Petrozuata is unable to sell the production for higher prices; and (3) an agreement to purchase up to 165,000 barrels per day of Venezuelan Merey, or equivalent, crude oil for a market price over a remaining 16-year term if a variety of conditions are met.*

****Does not include: (1) Taxes the company s consolidated balance sheet reflects liabilities related to income, excise, property, production, payroll and environmental taxes. We anticipate the current liability of $2,676 million for accrued income and other taxes will be paid in the next year. We have other accrued tax liabilities whose* *resolution may not occur for several years, so it is not possible to determine the exact timing or amount of future payments. Deferred income taxes reflect the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for tax purposes; (2) Pensions for the 2004 through 2008 time period, we expect to contribute an average of $400 million per year to our qualified and non-qualified pension and postretirement medical plans in the United States and an average of $100 million per year to our non-U.S. plans, which are expected to be in excess of required minimums in many cases. Our required minimum funding in 2004 is expected to be $95 million in the United States and $75 million outside the United States; (3) Severance we have expected severance payments of $109 million in 2004 and $3 million in 2005; and (4) Interest we anticipate payments of $1,046 million in 2004, $2,012 million for the period 2005 through 2006, $1,708 million for the period 2007 through 2008, and $8,955 million for the remaining years to total $13,721 million.*

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Capital Spending

Capital Expenditures and Investments

	Millions of Dollars			
	2004 Budget	**2003**	2002	2001
E&P				
United States Alaska	$ 656	**570**	706	965
United States Lower 48	763	**848**	499	389
International	3,939	**3,090**	2,071	1,162
	5,358	**4,508**	3,276	2,516
Midstream	10	**10**	5	
R&M				
United States	1,039	**860**	676	423
International	246	**319**	164	5
	1,285	**1,179**	840	428
Chemicals			60	6
Emerging Businesses	62	**284**	122	
Corporate and Other*	167	**188**	85	66
	$ 6,882	**6,169**	4,388	3,016
United States	$ 2,639	**2,493**	2,043	1,849
International	4,243	**3,676**	2,345	1,167
	$ 6,882	**6,169**	4,388	3,016
Discontinued operations	$	**224**	97	69

* *Excludes discontinued operations.*

Our capital spending for continuing operations for the three-year period ending December 31, 2003, totaled $13.6 billion. Spending was primarily focused on the growth of our E&P business, with 76 percent of total spending for continuing operations in this segment. The capital programs of DEFS, our gas gathering, processing and marketing joint-venture company, and CPChem, our chemicals joint-venture company, are intended to be self-funding, and are not reflected in the amounts above.

Including about $500 million in capitalized interest and $400 million that will be funded by minority interests in the Bayu-Undan gas export project, our Board has approved $6.9 billion for capital projects and investments for continuing operations in 2004, a 12 percent increase over our 2003 capital spending of $6.2 billion. We plan to direct 78 percent of our 2004 capital budget to E&P and 19 percent to R&M. The remaining budget will be allocated toward emerging businesses, mainly power generation; and general corporate purposes, with a majority related to global integration of systems. Thirty-eight percent of the budget is targeted for projects in the United States.

E&P

Capital spending for continuing operations for E&P during the three-year period ending December 31, 2003, totaled $10.3 billion. The expenditures over the three-year period supported several key exploration and development projects including:

National Petroleum Reserve-Alaska (NPR-A) and satellite field prospects on Alaska s North Slope;

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Magnolia development in the deepwater Gulf of Mexico;

Canadian conventional oil and gas projects, the Surmont oil sands project and expansion of the Syncrude project;

The Hamaca heavy-oil project in Venezuela s Orinoco Oil Belt;

The Jade, Clair, CMS3 and Britannia satellite developments in the United Kingdom;

The Grane field and Ekofisk Area growth project in the Norwegian North Sea;

The Kashagan field in the north Caspian Sea, offshore Kazakhstan;

The Peng Lai 19-3 discovery in China s Bohai Bay and additional Bohai Bay appraisal and satellite field prospects;

The Bayu-Undan gas recycle and gas development projects in the Timor Sea;

Blocks 15-1 and 15-2 in Vietnam;

The Belanak and Suban projects in Indonesia; and

Acquisition of deepwater exploratory interests in Angola, Nigeria, Brazil, and the U.S. Gulf of Mexico.
Capital expenditures for construction of our Endeavour Class tankers and an additional interest in the Trans-Alaska Pipeline System were also included in the E&P segment.

We have contracted to build, for approximately $200 million each, five double-hulled Endeavour Class tankers for use in transporting Alaskan crude oil to the U.S. West Coast. During 2001, the *Polar Endeavour*, the first Endeavour Class tanker, entered service. The second tanker, the *Polar Resolution*, entered service in May 2002 and the third tanker, the *Polar Discovery*, was delivered for service in September 2003. We expect to add a new Endeavour Class tanker to our fleet in both 2004 and 2005, allowing us to retire older ships and cancel non-operated charters.

In Alaska, we continued development drilling in the Kuparuk, Tabasco and West Sak fields in the Greater Kuparuk Area, Prudhoe Bay satellite fields and the Alpine field. In 2003, we, along with our co-venturers, drilled or participated in 71 new development wells at Greater Prudhoe Bay, 17 new development wells at Greater Kuparuk and five development wells at Alpine. Also in 2003, funds were expended on the Alpine capacity expansion project that is expected to start up in the second half of 2004.

In the Lower 48, we continued to explore and develop our acreage positions in the deepwater Gulf of Mexico, South Texas, the San Juan Basin, the Permian Basin, and the Texas Panhandle. In the Gulf of Mexico, development drilling has been completed in the Magnolia and Princess Phase 1 fields. Sanction for the K2 project development is expected in the first quarter of 2004. Preliminary engineering for Princess Phase 2 and Ursa waterflood is expected to begin in the first quarter of 2004. Magnolia s tension-leg platform construction is ongoing and first production is expected prior to the end of 2004. In February 2003, we began drilling the Lorien exploration well on Block 199, which was declared a discovery in July. The well has been temporarily suspended pending evaluation of development alternatives. The Voss deepwater exploratory well drilled in Keathley Canyon Block 511 was declared dry in early 2003 and as required was charged against 2002 earnings. The Yorick deepwater exploratory well in Green Canyon Block 435 was declared a dry hole in late 2003.

Onshore capital was focused on natural gas developments in the San Juan Basin of New Mexico and the Lobo Trend of South Texas. In addition, Lower 48 is pursuing select opportunities in its other producing basins.

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In Canada, we continued with development of the Stage III expansion-mining project in the Canadian province of Alberta, which is expected to increase our Canadian Syncrude production. The Aurora Train 2 project (the new mine) started up in late-October 2003. The upgrader expansion project is expected to start up in the second half of 2005. In the fourth quarter of 2003, approval was obtained for our project in Surmont. Our ownership share is 43.5 percent. The Surmont lease covers over 200 square miles. This initial development project is designed to use steam assisted gravity drainage technology, with first oil production expected in 2006. In addition to these projects, we also are involved in conventional oil and gas properties in Canada.

During the fourth quarter of 2001, we began production of heavy crude oil from the Hamaca project in Venezuela s Orinoco Oil Belt. Construction of an upgrader to convert heavy crude oil into a medium-grade crude oil continues. Completion of the upgrader is expected by the end of 2004. We own a 40 percent equity interest in the Hamaca project. Our other heavy-oil project in Venezuela, Petrozuata, incurred capital expenditures in 2003 associated with solids handling and restoration capacity projects, as well as ongoing drilling.

In addition to the Hamaca and Petrozuata developments, we have an interest in the Corocoro oil discovery in Venezuela s Gulf of Paria West. In April 2003, Venezuelan authorities and co-venturers approved Phase I of the development plan for the Corocoro field. We are the operator of the block. In September 2003, we acquired a 37.5 percent interest in the Gulf of Paria East Block. A portion of the Corocoro discovery extends onto this block. Our interest in the development is 32.2 percent.

In February 2003, Venezuelan authorities granted a 35-year license to ChevronTexaco to appraise and develop Plataforma Deltana Block 2. ChevronTexaco selected us as their minority partner in accordance with the terms of the license, which was approved by the Venezuelan government in late 2003. We now have a 40 percent interest in the project. Plataforma Deltana Block 2 is located to the east of our Corocoro discovery. Block 2 already has a gas discovery on it, and additional drilling is planned for 2004.

In Brazil, we added joint-venture partners for our two deepwater blocks, BM-ES-11 and BM-PAMA-3, and purchased additional seismic data in 2002. In 2003, 3-D seismic results indicated the prospect for BM-ES-11 was below expectations, leading to a write-off of our leasehold investment and the initiation of plans to exit the block. Further evaluation of BM-PAMA-3 is planned for 2004.

In 2003, we continued with several development projects in the U.K. and Norwegian sectors of the North Sea, including the Clair field in the U.K. sector. We expect first production from Clair in late 2004. Late in the third quarter of 2003, we and our co-venturers began oil production from the Grane field in the Norwegian North Sea. Net peak production from proved reserves of approximately 14,000 barrels per day is anticipated in 2005.

We continued the development of the CMS3 area, a single unitized project, comprising five natural gas reservoirs in the southern sector of the U.K. North Sea. Collectively, the fields are known as CMS3 due to their utilization of the production and transportation facilities of our operated Caister Murdoch System (CMS). In September 2002, production commenced from the Hawksley field, followed in the fourth quarter by production at the Murdoch K field. During 2003, McAdam came onstream in the second quarter and Watt began in the fourth quarter. Drilling operations on the final reservoir, Boulton H, are ongoing in 2004. We are the operator of CMS3 and hold a 59.5 percent interest.

In December 2003, our Board approved the development of the Britannia field satellites in the North Sea. A development plan has been submitted for government approval. These satellites are comprised of the Callanish and Brodgar fields. The Callanish field is an oil reservoir, and the Brodgar field is a gas

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condensate reservoir with properties similar to those of Britannia. The fields are planned to be developed jointly via a bridge-linked platform to Britannia, with production startup scheduled for 2007. We are the operator of both fields with an interest of 75 percent in Brodgar and 83.5 percent in Callanish.

Elsewhere in the Norwegian sector of the North Sea, in 2003, we, along with our co-venturers, approved a plan to further develop the Ekofisk Area to increase the recovery of oil and gas from the area by improving the area s processing capacity and reliability. The Ekofisk growth project consists of two interrelated components: the construction and installation of a new steel wellhead and process platform and an increase in capacity from existing facilities. We expect to complete and install the steel jacket in 2004 and the topsides early in the summer of 2005. Additional production from this development is anticipated to begin in the fall of 2005. We are modifying the existing Ekofisk Complex and four additional platforms to increase processing capacity.

In 2002, we and our co-venturers, in conjunction with the government of the Republic of Kazakhstan, declared the Kashagan field on the Kazakhstan shelf in the north Caspian Sea to be commercial. A development plan for the field was approved by the Republic of Kazakhstan in February 2004. Four of five planned appraisal wells on Kashagan had been successfully completed by the end of 2003. The fifth well is currently being tested. In May 2002, we along with the other remaining co-venturers, completed the acquisition of proportionate interests of two co-venturers' rights, which increased our ownership interest from 7.14 percent to 8.33 percent. In October 2002, we and our co-venturers announced a new hydrocarbon discovery in the Kazakhstan sector of the Caspian Sea. In 2003, a 3-D survey was carried out over the Kalamkas field and an initial appraisal well is planned for 2005.

During 2003, we exercised our pre-emptive rights related to B.G. International s sale of their share in the North Caspian License that includes the Kashagan field. The transaction is expected to close in 2004, at which time our interest in the license will increase from 8.33 percent to 10.19 percent. In November 2003, we and our co-venturers announced the successful completion of the first offshore exploration wells on the Aktote and Kashagan Southwest prospects. These two wells are located in the Kazakhstan sector of the Caspian Sea in an area adjacent to the Kashagan field. Another exploration well, on the Kairan prospect, completed drilling in 2003 and will be tested in 2004.

In late-December 2002, we began production from Phase I of our Peng Lai 19-3 development located on Block 11/05 in China s Bohai Bay. During 2003, we continued with planning and design for Phase II of the Peng Lai 19-3 development, which includes multiple wellhead platforms, central processing facilities, and a floating storage and offloading facility. We are developing, in conjunction with Phase II, the Peng Lai 25-6 oil field, located three miles east of Peng Lai 19-3. We also drilled exploration wells on the Peng Lai 19-9 prospect and the Peng Lai 13-1 prospect, which resulted in two discoveries. The Peng Lai 19-9-1 well is located two miles east of the Peng Lai 19-3 oil field, and along with adjacent structures will be a part of the Phase II development.

In the Timor Sea, we continued with development activities associated with the Bayu-Undan gas recycle and gas development projects. We continued to drill future production wells and have installed all major facilities, including two production, processing and living quarters platforms and an unmanned production platform. A multi-product floating, storage and offloading vessel was connected to the production facilities during the fourth quarter of 2003. First liquids production began in February 2004, and full capacity of 62,000 net barrels per day of condensate and natural gas liquids is anticipated to be reached in the third quarter of 2004. An average rate of 23,000 net barrels per day of combined condensate and natural gas liquids is expected for 2004.

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We also have received approval of the gas development plan for the Bayu-Undan project from the Timor Sea Designated Authority, concluded fiscal and legal provisions with the government of Timor Lesté, and executed new production sharing contract (PSC) arrangements with the Designated Authority. The gas development project includes a liquefied natural gas (LNG) plant, including a pipeline to Darwin, Australia. The first LNG cargo from the 3.52 million-ton-per-year facility is scheduled for delivery in early 2006. During the third quarter of 2003, construction of the LNG facility and the pipeline began. In June 2003, we sold what currently equates to a 10.08 percent interest in the unitized Bayu-Undan field; purchased other interests that currently equate to a 2.65 percent interest in the field; sold a 43.3 percent interest in the Bayu-Undan pipeline under construction; and sold a 43.3 percent interest in Darwin LNG Pty Ltd (owner of the LNG plant to be constructed). The net result is that we retain a 56.72 percent controlling interest in the integrated project.

In Vietnam s Block 15-1, the Su Tu Den Phase I (southwest area) development project was approved in December 2001 and production from this area began in late-October 2003. We also are evaluating the commerciality of the Su Tu Vang fields and the northeast portion of the Su Tu Den field. In November 2003, we announced the completion of a successful exploratory well in the Su Tu Trang field in Block 15-1. Technical evaluation is in progress to assess the reservoir potential of the Su Tu Trang field.

In the third quarter of 2002, we began production from two new wellhead platforms in the Block 15-2 Rang Dong field in Vietnam. During late 2003, field facilities were upgraded to include a utilities-living quarters platform, and a central processing platform with facilities to enable gas lift, gas export and water injection. With the completion of these facilities, water injection is now possible on all three wellhead platforms and gas lift is possible on the N-1 and E-1 wellhead platforms. These facilities became operational in the fourth quarter of 2003.

We continued with the appraisal and development of key gas fields in Indonesia. In 2003, we announced the successful test of the Suban-8 delineation well on the southwest flank of the Suban gas field, located in the Corridor PSC of South Sumatra. We also completed the successful test of the North Sumpal-1 well in the Sakakemang Block located in South Sumatra, and continued on the construction of the South Jambi gas project in the South Jambi B Block also located in South Sumatra. In addition, we continue to develop the offshore Belanak and other fields in the Block B PSC in the Natuna Sea, for which a floating production storage and offloading vessel is under construction. The vessel is expected to be completed in the first half of 2005.

In May 2002, initial results showed that the first exploratory well drilled in Block 34, offshore Angola, was a dry hole. In view of this information, we reassessed the fair value of the remainder of the block and determined that our investment in the block was impaired by $77 million, both before- and after-tax. In December 2003, the second exploration well was drilled in Block 34, offshore Angola. The well encountered non-commercial gas and was plugged and abandoned. In view of this information, we fully impaired our remaining investment in the block.

In 2003, we obtained a 40 percent interest in Block 248 and a 20 percent interest in Block 214, both offshore Nigeria. First exploration drilling is planned for Block 248 in the second quarter of 2004.

Other capital spending for E&P during the three-year period ended December 31, 2003, supported:

- The Eldfisk waterflood development in Norway;
- The Jade field development in the United Kingdom;
- The acquisition and development of coalbed methane and conventional gas prospects and producing properties in the U.S. Lower 48; and

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North Sea prospects in the U.K. and Norwegian sectors, plus other Atlantic Margin wells in the United Kingdom, Greenland and the Faroe Islands.

2004 Capital Budget

E&P s 2004 capital budget for continuing operations is $5.4 billion, 19 percent higher than actual expenditures in 2003. Twenty-six percent of E&P s 2004 capital budget is planned for the United States, with 46 percent of that slated for Alaska.

We have budgeted $628 million for worldwide exploration capital activities in 2004, with 17 percent of that amount, $106 million, allocated to the United States. Outside the United States, significant exploration expenditures are planned in Kazakhstan, Venezuela, the United Kingdom and Norway.

We plan to spend $656 million in 2004 for our Alaskan operations. A majority of the capital spending will fund Prudhoe Bay, Greater Kuparuk and Western North Slope operations including additional work on the Alpine capacity expansion project, Orion and West Sak field developments construction of Endeavour Class tankers, and the exploratory activity discussed above.

In the Lower 48, offshore capital expenditures will be focused on the continued development of the Magnolia, Ursa and Princess fields in the deepwater Gulf of Mexico. Onshore capital will focus primarily on developing natural gas reserves within core areas, such as the San Juan Basin of New Mexico and the Lobo Trend of South Texas.

E&P is directing $3.9 billion of its 2004 capital budget to international projects. The majority of these funds will be directed to developing major long-term projects, including the Bayu-Undan liquids and gas development projects in the Timor Sea; the Hamaca heavy-oil project in Venezuela; additional development of oil and gas reserves in offshore Block B and onshore South Sumatra blocks in Indonesia; the second phase of Bohai Bay in China; projects in the Caspian region, including Baku-Tbilisi-Ceyhan pipeline; projects in Canada, including Syncrude, Surmont heavy-oil and the Mackenzie Delta gas development; and the Qatargas 3 LNG facility in Qatar. In addition, funds will be used to expand the company s positions in the U.K. and Norwegian sectors of the North Sea.

Costs incurred for the years ended December 31, 2003, 2002, and 2001, relating to the development of proved undeveloped oil and gas reserves were $2,002 million, $1,631 million, and $1,423 million, respectively. As of December 31, 2003, estimated future development costs relating to the development of proved undeveloped oil and gas reserves for the years 2004 through 2006 were projected to be $1,767 million, $1,111 million, and $659 million, respectively.

R&M

Capital spending for continuing operations for R&M during the three-year period ending December 31, 2003, was primarily for refinery-upgrade projects to improve product yields, to meet new environmental standards, to improve the operating integrity of key processing units, and to install advanced process control technology, as well as for safety projects. Total capital spending for continuing operations for R&M for the three-year period was $2.4 billion, representing 18 percent of our total capital spending for continuing operations.

Key projects during the three-year period included:

- Construction of a polypropylene plant at the Bayway refinery in New Jersey;
- Construction of a fluid catalytic cracking unit and a S Zorb Sulfur Removal Technology (S Zorb) unit at the Ferndale, Washington, refinery;
- Expansion of the alkylation unit at the Los Angeles refinery;
- Capacity expansion and debottlenecking projects at the Borger, Texas, refinery;
- Completion of a commercial S Zorb unit at the Borger refinery;
- An expansion of capacity in the Seaway crude-oil pipeline; and
- Installation of an advanced central control building and associated technologies at the Borger facility.

In early 2003, we completed three major projects: a polypropylene plant at the Bayway refinery in Linden, New Jersey, and both a fluid catalytic cracking unit and a S Zorb unit at the Ferndale, Washington, refinery. The Bayway polypropylene plant utilizes propylene feedstock from the Bayway refinery to make up to 775 million pounds per year of polypropylene. The plant became operational in March 2003. At Ferndale, the fluid catalytic cracking unit significantly improves gasoline production per barrel of crude input and the new S Zorb unit reduces sulfur in gasoline. Both became fully operational in 2003.

Also in 2003, we made investments related to clean fuels, safety and environmental projects throughout our refining system. We completed projects at our refineries in Ponca City, Oklahoma and Roxana, Illinois, to produce the low-sulfur gasoline required by the Environmental Protection Agency (EPA). We also began construction of a new diesel hydrotreater at the Rodeo facility of our San Francisco area refinery that is expected to produce reformulated California highway diesel an estimated one year ahead of the June 2006 deadline.

In July 2003, we completed the acquisition of certain refining assets in Hartford, Illinois, from Premcor. The operations of these assets are being integrated into the operations of our nearby Wood River refinery. The overall production of the refinery will only increase slightly, but integration of the new assets will enable the refinery to process heavier, lower cost crude oil. Startup of the integrated facilities is expected in the second quarter of 2004.

Internationally, we continue to invest in our ongoing refining and marketing operations, including a replacement reformer at our Humber refinery in the United Kingdom and marketing growth in select countries in Europe and Asia.

2004 Capital Budget

R&M s 2004 capital budget for continuing operations is $1.3 billion, a 9 percent increase over spending of $1.2 billion in 2003. Domestic spending is expected to consume 81 percent of the R&M budget.

We plan to direct about $900 million of the R&M capital budget to domestic refining, primarily to fund clean fuels projects in order to comply with new EPA standards for refined products. Worldwide, clean fuels spending for our R&M business is expected to be about $600 million, or 55 percent of the total refining budget. Our U.S. marketing and transportation businesses are expected to spend about $125 million, while the remaining budget will fund projects in our international refining and marketing businesses in Europe and the Asia Pacific region.

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Emerging Businesses

Capital spending for Emerging Businesses during 2003 was primarily for construction of the Immingham combined heat and power cogeneration plant near the company s Humber refinery in the United Kingdom. We expect the plant to be operational in mid-2004.

Emerging Businesses 2004 capital budget of $62 million is primarily dedicated to the completion of the Immingham plant.

Contingencies

Legal and Tax Matters

We accrue for contingencies when a loss is probable and the amounts can be reasonably estimated. Based on currently available information, we believe that it is remote that future costs related to known contingent liability exposures will exceed current accruals by an amount that would have a material adverse impact on the company s financial statements.

All significant litigation arising from the March 27, 2000, explosion and fire that occurred in an out-of-service butadiene storage tank at the K-Resin styrene-butadiene copolymer (SBC) plant has now been resolved.

Environmental

We are subject to the same numerous international, federal, state, and local environmental laws and regulations, as are other companies in the petroleum exploration and production industry; and refining, marketing and transportation of crude oil and refined products businesses. The most significant of these environmental laws and regulations include, among others, the:

Federal Clean Air Act, which governs air emissions;

Federal Clean Water Act, which governs discharges to water bodies;

Federal Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), which imposes liability on generators, transporters, and arrangers of hazardous substances at sites where hazardous substance releases have occurred or are threatened to occur;

Federal Resource Conservation and Recovery Act (RCRA), which governs the treatment, storage, and disposal of solid waste;

Federal Oil Pollution Act of 1990 (OPA90), under which owners and operators of onshore facilities and pipelines, lessees or permittees of an area in which an offshore facility is located, and owners and operators of vessels are liable for removal costs and damages that result from a discharge of oil into navigable waters of the United States;

Federal Emergency Planning and Community Right-to-Know Act (EPCRA), which requires facilities to report toxic chemical inventories with local emergency planning committees and responses departments;

Federal Safe Drinking Water Act, which governs the disposal of wastewater in underground injection wells; and

U.S. Department of the Interior regulations, which relate to offshore oil and gas operations in U.S. waters and impose liability for the cost of pollution cleanup resulting from operations, as well as potential liability for pollution damages.

These laws and their implementing regulations set limits on emissions and, in the case of discharges to water, establish water quality limits. They also, in most cases, require permits in association with new or modified operations. These permits can require an applicant to collect substantial information in connection with the application process, which can be expensive and time-consuming. In addition, there can be delays associated with notice and comment periods and the agency s processing of the application. Many of the delays associated with the permitting process are beyond the control of the applicant.

Many states and foreign countries where we operate also have, or are developing, similar environmental laws and regulations governing these same types of activities. While similar, in some cases these regulations may impose additional, or more stringent, requirements that can add to the cost and difficulty of marketing or transporting products across state and international borders.

The ultimate financial impact arising from environmental laws and regulations is neither clearly known nor easily determinable as new standards, such as air emission standards, water quality standards and stricter fuel regulations, continue to evolve. However, environmental laws and regulations, including those that may arise to address concerns about global climate change, are expected to continue to have an increasing impact on our operations in the United States and in other countries in which we operate. Notable areas of potential impacts include air emission compliance and remediation obligations in the United States. Under the Clean Air Act, the EPA has promulgated a number of stringent limits on air emissions and established a federally mandated operating permit program. Violations of the Clean Air Act and most other environmental laws and regulations in the United States are enforceable with civil and criminal sanctions.

The EPA also has promulgated specific rules governing the sulfur content of gasoline, known generically as the Tier II Sulfur Rules, the first phase requirements of which became applicable to our gasoline as of January 2004. To meet the requirements, we are implementing a compliance strategy that relies on the use of a combination of technologies, including our proprietary S Zorb technology.

The EPA also has promulgated rules regarding the sulfur content in highway diesel fuel, which become applicable in 2006. In April 2003, the EPA proposed a rule regarding emissions from non-road diesel engines and limiting non-road diesel fuel sulfur content. If promulgated, this rule would significantly reduce non-road diesel fuel sulfur content limits as early as 2007. We are currently evaluating S Zorb systems for removing sulfur from diesel fuel in special applications. The refining industry is actively considering several advanced and conventional technologies for complying with these rules. Because the non-road rule is not final, we are still evaluating and developing capital strategies for future compliance. Additional areas of potential air-related impact are the proposed revisions to the National Ambient Air Quality Standards (NAAQS) and the Kyoto Protocol. In July 1997, the EPA promulgated more stringent revisions to the NAAQS for ozone and particulate matter. Since that time, final adoption of these revisions has been the subject of litigation (*American Trucking Association, Inc. et al. v. United States Environmental Protection Agency*) that eventually reached the U.S. Supreme Court during the fall of 2000. In February 2001, the U.S. Supreme Court remanded this matter, in part, to the EPA to address the implementation provisions relating to the revised ozone NAAQS. If adopted, the revised NAAQS could result in substantial future environmental expenditures for us.

In 1997, an international conference on global warming concluded an agreement, known as the Kyoto Protocol, which called for reductions of certain emissions that contribute to increases in atmospheric greenhouse gas concentrations. The United States has not ratified the treaty codifying the Kyoto Protocol

but may in the future. In addition, other countries where we have interests, or may have interests in the future, have made commitments to the Kyoto Protocol and are in various stages of formulating applicable regulations. Currently, it is not possible to accurately estimate the costs that we could incur to comply with such regulations, but such expenditures could be substantial.

We also are subject to certain laws and regulations relating to environmental remediation obligations associated with current and past operations. Such laws and regulations include CERCLA and RCRA and their state equivalents. Remediation obligations include cleanup responsibility arising from petroleum releases from underground storage tanks located at numerous past and present ConocoPhillips-owned and/or operated petroleum-marketing outlets throughout the United States. Federal and state laws require that contamination caused by such underground storage tank releases be assessed and remediated to meet applicable standards. In addition to other cleanup standards, many states have adopted cleanup criteria for methyl tertiary-butyl ether (MTBE) for both soil and groundwater. MTBE standards continue to evolve, and future environmental expenditures associated with the remediation of MTBE-contaminated underground storage tank sites could be substantial.

At RCRA permitted facilities, we are required to assess environmental conditions. If conditions warrant, we may be required to remediate contamination caused by prior operations. In contrast to CERCLA, which is often referred to as Superfund, the cost of corrective action activities under RCRA corrective action programs typically is borne solely by us. Over the next decade, we anticipate that significant ongoing expenditures for RCRA remediation activities may be required, but such annual expenditures for the near term are not expected to vary significantly from the range of such expenditures we have experienced over the past few years. Longer term, expenditures are subject to considerable uncertainty and may fluctuate significantly.

We, from time to time, receive requests for information or notices of potential liability from the EPA and state environmental agencies alleging that we are a potentially responsible party under CERCLA or an equivalent state statute. On occasion, we also have been made a party to cost recovery litigation by those agencies or by private parties. These requests, notices and lawsuits assert potential liability for remediation costs at various sites that typically are not owned by us, but allegedly contain wastes attributable to our past operations. As of December 31, 2002, we reported we had been notified of potential liability under CERCLA and comparable state laws at 58 sites around the United States. In the 2002 report, sites from Phillips and Conoco were listed separately resulting in eight duplicate listings. These duplicate listings are consolidated in this 2003 report. At December 31, 2003, we had combined the eight duplicate listings, reclassified one existing site, and resolved six sites. Additionally, we had received 16 new notices of potential liability, leaving 61 sites where we have been notified of potential liability.

For most Superfund sites, our potential liability will be significantly less than the total site remediation costs because the percentage of waste attributable to us, versus that attributable to all other potentially responsible parties, is relatively low. Although liability of those potentially responsible is generally joint and several for federal sites and frequently so for state sites, other potentially responsible parties at sites where we are a party typically have had the financial strength to meet their obligations, and where they have not, or where potentially responsible parties could not be located, our share of liability has not increased materially. Many of the sites at which we are potentially responsible are still under investigation by the EPA or the state agencies concerned. Prior to actual cleanup, those potentially responsible normally assess site conditions, apportion responsibility and determine the appropriate remediation. In some instances, we may have no liability or attain a settlement of liability. Actual cleanup costs generally occur after the parties obtain EPA or equivalent state agency approval. There are relatively few sites where we are a major participant, and given the timing and amounts of anticipated expenditures, neither the cost of remediation at those sites nor such costs at all CERCLA sites, in the aggregate, is expected to have a material adverse effect on our competitive or financial condition.

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Expensed environmental costs were $593 million in 2003 and are expected to be about $596 million in 2004 and $574 million in 2005. Capitalized environmental costs were $522 million in 2003 and are expected to be about $742 million and $967 million in 2004 and 2005, respectively.

Remediation Accruals

We accrue for remediation activities when it is probable that a liability has been incurred and reasonable estimates of the liability can be made. These accrued liabilities are not reduced for potential recoveries from insurers or other third parties and are not discounted (except those assumed in a purchase business combination, which we do record on a discounted basis).

Many of these liabilities result from CERCLA, RCRA and similar state laws that require us to undertake certain investigative and remedial activities at sites where we conduct, or once conducted, operations or at sites where ConocoPhillips-generated waste was disposed. The accrual also includes a number of sites we have identified that may require environmental remediation, but which are not currently the subject of CERCLA, RCRA or state enforcement activities. If applicable, we accrue receivables for probable insurance or other third-party recoveries. In the future, we may incur significant costs under both CERCLA and RCRA. Considerable uncertainty exists with respect to these costs, and under adverse changes in circumstances, potential liability may exceed amounts accrued as of December 31, 2003.

Remediation activities vary substantially in duration and cost from site to site, depending on the mix of unique site characteristics, evolving remediation technologies, diverse regulatory agencies and enforcement policies, and the presence or absence of potentially liable third parties. Therefore, it is difficult to develop reasonable estimates of future site remediation costs.

At December 31, 2003, our balance sheet included a total environmental accrual related to continuing operations of $1,119 million, compared with $743 million at December 31, 2002. The increase in accruals from year-end 2002, primarily resulted from evaluation of Conoco environmental liabilities during the purchase price allocation period. We expect to incur the majority of these expenditures within the next 30 years.

Notwithstanding any of the foregoing, and as with other companies engaged in similar businesses, environmental costs and liabilities are inherent in our operations and products, and there can be no assurance that material costs and liabilities will not be incurred. However, we currently do not expect any material adverse affect upon our results of operations or financial position as a result of compliance with environmental laws and regulations.

Other

We have deferred tax assets related to certain accrued liabilities, alternative minimum tax credits, and loss carryforwards. Valuation allowances have been established for certain foreign and state net operating loss carryforwards that reduce deferred tax assets to an amount that will, more likely than not, be realized. Uncertainties that may affect the realization of these assets include tax law changes and the future level of product prices and costs. Based on our historical taxable income, our expectations for the future, and available tax-planning strategies, management expects that the net deferred tax assets will be realized as offsets to reversing deferred tax liabilities and as reductions in future taxable income. The alternative minimum tax credit can be carried forward indefinitely to reduce our regular tax liability.

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NEW ACCOUNTING DEVELOPMENTS

In December 2003, the FASB revised and reissued SFAS No. 132 (revised 2003), Employers Disclosures about Pensions and Other Postretirement Benefits an amendment of FASB Statements No. 87, 88, and 106, which revises and requires additional disclosures about pension plans and other postretirement benefit plans. It does not change the measurement or recognition of those plans required by previous Financial Accounting Board Standards. We adopted the provisions of this Standard effective December 2003. Certain provisions of this Standard regarding disclosure of information about foreign plans and disclosure of estimated future benefit payments are not required until 2004. The adoption of the provisions applicable to 2003 did not have an impact on our results of operations or financial position, nor will the adoption of the additional provisions in 2004 have an impact on our results of operations or financial position.

In May 2003, the FASB issued SFAS No. 150, Accounting for Certain Financial Instruments with Characteristics of Liabilities and Equity, to address the balance sheet classification of certain financial instruments that have characteristics of both liabilities and equity. This statement was immediately effective for all contracts created or modified after May 31, 2003, and became effective July 1, 2003, for all previously existing contracts. On November 7, 2003, the FASB issued FASB Staff Position No. FAS 150-3, which deferred certain provisions of SFAS No. 150. As a result of adopting this new accounting standard in the third quarter of 2003, and the subsequent November 7, 2003, deferral of certain provisions, there was no impact on our 2003 financial statements. We continue to monitor the deferral status of SFAS No. 150.

In June 2001, the FASB issued SFAS No. 141, Business Combinations, and SFAS No. 142, Goodwill and Other Intangible Assets, which became effective on July 1, 2001, and January 1, 2002, respectively. The Securities and Exchange Commission (SEC) has requested the Emerging Issues Task Force (EITF) to consider the issue of whether SFAS Nos. 141 and 142 require interests held under oil, gas and mineral leases to be separately classified as intangible assets on the balance sheets of companies in the extractive industries. Historically, in accordance with SFAS No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies, we have capitalized the cost of oil and gas leasehold interests and, consistent with industry practice, reported these assets as part of tangible E&P properties, plants and equipment.

If such interests were deemed to be intangible assets by the EITF, mineral rights to extract oil and gas for both proved and unproved properties would be classified separately from E&P properties, plants and equipment as intangible assets on our balance sheet. This interpretation by the EITF would only affect the classification of oil and gas mineral rights on our balance sheet and would not affect total assets, net worth, results of operations or cash flows.

E&P properties, plants and equipment at December 31, 2003 and 2002, included approximately $10.5 billion and $10.8 billion, respectively, of mineral rights to extract oil and gas, net of accumulated depletion, that would be reclassified on the balance sheet as intangible assets, if the interpretation that the SEC requested the EITF to consider was applied. We plan to continue to classify oil and gas mineral rights as E&P properties, plants and equipment until further guidance is provided by the EITF.

CRITICAL ACCOUNTING POLICIES

The preparation of financial statements in conformity with generally accepted accounting principles requires management to select appropriate accounting policies and to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. See Note 1 Accounting Policies

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in the Notes to Consolidated Financial Statements for descriptions of our major accounting policies. Certain of these accounting policies involve judgments and uncertainties to such an extent that there is a reasonable likelihood that materially different amounts would have been reported under different conditions, or if different assumptions had been used. These critical accounting policies are discussed with the Audit and Compliance Committee on an annual basis and are presented below.

Oil and Gas Accounting

Accounting for oil and gas exploratory activity is subject to special accounting rules that are unique to the oil and gas industry. The acquisition of geological and geophysical seismic information, prior to the discovery of proved reserves, is expensed as incurred, similar to accounting for research and development costs. However, leasehold acquisition costs and exploratory well costs are capitalized on the balance sheet, pending determination of whether proved oil and gas reserves have been discovered on the prospect.

Property Acquisition Costs

For individually significant leaseholds, management periodically assesses for impairment based on exploration and drilling efforts to date. For leasehold acquisition costs that individually are relatively small, management exercises judgment and determines a percentage probability that the prospect ultimately will fail to find proved oil and gas reserves and pools that leasehold information with others in the geographic area. For prospects in areas that have had limited, or no, previous exploratory drilling, the percentage probability of ultimate failure is normally judged to be quite high. This judgmental percentage is multiplied by the leasehold acquisition cost, and that product is divided by the contractual period of the leasehold to determine a periodic leasehold impairment charge that is reported in exploration expense. This judgmental probability percentage is reassessed and adjusted throughout the contractual period of the leasehold based on favorable or unfavorable exploratory activity on the leasehold or on adjacent leaseholds, and leasehold impairment amortization expense is adjusted prospectively. By the end of the contractual period of the leasehold, the impairment probability percentage will have been adjusted to 100 percent if the leasehold is expected to be abandoned, or will have been adjusted to zero percent if there is an oil or gas discovery that is under development. See the supplemental Oil and Gas Operations disclosures about Costs Incurred and Capitalized Costs for more information about the amounts and geographic locations of costs incurred in acquisition activity, and the amounts on the balance sheet related to unproved properties.

Exploratory Costs

For exploratory wells, drilling costs are temporarily capitalized, or suspended, on the balance sheet, pending a judgmental determination of whether potentially economic oil and gas reserves have been discovered by the drilling effort. This judgment usually is made within two months of the completion of the drilling effort, but can take longer, depending on the complexity of the geologic structure. Accounting rules require that this judgment be made at least within one year of well completion. If a judgment is made that the well did not encounter potentially economic oil and gas quantities, the well costs are expensed as a dry hole and are reported in exploration expense. Exploratory wells that are judged to have discovered potentially economic quantities of oil and gas and that are in areas where a major capital expenditure (e.g., a pipeline or offshore platform) would be required before production could begin, and where the economic viability of that major capital expenditure depends upon the successful completion of further exploratory work in the area, remain capitalized on the balance sheet as long as additional exploratory appraisal work is under way or firmly planned. For complicated offshore exploratory discoveries, it is not unusual to have exploratory wells remain suspended on the balance sheet for several years while we perform additional appraisal work on the potential oil and gas field. Unlike leasehold acquisition costs, there is no periodic impairment assessment of suspended exploratory well costs. Management continuously monitors the results of the additional appraisal drilling and seismic work and expenses the suspended well costs as dry holes when it judges that the potential field does not warrant further exploratory efforts in the near term.

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See the supplemental Oil and Gas Operations disclosures about Costs Incurred and Capitalized Costs for more information about the amounts and geographic locations of costs incurred in exploration activity and the amounts on the balance sheet related to unproved properties, as well as the Wells In Progress disclosure for the number and geographic location of wells not yet declared productive or dry.

Proved Oil and Gas Reserves

Engineering estimates of the quantities of recoverable oil and gas reserves in oil and gas fields are inherently imprecise and represent only approximate amounts because of the subjective judgments involved in developing such information. Despite the inherent imprecision in these engineering estimates, accounting rules require supplemental disclosure of proved oil and gas reserve estimates due to the importance of these estimates to better understanding the perceived value and future cash flows of a company s oil and gas operations. The judgmental estimation of proved oil and gas reserves also is important to the income statement because the proved oil and gas reserve estimate for a field serves as the denominator in the unit-of-production calculation of depreciation, depletion and amortization of the capitalized costs for that field. There are several authoritative guidelines regarding the engineering criteria that have to be met before estimated oil and gas reserves can be designated as proved. Our reservoir engineering department has policies and procedures in place that are consistent with these authoritative guidelines. We have qualified and experienced internal engineering personnel who make these estimates. Proved reserve estimates are updated annually and take into account recent production and seismic information about each field. Also, as required by authoritative guidelines, the estimated future date when a field will be permanently shut-in for economic reasons is based on an extrapolation of oil and gas prices and operating costs prevalent at the balance sheet date. This estimated date when production will end affects the amount of estimated recoverable reserves. Therefore, as prices and cost levels change from year to year, the estimate of proved reserves also changes.

Canadian Syncrude Reserves

Canadian Syncrude proven reserves cannot be measured precisely. Reserve estimates of Canadian Syncrude are based on subjective judgments involving geological and engineering assessments of in-place crude bitumen volume, the mining plan, historical extraction recovery and upgrading yield factors, installed plant operating capacity and operating approval limits. The reliability of these estimates at any point in time depends on both the quality and quantity of the technical and economic data and the efficiency of extracting the bitumen and upgrading it into a light sweet crude oil. Despite the inherent imprecision in these engineering estimates, these estimates are used in determining depreciation expense.

Impairment of Assets

Long-lived assets used in operations are assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in the future cash flows expected to be generated by an asset group. If, upon review, the sum of the undiscounted pretax cash flows is less than the carrying value of the asset group, the carrying value is written down to estimated fair value. Individual assets are grouped for impairment purposes based on a judgmental assessment of the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets generally on a field-by-field basis for exploration and production assets, at an entire complex level for downstream assets, or at a site level for retail stores. Because there usually is a lack of quoted market prices for long-lived assets, the fair value usually is based on the present values of expected future cash flows using discount rates commensurate with the risks involved in the asset group. The expected future cash flows used for impairment reviews and related fair-value calculations are based on judgmental assessments of future production volumes, prices and costs, considering all available information at the date of review. See Note 12 Property Impairments, in the Notes to Consolidated Financial Statements, for additional information.

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Asset Retirement Obligations and Environmental Costs
Under various contracts, permits and regulations, we have material legal obligations to remove tangible equipment and restore the land or seabed at the end of operations at production sites. The largest asset removal obligations facing us involve removal and disposal of offshore oil and gas platforms around the world, and oil and gas production facilities and pipelines in Alaska. The estimated discounted costs of dismantling and removing these facilities are accrued at the installation of the asset. Estimating the future asset removal costs necessary for this accounting calculation is difficult. Most of these removal obligations are many years in the future and the contracts and regulations often have vague descriptions of what removal practices and criteria will have to be met when the removal event actually occurs. Asset removal technologies and costs are constantly changing, as well as political, environmental, safety and public relations considerations. See Note 1 Accounting Policies and Note 13 Asset Retirement Obligations and Accrued Environmental Costs, in the Notes to Consolidated Financial Statements, for additional information.

Business Acquisitions

Purchase Price Allocation
Accounting for the acquisition of a business requires the allocation of the purchase price to the various assets and liabilities of the acquired business. For most assets and liabilities, purchase price allocation is accomplished by recording the asset or liability at its estimated fair value. The most difficult estimations of individual fair values are those involving properties, plants and equipment and identifiable intangible assets. We use all available information to make these fair value determinations and, for major business acquisitions, typically engage an outside appraisal firm to assist in the fair value determination of the acquired long-lived assets. We have, if necessary, up to one year after the acquisition closing date to finish these fair value determinations and finalize the purchase price allocation.

Intangible Assets and Goodwill
In connection with the acquisition of Tosco Corporation on September 14, 2001, and the merger on August 30, 2002, we recorded material intangible assets for tradenames, air emission permit credits, and permits to operate refineries. These intangible assets were determined to have indefinite useful lives and so are not amortized. This judgmental assessment of an indefinite useful life has to be continuously evaluated in the future. If, due to changes in facts and circumstances, management determines that these intangible assets then have definite useful lives, amortization will have to commence at that time on a prospective basis. As long as these intangible assets are judged to have indefinite lives, they will be subject to periodic lower-of-cost-or-market tests, which requires management s judgment of the estimated fair value of these intangible assets. See Note 6 Acquisition of Tosco Corporation, Note 3 Merger of Conoco and Phillips, and Note 12 Property Impairments, in the Notes to Consolidated Financial Statements, for additional information.

Also in connection with the acquisition of Tosco and the merger, we recorded a material amount of goodwill. Under the accounting rules for goodwill, this intangible asset is not amortized. Instead, goodwill is subject to annual reviews for impairment based on a two-step accounting test. The first step is to compare the estimated fair value of any reporting units within the company that have recorded goodwill with the recorded net book value (including the goodwill) of the reporting unit. If the estimated fair value of the reporting unit is higher than the recorded net book value, no impairment is deemed to exist and no further testing is required that year. If, however, the estimated fair value of the reporting unit is below the recorded net book value, then a second step must be performed to determine the amount of the goodwill impairment to record, if any. In this second step, the estimated fair value from the first step is used as the purchase price in a hypothetical new acquisition of the reporting unit. The various purchase business combination rules are followed to determine a hypothetical purchase price allocation for the reporting unit s assets and liabilities. The residual amount of goodwill that results from this hypothetical purchase price allocation is compared with the recorded amount of goodwill for the reporting unit, and the recorded amount is written down to the hypothetical amount if lower. The reporting unit or units used to evaluate and measure goodwill for impairment are determined primarily from the manner in which the business is managed. A reporting unit is an operating segment or a component that is one level below an operating segment. A component is a reporting unit if the component constitutes a business for which discrete financial information is available and segment management regularly reviews the operating results of that component. However, two or more components of an operating segment shall be aggregated and deemed a single reporting unit if the components have similar economic characteristics. We have determined that we have three reporting units for purposes of assigning goodwill and testing for impairment. These are Worldwide Exploration and Production, Worldwide Refining and Worldwide Marketing. Our Midstream, Chemicals and Emerging Businesses operating segments were not assigned any goodwill from the merger because the two predecessor companies operations did not overlap in these operating segments so we were unable to capture significant synergies and strategic advantages from the merger in these areas.

In our Exploration and Production operating segment, management reporting is primarily organized based on geographic areas. All of these geographic areas have similar business processes, distribution networks and customers, and are supported by a worldwide exploration team and shared services organizations. Therefore, all components have been aggregated into one reporting unit, Worldwide Exploration and Production, which is the same as the operating segment. In contrast, in our Refining and Marketing operating segment, management reporting is primarily organized based on functional areas. Because the two broad functional areas of Refining and Marketing have dissimilar business processes and customers, we concluded that it would not be appropriate to aggregate these components into only one reporting unit at the Refining and Marketing operating segment level. Instead, we have identified two reporting units within the operating segment: Worldwide Refining and Worldwide Marketing. Components in those two reporting units have similar business processes, distribution networks and customers. If we later reorganize our businesses or management structure so that the components within these three reporting units are no longer economically similar, the reporting units would be revised and goodwill would be re-assigned using a relative fair value approach in accordance with SFAS No. 142, Goodwill and Other Intangible Assets. Goodwill impairment testing at a lower reporting unit level could result in the recognition of impairment that would not otherwise be recognized at the current higher level of aggregation. In addition, the sale or disposition of a portion of these three reporting units will be allocated a portion of the reporting unit s goodwill, based on relative fair values, which will adjust the amount of gain or loss on the sale or disposition.

Because quoted market prices for our reporting units are not available, management has to apply judgment in determining the estimated fair value of these reporting units for purposes of performing the first step of the periodic goodwill impairment test. Management uses all available information to make these fair value determinations, including the present values of expected future cash flows using discount rates commensurate with the risks involved in the assets and observed market multiples of operating cash flows and net income, and may engage an outside appraisal firm for assistance. In addition, if the first test step is not met, further judgment has to be applied in determining the fair values of individual assets and liabilities for purposes of the hypothetical purchase price allocation. Again, management has to use all available information to make these fair value determinations and may engage an outside appraisal firm for assistance. At year-end 2003, the estimated fair values of our Worldwide Exploration and Production, Worldwide Refining, and Worldwide Marketing reporting units, excluding those included in discontinued operations, ranged from between 15 percent to 35 percent higher than recorded net book values (including goodwill) of the reporting units. However, a lower fair value estimate in the future for any of these reporting units could result in impairment of the $15.1 billion of goodwill.

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Inventory Valuation

Prior to the acquisition of Tosco in September 2001 and the merger in August 2002, our inventories on the last-in, first-out (LIFO) cost basis were predominantly reflected on the balance sheet at historical cost layers established many years ago, when price levels were much lower. Therefore, prior to 2001, our LIFO inventories were relatively insensitive to current price level changes. However, the acquisition of Tosco and the ConocoPhillips merger added LIFO cost layers that were recorded at replacement cost levels prevalent in late September 2001 and August 2002, respectively. As a result, our LIFO cost inventories are now much more sensitive to lower-of-cost-or-market impairment write-downs, whenever price levels fall. We recorded a LIFO inventory lower-of-cost-or-market impairment in the fourth quarter of 2001 due to a crude oil price deterioration. While crude oil is not the only product in the company s LIFO pools, its market value is a major factor in lower-of-cost-or-market calculations. We estimate that additional impairments could occur if a 60 percent/40 percent blended average of West Texas Intermediate/Brent crude oil prices falls below $21.25 per barrel at a reporting date. The determination of replacement cost values for the lower-of-cost-or-market test uses objective evidence, but does involve judgment in determining the most appropriate objective evidence to use in the calculations.

Projected Benefit Obligations

Determination of the projected benefit obligations for our defined benefit pension and postretirement plans are important to the recorded amounts for such obligations on the balance sheet and to the amount of benefit expense in the income statement. This also impacts the required company contributions into the plans. The actuarial determination of projected benefit obligations and company contribution requirements involves judgment about uncertain future events, including estimated retirement dates, salary levels at retirement, mortality rates, lump-sum election rates, rates of return on plan assets, future health care cost-trend rates, and rates of utilization of health care services by retirees. Due to the specialized nature of these calculations, we engage outside actuarial firms to assist in the determination of these projected benefit obligations. For Employee Retirement Income Security Act-qualified pension plans, the actuary exercises fiduciary care on behalf of plan participants in the determination of the judgmental assumptions used in determining required company contributions into plan assets. Due to differing objectives and requirements between financial accounting rules and the pension plan funding regulations promulgated by governmental agencies, the actuarial methods and assumptions for the two purposes differ in certain important respects. Ultimately, we will be required to fund all promised benefits under pension and postretirement benefit plans not funded by plan assets or investment returns, but the judgmental assumptions used in the actuarial calculations significantly affect periodic financial statements and funding patterns over time. Benefit expense is particularly sensitive to the discount rate and return on plan assets assumptions. A 1 percent decrease in the discount rate would increase annual benefit expense by $85 million, while a 1 percent decrease in the return on plan assets assumption would increase annual benefit expense by $25 million.

OUTLOOK

After adjusting for asset dispositions, E&P s worldwide production for 2004 is expected to be about the same level as it was in 2003. The dispositions contributed approximately 37,000 barrels of oil equivalent per day to 2003 production. For 2004, production increases in Asia Pacific and Latin America are expected to offset net declines in the United States, Canada and the North Sea.

In R&M, the optimization of spending related to clean fuels project initiatives will be an important focus area during 2004. In addition, we expect our average refinery crude oil utilization rate for 2004 to average about the same as in 2003.

Crude oil and natural gas prices are subject to external factors over which we have no control, such as global economic conditions, political events, demand growth, inventory levels, weather, competing fuels prices, and availability of supply. Crude oil prices rose significantly in 2003 due to supply disruptions during the year in several producing countries and the delays in the return of Iraqi crude production to the market in the face of rising global oil demand. As a result of these factors, global oil inventories remained at exceptionally low levels throughout 2003. Low oil inventories, coupled with economic recovery and the prospects for higher oil demand growth are expected to keep prices elevated through the first half of 2004. U.S. natural gas prices weakened moderately during the second half of 2003 from the very strong levels experienced during the second quarter, but the annual average was significantly higher in 2003 versus 2002. Prices weakened in the second half due to a strong buildup of natural gas inventories during the summer and early fall, as mild weather, weak industrial demand and fuel switching reduced natural gas demand. At the same time, high prices and the startup of a mothballed regasification terminal increased LNG imports to the United States. However, natural gas prices rose moderately in December, reflecting continuing concerns about the adequacy of gas supplies in the United States. Supply adequacy concerns are expected to keep prices above historical levels in 2004.

Refining margins are subject to movements in the price of crude oil and other feedstocks, and the prices of petroleum products, which are subject to market factors over which we have no control, such as the U.S. and global economies; government regulations; military, political and social conditions in oil producing countries; seasonal factors that affect demand, such as the summer driving months; and the levels of refining output and product inventories. U.S. and international refining and marketing margins rose in 2003 versus 2002, due to improved refined product demand and a series of supply disruptions. U.S. refining margins were above the five-year historical average in 2003 as a result of refinery outages in several regions of the United States, a product pipeline rupture in Arizona, and labor strikes in Venezuela, which removed both crude and refined products from the market. Combined with strong product demand, product inventories were drawn down to extremely low levels in the first half of the year, which elevated refining margins. Stronger demand in the face of tight supplies also improved marketing margins in 2003 versus 2002. The sustainability of current refining and marketing margins depends on the continued recovery of the global economy and refined product demand growth.

In February 2003, the Venezuelan government implemented a currency exchange control regime. The government has published legal instruments supporting the controls, one of which establishes official exchange rates for the U.S. dollar. The devaluation of the Venezuelan currency by approximately 17 percent in February 2004 did not have a significant impact on our Venezuelan operations; however, future changes in the exchange rate could have a significant impact on our Venezuelan operations. In addition, our Venezuelan operations remain subject to civil unrest in the country. Our Venezuelan operations contributed approximately $150 million to our 2003 net income.

In June 2003, we and our co-venturers in the Mackenzie gas project in Canada announced that funding and participation agreements have been reached and a preliminary information package was submitted to relevant regulatory authorities. The Mackenzie gas project involves natural gas production facilities, compression and gathering pipelines in the Mackenzie Delta area, and a pipeline system in the Mackenzie River Valley. The filing of the information package is a key step in the process leading to the submission of applications for the development of the natural gas fields and pipeline facilities. Regulatory applications are expected to be filed in 2004. First gas production is currently targeted to commence in late 2009.

In July 2003, we signed a Heads of Agreement with Qatar Petroleum for the development of Qatargas 3, a large-scale LNG project located in Qatar and servicing the U.S. natural gas market. This provides the framework for the necessary agreements and the completion of key feasibility studies. Qatargas 3 would be an integrated project, jointly owned by us and Qatar Petroleum, consisting of facilities to produce and liquefy gas from Qatar s North field. The LNG would be shipped from Qatar, and we would be

responsible for regasification and marketing within the United States. Average daily gas sales volumes are projected to be approximately 1 billion cubic feet per day with startup anticipated in the 2009 timeframe.

In late October 2003, we signed a Heads of Agreement with the Nigerian National Petroleum Corporation, ENI and ChevronTexaco to conduct front-end engineering and design work for an LNG facility to be constructed in Nigeria s central Niger Delta. The participants have agreed to form an incorporated joint venture, Brass LNG Limited, to undertake the project. The engineering and design studies are expected to be completed in 2005, and the facility is targeted to be operational in 2009.

In December 2003, we signed a Statement of Intent with Qatar Petroleum regarding the construction of a gas-to-liquids plant in Ras Laffan, Qatar. The Statement of Intent initiates detailed technical and commercial pre-front-end engineering and design studies and establishes principles for negotiating a Heads of Agreement for an integrated reservoir-to-market plant. More definite agreements are expected in 2004.

Also in December 2003, we announced the signing of an agreement with Freeport LNG Development, L.P. to participate in its proposed LNG receiving terminal in Quintana, Texas. We would acquire 1 billion cubic feet per day of regasification capacity in the terminal for our use and obtain a 50 percent interest in the general partnership managing the venture. The terminal will be designed with a storage capacity of 6.9 billion cubic feet and a send-out capacity of 1.5 billion cubic feet per day. Pending government approvals, construction is scheduled to begin in the second half of 2004, with commercial startup in mid-2007.

In addition, we and our co-venturer are pursuing a proposed LNG receiving terminal in Harpswell, Maine. The proposal calls for construction of the terminal at a site previously used as a U.S. Navy fuel depot. LNG would be converted back to natural gas at the terminal for delivery through a new pipeline that would connect the terminal to the existing pipeline grid. Depending on receipt of the necessary regulatory approvals, construction could begin in 2006, with the facility operational by 2009.

CAUTIONARY STATEMENT FOR THE PURPOSES OF THE SAFE HARBOR PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

This annual report includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements can be identified by the words expects, anticipates, intends, plans, projects, believes, estimates and similar expressions.

We have based the forward-looking statements relating to our operations on our current expectations, estimates and projections about ourselves and the industries in which we operate in general. We caution you that these statements are not guarantees of future performance and involve risks, uncertainties and assumptions that we cannot predict. In addition, we have based many of these forward-looking statements on assumptions about future events that may prove to be inaccurate. Accordingly, our actual outcome and results may differ materially from what we have expressed or forecast in the forward-looking statements. Any differences could result from a variety of factors, including the following:

- Fluctuations in crude oil, natural gas and natural gas liquids prices, refining and marketing margins and margins for our chemicals business;
- Changes in our business, operations, results and prospects;
- The operation and financing of our midstream and chemicals joint ventures;

Potential failure to realize fully or within the expected time frame the expected cost savings and synergies from the combination of Conoco and Phillips;

Costs or difficulties related to the integration of the businesses of Conoco and Phillips, as well as the continued integration of businesses recently acquired by each of them;

Potential failure or delays in achieving expected reserve or production levels from existing and future oil and gas development projects due to operating hazards, drilling risks and the inherent uncertainties in predicting oil and gas reserves and oil and gas reservoir performance;

Unsuccessful exploratory drilling activities;

Failure of new products and services to achieve market acceptance;

Unexpected cost increases or technical difficulties in constructing or modifying facilities for exploration and production projects, manufacturing or refining;

Unexpected difficulties in manufacturing or refining our refined products, including synthetic crude oil, and chemicals products;

Lack of, or disruptions in, adequate and reliable transportation for our crude oil, natural gas, LNG and refined products;

Inability to timely obtain or maintain permits, including those necessary for construction of LNG terminals or regasification facilities, comply with government regulations or make capital expenditures required to maintain compliance;

Potential disruption or interruption of our facilities due to accidents, political events or terrorism;

International monetary conditions and exchange controls;

Liability for remedial actions, including removal and reclamation obligations, under environmental regulations;

Liability resulting from litigation;

General domestic and international economic and political conditions, including armed hostilities, homeland security, and governmental disputes over territorial boundaries;

Changes in tax and other laws or regulations applicable to our business; and

Inability to obtain economical financing for exploration and development projects, construction or modification of facilities and general corporate purposes.

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Financial Instrument Market Risk

We and certain of our subsidiaries hold and issue derivative contracts and financial instruments that expose cash flows or earnings to changes in commodity prices, foreign exchange rates or interest rates. We may use financial and commodity-based derivative contracts to manage the risks produced by changes in the prices of electric power, natural gas, crude oil and related products, fluctuations in interest rates and foreign currency exchange rates, or to exploit market opportunities.

Our use of derivative instruments is governed by an Authority Limitations document approved by our Board that prohibits the use of highly leveraged derivatives or derivative instruments without sufficient liquidity for comparable valuations without approval from the Chief Executive Officer. The Authority

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Limitations document also authorizes the Chief Executive Officer to establish the maximum Value at Risk (VaR) limits for the company and compliance with these limits is monitored daily. The Chief Financial Officer monitors risks resulting from foreign currency exchange rates and interest rates, while the Executive Vice President of Commercial monitors commodity price risk. Both report to the Chief Executive Officer. The Commercial group manages our commercial marketing, optimizes our commodity flows and positions, monitors related risks of our upstream and downstream businesses, and selectively takes price risk to add value.

Commodity Price Risk

We operate in the worldwide crude oil, refined products, natural gas, natural gas liquids, and electric power markets and are exposed to fluctuations in the prices for these commodities. These fluctuations can affect our revenues, as well as the cost of operating, investing, and financing activities. Generally, our policy is to remain exposed to market prices of commodities; however, executive management may elect to use derivative instruments to hedge the price risk of our crude oil and natural gas production, as well as refinery margins.

Our Commercial group uses futures, forwards, swaps, and options in various markets to optimize the value of our supply chain, which may move our risk profile away from market average prices to accomplish the following objectives:

- Balance physical systems. In addition to cash settlement prior to contract expiration, exchange traded futures contracts also may be settled by physical delivery of the commodity, providing another source of supply to meet our refinery requirements or marketing demand;

- Meet customer needs. Consistent with our policy to generally remain exposed to market prices, we use swap contracts to convert fixed-price sales contracts, which are often requested by natural gas and refined product consumers, to a floating market price;

- Manage the risk to our cash flows from price exposures on specific crude oil, natural gas, refined product and electric power transactions; and

- Enable us to use the market knowledge gained from these activities to do a limited amount of trading not directly related to our physical business. For the 12 months ended December 31, 2003 and 2002, the gains or losses from this activity were not material to our cash flows or income from continuing operations.

We use a VaR model to estimate the loss in fair value that could potentially result on a single day from the effect of adverse changes in market conditions on the derivative financial instruments and derivative commodity instruments held or issued, including commodity purchase and sales contracts recorded on the balance sheet at December 31, 2003, as derivative instruments in accordance with SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended. Using Monte Carlo simulation, a 95 percent confidence level and a one-day holding period, the VaR for those instruments issued or held for trading purposes at December 31, 2003 and 2002, was immaterial to our net income and cash flows. The VaR for instruments held for purposes other than trading at December 31, 2003 and 2002, was also immaterial to our net income and cash flows.

Interest Rate Risk

The following tables provide information about our financial instruments that are sensitive to changes in interest rates. The debt tables present principal cash flows and related weighted-average interest rates by expected maturity dates; the derivative table shows the notional quantities on which the cash flows will be calculated by swap termination date. Weighted-average variable rates are based on implied forward rates in the yield curve at the reporting date. The carrying amount of our floating-rate debt approximates its fair value. The fair value of the fixed-rate financial instruments is estimated based on quoted market prices.

	Millions of Dollars Except as Indicated					
	Debt				Mandatorily Redeemable Other Minority Interests and Preferred Securities	
Expected Maturity Date	Fixed Rate Maturity	Average Interest Rate	Floating Rate Maturity	Average Interest Rate	Fixed Rate Maturity	Average Interest Rate
Year-End 2003						
2004	**$ 1,360**	**5.91%**	**$ 7**	**5.85%**	**$**	**%**
2005	**1,168**	**8.49**	**8**	**5.85**		
2006	**1,506**	**5.82**	**320**	**2.71**		
2007	**612**	**4.88**				
2008	**18**	**7.10**	**500**	**1.05**		
Remaining years	**10,849**	**6.98**	**776**	**1.59**	**141**	**7.86**
Total	**$ 15,513**		**$ 1,611**		**$ 141**	
Fair value	**$ 17,294**		**$ 1,611**		**$ 142**	
Year-End 2002						
2003	$ 762	7.99%	$ 706	2.60%	$	%
2004	1,362	5.91				
2005	1,169	8.49				
2006	1,507	5.82	1,517	4.54		
2007	613	4.88				
Remaining years	10,740	6.95	691	6.02	491	7.96
Total	$ 16,153		$ 2,914		$ 491	

Fair value	$ 17,930	$ 2,914	$ 516

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In October and early November 2003, we executed certain interest rate swaps that had the effect of converting $1.5 billion of debt from fixed to floating rate. Under SFAS 133, Accounting for Derivative Instruments and Hedging Activities, these swaps were designated as hedging the exposure to changes in the fair value of $400 million of 3.625% Notes due 2007, $750 million of 6.35% Notes due 2009, and $350 million of 4.75% Notes due 2012. These swaps qualify for the shortcut method of hedge accounting, so over the term of the swaps we will not recognize gain or loss due to ineffectiveness in the hedge.

	Interest Rate Derivatives		
Expected Maturity Date	Notional	Average Pay Rate	Average Receive Rate
Year-End 2003			
2004	$	%	%
2005			
2006 variable to fixed	**131**	**5.85**	**1.15**
2007 fixed to variable	**400**	**1.07**	**3.63**
2008			
Remaining years fixed to variable	**1,100**	**2.67**	**5.84**
Total	**$ 1,631**		
Fair value position	**$**		
Year-End 2002			
2003 variable to fixed	$ 500	3.41%	2.56%
2004			
2005			
2006 variable to fixed	166	5.85	4.76
2007			
Remaining years			
Total	$ 666		
Fair value loss position	$ 22		

Foreign Currency Risk

We have foreign currency exchange rate risk resulting from operations in over 40 countries around the world. We do not comprehensively hedge the exposure to currency rate changes, although we may choose to selectively hedge exposures to foreign currency rate risk. Examples include firm commitments for capital projects, certain local currency tax payments and dividends, and cash returns from net investments in foreign affiliates to be remitted within the coming year.

At December 31, 2003, we held foreign currency swaps hedging short-term intercompany loans between European subsidiaries and a U.S. subsidiary. Although these swaps hedge exposures to fluctuations in exchange rates, we elected not to utilize hedge accounting as allowed by SFAS No. 133. As a result, the change in the fair value of these foreign currency swaps is recorded directly in earnings. Since the gain or loss on the swaps is offset by the gain or loss from remeasuring the intercompany loans into the functional currency of the lender or borrower, there would be no impact to income from an adverse hypothetical 10 percent change in the December 31, 2003, exchange rates. The notional and fair market values of these positions at December 31, 2003, were as follows:

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	Millions of Dollars	
Foreign Currency Swaps	Notional	Fair Market Value
Sell U.S. dollar, buy euro	$ 267	2
Sell U.S. dollar, buy British pound	789	26
Sell U.S. dollar, buy Danish krone	12	
Sell U.S. dollar, buy Norway kroner	380	7
Sell U.S. dollar, buy Swedish krona	93	5

At December 31, 2002, ConocoPhillips had the following significant foreign currency derivative contracts:

Approximately $194 million in foreign currency swaps hedging the company s European commercial paper program, with a fair value of $7.1 million;

Approximately $536 million in foreign currency swaps hedging short-term intercompany loans between U.K. subsidiaries and a U.S. subsidiary, with a fair value of $9 million; and

Approximately $24 million in foreign currency swaps hedging the company s firm purchase and sales commitments for gasoline in Germany, with a negative fair value of $4 million.

Although these swaps hedge exposures to fluctuations in exchange rates, the company elected not to utilize hedge accounting as allowed by SFAS No. 133. As a result, the change in the fair value of these foreign currency swaps is recorded directly in earnings. Assuming an adverse hypothetical 10 percent change in the December 31, 2002, exchange rates, the potential foreign currency remeasurement loss in non-cash pretax earnings from these swaps, intercompany loans, and commercial paper would be approximately $3 million.

In addition to the intercompany loans discussed above, at December 31, 2002, U.S. subsidiaries held long-term sterling-denominated intercompany receivables totaling $152 million due from a U.K. subsidiary. A Norwegian subsidiary held $198 million of intercompany U.S. dollar-denominated receivables due from its U.S. parent at December 31, 2002. The potential foreign currency remeasurement gains or losses in non-cash pretax earnings from a hypothetical 10 percent change in the year-end 2002 exchange rates from these intercompany balances was $35 million.

For additional information about our use of derivative instruments, see Note 18 Derivative Instruments in the Notes to Consolidated Financial Statements.

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Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

CONOCOPHILLIPS

INDEX TO FINANCIAL STATEMENTS

INDEX TO FINANCIAL STATEMENT SCHEDULES

All other schedules are omitted because they are either not required, not significant, not applicable or the information is shown in another schedule, the financial statements or in the notes to consolidated financial statements.

Report of Management

Management prepared, and is responsible for, the consolidated financial statements and the other information appearing in this annual report. The consolidated financial statements present fairly the company s financial position, results of operations and cash flows in conformity with accounting principles generally accepted in the United States. In preparing its consolidated financial statements, the company includes amounts that are based on estimates and judgments that management believes are reasonable under the circumstances.

The company maintains internal controls designed to provide reasonable assurance that the company s assets are protected from unauthorized use and that all transactions are executed in accordance with established authorizations and recorded properly. The internal controls are supported by written policies and guidelines and are complemented by a staff of internal auditors. Management believes that the internal controls in place at December 31, 2003, provide reasonable assurance that the books and records reflect the transactions of the company and there has been compliance with its policies and procedures.

The company s financial statements have been audited by Ernst & Young LLP, independent auditors selected by the Audit and Compliance Committee of the Board of Directors. Management has made available to Ernst & Young LLP all of the company s financial records and related data, as well as the minutes of stockholders and directors meetings.

/s/ Archie W. Dunham	/s/ J. J. Mulva	/s/ John A. Carrig
Archie W. Dunham	**J. J. Mulva**	**John A. Carrig**
Chairman of the Board	President and Chief Executive Officer	Executive Vice President, Finance, and Chief Financial Officer

February 25, 2004

Report of Independent Auditors
The Board of Directors and Stockholders
ConocoPhillips

We have audited the accompanying consolidated balance sheets of ConocoPhillips as of December 31, 2003 and 2002, and the related consolidated statements of income, changes in common stockholders equity, and cash flows for each of the three years in the period ended December 31, 2003. Our audits also included the condensed consolidating financial information and financial statement schedule listed in the Index in Item 8. These financial statements, condensed consolidating financial information and schedule are the responsibility of the company s management. Our responsibility is to express an opinion on these financial statements, condensed consolidating financial information and schedule based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of ConocoPhillips at December 31, 2003 and 2002, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States. Also, in our opinion, the related condensed consolidating financial information and financial statement schedule, when considered in relation to the basic financial statements taken as a whole, present fairly in all material respects the information set forth therein.

As discussed in Note 2 to the consolidated financial statements, in 2003 ConocoPhillips adopted Statement of Financial Accounting Standards (SFAS) No. 143, Accounting for Asset Retirement Obligations, SFAS No. 123, Accounting for Stock-Based Compensation, and Financial Accounting Standards Board Interpretation No. 46, Consolidation of Variable Interest Entities, and in 2001 ConocoPhillips changed its method of accounting for the costs of major maintenance turnarounds.

/s/ Ernst & Young LLP

ERNST & YOUNG LLP

Houston, Texas
February 25, 2004

Consolidated Income Statement **ConocoPhillips**

Years Ended December 31	Millions of Dollars		
	2003	2002	2001
Revenues			
Sales and other operating revenues*	**$ 104,196**	56,748	24,892
Equity in earnings of affiliates	**542**	261	41
Other income	**359**	192	97
Total Revenues	**105,097**	57,201	25,030
Costs and Expenses			
Purchased crude oil and products	**67,424**	37,823	13,708
Production and operating expenses	**7,208**	4,698	2,643
Selling, general and administrative expenses	**2,166**	1,950	613
Exploration expenses	**601**	592	306
Depreciation, depletion and amortization	**3,485**	2,223	1,344
Property impairments	**252**	177	26
Taxes other than income taxes*	**14,679**	6,937	2,740
Accretion on discounted liabilities	**145**	22	7
Interest and debt expense	**844**	566	338
Foreign currency transaction (gains) losses	**(36)**	24	11
Minority interests and preferred dividend requirements of capital trusts	**20**	48	53
Total Costs and Expenses	**96,788**	55,060	21,789
Income from continuing operations before income taxes and subsidiary equity transactions	**8,309**	2,141	3,241
Gain on subsidiary equity transactions	**28**		
Income from continuing operations before income taxes	**8,337**	2,141	3,241
Provision for income taxes	**3,744**	1,443	1,640
Income From Continuing Operations	**4,593**	698	1,601
Income (loss) from discontinued operations	**237**	(993)	32
	4,830	(295)	1,633

Income (loss) before cumulative effect of changes in accounting principles			
Cumulative effect of changes in accounting principles	**(95)**		28
Net Income (Loss)	**$ 4,735**	(295)	1,661
Income (Loss) Per Share of Common Stock			
Basic			
Continuing operations	**$ 6.75**	1.45	5.46
Discontinued operations	**.35**	(2.06)	.11
Before cumulative effect of changes in accounting principles	**7.10**	(.61)	5.57
Cumulative effect of changes in accounting principles	**(.14)**		.10
Net Income (Loss)	**$ 6.96**	(.61)	5.67
Diluted			
Continuing operations	**$ 6.70**	1.44	5.43
Discontinued operations	**.35**	(2.05)	.11
Before cumulative effect of changes in accounting principles	**7.05**	(.61)	5.54
Cumulative effect of changes in accounting principles	**(.14)**		.09
Net Income (Loss)	**$ 6.91**	(.61)	5.63
Average Common Shares Outstanding (in thousands)			
Basic	**680,490**	482,082	292,964
Diluted	**685,433**	485,505	295,016
**Includes excise taxes on petroleum products sales:*	***$ 13,705***	*6,236*	*2,178*

See Notes to Consolidated Financial Statements.

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Consolidated Balance Sheet **ConocoPhillips**

At December 31	Millions of Dollars	
	2003	2002
Assets		
Cash and cash equivalents	$ **490**	307
Accounts and notes receivable (net of allowance of $43 million in 2003 and $48 million in 2002)	**3,606**	2,873
Accounts and notes receivable related parties	**1,399**	1,507
Inventories	**3,957**	3,845
Prepaid expenses and other current assets	**876**	766
Assets of discontinued operations held for sale	**864**	1,605
Total Current Assets	**11,192**	10,903
Investments and long-term receivables	**7,258**	6,821
Net properties, plants and equipment	**47,428**	43,030
Goodwill	**15,084**	14,444
Intangibles	**1,085**	1,119
Other assets	**408**	519
Total Assets	$ **82,455**	76,836
Liabilities		
Accounts payable	$ **6,598**	5,949
Accounts payable related parties	**301**	303
Notes payable and long-term debt due within one year	**1,440**	849
Accrued income and other taxes	**2,676**	1,991
Other accruals	**2,817**	3,075
Liabilities of discontinued operations held for sale	**179**	649
Total Current Liabilities	**14,011**	12,816
Long-term debt	**16,340**	18,917
Asset retirement obligations and accrued environmental costs	**3,603**	1,666
Deferred income taxes	**8,565**	8,361
Employee benefit obligations	**2,445**	2,755
Other liabilities and deferred credits	**2,283**	1,803
Total Liabilities	**47,247**	46,318

Company-Obligated Mandatorily Redeemable Preferred Securities of Phillips 66 Capital Trust II		350
Other Minority Interests	**842**	651
Common Stockholders Equity		
Common stock (2,500,000,000 shares authorized at $.01 par value)		
Issued (2003 708,085,097 shares; 2002 704,354,839 shares)		
Par value	**7**	7
Capital in excess of par	**25,361**	25,178
Compensation and Benefits Trust (CBT) (at cost: 2003 25,301,314 shares; 2002 26,785,094 shares)	**(857)**	(907)
Accumulated other comprehensive income (loss)	**821**	(164)
Unearned employee compensation	**(200)**	(218)
Retained earnings	**9,234**	5,621
Total Common Stockholders Equity	**34,366**	29,517
Total	**$ 82,455**	76,836

See Notes to Consolidated Financial Statements.

Consolidated Statement of Cash Flows **ConocoPhillips**

Years Ended December 31	Millions of Dollars		
	2003	2002	2001
Cash Flows From Operating Activities			
Income from continuing operations	$ **4,593**	698	1,601
Adjustments to reconcile income from continuing operations to net cash provided by continuing operations			
Non-working capital adjustments			
Depreciation, depletion and amortization	**3,485**	2,223	1,344
Property impairments	**252**	177	26
Dry hole costs and leasehold impairment	**300**	307	99
Accretion on discounted liabilities	**145**	22	7
Acquired in-process research and development		246	
Deferred taxes	**401**	142	513
Undistributed equity earnings	**(59)**	18	92
Gain on asset dispositions	**(211)**	(7)	(34)
Other	**(328)**	(32)	80
Working capital adjustments*			
Decrease in aggregate balance of accounts receivable sold	**(161)**	(22)	(174)
Decrease (increase) in other accounts and notes receivable	**(28)**	(401)	1,357
Decrease (increase) in inventories	**(24)**	200	(289)
Decrease (increase) in prepaid expenses and other current assets	**(105)**	(37)	50
Increase (decrease) in accounts payable	**345**	788	(1,004)
Increase (decrease) in taxes and other accruals	**562**	454	(142)
Net cash provided by continuing operations	**9,167**	4,776	3,526
Net cash provided by discontinued operations	**189**	202	33
Net Cash Provided by Operating Activities	**9,356**	4,978	3,559
Cash Flows From Investing Activities			
Acquisitions, net of cash acquired		1,180	80
Cash consolidated from adoption of FIN 46	**225**		
Capital expenditures and investments, including dry hole costs	**(6,169)**	(4,388)	(3,016)
Proceeds from asset dispositions	**2,659**	815	262
Long-term advances to affiliates and other investments	**23**	(92)	(28)
Net cash used in continuing operations	**(3,262)**	(2,485)	(2,702)
Net cash used in discontinued operations	**(236)**	(99)	(68)

Net Cash Used in Investing Activities	**(3,498)**	(2,584)	(2,770)
Cash Flows From Financing Activities			
Issuance of debt	**348**	3,502	566
Repayment of debt	**(5,159)**	(4,592)	(945)
Redemption of preferred stock of subsidiary		(300)	
Issuance of company common stock	**108**	44	51
Dividends paid on common stock	**(1,107)**	(684)	(403)
Other	**111**	(190)	(68)
Net cash used in continuing operations	**(5,699)**	(2,220)	(799)
Net Cash Used in Financing Activities	**(5,699)**	(2,220)	(799)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**24**	(9)	3
Net Change in Cash and Cash Equivalents	**183**	165	(7)
Cash and cash equivalents at beginning of year	**307**	142	149
Cash and Cash Equivalents at End of Year	**$ 490**	307	142

**Net of acquisition and disposition of businesses.*
See Notes to Consolidated Financial Statements.

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Consolidated Statement of Changes in Common Stockholders Equity **ConocoPhillips**

	Shares of Common Stock			Millions of Dollars							
				Common Stock							
	Issued	Held in Treasury	Held in CBT	Par Value	Capital in Excess of Par	Treasury Stock	CBT	Accumulated Other Comprehensive Income (Loss)	Unearned Employee Compensation	Retained Earnings	Total
December 31, 2000	306,380,511	23,142,005	27,849,430	$ 383	2,153	(1,156)	(943)	(100)	(263)	6,019	6,093
Net income										1,661	1,661
Other comprehensive income (loss)											
Minimum pension liability adjustment								(143)			(143)
Foreign currency translation								(14)			(14)
Unrealized loss on securities								(2)			(2)
Hedging activities								(4)			(4)
Equity affiliates:											
Foreign currency translation								(3)			(3)
Derivatives related								11			11
Comprehensive income											1,506
Cash dividends paid on common stock										(403)	(403)
Tosco	124,059,232			155	6,883						7,038

acquisition											
Distributed under incentive compensation and other benefit plans		(2,416,891)	(292,857)		33	118	9			(84)	76
Recognition of unearned compensation									26		26
Other										4	4
December 31, 2001	430,439,743	20,725,114	27,556,573	538	9,069	(1,038)	(934)	(255)	(237)	7,197	14,340
Net loss										(295)	(295)
Other comprehensive income (loss)											
Minimum pension liability adjustment								(93)			(93)
Foreign currency translation								182			182
Unrealized loss on securities								(3)			(3)
Hedging activities								(1)			(1)
Equity affiliates:											
Foreign currency translation								40			40
Derivatives related								(34)			(34)
Comprehensive loss											(204)
Cash dividends paid on common stock										(684)	(684)
ConocoPhillips merger	273,471,505	(19,852,674)		(531)	16,056	999				(562)	15,962
Distributed	443,591	(872,440)	(771,479)		53	39	27			(39)	80

under incentive compensation and other benefit plans											
Recognition of unearned compensation									19		19
Other										4	4
December 31, 2002	704,354,839		26,785,094	7	25,178		(907)	(164)	(218)	5,621	29,517
Net income										**4,735**	**4,735**
Other comprehensive income (loss)											
Minimum pension liability adjustment								**168**			**168**
Foreign currency translation								**637**			**637**
Unrealized gain on securities								**4**			**4**
Hedging activities								**7**			**7**
Equity affiliates:											
Foreign currency translation								**149**			**149**
Derivatives related								**20**			**20**
Comprehensive income											**5,720**
Cash dividends paid on common stock										**(1,107)**	**(1,107)**
Distributed under incentive compensation and other benefit plans	**3,730,258**		**(1,483,780)**		**183**		**50**				**233**

Recognition of unearned compensation									**18**		**18**
Other										**(15)**	**(15)**
December 31, 2003	**708,085,097**		**25,301,314**	**$ 7**	**25,361**		**(857)**	**821**	**(200)**	**9,234**	**34,366**

See Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements **ConocoPhillips**

Note 1 Accounting Policies

- **Consolidation Principles and Investments** Consolidation decisions are based on the risk, rewards and voting rights associated with our interest in an entity. Entities that are determined to be Variable Interest Entities (VIEs), as defined by Financial Accounting Standards Board (FASB) Interpretation No. 46, as revised, (FIN 46) will be consolidated if we are the primary beneficiary of that entity. For entities that are not VIEs under FIN 46, we consolidate majority-owned, controlled subsidiaries. The equity method is used to account for investments in affiliates in which we exert significant influence, generally having a 20 to 50 percent ownership interest. We also use the equity method for our 50.1 percent and 57.1 percent non-controlling interests in Petrozuata C.A. and Hamaca Holding LLC, respectively, located in Venezuela because the minority shareholders have substantive participating rights, under which all substantive operating decisions (e.g., annual budgets, major financings, selection of senior operating management, etc.) require joint approvals. The cost method is used when we do not have significant influence. Undivided interests in oil and gas joint ventures, pipelines, natural gas plants, certain transportation assets and Canadian Syncrude mining operations are consolidated on a proportionate basis. Other securities and investments, excluding marketable securities, are generally carried at cost.

- **Revenue Recognition** Revenues associated with sales of crude oil, natural gas, natural gas liquids, petroleum and chemical products, and all other items are recorded when title passes to the customer. Revenues include the sales portion of contracts involving purchases and sales necessary to reposition supply to address location or quality or grade requirements (e.g., when we reposition crude by entering into a contract with a counterparty to sell crude in one location and purchase it in a different location) and sales related to purchase for resale activity. Revenues from the production of natural gas properties, in which we have an interest with other producers, are recognized based on the actual volumes we sold during the period. Any differences between volumes sold and entitlement volumes, based on our net working interest, which are deemed non-recoverable through remaining production, are recognized as accounts receivable or accounts payable, as appropriate. Cumulative differences between volumes sold and entitlement volumes are not significant. Revenues associated with royalty fees from licensed technology are recorded based either upon volumes produced by the licensee or upon the successful completion of all substantive performance requirements related to the installation of licensed technology.

- **Reclassification** Certain amounts in the 2002 and 2001 financial statements have been reclassified to conform with the 2003 presentation.

- **Use of Estimates** The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosures of contingent assets and liabilities. Actual results could differ from the estimates and assumptions used.

- **Cash Equivalents** Cash equivalents are highly liquid short-term investments that are readily convertible to known amounts of cash and have original maturities within three months from their date of purchase. They are carried at cost plus accrued interest, which approximates fair value.

- **Inventories** We have several valuation methods for our various types of inventories and consistently use the following methods for each type of inventory. Crude oil, petroleum products, and Canadian Syncrude inventories are valued at the lower of cost or market in the aggregate, primarily on the last-in, first-out (LIFO) basis. Any necessary lower-of-cost-or-market write-downs are recorded as permanent adjustments to the LIFO cost basis. LIFO is used to better match current inventory costs with current revenues and to meet tax-conformity requirements. Costs include both direct and indirect expenditures incurred in bringing an item or product to its existing condition and location, but not unusual/non-recurring costs or research and development costs. Materials, supplies and other miscellaneous inventories are valued using the weighted-average-cost method, consistent with general industry practice. Merchandise inventories at our retail marketing outlets are valued using the first-in, first-out (FIFO) retail method, consistent with general industry practice.

- **Derivative Instruments** All derivative instruments are recorded on the balance sheet at fair value in either accounts and notes receivable, other assets, accounts payable, or other liabilities and deferred credits. Recognition of the gain or loss that results from recording and adjusting a derivative to fair value depends on the purpose for issuing or holding the derivative. Gains and losses from derivatives that are not used as hedges are recognized immediately in earnings. For derivative instruments that are designated and qualify as a fair value hedge, the gains or losses from adjusting the derivative to its fair value will be immediately recognized in earnings and, to the extent the hedge is effective, offset the concurrent recognition of changes in the fair value of the hedged item. Gains or losses from derivative instruments that are designated and qualify as a cash flow hedge will be recorded on the balance sheet in accumulated other comprehensive income/(loss) until the hedged transaction is recognized in earnings; however, to the extent the change in the value of the derivative exceeds the change in the anticipated cash flows of the hedged transaction, the excess gains or losses will be recognized immediately in earnings.

  In the consolidated income statement, gains and losses from derivatives that are held for trading and not directly related to our physical business are recorded in other income. Gains and losses from derivatives used for other purposes are recorded in either sales and other operating revenues, other income, purchased crude oil and products, interest and debt expense, or foreign currency transaction gains/losses, depending on the purpose for issuing or holding the derivative.

- **Oil and Gas Exploration and Development** Oil and gas exploration and development costs are accounted for using the successful efforts method of accounting.

  Property Acquisition Costs Oil and gas leasehold acquisition costs are capitalized and included in the balance sheet caption properties, plants and equipment. Leasehold impairment is recognized based on exploratory experience and management s judgment. Upon discovery of commercial reserves, leasehold costs are transferred to proved properties.

  Exploratory Costs Geological and geophysical costs and the costs of carrying and retaining undeveloped properties are expensed as incurred. Exploratory well costs are capitalized pending further evaluation of whether economically recoverable reserves have been found. If economically recoverable reserves are not found, exploratory well costs are expensed as dry holes. All exploratory wells are evaluated for economic viability within one year of well completion. Exploratory wells that discover potentially economic reserves that are in areas where a major capital expenditure would be required before production could begin, and where the economic viability of that major capital expenditure depends upon the successful completion of further exploratory work in the area, remain capitalized as long as the additional exploratory work is under way or firmly planned.

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Development Costs Costs incurred to drill and equip development wells, including unsuccessful development wells, are capitalized.

Depletion and Amortization Leasehold costs of producing properties are depleted using the unit-of-production method based on estimated proved oil and gas reserves. Amortization of intangible development costs is based on the unit-of-production method using estimated proved developed oil and gas reserves.

- **Syncrude Mining Operations** Capitalized costs, including support facilities, include the cost of the acquisition and other capital costs incurred. Capital costs are depreciated using the unit-of-production method based on the applicable portion of proven reserves associated with each mine location and its facilities.

- **Intangible Assets Other Than Goodwill** Intangible assets that have finite useful lives are amortized by the straight-line method over their useful lives. Intangible assets that have indefinite useful lives are not amortized but are tested at least annually for impairment. Each reporting period, we evaluate the remaining useful lives of intangible assets not being amortized to determine whether events and circumstances continue to support indefinite useful lives. Intangible assets are considered impaired if the fair value of the intangible asset is lower than cost. The fair value of intangible assets is determined based on quoted market prices in active markets, if available. If quoted market prices are not available, fair value of intangible assets is determined based upon the present values of expected future cash flows using discount rates commensurate with the risks involved in the asset, or upon estimated replacement cost, if expected future cash flows from the intangible asset are not determinable.

- **Goodwill** Goodwill is not amortized but is tested at least annually for impairment. If the fair value of a reporting unit is less than the recorded book value of the reporting unit s assets (including goodwill), less liabilities, then a hypothetical purchase price allocation is performed on the reporting unit s assets and liabilities using the fair value of the reporting unit as the purchase price in the calculation. If the amount of goodwill resulting from this hypothetical purchase price allocation is less than the recorded amount of goodwill, the recorded goodwill is written down to the new amount. For purposes of goodwill impairment calculations, reporting units have been determined to be Worldwide Exploration and Production, Worldwide Refining and Worldwide Marketing. Because quoted market prices are not available for the company s reporting units, the fair value of the reporting units is determined based upon consideration of several factors, including the present values of expected future cash flows using discount rates commensurate with the risks involved in the operations and observed market multiples of operating cash flows and net income.

- **Depreciation and Amortization** Depreciation and amortization of properties, plants and equipment on producing oil and gas properties, certain pipeline assets (those which are expected to have a declining utilization pattern), and on Syncrude mining operations are determined by the unit-of-production method. Depreciation and amortization of all other properties, plants and equipment are determined by either the individual-unit-straight-line method or the group-straight-line method (for those individual units that are highly integrated with other units).

- **Impairment of Properties, Plants and Equipment** Properties, plants and equipment used in operations are assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in the future cash flows expected to be generated by an asset group. If, upon review, the sum of the undiscounted pretax cash flows is less than the carrying value of the asset group, the carrying value is written down to estimated fair value through additional amortization or depreciation provisions in the periods in which the determination of impairment is made.

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Individual assets are grouped for impairment purposes at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets generally on a field-by-field basis for exploration and production assets, at an entire complex level for refining assets or at a site level for retail stores. The fair value of impaired assets is determined based on quoted market prices in active markets, if available, or upon the present values of expected future cash flows using discount rates commensurate with the risks involved in the asset group. Long-lived assets committed by management for disposal within one year are accounted for at the lower of amortized cost or fair value, less cost to sell.

The expected future cash flows used for impairment reviews and related fair value calculations are based on estimated future production volumes, prices and costs, considering all available evidence at the date of review. If the future production price risk has been hedged, the hedged price is used in the calculations for the period and quantities hedged. The impairment review includes cash flows from proved developed and undeveloped reserves, including any development expenditures necessary to achieve that production. The price and cost outlook assumptions used in impairment reviews differ from the assumptions used in the Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserve Quantities. In that disclosure, Statement of Financial Accounting Standards (SFAS) No. 69, Disclosures about Oil and Gas Producing Activities, requires the use of prices and costs at the balance sheet date, with no projection of future changes in those assumptions.

n **Maintenance and Repairs** The costs of maintenance and repairs, which are not significant improvements, are expensed when incurred.

n **Shipping and Handling Costs** Our Exploration and Production segment includes shipping and handling costs in production and operating expenses, while the Refining and Marketing segment records shipping and handling costs in purchased crude oil and products. Freight costs billed to customers are recorded as a component of revenue.

n **Advertising Costs** Production costs of media advertising are deferred until the first public showing of the advertisement. Advances to secure advertising slots at specific sporting or other events are deferred until the event occurs. All other advertising costs are expensed as incurred, unless the cost has benefits which clearly extend beyond the interim period in which the expenditure is made, in which case the advertising cost is deferred and amortized ratably over the interim periods which clearly benefit from the expenditure.

n **Property Dispositions** When complete units of depreciable property are retired or sold, the asset cost and related accumulated depreciation are eliminated, with any gain or loss reflected in income. When less than complete units of depreciable property are disposed of or retired, the difference between asset cost and salvage value is charged or credited to accumulated depreciation.

n **Asset Retirement Obligations and Environmental Costs** Effective January 1, 2003, the company adopted SFAS No. 143, Accounting for Asset Retirement Obligations, which applies to legal obligations associated with the retirement and removal of long-lived assets. SFAS 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period when it is incurred (typically when the asset is installed at the production location). Through December 31, 2002, the estimated undiscounted costs, net of salvage values, of dismantling and removing major oil and gas production and transportation facilities, including necessary site restoration, were accrued using either the unit-of-production or the straight-line method, which was used for certain regional production transportation assets that are expected to have a straight-line utilization pattern. See Note 2 Changes in Accounting Principles for additional information.

Environmental expenditures are expensed or capitalized, depending upon their future economic benefit. Expenditures that relate to an existing condition caused by past operations, and do not have a future economic benefit, are expensed. Liabilities for these expenditures are recorded on an undiscounted basis (unless acquired in a purchase business acquisition) when environmental assessments or cleanups are probable and the costs can be reasonably estimated. Recoveries of environmental remediation costs from other parties, such as state reimbursement funds, are recorded as assets when their receipt is probable.

n **Stock-Based Compensation** Effective January 1, 2003, we voluntarily adopted the fair-value accounting method provided for under SFAS No. 123, Accounting for Stock-Based Compensation. We used the prospective transition method provided under SFAS 123, applying the fair-value accounting method and recognizing compensation expense equal to the fair-market value on the grant date for all stock options granted or modified after December 31, 2002.

Employee stock options granted prior to 2003 continue to be accounted for under Accounting Principles Board Opinion (APB) No. 25, Accounting for Stock Issued to Employees, and related Interpretations. Because the exercise price of our employee stock options equals the market price of the underlying stock on the date of grant, no compensation expense is generally recognized under APB No. 25. The following table displays pro forma information as if the provisions of SFAS No. 123 had been applied to all employee stock options granted:

	2003	2002	2001
Net income (loss), as reported	**$ 4,735**	(295)	1,661
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects	**50**	74	13
Deduct: Total stock-based employee compensation expense determined under fair-value based method for all awards, net of related tax effects	**78**	135	29
Pro forma net income (loss)	**$ 4,707**	(356)	1,645
Earnings per share:			
Basic as reported	**$ 6.96**	(.61)	5.67
Basic pro forma	**6.92**	(.74)	5.62
Diluted as reported	**6.91**	(.61)	5.63
Diluted pro forma	**6.87**	(.73)	5.58

n **Foreign Currency Translation** Adjustments resulting from the process of translating foreign functional currency financial statements into U.S. dollars are included in accumulated other comprehensive income/loss in common stockholders equity. Foreign currency transaction gains and losses are included in current earnings. Most of our foreign operations use their local currency as the functional currency.

n **Income Taxes** Deferred income taxes are computed using the liability method and are provided on all temporary differences between the financial-reporting basis and the tax basis of our assets and liabilities, except for deferred taxes on income considered to be permanently reinvested in certain foreign subsidiaries and foreign corporate joint ventures. Allowable tax credits are applied currently as reductions of the provision for income taxes.

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- **Net Income Per Share of Common Stock** Basic income per share of common stock is calculated based upon the daily weighted-average number of common shares outstanding during the year, including unallocated shares held by the stock savings feature of the ConocoPhillips Savings Plan. Diluted income per share of common stock includes the above, plus in-the-money stock options issued under our compensation plans. Treasury stock and shares held by the Compensation and Benefits Trust (CBT) are excluded from the daily weighted-average number of common shares outstanding in both calculations.

- **Capitalized Interest** Interest from external borrowings is capitalized on major projects with an expected construction period of one year or longer. Capitalized interest is added to the cost of the underlying asset and is amortized over the useful lives of the assets in the same manner as the underlying assets.

- **Accounting for Sales of Stock by Subsidiary or Equity Investees** We recognize a gain or loss upon the direct sale of equity by our subsidiaries or equity investees if the sales price differs from our carrying amount, and provided that the sale of such equity is not part of a broader corporate reorganization.

Note 2 Changes in Accounting Principles

Accounting for Asset Retirement Obligations

Effective January 1, 2003, we adopted SFAS No. 143, Accounting for Asset Retirement Obligations, which applies to legal obligations associated with the retirement and removal of long-lived assets. SFAS No. 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period when it is incurred (typically when the asset is installed at the production location). When the liability is initially recorded, the entity capitalizes the cost by increasing the carrying amount of the related properties, plants and equipment. Over time, the liability is increased for the change in its present value each period, and the initial capitalized cost is depreciated over the useful life of the related asset.

Application of this new accounting principle resulted in an initial increase in net properties, plants and equipment of $1.2 billion and an asset retirement obligation liability increase of $1.1 billion. The cumulative effect of the change increased 2003 net income by $145 million (after reduction of income taxes of $21 million). The 2003 effect of the adoption increased income from continuing operations and net income for 2003 by $32 million, or $.05 per basic and diluted share.

We have numerous asset removal obligations that we are required to perform under law or contract once an asset is permanently taken out of service. Most of these obligations are not expected to be paid until several years, or decades, in the future and will be funded from general company resources at the time of removal. Our largest individual obligations are related to fixed-base offshore production platforms around the world and to production facilities and pipelines in Alaska.

SFAS No. 143 calls for measurements of asset retirement obligations to include, as a component of expected costs, an estimate of the price that a third party would demand, and could expect to receive, for bearing the uncertainties and unforeseeable circumstances inherent in the obligations, sometimes referred to as a market-risk premium. To date, the oil and gas industry has no examples of credit-worthy third parties who are willing to assume this type of risk, for a determinable price, on major oil and gas production facilities and pipelines. Therefore, because determining such a market-risk premium would be an arbitrary process, we have excluded it from our SFAS No. 143 estimates.

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During 2003, our overall asset retirement obligation changed as follows:

	Millions of Dollars
Opening balance at January 1, 2003	$ 2,110
Accretion of discount	118
New obligations	43
Spending on existing obligations	(62)
Property dispositions	(95)
Foreign currency translation	109
Adjustment due to repeal of Norway Removal Grant Act	414
Other adjustments	48
Ending balance at December 31, 2003	$ 2,685

The following table presents the pro forma effects of the retroactive application of this change in accounting principle as if the principle had been adopted on January 1, 2001.

	Millions of Dollars Except Per Share Amounts		
	2003	2002	2001
Net income (loss)*	**$ 4,590**	(254)	1,712
Earnings per share			
Basic	**6.75**	(.53)	5.84
Diluted	**6.70**	(.52)	5.80

** Net income of $4,735 million for 2003 has been adjusted to remove the $145 million cumulative effect of the change in accounting principle attributable to SFAS No. 143.*

	Millions of Dollars
Pro forma asset retirement obligation	
At January 1, 2002	$ 1,171
At December 31, 2002	2,110

Consolidation of Variable Interest Entities

In January 2003, the FASB issued Interpretation No. 46, Consolidation of Variable Interest Entities, (FIN 46) to expand existing accounting guidance about when a company should include in its consolidated financial statements the assets, liabilities and activities of another entity. In general, a variable interest entity (VIE) is a corporation, partnership, trust, or any other legal structure used for business purposes that either (a) does not have equity investors with voting rights or (b) has equity investors that do not provide sufficient financial resources for the entity to support its activities. FIN 46 requires a VIE to be consolidated by a company if that company is subject to a majority of the risk of loss from the VIE s activities, is entitled to receive a majority of the VIE s residual returns, or both (the company required to consolidate is called the primary beneficiary). It also requires deconsolidation of a VIE if a company is not the primary beneficiary of the VIE. The interpretation also requires disclosures about VIEs that a company does not have to consolidate, but in which it has a significant variable interest, and about any potential VIE when a company is unable to obtain the information necessary to confirm if an entity is a VIE or determine if a company is the primary beneficiary.

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In December 2003, the FASB issued a revision to FIN 46 to clarify some of the provisions and to exempt certain entities from its guidance. Under the new guidance, special effective date provisions apply to enterprises that have fully or partially applied FIN 46 prior to the revision. The consolidation requirements of FIN 46, as revised, apply to all special purpose entities for periods ending after December 15, 2003. For all other types of variable interest entities the consolidation requirement applies for periods ending after March 15, 2004.

We adopted FIN 46 in the third quarter of 2003, with retroactive application to January 1, 2003, for VIEs involving synthetic leases and certain other financing structures as discussed below. We adopted FIN 46 for such VIEs because our work on these VIEs was complete and we believed the FASB s potential modifications of FIN 46 interpretive guidance was unlikely to change the primary beneficiary determination for these VIEs. We consolidated all VIEs created prior to February 1, 2003 (except as noted below), in which we concluded we were the primary beneficiary. In addition, we deconsolidated an entity where we determined we were not the primary beneficiary. The revision of FIN 46 did not change our accounting for any of the entities we consolidated or deconsolidated under FIN 46 in the third quarter. We continue to review FIN 46 and related guidance. If subsequent guidance or interpretation is different from our current understanding, it is possible that our determination of VIEs and primary beneficiaries could change.

There are two entities which could potentially be VIEs for which we were unable to obtain sufficient information to confirm that the entities were VIEs or determine if we are the primary beneficiary. In February 2003, we entered into two agreements establishing separate guarantee facilities of $50 million each for two liquefied natural gas ships that were then under construction. Subject to the terms of each such facility, we will be required to make payments should the charter revenue generated by the respective ship fall below certain specified minimum thresholds, and we will receive payments to the extent that such revenues exceed those thresholds. The net maximum future payments that we may have to make over the 20-year terms of the two agreements could be up to an aggregate of $100 million. Actual gross payments over the 20 years could exceed that amount to the extent cash is received by us. In September 2003, the first ship was delivered to its owner and the second ship is scheduled for delivery to its owner in 2005. We have determined that the agreements give us a variable interest in the two entities involved, but we do not have enough information regarding these entities and their activities to confirm that the entities are VIEs or to determine if we are the primary beneficiary. With respect to the first ship, the amount drawn under the guarantee facility at December 31, 2003, was less than $1 million. We continue to make efforts to obtain the information required to complete the FIN 46 analysis. We currently account for the guarantees under these agreements as guarantees and contingent liabilities. See Note 16 Guarantees for additional information.

The adoption of FIN 46 for VIEs involving synthetic leases and certain other financing structures resulted in the following:

Consolidated VIEs

We consolidated certain VIEs from which we lease certain ocean vessels, airplanes, refining assets, marketing sites and office buildings. The consolidation increased net properties, plants and equipment by $940 million and increased assets of discontinued operations held for sale by $726 million (both are collateral for the debt obligations); increased cash by $225 million; increased debt by $2.4 billion; increased minority interest by $90 million; reduced other accruals by $263 million, and resulted in a cumulative after-tax effect-of-adoption loss that decreased net income and common stockholders equity by $240 million. However, during 2003 we exercised our option to purchase most of these assets and as a result, the leasing arrangements and our involvement with all but one of the associated VIEs was terminated. See Note 14 Debt for more information about the resulting debt redemptions. At December 31, 2003, we continue to lease refining assets totaling $126 million, which are collateral for the debt obligations of $126 million from a VIE. Other than the obligation to make lease payments and residual value guarantees, the creditors of the VIE have no recourse to our general credit. In addition, we discontinued hedge accounting for an interest rate swap since it had been designated as a cash flow hedge of the variable interest rate component of a lease with a VIE that is now consolidated. At December 31, 2003, the fair market value of the swap was a liability of $13 million.

Ashford Energy Capital S.A. continues to be consolidated in our financial statements under the provisions of FIN 46 because we are the primary beneficiary. In December 2001, in order to raise funds for general corporate purposes, Conoco and Cold Spring Finance S.a.r.l. formed Ashford Energy Capital S.A. through the contribution of a $1 billion Conoco subsidiary promissory note and $500 million cash. Through its initial $500 million investment, Cold Spring is entitled to a cumulative annual preferred return, based on three-month LIBOR rates, plus 1.27 percent. The preferred return at December 31, 2003, was 2.48 percent. In 2008, and each 10-year anniversary thereafter, Cold Spring may elect to remarket their investment in Ashford, and if unsuccessful, could require ConocoPhillips to provide a letter of credit in support of Cold Spring s investment, or in the event that such letter of credit is not provided, then cause the redemption of their investment in Ashford. Should ConocoPhillips credit rating fall below investment grade, Ashford would require a letter of credit to support $475 million of the term loans, as of December 31, 2003, made by Ashford to other ConocoPhillips subsidiaries. If the letter of credit is not obtained within 60 days, Cold Spring could cause Ashford to sell the ConocoPhillips subsidiary notes. At December 31, 2003, Ashford held $1.6 billion of ConocoPhillips subsidiary notes and $25 million in investments unrelated to ConocoPhillips. We report Cold Spring s investment as a minority interest because it is not mandatorily redeemable and the entity does not have a specified liquidation date. Other than the obligation to make payment on the subsidiary notes described above, Cold Spring does not have recourse to our general credit.

Unconsolidated VIEs

Phillips 66 Capital II (Trust) was deconsolidated under the provisions of FIN 46 because ConocoPhillips is not the primary beneficiary. During 1997 in order to raise funds for general corporate purposes, we formed the Trust (a statutory business trust), in which we own all common beneficial interests. The Trust was created for the sole purpose of issuing mandatorily redeemable preferred securities to third-party investors and investing the proceeds thereof in an approximate equivalent amount of subordinated debt securities of ConocoPhillips. Application of FIN 46 required deconsolidation of the Trust, which increased debt by $361 million since the 8% Junior Subordinated Deferrable Interest Debentures due 2037 were no longer eliminated in consolidation, and the $350 million of mandatorily redeemable preferred securities were deconsolidated.

In 2003, we recorded a charge of $240 million (after an income tax benefit of $145 million) for the cumulative effect of adopting FIN 46. The effect of adopting FIN 46 increased 2003 income from continuing operations by $34 million, or $.05 per basic and diluted share. Excluding the cumulative effect, the adoption of FIN 46 increased net income by $139 million, or $.20 per basic and diluted share in 2003.

Stock-Based Compensation

Effective January 1, 2003, we adopted the fair-value accounting method provided for under SFAS No. 123, Accounting for Stock-Based Compensation. We used the prospective transition method provided under SFAS 123, applying the fair-value accounting method and recognizing compensation expense for all stock options granted or modified after December 31, 2002. See Note 1 Accounting Policies and Note 22 Employee Benefit Plans for additional information.

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Other

Effective January 1, 2003, we adopted SFAS No. 145, Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections. The adoption of SFAS No. 145 requires that gains and losses on extinguishments of debt no longer be presented as extraordinary items in the income statement. Accordingly, losses from the extinguishment of debt of $16 million (after reduction for income taxes of $8 million), previously reported as an extraordinary item in 2002, have been reclassified as a $24 million charge to other income with the tax benefit reclassified to provision for income taxes. Similarly, in 2001, a loss from the early retirement of debt of $10 million (after reduction for income taxes of $4 million), has been reclassified as a $14 million charge to other income with the tax benefit reclassified to provision for income taxes.

In December 2003, the FASB revised and reissued SFAS No. 132 (revised 2003), Employer s Disclosures about Pensions and Other Postretirement Benefits an amendment of FASB Statements No. 87, 88 and 106. While requiring certain new disclosures, the new Standard does not change the measurement or recognition of employee benefit plans. We adopted the provisions of this Standard effective December 2003, except for certain provisions regarding disclosure of information about estimated future benefit payments which are not required until periods ending after December 15, 2004.

Effective January 1, 2001, the company changed its method of accounting for the costs of major maintenance turnarounds from the accrue-in-advance method to the expense-as-incurred method to reflect the impact of a turnaround in the period that it occurs. The new method is preferable because it results in the recognition of costs at the time obligations are incurred. The cumulative effect of this accounting change increased net income in 2001 by $28 million (after reduction for income taxes of $15 million).

Note 3 Merger of Conoco and Phillips

On August 30, 2002, Conoco and Phillips combined their businesses by merging with separate acquisition subsidiaries of ConocoPhillips (the merger). As a result, each company became a wholly owned subsidiary of ConocoPhillips. For accounting purposes, Phillips was treated as the acquirer of Conoco, and ConocoPhillips was treated as the successor of Phillips. Conoco s operating results have been included in ConocoPhillips consolidated financial statements since the merger date.

Immediately after the closing of the merger, former Phillips stockholders held approximately 56 percent of the outstanding shares of ConocoPhillips common stock, while former Conoco stockholders held approximately 44 percent. ConocoPhillips common stock, listed on the New York Stock Exchange under the symbol COP, began trading on September 3, 2002.

The primary reasons for the merger and the principal factors that contributed to a purchase price that resulted in the recognition of goodwill were:

- The combination of Conoco and Phillips would create a stronger, major, integrated oil company with the benefits of increased size and scale, improving the stability of the combined business earnings in varying economic and market climates;

- ConocoPhillips would emerge with a global presence in both upstream and downstream petroleum businesses, increasing its overall international presence to over 40 countries while maintaining a strong domestic base; and

- Combining the two companies operations would provide significant synergies and related cost savings, and improve future access to capital.

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The $16 billion purchase price attributed to Conoco for accounting purposes was based on an exchange of Conoco shares for ConocoPhillips common shares. ConocoPhillips issued approximately 293 million shares of common stock and approximately 23.3 million of employee stock options in exchange for 627 million shares of Conoco common stock and 49.8 million Conoco stock options. The common stock was valued at $53.15 per share, which was Phillips average common stock price over the two-day trading period immediately before and after the November 18, 2001, public announcement of the transaction. The Conoco stock options, the fair value of which was determined using the Black-Scholes option-pricing model, were exchanged for ConocoPhillips stock options valued at $384 million. Transaction-related costs, included in the purchase price, were $78 million.

The allocation of the purchase price to specific assets and liabilities was based, in part, upon an outside appraisal of the fair value of Conoco s assets. The following table summarizes the final purchase price allocation of the fair values of the assets acquired and liabilities assumed as of August 30, 2002:

	Millions of Dollars
Cash and cash equivalents	$ 1,250
Accounts and notes receivable	2,871
Inventories	1,615
Prepaid expenses and other current assets	327
Investments and long-term receivables	2,985
Properties, plants and equipment (including $300 million of land)	18,842
Goodwill	12,721
Intangibles	554
In-process research and development	246
Other assets	322
Total assets	$ 41,733
Accounts payable	$ 2,876
Notes payable and long-term debt due within one year	3,101
Accrued income and other taxes	1,471
Other accruals	1,636
Long-term debt	8,930
Accrued dismantlement, removal and environmental costs	594
Deferred income taxes	3,473
Employee benefit obligations	1,566
Other liabilities and deferred credits	1,385
Minority interests	648
Common stockholders equity	16,053
Total liabilities and equity	$ 41,733

Goodwill and certain identifiable intangible assets recorded in the acquisition are not subject to amortization. However, goodwill and intangible assets are tested periodically for impairment as is required by SFAS No. 142, *Goodwill and Other Intangible Assets*.

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The acquired intangible assets include $441 million assigned to marketing tradenames, which are not subject to amortization, $95 million assigned to refining technology, with a weighted-average amortization period of 12 years, and $18 million assigned to other intangible assets, with a weighted-average amortization period of eight years.

We assigned the Conoco goodwill to specific reporting units in the fourth quarter of 2003. Previously, it had all been reported as part of Corporate and Other. Included in the $12,721 million of goodwill is $3,841 million attributable to recording a liability required for deferred taxes under purchase accounting. This, and the remaining goodwill of $8,880 million, was assigned to reporting units based on the benefits received by the units from the synergies and strategic advantages of the merger. The $12,721 million of goodwill has been allocated to three reporting units. See Note 11   Goodwill and Intangibles for additional information. None of the goodwill is deductible for tax purposes. During 2003, the balance of goodwill was adjusted upward by $642 million, primarily due to revisions in the valuation of properties, plants and equipment, and assumed contingent liabilities.

The purchase price allocation included $246 million of in-process research and development costs related to Conoco s natural gas-to-liquids and other technologies. In accordance with FASB Interpretation No. 4, Applicability of FASB Statement No. 2 to Business Combinations Accounted for by the Purchase Method, the value assigned to the research and development activities was charged to selling, general and administrative expenses in the Emerging Businesses segment at the date of the merger, as these research and development costs had no alternative future use.

Merger-related items that reduced our 2003 and 2002 income from continuing operations were:

	Millions of Dollars			
	Before-Tax		After-Tax	
	2003	2002	**2003**	2002
Write-off of acquired in-process research and development costs	$	246		246
Restructuring charges (see Note 5)	**240**	422	**131**	253
Incremental seismic contract costs		35		22
Transition costs	**110**	55	**92**	36
Total	$ **350**	758	**223**	557

In total, these items reduced 2003 and 2002 income from continuing operations by $223 million and $557 million, respectively ($.33 per share and $1.15 per share on a diluted basis).

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The following pro forma summary presents information as if the merger had occurred at the beginning of each period presented, and includes for 2002 the $557 million effect of the merger-related items mentioned above.

	Millions of Dollars Except Per Share Amounts	
	2002	2001
Revenues	$ 81,433	79,554
Income from continuing operations	918	3,635
Net income (loss)	(70)	4,072
Income from continuing operations per share of common stock		
Basic	1.36	5.39
Diluted	1.34	5.32
Net income (loss) per share of common stock		
Basic	(.10)	6.04
Diluted	(.10)	5.97

During 2001, both Phillips and Conoco entered into other significant transactions that are not reflected in each of their historical income statements for the full year 2001. The pro forma results have been prepared as if the Phillips September 14, 2001, acquisition of Tosco Corporation (Tosco) (see Note 6 Acquisition of Tosco Corporation) and Conoco s July 16, 2001, $4.6 billion acquisition of Gulf Canada Resources Limited occurred on January 1, 2001. Gulf Canada Resources Limited was a Canadian-based independent exploration and production company with primary operations in Western Canada, Indonesia, the Netherlands and Ecuador.

The pro forma results reflect the following:

- Recognition of depreciation and amortization based on the preliminary allocated purchase price of the properties, plants and equipment acquired;
- Adjustment of interest for the amortization of the fair-value adjustment to debt;
- Cessation of the amortization of deferred gains not recognizable in the purchase price allocation;
- Accretion of discount on environmental accruals recorded at net present value; and
- Various other adjustments to conform Conoco s accounting policies to ConocoPhillips .

The pro forma adjustments use estimates and assumptions based on currently available information. Management believes that the estimates and assumptions are reasonable, and that the significant effects of the transactions are properly reflected.

The pro forma information does not reflect any anticipated synergies that might be achieved from combining the operations. The pro forma information is not intended to reflect the actual results that would have occurred had the companies been combined during the periods presented. This pro forma information is not intended to be indicative of the results of operations that may be achieved by ConocoPhillips in the future.

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Note 4 Discontinued Operations

During 2002 and 2003, we disposed of, or had committed to a plan to dispose of, certain U.S. retail and wholesale marketing assets, certain U.S. refining and related assets, certain U.S. midstream natural gas gathering and processing assets, and exploration and production assets in the Netherlands. Some of these planned dispositions were mandated by the FTC as a condition of the merger. For reporting purposes, these operations are classified as discontinued operations, and in Note 28-Segment Disclosures and Related Information, these operations are included in Corporate and Other.

FTC Mandated Divestitures
In the fourth quarter of 2002, we sold our propane terminal assets at Jefferson City, Missouri, and East St. Louis, Illinois.

During 2003 we sold:

- Our Woods Cross business unit, which includes the Woods Cross, Utah, refinery; the Utah, Idaho, Montana, and Wyoming Phillips-branded motor fuel marketing operations (both retail and wholesale) and associated assets; and a refined products terminal in Spokane, Washington;

- Certain midstream natural gas gathering and processing assets in southeast New Mexico, and certain midstream natural gas gathering assets in West Texas; and

- Our Commerce City, Colorado, refinery, and related crude oil pipelines, and our Colorado Phillips-branded motor fuel marketing operations (both retail and wholesale).

As a result, all asset dispositions mandated by the FTC as a condition of the merger have been completed.

Other Dispositions
In the fourth quarter of 2002, we committed to and initiated a plan to dispose of 3,200 marketing sites that did not fit into our long-range plans. In connection with the anticipated sale of these retail sites, we recorded charges in 2002 totaling $1,412 million before-tax, $1,008 million after-tax, primarily related to the impairment of properties, plants and equipment ($249 million); goodwill ($257 million); intangible asset ($429 million); and provisions for losses and penalties associated with various operating lease commitments ($477 million).

The intangible asset represented the Circle K tradename. Properties, plants and equipment included land, buildings and equipment of owned retail sites and leasehold improvements of leased sites. Fair value determinations were based on estimated sales prices for comparable sites.

The provisions for losses and penalties associated with various operating lease commitments included obligations for residual value guarantee deficiencies, and future minimum rental payments that existed prior to the commitment date that would continue after the exit plan is completed with no economic benefit. It also included penalties incurred to cancel the contractual arrangements.

In the third quarter of 2003, we concluded the sale of all of our Exxon-branded marketing assets in New York and New England, including contracts with independent dealers and marketers. Approximately 230 of the 3,200 sites were included in this package.

In the fourth quarter of 2003, we completed the sale of The Circle K Corporation and its subsidiaries. The transaction included about 1,660 retail marketing outlets in 16 states and the Circle K brand, as well as the assignment of the franchise relationship with more than 350 franchised and licensed stores. In January 2004, we signed agreements to sell our Mobil-branded marketing assets on the East Coast in two separate

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transactions. Assets in the packages include 104 company-owned and operated sites, and 352 dealer sites. Each of the transactions is expected to close in the second quarter of 2004. Discussions are under way with potential buyers for the remaining sites, and we expect to complete the sales of these assets during 2004. Based on disposals completed and signed agreements as of December 31, 2003, we recognized an additional charge in 2003 of approximately $96 million before-tax, $11 million after-tax.

Sales and other operating revenues and income (loss) from discontinued operations were as follows:

	Millions of Dollars		
	2003	2002	2001
Sales and other operating revenues from discontinued operations	**$ 8,076**	7,406	2,670
Income (loss) from discontinued operations before-tax	**$ 317**	(1,387)	47
Income tax expense (benefit)	**80**	(394)	15
Income (loss) from discontinued operations	**$ 237**	(993)	32

Major classes of assets and liabilities of discontinued operations held for sale at December 31 were as follows:

	Millions of Dollars	
	2003	2002
Assets		
Inventories	**$**	211
Other current assets		136
Net properties, plants and equipment	**857**	1,178
Intangibles		23
Other assets	**7**	57
Assets of discontinued operations	**$ 864**	1,605
Liabilities		
Accounts payable and other current liabilities	**$**	331
Long-term debt		34
Asset retirement obligations and accrued environmental costs		86

Deferred income taxes, other liabilities and deferred credits		**179**	198
Liabilities of discontinued operations	**$**	**179**	649

Note 5 Restructuring

In 2002, as a result of the merger, we began a restructuring program to capture the benefits of combining Conoco and Phillips by eliminating redundancies, consolidating assets, and sharing common services and functions across regions. In connection with this program, the company recorded accruals in 2002 totaling $770 million for anticipated employee severance payments and incremental pension and medical plan benefit costs associated with the work force reductions, site closings, and Conoco employee relocations. Of the total 2002 accrual, $337 million was reflected in the Conoco purchase price allocation as an assumed liability, and $422 million ($253 million after-tax) related to Phillips was reflected in selling, general and administrative expense and production and operating expense, and $11 million before-tax was included in discontinued operations.

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Included in the total accruals of $770 million was $172 million related to pension and other post-retirement benefits that will be paid in conjunction with other retirement benefits over a number of future years. The table below summarizes the balance of the 2002 accrual of $598 million, which consists of severance related benefits to be provided to approximately 2,900 employees worldwide and other merger related expenses. By the end of 2002, approximately 775 employees had been terminated. Changes in the 2002 severance related accrual balance are summarized below.

	Millions of Dollars		
	2002 Accruals	Benefit Payments	Reserve at December 31, 2002
Conoco	$ 297	(191)	106
Phillips	301	(32)	269
Total	$ 598	(223)	375

In 2003, as individual components of the restructuring program were finalized, we recorded an additional $350 million for severance-related benefits, site closings, Conoco employee relocation costs, and pension and other postretirement benefits. Of this total, $110 million was reflected as a purchase price adjustment in the consolidated financial statements and $240 million was reflected in selling, general and administrative expense and production and operating expense. Included in the total 2003 additional accruals of $350 million was a $118 million expense related to pension and other postretirement benefits that will be paid in conjunction with other retirement benefits over a number of future years. This is reported as part of our employee benefit plan obligations. A roll-forward of activity during 2003 is provided below for the non-pension portion of the accrual, which primarily consists of severance-related benefits to be provided to approximately 3,900 employees worldwide, most of whom are in the United States, as well as other merger related expenses.

	Millions of Dollars			
		Twelve Months 2003		
	Reserve at December 31, 2002	Accruals	Payments	Reserve at December 31, 2003
Conoco	$ 106	107	(130)	83
Phillips	269	125	(230)	164
Total	$ 375	232	(360)	247

The restructuring liability at December 31 of $247 million is expected to be expended by the end of the first quarter of 2004; except for $53 million, classified as long-term. The remaining $194 million is included in other accruals in the current liabilities section of the balance sheet. Approximately 2,225 employees were terminated during 2003 and approximately 3,000 employees have been terminated since the restructuring program was implemented.

Note 6 Acquisition of Tosco Corporation

On September 14, 2001, Tosco was merged with a subsidiary of ConocoPhillips, as a result of which we became the owner of 100 percent of the outstanding common stock of Tosco. Tosco s results of operations have been included in our consolidated financial statements since that date. Tosco s operations included seven U.S. refineries with a total crude oil capacity of 1.31 million barrels per day; one 75,000-barrel-per-day refinery located in Cork, Ireland; and various marketing, transportation, distribution and corporate assets.

The primary reasons for our acquisition of Tosco, and the primary factors that contributed to a purchase price that resulted in recognition of goodwill, are:

- The Tosco operations would deliver earnings prospects, and potential strategic and other benefits;
- Combining the two companies operations would provide significant cost savings;
- Adding Tosco to our Refining and Marketing (R&M) operations would give the segment the size, scale and resources to compete more effectively;
- The merger would transform us into a stronger, more integrated oil company with the benefits of increased size and scale, improving the stability of the combined business earnings in varying economic and market climates;
- The combined company would have a stronger balance sheet, improving its access to capital in the future; and
- The increased cash flow and access to capital resulting from the Tosco acquisition would allow us to pursue other opportunities in the future.

The allocation of the purchase price to specific assets and liabilities was based, in part, upon an outside appraisal of Tosco s long-lived assets. Goodwill and indefinite-lived intangible assets recorded in the acquisition are not subject to amortization, but the goodwill and intangible assets will be tested periodically for impairment as required by SFAS No. 142, Goodwill and Other Intangible Assets.

During the third quarter of 2002, we concluded:

- The outside appraisal of the long-lived assets;
- The determination of the fair value of all other Tosco assets and liabilities;
- The tax basis calculation of Tosco s assets and liabilities and the related deferred tax liabilities; and
- The allocation of Tosco goodwill to reporting units within the R&M operating segment.

The resulting adjustments to the purchase price allocation made in 2002 increased goodwill by $341 million. The more significant adjustments to goodwill were a $247 million reduction in the value of refinery air emission permits to reflect a more appropriate appraisal methodology, a $70 million liability recorded for Tosco Long-Term Incentive Plan performance units, and a $69 million increase in deferred tax liabilities, resulting primarily from an updated analysis of the tax bases of Tosco s assets and liabilities. All other adjustments in the aggregate reduced goodwill by $45 million.

Tosco Long-Term Incentive Plan performance units were derivative financial instruments tied to our stock price and were marked-to-market each reporting period. The resulting gains or losses from these mark-to-market adjustments were reported in other income in the consolidated income statement. In October 2002, we and former Tosco executives negotiated a complete cancellation of the performance units in exchange for a cash payment to the former executives. During 2002, we recorded gains totaling $38 million, after-tax, as this liability was marked-to-market each reporting period and eventually settled.

Note 7 Subsidiary Equity Transactions

ConocoPhillips, through various affiliates, and its unaffiliated co-venturers received final approvals from authorities in June 2003 to proceed with the natural gas development phase of the Bayu-Undan project in the Timor Sea. The natural gas development phase of the project includes a pipeline from the offshore Bayu-Undan field to Darwin, Australia, and a liquefied natural gas facility, also located in Darwin. The pipeline portion of the project is owned and operated by an unincorporated joint venture, while the liquefied natural gas facility is owned and operated by Darwin LNG Pty Ltd (DLNG). Both of these entities are consolidated subsidiaries of ConocoPhillips.

In June 2003, as part of a broad Bayu-Undan ownership interest re-alignment with co-venturers, these entities issued equity and sold interests to the co-venturers (as described below), which resulted in a gain of $28 million before-tax, $25 million after-tax, in 2003. This non-operating gain is shown in the consolidated statement of income in the line item entitled Gain on subsidiary equity transactions.

DLNG DLNG issued 118.9 million shares of stock, valued at 1 Australian dollar per share, to co-venturers for 118.9 million Australian dollars ($76.2 million U.S. dollars), reducing our ownership interest in DLNG from 100 percent to 56.72 percent. The transaction resulted in a before-tax gain of $21 million in the consolidated financial statements. Deferred income taxes were not recognized because this was an issuance of common stock and therefore not taxable.

Unincorporated Pipeline Joint Venture The co-venturers purchased pro-rata interests in the pipeline assets held by ConocoPhillips Pipeline Australia Pty Ltd for $26.6 million U.S. dollars and contributed the purchased assets to the unincorporated joint venture, reducing our ownership interest from 100 percent to 56.72 percent. The transaction resulted in a before-tax gain of $7 million. A deferred tax liability of $1.3 million was recorded in connection with the transaction.

Note 8 Inventories

Inventories at December 31 were:

	Millions of Dollars	
	2003	2002
Crude oil and petroleum products	**$ 3,467**	3,395
Materials, supplies and other	**490**	450
	$ 3,957	3,845

Inventories valued on a LIFO basis totaled $3,224 million and $3,349 million at December 31, 2003 and 2002, respectively. The remainder of our inventories are valued under various methods, including FIFO and weighted average. The excess of current replacement cost over LIFO cost of inventories amounted to $1,421 million and $1,803 million at December 31, 2003 and 2002, respectively.

During 2003, certain inventory quantity reductions caused a liquidation of LIFO inventory values. This liquidation increased income from continuing operations by $24 million, of which $22 million was attributable to our R&M segment.

In the fourth quarter of 2001, the company recognized a $42 million before-tax, $27 million after-tax, lower-of-cost-or-market write-down of its petroleum products inventory.

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Note 9 Investments and Long-Term Receivables

Components of investments and long-term receivables at December 31 were:

	Millions of Dollars	
	2003	2002
Investment in and advances to affiliated companies	$ **6,258**	5,900
Long-term receivables	**476**	526
Other investments	**524**	395
	$ **7,258**	6,821

At December 31, 2003, retained earnings included $835 million related to the undistributed earnings of affiliated companies, and distributions received from affiliates were $496 million, $313 million and $163 million in 2003, 2002 and 2001, respectively.

Equity Investments
We own or owned investments in chemicals, heavy-oil projects, oil and gas transportation, coal mining and other industries. The affiliated companies for which we use the equity method of accounting include, among others, the following companies:

Chevron Phillips Chemical Co. LLC (CPChem) 50 percent ownership interest manufactures and markets petrochemicals and plastics;

Duke Energy Field Services, LLC (DEFS) 30.3 percent ownership interest owns and operates gas plants, gathering systems, storage facilities and fractionation plants;

Hamaca Holding LLC 57.1 percent non-controlling ownership interest currently building facilities to extract extra heavy crude oil from reserves in Eastern Venezuela;

Merey Sweeny L.P. (MSLP) 50 percent ownership interest processes heavy crude oil into intermediate products for the Sweeny, Texas, refinery;

Petrovera Resources Limited 46.7 percent ownership interest owns, operates and finances heavy-oil producing properties in Western Canada. On February 18, 2004, we sold our interest in this joint venture; and

Petrozuata C.A. 50.1 percent non-controlling ownership interest produces extra heavy crude oil and upgrades it into medium grade crude oil at Jose on the northern coast of Venezuela.

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Summarized 100 percent financial information for equity-basis investments in affiliated companies, combined, was as follows:

2003	Millions of Dollars			
	DEFS	CPChem	Other Equity Companies	Total
Revenues	**$ 8,886**	**7,018**	**13,873**	**29,777**
Income before income taxes	**268**	**12**	**1,753**	**2,033**
Net income	**214**	**7**	**1,274**	**1,495**
Current assets	**1,201**	**1,636**	**6,163**	**9,000**
Noncurrent assets	**5,313**	**4,606**	**23,776**	**33,695**
Current liabilities	**1,274**	**1,184**	**5,909**	**8,367**
Noncurrent liabilities	**2,376**	**1,298**	**7,629**	**11,303**

2002	Millions of Dollars			
	DEFS	CPChem	Other Equity Companies	Total
Revenues	$ 5,992	5,473	5,378	16,843
Income (loss) before income taxes	(37)	(24)	776	715
Net income (loss)	(47)	(30)	751	674
Current assets	1,182	1,561	5,783	8,526
Noncurrent assets	5,417	4,548	14,386	24,351
Current liabilities	1,504	1,051	5,046	7,601
Noncurrent liabilities	2,320	1,307	9,713	13,340

2001	Millions of Dollars			
	DEFS	CPChem	Other Equity Companies	Total
Revenues	$ 8,321	6,010	1,555	15,886
Income (loss) before income taxes	367	(431)	607	543
Net income (loss)	364	(480)	414	298

Our share of income taxes incurred directly by the equity companies is reported in equity in earnings of affiliates, and as such is not included in income taxes in our consolidated financial statements.

Duke Energy Field Services, LLC

DEFS owns and operates gas plants, gathering systems, storage facilities and fractionation plants. At December 31, 2003, the book value of our common investment in DEFS was $212 million. Our 30.3 percent share of the net assets of DEFS was $831 million. This basis difference of $619 million is being amortized on a straight-line basis through 2014 consistent with the remaining estimated useful lives of DEFS properties, plants and equipment. Included in net income for 2003, 2002 and 2001 was after-tax income of $36 million, $35 million and $36 million, respectively, representing the amortization of the basis difference.

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DEFS supplies a substantial portion of its natural gas liquids to us and CPChem under a supply agreement that continues until December 31, 2014. This purchase commitment is on an if-produced, will-purchase basis so it has no fixed production schedule, but has been, and is expected to be, a relatively stable purchase pattern over the term of the contract. Natural gas liquids are purchased under this agreement at various published market index prices, less transportation and fractionation fees.

On December 31, 2003, DEFS redeemed the remaining $75 million of its preferred member interests. We received our 30.3 percent share, a $23 million distribution representing the return of our preferred member interests.

Chevron Phillips Chemical Company LLC
CPChem manufactures and markets petrochemicals and plastics. At December 31, 2003, the book value of our investment in CPChem was $1,917 million. Our 50 percent share of the total net assets of CPChem was $1,755 million. This basis difference of $162 million is being amortized through 2020, consistent with the remaining estimated useful lives of CPChem properties, plants and equipment.

We have multiple supply and purchase agreements in place with CPChem, ranging in initial terms from one to 99 years, with extension options. These agreements cover sales and purchases of refined products, solvents, and petrochemical and natural gas liquids feedstocks, as well as fuel oils and gases. Delivery quantities vary by product, and are generally on an if-produced, will-purchase basis. All products are purchased and sold under specified pricing formulas based on various published pricing indices, consistent with terms extended to third-party customers.

Note 10 Properties, Plants and Equipment

The company s investment in properties, plants and equipment (PP&E), with accumulated depreciation, depletion and amortization (Accum. DD&A), at December 31 was:

	Millions of Dollars					
	2003			2002		
	Gross PP&E	Accum. DD&A	Net PP&E	Gross PP&E	Accum. DD&A	Net PP&E
E&P	**$ 42,358**	**10,837**	**31,521**	36,884	8,600	28,284
Midstream	**944**	**87**	**857**	903	16	887
R&M	**16,469**	**2,870**	**13,599**	15,605	2,765	12,840
Chemicals						
Emerging Businesses	**1,013**	**214**	**799**	690	5	685
Corporate and Other	**1,055**	**403**	**652**	477	143	334
	$ 61,839	**14,411**	**47,428**	54,559	11,529	43,030

Our investment in PP&E is recorded at cost. PP&E acquired in mergers and acquisitions is recorded at its fair market value at the time of the merger or acquisition. Effective January 1, 2003, we adopted SFAS No. 143, Accounting for

Asset Retirement Obligations, which applies to legal obligations associated with the retirement and removal of long-lived assets. SFAS No. 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period when it is incurred (typically when the asset is installed at the production location). When the liability is initially recorded, the entity capitalizes the cost by increasing the carrying amount of the related PP&E. Over time, the liability is increased for the

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change in its present value each period, and the initial capitalized cost is depreciated over the useful life of the related asset. Application of this new accounting principle resulted in an initial increase in net PP&E of $1.2 billion.

In June 2001, the FASB issued SFAS No. 141, Business Combinations, and SFAS No. 142, Goodwill and Other Intangible Assets, which became effective on July 1, 2001, and January 1, 2002, respectively. The Securities and Exchange Commission (SEC) has requested the Emerging Issues Task Force (EITF) to consider the issue of whether SFAS Nos. 141 and 142 require interests held under oil, gas and mineral leases to be separately classified as intangible assets on the balance sheets of companies in the extractive industries. Historically, in accordance with SFAS No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies, we have capitalized the cost of oil and gas leasehold interests and, consistent with industry practice, reported these assets as part of tangible E&P properties, plants and equipment.

If such interests were deemed to be intangible assets by the EITF, mineral rights to extract oil and gas for both proved and unproved properties would be classified separately from E&P properties, plants and equipment as intangible assets on our balance sheet. This interpretation by the EITF would only affect the classification of oil and gas mineral rights on our balance sheet and would not affect total assets, net worth, results of operations or cash flows.

E&P properties, plants and equipment at December 31, 2003 and 2002, included approximately $10.5 billion and $10.8 billion, respectively, of mineral rights to extract oil and gas, net of accumulated depletion, that would be reclassified on the balance sheet as intangible assets, if the interpretation that the SEC requested the EITF to consider was applied. We plan to continue to classify oil and gas mineral rights as E&P properties, plants and equipment until further guidance is provided by the EITF.

Note 11 Goodwill and Intangibles

Changes in the carrying amount of goodwill are as follows:

	Millions of Dollars			
	E&P	R&M	Corporate	Total
Balance at December 31, 2001	$ 15	2,266		2,281
Acquired (merger of Conoco and Phillips)			12,079	12,079
Valuation and other adjustments		341		341
Allocated to discontinued operations		(257)		(257)
Balance at December 31, 2002	$ 15	2,350	12,079	14,444
Valuation and other adjustments	**3**	**7**	**630**	**640**
Allocation to reporting units	**11,166**	**1,543**	**(12,709)**	
Balance at December 31, 2003	**$ 11,184**	**3,900***		**15,084**

**Consists of two reporting units: Worldwide Refining ($2,000) and Worldwide Marketing ($1,900).*

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Information on the carrying value of intangible assets follows:

	Millions of Dollars		
	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Amortized Intangible Assets			
Balance at December 31, 2003			
Refining technology related	**$ 101**	**9**	**92**
Other*	**57**	**29**	**28**
	$ 158	**38**	**120**
Balance at December 31, 2002			
Refining technology related	$ 95	1	94
Other*	60	22	38
	$ 155	23	132

**Primarily related to seismic technology, land rights, supply contracts and licenses.*

Indefinite-Lived Intangible Assets	
Balance at December 31, 2003	
Tradenames	**$ 604**
Refinery air and operating permits	**315**
Other*	**46**
	$ 965
Balance at December 31, 2002	
Tradenames	$ 669
Refinery air and operating permits	315
Other*	3
	$ 987

**Primarily pension related.*

Amortization expense related to the intangible assets above for the year ended December 31, 2003, was $17 million. The estimated amortization expense for the next five years is approximately $20 million per year. Amortization expense for the year ended December 31, 2002, was not material.

Note 12 Property Impairments

During 2003, 2002 and 2001, we recognized the following impairment charges:

	Millions of Dollars		
	2003	2002	2001
E&P			
United States	$ **65**	12	3
International	**180**	37	23
R&M			
Tradenames		102	
Retail site leasehold improvements		26	
Transportation	**2**		
Corporate and Other	**5**		
	$ **252**	177	26

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2003
The E&P segment recognized property impairments of $245 million in 2003. These impairments were the result of:

- The write-down to market value of properties planned for disposition;
- Properties failing to meet recoverability tests; and
- International tax law changes affecting asset removal costs.

2002
Our E&P segment recognized impairments of $49 million on four fields in 2002. Impairment of the Janice field in the U.K. North Sea was triggered by its sale, while the Viscount field in the U.K. North Sea was impaired following an evaluation of development drilling results. Sales of properties in Alaska and offshore California resulted in the remaining E&P impairments in 2002.

We initiated a plan in late 2002 to sell a substantial portion of our R&M retail sites. The planned dispositions will result in a reduction of the amount of gasoline volumes marketed under our 76 tradename. As a result, the carrying value of the 76 tradename was impaired, with the $102 million impairment determined by an analysis of the discounted cash flows based on the gasoline volumes projected to be sold under the brand name after the planned dispositions, compared with the volumes being sold prior to the dispositions. We also impaired the carrying value of certain leasehold improvements associated with leased retail sites that are held for use by comparing the guaranteed residual values and leasehold improvements with current market values of the related assets.

See Note 4 Discontinued Operations for information regarding the impairments recognized in 2002 in connection with the anticipated sale of certain assets mandated by the FTC, and the planned sale of a substantial portion of the company s retail marketing operations.

2001
In the second quarter of 2001, we committed to a plan to sell our 12.5 percent interest in the Siri oil field, offshore Denmark, triggering a write-down of the field s assets to fair market value. The sale closed in early 2002. We also recorded a property impairment on a crude oil tanker that was sold in the fourth quarter of 2001.

Note 13 Asset Retirement Obligations and Accrued Environmental Costs

Asset retirement obligations and accrued environmental costs at December 31 were:

	Millions of Dollars	
	2003	2002
Asset retirement obligations	$ **2,685**	1,065
Accrued environmental costs	**1,119**	743
Total asset retirement obligations and accrued environmental costs	**3,804**	1,808
Asset retirement obligations and accrued environmental costs due within one year*	**(201)**	(142)

Long-term asset retirement obligations and accrued environmental costs	**$ 3,603**	1,666

**Classified as a current liability on the balance sheet, under the caption Other accruals.*

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Asset Retirement Obligations

For information on the company s adoption of SFAS 143 and related disclosures, see Note 2 Changes in Accounting Principles.

Accrued Environmental Costs

Total environmental accruals at December 31, 2003 and 2002, were $1,119 million and $743 million, respectively. The 2003 increase in total accrued environmental costs primarily resulted from evaluation of Conoco environmental liabilities during the purchase price allocation period.

We had accrued environmental costs of $625 million and $427 million at December 31, 2003 and 2002, respectively, primarily related to cleanup at domestic refineries and underground storage tanks at U.S. service stations, and remediation activities required by the state of Alaska at exploration and production sites formerly owned by Atlantic Richfield Company. We had also accrued in Corporate and Other $367 million and $246 million of environmental costs associated with non-operating sites at December 31, 2003 and 2002, respectively. In addition, $127 million and $70 million were included at December 31, 2003 and 2002, respectively, where the company has been named a potentially responsible party under the Federal Comprehensive Environmental Response, Compensation and Liability Act, or similar state laws. Accrued environmental liabilities will be paid over periods extending up to 30 years.

Because a large portion of our accrued environmental costs were acquired in various business combinations, they are discounted obligations. Expected expenditures for acquired environmental obligations are discounted using a weighted-average 5 percent discount factor, resulting in an accrued balance for acquired environmental liabilities of $908 million at December 31, 2003. The expected future undiscounted payments related to the portion of the accrued environmental costs that have been discounted are: $131 million in 2004, $121 million in 2005, $88 million in 2006, $72 million in 2007, $67 million in 2008, and $596 million for all future years after 2008.

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Note 14 Debt

Long-term debt at December 31 was:

	Millions of Dollars	
	2003	2002
9 3/8% Notes due 2011	**$ 350**	350
8.75% Notes due 2010	**1,350**	1,350
8.5% Notes due 2005	**1,150**	1,150
8.49% Notes due 2023		250
8.25% Mortgage Bonds due 2003		150
8.125% Notes due 2030	**600**	600
8% Junior Subordinated Debentures due 2037	**361**	
7.92% Notes due 2023		250
7.9% Notes due 2047	**100**	100
7.8% Notes due 2027	**300**	300
7.68% Notes due 2012	**59**	64
7.625% Notes due 2006	**240**	240
7.25% Notes due 2007	**200**	200
7.25% Notes due 2031	**500**	500
7.20% Notes due 2023		250
7.125% Debentures due 2028	**300**	300
7% Debentures due 2029	**200**	200
6.95% Notes due 2029	**1,900**	1,900
6.65% Notes due 2003		100
6.65% Debentures due 2018	**300**	300
6.375% Notes due 2009	**300**	300
6.35% Notes due 2009	**750**	750
6.35% Notes due 2011	**1,750**	1,750
5.90% Notes due 2004	**1,350**	1,350
5.90% Notes due 2032	**600**	600
5.847% Notes due 2006	**126**	
5.45% Notes due 2006	**1,250**	1,250
4.75% Notes due 2012	**1,000**	1,000
3.625% Notes due 2007	**400**	400
Commercial paper and revolving debt due to banks and others through 2008 at 1.05% - 1.08% at year-end 2003 and 1.46% - 1.94% at year-end 2002	**709**	1,517
SRW Cogeneration Limited Partnership		180
Floating Rate Notes due 2003		500
Industrial Development bonds at 1.1% - 6.1% at year-end 2003 and 1.55% - 3.0% at year-end 2002	**256**	153
Guarantee of savings plan bank loan payable at 1.4375% at year-end 2003	**275**	299
Note payable to Merey Sweeny, L.P. at 7%	**131**	131

Marine Terminal Revenue Refunding Bonds at 2.0% at year-end 2003	**265**	265
Other notes payable	**52**	68
Debt at face value	**17,124**	19,067
Capitalized leases	**60**	23
Net unamortized premiums and discounts	**596**	676
Total debt	**17,780**	19,766
Notes payable and long-term debt due within one year	**(1,440)**	(849)
Long-term debt	**$ 16,340**	18,917

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Maturities inclusive of net unamortized premiums and discounts in 2004 through 2008 are: $1,440 million (included in current liabilities), $1,237 million, $1,885 million, $653 million and $587 million, respectively.

Effective October 14, 2003, we entered into two new revolving credit facilities, replacing a $2 billion 364-day facility that expired on that same date. The new revolving credit facilities are a $1.5 billion 364-day facility and a $500 million five-year facility. In addition, we have two revolving credit facilities totaling $2 billion expiring in October 2006. In total, at December 31, 2003, we had four bank credit facilities in place, totaling $4 billion, available for use either as direct bank borrowings or as support for the issuance of up to $4 billion in commercial paper, a portion of which may be denominated in other currencies (limited to euro 3 billion equivalent). At December 31, 2003, we had no debt outstanding under these credit facilities, but had $709 million in commercial paper outstanding. The commercial paper is supported 100 percent by the credit facilities and the amount approximates fair value.

At December 31, 2003, $984 million of short-term obligations were classified as non-current, based on management s intent to refinance the obligations on a long-term basis through the use of existing facilities.

One of our Norwegian subsidiaries has two $300 million revolving credit facilities expiring in June 2004, under which no borrowings were outstanding at December 31, 2003.

Depending on the credit facility, borrowings may bear interest at a margin above rates offered by certain designated banks in the London interbank market or at margins above certificate of deposit or prime rates offered by certain designated banks in the United States. The agreements call for commitment fees on available, but unused, amounts. The agreements also contain early termination rights if our current directors or their approved successors cease to be a majority of the Board of Directors.

In the third quarter of 2003, the adoption of FIN 46 for VIEs involving synthetic leases and certain other financing structures, was made and retroactively applied to January 1, 2003. The application of FIN 46 increased our balance sheet debt by approximately $2.8 billion. See Note 2 Changes in Accounting Principles for additional information about FIN 46. With the adoption of FIN 46:

The Phillips 66 Capital Trust II (Trust) is no longer consolidated, which removed $350 million of mandatorily redeemable preferred securities from the consolidated balance sheet and added to long-term debt $361 million of 8% Junior Subordinated Deferrable Interest Debentures due 2037. Previously this debt was eliminated in consolidation; and

VIEs involving synthetic leases and certain other financing structures in which we are the primary beneficiary were consolidated retroactively as of January 1, 2003, which increased consolidated debt approximately $2.4 billion. Of this $2.4 billion, approximately $1.5 billion was associated with approximately 1,000 retail store sites, the majority of which we have sold or plan to sell, and two office buildings that also are part of our divestiture plan.

The $2.4 billion in debt at January 1, 2003, was comprised of the following:

$90 million Tosco Trust 2000 E 8.78% Senior Secured Notes due 2010;

$245 million Tosco Trust 2000 E 8.58% Senior Secured Notes due 2010;

$199 million Arctic Funding, Limited Partnership 6.85% Senior Secured Note due 2011;

$100 million of floating rate aviation equipment lease obligations having a final maturity in 2004;

$489 million of various fixed and floating rate ocean vessel lease obligations having final maturities from 2004 to 2005;

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- $1,130 million of floating rate marketing lease obligations having final maturities from 2003 to 2006; and
- $160 million of refining equipment lease obligations at 5.847% having a final maturity in 2006.

During 2003, we reduced our commercial paper balance outstanding from $1.5 billion at December 31, 2002, to $709 million at December 31, 2003. In 2003, we paid off the following notes and debt facilities as they were called or matured and funded the payments with cash from operating activities and proceeds from asset dispositions:

- $250 million 8.49% Notes due 2023, at 104.245 percent;
- $150 million 8.25% Mortgage Bonds due May 15, 2003;
- $250 million 7.92% Notes due in 2023, at 103.96 percent;
- $250 million 7.20% Notes due 2023, at 103.60 percent;
- $100 million 6.65% Notes that matured on March 1, 2003;
- $180 million SRW Cogeneration Limited Partnership note;
- $500 million Floating Rate Notes due April 15, 2003;
- $90 million Tosco Trust 2000-E 8.78% Senior Secured Notes due 2010;
- $245 million Tosco Trust 2000-E 8.58% Senior Secured Notes due 2010;
- $199 million Arctic Funding, Limited Partnership 6.85% Senior Secured Note due 2011;
- $100 million of floating rate aviation equipment lease obligations having a final maturity in 2004;
- $489 million of fixed and floating rate ocean vessel lease obligations having final maturities from 2004 to 2005; and
- $1,130 million of floating rate marketing lease obligations having maturities from 2003 to 2006.

Also, in October and November 2003, we executed certain interest rate swaps that had the effect of converting $1.5 billion of debt from fixed to floating rate. The swaps were placed on $400 million of 3.625% Notes due 2007, $750 million of 6.35% Notes due 2009, and $350 million of 4.75% Notes due 2012. The weighted average floating rate in effect on these notes at December 31, 2003, was 2.26 percent, based on LIBOR. These swaps qualify for hedge accounting under SFAS 133, Accounting for Derivative Instruments and Hedging Activities.

At December 31, 2003, $275 million was outstanding under the ConocoPhillips Savings Plan term loan, which will require repayment in annual installments beginning in 2009 and continuing through 2015. Under this bank loan, any participating bank in the syndicate of lenders may cease to participate on December 5, 2004, by giving not less than 180 days prior notice to the ConocoPhillips Savings Plan and the company. One participating lender has given cessation notice. This note is classified as non-current, based on management s intent to resyndicate the loan or alternatively to refinance the note on a long-term basis through the use of existing facilities.

Each bank participating in the ConocoPhillips Savings Plan loan has the optional right, if our current directors or their approved successors cease to be a majority of the Board, and upon not less than 90 days notice, to cease to participate in the loan. Under the above conditions, we are required to purchase such bank s rights and obligations under the loan agreement if they are not transferred to another bank of our choice. See Note 22 Employee Benefit Plans for additional discussion of the ConocoPhillips Savings Plan.

Note 15 Sales of Receivables

At December 31, 2002, certain credit card and trade receivables had been sold to two Qualifying Special Purpose Entities (QSPEs) in revolving-period securitization arrangements. These arrangements provided for us to sell, and the QSPEs to purchase, certain receivables and for the QSPEs to then issue beneficial interests of up to $1.5 billion to five bank-sponsored entities. All five bank-sponsored entities are multi-seller conduits with access to the commercial paper market and purchase interests in similar receivables from numerous other companies unrelated to us. We have no ownership interests, nor any variable interests, in any of the bank-sponsored entities. As a result, we do not consolidate any of these entities. Furthermore, we do not consolidate the QSPEs because they meet the requirements of SFAS No. 140, Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities, to be excluded from the consolidated financial statements of ConocoPhillips.

During 2003, we purchased from the bank-sponsored entities the senior interests of one of our two existing QSPEs and discontinued selling receivables to it. We have consolidated this QSPE since acquiring the senior interests. Also during 2003, the third-party beneficial interest holders approved amendments to the other QSPE to increase the amount of third-party beneficial interests that can be issued to $1.2 billion. These changes resulted in a net reduction of the maximum level of senior beneficial interests that can be issued to third-party beneficial interest holders from $1.5 billion to $1.2 billion. At December 31, 2003 and 2002, we had sold accounts receivable of $1.2 billion and $1.3 billion, respectively. The receivables transferred to the QSPE meets the isolation requirements and other requirements of SFAS No. 140 to be accounted for as sales. Accordingly, receivables transferred to the QSPEs were accounted for as sales.

We retain beneficial interests in the QSPE that are subordinate to the beneficial interests issued to the bank-sponsored entities. These retained interests, which are reported on the balance sheet in accounts and notes receivable related parties, were $1.3 billion at both December 31, 2003 and 2002. We also retain servicing responsibility related to the sold receivables, which gives us certain benefits, the fair value of which approximates the fair value of the liability incurred for continuing to service the receivables. The carrying value of the subordinated beneficial interests approximates fair market value due to the short term of the underlying assets, which makes stress testing unnecessary.

Total cash flows received from and paid under the securitization arrangements were as follows:

	Millions of Dollars	
	2003	2002
Receivables sold at beginning of year	$ **1,323**	940
Conoco receivables sold at August 30, 2002		400
New receivables sold	**25,201**	19,943*
Cash collections remitted	**(25,324)**	(19,960)*
Receivables sold at end of year	$ **1,200**	1,323
Discounts and other fees paid on revolving balances	$ **19**	21

**New receivables sold and cash collections remitted under these ongoing revolving securitization arrangements have been rev*

At December 31, 2003 and 2002, we also had sold $226 million and $264 million of receivables under factoring arrangements. We retain servicing responsibility related to these sold receivables, which gives us certain benefits, the fair value of which approximates the fair value of the liability incurred for continuing to service the receivables.

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Note 16 Guarantees

At December 31, 2003, we were liable for certain contingent obligations under various contractual arrangements as described below. We are required to recognize a liability at inception for the fair value of our obligation as a guarantor for guarantees issued or modified after December 31, 2002. Unless the carrying amount of the liability is noted, we have not recognized a liability either because the guarantees were issued prior to December 31, 2002, or because the fair value of the obligation is immaterial.

Construction Completion Guarantees

We have a construction completion guarantee related to debt and bond financing arrangements secured by the Merey Sweeny, L.P. (MSLP) joint-venture project in Texas. The maximum potential amount of future payment under the guarantee, including joint-and-several debt at its gross amount, is estimated to be $400 million assuming that completion certification is not achieved. Of this amount, $200 million is attributable to Petroleos de Venezuela, S.A. (PDVSA), because they are joint-and-severally liable for a portion of the debt. If completion certification is not attained by June 18, 2004, the full debt balance could be called. MSLP is currently awaiting receipt of a permit for a new waste water pipeline and working to resolve issues in placing its insurance program, after which we expect to achieve completion certification in the second quarter of 2004. The debt is non-recourse to us upon completion certification.

We also issued a construction completion guarantee related to debt financing arrangements for the Hamaca Holding LLC joint-venture project in Venezuela. The maximum potential amount of future payments under the guarantee is estimated to be $440 million, which could be payable if the full debt financing capacity is utilized and startup and completion of the Hamaca project is not achieved by October 1, 2005. The project financing debt will become non-recourse upon startup and completion certification.

Guarantees of Joint-Venture Debt

At December 31, 2003, we had guarantees of approximately $340 million outstanding for our portion of joint-venture debt obligations, which have terms of up to 22 years. Included in these outstanding guarantees was $156 million associated with the Polar Lights Company joint venture in Russia. Payment will be required if a joint venture defaults on its debt obligations.

Other Guarantees

In addition to the construction completion guarantee explained above, the MSLP agreement also requires the partners in the venture to pay cash calls as required to meet the minimum operating requirements of the venture, in the event revenues do not cover expenses over the next 20 years. Our maximum potential future payments under the agreement are estimated to be $300 million, assuming MSLP does not earn any revenue over the entire period and fixed costs cannot be reduced. To the extent revenue is generated by the venture or fixed costs are reduced, future required payments would be reduced accordingly.

In February 2003, we entered into two agreements establishing separate guarantee facilities of $50 million each for two liquefied natural gas ships that were then under construction. Subject to the terms of each such facility, we will be required to make payments should the charter revenue generated by the respective ship fall below certain specified minimum thresholds, and we will receive payments to the extent that such revenues exceed those thresholds. The net maximum future payments that we may have to make over the 20-year terms of the two agreements could be up to an aggregate of $100 million. Actual gross payments over the 20 years could exceed that amount to the extent cash is received by us. In the event either ship is sold or a total loss occurs, we also may have recourse to the sales or insurance proceeds to recoup payments made under the

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guarantee facilities. In February 2003, based on the then current market view of both long-term and short-term shipping capacity, rates, and utilization probability, we estimated the fair value of the liability under these guarantee facilities to be immaterial. In September 2003, the first ship was delivered to its owner and the second ship is scheduled for delivery to its owner in 2005. With respect to the first ship, the amount drawn under the guarantee facility at December 31, 2003, was less than $1 million.

We have other guarantees totaling approximately $190 million, which consist primarily of dealer and jobber loan guarantees to support our marketing business, a guarantee supporting a lease assignment on a corporate aircraft, a guarantee associated with a pending lawsuit and guarantees of lease payment obligations for a joint venture. The carrying amount recorded for these other guarantees as of December 31, 2003, was $13 million. These guarantees generally extend up to 15 years and payment would only be required if the dealer, jobber or lessee goes into default, or if an adverse decision occurs in the lawsuit.

Indemnifications

Over the years, we have entered into various agreements to sell ownership interests in certain corporations and joint ventures. In addition, we entered into a Tax Sharing Agreement in 1998 related to Conoco s separation from DuPont. These agreements typically include indemnifications for additional taxes determined to be due under the relevant tax law, in connection with operations for years prior to the sale or separation. Generally, the obligation extends until the related tax years are closed. The maximum potential amount of future payments under the indemnifications is the amount of additional tax determined to be due under relevant tax law and the various agreements. There are no material outstanding claims that have been asserted under these agreements.

During 2003, we sold several assets, including FTC-mandated sales of downstream and midstream assets, certain exploration and production assets, and downstream retail and wholesale sites, giving rise to qualifying indemnifications. Agreements associated with these sales include indemnifications for taxes, environmental liabilities, underground storage tank repairs or replacements, permits and licenses, employee claims, real estate indemnity against tenant defaults, and litigation. The term of these indemnifications is generally indefinite and the maximum amount of future payments is generally unlimited. The carrying amount recorded for these indemnifications as of December 31, 2003, is $221 million. Although it is reasonably possible that future payments may exceed amounts recorded, due to the nature of the indemnifications, it is not possible to make a reasonable estimate of the maximum potential amount of future payments. Included in the carrying amount recorded are $81 million of environmental accruals for known contamination that is included in asset retirement obligations and accrued environmental costs at December 31, 2003. For additional information about environmental liabilities, see Note 13 Asset Retirement Obligations and Accrued Environmental Costs, and Note 17 Contingencies.

As part of our normal ongoing business operations and consistent with industry practice, we enter into numerous agreements with other parties, which apportion future risks among the parties to the transaction or relationship governed by the agreements. One method of apportioning risk is the inclusion of provisions requiring one party to indemnify the other against losses that might otherwise be incurred by the other party in the future. Many of our agreements contain an indemnity or indemnities that require us to perform certain acts, such as remediation, as a result of the occurrence of a triggering event or condition. In some instances we indemnify third parties against losses resulting from certain events or conditions that arise out of the operations of our equity affiliates.

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The nature of these numerous indemnity obligations are diverse and each has different terms, business purposes, and triggering events or conditions. Consistent with customary business practice, any particular indemnity obligation incurred is the result of a negotiated transaction or contractual relationship for which we have accepted a certain level of risk in return for a financial or other type of benefit. In addition, the indemnities in each agreement vary widely in their definitions of both triggering events and the resulting obligations contingent on those triggering events.

With regard to indemnifications, our risk management philosophy is to limit risk in any transaction or relationship to the maximum extent reasonable in relation to commercial and other considerations. Before accepting any indemnity obligation, we make an informed risk management decision considering, among other things, the remoteness of the possibility that the triggering event will occur, the potential costs to perform under any resulting indemnity obligation, possible actions to reduce the likelihood of a triggering event or to reduce the costs of performing under the indemnity obligation, whether we are indemnified by an unrelated third party, insurance coverage that may be available to offset the cost of the indemnity obligation, and the benefits from the transaction or relationship.

Because many of our indemnity obligations are not limited in duration or potential monetary exposure, we cannot calculate a reasonable estimate of the maximum potential amount of future payments that could be paid under our indemnity obligations stemming from all our existing agreements. The carrying amount recorded for these indemnifications as of December 31, 2003, was $224 million, which is for known contamination and is included in asset retirement obligations and accrued environmental costs. For additional information about environmental liabilities and contingencies, see Note 13 Asset Retirement Obligations and Accrued Environmental Costs, and Note 17 Contingencies.

Note 17 Contingencies

We are subject to various lawsuits and claims including, but not limited to: actions challenging oil and gas royalty and severance tax payments; actions related to gas measurement and valuation methods; actions related to joint interest billings to operating agreement partners; and claims for damages resulting from leaking underground storage tanks, or other accidental releases, with related toxic tort claims. As a result of Conoco s separation agreement with DuPont, we also have assumed responsibility for current and future claims related to certain discontinued chemicals and agricultural chemicals businesses operated by Conoco in the past. In general, the effect on future financial results is not subject to reasonable estimation because considerable uncertainty exists. The ultimate liabilities resulting from such lawsuits and claims may be material to results of operations in the period in which they are recognized.

In the case of all known contingencies, we accrue a liability when the loss is probable and the amount is reasonably estimable. We do not reduce these liabilities for potential insurance or third-party recoveries. If applicable, we accrue receivables for probable insurance or other third-party recoveries. Based on currently available information, we believe that it is remote that future costs related to known contingent liability exposures will exceed current accruals by an amount that would have a material adverse impact on our financial statements.

As we learn new facts concerning contingencies, we reassess our position both with respect to accrued liabilities and other potential exposures. Estimates that are particularly sensitive to future changes include contingent liabilities recorded for environmental remediation, tax and legal matters. Estimated future environmental remediation costs are subject to change due to such factors as the uncertain magnitude of cleanup costs, the unknown time and extent of such remedial actions that may be required, and the determination of our liability in proportion to that of other responsible parties. Estimated future costs related to tax and legal matters are subject to change as events evolve and as additional information becomes available during the administrative and litigation processes.

Environmental We are subject to federal, state and local environmental laws and regulations. These may result in obligations to remove or mitigate the effects on the environment of the placement, storage, disposal or release of certain chemical, mineral and petroleum substances at various sites. When we prepare our financial statements, we record accruals for environmental liabilities based on management s best estimates, using all information that is available at the time. We measure estimates and base liabilities on currently available facts, existing technology, and presently enacted laws and regulations, taking into consideration the likely effects of societal and economic factors. When measuring environmental liabilities, we also consider our prior experience in remediation of contaminated sites, other companies cleanup experience, and data released by the U.S. Environmental Protection Agency (EPA) or other organizations. We consider unasserted claims in our determination of environmental liabilities and we accrue them in the period that they are both probable and reasonably estimable.

Although liability of those potentially responsible for environmental remediation costs is generally joint and several for federal sites and frequently so for state sites, we are usually only one of many companies cited at a particular site. Due to the joint and several liabilities, we could be responsible for all of the cleanup costs related to any site at which we have been designated as a potentially responsible party. If we were solely responsible, the costs, in some cases, could be material to our, or one of our segments , operations, capital resources or liquidity. However, settlements and costs incurred in matters that previously have been resolved have not been material to our results of operations or financial condition. We have been successful to date in sharing cleanup costs with other financially sound companies. Many of the sites at which we are potentially responsible are still under investigation by the EPA or the state agencies concerned. Prior to actual cleanup, those potentially responsible normally assess the site conditions, apportion responsibility and determine the appropriate remediation. In some instances, we may have no liability or may attain a settlement of liability. Where it appears that other potentially responsible parties may be financially unable to bear their proportional share, we consider this inability in estimating our potential liability and we adjust our accruals accordingly.

As a result of various acquisitions in the past, we assumed certain environmental obligations. Some of these environmental obligations are mitigated by indemnifications made by others for our benefit and some of the indemnifications are subject to dollar limits and time limits. We have not recorded accruals for any potential contingent liabilities that we expect to be funded by the prior owners under these indemnifications.

We are currently participating in environmental assessments and cleanups at numerous federal Superfund and comparable state sites. After an assessment of environmental exposures for cleanup and other costs, we make accruals on an undiscounted basis (except those assumed in a purchase business combination, which we record such costs on a discounted basis) for planned investigation and remediation activities for sites where it is probable that future costs will be incurred and these costs can be reasonably estimated. We have not reduced these accruals for possible insurance recoveries. In the future, we may be involved in additional environmental assessments, cleanups and proceedings. See Note 13 Asset Retirement Obligations and Accrued Environmental Costs for a summary of our accrued environmental liabilities.

Other Legal Proceedings We are a party to a number of other legal proceedings pending in various courts or agencies for which, in some instances, no provision has been made.

Other Contingencies We have contingent liabilities resulting from throughput agreements with pipeline and processing companies. Under these agreements, we may be required to provide any such company with additional funds through advances and penalties for fees related to throughput capacity not utilized by us. In addition, we have various purchase commitments for materials, supplies, services and items of permanent investment incident to the ordinary conduct of business.

Note 18 Financial Instruments and Derivative Contracts

Derivative Instruments

We, and certain of our subsidiaries, may use financial and commodity-based derivative contracts to manage exposures to fluctuations in foreign currency exchange rates, commodity prices, and interest rates, or to exploit market opportunities. Our use of derivative instruments is governed by an Authority Limitations document approved by our Board of Directors that prohibits the use of highly leveraged derivatives or derivative instruments without sufficient liquidity for comparable valuations without approval from the Chief Executive Officer. The Authority Limitations document also authorizes the Chief Executive Officer to establish the maximum Value at Risk (VaR) limits for the company and compliance with these limits is monitored daily. The Chief Financial Officer monitors risks resulting from foreign currency exchange rates and interest rates, while the Executive Vice President of Commercial monitors commodity price risk. Both report to the Chief Executive Officer. The Commercial Group manages our commercial marketing, optimizes our commodity flows and positions, monitors related risks of our upstream and downstream businesses and selectively takes price risk to add value.

SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended (Statement No. 133 or SFAS No. 133), requires companies to recognize all derivative instruments as either assets or liabilities on the balance sheet at fair value. Assets and liabilities resulting from derivative contracts open at December 31, 2003, were $340 million and $268 million, respectively, and appear as accounts and notes receivables, other assets, accounts payable, or other liabilities and deferred credits on the balance sheet.

The accounting for changes in fair value (i.e., gains or losses) of a derivative instrument depends on whether it meets the qualifications for, and has been designated as, a SFAS No. 133 hedge, and the type of hedge. At this time, we are not using SFAS No. 133 hedge accounting for commodity derivative contracts, but we are using hedge accounting for the interest-rate derivatives noted below. All gains and losses, realized or unrealized, from derivative contracts not designated as SFAS No. 133 hedges have been recognized in the income statement. Gains and losses from derivative contracts held for trading not directly related to our physical business, whether realized or unrealized, have been reported net in other income.

SFAS No. 133 also requires purchase and sales contracts for commodities that are readily convertible to cash (e.g., crude oil, natural gas, and gasoline) to be recorded on the balance sheet as derivatives unless the contracts are for quantities we expect to use or sell over a reasonable period in the normal course of business (the normal purchases and normal sales exception), among other requirements, and we have documented our intent to apply this exception. Except for contracts to buy or sell natural gas, we generally apply this exception to eligible purchase and sales contracts; however, we may elect not to apply this exception (e.g., when another derivative instrument will be used to mitigate the risk of the purchase or sale contract but hedge accounting will not be applied). When this occurs, both the purchase or sales contract and the derivative contract mitigating the resulting risk will be recorded on the balance sheet at fair value in accordance with the preceding paragraphs. Most of our contracts to buy or sell natural gas are recorded on the balance sheet as derivatives, except for certain long-term contracts to sell our natural gas production, which either have been designated normal purchase/normal sales, or do not meet the SFAS No. 133 definition of a derivative.

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Interest Rate Derivative Contracts During the fourth quarter of 2003, we executed interest rate swaps that had the effect of converting $1.5 billion of debt from fixed to floating rates. These swaps qualified for and have been designated as fair-value hedges using the short-cut method of hedge accounting provided by SFAS No. 133, which permits the assumption that changes in the value of the derivative perfectly offset changes in the value of the debt; therefore, no gain or loss is recognized due to hedge ineffectiveness.

Currency Exchange Rate Derivative Contracts We have foreign currency exchange rate risk resulting from operations in over 40 countries. We do not comprehensively hedge the exposure to currency rate changes, although we may choose to selectively hedge exposures to foreign currency rate risk. Examples include firm commitments for capital projects, certain local currency tax payments and dividends, short-term intercompany loans between subsidiaries operating in different countries, and cash returns from net investments in foreign affiliates to be remitted within the coming year. Hedge accounting is not currently being used for any of our foreign currency derivatives.

Commodity Derivative Contracts We operate in the worldwide crude oil, refined product, natural gas, natural gas liquids, and electric power markets and are exposed to fluctuations in the prices for these commodities. These fluctuations can affect our revenues as well as the cost of operating, investing, and financing activities. Generally, our policy is to remain exposed to market prices of commodity purchases and sales; however, executive management may elect to use derivative instruments to hedge the price risk of our crude oil and natural gas production, as well as refinery margins.

Our Commercial group uses futures, forwards, swaps, and options in various markets to optimize the value of our supply chain, which may move our risk profile away from market average prices to accomplish the following objectives:

- Balance physical systems. In addition to cash settlement prior to contract expiration, exchange traded futures contracts may also be settled by physical delivery of the commodity, providing another source of supply to meet our refinery requirements or marketing demand;
- Meet customer needs. Consistent with our policy to generally remain exposed to market prices, we use swap contracts to convert fixed-price sales contracts, which are often requested by natural gas and refined product consumers, to a floating market price;
- Manage the risk to our cash flows from price exposures on specific crude oil, natural gas, refined product and electric power transactions; and
- Enable us to use the market knowledge gained from these activities to do a limited amount of trading not directly related to our physical business. For the 12 months ended December 31, 2003, 2002 and 2001, the gains or losses from this activity were not material to our cash flows or income from continuing operations.

At December 31, 2003, we were not using hedge accounting for any commodity derivative contracts.

Credit Risk
Our financial instruments that are potentially exposed to concentrations of credit risk consist primarily of cash equivalents, over-the-counter derivative contracts, and trade receivables. Our cash equivalents, which are placed in high-quality money market funds and time deposits with major international banks and financial institutions, are generally not maintained at levels material to our financial position. The credit risk from our over-the-counter derivative contracts, such as forwards and swaps, derives from the counterparty to the transaction, typically a major bank or financial institution. We closely monitor these credit exposures against predetermined credit limits, including the continual exposure adjustments that result from market movements. Individual counterparty exposure is managed within these limits, and

includes the use of cash-call margins when appropriate, thereby reducing the risk of significant non-performance. We also use futures contracts, but futures have a negligible credit risk because they are traded on the New York Mercantile Exchange or the International Petroleum Exchange of London Limited.

Our trade receivables result primarily from our petroleum operations and reflect a broad national and international customer base, which limits our exposure to concentrations of credit risk. The majority of these receivables have payment terms of 30 days or less, and we continually monitor this exposure and the creditworthiness of the counterparties. We do not generally require collateral to limit the exposure to loss; however, we will sometimes use letters of credit, prepayments, and master netting arrangements to mitigate credit risk with counterparties that both buy from and sell to us, as these agreements permit the amounts owed by us or owed to others to be offset against amounts due us.

Fair Values of Financial Instruments

We used the following methods and assumptions to estimate the fair value of financial instruments:

Cash and cash equivalents: The carrying amount reported on the balance sheet approximates fair value.

Accounts and notes receivable: The carrying amount reported on the balance sheet approximates fair value.

Debt and mandatorily redeemable preferred securities: The carrying amount of our floating-rate debt approximates fair value. The fair value of the fixed-rate debt and mandatorily redeemable preferred securities is estimated based on quoted market prices.

Swaps: Fair value is estimated based on forward market prices and approximates the net gains and losses that would have been realized if the contracts had been closed out at year-end. When forward market prices are not available, they are estimated using the forward prices of a similar commodity with adjustments for differences in quality or location.

Futures: Fair values are based on quoted market prices obtained from the New York Mercantile Exchange, the International Petroleum Exchange of London Limited, or other traded exchanges.

Forward-exchange contracts: Fair value is estimated by comparing the contract rate to the forward rate in effect on December 31 and approximates the net gains and losses that would have been realized if the contracts had been closed out at year-end.

Certain of our financial instruments at December 31 were:

	Millions of Dollars			
	Carrying Amount		Fair Value	
	2003	2002	**2003**	2002
Financial assets				
Foreign currency derivatives	$ **44**	17	**44**	17
Interest rate derivatives	**13**		**13**	
Commodity derivatives	**283**	180	**283**	180
Financial liabilities				
Total debt, excluding capital leases	**17,720**	19,743	**18,905**	20,844

Mandatorily redeemable other minority interests and preferred securities	**141**	491	**142**	516
Interest rate derivatives	**13**	22	**13**	22
Foreign currency derivatives	**5**	4	**5**	4
Commodity derivatives	**250**	180	**250**	180

Note 19 Preferred Stock and Other Minority Interests

Company-Obligated Mandatorily Redeemable Preferred Securities of Phillips 66 Capital Trusts

During 1996 and 1997, we formed two statutory business trusts, Phillips 66 Capital I (Trust I) and Phillips 66 Capital II (Trust II), with ConocoPhillips owning all the common stock. The trusts were created for the sole purpose of issuing securities and investing the proceeds thereof in an equivalent amount of our subordinated debt securities. We established the trusts to raise funds for general corporate purposes.

On May 31, 2002, we redeemed all of our outstanding 8.24% Junior Subordinated Deferrable Interest Debentures due 2036 held by Trust I. This triggered the redemption of $300 million of Trust I s 8.24% Trust Originated Preferred Securities at par value, $25 per share. A loss of $8 million before-tax, $6 million after-tax, was incurred during the second quarter of 2002 as a result of the redemption.

Trust II has outstanding $350 million of 8% Capital Securities (Capital Securities). The sole asset of Trust II is $361 million of the company s 8% Junior Subordinated Deferrable Interest Debentures due 2037 (Subordinated Debt Securities II) purchased by Trust II on January 17, 1997. The Subordinated Debt Securities II are due January 15, 2037, and are redeemable in whole, or in part, at our option on or after January 15, 2007, at 103.94 percent declining annually until January 15, 2017, when they can be called at par, $1,000 per share, plus accrued and unpaid interest. When we redeem the Subordinated Debt Securities II, Trust II is required to apply all redemption proceeds to the immediate redemption of the Capital Securities. We fully and unconditionally guarantee Trust II s obligations under the Capital Securities.

Subordinated Debt Securities II are unsecured obligations of ours that are subordinate and junior in right of payment to all our present and future senior indebtedness.

Effective January 1, 2003, with the adoption of FIN 46, Trust II was deconsolidated because we are not the primary beneficiary. Application of FIN 46 required deconsolidation of Trust II, which had the effect of increasing debt by $361 million since the Subordinated Debt Securities II were no longer eliminated in consolidation, and eliminating the $350 million of mandatorily redeemable preferred securities. Prior to the adoption of FIN 46, the subordinated debt securities and related income statement effects were eliminated in the company s consolidated financial statements. See Note 2 Changes in Accounting Principles for additional information.

Other Minority Interests

The minority limited partner in Conoco Corporate Holdings L.P., a limited-life entity that must be liquidated in 2019, is entitled to a cumulative annual 7.86 percent priority return on its investment. The net minority interest in Conoco Corporate Holdings held by the limited partner was $141 million at December 31, 2003 and 2002, and is callable without penalty beginning in the fourth quarter of 2004.

The minority interest owner in Ashford Energy Capital S.A. is entitled to a cumulative annual preferred return on its investment, based on three-month LIBOR rates plus 1.27 percent. The preferred return at December 31, 2003 and 2002, was 2.48 percent and 2.70 percent, respectively. At December 31, 2003 and 2002, the minority interest was $496 million and $504 million, respectively.

Ashford Energy Capital S.A. continues to be consolidated in our financial statements under the provisions of FIN 46 because we are the primary beneficiary. See Note 2 Changes in Accounting Principles for additional information.

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The remaining minority interest amounts relate to consolidated operating joint ventures that have minority interest owners. The largest amount relates to the Bayu-Undan project. See Note 7-Subsidiary Equity Transactions.

Preferred Stock
We have 500 million shares of preferred stock authorized, par value $.01 per share, none of which was issued or outstanding at December 31, 2003.

Note 20 Preferred Share Purchase Rights

Our Board of Directors authorized and declared a dividend of one preferred share purchase right for each common share outstanding, and authorized and directed the issuance of one right per common share for any newly issued shares. The rights, which expire June 30, 2012, will be exercisable only if a person or group acquires 15 percent or more of the company s common stock or commences a tender offer that would result in ownership of 15 percent or more of the common stock. Each right would entitle stockholders to buy one one-hundredth of a share of preferred stock at an exercise price of $300. In addition, the rights enable holders to either acquire additional shares of ConocoPhillips common stock or purchase the stock of an acquiring company at a discount, depending on specific circumstances. We may redeem the rights in whole, but not in part, for one cent per right.

Note 21 Non-Mineral Leases

The company leases ocean transport vessels, railcars, corporate aircraft, service stations, computers, office buildings and other facilities and equipment. Certain leases include escalation clauses for adjusting rentals to reflect changes in price indices, as well as renewal options and/or options to purchase the leased property for the fair market value at the end of the lease term. There are no significant restrictions on us imposed by the leasing agreements in regards to dividends, asset dispositions or borrowing ability. Leased assets under capital leases were not significant in any period presented.

At December 31, 2003, future minimum rental payments due under non-cancelable leases, including those associated with discontinued operations, were:

	Millions of Dollars
2004	$ 471
2005	434
2006	376
2007	328
2008	291
Remaining years	1,173
Total	3,073
Less income from subleases	419*
Net minimum operating lease payments	$ 2,654

**Includes $182 million related to railroad cars subleased to CPChem, a related party.*

We have agreements with a shipping company for the long-term charter of two crude oil tankers that are currently under construction. The charters will be accounted for as operating leases upon delivery, which is expected in the first quarter of 2004. Upon delivery, the base term of the charter agreements is 12 years,

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with certain renewal options by ConocoPhillips. The total operating lease commitment over the 12-year term for the two tankers would be $87 million on an estimated bareboat basis.

Operating lease rental expense from continuing operations for the years ended December 31 was:

	Millions of Dollars		
	2003	2002	2001
Total rentals*	$ **448**	541	271
Less sublease rentals	**24**	21	22
	$ **424**	520	249

**Includes $31 million and $12 million of contingent rentals in 2003 and 2002, respectively. Contingent rentals primarily are related to retail sites and refining equipment, and are based on volume of product sold or throughput. Contingent rentals in 2001 were not significant.*

Note 22 Employee Benefit Plans

Pension and Postretirement Plans

An analysis of the projected benefit obligations for our pension plans and accumulated benefit obligations for our postretirement health and life insurance plans follows:

	Millions of Dollars					
	Pension Benefits				Other Benefits	
	2003		2002		**2003**	2002
	U.S.	**Int'l.**	U.S.	Int'l.		
Change in Benefit Obligation						
Benefit obligation at January 1	$ **3,079**	**1,501**	1,432	417	**919**	239
Service cost	**131**	**61**	75	32	**17**	9
Interest cost	**197**	**89**	133	48	**61**	31
Plan participant contributions		**1**		2	**27**	15
Plan amendments		**54**	(12)			133
Actuarial (gain) loss	**187**	**268**	205	(21)	**46**	31
Acquisitions			1,349	908		509
Benefits paid	**(571)**	**(60)**	(159)	(23)	**(72)**	(47)
Curtailment	**(3)**	**(5)**	(36)			(4)
Recognition of termination benefits		**9**	92	3		3

Foreign currency exchange rate change		**157**		135	**6**	
Benefit obligation at December 31	**$ 3,020**	**2,075**	3,079	1,501	**1,004**	919
Accumulated benefit obligation portion of above at December 31	**$ 2,379**	**1,764**	2,455	1,325		
Change in Fair Value of Plan Assets						
Fair value of plan assets at January 1	**$ 1,233**	**1,027**	732	381	**11**	21
Actual return on plan assets	**228**	**133**	(85)	(74)	**2**	(5)
Acquisitions			600	594		
Company contributions	**570**	**91**	145	39	**39**	27
Plan participant contributions		**1**		2	**27**	15
Benefits paid	**(571)**	**(60)**	(159)	(21)	**(72)**	(47)
Foreign currency exchange rate change		**111**		106		
Fair value of plan assets at December 31	**$ 1,460**	**1,303**	1,233	1,027	**7**	11

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	Millions of Dollars					
	Pension Benefits				Other Benefits	
	2003		2002		**2003**	2002
	U.S.	**Int'l.**	U.S.	Int'l.		
Funded Status						
Excess obligation	**$ (1,560)**	**(772)**	(1,846)	(474)	**(997)**	(908)
Unrecognized net actuarial loss	**554**	**369**	697	171	**100**	60
Unrecognized prior service cost	**26**	**53**	30	5	**111**	131
Total recognized amount in the consolidated balance sheet	**$ (980)**	**(350)**	(1,119)	(298)	**(786)**	(717)
Components of above amount:						
Prepaid benefit cost	**$**	**73**		52		
Accrued benefit liability	**(999)**	**(538)**	(1,484)	(400)	**(786)**	(717)
Intangible asset	**5**	**40**	43	3		
Accumulated other comprehensive loss	**14**	**75**	322	47		
Total recognized	**$ (980)**	**(350)**	(1,119)	(298)	**(786)**	(717)
Weighted-Average Assumptions Used to Determine Benefit Obligations at December 31						
Discount rate	**6.00%**	**5.45**	6.75	5.85	**6.00**	6.75
Rate of compensation increase	**4.00**	**3.55**	4.00	3.80	**4.00**	4.00
Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for years ended December 31						
Discount rate	**6.75%**	**5.85**	7.25	6.30	**6.75**	7.25
Expected return on plan assets	**7.05**	**7.45**	8.70	7.60	**5.50**	5.20
Rate of compensation increase	**4.00**	**3.80**	4.00	3.75	**4.00**	4.00

For both U.S. and international pensions, the overall expected long-term rate of return is developed from the expected future return of each asset class, weighted by the expected allocation of pension assets to that asset class. We rely on a variety of independent market forecasts in developing the expected rate of return for each class of assets.

We use a December 31 measurement date for the majority of our plans.

During 2003, we recorded a benefit to other comprehensive income related to minimum pension liability adjustments totaling $280 million ($175 million net of tax), resulting in accumulated other comprehensive loss due to minimum pension liability adjustments at December 31, 2003, of $89 million ($61 million net of tax). During 2002, we recorded charges to other comprehensive loss totaling $149 million ($93 million net of tax), resulting in accumulated other comprehensive loss due to minimum pension liability adjustments at December 31, 2002, of $369 million ($236 million net of tax).

For our tax-qualified pension plans with projected benefit obligations in excess of plan assets, the projected benefit obligation, the accumulated benefit obligation, and the fair value of plan assets were $4,489 million, $3,661 million, and $2,415 million at December 31, 2003, respectively, and $4,288 million, $3,542 million, and $2,259 million at December 31, 2002, respectively.

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For our unfunded non-qualified supplemental key employee pension plans, the projected benefit obligation and the accumulated benefit obligation were $237 million and $177 million, respectively, at December 31, 2003, and were $260 million and $206 million, respectively, at December 31, 2002.

	Millions of Dollars								
	Pension Benefits						Other Benefits		
	2003		2002		2001		**2003**	2002	2001
	U.S.	**Int'l.**	U.S.	Int'l.	U.S.	Int'l.			
Components of Net Periodic Benefit Cost									
Service cost	$ **131**	**61**	75	32	40	15	**17**	9	4
Interest cost	**197**	**89**	133	48	82	24	**61**	31	11
Expected return on plan assets	**(90)**	**(78)**	(73)	(49)	(74)	(30)		(1)	(1)
Amortization of prior service cost	**4**	**5**	5	2	6	1	**19**	8	(1)
Recognized net actuarial loss	**70**	**17**	48	7	16		**6**	3	2
Amortization of net asset						(1)			
Net periodic benefit cost	$ **312**	**94**	188	40	70	9	**103**	50	15

As a result of the ConocoPhillips merger, we recognized settlement losses of $120 million and special termination benefits of $9 million in 2003, and we recorded curtailment losses of $23 million and special termination benefits of $98 million in 2002. During 2001, we recorded a curtailment gain of $2 million and settlement losses of $10 million.

In determining net pension and other postretirement benefit costs, we have elected to amortize net gains and losses on a straight-line basis over 10 years. Prior service cost is amortized on a straight-line basis over the average remaining service period of employees expected to receive benefits under the plan.

We have multiple non-pension postretirement benefit plans for health and life insurance. The health care plans are contributory, with participant and company contributions adjusted annually; the life insurance plans are non-contributory. For most groups of retirees, any increase in the annual health care escalation rate above 4.5 percent is borne by the participant. The weighted-average health care cost trend rate for those participants not subject to the cap is assumed to decrease gradually from 10 percent in 2004 to 5.5 percent in 2015.

The assumed health care cost trend rate impacts the amounts reported. A one-percentage-point change in the assumed health care cost trend rate would have the following effects on the 2003 amounts:

	Millions of Dollars	
	One-Percentage-Point	
	Increase	Decrease
Effect on total of service and interest cost components	$ 1	(1)
Effect on the postretirement benefit obligation	18	(14)

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In December 2003, President Bush signed into law the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act). The Act expanded Medicare to include, for the first time, coverage for prescription drugs. We sponsor retiree medical programs for most groups of employees in the United States, and we expect that this legislation will eventually reduce our costs for some of these programs. At this point, our investigation into our response to the legislation is preliminary, as we await guidance from various governmental and regulatory agencies concerning the requirements that must be met to obtain these cost reductions, as well as the manner in which such savings should be measured. Because of various uncertainties related to our response to this legislation and the appropriate accounting methodology for this event, we have elected to defer financial recognition of this legislation until the FASB issues final accounting guidance. When issued, that final guidance could require us to change previously reported information. This deferral is permitted under FASB Staff Position No. FAS 106-1, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003.

Plan Assets

The company follows a policy of broadly diversifying pension plan assets across asset classes, investment managers, and individual holdings. Asset classes that are considered appropriate include U.S. equities, non-U.S. equities, U.S. fixed income, non-U.S. fixed income, real estate, and private equity investments. Plan fiduciaries may consider and add other asset classes to the investment program from time to time. Any use of leverage is prohibited. At December 31, 2003, there were no shares of company stock included in plan assets, compared with 4,300 shares at year-end 2002. Our funding policy for U.S. plans is to contribute at least the minimum required by the Employee Retirement Income Security Act of 1974. Contributions to foreign plans are dependent upon local laws and tax regulations. In 2004, we expect to contribute approximately $400 million to our domestic qualified and non-qualified benefit plans and $100 million to our international qualified and non-qualified benefit plans.

Weighted-average asset allocations at December 31 by asset category are as follows:

	Pension			
	U.S.		International	
	2003	2002	**2003**	2002
Asset Category				
Equity securities	**62%**	55	**48**	48
Debt securities	**22**	24	**46**	47
Participating interest in annuity contract	**12**	16		
Real estate	**1**	2	**1**	1
Other	**3**	3	**5**	4
	100%	100	**100**	100

The above asset allocations are all within guidelines established by the plan fiduciaries.

A portion of the U.S. pension plan assets are held as a participating interest in an insurance annuity contract. This participating interest is calculated as the market value of investments held under this contract, less the accumulated benefit obligation covered by the contract, and was valued at $169 million and $198 million at December 31, 2003, and December 31, 2002, respectively. At both December 31, 2003, and December 31, 2002, the participating interest consisted of 62 percent debt securities and 38 percent equity securities. The participating interest is not available for meeting general pension benefit obligations in the near term. No future company contributions are required and no new benefits are being accrued under this insurance annuity contract.

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Weighted-average target asset allocations by asset category are as follows:

	Pension	
	U.S.	International
Asset Category		
Equity securities	57%	52
Debt securities	24	46
Participating interest in annuity contract	12	
Real estate	5	1
Other	2	1
	100%	100

Defined Contribution Plans
Prior to the close of business on December 31, 2002, most U.S. employees (excluding retail service station employees) were eligible to participate in either the company-sponsored Thrift Plan of Phillips Petroleum Company, the Long-Term Stock Savings Plan of Phillips Petroleum Company, the Tosco Corporation Capital Accumulation Plan, and/or the Thrift Plan for Employees of Conoco Inc. The new ConocoPhillips Savings Plan (CPSP) was created at the close of business on December 31, 2002, with the merger of the Thrift Plan of Phillips Petroleum Company into the Long-Term Stock Savings Plan of Phillips Petroleum Company. The Thrift Plan of Phillips Petroleum Company became the thrift feature of the CPSP, and the Long-Term Stock Savings Plan became the stock savings feature. On the same date, most of the accounts in the Tosco Corporation Capital Accumulation Plan were transferred into the CPSP. On October 3, 2003, the assets of the Thrift Plan for Employees of Conoco Inc. were merged into the CPSP, resulting in the CPSP becoming the primary defined contribution plan for ConocoPhillips.

At December 31, 2003, employees could deposit up to 30 percent of their pay in the thrift feature of the CPSP to a choice of 31 investment funds. ConocoPhillips matched $1 for each $1 deposited, up to 1.25 percent of pay. Company contributions charged to expense for the CPSP and the predecessor plans, excluding the stock savings feature (discussed below), were $19 million in 2003, $40 million in 2002, and $14 million in 2001.

The stock savings feature of the CPSP is a leveraged employee stock ownership plan. Employees may elect to participate in the stock savings feature by contributing 1 percent of their salaries and receiving an allocation of shares of common stock proportionate to their contributions.

In 1990, the Long-Term Stock Savings Plan of Phillips Petroleum Company (now the stock savings feature of the CPSP) borrowed funds that were used to purchase previously unissued shares of company common stock. Since the company guarantees the CPSP s borrowings, the unpaid balance is reported as a liability of the company and unearned compensation is shown as a reduction of common stockholders equity. Dividends on all shares are charged against retained earnings. The debt is serviced by the CPSP from company contributions and dividends received on certain shares of common stock held by the plan, including all unallocated shares. The shares held by the stock savings feature of the CPSP are released for allocation to participant accounts based on debt service payments on CPSP borrowings. In addition, during the period from 2004 through 2008, when no debt principal payments are scheduled to occur, the company has committed to make direct contributions of stock to the stock savings feature of the CPSP, or make prepayments on CPSP borrowings, to ensure a certain minimum level of stock allocation to participant accounts.

We recognize interest expense as incurred and compensation expense based on the fair market value of the stock contributed or on the cost of the unallocated shares released, using the shares-allocated method. We recognized total CPSP expense related to the stock savings feature of $76 million, $39 million and $33 million in 2003, 2002 and 2001, respectively, all of which was compensation expense. In 2003, 2002 and 2001, respectively, we made cash contributions to the CPSP of $0.2 million, $2 million and $17 million. In 2003, 2002 and 2001, we contributed 1,483,780 shares, 771,479 shares and 292,857 shares, respectively, of company common stock from the Compensation and Benefits Trust. The shares had a fair market value of $80 million, $41 million and $17 million, respectively. Dividends used to service debt were $28 million each in 2003, 2002 and 2001.

These dividends reduced the amount of expense recognized each period. Interest incurred on the CPSP debt in 2003, 2002 and 2001 was $5 million, $7 million and $17 million, respectively.

The total CPSP stock savings feature shares as of December 31 were:

	2003	2002
Unallocated shares	**7,077,880**	7,717,710
Allocated shares	**10,312,220**	14,925,443
Total shares	**17,390,100**	22,643,153

The fair value of unallocated shares at December 31, 2003, and 2002, was $464 million and $373 million, respectively.

We have several defined contribution plans for our international employees, each with its own terms and eligibility depending on location. Total compensation expense recognized for these international plans was approximately $20 million in 2003, and was not significant in 2002 and 2001 because the majority of these plans were acquired in the merger.

Stock-Based Compensation Plans
Under the Phillips Omnibus Securities Plan approved by shareholders in 1993, stock options and stock awards for certain employees were authorized for up to eight-tenths of 1 percent (0.8 percent) of the total outstanding shares as of December 31 of the year preceding the awards. Any shares not issued in the current year were available for future grant. Upon the adoption of the Phillips 2002 Omnibus Securities Plan discussed below, the number of shares available for issuance under the Phillips Omnibus Securities Plan was limited to 700,000. The term of the Phillips Omnibus Securities Plan ended on December 31, 2002.

In 2001, shareholders approved the Phillips 2002 Omnibus Securities Plan, which has a term of five years, from January 1, 2002, through December 31, 2006, and which is authorized to issue approximately 18,000,000 shares of company common stock. The two plans also provided for non-stock-based awards.

Shares of company stock to employees were:

	2003	2002	2001
Shares	**260,677**	1,090,082	237,849
Weighted-average fair value	**$ 48.75**	57.84	56.23

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Stock options granted under provisions of the plans and earlier plans permit purchase of our common stock at exercise prices equivalent to the average market price of the stock on the date the options were granted. The options have terms of 10 years and normally become exercisable in increments of up to one-third on each anniversary date following the date of grant. Stock Appreciation Rights (SARs) may, from time to time, be affixed to the options. Options exercised in the form of SARs permit the holder to receive stock, or a combination of cash and stock, subject to a declining cap on the exercise price.

The merger was a change-in-control event that resulted in a lapsing of restrictions on, and payout of, stock and stock option awards under the plans. We offered to exchange certain stock awards under the plans with new awards in the form of restricted stock units. These new restricted stock units were converted, at the time of the merger, into awards based on the same number of shares of our common stock.

Conoco had several stock-based compensation plans that were assumed in the merger: the 1998 Stock and Performance Incentive Plan; the 1998 Key Employee Stock Performance Plan; the 1998 Global Performance Sharing Plan; and the 2001 Global Performance Sharing Plan. Upon the merger, outstanding stock options under these plans were converted to ConocoPhillips stock options at the merger exchange ratio of 0.4677.

The Conoco plans award stock options at exercise prices equivalent to the average market price of the stock on the date the option was granted. Awards have option terms of 10 years and become exercisable based on various formulas, including those that become exercisable one year from date of grant, and those that become exercisable in increments of one-third on each anniversary date following date of grant. In total, there were 10.3 million shares of company stock at December 31, 2003, available for issuance under the Conoco plans.

In August 2002, we issued 23.3 million vested stock options to replace unexercised Conoco stock options at the time of the merger. These options had a weighted-average exercise price of $47.65 per option, and a Black-Scholes option-pricing model value of $16.50 per option. In September 2001, we issued 4.7 million vested stock options to replace unexercised Tosco stock options at the time of the acquisition. These options had a weighted-average exercise price of $23.15 per option, and a Black-Scholes option-pricing model value of $32.51 per option.

A summary of our stock option activity follows:

	Options	Weighted-Average Exercise Price
Outstanding at December 31, 2000	9,862,967	$ 43.82
Granted (including Tosco exchange)	9,038,571	38.81
Exercised	(2,373,062)	22.36
Forfeited	(96,126)	60.41
Outstanding at December 31, 2001	16,432,350	$ 44.06
Granted (including the merger)	28,830,903	48.11
Exercised	(2,032,232)	24.66
Forfeited	(124,416)	57.78
Outstanding at December 31, 2002	43,106,605	$ 47.65
Granted	**6,719,874**	**48.79**

Exercised	(3,697,271)		31.98
Forfeited	(299,631)		50.07
Outstanding at December 31, 2003	**45,829,577**	**$**	**49.07**

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The weighted-average fair market values of the options granted over the past three years, as calculated using the Black-Scholes option-pricing model, and the significant assumptions used to calculate these values were as follows:

	2003	2002	2001
Average grant date fair value of options	**$ 9.95**	11.67	23.19
Assumptions used			
Risk-free interest rate	**3.4%**	4.1	4.5
Dividend yield	**3.3%**	3.0	2.5
Volatility factor	**25.9%**	26.2	27.0
Expected life (years)	**6**	6	5

Options Outstanding at December 31, 2003

		Weighted-Average	
Exercise Prices	Options	Remaining Lives	Exercise Price
$12.16 to $41.22	**7,390,364**	**2.41 years**	**$ 34.04**
$42.42 to $49.95	**23,070,483**	**6.64 years**	**47.38**
$50.22 to $66.72	**15,368,730**	**7.52 years**	**58.82**

Options Exercisable at December 31

	Exercise Prices	Options	Weighted-Average Exercise Price
2003	**$12.16 to $41.22**	**7,217,227**	**$ 34.20**
	$42.42 to $49.95	**14,322,066**	**46.83**
	$50.22 to $66.72	**12,987,973**	**59.54**
2002	$9.04 to $31.44	5,067,979	$ 25.06
	$31.52 to $44.91	6,384,431	39.88
	$45.75 to $66.72	21,614,181	52.17

2001	$9.04 to $31.44	3,056,009	$ 22.67
	$31.52 to $44.91	3,075,354	38.06
	$45.75 to $64.43	3,525,616	48.32

For information on our 2003 adoption of SFAS No. 123, see Note 1-Accounting Policies.

Compensation and Benefits Trust (CBT)

The CBT is an irrevocable grantor trust, administered by an independent trustee and designed to acquire, hold and distribute shares of our common stock to fund certain future compensation and benefit obligations of the company. The CBT does not increase or alter the amount of benefits or compensation that will be paid under existing plans, but offers us enhanced financial flexibility in providing the funding requirements of those plans. We also have flexibility in determining the timing of distributions of shares from the CBT to fund compensation and benefits, subject to a minimum distribution schedule. The trustee votes shares held by the CBT in accordance with voting directions from eligible employees, as specified in a trust agreement with the trustee.

We sold 29.2 million shares of previously unissued company common stock to the CBT in 1995 for $37 million of cash, previously contributed to the CBT by us, and a promissory note from the CBT to us of $952 million. The CBT is consolidated by ConocoPhillips, therefore the cash contribution and promissory note are eliminated in consolidation. Shares held by the CBT are valued at cost and do not affect earnings per share or total common stockholders equity until after they are transferred out of the CBT. In 2003 and 2002, shares transferred out of the CBT were 1,483,780 and 771,479, respectively. At December 31, 2003, 25.3 million shares remained in the CBT. All shares are required to be transferred out of the CBT by January 1, 2021.

Note 23-Taxes

Taxes charged to income from continuing operations were:

	Millions of Dollars		
	2003	2002	2001
Taxes Other Than Income Taxes			
Excise	**$ 13,738**	6,246	2,177
Property	**290**	244	148
Production	**413**	303	328
Payroll	**149**	99	54
Environmental	**7**	5	14
Other	**82**	40	19
	$ 14,679	6,937	2,740
Income Taxes			
Federal			
Current	**$ 536**	64	129
Deferred	**637**	56	426
Foreign			
Current	**2,559**	1,188	842
Deferred	**(161)**	114	126
State and local			
Current	**136**	57	97
Deferred	**37**	(36)	20
	$ 3,744	1,443	1,640

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Deferred income taxes reflect the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for tax purposes. Major components of deferred tax liabilities and assets at December 31 were:

	Millions of Dollars	
	2003	2002
Deferred Tax Liabilities		
Properties, plants and equipment, and intangibles	**$ 10,436**	10,147
Investment in joint ventures	**1,490**	1,013
Inventory	**486**	385
Other	**267**	144
Total deferred tax liabilities	**12,679**	11,689
Deferred Tax Assets		
Benefit plan accruals	**1,334**	1,304
Asset retirement obligations and accrued environmental costs	**1,584**	724
Deferred state income tax	**227**	201
Other financial accruals and deferrals	**144**	311
Alternative minimum tax carryforwards	**317**	421
Operating loss and credit carryforwards	**1,105**	650
Other	**153**	394
Total deferred tax assets	**4,864**	4,005
Less valuation allowance	**906**	608
Net deferred tax assets	**3,958**	3,397
Net deferred tax liabilities	**$ 8,721**	8,292

Current assets, long-term assets, current liabilities and long-term liabilities included deferred taxes of $-0- million, $53 million, $209 million and $8,565 million, respectively, at December 31, 2003, and $68 million, $41 million, $40 million and $8,361 million, respectively, at December 31, 2002.

We have operating loss and credit carryovers in multiple taxing jurisdictions. These attributes generally expire between 2004 and 2013 with some carryovers, including the alternative minimum tax, having indefinite carryforward periods.

Valuation allowances have been established for certain operating loss and credit carryforwards that reduce deferred tax assets to an amount that will, more likely than not, be realized. Uncertainties that may affect the realization of these assets include tax law changes and the future level of product prices and costs. During 2003, valuation allowances increased $298 million. This reflects increases of $498 million primarily related to foreign tax loss carryforwards, partially offset by decreases of $200 million, primarily related to foreign tax loss carryforwards that have expired or that have been utilized. Based on our historical taxable income, its expectations for the future, and available tax-planning strategies, management expects that remaining net deferred tax assets will be realized as offsets to reversing deferred tax liabilities and as offsets to the tax consequences of future taxable income.

The Conoco purchase price allocation for the merger resulted in deferred tax liabilities of $3,841 million. Included in this amount is a valuation allowance for certain deferred tax assets of $251 million, for which subsequently recognized tax benefits, if any, will be allocated to goodwill.

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At December 31, 2003, and December 31, 2002, income considered to be permanently reinvested in certain foreign subsidiaries and foreign corporate joint ventures totaled approximately $2,046 million and $2,171 million, respectively. Deferred income taxes have not been provided on this income, as we do not plan to initiate any action that would require the payment of income taxes. It is not practicable to estimate the amount of additional tax that might be payable on this foreign income if distributed.

The amounts of U.S. and foreign income from continuing operations before income taxes, with a reconciliation of tax at the federal statutory rate with the provision for income taxes, were:

	Millions of Dollars			Percent of Pretax Income		
	2003	2002	2001	**2003**	2002	2001
Income from continuing operations before income taxes						
United States	**$ 4,137**	605	2,066	**49.6%**	28.3	63.7
Foreign	**4,200**	1,536	1,175	**50.4**	71.7	36.3
	$ 8,337	2,141	3,241	**100.0%**	100.0	100.0
Federal statutory income tax	**$ 2,918**	749	1,134	**35.0%**	35.0	35.0
Foreign taxes in excess of federal statutory rate	**792**	680	515	**9.5**	31.8	15.9
Domestic tax credits	**(25)**	(77)	(84)	**(.3)**	(3.6)	(2.6)
Write-off of acquired in-process research and development costs		86			4.0	
State income tax	**112**	14	76	**1.3**	.6	2.3
Other	**(53)**	(9)	(1)	**(.6)**	(.4)	
	$ 3,744	1,443	1,640	**44.9%**	67.4	50.6

Our 2003 tax expense was reduced by $227 million as a result of tax law changes in Norway, Canada and Timor Lesté due to adjustments of net deferred tax liabilities.

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Note 24-Other Comprehensive Income (Loss)

The components and allocated tax effects of other comprehensive income (loss) follow:

	Millions of Dollars		
	Before-Tax	Tax Expense (Benefit)	After-Tax
2003			
Minimum pension liability adjustment	**$ 271**	**103**	**168**
Unrealized gain on securities	**6**	**2**	**4**
Foreign currency translation adjustments	**865**	**228**	**637**
Hedging activities	**7**		**7**
Equity affiliates:			
Foreign currency translation	**149**		**149**
Derivatives related	**32**	**12**	**20**
Other comprehensive income	**$ 1,330**	**345**	**985**
2002			
Minimum pension liability adjustment	$ (149)	(56)	(93)
Unrealized loss on securities	(3)		(3)
Foreign currency translation adjustments	223	41	182
Hedging activities	(1)		(1)
Equity affiliates:			
Foreign currency translation	40		40
Derivatives related	(34)		(34)
Other comprehensive income	$ 76	(15)	91
2001			
Minimum pension liability adjustment	$ (220)	(77)	(143)
Unrealized loss on securities	(3)	(1)	(2)
Foreign currency translation adjustments	(14)		(14)
Hedging activities	(4)		(4)
Equity affiliates:			
Foreign currency translation	(3)		(3)
Derivatives related	17	6	11
Other comprehensive loss	$ (227)	(72)	(155)

See Note 22 Employee Benefit Plans for more information on the minimum pension liability adjustment. The after-tax amount for 2003 of $168 million includes a net charge of $7 million related to a pension plan for which we are not the primary obligor, and thus is not included in the pension disclosures in Note 22 Employee Benefit Plans. The accumulated pension liability adjustment at December 31, 2003, of $68 million also included this $7 million accumulated loss.

Unrealized gain (loss) on securities relate to available-for-sale securities held by irrevocable grantor trusts that fund certain of our domestic, non-qualified supplemental key employee pension plans.

Deferred taxes have not been provided on temporary differences related to foreign currency translation adjustments for investments in certain foreign subsidiaries and foreign corporate joint ventures that are essentially permanent in duration.

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Accumulated other comprehensive income (loss) in the equity section of the balance sheet included:

	Millions of Dollars	
	2003	2002
Minimum pension liability adjustment	$ **(68)**	(236)
Foreign currency translation adjustments	**735**	98
Unrealized gain on securities	**5**	1
Deferred net hedging gain/(loss)	**2**	(5)
Equity affiliates:		
Foreign currency translation	**150**	1
Derivatives related	**(3)**	(23)
Accumulated other comprehensive income (loss)	$ **821**	(164)

Note 25-Cash Flow Information

	Millions of Dollars		
	2003	2002	2001
Non-Cash Investing and Financing Activities			
Increase in properties, plants and equipment in exchange for related increase in asset retirement obligations associated with the initial implementation of SFAS No. 143	$ **1,229**		
Increase in properties, plants and equipment from incurrence of asset retirement obligations due to repeal of Norway Removal Grant Act	**336**		
Increase in properties, plants and equipment related to the implementation of FIN 46	**940**		
Increase in long-term debt through the implementation and continuing application of FIN 46	**2,774**		
Increase in assets of discontinued operations held for sale related to implementation of FIN 46	**726**		
The merger by issuance of stock		15,974	
Acquisition of Tosco by issuance of stock			7,049
Investment in properties, plants and equipment of businesses through the assumption of non-cash liabilities		181	125

Cash Payments			
Interest	$ **839**	441	324
Income taxes	**2,909**	1,363	1,504

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Note 26-Other Financial Information

	Millions of Dollars Except Per Share Amounts		
	2003	2002	2001
Interest			
Incurred			
Debt	$ **1,061**	740	524
Other	**110**	58	45
	1,171	798	569
Capitalized	**(327)**	(232)	(231)
Expensed	$ **844**	566	338
Research and Development Expenditures expensed	$ **136**	355*	44

* *Includes $246 million of in-process research and development expenses related to the merger.*

Advertising Expenses*	$ **70**	37	56

* *Deferred amounts at December 31 were immaterial in all three years.*

Cash Dividends paid per common share	$ **1.63**	1.48	1.40
Foreign Currency Transaction Gains (Losses) after-tax			
E&P	$ **(50)**	(34)	2
R&M	**18**	9	3
Chemicals			
Emerging Businesses	**(1)**		
Corporate and Other	**67**	21	(8)
	$ **34**	(4)	(3)

Note 27-Related Party Transactions

Significant transactions with related parties were:

	Millions of Dollars		
	2003	2002	2001
Revenues (a)	$ **3,812**	1,554	935
Purchases (b)	**3,316**	1,545	1,110
Operating expenses and selling, general and administrative expenses (c)	**560**	279	243
Net interest (income) expense (d)	**19**	(6)	8

(a) Our Exploration and Production (E&P) segment sells natural gas to Duke Energy Field Services, LLC (DEFS) and crude oil to the Malaysian Refining Company Sdn. Bhd (Melaka), among others, for processing and marketing. Natural gas liquids, solvents and petrochemical feedstocks are sold to Chevron Phillips Chemical Company LLC (CPChem) and refined products are sold primarily to CFJ Properties. Also, we charge several of our affiliates including CPChem, MSLP, Hamaca Holding LLC, and Venture Coke Company for the use of common facilities, such as steam generators, waste and water treaters, and warehouse facilities.

(b) We purchase natural gas and natural gas liquids from DEFS and CPChem for use in our refinery processes and other feedstocks from various affiliates. We purchase crude oil from Petrozuata C.A. and refined products from Melaka. We also pay fees to various pipeline equity companies for transporting finished refined products.

(c) We pay processing fees to various affiliates, the most significant being MSLP. Additionally, we pay contract drilling fees to deepwater drillship affiliates, crude oil transportation fees to pipeline equity companies, and commissions to the receivable monetization companies.

(d) We pay and/or receive interest to/from various affiliates including the receivable monetization companies and MSLP.

Elimination of our equity percentage share of profit or loss included in our inventory at December 31, 2003, 2002, and 2001, on the purchases from related parties described above was not material. Additionally, elimination of our profit or loss included in the related parties inventory at December 31, 2003, 2002, and 2001, on the revenues from related parties described above were not material.

Note 28-Segment Disclosures and Related Information

We have organized our reporting structure based on the grouping of similar products and services, resulting in five operating segments:

1) E&P This segment primarily explores for and produces crude oil, natural gas, and natural gas liquids on a worldwide basis. At December 31, 2003, E&P was producing in the United States; the Norwegian and U.K. sectors of the North Sea; Canada; Nigeria; Venezuela; the Timor Sea; offshore Australia and China; Indonesia; the United Arab Emirates; Vietnam; and Russia. The E&P segment s U.S. and international operations are disclosed separately for reporting purposes.

2) Midstream Through both consolidated and equity interests, this segment gathers and processes natural gas produced by ConocoPhillips and others, and fractionates and markets natural gas liquids, primarily in the United States, Canada and Trinidad. The Midstream segment includes our 30.3 percent equity investment in DEFS.

3) R&M This segment refines, markets and transports crude oil and petroleum products, mainly in the United States, Europe and Asia. At December 31, 2003, we owned 12 refineries in the United States; one in the United Kingdom; one in Ireland; and had equity interests in one refinery in Germany, two in the Czech Republic, and one in Malaysia. The R&M segment s U.S. and international operations are disclosed separately for reporting purposes.

4) Chemicals This segment manufactures and markets petrochemicals and plastics on a worldwide basis. The Chemicals segment consists of our 50 percent equity investment in CPChem.

5) Emerging Businesses This segment encompasses the development of new businesses beyond our traditional operations. Emerging Businesses includes new technologies related to natural gas conversion into clean fuels and related products (gas-to-liquids), technology solutions, power generation, and emerging technologies.

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Corporate and Other includes general corporate overhead; all interest income and expense; preferred dividend requirements of capital trusts; discontinued operations; restructuring charges; goodwill resulting from the merger of Conoco and Phillips that had not yet been allocated to the operating segments; certain eliminations; and various other corporate activities. Corporate assets include all cash and cash equivalents.

We evaluate performance and allocate resources based on net income. Segment accounting policies are the same as those in Note 1-Accounting Policies. Intersegment sales are at prices that approximate market.

Analysis of Results by Operating Segment

	Millions of Dollars		
	2003	2002	2001
Sales and Other Operating Revenues			
E&P			
United States	$ **18,521**	7,222	5,879
International	**12,964**	4,850	2,266
Intersegment eliminations-U.S.	**(2,439)**	(1,304)	(534)
Intersegment eliminations-international	**(3,202)**	(484)	
E&P	**25,844**	10,284	7,611
Midstream			
Total sales	**4,735**	2,049	1,193
Intersegment eliminations	**(1,431)**	(510)	(416)
Midstream	**3,304**	1,539	777
R&M			
United States	**57,222**	41,011	16,445
International	**19,454**	5,630	142
Intersegment eliminations-U.S.	**(1,815)**	(1,773)	(92)
Intersegment eliminations-international	**(13)**		
R&M	**74,848**	44,868	16,495
Chemicals	**14**	13	
Emerging Businesses	**178**	36	7
Corporate and Other	**8**	8	2

Consolidated sales and other operating revenues	**$ 104,196**	56,748	24,892
Depreciation, Depletion, Amortization and Impairments			
E&P			
United States	**$ 1,172**	999	817
International	**1,736**	735	324
Total E&P	**2,908**	1,734	1,141
Midstream	**54**	19	1
R&M			
United States	**551**	564	203
International	**140**	50	1
Total R&M	**691**	614	204
Chemicals			
Emerging Businesses	**10**	4	
Corporate and Other	**74**	29	24
Consolidated depreciation, depletion, amortization and impairments	**$ 3,737**	2,400	1,370

	Millions of Dollars		
	2003	2002	2001
Equity in Earnings of Affiliates			
E&P			
United States	$ **27**	29	9
International	**289**	162	19
Total E&P	**316**	191	28
Midstream	**138**	46	165
R&M			
United States	**89**	43	88
International	**5**		
Total R&M	**94**	43	88
Chemicals	**(6)**	(16)	(240)
Emerging Businesses		(3)	
Corporate and Other			
Consolidated equity in earnings of affiliates	$ **542**	261	41
Income Taxes			
E&P			
United States	$ **1,231**	473	670
International	**2,269**	1,337	913
Total E&P	**3,500**	1,810	1,583
Midstream	**83**	42	73
R&M			
United States	**652**	90	210

International	**64**	(11)	
Total R&M	**716**	79	210
Chemicals	**(12)**	(18)	(89)
Emerging Businesses	**(51)**	(38)	(7)
Corporate and Other	**(492)**	(432)	(130)
Consolidated income taxes	**$ 3,744**	1,443	1,640
Net Income (Loss)			
E&P			
United States	**$ 2,374**	1,156	1,342
International	**1,928**	593	357
Total E&P	**4,302**	1,749	1,699
Midstream	**130**	55	120
R&M			
United States	**990**	138	395
International	**282**	5	2
Total R&M	**1,272**	143	397
Chemicals	**7**	(14)	(128)
Emerging Businesses	**(99)**	(310)*	(12)
Corporate and Other	**(877)**	(1,918)	(415)
Consolidated net income (loss)	**$ 4,735**	(295)	1,661

* *Includes a non-cash $246 million write-off of acquired in-process research and development costs.*

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	Millions of Dollars		
	2003	2002	2001
Investments In and Advances To Affiliates			
E&P			
United States	$ **133**	156	13
International	**2,351**	2,184	573
Total E&P	**2,484**	2,340	586
Midstream	**394**	318	166
R&M			
United States	**777**	762	166
International	**517**	416	
Total R&M	**1,294**	1,178	166
Chemicals	**2,059**	2,050	1,852
Emerging Businesses	**2**		
Corporate and Other	**25**	14	18
Consolidated investments in and advances to affiliates	$ **6,258**	5,900	2,788
Total Assets			
E&P			
United States	$ **15,262**	14,196	9,501
International	**22,458**	19,526	5,280
Goodwill	**11,184**	15	15
Total E&P	**48,904**	33,737	14,796
Midstream	**1,736**	1,931	196
R&M			

United States	**17,172**	16,718	12,327
International	**5,020**	4,117	183
Goodwill	**3,900**	2,350	2,226
Total R&M	**26,092**	23,185	14,736
Chemicals	**2,094**	2,095	1,934
Emerging Businesses	**843**	737	2
Corporate and Other	**2,786**	15,151*	3,553
Consolidated total assets	**$ 82,455**	76,836	35,217

** Includes goodwill not yet allocated to reporting units of $12,079 million.*

Capital Expenditures and Investments*			
E&P			
United States	**$ 1,418**	1,205	1,354
International	**3,090**	2,071	1,162
Total E&P	**4,508**	3,276	2,516
Midstream	**10**	5	
R&M			
United States	**860**	676	423
International	**319**	164	5
Total R&M	**1,179**	840	428
Chemicals		60	6
Emerging Businesses	**284**	122	
Corporate and Other	**188**	85	66
Consolidated capital expenditures and investments	**$ 6,169**	4,388	3,016

** Includes dry hole costs.*

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Additional information on items included in Corporate and Other (on a before-tax basis unless otherwise noted):

	Millions of Dollars		
	2003	2002	2001
Interest income	$ **104**	40	13
Interest expense	**844**	566	338
Significant non-cash items			
Impairments included in discontinued operations	**96**	1,048	
Loss accruals related to retail site leases included in discontinued operations		477	
Restructuring charges, net of benefits paid		269	

Geographic Information

	Millions of Dollars					
	United States	Norway	United Kingdom	Canada	Other Foreign Countries	Worldwide Consolidated
2003						
Sales and Other Operating Revenues*	$ **74,768**	**3,068**	**11,203**	**2,735**	**12,422**	**104,196**
Long-Lived Assets**	$ **29,899**	**4,215**	**5,762**	**4,347**	**9,463**	**53,686**
2002						
Sales and Other Operating Revenues*	$ 46,674	1,850	3,387	997	3,840	56,748
Long-Lived Assets**	$ 28,492	3,767	4,969	3,460	8,242	48,930
2001						
Sales and Other Operating Revenues*	$ 22,466	1,322	380	42	682	24,892
Long-Lived Assets**	$ 19,955	1,484	654	29	2,799	24,921

* *Sales and other operating revenues are attributable to countries based on the location of the operations generating the revenues.*

** *Defined as net properties, plants and equipment plus investments in and advances to affiliates.*

Note 29-New Accounting Standards

In December 2003, the FASB revised and reissued SFAS No. 132 (revised 2003), Employers Disclosures about Pensions and Other Postretirement Benefits-an amendment of FASB Statements No. 87, 88, and 106, which revises and requires additional disclosures about pension plans and other postretirement benefit plans. It does not change the measurement or recognition of those plans required by previous Financial Accounting Board Standards. We adopted the provisions of this Standard effective December 2003. Certain provisions of this Standard regarding disclosure of information about foreign plans and disclosure of estimated future benefit payments are not required until 2004. The adoption of the

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provisions applicable to 2003 did not have an impact on our results of operations or financial position, nor will the adoption of the additional provisions in 2004 have an impact on our results of operations or financial position.

In May 2003, the FASB issued SFAS No. 150, Accounting for Certain Financial Instruments with Characteristics of Liabilities and Equity, to address the balance sheet classification of certain financial instruments that have characteristics of both liabilities and equity. This statement was immediately effective for all contracts created or modified after May 31, 2003, and became effective July 1, 2003, for all previously existing contracts. On November 7, 2003, the FASB issued FASB Staff Position No. FAS 150-3, which deferred certain provisions of SFAS No. 150. As a result of adopting this new accounting standard in the third quarter of 2003, and the subsequent November 7, 2003, deferral of certain provisions, there was no impact on our 2003 financial statements. We continue to monitor the deferral status of SFAS No. 150.

Oil and Gas Operations (Unaudited)
Exploration and Production

In accordance with SFAS No. 69, Disclosures about Oil and Gas Producing Activities, and regulations of the U.S. Securities and Exchange Commission (SEC), we are making certain supplemental disclosures about our oil and gas exploration and production operations. While this information was developed with reasonable care and disclosed in good faith, it is emphasized that some of the data is necessarily imprecise and represents only approximate amounts because of the subjective judgments involved in developing such information. Accordingly, this information may not necessarily represent our current financial condition or our expected future results.

Our disclosures by geographic area include the United States (U.S.), European North Sea (Norway and the United Kingdom), Asia Pacific, Canada and Other Areas. When we use equity accounting for operations that have proved reserves, these oil and gas operations are shown separately and designated as Equity Affiliates. In 2003 and 2002, these consisted of two heavy-oil projects in Venezuela, an oil development project in Northern Russia and a heavy-oil project in Canada. In 2001, this consisted of a heavy-oil project in Venezuela.

Amounts in 2002 were impacted by the merger of Conoco and Phillips (the merger) in late August 2002.

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n **Proved Reserves Worldwide**

Years Ended December 31	Crude Oil									
	Millions of Barrels									
	Consolidated Operations									
	Alaska	Lower 48	Total U.S.	European North Sea	Asia Pacific	Canada	Other Areas	Total	Equity Affiliates	Combined Total
Developed and Undeveloped										
End of 2000	1,604	112	1,716	609	136	2	112	2,575	613	3,188
Revisions	77	(2)	75	45	9		(5)	124	48	172
Improved recovery	67	1	68	12				80		80
Purchases					17			17		17
Extensions and discoveries	9	6	15	2	2		10	29		29
Production	(126)	(12)	(138)	(49)	(6)		(13)	(206)	(1)	(207)
Sales							(3)	(3)		(3)
End of 2001	1,631	105	1,736	619	158*	2	101	2,616	660	3,276
Revisions	32	(8)	24	(31)	(28)	5	(4)	(34)	(27)	(61)
Improved recovery	46	1	47	7				54		54
Purchases		132	132	405	124	101	99	861	733	1,594
Extensions and discoveries	14	6	20	6	9	1	13	49	4	53
Production	(120)	(14)	(134)	(72)	(9)	(5)	(15)	(235)	(13)	(248)
Sales		(2)	(2)	(20)		(13)	(1)	(36)		(36)
End of 2002	1,603	220	1,823	914	254**	91	193	3,275	1,357	4,632
Revisions	**35**	**(5)**	**30**	**15**	**40**	**(9)**	**(4)**	**72**	**48**	**120**
Improved recovery	**15**	**1**	**16**	**47**			**1**	**64**		**64**
Purchases					**5**			**5**	**1**	**6**
Extensions and discoveries	**19**	**4**	**23**	**4**	**10**	**223**	**10**	**270**	**8**	**278**
Production	**(119)**	**(19)**	**(138)**	**(106)**	**(24)**	**(11)**	**(27)**	**(306)**	**(37)**	**(343)**
Sales		**(15)**	**(15)**	**(9)**	**(21)**	**(20)**	**(25)**	**(90)**		**(90)**
End of 2003	**1,553**	**186**	**1,739**	**865**	**264**	**274**	**148**	**3,290**	**1,377**	**4,667**

Developed										
End of 2000	1,207	98	1,305	503	16	2	100	1,926		1,926
End of 2001	1,275	91	1,366	534	13	2	83	1,998	47	2,045
End of 2002	1,335	169	1,504	713	55	81	168	2,521	378	2,899
End of 2003	**1,365**	**163**	**1,528**	**454**	**95**	**51**	**137**	**2,265**	**529**	**2,794**

**Includes proved reserves of 17 million barrels attributable to a consolidated subsidiary in which there is a 13 percent minority interest.*

***Includes proved reserves of 14 million barrels attributable to a consolidated subsidiary in which there is a 10 percent minority interest.*

- n Purchases in 2002 were primarily related to the merger.

- n At the end of 2000, Other Areas included 2 million barrels of reserves in Venezuela in which we had an economic interest through risk-service contracts. These properties were sold in June 2001. Our net production related to these contracts was approximately 400,000 barrels in 2001 and 1,200,000 barrels in 2000.

- n In addition to conventional crude oil, natural gas and natural gas liquids (NGL) proved reserves, we have proved oil sands reserves in Canada, associated with a Syncrude project totaling 265 million barrels at the end of 2003. For internal management purposes, we view these reserves and their development as part of our total exploration and production operations. However, U.S. Securities and Exchange Commission regulations define these reserves as mining related. Therefore, they are not included in our tabular presentation of proved crude oil, natural gas and NGL reserves. These oil sands reserves also are not included in the standardized measure of discounted future net cash flows relating to proved oil and gas reserve quantities.

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Years Ended December 31	Natural Gas									
	Billions of Cubic Feet									
	Consolidated Operations									
	Alaska	Lower 48	Total U.S.	European North Sea	Asia Pacific	Canada	Other Areas	Total	Equity Affiliates	Combined Total
Developed and Undeveloped										
End of 2000	3,237	2,853	6,090	1,624	64	64	561	8,403	131	8,534
Revisions	60	9	69	(124)	(1)	(2)	65	7	14	21
Improved recovery				13				13		13
Purchases		12	12	10	10			32		32
Extensions and discoveries	5	405	410	23	265		109	807		807
Production	(141)	(261)	(402)	(121)	(21)	(7)	(19)	(570)		(570)
Sales				(8)				(8)		(8)
End of 2001	3,161	3,018	6,179	1,417	317*	55	716	8,684	145	8,829
Revisions	(27)	(70)	(97)	(20)	(60)	16	(15)	(176)		(176)
Improved recovery	5	1	6	14				20		20
Purchases		1,862	1,862	2,583	1,856	1,241	206	7,748	17	7,765
Extensions and discoveries	2	225	227	43	6	21	414	711	1	712
Production	(147)	(340)	(487)	(226)	(49)	(59)	(19)	(840)	(2)	(842)
Sales	(5)	(1)	(6)	(4)		(97)	(161)	(268)		(268)
End of 2002	2,989	4,695	7,684	3,807	2,070**	1,177	1,141	15,879	161	16,040
Revisions	**75**	**(140)**	**(65)**	**17**	**(79)**	**(51)**		**(178)**	**65**	**(113)**
Improved recovery	**6**	**1**	**7**	**51**			**1**	**59**		**59**
Purchases		**39**	**39**		**60**			**99**		**99**
Extensions and discoveries		**254**	**254**	**65**	**1,371**	**90**	**85**	**1,865**	**5**	**1,870**
Production	**(148)**	**(477)**	**(625)**	**(462)**	**(121)**	**(159)**	**(35)**	**(1,402)**	**(5)**	**(1,407)**
Sales		**(114)**	**(114)**	**(60)**	**(295)**	**(15)**	**(4)**	**(488)**		**(488)**
End of 2003	**2,922**	**4,258**	**7,180**	**3,418**	**3,006**	**1,042**	**1,188**	**15,834**	**226**	**16,060**

Developed										
End of 2000	2,969	2,564	5,533	1,059	1	54	335	6,982		6,982
End of 2001	2,969	2,684	5,653	1,053	245	45	491	7,487	3	7,490
End of 2002	2,806	4,302	7,108	3,278	832	1,098	517	12,833	28	12,861
End of 2003	**2,763**	**3,968**	**6,731**	**2,748**	**1,342**	**971**	**596**	**12,388**	**123**	**12,511**

**Includes proved reserves of 10 billion cubic feet attributable to a consolidated subsidiary in which there is a 13 percent minority interest.*

***Includes proved reserves of 10 billion cubic feet attributable to a consolidated subsidiary in which there is a 10 percent minority interest.*

- n Natural gas production may differ from gas production (delivered for sale) in our statistics disclosure, primarily because the quantities above include gas consumed at the lease, but omit the gas equivalent of liquids extracted at any of our owned, equity-affiliate, or third-party processing plant or facility.
- n Purchases in 2002 were related to the merger.
- n Natural gas reserves are computed at 14.65 pounds per square inch absolute and 60 degrees Fahrenheit.

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Years Ended December 31	Natural Gas Liquids									
	Millions of Barrels									
	Consolidated Operations									
	Alaska	Lower 48	Total U.S.	European North Sea	Asia Pacific	Canada	Other Areas	Total	Equity Affiliates	Combined Total
Developed and Undeveloped										
End of 2000	198	96	294	37	60		18	409		409
Revisions	(25)	2	(23)		5		(1)	(19)		(19)
Improved recovery				1				1		1
Purchases					10			10		10
Extensions and discoveries		2	2					2		2
Production	(9)	(7)	(16)	(2)			(1)	(19)		(19)
End of 2001	164	93	257	36	75*		16	384		384
Revisions	(4)	5	1	(1)	(11)			(11)		(11)
Improved recovery		1	1					1		1
Purchases		80	80	14	20	38	1	153		153
Extensions and discoveries		4	4			1		5		5
Production	(9)	(9)	(18)	(3)		(2)	(1)	(24)		(24)
Sales						(2)	(1)	(3)		(3)
End of 2002	151	174	325	46	84**	35	15	505		505
Revisions	**(2)**	**35**	**33**	**3**	**(5)**	**(1)**	**1**	**31**		**31**
Improved recovery				**2**				**2**		**2**
Purchases					**3**			**3**		**3**
Extensions and discoveries		**2**	**2**		**10**	**2**		**14**		**14**
Production	**(8)**	**(17)**	**(25)**	**(5)**		**(4)**	**(1)**	**(35)**		**(35)**
Sales		**(1)**	**(1)**		**(13)**	**(2)**		**(16)**		**(16)**
End of 2003	**141**	**193**	**334**	**46**	**79**	**30**	**15**	**504**		**504**
Developed										
End of 2000	197	94	291	29		1	17	338		338

End of 2001	163	92	255	31			16	302		302
End of 2002	151	166	317	40		30	15	402		402
End of 2003	**141**	**188**	**329**	**26**		**27**	**15**	**397**		**397**

**Includes proved reserves of 10 million barrels attributable to a consolidated subsidiary in which there is a 13 percent minority interest.*

***Includes proved reserves of 9 million barrels attributable to a consolidated subsidiary in which there is a 10 percent minority interest.*

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n Natural gas liquids reserves include estimates of natural gas liquids to be extracted from our leasehold gas at our gas processing plants or facilities. Estimates are based at the wellhead and assume full extraction. Production above differs from natural gas liquids production per day delivered for sale primarily due to:

(1) Natural gas consumed at the lease.

(2) Natural gas liquids production delivered for sale includes only natural gas liquids extracted from our leasehold gas and sold by our Exploration and Production (E&P) segment, whereas the production above also includes natural gas liquids extracted from our leasehold gas at equity-affiliate or third-party facilities.

n Purchases in 2002 were related to the merger.

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n **Results of Operations**

Years Ended December 31	Millions of Dollars									
	Consolidated Operations									
	Alaska	Lower 48	Total U.S.	European North Sea	Asia Pacific	Canada	Other Areas	Total	Equity Affiliates	Combined Total
2003										
Sales	**$ 3,564**	**2,464**	**6,028**	**3,872**	**879**	**225**	**677**	**11,681**	**423**	**12,104**
Transfers	**103**	**545**	**648**	**903**	**142**	**841**	**77**	**2,611**	**266**	**2,877**
Other revenues	**(11)**	**93**	**82**	**8**	**33**	**31**	**10**	**164**	**34**	**198**
Total revenues	**3,656**	**3,102**	**6,758**	**4,783**	**1,054**	**1,097**	**764**	**14,456**	**723**	**15,179**
Production costs	**792**	**657**	**1,449**	**645**	**175**	**271**	**170**	**2,710**	**179**	**2,889**
Exploration expenses	**56**	**143**	**199**	**121**	**51**	**94**	**127**	**592**	**2**	**594**
Depreciation, depletion and amortization	**436**	**571**	**1,007**	**954**	**163**	**326**	**40**	**2,490**	**104**	**2,594**
Property impairments		**65**	**65**	**160**		**5**		**230**		**230**
Transportation costs	**666**	**188**	**854**	**266**	**40**	**40**	**23**	**1,223**	**20**	**1,243**
Other related expenses	**7**	**78**	**85**	**29**	**13**	**91**	**44**	**262**	**27**	**289**
Accretion	**25**	**18**	**43**	**50**	**5**	**11**	**2**	**111**	**2**	**113**
	1,674	**1,382**	**3,056**	**2,558**	**607**	**259**	**358**	**6,838**	**389**	**7,227**
Provision for income taxes	**595**	**486**	**1,081**	**1,539**	**225**	**57**	**362**	**3,264**	**83**	**3,347**
Results of operations for producing activities	**1,079**	**896**	**1,975**	**1,019**	**382**	**202**	**(4)**	**3,574**	**306**	**3,880**
Other earnings	**223**	**34**	**257**	**51**	**3**	**68***	**(46)**	**333**	**(51)**	**282**
Cumulative effect of accounting change	**143**	**(1)**	**142**	**20**		**(8)**	**(12)**	**142**	**(2)**	**140**
E&P net income (loss)	**$ 1,445**	**929**	**2,374**	**1,090**	**385**	**262**	**(62)**	**4,049**	**253**	**4,302**

2002										
Sales	$ 2,997	927	3,924	1,194	347	125	400	5,990	180	6,170
Transfers	102	401	503	1,315		235		2,053	62	2,115
Other revenues	(2)	3	1	63	7	7	14	92	12	104
Total revenues	3,097	1,331	4,428	2,572	354	367	414	8,135	254	8,389
Production costs	769	444	1,213	343	76	118	114	1,864	57	1,921
Exploration expenses	101	108	209	67	45	32	231	584		584
Depreciation, depletion and amortization	552	334	886	480	59	105	26	1,556	30	1,586
Property impairments	4	8	12	41				53		53
Transportation costs	681	87	768	125	10		5	908	8	916
Other related expenses	23	16	39	75	1	14	11	140	12	152
	967	334	1,301	1,441	163	98	27	3,030	147	3,177
Provision for income taxes	294	66	360	981	79	49	196	1,665	(18)	1,647
Results of operations for producing activities	673	268	941	460	84	49	(169)	1,365	165	1,530
Other earnings	197	18	215	10	(2)	24*	(4)	243	(24)	219
E&P net income (loss)	$ 870	286	1,156	470	82	73	(173)	1,608	141	1,749
2001										
Sales	$ 3,020	1,178	4,198	546	154	31	324	5,253	8	5,261
Transfers	119	119	238	1,039				1,277		1,277
Other revenues	34	26	60	23	(4)	5		84	1	85
Total revenues	3,173	1,323	4,496	1,608	150	36	324	6,614	9	6,623
Production costs	784	328	1,112	165	37	6	55	1,375	2	1,377
Exploration expenses	61	69	130	31	33		121	315		315
Depreciation, depletion and	531	203	734	233	22	4	27	1,020	2	1,022

amortization										
Property impairments							23	23		23
Transportation costs	726	77	803	60		3	6	872		872
Other related expenses	2	5	7	(8)	5	1	23	28	2	30
	1,069	641	1,710	1,127	53	22	69	2,981	3	2,984
Provision for income taxes	392	173	565	779	22	7	117	1,490		1,490
Results of operations for producing activities	677	468	1,145	348	31	15	(48)	1,491	3	1,494
Other earnings	189	8	197	17			(9)	205		205
E&P net income (loss)	$ 866	476	1,342	365	31	15	(57)	1,696	3	1,699

* *Includes $63 million and $27 million in 2003 and 2002, respectively, for a Syncrude oil project in Canada that is defined as a mining operation by U.S. Securities and Exchange Commission regulations.*

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- n Results of operations for producing activities consist of all the activities within the E&P organization, except for pipeline and marine operations, liquefied natural gas operations, a Canadian Syncrude operation, and crude oil and gas marketing activities, which are included in Other earnings. Also excluded are non-E&P activities, including our Midstream segment, downstream petroleum and chemical activities, as well as general corporate administrative expenses and interest.

- n Transfers are valued at prices that approximate market.

- n Other revenues include gains and losses from asset sales, including net gains of approximately $165 million in 2003; certain amounts resulting from the purchase and sale of hydrocarbons; and other miscellaneous income.

- n Production costs consist of costs incurred to operate and maintain wells and related equipment and facilities used in the production of petroleum liquids and natural gas. These costs also include taxes other than income taxes, depreciation of support equipment and administrative expenses related to the production activity. Excluded are transportation costs, fees for processing natural gas to natural gas liquids, depreciation, depletion and amortization of capitalized acquisition, exploration and development costs.

- n Exploration expenses include dry hole, leasehold impairment, geological and geophysical expenses, the cost of retaining undeveloped leaseholds, and depreciation of support equipment and administrative expenses related to the exploration activity.

  Exploration expenses for Other Areas in 2002 included $77 million for the impairment of a substantial portion of the company s investment in deepwater Block 34, offshore Angola. Initial results released in early May 2002 indicated that the first exploratory well drilled in Block 34 was a dry hole, resulting in our reassessment of the fair value of the remainder of the block. In December 2003, a second exploration well was drilled, which encountered non-commercial gas and was plugged and abandoned. As a result, additional exploration expenses in 2003 included $34 million related to the impairment of the remaining value of this block.

- n Depreciation, depletion and amortization (DD&A) in Results of Operations differs from that shown for total E&P in Note 28 Segment Disclosures and Related Information in the Notes to Consolidated Financial Statements, mainly due to depreciation of support equipment being reclassified to production or exploration expenses, as applicable, in Results of Operations. In addition, Other earnings include certain E&P activities, including their related DD&A charges.

- n Property impairments for the European North Sea in 2003 included a charge of $94 million related to the repeal of the Norway Removal Grant Act.

- n Transportation costs include costs to transport our produced oil, natural gas or natural gas liquids to their points of sale, as well as, processing fees paid to process natural gas to natural gas liquids. The profit element of transportation operations in which we have an ownership interest are deemed to be outside the oil and gas producing activity. The net income of the transportation operations is included in Other earnings.

- n Other related expenses include foreign currency gains and losses, and other miscellaneous expenses.

- The provision for income taxes is computed by adjusting each country s income before income taxes for permanent differences related to the oil and gas producing activities that are reflected in our consolidated income tax expense for the period, multiplying the result by the country s statutory tax rate and adjusting for applicable tax credits. In 2003, this included a $105 million benefit related to the repeal of the Norway Removal Grant Act, a $95 million benefit related to the reduction in the Canada and Alberta provincial tax rates, a $46 million benefit related to the impairment of Angola Block 34, and a $27 million benefit related to the re-alignment agreement of the Bayu-Undan project in the Timor Sea.

- Other earnings consist of activities within the E&P segment that are not a part of the Results of operations for producing activities. These non-producing activities include pipeline and marine operations, liquefied natural gas operations, a Canadian Syncrude operation, and crude oil and gas marketing activities.

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n **Statistics**

Net Production	**2003**	2002	2001
	Thousands of Barrels Daily		
Crude Oil			
Alaska	**325**	331	339
Lower 48	**54**	40	34
United States	**379**	371	373
European North Sea	**290**	196	136
Asia Pacific	**61**	24	17
Canada	**30**	13	1
Other areas	**72**	43	34
Total consolidated	**832**	647	561
Equity affiliates	**102**	35	2
	934	682	563
Natural Gas Liquids*			
Alaska	**23**	24	25
Lower 48	**25**	8	1
United States	**48**	32	26
European North Sea	**9**	8	7
Canada	**10**	4	
Other areas	**2**	2	2
	69	46	35

**Represents amounts extracted attributable to E&P operations (see natural gas liquids reserves for further discussion). Includes for 2003, 2002 and 2001, 15,000, 14,000, and 15,000 barrels daily in Alaska, respectively, that were sold from the Prudhoe Bay lease to the Kuparuk lease for reinjection to enhance crude oil production.*

	Millions of Cubic Feet Daily		
Natural Gas*			
Alaska	**184**	175	177

Lower 48	**1,295**	928	740
United States	**1,479**	1,103	917
European North Sea	**1,215**	595	308
Asia Pacific	**318**	137	51
Canada	**435**	165	18
Other areas	**63**	43	41
Total consolidated	**3,510**	2,043	1,335
Equity affiliates	**12**	4	
	3,522	2,047	1,335

**Represents quantities available for sale. Excludes gas equivalent of natural gas liquids shown above.*

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	2003	2002	2001
Average Sales Price			
Crude Oil Per Barrel			
Alaska	$ **28.87**	23.75	23.60
Lower 48	**28.76**	24.48	23.27
United States	**28.85**	23.83	23.57
European North Sea	**28.83**	25.24	24.09
Asia Pacific	**27.87**	26.33	24.27
Canada	**25.06**	22.87	26.96
Other areas	**27.68**	24.76	24.32
Total international	**28.27**	25.14	24.16
Total consolidated	**28.54**	24.38	23.77
Equity affiliates	**18.58**	18.41	12.36
Worldwide	**27.47**	24.07	23.74
Average Sales Price			
Natural Gas Liquids Per Barrel			
Alaska	$ **29.04**	23.48	23.61
Lower 48	**20.02**	15.66	22.47
United States	**22.30**	20.00	23.49
European North Sea	**21.34**	17.38	17.12
Canada	**23.93**	20.39	18.77
Other areas	**7.24**	7.23	7.22
Total international	**21.39**	17.47	14.61
Worldwide	**21.95**	18.93	19.74
Average Sales Price			
Natural Gas (Lease) Per Thousand Cubic Feet			
Alaska	$ **1.76**	1.85	1.75
Lower 48	**4.76**	2.79	3.68
United States	**4.62**	2.75	3.56
European North Sea	**3.63**	3.00	3.16
Asia Pacific	**3.56**	2.34	.43
Canada	**4.48**	3.03	3.80
Other areas	**.58**	.48	.57
Total international	**3.71**	2.79	2.60
Total consolidated	**4.07**	2.77	3.23
Equity affiliates	**4.44**	2.71	
Worldwide	**4.07**	2.77	3.23
Average Production Costs Per Barrel of Oil Equivalent			
Alaska	$ **5.73**	5.48	5.46

Lower 48	**6.10**	6.00	5.67
United States	**5.89**	5.66	5.52
European North Sea	**3.52**	3.10	2.33
Asia Pacific	**4.20**	4.45	3.98
Canada	**6.60**	7.26	4.08
Other areas	**5.51**	5.99	3.52
Total international	**4.25**	3.99	2.70
Total consolidated	**5.00**	4.94	4.60
Equity affiliates	**4.72**	4.38	2.74
Worldwide	**4.98**	4.92	4.60

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		2003	2002	2001
Depreciation, Depletion and Amortization Per Barrel of Oil Equivalent				
Alaska	$	**3.15**	3.94	3.70
Lower 48		**5.31**	4.52	3.51
United States		**4.10**	4.14	3.64
European North Sea		**5.21**	4.34	3.28
Asia Pacific		**3.92**	3.46	2.37
Canada		**7.94**	6.46	2.72
Other areas		**1.30**	1.37	1.73
Total international		**5.00**	4.11	2.94
Total consolidated		**4.59**	4.13	3.41
Equity affiliates		**2.74**	2.30	2.74
Worldwide		**4.47**	4.06	3.41

Net Wells Completed*	Productive			Dry		
	2003	2002	2001	**2003**	2002	2001
Exploratory						
Alaska			1	**1**	4	1
Lower 48	**35**	29	63	**23**	6	3
United States	**35**	29	64	**24**	10	4
European North Sea	**1**	**	**	**2**	2	1
Asia Pacific		**	2	**2**	7	1
Canada	**72**	19		**16**	2	
Other areas		2		**	**	
Total consolidated	**108**	50	66	**44**	21	6
Equity affiliates	**23**	3		**6**	1	
	131	53	66	**50**	22	6
Development						
Alaska	**39**	48	47	**1**	1	2
Lower 48	**283**	283	333	**7**	14	11

United States	**322**	331	380	**8**	15	13
European North Sea	**12**	11	4			
Asia Pacific	**19**	9	1	**2**		
Canada	**114**	20	5	**5**	1	
Other areas	**11**	4	1		**	
Total consolidated	**478**	375	391	**15**	16	13
Equity affiliates	**98**	49	20	**3**	1	
	576	424	411	**18**	17	13

* *Includes wildcat and production step-out wells. Excludes farmout arrangements.*
** *Our total proportionate interest was less than one.*

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Wells at Year-End 2003

	In Progress*		Productive** Oil		Productive** Gas	
	Gross	Net	Gross	Net	Gross	Net
Alaska	**16**	**10**	**1,460**	**662**	**27**	**18**
Lower 48	**118**	**80**	**9,343**	**4,412**	**14,772**	**8,545**
United States	**134**	**90**	**10,803**	**5,074**	**14,799**	**8,563**
European North Sea	**20**	**5**	**584**	**98**	**253**	**85**
Asia Pacific	**41**	**24**	**381**	**177**	**55**	**28**
Canada	**73**	**53**	**2,153**	**1,419**	**4,754**	**3,061**
Other areas	**18**	**3**	**506**	**135**	**13**	**3**
Total consolidated	**286**	**175**	**14,427**	**6,903**	**19,874**	**11,740**
Equity affiliates	**7**	**3**	**2,198**	**919**	**212**	**75**
	293	**178**	**16,625**	**7,822**	**20,086**	**11,815**

**Includes wells that have been temporarily suspended.*
***Includes 3,274 gross and 1,970 net multiple completion wells.*

Acreage at December 31, 2003	Thousands of Acres Gross	Thousands of Acres Net
Developed		
Alaska	**1,021**	**568**
Lower 48	**5,347**	**3,085**
United States	**6,368**	**3,653**
European North Sea	**1,154**	**336**
Asia Pacific	**4,538**	**1,993**
Canada	**4,705**	**2,328**
Other areas	**544**	**104**
Total consolidated	**17,309**	**8,414**
Equity affiliates	**695**	**239**
	18,004	**8,653**
Undeveloped		
Alaska	**2,164**	**1,406**
Lower 48	**2,883**	**1,681**

United States	**5,047**	**3,087**
European North Sea	**6,056**	**1,783**
Asia Pacific	**27,223**	**17,473**
Canada	**12,604**	**8,076**
Other areas	**34,163**	**12,748**
Total consolidated	**85,093**	**43,167**
Equity affiliates	**1,826**	**806**
	86,919	**43,973**

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n **Costs Incurred**

	Millions of Dollars									
	Consolidated Operations									
	Alaska	Lower 48	Total U.S.	European North Sea	Asia Pacific	Canada	Other Areas	Total	Equity Affiliates	Combined Total
2003										
Unproved property acquisition	**$ 10**	**7**	**17**		**3**		**64**	**84**		**84**
Proved property acquisition		**6**	**6**	**(92)**	**27**	**20**	**(43)**	**(82)**	**(10)**	**(92)**
	10	**13**	**23**	**(92)**	**30**	**20**	**21**	**2**	**(10)**	**(8)**
Exploration	**65**	**164**	**229**	**105**	**101**	**152**	**167**	**754**	**12**	**766**
Development	**386**	**693**	**1,079**	**1,075**	**844**	**197**	**194**	**3,389**	**333**	**3,722**
	$ 461	**870**	**1,331**	**1,088**	**975**	**369**	**382**	**4,145**	**335**	**4,480**
2002										
Unproved property acquisition	$ 9	315	324	679	388	559	194	2,144		2,144
Proved property acquisition		3,420	3,420	3,719	1,385	2,003	97	10,624	1,671	12,295
	9	3,735	3,744	4,398	1,773	2,562	291	12,768	1,671	14,439
Exploration	93	112	205	61	55	58	202	581	1	582
Development	434	409	843	406	787	46	122	2,204	467	2,671
	$ 536	4,256	4,792	4,865	2,615	2,666	615	15,553	2,139	17,692
2001										
Unproved property acquisition	$ 17	24	41				165	206		206
Proved property acquisition		13	13		63			76		76
	17	37	54		63		165	282		282
Exploration	91	57	148	44	38		185	415		415
Development	612	312	924	169	349	3	52	1,497	420	1,917
	$ 720	406	1,126	213	450	3	402	2,194	420	2,614

- Costs incurred include capitalized and expensed items.
- Acquisition costs include the costs of acquiring proved and unproved oil and gas properties. Proved property acquisition costs in 2003 included net negative merger-related adjustments totaling $178 million. Acquisition costs in 2002 related primarily to the merger.
- Exploration costs include geological and geophysical expenses, the cost of retaining undeveloped leaseholds, and exploratory drilling costs.
- Development costs include the cost of drilling and equipping development wells and building related production facilities for extracting, treating, gathering and storing petroleum liquids and natural gas.
- Approximately $1,211 million of properties, plants and equipment adjustments related to the cumulative effect of accounting changes in connection with the implementation of SFAS No. 143, Accounting for Asset Retirement Obligations, has been excluded from the 2003 costs incurred.
- Costs incurred for the European North Sea in 2003 included approximately $430 million of increased properties, plants and equipment related to the repeal of the Norway Removal Grant Act.

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n **Capitalized Costs**

At December 31	Millions of Dollars									
	Consolidated Operations									
	Alaska	Lower 48	Total U.S.	European North Sea	Asia Pacific	Canada	Other Areas	Total	Equity Affiliates	Combined Total
2003										
Proved properties	**$ 7,664**	**7,388**	**15,052**	**11,534**	**3,835**	**2,700**	**918**	**34,039**	**3,252**	**37,291**
Unproved properties	**936**	**458**	**1,394**	**509**	**642**	**658**	**1,059**	**4,262**		**4,262**
	8,600	**7,846**	**16,446**	**12,043**	**4,477**	**3,358**	**1,977**	**38,301**	**3,252**	**41,553**
Accumulated depreciation, depletion and amortization	**2,166**	**2,481**	**4,647**	**4,261**	**421**	**561**	**602**	**10,492**	**161**	**10,653**
	$ 6,434	**5,365**	**11,799**	**7,782**	**4,056**	**2,797**	**1,375**	**27,809**	**3,091**	**30,900**
2002										
Proved properties	$ 7,037	7,737	14,774	9,600	3,140	2,023	692	30,229	2,847	33,076
Unproved properties	849	489	1,338	764	582	546	974	4,204		4,204
	7,886	8,226	16,112	10,364	3,722	2,569	1,666	34,433	2,847	37,280
Accumulated depreciation, depletion and amortization	1,636	2,891	4,527	3,257	205	182	456	8,627	37	8,664
	$ 6,250	5,335	11,585	7,107	3,517	2,387	1,210	25,806	2,810	28,616

n Capitalized costs include the cost of equipment and facilities for oil and gas producing activities. These costs include the activities of our E&P organization, excluding pipeline and marine operations, liquefied natural gas operations, a Canadian Syncrude operation, and crude oil and natural gas marketing activities.

n Proved properties include capitalized costs for oil and gas leaseholds holding proved reserves; development wells and related equipment and facilities (including uncompleted development well costs); and support equipment.

n Unproved properties include capitalized costs for oil and gas leaseholds under exploration (including where petroleum liquids and natural gas were found but determination of the economic viability of the required infrastructure is dependent upon further exploratory work under way or firmly planned) and for uncompleted exploratory well costs, including exploratory wells under evaluation.

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n **Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserve Quantities**

Amounts are computed using year-end prices and costs (adjusted only for existing contractual changes), appropriate statutory tax rates and a prescribed 10 percent discount factor. Continuation of year-end economic conditions also is assumed. The calculation is based on estimates of proved reserves, which are revised over time as new data become available. Probable or possible reserves, which may become proved in the future, are not considered. The calculation also requires assumptions as to the timing of future production of proved reserves, and the timing and amount of future development, including dismantlement, and production costs.

While due care was taken in its preparation, we do not represent that this data is the fair value of our oil and gas properties, or a fair estimate of the present value of cash flows to be obtained from their development and production.

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Discounted Future Net Cash Flows

	Millions of Dollars									
	Consolidated Operations									
	Alaska	Lower 48	Total U.S.	European North Sea	Asia Pacific	Canada	Other Areas	Total	Equity Affiliates	Combined Total
2003										
Future cash inflows	**$ 54,351**	**29,865**	**84,216**	**41,125**	**18,277**	**10,107**	**5,075**	**158,800**	**32,622**	**191,422**
Less:										
Future production and transportation costs	**21,557**	**7,559**	**29,116**	**10,429**	**4,480**	**3,974**	**2,068**	**50,067**	**5,823**	**55,890**
Future development costs	**4,104**	**1,404**	**5,508**	**5,358**	**1,163**	**1,111**	**283**	**13,423**	**1,510**	**14,933**
Future income tax provisions	**9,879**	**5,162**	**15,041**	**15,616**	**4,487**	**1,084**	**2,176**	**38,404**	**8,049**	**46,453**
Future net cash flows	**18,811**	**15,740**	**34,551**	**9,722**	**8,147**	**3,938**	**548**	**56,906**	**17,240**	**74,146**
10 percent annual discount	**9,323**	**8,084**	**17,407**	**3,234**	**3,348**	**1,703**	**152**	**25,844**	**11,061**	**36,905**
Discounted future net cash flows	**$ 9,488**	**7,656**	**17,144**	**6,488**	**4,799**	**2,235**	**396**	**31,062**	**6,179**	**37,241**
2002										
Future cash inflows	$ 54,497	28,679	83,176	41,280	16,581	8,076	6,073	155,186	32,983	188,169
Less:										
Future production and transportation costs	26,035	7,763	33,798	7,974	3,764	1,885	1,639	49,060	4,992	54,052
Future development	2,927	1,168	4,095	2,989	1,821	617	428	9,950	1,698	11,648

costs										
Future income tax provisions	7,665	5,349	13,014	20,075	3,917	2,361	2,995	42,362	8,501	50,863
Future net cash flows	17,870	14,399	32,269	10,242	7,079	3,213	1,011	53,814	17,792	71,606
10 percent annual discount	9,097	7,405	16,502	3,998	3,272	1,422	458	25,652	11,585	37,237
Discounted future net cash flows	$ 8,773	6,994	15,767	6,244	3,807*	1,791	553	28,162	6,207	34,369
2001										
Future cash inflows	$ 33,138	9,441	42,579	16,421	4,258	174	2,454	65,886	11,581	77,467
Less:										
Future production and transportation costs	20,541	4,241	24,782	2,474	843	52	583	28,734	3,483	32,217
Future development costs	3,071	530	3,601	875	918	9	161	5,564	1,282	6,846
Future income tax provisions	1,797	1,253	3,050	9,151	1,409	8	1,187	14,805	2,133	16,938
Future net cash flows	7,729	3,417	11,146	3,921	1,088	105	523	16,783	4,683	21,466
10 percent annual discount	3,297	1,821	5,118	1,607	760	44	259	7,788	3,687	11,475
Discounted future net cash flows	$ 4,432	1,596	6,028	2,314	328**	61	264	8,995	996	9,991

**Includes $139 million attributable to a consolidated subsidiary in which there is a 10 percent minority interest.*
***Includes $17 million attributable to a consolidated subsidiary in which there is a 13 percent minority interest. Excludes discounted future net cash flows from Canadian Syncrude of $1,048 million in 2003 and $869 million in 2002.*

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Sources of Change in Discounted Future Net Cash Flows

	Millions of Dollars								
	Consolidated Operations			Equity Affiliates			Total		
	2003	2002	2001	**2003**	2002	2001	**2003**	2002	2001

**Includes amounts resulting from changes in the timing of production.*

n The net change in prices, and production and transportation costs is the beginning-of-the-year reserve-production forecast multiplied by the net annual change in the per-unit sales price, and production and transportation cost, discounted at 10 percent.

n Purchases and sales of reserves in place, along with extensions, discoveries and improved recovery, are calculated using production forecasts of the applicable reserve quantities for the year multiplied by the end-of-the-year sales prices, less future estimated costs, discounted at 10 percent.

n The accretion of discount is 10 percent of the prior year s discounted future cash inflows, less future production, transportation and development costs.

n The net change in income taxes is the annual change in the discounted future income tax provisions.

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Selected Quarterly Financial Data

	Millions of Dollars				Per Shares of Common Stock			
					Income (Loss) Before Cumulative Effect of Changes in Accounting Principles		Net Income(Loss)	
	Sales and Other Operating Revenues*	Income from Continuing Operations Before Income Taxes	Income (Loss) Before Cumulative Effect of Changes in Accounting Principles	Net Income (Loss)	Basic	Diluted	Basic	Diluted
2003								
First**	**$ 26,940**	**2,569**	**1,316**	**1,221**	**1.94**	**1.93**	**1.80**	**1.79**
Second**	**25,321**	**1,781**	**1,187**	**1,187**	**1.75**	**1.73**	**1.75**	**1.73**
Third	**26,105**	**2,310**	**1,306**	**1,306**	**1.92**	**1.90**	**1.92**	**1.90**
Fourth	**25,830**	**1,677**	**1,021**	**1,021**	**1.50**	**1.48**	**1.50**	**1.48**
2002								
First	$ 8,431	51	(102)	(102)	(.27)	(.27)	(.27)	(.27)
Second	10,414	657	351	351	.91	.91	.91	.91
Third	14,557	312	(116)	(116)	(.24)	(.24)	(.24)	(.24)
Fourth	23,346	1,121	(428)	(428)	(.63)	(.63)	(.63)	(.63)

**Includes excise taxes on petroleum products sales.*

***During the fourth quarter, in connection with the consolidation requirements of FASB Interpretation No. 46 for certain variable interest entities created before February 1, 2003, we made an additional adjustment of $18 million, or 3 cents per share, both on a basic and diluted basis, to Cumulative Effect of Changes in Accounting Principles. This adjustment was effective as of January 1, 2003, and as a result, the first and second quarter results have been restated from those disclosed in Note 2 Changes in Accounting Principles, in the Notes to Consolidated Financial Statements, in our third quarter 2003 Form 10-Q.*

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Condensed Consolidating Financial Information

In connection with the merger of ConocoPhillips Holding Company (formerly named Conoco Inc.) and ConocoPhillips Company (formerly named Phillips Petroleum Company) with wholly owned subsidiaries of ConocoPhillips, and to simplify our credit structure, the companies have established various cross guarantees. With the new organizational structure, ConocoPhillips Company is the direct or indirect parent of former Conoco and Phillips subsidiaries and is wholly owned by ConocoPhillips Holding Company, which is wholly owned by ConocoPhillips. ConocoPhillips and ConocoPhillips Holding Company have fully and unconditionally guaranteed the payment obligations of ConocoPhillips Company with respect to its publicly held debt securities. Similarly, ConocoPhillips and ConocoPhillips Company have fully and unconditionally guaranteed the payment obligations of ConocoPhillips Holding Company with respect to the publicly held debt securities of ConocoPhillips Holding Company. In addition, ConocoPhillips Company and ConocoPhillips Holding Company have fully and unconditionally guaranteed the payment obligations of ConocoPhillips with respect to its publicly held debt securities. All guarantees are joint and several. The following condensed consolidating financial statements present the results of operations, financial position and cash flows for:

ConocoPhillips, ConocoPhillips Holding Company, ConocoPhillips Company, (in each case, reflecting investments in subsidiaries utilizing the equity method of accounting);

All other non-guarantor subsidiaries of ConocoPhillips Holding Company and ConocoPhillips Company; and

The consolidating adjustments necessary to present ConocoPhillips results on a consolidated basis.

During 2003, Tosco Corporation, Bayway Refining Company and Marcus Hook Refining Company were merged into ConocoPhillips Company. Previously reported prior period information has been restated to reflect this reorganization of companies under common control.

This condensed consolidating financial information should be read in conjunction with our accompanying consolidated financial statements.

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	Millions of Dollars					
	Year Ended December 31, 2003					
Income Statement	ConocoPhillips	ConocoPhillips Holding Company	ConocoPhillips Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Revenues						
Sales and other operating revenues	$		68,412	35,784		104,196
Equity in earnings (losses) of affiliates	4,646	4,462	3,497	524	(12,587)	542
Other income			621	(262)		359
Intercompany revenues	28	600	3,014	4,843	(8,485)	
Total revenues	4,674	5,062	75,544	40,889	(21,072)	105,097
Costs and Expenses						
Purchased crude oil and products			57,331	17,559	(7,466)	67,424
Production and operating expenses			3,900	3,368	(60)	7,208
Selling, general and administrative expenses	18		1,554	608	(14)	2,166
Exploration expenses			170	431		601
Depreciation, depletion and amortization			1,264	2,221		3,485
Property impairments			43	209		252
Taxes other than income taxes			5,114	9,565		14,679
Accretion on discounted liabilities			37	108		145
Interest and debt expense	117	316	1,159	197	(945)	844
Foreign currency transaction (gains) losses			(41)	5		(36)
Minority interests and preferred dividend requirements of capital trusts				20		20
Total Costs and Expenses	135	316	70,531	34,291	(8,485)	96,788

Income from continuing operations before income taxes and subsidiary equity transactions	4,539	4,746	5,013	6,598	(12,587)	8,309
Gain on subsidiary equity transactions				28		28
Income from continuing operations before income taxes	4,539	4,746	5,013	6,626	(12,587)	8,337
Provision for income taxes	(54)	100	629	3,069		3,744
Income from continuing operations	4,593	4,646	4,384	3,557	(12,587)	4,593
Income (loss) from discontinued operations	237	237	237	228	(702)	237
Income (loss) before cumulative effect of changes in accounting principles	4,830	4,883	4,621	3,785	(13,289)	4,830
Cumulative effect of changes in accounting principles	(95)	(95)	(95)	52	138	(95)
Net Income (Loss)	$ 4,735	4,788	4,526	3,837	(13,151)	4,735

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	Millions of Dollars					
	Year Ended December 31, 2002					
Income Statement	ConocoPhillips	ConocoPhillips Holding Company	ConocoPhillips Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Revenues						
Sales and other operating revenues	$		38,860	17,888		56,748
Equity in earnings (losses) of affiliates	463	426	1,631	254	(2,513)	261
Other income			(31)	223		192
Intercompany revenues		191	2,926	3,883	(7,000)	
Total revenues	463	617	43,386	22,248	(9,513)	57,201
Costs and Expenses						
Purchased crude oil and products			35,196	8,964	(6,337)	37,823
Production and operating expenses		9	2,466	2,308	(85)	4,698
Selling, general and administrative expenses	2		1,782	170	(4)	1,950
Exploration expenses			130	462		592
Depreciation, depletion and amortization			1,099	1,124		2,223
Property impairments				177		177
Taxes other than income taxes			1,464	5,473		6,937
Accretion on discounted liabilities			13	9		22
Interest and debt expense	29	119	857	135	(574)	566
Foreign currency transaction (gains) losses			8	16		24
Minority interests and preferred dividend requirements of capital trusts				48		48
Total Costs and Expenses	31	128	43,015	18,886	(7,000)	55,060

Income from continuing operations before income taxes and subsidiary equity transactions	432	489	371	3,362	(2,513)	2,141
Gain on subsidiary equity transactions						
Income from continuing operations before income taxes	432	489	371	3,362	(2,513)	2,141
Provision for income taxes	(11)	26	(290)	1,718		1,443
Income from continuing operations	443	463	661	1,644	(2,513)	698
Income (loss) from discontinued operations	(1,043)	(1,043)	(993)	(917)	3,003	(993)
Income (loss) before cumulative effect of changes in accounting principles	(600)	(580)	(332)	727	490	(295)
Cumulative effect of changes in accounting principles						
Net Income (Loss)	$ (600)	(580)	(332)	727	490	(295)

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	Millions of Dollars					
	Year Ended December 31, 2001					
Income Statement	ConocoPhillips	ConocoPhillips Holding Company	ConocoPhillips Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Revenues						
Sales and other operating revenues	$		18,182	6,710		24,892
Equity in earnings (losses) of affiliates			1,533	221	(1,713)	41
Other income			(13)	110		97
Intercompany revenues			1,560	1,933	(3,493)	
Total revenues			21,262	8,974	(5,206)	25,030
Costs and Expenses						
Purchased crude oil and products			14,549	2,189	(3,030)	13,708
Production and operating expenses			1,348	1,335	(40)	2,643
Selling, general and administrative expenses			627	5	(19)	613
Exploration expenses			132	229	(55)	306
Depreciation, depletion and amortization			429	915		1,344
Property impairments				26		26
Taxes other than income taxes			1,911	829		2,740
Accretion on discounted liabilities			4	3		7
Interest and debt expense			591	96	(349)	338
Foreign currency transaction (gains) losses			(1)	12		11
Minority interests and preferred dividend requirements of capital trusts				53		53
Total Costs and Expenses			19,590	5,692	(3,493)	21,789

Income from continuing operations before income taxes and subsidiary equity transactions		1,672	3,282	(1,713)	3,241
Gain on subsidiary equity transactions					
Income from continuing operations before income taxes		1,672	3,282	(1,713)	3,241
Provision for income taxes		71	1,569		1,640
Income from continuing operations		1,601	1,713	(1,713)	1,601
Income (loss) from discontinued operations		32	21	(21)	32
Income before cumulative effect of changes in accounting principles		1,633	1,734	(1,734)	1,633
Cumulative effect of changes in accounting principles		28			28
Net Income (Loss)	$	1,661	1,734	(1,734)	1,661

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	Millions of Dollars					
	At December 31, 2003					
Balance Sheet	ConocoPhillips	ConocoPhillips Holding Company	ConocoPhillips Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Assets						
Cash and cash equivalents	$		268	222		490
Accounts and notes receivable		564	22,065	14,051	(31,675)	5,005
Inventories			2,579	1,378		3,957
Prepaid expenses and other current assets	8	7	388	473		876
Assets of discontinued operations held for sale				864		864
Total Current Assets	8	571	25,300	16,988	(31,675)	11,192
Investments and long-term receivables	40,882	37,410	37,655	17,501	(126,190)	7,258
Net properties, plants and equipment			17,102	30,326		47,428
Goodwill			15,046	38		15,084
Intangibles			721	364		1,085
Other assets	20		99	289		408
Total Assets	$ 40,910	37,981	95,923	65,506	(157,865)	82,455
Liabilities and Stockholders Equity						
Accounts payable	$ 10,096	2	19,263	9,213	(31,675)	6,899
Notes payable and long-term debt due within one year		1,350	70	20		1,440
Accrued income and other taxes		96	663	1,917		2,676
Other accruals	20	45	1,229	1,523		2,817
Liabilities of discontinued operations held for sale			1	178		179
Total Current Liabilities	10,116	1,493	21,226	12,851	(31,675)	14,011
Long-term debt	2,704	2,938	6,394	4,304		16,340
			930	2,673		3,603

Asset retirement obligation and accrued environmental costs						
Deferred income taxes		(33)	2,752	5,854	(8)	8,565
Employee benefit obligations			1,828	617		2,445
Other liabilities and deferred credits		5,961	36,462	21,460	(61,600)	2,283
Total Liabilities	12,820	10,359	69,592	47,759	(93,283)	47,247
Trust preferred securities and other minority interests		(12)	5	849		842
Retained earnings	2,695	1,451	9,487	10,879	(15,278)	9,234
Other stockholders equity	25,395	26,183	16,839	6,019	(49,304)	25,132
Total	$ 40,910	37,981	95,923	65,506	(157,865)	82,455

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	Millions of Dollars					
	At December 31, 2002					
Balance Sheet	ConocoPhillips	ConocoPhillips Holding Company	ConocoPhillips Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Assets						
Cash and cash equivalents	$		116	191		307
Accounts and notes receivable	8		21,652	13,504	(30,784)	4,380
Inventories			2,811	1,034		3,845
Prepaid expenses and other current assets	5		186	511	64	766
Assets of discontinued operations held for sale			264	1,341		1,605
Total Current Assets	13		25,029	16,581	(30,720)	10,903
Investments and long-term receivables	32,301	35,538	40,654	21,897	(123,569)	6,821
Net properties, plants and equipment			15,407	27,623		43,030
Goodwill*			2,350	12,094		14,444
Intangibles			457	662		1,119
Other assets	14	19	113	373		519
Total Assets	$ 32,328	35,557	84,010	79,230	(154,289)	76,836
Liabilities and Stockholders Equity						
Accounts payable	$ 5,840	3,291	15,200	12,705	(30,784)	6,252
Notes payable and long-term debt due within one year		526	314	9		849
Accrued income and other taxes	(1)	53	518	1,421		1,991
Other accruals	21	58	1,421	1,575		3,075
Liabilities of discontinued operations held for sale			124	525		649
Total Current Liabilities	5,860	3,928	17,577	16,235	(30,784)	12,816
Long-term debt	3,509	4,054	7,105	4,249		18,917
			452	1,214		1,666

Asset retirement obligation and accrued environmental costs						
Deferred income taxes		(41)	2,560	5,850	(8)	8,361
Employee benefit obligations			1,401	1,354		2,755
Other liabilities and deferred credits		3,729	33,260	24,997	(60,183)	1,803
Total Liabilities	9,369	11,670	62,355	53,899	(90,975)	46,318
Trust preferred securities and other minority interests		(12)		1,013		1,001
Retained earnings	(937)	(2,549)	5,746	8,613	(5,252)	5,621
Other stockholders equity	23,896	26,448	15,909	15,705	(58,062)	23,896
Total	$ 32,328	35,557	84,010	79,230	(154,289)	76,836

* *At December 31, 2002, we had not yet determined the assignment of Conoco goodwill to specific reporting units and related subsidiaries. Conoco goodwill was reported as part of the Corporate and Other reporting segment in All Other Subsidiaries.*

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	Millions of Dollars					
	Year Ended December 31, 2003					
Statement of Cash Flows	ConocoPhillips	ConocoPhillips Holding Company	ConocoPhillips Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Cash Flows From Operating Activities						
Net cash provided by (used in) continuing operations	$ 7,757	(977)	6,209	(678)	(3,144)	9,167
Net cash provided by (used in) discontinued operations			(532)	721		189
Net Cash Provided by (Used in) Operating Activities	7,757	(977)	5,677	43	(3,144)	9,356
Cash Flows From Investing Activities						
Acquisitions, net of cash acquired						
Cash consolidated from adoption of FIN 46				225		225
Capital expenditures and investments, including dry holes		(44)	(5,497)	(3,021)	2,393	(6,169)
Proceeds from asset dispositions	3		1,508	1,151	(3)	2,659
Long-term advances to affiliates and other investments	(5,950)	72	(2,272)	31	8,142	23
Net cash used in continuing operations	(5,947)	28	(6,261)	(1,614)	10,532	(3,262)
Net cash used in discontinued operations			(58)	(178)		(236)
Net Cash Used in Investing Activities	(5,947)	28	(6,319)	(1,792)	10,532	(3,498)
Cash Flows From Financing Activities						
Issuance of debt		2,238	2,603	3,649	(8,142)	348
Repayment of debt	(809)	(500)	(1,057)	(2,793)		(5,159)

Redemption of preferred stock of subsidiaries						
Issuance of company common stock	108					108
Dividends paid on common stock	(1,107)	(789)	(789)	(1,566)	3,144	(1,107)
Other	(2)		31	2,472	(2,390)	111
Net Cash Provided by (Used in) Financing Activities	(1,810)	949	788	1,762	(7,388)	(5,699)
Effect of Exchange Rate Changes on Cash and Cash Equivalents			6	18		24
Net Change in Cash and Cash Equivalents			152	31		183
Cash and cash equivalents at beginning of year			113	194		307
Cash and Cash Equivalents at End of Year	$		265	225		490

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Statement of Cash Flows	ConocoPhillips	ConocoPhillips Holding Company	ConocoPhillips Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
	Millions of Dollars					
	Year Ended December 31, 2002					
Cash Flows From Operating Activities						
Net cash provided by (used in) continuing operations	$ 1,120	2,859	(2,428)	5,426	(2,201)	4,776
Net cash provided by (used in) discontinued operations			247	(45)		202
Net Cash Provided by (Used in) Operating Activities	1,120	2,859	(2,181)	5,381	(2,201)	4,978
Cash Flows From Investing Activities						
Acquisitions, net of cash acquired			(81)	1,261		1,180
Cash consolidated from adoption of FIN 46						
Capital expenditures and investments, including dry holes		(346)	(779)	(3,736)	473	(4,388)
Proceeds from asset dispositions			(175)	790	200	815
Long-term advances to affiliates and other investments	(4,344)	(1,200)	(5,190)	(5,461)	16,103	(92)
Net cash used in continuing operations	(4,344)	(1,546)	(6,225)	(7,146)	16,776	(2,485)
Net cash used in discontinued operations			(6)	(93)		(99)
Net Cash Used in Investing Activities	(4,344)	(1,546)	(6,231)	(7,239)	16,776	(2,584)
Cash Flows From Financing Activities						
Issuance of debt	3,502	3,012	11,817	1,274	(16,103)	3,502
Repayment of debt		(3,006)	(1,717)	(178)	309	(4,592)

Redemption of preferred stock of subsidiaries				(300)		(300)
Issuance of company common stock	7		37			44
Dividends paid on common stock	(271)	(1,200)	(1,622)	1,190	1,219	(684)
Other	(14)	(119)	(7)	(50)		(190)
Net Cash Provided by (Used in) Financing Activities	3,224	(1,313)	8,508	1,936	(14,575)	(2,220)
Effect of Exchange Rate Changes on Cash and Cash Equivalents			(2)	(7)		(9)
Net Change in Cash and Cash Equivalents			94	71		165
Cash and cash equivalents at beginning of year			19	123		142
Cash and Cash Equivalents at End of Year	$		113	194		307

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	Millions of Dollars					
	Year Ended December 31, 2001					
Statement of Cash Flows	ConocoPhillips	ConocoPhillips Holding Company	ConocoPhillips Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Cash Flows From Operating Activities						
Net cash provided by (used in) continuing operations	$		2,712	1,215	(401)	3,526
Net cash provided by discontinued operations			25	8		33
Net Cash Provided by (Used in) Operating Activities			2,737	1,223	(401)	3,559
Cash Flows From Investing Activities						
Acquisitions, net of cash acquired			5	75		80
Cash consolidated from adoption of FIN 46						
Capital expenditures and investments, including dry holes			(976)	(2,181)	141	(3,016)
Proceeds from asset dispositions			12	250		262
Long-term advances to affiliates and other investments			(601)	446	127	(28)
Net cash used in continuing operations			(1,560)	(1,410)	268	(2,702)
Net cash used in discontinued operations			(8)	(60)		(68)
Net Cash Used in Investing Activities			(1,568)	(1,470)	268	(2,770)
Cash Flows From Financing Activities						
Issuance of debt			566	573	(573)	566
Repayment of debt			(1,390)	(1)	446	(945)
Issuance of company common stock			51			51
Dividends paid on common stock			(403)	(259)	259	(403)
Other			(13)	(56)	1	(68)

Net Cash Provided by (Used in) Financing Activities	(1,189)	257	133	(799)
Effect of Exchange Rate Changes on Cash and Cash Equivalents		3		3
Net Change in Cash and Cash Equivalents	(20)	13		(7)
Cash and cash equivalents at beginning of year	39	110		149
Cash and Cash Equivalents at End of Year	$ 19	123		142

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Item 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

Item 9A. CONTROLS AND PROCEDURES

As of December 31, 2003, with the participation of our management, our President and Chief Executive Officer and our Executive Vice President, Finance, and Chief Financial Officer carried out an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) of the Securities Exchange Act of 1934, as amended. Based upon that evaluation, our President and Chief Executive Officer and our Executive Vice President, Finance, and Chief Financial Officer concluded that our disclosure controls and procedures were operating effectively as of December 31, 2003.

There have been no changes in our internal control over financial reporting, as defined in Rule 13a-15(f) of the Securities Exchange Act, that occurred during the period covered by this report that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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PART III

Item 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

Information presented under the headings Election of Directors and Director Biographies and Stock Ownership-Section 16(a) Beneficial Ownership Reporting Compliance in our definitive proxy statement for the Annual Meeting of Stockholders on May 5, 2004 (2004 Proxy Statement), is incorporated herein by reference.* Information regarding the executive officers appears in Part I of this report on pages 35 and 36.

Code of Business Conduct and Ethics for Directors and Employees

We have adopted a Code of Business Conduct and Ethics for Directors and Employees (Code of Ethics), including our principal executive officer, principal financial officer, principal accounting officer and persons performing similar functions. We have posted a copy of our Code of Ethics on the Corporate Governance section of our Internet website at *www.conocophillips.com.* Any waivers of the Code of Ethics must be approved, in advance, by our full Board of Directors. Any amendments to, or waivers from the Code of Ethics that apply to our executive officers and directors will be posted on the Corporate Governance section of our Internet website located at *www.conocophillips.com.*

Item 11. EXECUTIVE COMPENSATION

Information presented under the following headings in the 2004 Proxy Statement is incorporated herein by reference:

Board of Directors Information-How are Directors Compensated?
Executive Compensation-Compensation Tables
Executive Compensation-Employment Agreements
Executive Compensation-Severance Arrangements

Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

Information presented under the headings Stock Ownership-Holdings of Major Stockholders, -Holdings of Officers and Directors and Executive Compensation-Compensation Tables-Equity Compensation Plan Information in the 2004 Proxy Statement is incorporated herein by reference.

Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Information presented under the heading Certain Relationships and Related Transactions in the 2004 Proxy Statement is incorporated herein by reference.

Item 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information presented under the heading Proposal To Ratify the Appointment of Ernst & Young LLP in the 2004 Proxy Statement is incorporated herein by reference.

**Except for information or data specifically incorporated herein by reference under Items 10 through 14, other information and data appearing in the 2004 Proxy Statement are not deemed to be a part of this Annual Report on*

Form 10-K or deemed to be filed with the Commission as a part of this report.

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PART IV

Item 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

(a) 1. Financial Statements and Financial Statement Schedules

The financial statements and schedule listed in the Index to Financial Statements and Financial Statement Schedules, which appears on page 89 are filed as part of this annual report.

2. Exhibits

The exhibits listed in the Index to Exhibits, which appears on pages 187 through 191, are filed as a part of this annual report.

(b) Reports on Form 8-K

During the three months ended December 31, 2003, we furnished the following Current Reports on Form 8-K:

Current Report furnished October 2, 2003, reporting Item 7 and Item 12.

Current Report furnished October 29, 2003, reporting Item 7 and Item 12.

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CONOCOPHILLIPS

(Consolidated)

SCHEDULE II-VALUATION AND QUALIFYING ACCOUNTS

	Millions of Dollars				
		Additions			
Description	Balance At January 1	Charged to Expense	Other (a)	Deductions	Balance At December 31
2003					
Deducted from asset accounts:					
Allowance for doubtful accounts and notes receivable	**$ 48**	**29**		**34(b)**	**43**
Deferred tax asset valuation allowance	**608**	**498**		**200**	**906**
Included in other liabilities:					
Employee termination benefits	**375**	**122**	**110(d)**	**360(e)**	**247**
2002					
Deducted from asset accounts:					
Allowance for doubtful accounts and notes receivable	$ 33	21	13(d)	19(b)	48
Deferred tax asset valuation allowance	263	102	251(d)	8	608
Included in other liabilities:					
Employee termination benefits		301	297(d)	223(e)	375
2001					
Deducted from asset accounts:					
Allowance for doubtful accounts and notes receivable	$ 18	13	18	16(b)	33
Deferred tax asset valuation allowance	315	14	(47)	19	263
Included in other liabilities:					
Reserve for maintenance turnarounds	47			47(c)	

(a) *Represents acquisitions/dispositions and the effect of translating foreign financial statements.*

(b) *Amounts charged off less recoveries of amounts previously charged off.*

(c)

Effective January 1, 2001, we changed our method of accounting for the costs of major maintenance turnarounds from the accrue-in-advance method to the expense as incurred method.

(d) *Included in the merger purchase price allocation.*

(e) *Benefit payments.*

CONOCOPHILLIPS

INDEX TO EXHIBITS

Exhibit Number	Description
2	Agreement and Plan of Merger, dated as of November 18, 2001, by and among ConocoPhillips Company (formerly named Phillips Petroleum Company), ConocoPhillips (formerly named CorvettePorsche Corp.), P Merger Corp. (formerly named Porsche Merger Corp.), C Merger Corp. (formerly named Corvette Merger Corp.) and ConocoPhillips Holding Company (formerly named Conoco Inc.) (Holding) (incorporated by reference to Annex A to the Joint Proxy Statement/Prospectus included in ConocoPhillips Registration Statement on Form S-4; Registration No. 333-74798 (the Form S-4)).
3.1	Restated Certificate of Incorporation of ConocoPhillips (incorporated by reference to Exhibit 3.1 to the Current Report of ConocoPhillips on Form 8-K filed on August 30, 2002; File No. 000-49987 (the Form 8-K)).
3.2	Certificate of Designations of Series A Junior Participating Preferred Stock of ConocoPhillips (incorporated by reference to Exhibit 3.2 to the Form 8-K).
3.3	By-Laws of ConocoPhillips, as amended on February 9, 2004.
4.1	Rights agreement, dated as of June 30, 2002, between ConocoPhillips and Mellon Investor Services LLC, as rights agent, which includes as Exhibit A the form of Certificate of Designations of Series A Junior Participating Preferred Stock, as Exhibit B the form of Rights Certificate and as Exhibit C the Summary of Rights to Purchase Preferred Stock (incorporated by reference to Exhibit 4.1 to the Form 8-K).
	ConocoPhillips and its subsidiaries are parties to several debt instruments under which the total amount of securities authorized does not exceed 10% of the total assets of ConocoPhillips and its subsidiaries on a consolidated basis. Pursuant to paragraph 4(iii)(A) of Item 601(b) of Regulation S-K, ConocoPhillips agrees to furnish a copy of such instruments to the SEC upon request.
Material Contracts	
10.1	Trust Agreement dated June 23, 1995, between ConocoPhillips Company and WestStar Bank, as Trustee of the Deferred Compensation Plan for Non-Employee Directors of Phillips Petroleum Company Trust (incorporated by reference to Exhibit 10.1 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.2	Trust Agreement dated December 12, 1995, between ConocoPhillips Company and Vanguard Fiduciary Trust Company, as Trustee of the Phillips Petroleum Company Compensation and Benefits Arrangements Stock Trust (incorporated by reference to Exhibit 10(c) to the Annual Report of ConocoPhillips Company on Form 10-K for the year ended December 31, 1995; File No. 1-720).

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Exhibit Number	Description
10.3	Contribution Agreement, dated as of December 16, 1999, by and among ConocoPhillips Company, Duke Energy Corporation and Duke Energy Field Services, LLC (incorporated by reference to Exhibit 99.1 to the Current Report of ConocoPhillips Company on Form 8-K, filed December 22, 1999; File No. 1-720).
10.4	Governance Agreement, dated as of December 16, 1999, by and among ConocoPhillips Company, Duke Energy Corporation and Duke Energy Field Services, LLC (incorporated by reference to Exhibit 99.2 to the Current Report of ConocoPhillips Company on Form 8-K, filed December 22, 1999; File No. 1-720).
10.5	Amended and Restated Limited Liability Company Agreement of Duke Energy Field Services, LLC, dated as of March 31, 2000, by and between Phillips Gas Company and Duke Energy Field Services Corporation (incorporated by reference to Exhibit 99.1 to the Current Report of ConocoPhillips Company on Form 8-K, filed April 13, 2000; File No. 1-720).
10.6	Parent Company Agreement, dated as of March 31, 2000, by and among ConocoPhillips Company, Duke Energy Corporation, Duke Energy Field Services, LLC, and Duke Energy Field Services Corporation (incorporated by reference to Exhibit 99.2 to the Current Report of ConocoPhillips Company on Form 8-K, filed April 13, 2000; File No. 1-720).
10.7	Contribution Agreement, dated as of May 23, 2000, by and among ConocoPhillips Company, Chevron Corporation and Chevron Phillips Chemical Company LLC (incorporated by reference to Exhibit 2.1 to the Current Report of ConocoPhillips Company on Form 8-K, filed June 1, 2000; File No. 1-720).
10.8	Amended and Restated Limited Liability Company Agreement of Chevron Phillips Chemical Company LLC, dated as of July 1, 2000, by and between ConocoPhillips Company, Chevron Corporation, Chevron U.S.A. Inc., Chevron Overseas Petroleum Inc., Chevron Pipe Line Company, Drilling Specialties Co., WesTTex 66 Pipeline Co., and Phillips Petroleum International Corporation (incorporated by reference to Exhibit 99.1 to the Current Report of ConocoPhillips Company on Form 8-K filed July 14, 2000; File No. 1-720).
10.9	Master Purchase and Sale Agreement dated as of March 15, 2000, as amended as of April 6, 2000, among Atlantic Richfield Company, CH-Twenty, Inc., BP Amoco p.l.c. and ConocoPhillips Company (incorporated by reference to Exhibit 2 to the Current Report of ConocoPhillips Company on Form 8-K, filed April 18, 2000; File No. 1-720).
10.10	Trust Agreement dated June 1, 1998, between ConocoPhillips Company and Wachovia Bank, N.A., as Trustee of the Phillips Petroleum Company Grantor Trust (incorporated by reference to Exhibit 10.10 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
Management Contracts and Compensatory Plans or Arrangements	
10.11	1986 Stock Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.11 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).

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10.12	1990 Stock Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.12 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.13	Annual Incentive Compensation Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.13 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
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10.19	Omnibus Securities Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.19 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
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10.22	Phillips Petroleum Company Stock Plan for Non-Employee Directors (incorporated by reference to Exhibit 10.22 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
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Key Employee Supplemental Retirement Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.23 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).

Exhibit Number	Description
10.24	Defined Contribution Makeup Plan of ConocoPhillips (incorporated by reference to Exhibit 10.24 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.25	Phillips Petroleum Company Executive Severance Plan (incorporated by reference to Exhibit 10(a) to the Quarterly Report of ConocoPhillips Company on Form 10-Q for the quarter ended June 30, 1999; File No. 1-720).
10.26	2002 Omnibus Securities Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.26 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.27	1998 Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Exhibit 10.27 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.28	1998 Key Employee Stock Performance Plan of ConocoPhillips (incorporated by reference to Exhibit 10.28 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.29	Deferred Compensation Plan for Non-Employee Directors of ConocoPhillips (incorporated by reference to Exhibit 10.29 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.30	Conoco Inc. Key Employee Severance Plan (incorporated by reference to Exhibit 10.6 to the Annual Report of Holding on Form 10-K for the year ended December 31, 2001; File No. 1-14521).
10.31	Conoco Inc. Salary Deferral & Savings Restoration Plan (incorporated by reference to Exhibit 10.31 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.32	Conoco Inc. Directors Charitable Gift Plan (incorporated by reference to Exhibit 10.32 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.33	Phillips Petroleum Company Director Charitable Contribution Plan (incorporated by reference to Exhibit 10.33 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.34	ConocoPhillips Form Indemnity Agreement with Directors (incorporated by reference to Exhibit 10.34 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.35	Employment Agreement, dated as of November 18, 2001, by and among ConocoPhillips, ConocoPhillips Company and J. J. Mulva (incorporated by reference to Exhibit 10.1 to the Form S-4).

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Exhibit Number	Description
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10.36.1	Letter Agreement, dated as of July 22, 2002, by and among Holding and Archie W. Dunham (incorporated by reference to Exhibit 10.36.1 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.37	Letter Agreement, dated as of April 12, 2002, between Holding and Robert E. McKee III (incorporated by reference to Exhibit 10.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarterly period ended September 30, 2002; File No. 000-49987 (the Form 10-Q)).
10.38	Letter Agreement, dated as of April 12, 2002, between Holding and Jim W. Nokes (incorporated by reference to Exhibit 10.2 to the Form 10-Q).
10.39	Rabbi Trust Agreement dated December 17, 1999 (incorporated by reference to Exhibit 10.11 of Holding s Form 10-K for the year ended December 31, 1999, File No. 001-14521).
10.39.1	Amendment to Rabbi Trust Agreement dated February 25, 2002 (incorporated by reference to Exhibit 10.39.1 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.40	ConocoPhillips Directors Charitable Gift Program.
10.41	ConocoPhillips Matching Gift Plan for Directors and Executives.
10.42	Key Employee Deferred Compensation Plan of ConocoPhillips.
12	Computation of Ratio of Earnings to Fixed Charges.
21	List of Principal Subsidiaries of ConocoPhillips.
23	Consent of Independent Auditors.
31.1	Certification of the Chief Executive Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.
31.2	Certification of the Chief Financial Officer pursuant to Rule 13A-14(a) under the Securities Exchange Act of 1934.
32	Certifications pursuant to 18 U.S.C. Section 1350.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CONOCOPHILLIPS

February 25, 2004

/s/ J. J. Mulva
J. J. Mulva
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed, as of February 25, 2004, on behalf of the registrant by the following officers in the capacity indicated and by a majority of directors.

Signature	Title
/s/ Archie W. Dunham *Archie W. Dunham*	Chairman of the Board of Directors
/s/ J. J. Mulva *J. J. Mulva*	President and Chief Executive Officer (Principal executive officer)
/s/ John A. Carrig *John A. Carrig*	Executive Vice President, Finance, and Chief Financial Officer (Principal financial officer)
/s/ Rand C. Berney *Rand C. Berney*	Vice President and Controller (Principal accounting officer)

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/s/ Richard H. Auchinleck	Director
Richard H. Auchinleck /s/ Norman R. Augustine	Director
Norman R. Augustine /s/ David L. Boren	Director
David L. Boren */s/ James E. Copeland, Jr.*	Director
James E. Copeland, Jr. */s/ Kenneth M. Duberstein*	Director
Kenneth M. Duberstein /s/ Ruth R. Harkin	Director
Ruth R. Harkin /s/ Larry D. Horner	Director
Larry D. Horner /s/ Charles C. Krulak	Director
Charles C. Krulak /s/ Frank A. McPherson	Director
Frank A. McPherson /s/ William K. Reilly	Director
William K. Reilly /s/ William R. Rhodes	Director
William R. Rhodes /s/ J. Stapleton Roy	Director
J. Stapleton Roy /s/ Victoria J. Tschinkel	Director
Victoria J. Tschinkel /s/ Kathryn C. Turner	Director
Kathryn C. Turner	

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CONOCOPHILLIPS

INDEX TO EXHIBITS

Exhibit Number	Description
2	Agreement and Plan of Merger, dated as of November 18, 2001, by and among ConocoPhillips Company (formerly named Phillips Petroleum Company), ConocoPhillips (formerly named CorvettePorsche Corp.), P Merger Corp. (formerly named Porsche Merger Corp.), C Merger Corp. (formerly named Corvette Merger Corp.) and ConocoPhillips Holding Company (formerly named Conoco Inc.) (Holding) (incorporated by reference to Annex A to the Joint Proxy Statement/Prospectus included in ConocoPhillips Registration Statement on Form S-4; Registration No. 333-74798 (the Form S-4)).
3.1	Restated Certificate of Incorporation of ConocoPhillips (incorporated by reference to Exhibit 3.1 to the Current Report of ConocoPhillips on Form 8-K filed on August 30, 2002; File No. 000-49987 (the Form 8-K)).
3.2	Certificate of Designations of Series A Junior Participating Preferred Stock of ConocoPhillips (incorporated by reference to Exhibit 3.2 to the Form 8-K).
3.3	By-Laws of ConocoPhillips, as amended on February 9, 2004.
4.1	Rights agreement, dated as of June 30, 2002, between ConocoPhillips and Mellon Investor Services LLC, as rights agent, which includes as Exhibit A the form of Certificate of Designations of Series A Junior Participating Preferred Stock, as Exhibit B the form of Rights Certificate and as Exhibit C the Summary of Rights to Purchase Preferred Stock (incorporated by reference to Exhibit 4.1 to the Form 8-K).
	ConocoPhillips and its subsidiaries are parties to several debt instruments under which the total amount of securities authorized does not exceed 10% of the total assets of ConocoPhillips and its subsidiaries on a consolidated basis. Pursuant to paragraph 4(iii)(A) of Item 601(b) of Regulation S-K, ConocoPhillips agrees to furnish a copy of such instruments to the SEC upon request.

Material Contracts

10.1	Trust Agreement dated June 23, 1995, between ConocoPhillips Company and WestStar Bank, as Trustee of the Deferred Compensation Plan for Non-Employee Directors of Phillips Petroleum Company Trust (incorporated by reference to Exhibit 10.1 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.2	Trust Agreement dated December 12, 1995, between ConocoPhillips Company and Vanguard Fiduciary Trust Company, as Trustee of the Phillips Petroleum Company Compensation and Benefits Arrangements Stock Trust (incorporated by reference to Exhibit 10(c) to the Annual Report of ConocoPhillips Company on Form 10-K for the year ended December 31, 1995; File No. 1-720).

Exhibit Number	Description
10.3	Contribution Agreement, dated as of December 16, 1999, by and among ConocoPhillips Company, Duke Energy Corporation and Duke Energy Field Services, LLC (incorporated by reference to Exhibit 99.1 to the Current Report of ConocoPhillips Company on Form 8-K, filed December 22, 1999; File No. 1-720).
10.4	Governance Agreement, dated as of December 16, 1999, by and among ConocoPhillips Company, Duke Energy Corporation and Duke Energy Field Services, LLC (incorporated by reference to Exhibit 99.2 to the Current Report of ConocoPhillips Company on Form 8-K, filed December 22, 1999; File No. 1-720).
10.5	Amended and Restated Limited Liability Company Agreement of Duke Energy Field Services, LLC, dated as of March 31, 2000, by and between Phillips Gas Company and Duke Energy Field Services Corporation (incorporated by reference to Exhibit 99.1 to the Current Report of ConocoPhillips Company on Form 8-K, filed April 13, 2000; File No. 1-720).
10.6	Parent Company Agreement, dated as of March 31, 2000, by and among ConocoPhillips Company, Duke Energy Corporation, Duke Energy Field Services, LLC, and Duke Energy Field Services Corporation (incorporated by reference to Exhibit 99.2 to the Current Report of ConocoPhillips Company on Form 8-K, filed April 13, 2000; File No. 1-720).
10.7	Contribution Agreement, dated as of May 23, 2000, by and among ConocoPhillips Company, Chevron Corporation and Chevron Phillips Chemical Company LLC (incorporated by reference to Exhibit 2.1 to the Current Report of ConocoPhillips Company on Form 8-K, filed June 1, 2000; File No. 1-720).
10.8	Amended and Restated Limited Liability Company Agreement of Chevron Phillips Chemical Company LLC, dated as of July 1, 2000, by and between ConocoPhillips Company, Chevron Corporation, Chevron U.S.A. Inc., Chevron Overseas Petroleum Inc., Chevron Pipe Line Company, Drilling Specialties Co., WesTTex 66 Pipeline Co., and Phillips Petroleum International Corporation (incorporated by reference to Exhibit 99.1 to the Current Report of ConocoPhillips Company on Form 8-K filed July 14, 2000; File No. 1-720).
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