Table of Contents

2004

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, 2004**

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 001-32395

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. [ ]

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, 2004, the last business day of the registrant's most recently completed second fiscal quarter, based on the closing price on that date of $76.29, was $52.5 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 397,605 and 24,701,314 shares, respectively, in determining the aggregate market value.

The registrant had 695,810,445 shares of common stock outstanding at January 31, 2005.

Documents incorporated by reference:
Portions of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 5, 2005 (Part III)

TABLE OF CONTENTS

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," "goal," "may," "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 92.

Items 1 and 2. BUSINESS AND PROPERTIES

CORPORATE STRUCTURE

ConocoPhillips is an international, integrated 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. Effective January 1, 2005, ConocoPhillips Holding Company was merged into ConocoPhillips Company.

Our business is organized into six operating segments:

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

- **Midstream—**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.

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

- **LUKOIL Investment—**This segment consists of our equity investment in the ordinary shares of LUKOIL, an international, integrated oil and gas company headquartered in Russia. Our investment was 10 percent at December 31, 2004.

- **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.

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

At December 31, 2004, ConocoPhillips employed approximately 35,800 people.

SEGMENT AND GEOGRAPHIC INFORMATION

For operating segment and geographic information, see Note 27—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, produces and markets 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. Operations to liquefy and transport natural gas are also included in the E&P segment. At December 31, 2004, our E&P operations were producing in the United States, Norway, the United Kingdom, Canada, Venezuela, Indonesia, offshore Timor Leste in the Timor Sea, Australia, Vietnam, China, Nigeria, the United Arab Emirates, and Russia.

The E&P segment does not include the results or statistics from our equity investment in LUKOIL, which are reported in a separate segment (LUKOIL Investment). As a result, references to results, production, prices and other statistics throughout the E&P segment exclude those related to our equity investment in LUKOIL.

The information listed below appears in the supplemental oil and gas operations disclosures on pages 168 through 186 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.

- Developed and undeveloped acreage.

In 2004, E&P's worldwide production, including its share of equity affiliates' production other than LUKOIL, averaged 1,542,000 barrels-of-oil-equivalent (BOE) per day, a 3 percent decrease from 1,590,000 BOE per day in 2003. During 2004, 629,000 BOE per day were produced in the United States, a 7 percent decrease from 674,000 BOE per day in 2003. Production from our international E&P operations averaged 913,000 BOE per day in 2004, down slightly from 916,000 BOE per day in 2003. In addition, our Canadian Syncrude mining operations had net production of 21,000 barrels per day in 2004, compared with 19,000 barrels per day in 2003. The decreased production mainly reflects the impact of asset dispositions during 2003 and 2004, as well as normal field production declines. The impact of these items was partially offset by the ramp-up of oil production from the Su Tu Den field in Vietnam since startup in late 2003, the ramp-up of liquids production from the Bayu-Undan field in the Timor Sea since startup in February 2004, and the startup of the Hamaca upgrader in Venezuela in the fourth quarter of 2004. 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.

E&P's worldwide annual average crude oil sales price increased 31 percent in 2004, from $27.52 per barrel to $36.06 per barrel. E&P's annual average worldwide natural gas sales price also increased, going from $4.08 per thousand cubic feet in 2003 to $4.61 per thousand cubic feet in 2004.

At December 31, 2004, E&P held, including its share of equity affiliates other than LUKOIL, a combined 43.2 million net developed and undeveloped acres, compared with 52.6 million net acres at year-end 2003. The decrease in acreage primarily reflects the assignment of our interests in Barbados and Brazil, in addition to the sale of Petrovera. At year-end 2004, E&P held acreage in 22 countries, including acreage held by equity affiliates.

Our finding-and-development-cost-per-BOE metric reported in prior years was calculated by dividing the net reserve change for each reporting 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." Due to the timing of proved reserve additions and the timing of the related costs incurred to find and develop such proved reserves, this metric often includes quantities of proved reserves for which a majority of the costs of development have not yet been incurred. Conversely, the metric also often includes costs to develop proved reserves that had been added in earlier years. Because this metric may not necessarily represent total finding and development costs for projects under way or may not be indicative of expected future finding and development costs, we discontinued reporting it in our filings with the U.S. Securities and Exchange Commission.

E&P—U.S. OPERATIONS

In 2004, U.S. E&P operations contributed 40 percent of E&P's worldwide liquids production, compared with 43 percent in 2003. U.S. E&P contributed 42 percent of natural gas production in both years.

Alaska

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.

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 operation, 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 109,600 barrels per day in 2004, compared with 121,500 barrels per day in 2003, while natural gas liquids production averaged 23,100 barrels per day in 2004, compared with 23,000 barrels per day in 2003. Normal field production declines and facility maintenance were the main causes of the lower production rates in 2004.

Prudhoe Bay satellite fields, including Aurora, Borealis, Polaris, Midnight Sun, and Orion, produced 14,600 net barrels per day of crude oil in 2004, compared with 16,200 net barrels per day in 2003. Borealis contributed the biggest share in 2004, producing 8,000 net barrels per day. All Prudhoe Bay satellite fields produce through the Prudhoe Bay production facilities.

The Greater Point McIntyre Area (GPMA) primarily is made up of the Point McIntyre, Niakuk, and Lisburne fields. The fields within the GPMA generally produce through the Lisburne Production Center. Net crude oil production for GPMA averaged 17,800 barrels per day in 2004, compared with 18,200 barrels per day in 2003. 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.

In January 2005, the Governor of Alaska announced that effective February 1, 2005, most satellite fields surrounding the Prudhoe Bay field would no longer qualify for a state production tax incentive that was intended to encourage development of these marginal deposits. Beginning in February, these satellite fields bear the same production tax rate as Prudhoe Bay.

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 67,900 barrels per day in 2004, compared with 78,600 barrels per day in 2003.

Other fields within the Greater Kuparuk Area produced 19,300 net barrels per day of crude oil in 2004, compared with 21,800 net barrels per day 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. Our net crude oil production from West Sak averaged 5,500 barrels per day in 2004, compared with 3,800 barrels per day in 2003. We have a 52.2 percent interest in this field.

During 2004, we and our co-venturers announced plans for the expansion of the West Sak development. The development program includes two drill sites: Drill Site 1E, which is an existing drill site, and Drill Site 1J, which will be the first stand-alone West Sak drill site. Plans call for the drilling of 13 wells at Drill Site 1E and 31 wells at Drill Site 1J. The development projects also include expansion of facilities at Drill Site 1E, and the construction of new facilities, pipelines and power lines for Drill Site 1J. Drill Site 1E, which started up in July 2004, is expected to average 4,100 net barrels of oil per day in 2005. First production from Drill Site 1J, expected in late 2005, is expected to add approximately 800 net barrels per day. Peak production from Drill Site 1J is expected to occur in 2007.

Western North Slope

The Alpine field, located west of the Kuparuk field, began production in November 2000. In 2004, the field produced at a net rate of 63,500 barrels of oil per day, compared with 64,500 barrels per day in 2003. We are the operator and hold a 78 percent interest in Alpine.

During 2004, the Alpine Capacity Expansion Phase I was completed. As a result, Alpine’s gross crude oil production capacity increased approximately 5,000 barrels per day, along with an increase in the site’s produced-water capacity. Originally designed to process about 10,000 barrels per day of produced water, the site can now process about 100,000 barrels per day. The completion of Phase II is scheduled for 2005, after which Alpine's crude oil production capacity is expected to be further expanded by approximately 30,000 gross barrels per day with increased seawater injection rates to boost reservoir pressure.

In January 2003, ConocoPhillips and the U.S. Department of Interior Bureau of Land Management (BLM) signed a Memorandum of Understanding that provides for completion of an Environmental Impact Statement (EIS) for Alpine satellites, as well as future potential developments in the northeast corner of the National Petroleum Reserve-Alaska (NPR-A) and near the Alpine oil field. The BLM issued a favorable EIS Record of Decision in November 2004. In December 2004, we and our co-venturers announced that the companies approved the development of two Alpine satellite oil fields—Fiord and Nanuq. The project will include two satellite drill sites—CD 3 on the Fiord oil field, and CD 4 on the Nanuq oil field—located within an 8-mile radius of the Alpine oil field. Plans call for the drilling of approximately 40 wells, with first production scheduled for late 2006 and peak production in 2008. The oil will be processed through the existing Alpine facilities. The companies intend to seek state, local and federal permits for additional Alpine satellite developments in the NPR-A. A final decision to move forward on these satellite oil fields is not expected to be made until the outcomes of remaining permits are known.

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

We have a 100 percent interest in the North Cook Inlet field. Net production in 2004 averaged 94 million cubic feet per day, compared with 112 million cubic feet per day in 2003. Production from the North Cook Inlet field is used to supply our share of gas to the Kenai LNG plant (discussed below).

Our interest in the Beluga River field is 33 percent. Net production averaged 63 million cubic feet per day in 2004, the same as in 2003. Gas from the Beluga River field is sold to local utilities and industrial consumers, and used as back-up supply to the Kenai LNG plant.

We have a 70 percent interest in the Kenai LNG plant, which supplies LNG to two utility companies in Japan. Using two tankers, the company transports the LNG to Japan, where it is reconverted to dry gas at the receiving terminal. We sold 38.6 net billion cubic feet of LNG to Japan in 2004, compared with 44.0 billion cubic feet in 2003.

Exploration
During the 2004 winter drilling season, we drilled six North Slope exploration and appraisal wells. This activity resulted in two successful appraisal wells in the NPR-A and one successful appraisal well in the West Sak field. We expensed the other three wells as dry holes. In addition, successful exploratory production tests were run in two wells, one each in the Alpine and Prudhoe Bay fields. During 2004, we completed evaluation of six wells drilled in prior drilling seasons, with five of those determined to be successful and one expensed as a dry hole. We were also the successful bidder on 71 tracts covering over 808,000 gross acres (approximately 484,000 net acres) at the June 2004 Bureau of Land Management oil and gas lease sale for the Northwest Planning Area of the NPR-A. As a result of this additional acreage, we now have under lease approximately 1.3 million net exploration acres in the NPR-A.

Transportation
We transport the petroleum liquids that 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. We have a 28.3 percent ownership interest in TAPS. We also have ownership interests in the Alpine, Kuparuk and Oliktok pipelines on the North Slope.

The owners of TAPS approved plans to upgrade the pipeline's pump stations. The project is expected to be substantially completed in 2005. The project is expected to reduce operating costs and extend the economic life of the pipeline through increased efficiencies, while maintaining safety and environmental performance standards.

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. The Alaska Natural Gas Pipeline Act was passed by Congress and signed by the President in October 2004. This legislation was designed to help facilitate and streamline the federal regulatory process and provides up to $18 billion in federal loan guarantees. Also approved was tax legislation granting seven-year depreciation to the Alaska portion of the pipeline and confirming the existing 15 percent enhanced oil recovery tax credit would apply to the gas treating plant. This federal legislation, along with gaining a fiscal contract with the state of Alaska, is an integral part of moving the project forward. Also in 2004, ConocoPhillips, along with BP and ExxonMobil, entered into negotiations with the state of Alaska under the Stranded Gas Development Act and submitted a detailed proposal to the state in December. These negotiations are ongoing.

Our wholly owned subsidiary, Polar Tankers Inc., manages the marine transportation of our Alaska North Slope production. Polar Tankers operates six ships in the Alaskan trade, chartering additional third-party-operated vessels, as necessary. Beginning with the *Polar Endeavour* in 2001, Polar Tankers has brought into service a new Endeavour Class tanker each year since: the *Polar Resolution* in 2002; the *Polar Discovery* in 2003; and the *Polar Adventure* in 2004. These 125,000-deadweight-ton, double-hulled crude oil tankers are the first four of five Endeavour Class tankers that we are adding to our Alaska-trade fleet. The fifth and final tanker is scheduled to be in Alaska North Slope service by 2006.

Lower 48 States

Gulf of Mexico

At year-end 2004, our portfolio of producing properties in the Gulf of Mexico included four fields operated by us and four fields operated by our co-venturers. At December 31, 2004, we had 28 leases in production or under development in the deepwater Gulf of Mexico.

We hold a 16 percent interest in the Ursa field located in the Mississippi Canyon area. Ursa utilizes a tension-leg platform in approximately 3,900 feet of water. We also own a 16 percent interest in the Princess field, a northern, subsalt extension of the Ursa field. Our total net production from both fields in 2004 averaged 21,000 barrels per day of liquids and 30 million cubic feet per day of natural gas, compared with 15,900 barrels per day of liquids and 20 million cubic feet per day of natural gas in 2003.

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, located in approximately 4,700 feet of water, was completed during 2004. First oil production began in December 2004, with the remaining well completions scheduled through the first half of 2005. Peak production of 48,000 net BOE per day is expected during 2005.

We have a 16.8 percent interest in the K2 discovery. K2, located in Green Canyon Block 562, was company-sanctioned for development in the first quarter of 2004. The development will utilize a subsea tieback to a nearby third-party platform. First production is expected in the second half of 2005, with peak net production of 7,000 BOE per day expected during 2007.

During 2004, we sold our interest in the Lorien discovery located in Green Canyon Block 199.

Onshore
Our onshore Lower 48 production primarily consists of 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 to our coalbed methane production from the San Juan Basin, we also hold coalbed methane acreage positions in the Uinta Basin in Utah and the Black Warrior Basin in Alabama. Our interest in the coalbed methane acreage position in the Powder River Basin in Wyoming was sold in early 2005.

Activities in 2004 primarily were centered on continued optimization and development of these assets. Combined production from Lower 48 onshore fields in 2004 averaged a net 1,184 million cubic feet per day of natural gas and 54,100 barrels per day of liquids, compared with 1,237 million cubic feet per day of natural gas and 57,000 barrels per day of liquids in 2003.

E&P—NORTHWEST EUROPE

In 2004, E&P operations in Northwest Europe contributed 29 percent of E&P’s worldwide liquids production, compared with 30 percent in 2003. Our Northwest European assets are principally located in the Norwegian and U.K. sectors of the North Sea. Northwest Europe operations contributed 34 percent of natural gas production in both years.

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 2004 from the Ekofisk Area was 127,400 barrels of liquids per day and 125 million cubic feet of natural gas per day, compared with 126,500 barrels of liquids per day and 127 million cubic feet of natural gas per day in 2003. 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: construction of a new platform, Ekofisk 2/4M, and modification of the existing Ekofisk Complex to increase processing capacity. Construction began in 2003, and during 2004 the 2/4M platform progressed on schedule. 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, and Norwegian 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, a 6.4 percent interest in the Grane 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 87,700 barrels of liquids per day and 176 million cubic feet of natural gas per day in 2004, compared with 93,300 barrels of liquids per day and 149 million cubic feet of natural gas per day in 2003.

We and our co-venturers received approval from Norwegian authorities in October 2004 for the Alvheim North Sea development. The development plans include a floating production storage and offloading vessel and subsea installations. Production from the field is expected to commence in 2007. We have a 20 percent interest in the project.

Transportation
We have interests in the transportation and processing infrastructure in 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.

Exploration
Three partner-operated exploration wells were drilled in 2004. All three were near-field exploration wells in the Heidrun and Visund licenses. The drilling near Heidrun resulted in one discovery and one dry hole. The well in the Visund area was a hydrocarbon discovery. In 2005, seven to eight wells are planned to be drilled in Norway and Denmark.

United Kingdom
We are a joint operator of the Britannia natural gas/condensate field, in which we have a 58.7 percent interest. Our net production from Britannia averaged 347 million cubic feet of natural gas per day and 15,500 barrels of liquids per day in 2004, compared with 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 in the Britannia field is expected to continue into the year 2007.

In December 2003, we approved a plan for the development of two new Britannia satellite fields: the Callanish and Brodgar fields. The U.K. government approved the development plan in early 2004. The development plan involves producing the fields via subsea manifolds and two new pipelines to Britannia. A new platform, bridge-linked to Britannia, will also be installed to separate production prior to processing on the Britannia platform. Drilling began in the second half of 2004, with the pipelines, manifolds and installation of the bridge-linked platform anticipated for 2006. First production is targeted for 2007. 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 produces 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 14,100 barrels of liquids per day and 118 million cubic feet of natural gas per day in 2004, compared with 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. 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. Net production in 2004 averaged 306 million cubic feet per day of natural gas and 1,400 barrels of liquids per day, compared with 371 million cubic feet per day of natural gas and 2,000 barrels per day of liquids in 2003.

The Valkyrie development was brought into production in 2004. This is a single well development drilled from a nearby platform. We are the operator with a 50 percent interest.

During 2004, we received approval from the U.K. government for development of the Saturn Unit Area in the southern North Sea. First gas production from the Saturn Unit Area is expected in the fourth quarter of 2005, with net production expected to increase to a maximum rate of approximately 73 million cubic feet per day within a year following startup. Initially, the development will consist of three wells from a six-slot wellhead platform. We are the operator of the Saturn Unit Area and have an interest of 42.9 percent.

During 2004, we concluded the development of the CMS3 area in the southern sector of the U.K. North Sea with the completion of the Boulton H-1 well. This development consists of five natural gas reservoirs developed as a single, unitized project. 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.

Also during 2004, we received internal and co-venturer approvals for the Munro development, and are working toward U.K. governmental approval in the first quarter of 2005. Munro is a single well development which would tie into the Hawksley subsea manifold (part of CMS3). We are the operator of Munro with a 46 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, a 30 percent interest in the Miller 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 38,800 barrels of liquids per day and 47 million cubic feet of natural gas per day in 2004, compared with 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. First production from Clair is expected in early 2005, with plateau production expected in 2006 at a net rate of 14,400 BOE per day.

Transportation
The Interconnector pipeline, which connects the United Kingdom and Belgium, facilitates marketing natural gas produced in the United Kingdom throughout Europe. Our 10 percent equity share of the Interconnector pipeline allows us to ship approximately 200 million net cubic feet of natural gas per day to markets in continental Europe.

We operate two terminals in the United Kingdom: the Teesside oil terminal (in which we have a 29.3 percent interest) and the Theddlethorpe gas terminal (in which we have a 50 percent interest).

Exploration
In the U.K. sector of the North Sea, we participated in two wells in the southern North Sea and one well on a structure adjacent to the Callanish field in the central North Sea during 2004. All three of these wells were successful in locating commercial quantities of hydrocarbons. The planned drilling program for 2005 includes seven to eight exploration and appraisal wells.

E&P—CANADA

In 2004, E&P operations in Canada contributed 4 percent of E&P’s worldwide liquids production (excluding Syncrude production), compared with 5 percent in 2003. Canadian operations contributed 13 percent of natural gas production in both years.

Oil and Gas Operations

Western Canada

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 accessible only in the winter. The central and west regions mainly produce natural gas. The south region has shallow gas and medium-to-heavy oil. Production from these oil and gas operations in western Canada averaged a net 35,000 barrels per day of liquids and 433 million cubic feet per day of natural gas in 2004, compared with 30,300 barrels per day of liquids and 435 million cubic feet per day of natural gas in 2003.

In February 2004, we sold our 46.7 percent interest in Petrovera, a joint venture that produced heavy oil.

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. In May 2003, we received regulatory approval to develop the Surmont project from the Alberta Energy and Utilities Board and in late 2003, our Board of Directors approved the project. In 2003, we classified 223 million barrels as proved crude oil reserves from our Canadian operations, the majority of which related to the Surmont heavy-oil project. Consistent with our practice and in accordance with U.S. Securities and Exchange Commission guidelines that require the use of year-end prices for reserve estimation, due to low December 31, 2004, Canadian bitumen values, we removed all of the crude oil reserves for the Surmont project from the proved category at year-end 2004. Despite this revision, the Surmont project remains an economically viable and important component of our E&P project portfolio.

The Surmont project uses an enhanced thermal oil recovery method called steam assisted gravity drainage. This process involves heating the oil by the injection of steam deep into the oil sands through a horizontal well bore, effectively lowering the viscosity and enhancing the flow of the oil, which is then recovered via gravity drainage into a lower horizontal well bore and pumped to the surface. Over the life of this 30+ year project, we anticipate that approximately 500 production and steam-injection well pairs will be drilled. Construction of the facilities and development drilling began in 2004. Commercial production is expected to begin in late 2006, with peak production expected in 2012. We anticipate using our share of the heavy oil produced as a feedstock in our U.S. refineries.

Transportation

We are working with three other energy companies, as members of the Mackenzie Delta Producers' 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 established markets in North America. Initial design capacity for the Mackenzie Valley pipeline is proposed to be 1.2 billion 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 primary fields in the Mackenzie Delta that would anchor the pipeline development. Regulatory applications for the project were submitted in 2004, and first gas production is currently targeted for the 2009 timeframe.

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. As part of our evaluation, we are waiting on the results from drilling on adjacent blocks. In deepwater Newfoundland, we converted our large Laurentian permit into specific exploration licenses. Exploration of these licenses began in 2004 with a 2D seismic survey, and a larger

3D seismic program is planned for 2005. In the foothills, we drilled four wildcat exploratory wells in 2004. One was successful, and the other three are being tested. In the Mackenzie Delta/Beaufort Sea, we participated in the Umiak well. This well will be tested during the first quarter of 2005 and an appraisal well is also planned.

Other Canadian Operations

Syncrude Canada Ltd.

We own a 9.03 percent 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 21,000 barrels per day in 2004, compared with 19,000 barrels per day in 2003.

The development of the Stage III expansion-mining project continued in 2004, which is expected to increase our Syncrude production. The new mine was completed and started up in the fourth quarter of 2003. The upgrader expansion project is expected to be fully operational by mid-2006.

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 our supplemental oil and gas information.

E&P—SOUTH AMERICA

In 2004, E&P operations in South America were comprised of interests in Venezuela and Brazil. South American operations contributed 9 percent of E&P's worldwide liquids production in 2004, compared with 8 percent in 2003.

Venezuela

Petrozuata and Hamaca

Petrozuata is a Venezuelan Corporation formed under an Association Agreement between a wholly owned subsidiary of ConocoPhillips that has a 50.1 percent non-controlling equity interest and a subsidiary of Petroleos de Venezuela S.A. (PDVSA), the national oil company of Venezuela. The Association Agreement has a term of 35 years, that began in 2001.

The project is an integrated operation that produces 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 heavy, processed crude oil and light, processed crude oil. Associated products produced are liquefied petroleum gas, sulfur, petroleum coke and heavy gas oil. The processed crude oil produced by Petrozuata is used as a feedstock for our Lake Charles, Louisiana, refinery, as well as the Cardon refinery in Venezuela operated by PDVSA. Our net production was 59,600 barrels of heavy crude oil per day in 2004, compared with 51,600 barrels per day in 2003, and is included in equity affiliate production.

In 1997, 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.

The Hamaca project also involves the development of heavy-oil reserves from the Orinoco Oil Belt. We own a 40 percent interest in the Hamaca project, which has a 35-year term, beginning in 2004, and 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 32,600 barrels per day of heavy crude oil in 2004, compared with 22,100 barrels per day in 2003, and is included in equity affiliate production.

Construction of the heavy-oil upgrader, pipelines and associated production facilities for the Hamaca project at the Jose industrial complex began in 2000. In the fourth quarter of 2004, we began producing on-specification medium-grade crude oil for export at the planned ramp-up capacity of the plant. Our net oil production from the Hamaca field is expected to be approximately 56,100 barrels per day in 2005.

In October 2004, the President of Venezuela made a public statement that the reduction in the royalty rate to 1 percent from 16.67 percent for a period of nine years, or until revenues exceed three times the initial investment, would no longer apply to extra-heavy crude oil producing and processing projects. This statement was later confirmed in writing by the Ministry of Energy and Mines (MEM) to the Petrozuata and Hamaca project representatives. Consequently, Petrozuata and Hamaca began paying royalties at the higher rate effective October 2004. As a result, 2005 production estimates were reduced by approximately 20,000 net barrels per day and our proved reserves at year-end 2004 were reduced 46 million barrels.

Gulf of Paria
In 2003, the Venezuelan authorities approved the original development plan for Phase I of the Corocoro field. Venezuelan authorities did not approve a development plan addendum submitted in 2004. However, in early 2005 verbal agreement of requirements to progress the project was achieved. We will be working with the Venezuelan government and co-venturers to finalize the terms agreed and move the project forward to development. We operate the field with a 32.2 percent interest.

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. Two appraisal wells were completed in 2004, and a third was completed in January 2005. All appraisal wells indicated that the target zones were natural gas bearing. In addition, a new natural gas/condensate discovery was made in a deeper zone. Development of the field may include a well platform, a 170-mile pipeline to shore, and an LNG plant. The LNG would be shipped to the U.S. market.

Exploration
Wildcat exploratory activity in both the Gulf of Paria East and West Blocks was commercially unsuccessful in 2004, which resulted in a full impairment of our leasehold investment in these blocks. However, we are still pursuing evaluation plans to assess future potential.

Brazil
Exploration
We had concession agreements on two deepwater exploration blocks (BM-ES-11 and BM-PAMA-3) offshore Brazil. During 2003 and 2004, further evaluation led to the write-off of our leasehold investments in both blocks. By the end of 2004, we had ceased all operations in Brazil and exited the country.

E&P—ASIA PACIFIC

In 2004, E&P operations in the Asia Pacific area contributed 10 percent of E&P's worldwide liquids production, compared with 6 percent in 2003. Asia Pacific operations contributed 9 percent of natural gas production in both years.

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 onshore South Sumatra. A potentially emerging area is offshore East Java. We are a party to five long-term, U.S.-dollar-denominated natural gas contracts that are based on oil price benchmarks. In addition, in 2004 we began supplying natural gas to markets on the Indonesian island of Batam and new contracts were signed to supply natural gas to domestic markets in West Java and East Java. These are U.S.-dollar-denominated, fixed-price contracts. Production from Indonesia in 2004 averaged a net 250 million cubic feet per day of natural gas and 15,400 barrels per day of oil, compared with 255 million cubic feet per day of natural gas and 16,000 barrels per day of oil in 2003.

Offshore Assets
We operate three offshore PSCs: South Natuna Sea Block B, Nila, and Ketapang. We also hold a non-operator interest in the Pangkah PSC offshore East Java.

The South Natuna Sea Block B PSC, in which we have a 40 percent interest, has two currently producing oil fields and 16 gas fields in various stages of development (seven of which have recoverable oil or condensate volumes). In late 2004, oil production began from the Belanak oil and gas field through a new floating production, storage and offloading (FPSO) vessel and related facilities. Also in Block B, we began development of the Kerisi and Hiu fields, with construction contract awards under way, and we began the preliminary engineering phase of the North Belut field development.

In the Pangkah PSC, in which we have a 22 percent interest, the development of the Ujung Pangkah field was approved by the Indonesian government in late 2004 following the signing of contracts for the supply of natural gas to markets in East Java.

Onshore Assets
We operate six onshore PSCs. Four are in South Sumatra: Corridor PSC, Corridor TAC, South Jambi 'B', and Sakakemang JOB. We also operate Block A PSC in Aceh, and Warim in Papua. We hold non-operator interests in the Banyumas PSC in Java and the Bentu and Korinci-Baru PSCs in Sumatra.

The Corridor PSC is located onshore South Sumatra and we have a 54 percent interest. We operate six oil fields and six natural gas fields, and supply natural gas from the Grissik and Suban gas processing plants to the Duri steamflood in central Sumatra operated by Caltex and to markets in Singapore and Batam.

In August 2004, we announced the signing of a gas sales agreement with PT Perusahaan Gas Negara (Persero) Tbk. (PGN), the Indonesian state-owned gas transportation company, to supply natural gas for delivery to the industrial markets in West Java and Jakarta. The agreement calls for us to supply approximately 850 billion net cubic feet of gas over a 17-year period commencing in the first quarter of 2007. At the contracted rates, initial gas deliveries are about 65 million net cubic feet per day, ramping up to approximately 140 million net cubic feet per day in 2012, and continuing at that level until the contract terminates in 2023.

Following the execution of the West Java gas sales agreement with PGN in August, we began the development of the Suban Phase II project, which is an expansion of the existing Suban gas plant in the Corridor PSC.

The South Jambi ‘B’ PSC is also located in South Sumatra, and we have a 45 percent interest. In 2004, we completed the construction of the South Jambi shallow gas project for supply of natural gas to Singapore from the South Jambi B Block, with first production occurring in June 2004.

Transportation
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, and Grissik to Singapore, natural gas pipelines.

Exploration
In Indonesia, a total of 11 exploration and appraisal wells were drilled during 2004, of which five were successful. In the Pangkah PSC, two appraisal wells confirmed a western extension of the Ujung Pangkah field. In the Ketapang PSC, an appraisal well of the Bukit Tua field provided data for progressing a development plan in 2005. In Sumatra, two appraisal wells were successful in finding additional gas volumes in both the Korinci-Baru and the Bentu PSCs.

China
Our combined net production of crude oil from the Xijiang facilities averaged 10,400 barrels per day in 2004, compared with 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 FPSO facility.

Production from Phase I development of the Peng Lai 19-3 field in Bohai Bay Block 11-05 began in late 2002. In 2004, the field produced 15,000 net barrels of oil per day, compared with 14,800 barrels per day in 2003. 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 FPSO facility.

In December 2004, our Board of Directors approved the second phase of development of the Peng Lai 19-3 field, as well as concurrent development through the same facilities of the nearby Peng Lai 25-6 field. The “Overall Development Program” for both fields was submitted to the Chinese government in November 2004, and was approved in January 2005. Construction activities have since begun. The second phase will include multiple wellhead platforms and a larger FPSO facility.

Vietnam
We have a 23.25 percent interest in Block 15-1 in the Cuu Long Basin in the South China Sea. First production from Block 15-1 began in the fourth quarter of 2003 with the startup of the Su Tu Den development. Net production in 2004 was 20,800 barrels of oil per day. The oil is being processed through a 1 million barrel FPSO vessel.

We have a 36 percent interest in the Rang Dong field in Block 15-2 in the Cuu Long Basin. All wellhead platforms produce into a FPSO vessel. Net production in 2004 was 11,800 barrels of liquids per day and 16 million cubic feet per day of natural gas. Development of the central part of the field is under way, with two additional platforms and additional production and injection wells expected to be completed in the third quarter of 2005.

Transportation
We own a 16.33 percent interest in the Nam Con Son gas pipeline. This 242-mile transportation system links gas supplies from the Nam Con Son Basin to gas markets in southern Vietnam.

Exploration
An oil discovery was made on the Su Tu Vang prospect in Block 15-1 in the third quarter of 2001, with successful appraisal drilling conducted in 2004. Development scenarios are currently under evaluation, with preliminary engineering commencing in early 2005. The commerciality of the northeast portion of Su Tu Den is also being evaluated, with additional appraisal drilling planned for 2005. In addition to these areas, a successful exploration well was drilled in the Su Tu Trang southeast area of the block in the fourth quarter of 2003. A 3D seismic study was conducted on this area in 2004 and is currently under interpretation. Additional appraisal drilling is scheduled for 2005 to further define this gas condensate discovery. We also own interests in offshore Blocks 5-3, 133 and 134. Our interest in Block 16-2 was relinquished in April 2004 after unsuccessful exploratory activity.

Timor Sea and Australia
Bayu-Undan
We are the operator and hold a 56.7 percent interest in the unitized Bayu-Undan field, located in the Timor Sea, which is being developed in two phases. Phase I is a gas-recycle project, where condensate and natural gas liquids are separated and removed and the dry gas reinjected back into the reservoir. This phase began production in February 2004, and averaged a net rate of 28,100 barrels of liquids per day in 2004.

Phase II involves the installation of a natural gas pipeline from the field to Darwin, and construction of an LNG facility located at Wickham Point, Darwin, to meet gross contracted sales of up to 3 million tons of LNG per year for a period of 17 years to customers in Japan. During 2004, construction of the LNG facility proceeded, as did the laying of the pipeline. The first LNG cargo is scheduled for delivery in early 2006. We have a 56.7 percent controlling interest in the pipeline and LNG facility. Our net share of natural gas production from the Bayu-Undan field is expected to be approximately 100 million cubic feet per day initially, then ramping up to approximately 260 net million cubic feet per day by 2009.

Greater Sunrise
We and our co-venturers evaluated commercial development options and LNG markets in the Asia Pacific region and the North American West Coast during 2004. The focus in 2004 was on an onshore LNG facility located at Darwin, although other alternatives, such as a floating LNG facility and an onshore plant in Timor-Leste, were also considered. Further progress on the project will require resolution of the maritime border dispute between Australia and Timor-Leste and ratification of the International Unitization Agreement by Timor-Leste. We have a 30 percent, non-operator interest in Greater Sunrise.

Athena/Perseus
A cooperative field development agreement for the Athena/Perseus (WA-17-L) gas field, located offshore western Australia, was executed in early 2001. In 2004, our net share of production was 35 million cubic feet of natural gas per day.

Malaysia
Exploration
In 2000, we acquired interests in deepwater Blocks G and J located off the east Malaysian state of Sabah. We participated in four exploration wells in the blocks. The Gumusut 1 well, in which we have a 40 percent interest, was drilled in Block J in 2003 and resulted in an oil discovery. Further exploratory drilling is planned. In September 2004, we successfully completed the drilling of the Malikai discovery, in which we have a 35 percent interest, in Block G. Appraisal of the Malikai discovery is anticipated in 2005. In addition, we plan to acquire a 40 percent interest in the Kebabangan discovery in early 2005. Appraisal work is planned for 2005.

E&P—AFRICA AND THE MIDDLE EAST

Nigeria
At year-end 2004, we were producing from four onshore Oil Mining Leases (OMLs), in which we have a 20 percent non-operator interest. Our interest in a shallow-water offshore OML was sold in the second quarter of 2004. Together, in 2004 these leases produced a net 30,100 barrels of oil per day and 71 million cubic feet of natural gas per day, compared with 36,900 barrels per day and 63 million cubic feet per day in 2003. In 2004, we continued development of projects in the onshore OMLs to supply feedstock natural gas under a gas sales contract with Nigeria LNG Limited, which owns an LNG facility on Bonny Island.

We have a 20 percent interest in a 480-megawatt gas-fired power plant being constructed in Kwale, Nigeria, to supply electricity to Nigeria's national electricity supplier under a 20-year agreement. When operational, the plant is expected to consume 68 million gross cubic feet per day of natural gas, sourced from proved natural gas reserves in the OMLs. The plant is targeted to become fully operational in 2005.

In October 2003, ConocoPhillips, the Nigerian National Petroleum Corporation (NNPC), Eni and ChevronTexaco signed a Heads of Agreement 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 agreed to form an incorporated joint venture, Brass LNG Limited, to undertake the project. These front-end studies are expected to be completed in 2006, and the LNG facility is targeted to become operational in 2010.

Exploration
We also have production sharing contracts on deepwater Nigeria Oil Prospecting Licenses (OPLs), including OPL 318 with a 50 percent interest, OPL 248 with a 28.8 percent interest, OPL 220 with a 47.5 percent interest, OPL 214 with a 20 percent interest, and OPL 250 with a 6.375 percent interest. We drilled the first exploration wells on both OPL 248 and OPL 250 in 2004. Neither of these wells encountered significant hydrocarbons and were classified as dry holes. The first exploration wells on both OPL 214 and OPL 318 are planned for 2005.

Cameroon
Exploration
In December 2002, we announced a successful test of an exploratory well offshore Cameroon. The Coco Marine No. 1 well was located in exploration permit PH 77, offshore in the Douala Basin. Contractor interests in the permit are held 50 percent by ConocoPhillips and 50 percent by a subsidiary of Petronas Carigali. We serve as the operator of the consortium. Seismic data was analyzed during 2004, and we plan an appraisal well and further exploratory drilling in 2005.

Libya
We are participating in discussions with our co-venturers and Libyan authorities regarding terms in connection with our anticipated re-entry into the country.

Qatar
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 markets. The agreement provided the framework for the necessary project agreements and the completion of feasibility studies, both of which were advanced in 2004. 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 7.8 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 of up to 1 billion cubic feet per day. Startup of the Qatargas 3 project is estimated to be in the 2009 timeframe.

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. Negotiations on more definitive agreements and progress on the studies continued in 2004.

Dubai
In Dubai, United Arab Emirates, we operate Dubai's four large, offshore oil fields. We are using advanced horizontal drilling techniques and advanced reservoir drainage technology to enhance the recovery rates and efficiencies in these late-life fields.

Iraq
We, along with LUKOIL, will cooperate with the Iraqi government to confirm LUKOIL's rights under its production sharing agreement (PSA) relating to the West Qurna field in Iraq. Subject to confirmation and the consents of governmental authorities and the parties to the contract, we expect to enter into further agreements regarding the assignment of a 17.5 percent interest in the PSA to us by LUKOIL.

E&P—RUSSIA AND CASPIAN SEA REGION

Russia
Polar Lights
We have a 50 percent ownership interest in Polar Lights Company, a Russian limited liability company established in January 1992 to develop fields in the Timan-Pechora basin in Northern Russia. Our net production from Polar Lights averaged 13,300 barrels of oil per day in 2004, compared with 13,600 barrels per day in 2003, and is included in equity affiliate production.

LUKOIL Joint Venture
We have entered into an arrangement with LUKOIL under which it is anticipated that we will acquire a 30 percent economic interest and a 50 percent voting interest in a joint venture to develop oil and gas resources in the northern part of Russia's Timan-Pechora province. We anticipate that our acquisition of a 30 percent interest will be completed in the first half of 2005. While this joint venture will be included in our E&P segment, our equity investment in LUKOIL is reflected in the LUKOIL Investment segment.

Other
In late 2004 we signed a Memorandum of Understanding with Gazprom to undertake a joint study on the development of the Shtokman gas field in the Barents Sea. The cooperative study will include the evaluation of LNG feasibility and transportation to the United States and European markets.

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 exercised our pre-emptive rights to acquire a proportionate share of BG International's 16.67 percent interest in the project. Discussions continue with the Republic of Kazakhstan government to conclude the sale.

Detailed design, procurement and construction activities continued on the Kashagan oil field development following approval by the Republic of Kazakhstan for the development plan and budget in February 2004. First commercial production is targeted for 2008. The initial production phase of the contract is for 20 years, with options to extend the agreement an additional 20 years.

Exploration

The contracting companies plan to continue to explore other structures within the North Caspian Sea license. The exploration area consists of 10.5 blocks, totaling nearly 2,000 square miles. In 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.

During 2004, the successful completion of the first offshore exploration well on the Kairan prospect was announced. Data analysis and additional studies are being conducted to evaluate the discovery. The testing of the Kairan-1 exploration well brings the Exploration Period under the NCPSA to a close. During 2004, appraisal of the Aktote discovery began with the successful drilling of the Aktote-2 appraisal well.

In the South Caspian Sea offshore Azerbaijan, we have a 20 percent interest in the Zafar Mashal prospect. The first exploratory well was completed in the third quarter of 2004 and the prospect declared non-commercial.

E&P—OTHER

In late 2003, we signed an agreement with Freeport LNG Development, L.P. (Freeport LNG) 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. Freeport LNG received conditional approval in June 2004 from the Federal Energy Regulatory Commission (FERC) to construct and operate the facility. Final approval from FERC was received in January 2005. Construction began in early 2005, and commercial startup is expected in 2008.

We are pursuing three other proposed LNG regasification terminals. The Beacon Port Terminal would be located in federal waters in the Gulf of Mexico, 56 miles south of the Louisiana mainland. Also in the Gulf of Mexico is the proposed Compass Port Terminal, to be located approximately 11 miles offshore Alabama. The third proposed facility would be a joint venture located in the Port of Long Beach, California. Each of these projects are in the initial regulatory permitting process.

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.

Natural Gas Pricing

Compared with the more global nature of crude oil commodity pricing, natural gas prices have historically varied more in different regions of the world. We produce natural gas from regions around the world that have significantly different supply, demand and regulatory circumstances, typically resulting in significantly lower average sales prices than in the Lower 48 region of the United States. Moreover, excess supply conditions that exist in certain parts of the world cannot easily serve to mitigate the relatively high-price conditions in the U.S. Lower 48 states and other markets because of a lack of infrastructure and because of the difficulties in transporting the natural gas. We, along with other companies in the oil and gas industry, are planning long-term projects in regions of excess supply to install the infrastructure required to produce and liquefy natural gas for transportation by tanker and subsequent regasification in regions where market demand is strong, such as to the U.S. Lower 48 states or certain parts of Asia, but where supplies are not as plentiful. Due to the significance of the overall investment in these long-term projects, the natural gas sales prices (to a third-party LNG facility) or transfer prices (to a company-owned LNG facility) in the areas of excess supply are expected to remain well below sales prices for natural gas that is produced closer to areas of high demand and which can be transferred to existing natural gas pipeline networks, such as in the U.S. Lower 48.

E&P—RESERVES

We have not filed any information with any other federal authority or agency with respect to our estimated total proved reserves at December 31, 2004. No difference exists between our estimated total proved reserves for year-end 2003 and year-end 2002, which are shown in this filing, and estimates of these reserves shown in a filing with another federal agency in 2004.

DELIVERY COMMITMENTS

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 5.4 trillion cubic feet of natural gas and 167 million barrels of crude oil in the future, including 1.0 trillion cubic feet related to the minority interests of consolidated subsidiaries. These contracts have various expiration dates through the year 2025. Although these delivery commitments could be fulfilled utilizing proved reserves in the United States, the Timor Sea, Nigeria, Indonesia, and the United Kingdom, we anticipate that some of them will be fulfilled with purchases in the spot market. A portion of the natural gas delivery commitment relates to proved undeveloped reserves in the Timor Sea and Indonesia. The Timor Sea reserves are expected to convert from proved undeveloped to proved developed in 2006 upon completion of the liquefied natural gas infrastructure in the region. A portion of the Indonesian reserves are expected to convert to proved developed in 2007, when additional wells are drilled and the expansion of the Suban gas plant is completed.

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. 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 2004, including our share of DEFS’, was 194,000 barrels per day, compared with 215,000 barrels per day in 2003.

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 is headquartered in Denver, Colorado. At December 31, 2004, DEFS owned and operated 55 natural gas liquids extraction plants, owned an equity interest in another nine, and had two classified in discontinued operations. Also at year end, DEFS’ gathering and transmission systems included approximately 59,000 miles of pipeline. In 2004, DEFS’ raw natural gas throughput averaged 6.4 billion cubic feet per day, and natural gas liquids extraction averaged 363,000 barrels per day, compared with 6.6 billion cubic feet per day and 353,000 barrels per day, respectively, in 2003. 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. natural gas liquids business included the following assets as of December 31, 2004:

- A 50 percent interest in a natural gas liquids extraction plant in San Juan County, New Mexico, with a gross plant inlet capacity of 500 million cubic feet per day. We also have minor interests in two other natural gas liquids extraction plants.
- A 25,000-barrel-per-day capacity natural gas liquids fractionation plant in Gallup, New Mexico.
- A 22.5 percent equity interest in Gulf Coast Fractionators, which owns a natural gas liquids fractionation plant in Mont Belvieu, Texas (with our net share of capacity at 25,000 barrels per day).
- A 40 percent interest in a fractionation plant in Conway, Kansas (with our net share of capacity at 42,000 barrels per day).

During 2004, we sold certain Midstream assets located primarily in Texas, Louisiana and New Mexico. This reflected our strategy to divest properties that did not support our natural gas production, while focusing on DEFS as the most effective vehicle for generating income from the processing of third-party natural gas. Included in the dispositions was a 700-mile intrastate natural gas and liquids pipeline system in Louisiana.

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 100 percent interest in a 580-mile Petroleum Transmission Company pipeline from Empress to Winnipeg and five related pipeline terminals.

- Two underground natural gas liquids storage facilities, comprised of the Richardson caverns with an approximate one-million-barrel capacity and the Dewdney caverns with an approximate three-million-barrel capacity, along with 800 million cubic feet of natural gas storage capacity.

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 was sold in the fourth quarter of 2004.

Canadian natural gas liquids extracted averaged 45,000 barrels per day in 2004, the same as 2003.

We also own a 39 percent equity interest in Phoenix Park Gas Processors Limited, a joint venture primarily 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 1.35-billion-cubic-feet-per-day gas processing plant and a 46,000-barrel-per-day natural gas liquids fractionator. Our share of natural gas liquids extracted averaged 6,000 barrels per day in 2004.

In Syria, we have a service contract with the Syrian Petroleum Company that expires on December 31, 2005. Our current plan is to honor that contract to its termination date. We expect our presence in Syria to end in 2006, once the formalities of closing out the service contract are accomplished. We have no plans to seek additional business in Syria.

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 R&M segment does not include the results or statistics from our equity investment in LUKOIL, which are reported in a separate segment (LUKOIL Investment). As a result, references to results, refinery crude oil throughput capacities and other statistics throughout the R&M segment exclude those related to our equity investment in LUKOIL.

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 facilitates supplying a portion of the gas and power needs of the R&M facilities. Commercial has buyers, traders and marketers in offices in Houston, London, Singapore and Calgary.

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. During the second quarter of 2004, we sold our Mobil-branded marketing assets on the East Coast in two separate transactions. Assets in the packages included approximately 100 company-owned-and-operated sites, and 350 dealer sites. The majority of the remaining sites are under contracts expected to close in 2005.

During the second quarter of 2004, we performed a review of the crude oil refining capacities for our worldwide refining operations. We utilize a "barrels-per-calendar-day" methodology, which includes allowances for maintenance turnarounds, regulatory constraints, crude oil quality and reliability. As a result of this review, effective July 1, 2004, R&M's total U.S. crude oil capacity was revised downward slightly, from 2,168,000 barrels per day to 2,160,000 barrels per day, while R&M's international refining capacity decreased from 447,000 barrels per day to 428,000 barrels per day.

Table of Contents

UNITED STATES

Refining

At December 31, 2004, we owned and operated 12 crude oil refineries in the United States, having an aggregate crude oil refining capacity of 2,160,000 barrels per day.

Refinery	Location		Region	Crude Throughput Capacity (MB/D)*
Bayway	Linden	New Jersey	East Coast	238
Trainer	Trainer	Pennsylvania	East Coast	185
				423
Alliance	Belle Chase	Louisiana	Gulf Coast	247
Lake Charles	Westlake	Louisiana	Gulf Coast	239
Sweeny	Old Ocean	Texas	Gulf Coast	216
				702
Wood River	Roxanna	Illinois	Central	306
Ponca City	Ponca City	Oklahoma	Central	187
Borger	Borger	Texas	Central	146
				639
Billings	Billings	Montana	West Coast	58
Los Angeles	Carson/Wilmington	California	West Coast	139
San Francisco	Santa Maria/Rodeo	California	West Coast	106
Ferndale	Ferndale	Washington	West Coast	93
				396
				2,160

** At December 31, 2004.*

East Coast Region

Bayway Refinery

Located on the New York Harbor in Linden, New Jersey, Bayway has a crude oil processing capacity of 238,000 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. The complex also includes a 775-million-pound-per-year polypropylene plant that 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 185,000 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 247,000 barrels per day and processes mainly light low-sulfur crudes. Alliance receives domestic crude oil from the Gulf of Mexico 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 major common-carrier pipeline systems.

Lake Charles Refinery

The Lake Charles refinery is located in Westlake, Louisiana. The refinery has a crude oil processing capacity of 239,000 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 its 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 its 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.

The Lake Charles facilities include a specialty coker and calciner that manufacture graphite petroleum coke, which is supplied to the steel and aluminum industries. The coker and calciner also provide 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 216,000 barrels per day, and processes mainly heavy, high-sulfur crude oil, but also processes light, low-sulfur crude oil. 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 by pipeline, barge and railcar.

ConocoPhillips has a 50 percent interest in Merey Sweeny, L.P., a limited partnership that owns a 65,000-barrel-per-day delayed coker and related facilities at the Sweeny refinery. PDVSA, which owns the other 50 percent interest, supplies the refinery with Venezuelan Merey, or equivalent Venezuelan, 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 R&M's largest refinery, with a crude oil processing capacity of 306,000 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, Illinois, 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 integration of these units into the refinery was completed during the second quarter of 2004, enabling the refinery to process heavier, lower-cost crude oil.

Ponca City Refinery

The Ponca City refinery is located in Ponca City, Oklahoma. It has a crude oil processing capacity of 187,000 barrels per day, and processes light and medium weight, low-sulfur crude oil. 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.

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 146,000 barrels per day, and the natural gas liquids fractionation capacity is 45,000 barrels per day. The natural gas liquids capacity was reduced during 2004 as part of a reconfiguration project. 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.

West Coast Region

Billings Refinery

The Billings refinery is located in Billings, Montana, and has a crude oil processing capacity of 58,000 barrels per day, processing a mixture of 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.

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 139,000 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 to meet federally mandated oxygenate requirements. Refined products are distributed to customers in Southern California, Nevada and Arizona by pipeline and truck.

San Francisco Refinery
The San Francisco 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 106,000 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 calcined and fuel-grade petroleum coke. The refinery produces CARB gasoline using ethanol to meet federally mandated oxygenate requirements. Refined products are distributed by pipeline, railcar, truck and barge.

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 93,000 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, R&M markets gasoline, diesel fuel, and aviation fuel through approximately 13,300 outlets in 46 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 12,300 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 the spot market. 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 Mountain, and West Coast regions. Most of these outlets market merchandise through the Kicks 66, Breakplace, or Circle K brand convenience stores.

At December 31, 2004, CFJ Properties, our 50/50 joint venture with Flying J, owned and operated 98 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. Flying J elected not to exercise their purchase option. As a result, we plan to continue as a co-venturer in CFJ Properties.

Transportation

Pipelines and Terminals

At December 31, 2004, we had approximately 32,500 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 66 finished product terminals, 10 liquefied petroleum gas terminals, seven crude oil terminals and one coke exporting facility.

Tankers

At December 31, 2004, we had under charter 16 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 have a domestic fleet of both owned and chartered boats and barges providing inland and ocean-going 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 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 5,000 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 blend the base oil into finished lubricants or market it to third parties.

We have a 50 percent interest in Penreco, a 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, 2004, R&M owned or had an interest in six refineries outside the United States with an aggregate crude oil capacity of 428,000 net barrels per day.

Refinery	Location		Ownership Interest	Crude Throughput Capacity (MB/D)*
Humber	N. Lincolnshire	United Kingdom	100.00%	221
Whitegate	Cork	Ireland	100.00%	71
MiRO	Karlsruhe	Germany	18.75%	53
CRC	Litvinov/Kralupy	Czech Republic	16.33%	27
Melaka	Melaka	Malaysia	47.00%	56
				428

** ConocoPhillips' share at December 31, 2004.*

Humber Refinery
Our wholly owned Humber refinery is located in North Lincolnshire, United Kingdom. The refinery's crude oil processing capacity is 221,000 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 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 70 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 has a crude oil processing capacity of 71,000 barrels per day. 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 45 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 a 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 Èeská 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. The refinery at Litvinov has a crude oil processing capacity of 103,000 barrels per day and processes Russian export blend crude oil delivered 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 63,000 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. The refinery has a rated crude oil processing capacity of 119,000 barrels per day, of which our share is 56,000 barrels per day. 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

R&M has marketing operations in 15 European countries. R&M's 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, 2004, R&M had approximately 2,100 marketing outlets in its European operations, of which about 1,480 were company-owned, and 620 were dealer-owned. Through our joint venture operations in Turkey and Switzerland, we also have interests in approximately 810 additional sites.

The company's largest branded site networks are in Germany and the United Kingdom, which account for approximately 63 percent of our total European branded units.

As of December 31, 2004, R&M had 143 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 43 retail sites. In Thailand and Malaysia, retail products are marketed under the "JET" and "ProJET" brands, respectively.

LUKOIL INVESTMENT

In September 2004, we made a joint announcement with LUKOIL, an international integrated oil and gas company headquartered in Russia, of an agreement to form a broad-based strategic alliance, whereby we would become a strategic equity investor in LUKOIL. Together, we also announced our intention to form a joint venture between the two companies to develop resources in the northern part of Russia's Timan-Pechora oil and gas province and the intention of the two companies to jointly seek the right to develop the West Qurna oil field in Iraq.

In the announcement, we disclosed that we were the successful bidder in an auction of 7.6 percent of LUKOIL's authorized and issued ordinary shares held by the Russian government. The transaction closed on October 7, 2004. By year-end 2004, we had increased our ownership in LUKOIL to 10 percent. Under the Shareholder Agreement between the two companies, we had the right to nominate a representative to the LUKOIL Board of Directors (Board). In January 2005, our nominee was elected to the LUKOIL Board, and certain amendments to LUKOIL's corporate charter that require unanimous Board consent for certain key decisions were approved. In addition, the Shareholder Agreement allows us to increase our ownership interest in LUKOIL to 20 percent and limits our ability to sell our LUKOIL shares for a period of four years, except in certain circumstances. Once we reach 12.5 percent ownership, we have the right to nominate a second representative to the LUKOIL Board. We use the equity method of accounting for our investment in LUKOIL. We estimate that our net share of LUKOIL's proved reserves at December 31, 2004, was 880 million barrels of oil equivalent.

As reported in LUKOIL's 2003 annual report, the majority of its upstream production is sourced within Russia, with 68 percent from the western Siberia region, 14 percent from the Timan-Pechora region and 13 percent from the Urals region. Outside of Russia, LUKOIL has projects in Azerbaijan, Kazakhstan, Egypt and Iraq. Downstream, LUKOIL has seven refineries with a net crude oil throughput capacity of approximately 1.2 million barrels daily. In addition, LUKOIL has an interest in approximately 4,600 retail sites in Russia and Europe, and another approximately 2,000 in the northeast United States.

CHEMICALS

Chevron Phillips Chemical Company LLC (CPChem) is a 50/50 joint venture with ChevronTexaco Corporation. We use the equity method of accounting for our investment in CPChem.

CPChem is headquartered in The Woodlands, Texas. 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.

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 one pipe fittings plant and nine plastic pipe plants in eight states.

Major international production facilities, including CPChem's joint-venture facilities, are located in Belgium, China, Saudi Arabia, Singapore, South Korea and Qatar. In addition, there is one plastic pipe plant in Mexico.

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

Construction of a major olefins and polyolefins complex in Mesaieed, Qatar, called "Q-Chem I," was completed in 2003. The facility completed performance testing and became fully operational in 2004. It 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, called "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 entered into a separate agreement with Atofina (now Total Petrochemical) and Qatar Petrochemical Company to jointly develop an ethane cracker in northern Qatar at Ras Laffan Industrial City. Request for final approval of the Q-Chem II projects by CPChem's Board of Directors is expected in 2005, with startup anticipated in 2008.

In 2003, CPChem formed a 50 percent-owned joint venture company to develop an integrated styrene facility in Al Jubail, Saudi Arabia. The facility, to be built on a site adjacent to the existing aromatics complex owned by Saudi Chevron Phillips Company (SCP), another 50 percent-owned CPChem joint venture, will include feed fractionation, an olefins cracker, and ethylbenzene and styrene monomer processing units. Construction of the facility will be in conjunction with an expansion of SCP's benzene plant. Construction began in the fourth quarter of 2004 and operational startup is anticipated in late 2007.

EMERGING BUSINESSES

Emerging Businesses encompass the development of new businesses beyond our traditional operations.

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, operated during 2004 as planned. The plant will be operated in 2005 as necessary to obtain technical data for commercial applications.

Technology Solutions
Our Technology Solutions businesses provide both upstream and downstream 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 SRT), alkylation technologies (ReVAP), and delayed coking (ThruPlus) technologies. We also offer a gasification technology (E-Gas) that uses petroleum coke, coal,

and other low-value hydrocarbon as feedstock, resulting in high-value synthesis gas that can be used for a slate of products, including power, hydrogen and chemicals.

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 their 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 completed development of a 730-megawatt, gas-fired combined heat and power plant in North Lincolnshire, United Kingdom. The facility provides steam and electricity to the Humber refinery and steam to a neighboring refinery, as well as merchant power into the U.K. market. Construction began in 2002, and the project was placed in commercial operations in October 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 advanced hydrocarbon processes, energy conversion technologies, new petroleum-based products, and renewable fuels.

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.

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 13, 2004, issue of the *Oil and Gas Journal*, our E&P segment had, on a BOE basis, 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 a large producer of natural gas liquids in the United States. 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 20, 2004, issue of the *Oil and Gas Journal*, our R&M segment had the largest U.S. refining capacity of 14 large refiners of petroleum products.

Worldwide, it ranked fifth among non-government-controlled companies. In the Chemicals segment, through our equity investment, CPChem generally ranks within the top 10 producers of many of its major product lines, based on average 2004 production capacity, as published by industry sources. 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 2004, we held a total of 1,692 active patents in 70 countries worldwide, including 697 active U.S. patents. During 2004, we received 51 patents in the United States and 121 foreign patents. Our products and processes generated licensing revenues of $28 million in 2004. 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 $126 million, $136 million and $355 million in 2004, 2003 and 2002, respectively.

The environmental information contained in Management's Discussion and Analysis on pages 77 through 80 under the caption, "Environmental" is incorporated herein by reference. It includes information on expensed and capitalized environmental costs for 2004 and those expected for 2005 and 2006.

International and domestic political developments and government regulation at all levels are prime factors that may materially affect our operations. Such political developments and regulation may affect prices; production levels; asset ownership; 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 and compliance for environmental protection. The occurrences and effects of such events are not predictable.

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.*

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 2004 and those matters previously reported in ConocoPhillips' 2003 Form 10-K and our first-, second- and third-quarter 2004 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 U.S. Securities and Exchange Commission's regulations.

In December 2004, the Puget Sound Clean Air Agency (PSCAA) notified us of their intent to seek civil penalties in the amount of $203,000 for alleged violations of various PSCAA regulations at our Tacoma Terminal in the state of Washington. We are currently assessing these allegations and expect to work with the PSCAA towards a resolution of this matter.

In December 2004, the San Luis Obispo Air Pollution Control District (SLOAPCD) notified us of their intent to seek civil penalties in the amount of $2,700,000 for alleged violations of various SLOAPCD regulations at the Santa Maria facility of our San Francisco refinery. We are currently assessing these allegations and expect to work with the SLOAPCD towards a resolution of this matter.

We participated in negotiations throughout 2004 with the U.S. Environmental Protection Agency (EPA), U.S. Department of Justice (DOJ), the states of Louisiana, Illinois, Pennsylvania, New Jersey, and the Northwest Clean Air Agency (the state of Washington) to settle allegations arising out of the EPA's national enforcement initiative, as well as other related Clean Air Act regulation issues. In January 2005, we entered into a consent decree with the United States and the local agency and states named above. In the consent decree, we agreed to reduce air emissions from refineries in Washington, California, Texas, Louisiana, Illinois, Pennsylvania, and New Jersey by approximately 47,000 tons per year over the next eight years. We plan to spend an estimated $525 million over that time period to install control technology and equipment to reduce emissions from stacks, vents, valves, heaters, boilers, and flares. The consent decree requires us to pay a civil penalty of $4.5 million in addition to at least $10 million to be spent on supplemental environmental projects in Illinois, Pennsylvania, Louisiana, Washington, and New Jersey.

The U.S. Coast Guard and Washington State Department of Ecology are investigating the possible sources of an alleged oil spill in Puget Sound. In November 2004, the U.S. Attorney and the U.S. Coast Guard offices in Seattle, Washington, issued subpoenas to Polar Tankers, Inc., a subsidiary of ConocoPhillips Company, for records related to the vessel Polar Texas. On December 23, 2004, the Governor of the state of Washington and the U.S. Coast Guard publicly announced that they believed the Polar Texas was the source of the alleged spill. Based on everything presently known by the company, we do not believe that we are the source of the alleged spill. The company is fully cooperating with the governmental authorities.

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 (BAAQMD) regulations at the Rodeo facility of our San Francisco refinery. On October 12, 2004, we entered into a settlement with the BAAQMD to resolve the alleged violations. We paid a civil penalty of $350,000 to the BAAQMD.

In August 2004 Polar Tankers, Inc., a subsidiary of ConocoPhillips Company, self-reported to the U.S. Coast Guard that a company employee had disclosed to management potential environmental violations onboard the vessel Polar Alaska. The potential violations related to allegations that certain actions may have resulted in one or more wastewater streams being discharged potentially having concentrations of oil exceeding an applicable regulatory limit of 15 parts per million. On September 1, 2004, the United States Attorney's office in Anchorage issued a subpoena to ConocoPhillips Company and Polar Tankers, Inc. for records relating to the company's report of potential violations. The company is fully cooperating with the governmental authorities.

On March 2, 2004, the BAAQMD notified us of their intent to seek civil penalties in the amount of $750,000 for 17 alleged violations of various BAAQMD regulations at our Rodeo facility and carbon plant located in the San Francisco area. We are currently assessing these allegations and expect to work with the BAAQMD towards a negotiated resolution of this matter.

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 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 alleged violations have been resolved as part of the January 2005 consent decree we entered into with the United States and other parties named above.

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 the EPA staff on several occasions to discuss the allegations. We believe the EPA staff is evaluating the information presented at the meetings. 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 agreed to resolve this matter for $410,000.

On December 17, 2002, the DOJ notified ConocoPhillips of various alleged violations of the National Pollution Discharge Elimination System permit for the Sweeny refinery. DOJ asserts that these alleged violations occurred at various times during the period beginning January 1997 through July 2002. A consent decree was lodged with the U.S. District Court for the Southern District of Texas, Houston Division on October 4, 2004, proposing a civil penalty of $610,000 and a Supplemental Environmental Project (SEP) valued at approximately $90,000. Under the SEP, ConocoPhillips will donate approximately 128 acres of land it owns near the Sweeny refinery to the U.S. Fish and Wildlife Service for inclusion in the San Bernard National Wildlife Refuge. We await the court's approval and entry of the consent decree.

On July 15, 2002, the United States filed a Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) cost recovery action against Conoco Inc. and seven other defendants alleging that the United States had incurred unreimbursed response costs at the Lowry Superfund Site located in Arapahoe County, Colorado. The United States seeks recovery of approximately $12.3 million in past response costs and a declaratory judgment for future CERCLA response cost liability. The defendants filed counterclaims seeking declaratory relief that certain response actions taken by the government were inconsistent with the National Contingency Plan. The defendants' counterclaims, if successful, will reduce the total amount of response costs that are reimbursable to the government.

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

None.

EXECUTIVE OFFICERS OF THE REGISTRANT

Name	Position Held	Age*
Rand C. Berney	Vice President and Controller	49
William B. Berry	Executive Vice President, Exploration and Production	52
John A. Carrig	Executive Vice President, Finance, and Chief Financial Officer	53
Philip L. Frederickson	Executive Vice President, Commercial	48
Stephen F. Gates	Senior Vice President, Legal, and General Counsel	58
John E. Lowe	Executive Vice President, Planning, Strategy and Corporate Affairs	46
J. J. Mulva	Chairman, President and Chief Executive Officer	58
J. W. Nokes	Executive Vice President, Refining, Marketing, Supply and Transportation	58

**On March 1, 2005.*

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, 2005. Set forth below is information about the executive officers.

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 effective 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; and Phillips' Senior Vice President, Treasurer and Chief Financial Officer since 2000.

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 p.l.c. (now BP p.l.c.) 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; and Phillips' Senior Vice President of Planning and Strategic Transactions since 2000.

J. J. Mulva was appointed Chairman of the Board of Directors, President and Chief Executive Officer of ConocoPhillips effective October 1, 2004, having previously served as ConocoPhillips' President and Chief Executive Officer since completion of the merger. Prior to the merger, he was Phillips' Chairman of the Board of Directors and Chief Executive Officer since 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.

[Table of Contents](#)

PART II

Item 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

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
2004			
First	**$ 71.49**	**64.30**	**.43**
Second	**78.99**	**68.58**	**.43**
Third	**84.35**	**71.28**	**.43**
Fourth	**91.22**	**81.49**	**.50**
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

Closing Stock Price at December 31, 2004	$ 86.83
Closing Stock Price at January 31, 2005	$ 92.79
Number of Stockholders of Record at January 31, 2005*	56,955

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

Table of Contents

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased*		Average Price** Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs***	Maximum Number of Shares (or Approximate Dollar Value) that May Yet Be Purchased Under the Plans or Programs***
January 1-31, 2004	28,301	$	65.64	-	-
February 1-29, 2004	7,710		66.36	-	-
March 1-31, 2004	6,510		69.65	-	-
Total	42,521	$	66.39	-	-
April 1-30, 2004	4,056	$	72.40	-	-
May 1-31, 2004	1,223		72.45	-	-
June 1-30, 2004	6,719		75.62	-	-
Total	11,998	$	74.21	-	-
July 1-31, 2004	6,403	$	77.86	-	-
August 1-31, 2004	326		73.81	-	-
September 1-30, 2004	3,018		79.93	-	-
Total	9,747	$	78.37	-	-
October 1-31, 2004	101,454	$	84.81	-	-
November 1-30, 2004	12,473		88.83	-	-
December 1-31, 2004	117,571		88.91	-	-
Total	231,498	$	87.11	-	-

**Transactions represent the repurchase of common shares from company employees to pay the option exercise price and to satisfy tax withholding obligations in connection with the exercise of stock options and restricted stock issued under the company's broad-based employee stock option and long-term incentive plans.*

***The average price paid per share is based on the low and high trading prices on the New York Stock Exchange on the date of the transaction.*

****No share repurchases were made pursuant to a publicly announced plan or program. On February 4, 2005, we announced a stock repurchase program that provides for the repurchase of up to $1 billion of the company's common stock over a period of up to two years. The program will serve as a means of offsetting dilution to shareholders from the company's stock-based compensation programs. Acquisitions for the share repurchase program will be made at management's discretion at prevailing prices, subject to market conditions and other factors. Purchases may be increased, decreased or discontinued at any time without prior notice. Shares of stock repurchased under the plan will be held as treasury shares.*

Table of Contents

Item 6. SELECTED FINANCIAL DATA

	Millions of Dollars Except Per Share Amounts				
	2004	2003	2002	2001	2000
Sales and other operating revenues	$ **135,076**	104,246	56,748	24,892	22,155
Income from continuing operations	**8,107**	4,593	698	1,601	1,848
Per common share					
Basic	**11.74**	6.75	1.45	5.46	7.26
Diluted	**11.57**	6.70	1.44	5.43	7.21
Net income (loss)	**8,129**	4,735	(295)	1,661	1,862
Per common share					
Basic	**11.77**	6.96	(.61)	5.67	7.32
Diluted	**11.60**	6.91	(.61)	5.63	7.26
Total assets	**92,861**	82,455	76,836	35,217	20,509
Long-term debt	**14,370**	16,340	18,917	8,610	6,622
Mandatorily redeemable minority interests and preferred securities	-	141	491	650	650
Cash dividends declared per common share	**1.79**	1.63	1.48	1.40	1.36

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.
- 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, 2005

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. The 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 92.

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 Overview

ConocoPhillips is an international, integrated energy company. We are the third largest integrated energy company in the United States, based on market capitalization. We have approximately 35,800 employees worldwide, and at year-end 2004 had assets of $93 billion. Our stock is listed on the New York Stock Exchange under the symbol "COP." Our business is organized into six operating segments:

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

- Midstream—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 (DEFS), a joint venture with Duke Energy Corporation.

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

- LUKOIL Investment—This segment consists of our equity investment in the ordinary shares of LUKOIL, an international, integrated oil and gas company headquartered in Russia. Our investment was 10 percent at December 31, 2004.

- 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 (CPChem), a joint venture with ChevronTexaco Corporation.

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

Crude oil and natural gas prices, along with refining margins, play the most significant roles in our profitability. Accordingly, our overall earnings depend primarily upon the profitability of our E&P and R&M segments. Crude oil and natural gas prices, along with refining 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:

- <u>Adding to our proved reserve base.</u> We add to our proved reserve base in three primary ways:

  - Successful exploration and development of new fields.
  - Acquisition of existing fields.
  - Applying new technologies and processes to boost recovery from existing fields.

  Through a combination of all three methods listed above, we have been successful in the past in maintaining or adding to our production and proved reserve base, and we anticipate being able to do so in the future. In the three years ending December 31, 2004, our reserve replacement exceeded 200 percent, excluding the impact of our equity investment in LUKOIL. The replacement rate was primarily attributable to the merger of Conoco and Phillips, and extensions and discoveries. Improved recovery also positively contributed to our reserve replacement success. Although it cannot be assured, going forward, we expect to more than replace our production over the next three years, excluding the impact of our equity investment in LUKOIL. This expectation is based on our current slate of exploratory and improved recovery projects.

- <u>Operating our producing properties and refining and marketing operations safely, consistently and in an environmentally sound manner.</u> Safety is our first priority and we are committed to protecting the health and safety of everyone who has a role in our operations. Maintaining 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. During 2004, our worldwide refinery utilization rate was 94 percent, compared with 95 percent in 2003. Finally, our operations are conducted in a manner that emphasizes our environmental stewardship.

- <u>Controlling costs and expenses.</u> 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 high 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. Because low operating and overhead costs are critical to maintaining competitive positions in our industries, cost control is a component of our variable compensation programs.

- <u>Selecting the appropriate projects in which to invest our capital dollars.</u> 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 expenditures and investments in 2004 totaled $9.5 billion, and we anticipate capital expenditures and investments to be approximately $7.9 billion in 2005. The 2005 amount excludes any discretionary expenditures that may be made to further increase our equity investment in LUKOIL. Excluding investments in LUKOIL, we project that 2005 capital expenditures will be higher than 2004 due to ongoing development projects, cost increases and new opportunities.

- Managing 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. During 2004 we substantially completed the asset disposition program that we announced at the time of the merger. Also during 2004, we acquired a 10 percent interest in LUKOIL, a major Russian integrated energy company.

- 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.

Our key performance indicators are shown in the statistical tables provided at the beginning of the 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.

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. Property impairments in 2004 totaled $164 million, compared with $252 million in 2003. We may also 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 mergers and acquisitions, at year-end 2004 we had $15 billion 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 our 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 2004, which contributed significantly to what we view as strong results from this segment in 2004. Industry crude oil prices were approximately $10 per barrel higher in 2004, versus 2003, averaging $41.42 per barrel for West Texas Intermediate. The increase primarily was due to strong global consumption associated with the robust global economic recovery and particularly strong demand growth in China, as well as oil supply disruptions in Iraq and in the U.S. Gulf of Mexico due to hurricane activity, with little excess OPEC production capacity available to replace lost supplies. Industry U.S. natural gas prices were moderately higher in 2004, versus 2003,

averaging approximately $6.13 per thousand cubic feet for Henry Hub. Natural gas prices rose in 2004 due primarily to higher oil prices, continued concerns regarding the adequacy of U.S. natural gas supplies, and hurricane activity disrupting production in the U.S. Gulf of Mexico. At year-end 2004, we estimated that a $1 per barrel change in crude oil prices would have an estimated $180 million annual impact on net income. For natural gas, the corresponding impact is approximately $50 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 DEFS. Higher natural gas liquids prices improved results from this segment in 2004. During 2004, we sold 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 2004 were improved over 2003, resulting in improved R&M profitability. Industry U.S. refining margins were sharply higher in 2004 versus 2003 due to robust U.S. refined product demand and concerns regarding the adequacy of refined product supplies in the U.S. market in light of tightening gasoline specifications and the ban on methyl tertiary-butyl ether (MTBE) in New York and Connecticut. Industry U.S. marketing margins declined in 2004 versus 2003, as wholesale and retail prices did not keep pace with rising gasoline and diesel spot market prices, which rose in part as a consequence of the increase in crude oil prices. At year-end 2004, we estimated that a 25 cent per barrel change in worldwide refining margins would have an estimated $125 million annual impact on net income. For U.S. marketing margins, the corresponding impact is approximately $100 million for a 1 cent per gallon margin change. Our refineries operated at 94 percent of capacity in 2004, and our goal in 2005 is to operate at an even higher level.

The LUKOIL Investment segment consists of our investment in the ordinary shares of LUKOIL. In October 2004, we closed on a transaction to acquire 7.6 percent of LUKOIL's shares held by the Russian government for approximately $2 billion. During the remainder of the year, we acquired additional shares in the open market for an additional $641 million, bringing our equity ownership interest in LUKOIL to 10 percent by year-end 2004.

The Chemicals segment consists of our 50 percent interest in 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 had been in a cyclical downturn that began in late 2000. In this difficult market environment, CPChem 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. During 2004, margins improved in the chemicals and plastics industries, leading to improved results from this segment.

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, 2004, we had a debt-to-capital ratio of 26 percent, compared with 34 percent at the end of 2003. The decrease was due to a $2.8 billion reduction in debt during 2004, along with increased equity reflecting strong earnings. If market conditions permit, we are targeting to lower our debt-to-capital ratio over the next several years to the low-20-percent range. This should improve our cost of capital and further position us for growth opportunities in the future.

Consolidated Results

	Millions of Dollars		
Years Ended December 31	**2004**	2003	2002
Income from continuing operations	$ **8,107**	4,593	698
Income (loss) from discontinued operations	**22**	237	(993)
Cumulative effect of accounting changes	**-**	(95)*	-
Net income (loss)	$ **8,129**	4,735	(295)

** 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	**2004**	2003	2002
Exploration and Production (E&P)	$ **5,702**	4,302	1,749
Midstream	**235**	130	55
Refining and Marketing (R&M)	**2,743**	1,272	143
LUKOIL Investment	**74**	-	-
Chemicals	**249**	7	(14)
Emerging Businesses	**(102)**	(99)	(310)
Corporate and Other	**(772)**	(877)	(1,918)
Net income (loss)	$ **8,129**	4,735	(295)

2004 vs. 2003

Net income was $8,129 million in 2004, compared with $4,735 million in 2003. The improved results in 2004 primarily were due to:

- Improved refining margins in our R&M segment.
- Higher crude oil, natural gas and natural gas liquids prices in our E&P and Midstream segments.
- Improved margins in the Chemicals segment.
- Initial equity earnings from our investment in LUKOIL.

See the "Segment Results" section for additional information on our segment results.

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

Income Statement Analysis

2004 vs. 2003

Sales and other operating revenues increased 30 percent in 2004, while purchased crude oil, natural gas and products increased 34 percent. These increases mainly were due to:

- Higher petroleum products prices.
- Higher prices for crude oil, natural gas and natural gas liquids.
- Increased volumes of natural gas bought and sold by our commercial organization in its role of optimizing the commodity flows of our E&P segment.
- Higher excise, value added and other similar taxes.

Equity in earnings of affiliates increased 183 percent in 2004. The increase reflects initial equity earnings from our investment in LUKOIL, as well as improved results from:

- Our heavy-oil joint ventures in Venezuela (Hamaca and Petrozuata), due to higher crude oil prices and higher production volumes.
- Our chemicals joint venture, Chevron Phillips Chemical Company LLC, due to higher volumes and margins.
- Our midstream joint venture, Duke Energy Field Services, LLC, reflecting higher natural gas liquids prices.
- Our joint-venture refinery in Melaka, Malaysia, due to improved refining margins in the Asia Pacific region.
- Our joint-venture delayed coker facilities at the Sweeny, Texas, refinery, Merey Sweeny LLP, due to wider heavy-light crude oil differentials.

Depreciation, depletion and amortization (DD&A) increased 9 percent in 2004, primarily due to new fields onstream for a full year for the first time in 2004, including the Bayu-Undan field in the Timor Sea; the Su Tu Den field, offshore Vietnam; and the Grane field in the Norwegian North Sea. In addition, foreign currency rates and the Norway Removal Grant Act increased DD&A in 2004. In 2005, we expect DD&A to increase by approximately 15 percent over 2004 levels, reflecting new projects in the E&P segment, including a full year's production from the Magnolia field in the Gulf of Mexico and the Belanak field, offshore Indonesia, as well as new production from the Clair field in the Atlantic Margin and continued ramp-up at the Bayu-Undan field.

Interest and debt expense declined 35 percent in 2004. The decrease primarily was due to lower average debt levels during 2004 and an increased amount of interest being capitalized on major capital projects.

Our effective tax rate for 2004 was 44 percent, compared with 45 percent for 2003. The decrease in the effective tax rate in 2004, compared with 2003, mainly was due to the impact of a higher proportion of income in lower tax rate jurisdictions, partially offset by reduced benefits from tax rate reductions.

We adopted Financial Accounting Standards Board (FASB) Statement No. 143, “Accounting for Asset Retirement Obligations,” (SFAS No. 143) effective January 1, 2003. As a result, we recognized a benefit of $145 million for the cumulative effect of this accounting change. Also effective January 1, 2003, we adopted Financial Accounting Standards Board Interpretation No. 46 (revised December 2003), “Consolidation of Variable Interest Entities,” (FIN 46(R)) 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. We recognized a net $95 million charge in 2003 for the cumulative effect of these two accounting changes.

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, when comparing 2003 with 2002, 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.
- 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.

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.

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.

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 SFAS No. 143. See Note 2—Changes in Accounting Principles, in the Notes to Financial Statements, for additional information.

In addition to the merger impact, interest and debt expense also increased in 2003 because of the adoption of FIN 46(R). The adoption of FIN 46(R) 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, 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 6—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.

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. The restructuring program was essentially completed during 2004. The information in Note 5—Restructuring, in the Notes to Consolidated Financial Statements, is incorporated herein by reference.

Segment Results

E&P

		2004	2003	2002
		Millions of Dollars		
Net Income				
Alaska	$	**1,832**	1,445	870
Lower 48		**1,110**	929	286
United States		**2,942**	2,374	1,156
International		**2,760**	1,928	593
	$	**5,702**	4,302	1,749

		Dollars Per Unit		
Average Sales Prices				
Crude oil (per barrel)				
United States	$	**38.25**	28.85	23.83
International		**37.18**	28.27	25.16
Total consolidated		**37.65**	28.54	24.39
Equity affiliates*		**24.18**	19.01	18.41
Worldwide E&P		**36.06**	27.52	24.08
Natural gas—lease (per thousand cubic feet)				
United States		**5.33**	4.67	2.75
International		**4.14**	3.69	2.79
Total consolidated		**4.62**	4.08	2.77
Equity affiliates*		**2.19**	4.44	2.71
Worldwide E&P		**4.61**	4.08	2.77

Average Production Costs Per Barrel of Oil Equivalent				
United States	$	**6.48**	5.89	5.66
International		**4.31**	4.12	3.99
Total consolidated		**5.26**	4.92	4.94
Equity affiliates*		**4.86**	4.85	4.38
Worldwide E&P		**5.23**	4.92	4.92

		Millions of Dollars		
Worldwide Exploration Expenses				
General administrative; geological and geophysical; and lease rentals	$	**286**	301	285
Leasehold impairment		**175**	133	146
Dry holes		**242**	167	161
	$	**703**	601	592

** Excludes our equity share of LUKOIL reported in the LUKOIL Investment segment.*

	2004	2003	2002
	Thousands of Barrels Daily		
Operating Statistics			
Crude oil produced			
Alaska	**298**	325	331
Lower 48	**51**	54	40
United States	**349**	379	371
European North Sea	**271**	290	196
Asia Pacific	**94**	61	24
Canada	**25**	30	13
Other areas	**58**	72	43
Total consolidated	**797**	832	647
Equity affiliates*	**108**	102	35
	905	934	682
Natural gas liquids produced			
Alaska	**23**	23	24
Lower 48	**26**	25	8
United States	**49**	48	32
European North Sea	**14**	9	8
Asia Pacific	**9**	-	-
Canada	**10**	10	4
Other areas	**2**	2	2
	84	69	46
	Millions of Cubic Feet Daily		
Natural gas produced**			
Alaska	**165**	184	175
Lower 48	**1,223**	1,295	928
United States	**1,388**	1,479	1,103
European North Sea	**1,119**	1,215	595
Asia Pacific	**301**	318	137
Canada	**433**	435	165
Other areas	**71**	63	43
Total consolidated	**3,312**	3,510	2,043
Equity affiliates*	**5**	12	4
	3,317	3,522	2,047

**Excludes our equity share of LUKOIL reported in the LUKOIL Investment segment.*
***Represents quantities available for sale. Excludes gas equivalent of natural gas liquids shown above.*

	Thousands of Barrels Daily		
Mining operations			
Syncrude produced	**21**	19	8

The E&P segment explores for, produces and markets 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, 2004, our E&P operations were producing in the United States, Norway, the United Kingdom, Canada, Nigeria, Venezuela, offshore Timor Leste in the Timor Sea, Australia, China, Indonesia, the United Arab Emirates, Vietnam, and Russia.

2004 vs. 2003

Net income from the E&P segment increased 33 percent in 2004. The increase primarily was due to higher crude oil prices and, to a lesser extent, higher natural gas and natural gas liquids prices. Increased sales prices were partially offset by lower crude oil and natural gas production, as well as higher exploration expenses and lower net gains on asset dispositions. The 2003 period included a net benefit of $142 million for the cumulative effect of accounting changes (SFAS No. 143 and FIN 46(R)), as well as benefits of $233 million from changes in certain international income tax and site restoration laws and equity realignment of certain Australian operations. Included in 2004 is a $72 million benefit related to the remeasurement of deferred tax liabilities from the 2003 Canadian graduated tax rate reduction and a 2004 Alberta provincial tax rate change.

If crude oil and natural gas prices in 2005 do not remain at the historically strong levels experienced in 2004, E&P's earnings would be negatively impacted in 2005. See the "Business Environment and Executive Overview" section for additional discussion of crude oil and natural gas prices, including estimates of our E&P segment's sensitivities to crude oil and natural gas prices.

Proved reserves at year-end 2004 were 7.61 billion barrels of oil equivalent (BOE), compared with 7.85 billion BOE at year-end 2003. This excludes the estimated 880 million BOE reported in the LUKOIL Investment segment. Our Canadian Syncrude mining operations had an additional 258 million barrels of proved oil sands reserves at the end of 2004, compared with 265 million barrels at year-end 2003.

2003 vs. 2002

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(R) for variable interest entities involving synthetic leases and certain other financing structures increased E&P's net income by $142 million in 2003.

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.

U.S. E&P

2004 vs. 2003

Net income from our U.S. E&P operations increased 24 percent in 2004. The increase was mainly the result of higher crude oil prices and, to a lesser extent, higher natural gas and natural gas liquids prices, partially offset by lower crude oil and natural gas production volumes and lower net gains on asset dispositions. In addition, the 2003 period included a net benefit of $142 million for the cumulative effect of accounting changes (SFAS No. 143 and FIN 46(R)).

U.S. E&P production on a BOE basis averaged 629,000 barrels per day in 2004, down 7 percent from 674,000 BOE per day in 2003. The decreased production primarily was the result of the impact of 2003 asset dispositions, normal field production declines, and planned maintenance activities during 2004.

2003 vs. 2002

Net income from our U.S. E&P operations increased 105 percent in 2003, compared with 2002. The improvement reflects higher crude oil and natural gas prices, higher production volumes, and a net $143 million benefit from the cumulative effect of adopting SFAS No. 143 and FIN 46(R).

U.S. E&P production averaged 674,000 BOE per day in 2003, an increase of 15 percent from 587,000 BOE per day in 2002. The increased production primarily was the result of the merger, as well as increased production from the Borealis satellite field at Kuparuk and from the Alpine field, partially offset by normal field production declines and the impact of asset dispositions.

International E&P

2004 vs. 2003

Net income from our international E&P operations increased 43 percent in 2004. The increase primarily was due to higher crude oil prices and, to a lesser extent, higher natural gas and natural gas liquids prices and higher natural gas liquids volumes. Higher prices were partially offset by increased exploration expenses.

International E&P production averaged 913,000 BOE per day in 2004, down slightly from 916,000 BOE per day in 2003. This excludes the estimated 38,000 barrels per day reported in the LUKOIL Investment segment. Production was favorably impacted in 2004 by the startup of production from the Su Tu Den field in Vietnam in late 2003, the ramp-up of liquids production from the Bayu-Undan field in the Timor Sea since startup in February 2004, and the startup of the Hamaca upgrader in Venezuela in the fourth quarter of 2004. These items were more than offset by the impact of asset dispositions, normal field production declines, and planned maintenance. In addition, our Syncrude mining operations produced 21,000 barrels per day in 2004, compared with 19,000 barrels per day in 2003.

Table of Contents

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 averaged 916,000 BOE per day in 2003, compared with 482,000 BOE 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. The merger was the primary reason for the production increase.

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 Leste 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 6—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.

Table of Contents

Midstream

		2004	2003	2002
			Millions of Dollars	
Net Income*	**$**	**235**	130	55
**Includes DEFS related net income:*	***$***	***143***	*72*	*23*
			Dollars Per Barrel	
Average Sales Prices				
U.S. natural gas liquids*				
Consolidated	**$**	**29.38**	22.67	19.07
Equity		**28.60**	22.12	15.92

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

		Thousands of Barrels Daily	
Operating Statistics			
Natural gas liquids extracted*	**194**	215	155
Natural gas liquids fractionated**	**205**	224	152

**Includes our share of equity affiliates.*
***Excludes DEFS.*

The Midstream segment purchases raw natural gas from producers and gathers natural gas through an extensive network of 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. The Midstream segment consists of our 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.

2004 vs. 2003

Net income from the Midstream segment increased 81 percent in 2004. The improvement was primarily attributable to improved results from DEFS, which had:

- Higher gross margins, primarily reflecting higher natural gas liquids prices.
- A $23 million (gross) charge in 2003 for the cumulative effect of accounting changes, mainly related to the adoption of SFAS No. 143; partially offset by investment impairments and write-downs of assets held for sale during 2004.

Our Midstream operations outside of DEFS had higher earnings in 2004 as well, reflecting the impact of higher natural gas liquids prices that more than offset the effect of asset dispositions in 2004.

Included in the Midstream segment’s net income was a benefit of $36 million in 2004, the same as 2003, 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.

2003 vs. 2002

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.

Table of Contents

R&M

	2004	2003	2002
	Millions of Dollars		
Net Income			
United States	**$ 2,126**	990	138
International	**617**	282	5
	$ 2,743	1,272	143

	Dollars Per Gallon		
U.S. Average Sales Prices*			
Automotive gasoline			
Wholesale	**$ 1.33**	1.05	.96
Retail	**1.52**	1.35	1.03
Distillates—wholesale	**1.24**	.92	.77

**Excludes excise taxes.*

	Thousands of Barrels Daily		
Operating Statistics			
Refining operations*			
United States			
Crude oil capacity**	**2,164**	2,168	1,829
Crude oil runs	**2,059**	2,074	1,661
Capacity utilization (percent)	**95%**	96	91
Refinery production	**2,245**	2,301	1,847
International			
Crude oil capacity**	**437**	442	195
Crude oil runs	**396**	414	161
Capacity utilization (percent)	**91%**	94	83
Refinery production	**405**	412	164
Worldwide			
Crude oil capacity**	**2,601**	2,610	2,024
Crude oil runs	**2,455**	2,488	1,822
Capacity utilization (percent)	**94%**	95	90
Refinery production	**2,650**	2,713	2,011
Petroleum products sales volumes			
United States			
Automotive gasoline	**1,356**	1,369	1,230
Distillates	**553**	575	502
Aviation fuels	**191**	180	185
Other products	**564**	492	372
	2,664	2,616	2,289
International	**477**	430	162
	3,141	3,046	2,451

**Includes our share of equity affiliates, except for our share of LUKOIL, which is reported in the LUKOIL Investment segment.*
***Weighted-average crude oil capacity for the period. Actual capacity at year-end 2004 and 2002 was 2,160,000 and 2,166,000 barrels per day, respectively, in the United States and 428,000 and 440,000 barrels per day, respectively, internationally.*

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 petroleum products, and transporting, distributing and marketing petroleum products. R&M has operations in the United States, Europe and Asia Pacific.

2004 vs. 2003

Net income from the R&M segment increased 116 percent in 2004, primarily due to higher refining margins. This was partially offset by lower U.S. marketing margins, and higher maintenance turnaround and utility costs. The 2003 period included a $125 million net charge for the cumulative effect of accounting changes (FIN 46(R)).

2003 vs. 2002

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(R) for variable interest entities involving synthetic leases and certain other financing structures.

U.S. R&M

2004 vs. 2003

Net income from our U.S. R&M operations increased 115 percent in 2004, primarily due to higher refining margins, partially offset by lower marketing margins, and higher maintenance turnaround and utility costs. The 2003 period included a $125 million net charge for the cumulative effect of accounting change (FIN 46(R)).

Our U.S. refining capacity utilization rate was 95 percent in 2004, compared with 96 percent in 2003. The lower capacity utilization was due to increased maintenance downtime.

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. 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(R) for variable interest entities involving synthetic leases and certain other financing structures, along with higher utility costs.

Our U.S. refineries ran at a crude oil capacity utilization rate of 96 percent in 2003, 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.

International R&M

2004 vs. 2003

Net income from the international R&M operations increased 119 percent in 2004, with the improvement primarily attributable to higher refining margins, partially offset by negative foreign currency impacts on operating costs.

Our international crude oil refining capacity utilization rate was 91 percent in 2004, compared with 94 percent in 2003. Beginning in the third quarter of 2004, we changed our crude oil capacity utilization statistic at the Humber refinery to make it consistent with our other refineries. This change has been applied to the operating statistics for 2003 and 2002.

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. 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 94 percent in 2003, compared with 83 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.

LUKOIL Investment

	Millions of Dollars		
	2004	2003	2002
Net Income	**$ 74**	-	-
Operating Statistics*			
Net crude oil production (thousands of barrels daily)	**38**	-	-
Net natural gas production (millions of cubic feet daily)	**13**	-	-
Net refinery crude processed (thousands of barrels daily)	**19**	-	-

**Represents our net share of our estimate of LUKOIL's production and processing.*

This segment represents our investment in the ordinary shares of LUKOIL, an international, integrated oil and gas company headquartered in Russia, which we account for under the equity method. In October 2004, we closed on a transaction to acquire 7.6 percent of LUKOIL's shares held by the Russian government. During the remainder of 2004, we increased our ownership interest to 10 percent.

In addition to our estimate of our fourth-quarter weighted-average 8.6 percent equity share of LUKOIL's earnings, this segment also reflects the amortization of the basis difference between our equity interest in the net assets of LUKOIL and the historical cost of our investment in LUKOIL. In addition, this segment will include the costs associated with the employees seconded to LUKOIL.

Because LUKOIL's accounting cycle close and preparation of U.S. GAAP financial statements occurs subsequent to our accounting cycle close, our equity earnings and statistics for 2004 from our LUKOIL investment are an estimate, based on market indicators, historical production trends of LUKOIL, and other factors. Any difference between the estimate and actual results will be recorded in a subsequent period. This estimate-to-actual adjustment will then be a recurring component of future period results.

Chemicals

	Millions of Dollars		
	2004	2003	2002
Net Income (Loss)	**$ 249**	7	(14)

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.

2004 vs. 2003

Net income from the Chemicals segment increased $242 million in 2004, compared with 2003. The improvement reflects that CPChem had improved equity earnings from Qatar Chemical Company Ltd. (Q-Chem), an olefins and polyolefins complex in Qatar, and Saudi Chevron Phillips Company, an aromatics complex in Saudi Arabia. Results from CPChem's consolidated operations also improved from higher ethylene and benzene margins, as well as increased ethylene, polyethylene and normal alpha olefins sales volumes.

2003 vs. 2002

The worldwide chemicals industry experienced an economic downturn beginning in the second half of 2000, and the downturn continued through 2003. The downturn 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.

Emerging Businesses

	Millions of Dollars		
	2004	2003	2002
Net Loss			
Technology solutions	**$ (18)**	(20)	(16)
Gas-to-liquids	**(33)**	(50)	(273)
Power	**(31)**	(5)	(3)
Other	**(20)**	(24)	(18)
	$ (102)	(99)	(310)

The Emerging Businesses segment includes the development of new businesses outside our traditional operations. These activities include gas-to-liquids (GTL) operations, power generation, technology solutions such as sulfur removal technologies, and emerging technologies, such as renewable fuels and emission management technologies.

2004 vs. 2003

Emerging Businesses incurred a net loss of $102 million in 2004, compared with a net loss of $99 million in 2003. Contributing to the higher losses in 2004 were lower domestic power margins and higher maintenance costs, as well as increased costs associated with the Immingham power plant project in the United Kingdom, which entered the initial commissioning phase of the project during 2004. Prior to the initial commissioning phase, most costs associated with this project were capitalized as construction costs. This project completed the initial commissioning phase and began commercial operations in October 2004. Partially offsetting these items were lower research and development costs, compared with 2003, which included the costs of a demonstration GTL plant then under construction. Construction of the GTL plant was substantially completed during the second quarter of 2003.

2003 vs. 2002

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 GTL 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.

Corporate and Other

	Millions of Dollars		
	2004	2003	2002
Net Income (Loss)			
Net interest	**$ (514)**	(632)	(412)
Corporate general and administrative expenses	**(212)**	(173)	(173)
Discontinued operations	**22**	237	(993)
Merger-related costs	**(14)**	(223)	(307)
Cumulative effect of accounting changes	**-**	(112)*	-
Other	**(54)**	26	(33)
	$ (772)	(877)	(1,918)

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

2004 vs. 2003

After-tax net interest consists of interest and debt expense, net of interest income and capitalized interest, as well as premiums incurred on the early retirement of debt and costs associated with the receivables monetization program. Net interest decreased 19 percent in 2004, primarily due to lower average debt levels, an increased amount of interest being capitalized in 2004, lower charges for premiums paid on the early retirement of debt, and lower costs associated with the receivables monetization program.

After-tax corporate general and administrative expenses increased 23 percent in 2004. The increase reflects higher compensation costs, which includes increased stock-based compensation due to an increase in both the number of units issued and higher stock prices in the 2004 period.

Discontinued operations net income declined 91 percent in 2004, reflecting asset dispositions completed during 2003 and 2004.

Beginning with the second quarter of 2004, we no longer separately identify merger-related costs because these activities have been substantially completed.

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 lower in 2004, mainly due to the inclusion in the 2003 period of gains related to insurance demutualization benefits, negative foreign currency transaction impacts, higher environmental costs and increased minority interest expense.

2003 vs. 2002

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(R) 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(R) at January 1, 2003, increased debt, which resulted in higher interest expense.

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.

Results from Other were improved in 2003, compared with 2002, 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.

CAPITAL RESOURCES AND LIQUIDITY

Financial Indicators

		Millions of Dollars Except as Indicated		
		2004	2003	2002
Current ratio		**1.0**	.8	.9
Net cash provided by operating activities	$	**11,959**	9,356	4,978
Total debt repayment obligations due within one year	$	**632**	1,440	849
Total debt*	$	**15,002**	17,780	19,766
Mandatorily redeemable preferred securities of trust subsidiaries*	$	**-**	-	350
Other minority interests	$	**1,105**	842	651
Common stockholders’ equity	$	**42,723**	34,366	29,517
Percent of total debt to capital**		**26%**	34	39
Percent of floating-rate debt to total debt		**19%**	17	12

*With the adoption of FIN 46(R) 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 short- and long-term liquidity requirements, we look to a variety of funding sources, primarily cash generated from operating activities. In addition, during 2004 we raised approximately $1.6 billion in funds from the sale of assets. During 2004, available cash was used to support the company’s ongoing capital expenditures and investments program, repay debt and pay dividends. In September 2004, our Board of Directors (Board) declared a quarterly dividend of $.50 per share, which represented a 16 percent increase from the previous quarter’s dividend rate. Total dividends paid on our common stock in 2004 were $1.2 billion. During 2004, cash and cash equivalents increased $897 million to $1,387 million. In early 2005, a portion of this cash was used to repay $544 million of commercial paper that had been outstanding at December 31, 2004.

In addition to cash flows from operating activities and proceeds from asset sales, we also rely on our commercial paper and credit facility programs, as well as our $5 billion universal shelf registration statement, to support our short- and long-term liquidity requirements. We anticipate that these sources of liquidity will be adequate to meet our funding requirements through 2006, including our capital spending program and required debt payments.

Our cash flows from operating activities increased in each of the annual periods from 2002 through 2004. In addition to favorable market conditions, major acquisitions and mergers played a significant role in the upward trend of our cash flows from operating activities. The most significant event during this period was the merger of Conoco and Phillips on August 30, 2002. Phillips was designated as the acquirer for accounting purposes, so 2002 operating cash flows included eight months (January through August) of Phillips’ activity only and four months of ConocoPhillips’ activity (September through December), while 2003 included the first full year of ConocoPhillips’ activity. Absent any other significant acquisitions or mergers during 2005, we expect that market conditions will be the most important factor affecting our 2005 cash flows, when compared with 2004.

Significant Sources of Capital

Operating Activities
During 2004 cash of $11,959 million was provided by operating activities, an increase of $2,603 million from 2003. This increase in cash provided by operating activities was primarily due to an increase in income from continuing operations, partially offset by an increase in working capital. The working capital increase primarily was driven by higher accounts receivable and a higher retained interest in receivables sold to a Qualifying Special Purpose Entity (QSPE), partly offset by higher accounts payable. Contributing to the increase in accounts receivable and accounts payable were higher sales and purchase prices, respectively. For additional information on income from continuing operations, see the Results of Operations section. For additional information on receivables sold to a QSPE, see Receivables Monetization in the Off-Balance Sheet Arrangements section.

Our cash flows from operating activities for both the short- and long-term are highly dependent upon prices for crude oil, natural gas and natural gas liquids, as well as refining and marketing margins. During 2003 and particularly in 2004, we benefited from high crude oil and natural gas prices, as well as strong refining margins. The sustainability of these prices and margins are driven by market conditions over which we have no control. In addition, the level of our production volumes of crude oil, natural gas and natural gas liquids also impacts our cash flows. These production levels are impacted by such factors as acquisitions and dispositions of fields, field production decline rates, new technologies, operating efficiency, the addition of proved reserves through exploratory success, and the timely and cost-effective development of those proved reserves.

We will need to continue to add to our proved reserve base through exploration and development of new fields, or by acquisition, and to apply new technologies and processes to boost recovery from existing fields in order to maintain or increase production and proved reserves. We have been successful in the past in maintaining or adding to our production and proved reserve base and, although it cannot be assured, anticipate being able to do so in the future. Our barrel-of-oil-equivalent (BOE) production, after adjusting our 2003 production for approximately 60,000 BOE per day for assets sold in 2003 and early 2004, has increased in each of the past three years (2002, 2003 and 2004). Excluding the impact of our equity investment in LUKOIL on our production, we expect our 2005 production level to be approximately 4 percent higher than our 2004 level of 1.54 million BOE per day. In 2006, we expect our production level to increase an additional 4 percent over our projected 2005 BOE production level. Beyond 2006, we estimate our BOE production to grow at an average annual rate of approximately 3 percent for the period 2007 through 2010. These projections are tied to projects currently scheduled to begin production or ramp-up in those years and exclude our Canadian Syncrude mining operations.

Excluding the impact of our equity investment in LUKOIL on our proved oil and gas reserves, our reserve replacement over the three-year period ending December 31, 2004, exceeded 200 percent. Contributing to our success during this three-year period were proved reserves added by the merger of Conoco and Phillips, volumes added through extensions and discoveries, and improved recovery. Although it cannot be assured, going forward, we expect to more than replace our production over the next three years. This expectation is based on our current slate of exploratory and improved recovery projects. As discussed in Critical Accounting Policies, engineering estimates of proved reserves are imprecise and therefore each year reserves may be revised upward or downward due to the impact of changes in oil and gas prices or as more technical data becomes available on the reservoirs. In 2004 and 2002, revisions decreased our reserves, while in 2003, revisions increased reserves. It is not possible to reliably predict how revisions will impact reserve quantities in the future. The net addition of proved undeveloped reserves accounted for 64 percent, 76 percent and 34 percent of our total net additions in 2004, 2003 and 2002, respectively.

During these years, we converted, on average, approximately 13 percent per year of our proved undeveloped reserves to proved developed reserves. Of the proved undeveloped reserves we had at December 31, 2004, we estimate that the average annual conversion rate for these reserves for the following three years will be in the 25 percent range. For additional information related to the development of proved undeveloped reserves, see the discussion under the E&P section of Capital Spending. The projections and actual results noted above exclude the impact of our equity investment in LUKOIL, and the anticipated production and reserve replacement results are subject to risks, including reservoir performance; operational downtime; finding and development execution; obtaining management, Board and third-party approval of development projects in a timely manner; regulatory changes; geographical location; market prices; and environmental issues; and therefore, cannot be assured.

Asset Sales
Following the merger, we initiated an asset disposition program. Our ultimate target was to raise approximately $4.5 billion by the end of 2004. During 2004, proceeds from asset sales were $1.6 billion, bringing total proceeds to approximately $5.0 billion since the program began. While we will continue to have modest asset disposition activity, this asset disposition program was essentially completed at the end of the second quarter of 2004. Proceeds from these asset sales were 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 $5 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, 2004, we had $544 million of commercial paper outstanding, compared with $709 million of commercial paper outstanding at December 31, 2003.

Effective October 12, 2004, we entered into two new revolving credit facilities totaling $5 billion to replace our previously existing $1.5 billion 364-day facility that was set to expire on October 13, 2004; two revolving credit facilities totaling $2 billion expiring in October 2006; and a $500 million facility expiring in October 2008. The two new facilities include a $2.5 billion four-year facility expiring in October 2008 and a $2.5 billion five-year facility expiring in October 2009. Both facilities are available for use as direct bank borrowings or as support for our $5 billion commercial paper program. In addition, the five-year facility may be used to support issuances of letters of credit totaling up to $750 million. The facilities are broadly syndicated among financial institutions and do not contain any material adverse change provisions or any covenants requiring maintenance of specified financial ratios or ratings. The credit agreements do contain a cross-default provision relating to our, or any of our consolidated subsidiaries', failure to pay principal or interest on other debt obligations of $200 million or more. There were no outstanding borrowings under these facilities at December 31, 2004.

One of our Norwegian subsidiaries had two $300 million revolving credit facilities that expired in June 2004, which were not renewed.

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 $5 billion revolving credit facilities. Based on our commercial paper balance of $544 million and having issued $173 million of letters of credit at year-end, we had access to $4.3 billion in borrowing capacity as of December 31, 2004, which provides liquidity to cover daily operations. In addition, at year-end 2004 our $1.4 billion cash balance and $720 million of remaining capacity related to our receivables monetization program also supported our liquidity position.

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, 2004, we had outstanding $1,105 million of equity held by minority interest owners, including a minority interest of $504 million in Ashford Energy Capital S.A. The remaining minority interest amounts related to controlled-operating joint ventures with minority interest owners. The largest of these, $542 million, was related to the Bayu-Undan liquefied natural gas project in the Timor Sea. During the third quarter of 2004, a $141 million net minority interest in Conoco Corporate Holdings L.P. was retired.

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 1.32 percent. The preferred return at December 31, 2004, was 3.34 percent. In 2008, and at 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, 2004, 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, 2004, Ashford held $1.7 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.

Receivables Factoring
At December 31, 2003, we had sold $226 million 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. At December 31, 2004, we had no receivables outstanding under similar arrangements. See Note 14—Sales of Receivables, in the Notes to Consolidated Financial Statements, for additional information.

Off-Balance Sheet Arrangements

Receivables Monetization
At December 31, 2004 and 2003, certain credit card and trade receivables had been sold to a QSPE in a revolving-period securitization arrangement. This arrangement provides for us to sell, and the QSPE to purchase, certain receivables, and for the QSPE to then issue beneficial interests of up to $1.2 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 QSPE because it meets 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.

At December 31, 2004 and 2003, the QSPE had issued beneficial interests to the bank-sponsored entities of $480 million and $1.2 billion, respectively. The receivables transferred to the QSPE met the isolation and other requirements of SFAS No. 140 to be accounted for as sales and were accounted for accordingly.

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 $3.2 billion at December 31, 2004, and $1.3 billion at December 31, 2003. We also retain servicing responsibility related to the sold receivables, which gives us certain rights and abilities, 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 in the QSPE approximates fair market value due to the very short term of the underlying assets. See Note 14—Sales of Receivables, in the Notes to Consolidated Financial Statements, for additional information.

Preferred Securities
In 1997, we formed a statutory business trust, Phillips 66 Capital II (Trust II), with ConocoPhillips owning all of the common securities of the trust. The sole purpose of the trust was to issue preferred securities to outside investors, investing the proceeds thereof in an equivalent amount of subordinated debt securities of ConocoPhillips. The trust was established to raise funds for general corporate purposes.

At December 31, 2004 and 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 of $29 million in both 2004 and 2003. In addition, we guaranteed the payment obligations of the trust on the trust preferred securities to the extent we made interest payments on the subordinated debt securities. 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 18—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, 2004, 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 limited liability company, Hamaca Holding LLC, for which we use the equity method of accounting. Hamaca Holding LLC revenues for 2004 were approximately $625 million, expenses were approximately $413 million and cash provided by operating activities was approximately $324 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. 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 $957 million was outstanding under these credit facilities at December 31, 2004. Of this amount, $383 million is recourse to ConocoPhillips. The proceeds of these joint financings were used to primarily fund a heavy-oil upgrader. The remaining necessary funding was 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, were jointly-and-severally liable for under a construction completion guarantee. In May 2004, MSLP achieved completion certification. As a result, the construction completion guarantee related to the debt and bond financing arrangements secured by MSLP expired and the debt became non-recourse to ConocoPhillips and the bondholders can look only to MSLP cash flows for payment.

- *Other:* At December 31, 2004, we had guarantees of approximately $250 million outstanding for our portion of other joint-venture debt obligations, which have terms of up to 20 years. Payment would be required if a joint venture defaults on its debt obligations. Included in these outstanding guarantees was $95 million associated with the Polar Lights Company joint venture in Russia.

For additional information about guarantees see Note 15—Guarantees, in the Notes to Consolidated Financial Statements.

Capital Requirements

For information about our capital expenditures and investments, see the "Capital Spending" section.

Our balance sheet debt at December 31, 2004, was $15.0 billion. This reflects debt reductions of approximately $2.8 billion during 2004. The debt reduction primarily resulted from repayment in April of the $1,350 million aggregate principal amount of our 5.90% Notes due 2004 at maturity, the redemption in August 2004 of the $1,150 million aggregate principal amount of our 8.5% Notes due 2005, and a reduction of $165 million in our outstanding commercial paper balance to $544 million at December 31, 2004. The 8.5% Notes were redeemed at a premium of $58 million plus accrued interest. In addition, we have given notice to redeem in March 2005 our $400 milion 3.625% Notes due 2007. Going forward, we have no significant mandatory debt retirements until payment of the $1,250 million aggregate principal amount of our 5.45% Notes due in 2006, at maturity.

On February 4, 2005, we announced a stock repurchase program that provides for the repurchase of up to $1 billion of the company's common stock over a period of up to two years. The program will serve as a means of offsetting dilution to shareholders from the company's stock-based compensation programs. Acquisitions for the share repurchase program will be made at management's discretion at prevailing prices, subject to market conditions and other factors. Purchases may be increased, decreased or discontinued at any time without prior notice. Shares of stock repurchased under the plan will be held as treasury shares.

Contractual Obligations

The following table summarizes our aggregate contractual fixed and variable obligations as of December 31, 2004:

	Millions of Dollars				
		Payments Due by Period			
At December 31, 2004	Total	Up to 1 Year	Year 2-3	Year 4-5	After 5 Years
Debt obligations*	$ 14,946	625	2,313	1,156	10,852
Capital lease obligations	56	7	15	34	-
Total debt	15,002	632	2,328	1,190	10,852
Operating lease obligations	2,813	476	780	548	1,009
Purchase obligations**	67,264	22,131	5,313	4,239	35,581
Other long-term liabilities***					
Asset retirement obligations	3,089	112	254	449	2,274
Accrued environmental costs	1,061	144	305	202	410
Total	$ 89,229	23,495	8,980	6,628	50,126

**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 $34,880 million, of which $16,243 million are primarily related to the supply of crude oil to our refineries and the optimization of the supply chain, $7,176 million primarily related to the supply of unfractionated NGLs to fractionators, optimization of NGL assets, and for resale to customers, $4,919 million primarily related to natural gas for resale to customers, $3,378 million related to transportation, $1,351 million of futures, $1,284 million related to product purchases and $529 million related to the purchase side of exchange agreements; (2) $27,615 million of purchase commitments for products, mostly natural gas and natural gas liquids, from CPChem over the remaining term of 96 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 15-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 $3,154 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 2005 through 2009 time period, we expect to contribute an average of $415 million per year to our qualified and non-qualified pension and postretirement medical plans in the United States and an average of $135 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 2005 is expected to be $60 million in the United States and $90 million outside the United States; and (3) Interest—we anticipate payments of $894 million in 2005, $1,672 million for the period 2006 through 2007, $1,496 million for the period 2008 through 2009, and $8,259 million for the remaining years to total $12,321 million.*

Table of Contents

Capital Spending

Capital Expenditures and Investments

		Millions of Dollars		
	2005 Budget	**2004**	2003	2002
E&P				
United States-Alaska	$ 751	**645**	570	706
United States-Lower 48	720	**669**	848	499
International	4,558	**3,935**	3,090	2,071
	6,029	**5,249**	4,508	3,276
Midstream	11	**7**	10	5
R&M				
United States	1,420	**1,026**	860	676
International	212	**318**	319	164
	1,632	**1,344**	1,179	840
LUKOIL Investment*	-	**2,649**	-	-
Chemicals	-	**-**	-	60
Emerging Businesses	5	**75**	284	122
Corporate and Other**	225	**172**	188	85
	$ 7,902	**9,496**	6,169	4,388
United States	$ 3,123	**2,520**	2,493	2,043
International	4,779	**6,976**	3,676	2,345
	$ 7,902	**9,496**	6,169	4,388
Discontinued operations	$ -	**1**	224	97

**Discretionary expenditures in 2005 for potential additional equity investment in LUKOIL to increase our ownership percentage up to 20 percent, from 10 percent at December 31, 2004, are not included in our 2005 budget amounts.*
***Excludes discontinued operations.*

Our capital spending for continuing operations for the three-year period ending December 31, 2004, totaled $20.1 billion, including $2.6 billion in 2004 relating to our purchase of a 10 percent interest in LUKOIL, an international integrated oil and gas company headquartered in Russia. Spending was primarily focused on the growth of our E&P segment, with 65 percent of total spending for continuing operations in this segment.

Excluding discretionary expenditures for potential additional investment in LUKOIL, our capital budget for 2005 is $7.9 billion. Included in this amount is approximately $500 million to acquire an interest in a joint venture with LUKOIL to develop oil and gas resources in Russia’s Timan-Pechora province. Also included are approximately $345 million in capitalized interest and approximately $145 million that will be funded by minority interests in the Bayu-Undan gas export project. We plan to direct approximately 76 percent of our 2005 capital budget to E&P and 21 percent to R&M.

E&P

Capital spending for continuing operations for E&P during the three-year period ending December 31, 2004, totaled $13 billion. The expenditures over the three-year period supported several key exploration and development projects including:

- The West Sak and Alpine projects and drilling of National Petroleum Reserve-Alaska (NPR-A) and satellite field prospects on Alaska’s North Slope.

- Magnolia development in the deepwater Gulf of Mexico.
- Expansion of the Syncrude oil sands project and development of the Surmont heavy-oil project in Canada.
- The Hamaca heavy-oil project in Venezuela's Orinoco Oil Belt.
- The Grane field and Ekofisk Area growth project in the Norwegian North Sea.
- The Clair, CMS3 and Britannia satellite developments in the United Kingdom.
- The Kashagan field and satellite prospects in the north Caspian Sea, offshore Kazakhstan.
- The Bayu-Undan gas recycle and gas development projects in the Timor Sea.
- The Belanak, Suban and South Jambi projects in Indonesia.
- The Peng Lai 19-3 development in China's Bohai Bay and additional Bohai Bay appraisal and satellite field prospects.
- The Su Tu Den project in Block 15-1 in Vietnam.

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.

UNITED STATES

Alaska
During the three year-period ending December 31, 2004, we made capital expenditures for the construction of double-hulled Endeavour Class tankers for use in transporting Alaskan crude oil to the U.S. West Coast and Hawaii. We expect the fifth and final Endeavour Class tanker will be in Alaska North Slope service in 2006.

We continued development drilling in the Greater Kuparuk Area, the Greater Prudhoe Area, the Alpine field and the development of West Sak's heavy-oil accumulations. In addition, we increased oil production capacity at the Alpine field with the completion of Alpine Capacity Expansion-Phase I and a significant portion of Phase II in the third quarter of 2004. We expect to complete the final component of Phase II in 2005. We also participated in exploratory drilling on the North Slope and we were the successful bidder on 71 tracts covering approximately 484 thousand net acres, at the June 2004 Bureau of Land Management oil and gas lease sale for the Northwest Planning Area of the NPR-A.

During 2004, we and our co-venturers in the Trans-Alaska Pipeline System began a project to upgrade the pipeline's pump stations that is expected to be substantially complete by the end of 2005 and anticipated to be fully complete by the third quarter of 2006.

Lower 48 States
In the Lower 48, we continued to explore or 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, we began production in late 2004 from the Magnolia field, and we sanctioned and began development of the K2 discovery in Green Canyon Block 562 in 2004.

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.

CANADA

In Canada, capital spending in the Western Canadian Sedimentary Basin continued to focus on development and exploration in the eastern foothills of the Rocky Mountains and the western edge of our core areas in Alberta, Northeast British Columbia and Southwest Saskatchewan.

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 be fully operational by mid-2006.

In 2004, we continued with development of the Surmont heavy-oil project. Over the life of this 30+ year project, we anticipate that approximately 500 production and steam-injection well pairs will be drilled, with our share of the project costs estimated at $1 billion. During 2004, our capital expenditures associated with development of the Surmont project were approximately $33 million.

SOUTH AMERICA

At our Hamaca project in Venezuela, construction of an upgrader to convert heavy crude oil into a medium-grade crude oil became fully operational in the fourth quarter of 2004.

NORTHWEST EUROPE

In the U.K. and Norwegian sectors of the North Sea, funds were invested during the three-year period ending December 31, 2004, for development of the Ekofisk Area growth project, expected to be completed in the third quarter of 2005; the Grane field in the Norwegian North Sea, where production began late in the third quarter of 2003; the U.K. Clair field, where production is expected to begin in early 2005, the CMS3 area, comprising five natural gas fields in the southern sector of the U.K. North Sea, where the final field began production in 2004; and the Britannia satellite fields, Callanish and Brodgar, where production is expected in 2007.

AFRICA

In Nigeria, we made capital expenditures for the ongoing development of onshore oil and natural gas fields, and for ongoing exploration activities both onshore and on deepwater leases.

CASPIAN SEA

In 2002, following a discovery well drilled in 2000, we and our co-venturers, and the government of the Republic of Kazakhstan, declared the Kashagan field on the Kazakhstan shelf in the North Caspian Sea to be commercial. In February 2004, the Republic of Kazakhstan approved a development plan for the field and construction activities began. Additional exploratory drilling through 2004 has resulted in the discovery of a total of five fields in the area. 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.

During 2003, we exercised our pre-emptive rights to acquire a proportionate share of B.G. International’s interest in the North Caspian Sea license that includes the Kashagan field. Discussions continue with the Republic of Kazakhstan government to conclude the sale.

In the South Caspian, drilling was completed in 2004 on the Zafar-Mashal #1 exploration well in Azerbaijan waters. The well was declared non-commercial and was written off to dry hole expense.

ASIA PACIFIC

Timor Sea
In the Timor Sea, we continued with development activities associated with Phase I of the Bayu-Undan gas recycle project, where condensate and natural gas liquids are separated and removed and the dry gas re-injected into the reservoir. Production of liquids began from Phase I in February of 2004. All Phase I development drilling is expected to be complete by April 2005.

In June of 2003, we received approval from the Timor Sea Designated Authority for Phase II, the development of a liquefied natural gas (LNG) plant near Darwin, Australia, as well as a gas pipeline from Bayu-Undan to the LNG facility. Construction activities continued through 2004, and the first LNG cargo from the 3.52-million-ton-per-year facility is scheduled for delivery in early 2006.

Indonesia
In Indonesia, funds were used to construct the Belanak floating production, storage and offloading (FPSO) facility and develop the Belanak field in the South Natuna Sea Block B, where commercial oil production began in late 2004. Also, in Block B we began development of the Kerisi and Hiu fields, and we began the preliminary engineering phase of the North Belut field development. In South Sumatra, following the execution of the West Java gas sales agreement in August, we began the development of the Suban Phase II project, which is an expansion of the existing Suban gas plant. Also in South Sumatra, we completed the construction of the South Jambi shallow gas project in the South Jambi B Block, where first production began in June 2004.

China
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. In late 2004, we approved development plans for the second phase of the Peng Lai 19-3 oil field, as well as concurrent development of the nearby 25-6 field. In early 2005, the Chinese government also approved the development. The development of Peng Lai 19-3 and Peng Lai 25-6 will include multiple wellhead platforms and a larger FPSO facility.

Vietnam
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 the fourth quarter of 2003. Water injection facilities were put into service in 2004, and preliminary engineering for the nearby Su Tu Vang development began in early 2005.

In 2004, we continued the development of the Rang Dong field on Block 15-2, including the development of the central part of the field, where two additional platforms and additional production and injection wells are expected to be completed in the third quarter of 2005.

2005 Capital Budget

E&P's 2005 capital budget is $6.0 billion, 15 percent higher than actual expenditures in 2004. Twenty-four percent of E&P's 2005 capital budget is planned for the United States, with 51 percent of that slated for Alaska.

We plan to spend $751 million in 2005 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 projects, two Alpine satellite and West Sak field developments, construction to complete our fifth and final Endeavour Class tanker, and exploration activities.

In the Lower 48, offshore capital expenditures will be focused on continued development of the K2 and Ursa fields and the completion of Magnolia wells in the deepwater Gulf of Mexico. Onshore capital will focus primarily on developing natural gas reserves within core areas, including the San Juan Basin of New Mexico and the Lobo Trend of South Texas.

E&P is directing $4.6 billion of its 2005 capital budget to international projects. Included in this amount is approximately $500 million for a 30 percent economic interest in a joint venture with LUKOIL to develop oil and gas resources in the northern part of Russia's Timan-Pechora province. Closing on the joint-venture arrangement is expected in the first half of 2005. The majority of the remaining funds will be directed to developing other major long-term projects, including the Bayu-Undan gas development project in the Timor Sea; the Kashagan project in the Caspian Sea; the Britannia satellites, Ekofisk Area growth, Alvheim and Saturn projects in the North Sea; the Bohai Bay project in China; the Syncrude expansion, Surmont heavy-oil and the Mackenzie Delta gas projects in Canada; the Belanak, Kerisi-Hiu and Suban Phase II projects in Indonesia; the Corocoro project in Venezuela; and the Qatargas 3 LNG project in Qatar.

PROVED UNDEVELOPED RESERVES

Excluding the impact of our equity investment in LUKOIL, costs incurred for the years ended December 31, 2004, 2003, and 2002, relating to the development of proved undeveloped oil and gas reserves were $2,351 million, $2,002 million, and $1,631 million, respectively. During these years, we converted, on average, approximately 13 percent per year of our proved undeveloped reserves to proved developed reserves. Although it cannot be assured, estimated future development costs relating to the development of proved undeveloped reserves for the years 2005 through 2007 are projected to be $2,223 million, $1,668 million, and $851 million, respectively, excluding the impact of our equity investment in LUKOIL. Of our 2,232 million BOE proved undeveloped reserves at year-end 2004, approximately 82 percent were associated with 12 major developments. Of these 12, three are expected to have an aggregate of approximately 300 million BOE convert from proved undeveloped reserves to proved developed reserves during 2005, 2006 and 2007 (with expected year of conversion noted parenthetically) as follows:

- Nigeria natural gas reserves (2005).
- Bayu-Undan field in the Timor Sea (natural gas for 2006).
- Brodgar field in the United Kingdom (2007).

The remaining nine developments are currently producing and are expected to have additional proved reserves convert from undeveloped to developed over time as development activities continue and/or production facilities are expanded or upgraded:

- The Hamaca and Petrozuata heavy-oil projects in Venezuela.
- The Ekofisk, Eldfisk, Heidrun and Visund fields in the North Sea and Norwegian Sea.
- Indonesia natural gas reserves.

- The Prudhoe Bay field on Alaska's North Slope.
- The Magnolia field in the Gulf of Mexico.

In addition, proved undeveloped reserves added in 2004 for the Kashagan field in Kazakhstan are expected to be converted to proved developed in 2008 with completion of the first phase of the project.

R&M

Capital spending for continuing operations for R&M during the three-year period ending December 31, 2004, was primarily for clean fuels projects to meet new environmental standards, refinery-upgrade projects to improve product yields, and the operating integrity of key processing units, as well as for safety projects. During this three-year period, R&M capital spending for continuing operations was $3.4 billion, representing 17 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 ZorbÔ Sulfur Removal Technology 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.
- An expansion of capacity in the Seaway crude-oil pipeline.
- Integration of certain refinery assets purchased adjacent to our Wood River refinery in Illinois.

In 2004, we continued to expend funds related to clean fuels, safety and environmental projects in the United States, including investing in a new diesel hydrotreater at the Rodeo facility of our San Francisco refinery. The new diesel hydrotreater is expected to produce reformulated California highway diesel an estimated one year ahead of the June 2006 deadline.

The integration of certain refining assets purchased adjacent to our Wood River refinery in Illinois was completed in the second quarter of 2004. Integration of the assets enables the refinery to process heavier, lower cost crude oil.

Internationally, we continued 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.

2005 Capital Budget

R&M's 2005 capital budget for continuing operations is $1.6 billion, a 21 percent increase over actual spending in 2004. Domestic spending is expected to consume 87 percent of the R&M budget.

We plan to direct about $1.3 billion of the R&M capital budget to domestic refining, of which approximately 65 percent will go toward domestic clean fuels projects in order to comply with new U.S. Environmental Protection Agency (EPA) standards for refined products. Worldwide, clean fuels spending for our R&M refining business is expected to be $814 million, or approximately 60 percent of the total refining budget. Our U.S. marketing and transportation businesses are expected to spend about $143 million, while the remaining budget will fund projects in our international refining and marketing businesses in Europe and the Asia Pacific region.

Emerging Businesses

Capital spending for Emerging Businesses during the three-year period ending December 31, 2004, was primarily for construction of the Immingham combined heat and power cogeneration plant near the company's Humber refinery in the United Kingdom. The plant began commercial operations in October 2004.

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.

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.
- 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.

For example, the EPA has promulgated rules regarding the sulfur content in highway diesel fuel, which become applicable in June 2006. In April 2003, the EPA proposed a rule regarding emissions from non-road diesel engines and limiting non-road diesel fuel sulfur content. The non-road rule, as promulgated in June 2004, significantly reduces non-road diesel fuel sulfur content limits as early as 2007. We are evaluating and developing capital strategies for future integrated compliance of our diesel fuel for the highway and non-road markets.

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. The EPA responded by promulgating a revised implementation rule for its new 8-hour NAAQS on April 30, 2004. Several environmental groups have since filed challenges to this new rule. Depending upon the outcomes of the various challenges, area designations, and the resulting State Implementation Plans, 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 ratify, support or sponsor either it or other climate change related emissions reduction programs. 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.

Because considerable uncertainty exists with respect to the regulations that would ultimately govern implementation of the Kyoto Protocol, it currently is not possible to accurately estimate our future compliance costs under the Kyoto Protocol, but they could be substantial. The Kyoto Protocol became effective as to its ratifying countries in February 2005.

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 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, 2003, we reported we had been notified of potential liability under CERCLA and comparable state laws at 61 sites around the United States. At December 31, 2004, we had resolved 9 of these sites and had received 12 new notices of potential liability, leaving 64 unresolved 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.

Expensed environmental costs were $623 million in 2004 and are expected to be about $610 million in 2005 and $620 million in 2006. Capitalized environmental costs were $652 million in 2004 and are expected to be about $1,096 million and $769 million in 2005 and 2006, 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 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, 2004.

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, 2004, our balance sheet included a total environmental accrual related to continuing operations of $1,061 million, compared with $1,119 million at December 31, 2003. We expect to incur a substantial 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, loss carryforwards, and credit carryforwards. Valuation allowances have been established for certain foreign operating and domestic capital 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.

NEW ACCOUNTING STANDARDS AND EMERGING ISSUES

New Accounting Standards
In December 2004, the FASB issued SFAS No. 153, “Exchange of Nonmonetary Assets an amendment of APB Opinion No. 29.” This amendment eliminates the Accounting Principles Board (APB) Opinion No. 29 exception for nonmonetary exchanges of similar productive assets and replaces it with an exception for exchanges of nonmonetary assets that do not have commercial substance. This Statement is effective on a prospective basis beginning July 1, 2005. We continue to evaluate this standard.

Also in December 2004, the FASB issued SFAS No. 123 (revised 2004), “Share-Based Payment,” (SFAS No. 123(R), which supercedes APB Opinion No. 25, “Accounting for Stock Issued to Employees,” and replaces SFAS No. 123, “Accounting for Stock-Based Compensation,” that we adopted at the beginning of 2003. SFAS No. 123(R) prescribes the accounting for a wide range of share-based compensation arrangements, including share options, restricted share plans, performance-based awards, share appreciation rights, and employee share purchase plans, and generally requires the fair value of share-based awards to be expensed in the income statement. We are studying the provisions of this new pronouncement to determine the impact, if any, on our financial statements. For more information on our adoption of SFAS No. 123 and its effect on net income, see Note 1—Accounting Policies, in the Notes to Consolidated Financial Statements.

In November 2004, the FASB issued SFAS No. 151, “Inventory Costs an amendment of ARB No. 43, Chapter 4.” This Statement requires that items, such as idle facility expense, excessive spoilage, double freight, and re-handling costs, be recognized as current-period charges. We are required to implement this Statement in the first quarter of 2006. We are analyzing the provisions of this standard to determine the effects, if any, on our financial statements.

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. The Statement, already effective for contracts created or modified after May 31, 2003, was originally intended to become effective July 1, 2003, for all contracts existing at May 31, 2003. However, on November 7, 2003, the FASB issued an indefinite deferral of certain provisions of SFAS No. 150. We continue to monitor and assess the FASB’s modifications of SFAS No. 150, but do not anticipate any material impact to our financial statements.

Emerging Issues
At a November 2004 meeting, the Emerging Issues Task Force (EITF) discussed Issue No. 04-13, “Accounting for Purchases and Sales of Inventory with the Same Counterparty,” which addresses accounting issues that arise when one company both sells inventory to and buys inventory from another company in the same line of business. This draft encompasses our buy/sell transactions described in the Revenue Recognition section of Note 1—Accounting Policies, in the Notes to Consolidated Financial Statements. Depending on the EITF’s conclusions on this issue, it is possible that we could have to decrease sales and other operating revenues for 2004, 2003 and 2002 by $15,492 million, $11,673 million and $4,371 million, respectively, with a corresponding decrease in purchased crude oil, natural gas and products on our consolidated income statement. We believe any impact to our income from continuing operations and net income would result from LIFO inventory and would not be material to our financial statements. Additionally, these transactions have no impact on reported volumes for the production of crude oil, natural gas and natural gas liquids or refinery throughput and are not a significant component of reported volumes for sales of petroleum products.

The FASB is currently reviewing the accounting guidance provided in SFAS No. 19, “Financial Accounting and Reporting by Oil and Gas Producing Companies,” relating to exploratory costs that have been capitalized, or "suspended," on the balance sheet, pending a determination of whether potential economic oil and gas reserves have been discovered. For additional information, see Note 9—Properties, Plants and Equipment, in the Notes to Consolidated Financial Statements.

In June 2004, the FASB published the Exposure Draft, "Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143." This interpretation clarifies that an entity is required to recognize a liability for a legal obligation to perform asset retirement activities when the retirement is conditional on a future event if the liability's fair value can be reasonably estimated. If the liability's fair value cannot be reasonably estimated, then the entity must disclose (a) a description of the obligation, (b) the fact that a liability has not been recognized because the fair value cannot be reasonably estimated, and (c) the reasons why the fair value cannot be reasonably estimated. Depending on the FASB's conclusions on this issue, it is possible that we would need to reconsider our asset retirement obligations and related disclosures for certain of our downstream assets (primarily refineries).

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, 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 Finance Committee at least annually. We believe the following discussions of critical accounting policies, along with the discussions of contingencies and of deferred tax asset valuation allowances in this report, address all important accounting areas where the nature of accounting estimates or assumptions is material due to the levels of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to change.

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. At year-end 2004, the book value of the pools of property acquisition costs, that individually are relatively small and thus subject to the above-described periodic leasehold impairment calculation, was approximately $604 million and the accumulated impairment reserve was approximately $116 million. The weighted average judgmental percentage probability of ultimate failure was approximately 69 percent and the weighted average amortization period was approximately 2.7 years. If that judgmental percentage were to be raised by 5 percent across all calculations, the pretax leasehold impairment expense in 2005, would increase by $11 million. The remaining $2,617 million of capitalized unproved property costs at year-end 2004 consisted of individually significant leaseholds, mineral rights held into perpetuity by title ownership, exploratory wells currently drilling, and suspended exploratory wells, which management periodically assesses for impairment based on exploration and drilling efforts to date on the individual prospects. Of this amount, approximately $1.7 billion is concentrated in nine major projects, of which management expects approximately $500 million to move to proved properties in 2005. See the following discussion of Exploratory Costs for more information on suspended exploratory wells.

Exploratory Costs
For exploratory wells, drilling costs are temporarily capitalized, or “suspended,” on the balance sheet, pending a determination of whether a sufficient quantity of potentially economic oil and gas reserves have been discovered by the drilling effort to justify completion of the find as a producing well.

Accounting rules require this judgment to be made within one year of well completion in areas not requiring major infrastructure capital expenditures. 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 reported in exploration expense. If exploratory wells encounter potentially economic quantities of oil and gas in areas where major infrastructure capital expenditures (e.g., a pipeline or offshore platform) are required before production can begin, and the economic viability of those capital expenditures depends upon the successful completion of further exploratory drilling work in the area, the well costs remain capitalized on the balance sheet as long as additional exploratory drilling work is under way or firmly planned. In these situations, recoverable reserves are considered economic if the quantity found justifies completion of the find as a producing well, without considering the major infrastructure capital expenditures that will need to be made. Once all additional exploratory drilling and testing work has been completed, the economic viability of the overall project, including any major infrastructure capital expenditures that will need to be made, is evaluated within one year of the last exploratory well completion. If economically viable, internal company approvals are obtained to move the project into the development phase. Often, the ability to move the project into the development phase and record proved reserves is dependent on obtaining permits and government or co-venturer approvals, the timing of which is ultimately beyond our control. Exploratory well costs remain suspended as long as the company is actively pursuing such approvals and permits and believes they will be obtained. Once all required approvals and permits have been obtained, the projects are moved into the development phase and the oil and gas reserves are designated as proved reserves. For complex exploratory discoveries, it is not unusual to have exploratory wells remain suspended on the balance sheet for several years while we perform additional drilling work on the potential oil and gas field, or we seek government or co-venturer approval of development plans or seek environmental permitting.

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 investment in the near term.

Included in total suspended well costs at year-end 2004 was $70 million related to eight exploratory wells in areas where major capital expenditures will be required and no further exploratory drilling is planned, but for which we are actively pursuing those activities necessary to classify the reserves as proved. These costs were suspended between 1999 and 2003. At year-end 2004, we were awaiting government approval of the development plan for the Bohai Bay Phase II project in China. Suspended well costs associated with this project represented $42 million of the $70 million total. This project was approved by the government in early 2005, which will allow us to book proved reserves in 2005, at which time the suspended well costs will be reclassified as part of the capitalized costs of the project. In addition, suspended amounts at year-end 2004 also included $28 million related to projects where infrastructure decisions are dependent on environmental permitting and production capacity, or where we are continuing to assess reserves and their potential development. During 2004 and 2003, additions to suspended wells in areas where major capital expenditures will be required and no further exploratory drilling is planned were $7 million and $22 million, respectively. Had these amounts been expensed, they would not have had a material impact on our trend of exploration expenses or our financial statements. At year-end 2004 and 2003, we did not have any amounts suspended that were associated with areas not requiring major capital expenditures before production could begin, where more than one year had elapsed since the completion of drilling.

For additional information on suspended wells, see Note 9—Properties, Plants and Equipment, in the Notes to Consolidated Financial Statements.

Proved Oil and Gas Reserves and Canadian Syncrude Reserves

Engineering estimates of the quantities of recoverable oil and gas reserves in oil and gas fields and in-place crude bitumen volumes in oil sand mining operations are inherently imprecise and represent only approximate amounts because of the subjective judgments involved in developing such information. Reserve estimates are based on subjective judgments involving geological and engineering assessments of in-place hydrocarbon volumes, the production or mining plan, historical extraction recovery and processing 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 and processing the hydrocarbons. Despite the inherent imprecision in these engineering estimates, accounting rules require disclosure of "proved" reserve estimates due to the importance of these estimates to better understand the perceived value and future cash flows of a company's exploration and production (E&P) operations. There are several authoritative guidelines regarding the engineering criteria that must be met before estimated 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 for our E&P segment. Proved reserve estimates are updated annually and take into account recent production and seismic information about each field or oil sand mining operation. Also, as required by authoritative guidelines, the estimated future date when a field or oil sand mining operation will be permanently shutdown for economic reasons is based on an extrapolation of sales 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. Year-end 2004 estimated reserves related to our LUKOIL Investment segment were based on LUKOIL's year-end 2003 oil and gas reserves. Because LUKOIL's accounting cycle close and preparation of U.S. GAAP financial statements occurs subsequent to our accounting cycle close, our 10 percent equity share of LUKOIL's oil and gas proved reserves at year-end 2004 have been estimated based on the prior year report without any provision for potential 2004 reserve additions and include adjustments to conform to our reserve policy and provide for estimated 2004 production. Any differences between the estimate and actual reserve computations will be recorded in a subsequent period. This estimate-to-actual adjustment will then be a recurring component of future period reserves.

The judgmental estimation of proved reserves also is important to the income statement because the proved oil and gas reserve estimate for a field or the estimated in-place crude bitumen volume for an oil sand mining operation serves as the denominator in the unit-of-production calculation of depreciation, depletion and amortization of the capitalized costs for that asset. At year-end 2004, the net book value of productive E&P properties, plants and equipment subject to a unit-of-production calculation, including our Canadian Syncrude bitumen oil sand assets, was approximately $29.5 billion and the depreciation, depletion and amortization recorded on these assets in 2004 was approximately $2.6 billion. The estimated proved developed oil and gas reserves on these fields were 4.7 billion BOE at the beginning of 2004 and were 4.8 billion BOE at the end of 2004. The estimated proved reserves on the Canadian Syncrude assets were 265 million barrels at the beginning of 2004 and were 258 million barrels at the end of 2004. If the judgmental estimates of proved reserves used in the unit-of-production calculations had been lower by 5 percent across all calculations, pretax depreciation, depletion and amortization in 2004 would have been increased by an estimated $174 million. Impairments of producing oil and gas properties in 2004, 2003 and 2002 totaled $67 million, $225 million and $49 million, respectively. Of these writedowns, only $52 million in 2004, $19 million in 2003 and $23 million in 2002 were due to downward revisions of proved reserves. The remainder of the impairments resulted either from properties being designated as held for sale or from the repeal of the Norway Removal Grant Act (1986) that increased asset removal obligations.

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 11—Property Impairments, in the Notes to Consolidated Financial Statements, for additional information.

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. Our largest asset removal obligations 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, or decades, in the future and the contracts and regulations often have vague descriptions of what removal practices and criteria must be met when the removal event actually occurs. Asset removal technologies and costs are changing constantly, as well as political, environmental, safety and public relations considerations. See Note 1—Accounting Policies, Note 12—Asset Retirement Obligations and Accrued Environmental Costs, and Note 28—New Accounting Standards and Emerging Issues, 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 of Conoco and Phillips on August 30, 2002, we recorded material intangible assets for trademarks and 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 3—Merger of Conoco and Phillips, and Note 11—Property Impairments, in the Notes to Consolidated Financial Statements, for additional information.

Also in connection with the acquisition of Tosco and the merger of Conoco and Phillips, 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. Within our Exploration and Production segment and our Refining and Marketing segment, we determined that we have one and two reporting units, respectively, 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 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 must 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 must be applied in determining the fair values of individual assets and liabilities for purposes of the hypothetical purchase price allocation. Again, management must use all available information to make these fair value determinations and may engage an outside appraisal firm for assistance. At year-end 2004, the estimated fair values of our Worldwide Exploration and Production, Worldwide Refining, and Worldwide Marketing reporting units ranged from between 18 percent to 59 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 $15.0 billion of goodwill.

Use of Equity Method Accounting for Investment in LUKOIL

In October 2004, we purchased 7.6 percent of the outstanding ordinary shares of LUKOIL from the Russian government. During the remainder of 2004, we purchased additional shares of LUKOIL on the open market and reached an ownership level of 10 percent in LUKOIL by the end of 2004. On January 24, 2005, LUKOIL held an extraordinary general meeting of stockholders at which our nominee to the LUKOIL Board of Directors was elected under the cumulative voting rules in Russia, and certain amendments to LUKOIL’s charter were approved which provide protections to preserve the significant influence of major stockholders in LUKOIL, such as ConocoPhillips. In addition, during the first quarter of 2005, the two companies began the secondment of managerial personnel between the two companies. Significant progress is also being made on advancing the major oil and gas joint venture between the two companies in the Timan-Pechora region of northern Russia, over which we expect to have joint control with LUKOIL.

Based on the overall facts and circumstances surrounding our investment in LUKOIL, we concluded that we have significant influence over the operating and financial policies of LUKOIL and thus applied the equity method of accounting in the fourth quarter of 2004. Determination of whether one company has significant influence over another, the criterion required by APB Opinion No. 18, "The Equity Method of Accounting for Investments in Common Stock," in order to use equity method accounting, is a judgmental accounting decision based on the overall facts and circumstances of each situation. Under the equity method of accounting, we estimate and record our weighted-average ownership share of LUKOIL's net income (determined in accordance with accounting principles generally accepted in the United States (U.S. GAAP)) each period as equity earnings on our income statement, with a corresponding increase in our recorded investment in LUKOIL. Cash dividends received from LUKOIL each period reduce our recorded investment in LUKOIL. The use of equity-method accounting also requires us to supplementally report our ownership share of LUKOIL's oil and gas disclosures in our report.

If future facts and circumstances were to change to where we no longer believe we have significant influence over LUKOIL's operating and financial policies, we would have to change our accounting classification for the investment to an available-for-sale equity security under SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities." If that unlikely event were to occur, our investment in LUKOIL would be marked to market each period, based on LUKOIL's publicly traded share price, with the offset recorded as a component of other comprehensive income. Additionally, we would no longer record our ownership share of LUKOIL's net income each period and any cash dividends received would be reported as dividend income when declared by LUKOIL. We also would no longer be able to supplementally report our ownership share of LUKOIL's oil and gas disclosures.

During the fourth quarter of 2004, we recorded $74 million of equity-method earnings from our 8.6 percent weighted-average ownership level in LUKOIL during the quarter and as of December 31, 2004, supplementally reported an estimated 770 million barrels of crude oil and 661 billion cubic feet of natural gas proved reserves from our ownership level of 10 percent at year-end 2004. Because LUKOIL's accounting cycle close and preparation of U.S. GAAP financial statements occurs subsequent to our accounting cycle close, we have used all available information to estimate LUKOIL's U.S. GAAP net income for the fourth quarter of 2004 for purposes of our equity-method accounting. Any differences between our estimate and the actual LUKOIL U.S. GAAP net income will be recorded in 2005 equity earnings. In addition, we used all available information to estimate our share of LUKOIL's oil and gas disclosures. If, instead of equity-method accounting, we had been required to follow the requirements of SFAS No. 115 for our investment in LUKOIL, the mark-to-market adjustment to reflect LUKOIL's publicly-traded share price at year-end 2004 would have been a pretax charge against other comprehensive income of approximately $17 million. Also, $19 million of acquisition related costs would have been expensed and $74 million of equity earnings would not have been recorded.

At the end of 2004, our cost of investment in LUKOIL shares exceeds our 10 percent share of LUKOIL's historical U.S. GAAP balance sheet equity by an estimated $659 million. Under the accounting guidelines of APB Opinion No. 18, the basis difference between the cost of our investment and the amount of underlying equity in the historical net assets of LUKOIL is accounted for as if LUKOIL were a consolidated subsidiary. In other words, a hypothetical purchase price allocation is performed to determine how LUKOIL assets and liabilities would have been adjusted in a hypothetical push-down accounting exercise to reflect the actual cost of our investment in LUKOIL's shares. Once these hypothetical push-down adjustments have been identified, the nature of the hypothetically adjusted assets or liabilities determines the future amortization pattern for the basis difference. We have up to one year after a stock purchase to finalize this hypothetical purchase price allocation, but have preliminarily decided to associate the basis difference primarily with LUKOIL's developed property, plant and equipment base. The earnings we recorded for our LUKOIL investment in the fourth quarter of 2004 thus included a reduction for the amortization of this basis difference. When finalizing this preliminary purchase price allocation in 2005, we will use all available information to make this estimate.

Inventory Valuation

Our LIFO cost inventories are sensitive to lower-of-cost-or-market impairment write-downs, whenever price levels fall. 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 impairments could occur if a 70 percent/30 percent blended average of West Texas Intermediate/Brent crude oil prices falls below $20.80 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 $105 million, while a 1 percent decrease in the return on plan assets assumption would increase annual benefit expense by $35 million.

OUTLOOK

E&P's production for 2005 is expected to be approximately 4 percent higher than the level achieved in 2004. This projection excludes the impact of our equity investment in LUKOIL. For 2005, production increases in Asia Pacific, South America and the United States are expected to offset net declines in the North Sea.

In R&M, the optimization of spending related to clean fuels project initiatives will be an important focus area during 2005. We expect our average refinery crude oil utilization rate for 2005 to average in the upper nineties. This projection excludes the impact of our equity investment in LUKOIL.

In January 2005, the Governor of Alaska announced that effective February 1, 2005, most satellite fields surrounding the Prudhoe Bay field would no longer qualify for a state production tax incentive that was intended to encourage development of marginal deposits. Beginning in February, these satellite fields bear the same production tax rate as Prudhoe Bay. This administrative change is anticipated to increase our production tax obligations by approximately $40 million in 2005.

In the first quarter of 2004, in regards to our Magnolia project in the Gulf of Mexico and on behalf of the Garden Banks 783/784 unit, we filed an application for royalty relief with the Minerals Management Service (MMS). Royalty relief may be granted if the value of the project using the MMS economic model and criteria is insufficient to recover the project investment without the relief. There is no assurance that such relief will be granted.

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 Libya, we are participating in discussions with our co-venturers and Libyan authorities regarding terms in connection with our anticipated re-entry into that country.

In the second quarter of 2004, Norwegian authorities ordered us to modify our facilities at two Ekofisk Area installations—Ekofisk and Eldfisk—and had initially given us until October 1, 2004, to submit a binding plan for implementing measures to ensure workers are not disturbed by noise from other sleeping workers while they are resting. The Norwegian Petroleum Safety Authority contended we were not in compliance with regulatory requirements for rest and restitution on the installations where there are shared sleeping quarters. We appealed this order and the response deadline was deferred by the Norwegian authorities to December 31, 2004. Concurrently, the Petroleum Safety Authority put the appeal on hold pending further meetings and a letter describing plans that will ensure necessary restitution and rest. On February 3, 2005, we received an official note from the Petroleum Safety Authority stating that our letter of December 28, 2004, presented plans that will meet the intention of their order. Consequently, our appeal will not need to be processed further, and the case is closed.

The Mackenzie gas project involves natural gas production facilities for three anchor fields, including the Parsons Lake field operated by us; compression and gathering pipelines in the Mackenzie Delta area; and a pipeline system in the Mackenzie River Valley. In September 2004, the National Energy Board in Canada confirmed the Commercial Discovery Declaration (CDD) for the Parsons Lake field. The CDD meets our development planning expectations, which is an important milestone in the regulatory approval process toward obtaining a production license. The main regulatory applications were filed in October 2004, triggering the start of the formal environmental and regulatory review process. This filing sets the stage for regulatory hearings in 2005, leading toward a regulatory decision in 2006. First gas production is currently targeted to commence in the 2009 timeframe.

In early July 2004, we announced the finalization of our transaction with Freeport LNG Development, L.P. (Freeport LNG) to participate in a proposed LNG receiving terminal in Quintana, Texas. Freeport LNG received conditional approval in June 2004 from the Federal Energy Regulatory Commission (FERC) to construct and operate the facility and received final approval from the FERC in January 2005. Construction began in early 2005, and commercial startup is expected in 2008. We do not have any limited partner ownership interest in the facility, but we do have a 50 percent interest in the general partnership managing the venture. In addition, we have contractual rights to two-thirds of the LNG regasification capacity in the facility, or 1 billion cubic feet per day. We entered into a credit agreement with Freeport LNG, whereby we will provide loan financing of approximately $600 million for the construction of the facility.

We are pursuing three other proposed LNG regasification terminals. The Beacon Port Terminal would be located in federal waters in the Gulf of Mexico, 56 miles south of the Louisiana mainland. Also in the Gulf of Mexico is the proposed Compass Port Terminal, to be located approximately 11 miles offshore Alabama. The third proposed facility would be a joint venture located in the Port of Long Beach, California. Each of these projects are in the initial regulatory permitting process.

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, both of which were advanced in 2004. Qatargas 3 would be an integrated project, jointly owned by Qatar Petroleum and us, 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 (FEED) work for an LNG facility to be constructed in Nigeria’s central Niger Delta. The participants formed an incorporated joint venture, Brass LNG Limited, to undertake the project. The FEED contract was awarded to Bechtel in the fourth quarter 2004. These engineering and design studies are expected to be completed in 2006. The LNG facility is targeted to be operational in 2010.

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 technical and commercial pre-FEED studies and establishes principles for negotiating a Heads of Agreement for an integrated reservoir-to-market plant. Negotiations on more definitive agreements and progress on the studies continue in 2005.

On February 24, 2005, ConocoPhillips and Duke Energy Corporation (Duke) agreed to terms to restructure their respective ownership levels in DEFS, which would cause DEFS to become a jointly controlled venture, owned 50 percent by each company. This restructuring has been approved by the Boards of Directors of both owners. We will increase our current 30.3 percent ownership in DEFS to 50 percent through a series of direct and indirect transfers of Midstream assets from ConocoPhillips to Duke, a disproportionate cash distribution to Duke from the sale of DEFS’ general partner interest in TEPPCO Partners, L.P., and a final cash payment to Duke of approximately $200 million, which we expect to fund from our general liquidity resources.

We anticipate recording our equity share of the financial gain from DEFS’ sale of the general partner interest in TEPPCO in the first quarter of 2005. The restructuring is expected to have the effect of significantly reducing the favorable basis difference in our investment in DEFS which, in turn, will significantly reduce the basis difference amortization reported in equity method earnings (see Note 8—Investments and Long-Term Receivables for more information on our basis difference in the DEFS investment). We anticipate that this reduction in basis difference amortization and the loss of earnings from the transfer of certain of our Midstream assets to Duke and DEFS will be approximately offset by our increased 50 percent share of the remaining DEFS earnings going forward.

The restructuring is expected to close in the second quarter of 2005, subject to normal regulatory approvals. Once completed, our Midstream segment will consist primarily of our 50 percent equity method interest in DEFS.

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

This 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. You can identify our forward-looking statements by the words "anticipate," "estimate," "believe," "continue," "could," "intend," "may," "plan," "potential," "predict," "should," "will," "expect," "objective," "projection," "forecast," "goal," "guidance," "outlook," "effort," "target" and similar expressions.

We 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 based many of these forward-looking statements on assumptions about future events that may prove to be inaccurate. Accordingly, our actual outcomes 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 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 changes in costs or technical requirements for constructing, modifying or operating facilities for exploration and production projects, manufacturing or refining.
- Unexpected technological or commercial difficulties in manufacturing or refining our products, including synthetic crude oil and chemicals products.
- Lack of, or disruptions in, adequate and reliable transportation for our crude oil, natural gas, natural gas liquids, 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.
- Failure to complete definitive agreements and feasibility studies for, and to timely complete construction of, announced and future LNG projects and related facilities.
- Potential disruption or interruption of our operations due to accidents, extraordinary weather events, civil unrest, 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 and governmental disputes over territorial boundaries.
- Changes in tax and other laws, regulations or royalty rules applicable to our business.
- 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 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 organization 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 organization 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.

- 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, 2004 and 2003, 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, 2004, 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, 2004 and 2003, was immaterial to our net income and cash flows. The VaR for instruments held for purposes other than trading at December 31, 2004 and 2003, 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 2004						
2005	**$ 19**	**7.70%**	**$ 552**	**2.34%**	**$ -**	**-%**
2006	**1,508**	**5.82**	**110**	**5.85**	**-**	**-**
2007	**613**	**4.89**	**-**	**-**	**-**	**-**
2008	**23**	**6.90**	**-**	**-**	**-**	**-**
2009	**1,065**	**6.37**	**3**	**2.84**	**-**	**-**
Remaining years	**9,788**	**7.05**	**751**	**2.24**	**-**	**-**
Total	**$ 13,016**		**$ 1,416**		**$ -**	
Fair value	**$ 14,710**		**$ 1,416**		**$ -**	
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	

During the fourth quarter of 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 No. 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 2004			
2005	**$ -**	**-%**	**-%**
2006—variable to fixed	**126**	**5.85**	**2.04**
2007—fixed to variable	**400**	**3.01**	**3.63**
2008	**-**	**-**	**-**
2009—fixed to variable	**750**	**5.22**	**6.35**
Remaining years—fixed to variable	**350**	**2.27**	**4.75**
Total	**$ 1,626**		
Fair value position	**$ 2**		
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	$ -		

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, 2004 and 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, 2004 or 2003, exchange rates. The notional and fair market values of these positions at December 31, 2004 and 2003, were as follows:

Foreign Currency Swaps	Millions of Dollars			
	Notional		Fair Market Value	
	2004	2003	**2004**	2003
Sell U.S. dollar, buy euro	**$ 370**	267	**13**	2
Sell U.S. dollar, buy British pound	**1,253**	789	**14**	26
Sell U.S. dollar, buy Canadian dollar	**85**	-	**2**	-
Sell U.S. dollar, buy Czech koruny	**13**	-	-	-
Sell U.S. dollar, buy Danish krone	**15**	12	-	-
Sell U.S. dollar, buy Norwegian kroner	**991**	380	**58**	7
Sell U.S. dollar, buy Polish zlotych	**2**	-	-	-
Sell U.S. dollar, buy Swedish krona	**148**	93	**3**	5

For additional information about our use of derivative instruments, see Note 17—Financial Instruments and Derivative Contracts, in the Notes to Consolidated Financial Statements.

Table of Contents

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's financial statements have been audited by Ernst & Young LLP, an independent registered public accounting firm appointed by the Audit and Finance Committee of the Board of Directors and ratified by stockholders. 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.

Assessment of Internal Control over Financial Reporting

Management is also responsible for establishing and maintaining adequate internal control over financial reporting. ConocoPhillips' internal control system was designed to provide reasonable assurance to the company's management and directors regarding the preparation and fair presentation of published financial statements.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Management assessed the effectiveness of the company's internal control over financial reporting as of December 31, 2004. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control—Integrated Framework*. Based on our assessment, we believe that, as of December 31, 2004, the company's internal control over financial reporting is effective based on those criteria.

Ernst & Young LLP has issued an audit report on our assessment of the company's internal control over financial reporting as of December 31, 2004.

/s/ J. J. Mulva
J. J. Mulva
Chairman, President and
Chief Executive Officer

/s/ John A. Carrig
John A. Carrig
Executive Vice President, Finance,
and Chief Financial Officer

February 25, 2005

Table of Contents

Report of Independent Registered Public Accounting Firm on Consolidated Financial Statements

The Board of Directors and Stockholders
ConocoPhillips

We have audited the accompanying consolidated balance sheets of ConocoPhillips as of December 31, 2004 and 2003, 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, 2004. Our audits also included the condensed consolidating financial information and financial statement schedule listed in the Index at 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 the standards of the Public Company Accounting Oversight Board (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, 2004 and 2003, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2004, in conformity with U.S. generally accepted accounting principles. 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(R), "Consolidation of Variable Interest Entities."

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of ConocoPhillips' internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 25, 2005 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

ERNST & YOUNG LLP

Houston, Texas
February 25, 2005

Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting

The Board of Directors and Stockholders
ConocoPhillips

We have audited management's assessment, included under the heading "Assessment of Internal Control over Financial Reporting" in the accompanying "Report of Management," that ConocoPhillips maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). ConocoPhillips' management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that ConocoPhillips maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, ConocoPhillips maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the 2004 consolidated financial statements of ConocoPhillips and our report dated February 25, 2005 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

ERNST & YOUNG LLP

Houston, Texas
February 25, 2005

Table of Contents

Consolidated Income Statement **ConocoPhillips**

Years Ended December 31	Millions of Dollars		
	2004	2003	2002
Revenues			
Sales and other operating revenues *(1)(2)*	**$ 135,076**	104,246	56,748
Equity in earnings of affiliates	**1,535**	542	261
Other income	**305**	309	192
Total Revenues	**136,916**	105,097	57,201
Costs and Expenses			
Purchased crude oil, natural gas and products *(3)*	**90,182**	67,475	37,857
Production and operating expenses	**7,372**	7,144	4,664
Selling, general and administrative expenses	**2,128**	2,179	1,950
Exploration expenses	**703**	601	592
Depreciation, depletion and amortization	**3,798**	3,485	2,223
Property impairments	**164**	252	177
Taxes other than income taxes *(1)*	**17,487**	14,679	6,937
Accretion on discounted liabilities	**171**	145	22
Interest and debt expense	**546**	844	566
Foreign currency transaction (gains) losses	**(36)**	(36)	24
Minority interests and preferred dividend requirements of capital trusts	**32**	20	48
Total Costs and Expenses	**122,547**	96,788	55,060
Income from continuing operations before income taxes and subsidiary equity transactions	**14,369**	8,309	2,141
Gain on subsidiary equity transactions	**-**	28	-
Income from continuing operations before income taxes	**14,369**	8,337	2,141
Provision for income taxes	**6,262**	3,744	1,443
Income From Continuing Operations	**8,107**	4,593	698
Income (loss) from discontinued operations	**22**	237	(993)
Income (loss) before cumulative effect of changes in accounting principles	**8,129**	4,830	(295)
Cumulative effect of changes in accounting principles	**-**	(95)	-
Net Income (Loss)	**$ 8,129**	4,735	(295)
Income (Loss) Per Share of Common Stock			
Basic			
Continuing operations	**$ 11.74**	6.75	1.45
Discontinued operations	**.03**	.35	(2.06)
Before cumulative effect of changes in accounting principles	**11.77**	7.10	(.61)
Cumulative effect of changes in accounting principles	**-**	(.14)	-
Net Income (Loss)	**$ 11.77**	6.96	(.61)
Diluted			
Continuing operations	**$ 11.57**	6.70	1.44
Discontinued operations	**.03**	.35	(2.05)
Before cumulative effect of changes in accounting principles	**11.60**	7.05	(.61)
Cumulative effect of changes in accounting principles	**-**	(.14)	-
Net Income (Loss)	**$ 11.60**	6.91	(.61)
Average Common Shares Outstanding (in thousands)			
Basic	**690,784**	680,490	482,082
Diluted	**700,650**	685,433	485,505
(1) Includes excise, value added and other similar taxes on petroleum products sales:	***$ 16,357***	*13,705*	*6,236*
(2) Includes sales related to purchases/sales with the same counterparty:	***15,492***	*11,673*	*4,371*
(3) Includes purchases related to purchases/sales with the same counterparty:	***15,255***	*11,453*	*4,166*

See Notes to Consolidated Financial Statements.

Consolidated Balance Sheet **ConocoPhillips**

At December 31	Millions of Dollars	
	2004	2003
Assets		
Cash and cash equivalents	**$ 1,387**	490
Accounts and notes receivable (net of allowance of $55 million in 2004 and $43 million in 2003)	**5,449**	3,606
Accounts and notes receivable—related parties	**3,339**	1,399
Inventories	**3,666**	3,957
Prepaid expenses and other current assets	**986**	876
Assets of discontinued operations held for sale	**194**	864
Total Current Assets	**15,021**	11,192
Investments and long-term receivables	**10,408**	7,258
Net properties, plants and equipment	**50,902**	47,428
Goodwill	**14,990**	15,084
Intangibles	**1,096**	1,085
Other assets	**444**	408
Total Assets	**$ 92,861**	82,455
Liabilities		
Accounts payable	**$ 8,727**	6,598
Accounts payable—related parties	**404**	301
Notes payable and long-term debt due within one year	**632**	1,440
Accrued income and other taxes	**3,154**	2,676
Employee benefit obligations	**1,215**	1,346
Other accruals	**1,351**	1,471
Liabilities of discontinued operations held for sale	**103**	179
Total Current Liabilities	**15,586**	14,011
Long-term debt	**14,370**	16,340
Asset retirement obligations and accrued environmental costs	**3,894**	3,603
Deferred income taxes	**10,385**	8,565
Employee benefit obligations	**2,415**	2,445
Other liabilities and deferred credits	**2,383**	2,283
Total Liabilities	**49,033**	47,247
Minority Interests	**1,105**	842
Common Stockholders' Equity		
Common stock (2,500,000,000 shares authorized at $.01 par value)		
Issued (2004—718,864,831 shares; 2003—708,085,097 shares)		
Par value	**7**	7
Capital in excess of par	**26,054**	25,361
Compensation and Benefits Trust (CBT) (at cost: 2004—24,091,410 shares; 2003—25,301,314 shares)	**(816)**	(857)
Accumulated other comprehensive income	**1,592**	821
Unearned employee compensation	**(242)**	(200)
Retained earnings	**16,128**	9,234
Total Common Stockholders' Equity	**42,723**	34,366
Total	**$ 92,861**	82,455

See Notes to Consolidated Financial Statements.

Consolidated Statement of Cash Flows **ConocoPhillips**

Years Ended December 31	Millions of Dollars		
	2004	2003	2002
Cash Flows From Operating Activities			
Income from continuing operations	$ **8,107**	4,593	698
Adjustments to reconcile income from continuing operations to net cash provided by continuing operations			
Non-working capital adjustments			
Depreciation, depletion and amortization	**3,798**	3,485	2,223
Property impairments	**164**	252	177
Dry hole costs and leasehold impairments	**417**	300	307
Accretion on discounted liabilities	**171**	145	22
Acquired in-process research and development	-	-	246
Deferred income taxes	**1,025**	401	142
Undistributed equity earnings	**(777)**	(59)	18
Gain on asset dispositions	**(116)**	(211)	(7)
Other	**(190)**	(328)	(32)
Working capital adjustments*			
Increase (decrease) in aggregate balance of accounts receivable sold	**(720)**	274	(22)
Increase in other accounts and notes receivable	**(2,685)**	(463)	(401)
Decrease (increase) in inventories	**360**	(24)	200
Decrease (increase) in prepaid expenses and other current assets	**15**	(105)	(37)
Increase in accounts payable	**2,103**	345	788
Increase in taxes and other accruals	**326**	562	454
Net cash provided by continuing operations	**11,998**	9,167	4,776
Net cash provided by (used in) discontinued operations	**(39)**	189	202
Net Cash Provided by Operating Activities	**11,959**	9,356	4,978
Cash Flows From Investing Activities			
Acquisitions, net of cash acquired	-	-	1,180
Cash consolidated from adoption and application of FIN 46(R)	**11**	225	-
Capital expenditures and investments, including dry hole costs	**(9,496)**	(6,169)	(4,388)
Proceeds from asset dispositions	**1,591**	2,659	815
Long-term advances/loans to affiliates and other investments	**(167)**	(63)	(169)
Collection of advances/loans to affiliates	**274**	86	77
Net cash used in continuing operations	**(7,787)**	(3,262)	(2,485)
Net cash used in discontinued operations	**(1)**	(236)	(99)
Net Cash Used in Investing Activities	**(7,788)**	(3,498)	(2,584)
Cash Flows From Financing Activities			
Issuance of debt	-	348	3,502
Repayment of debt	**(2,775)**	(5,159)	(4,592)
Redemption of preferred stock of subsidiary	-	-	(300)
Issuance of company common stock	**430**	108	44
Dividends paid on common stock	**(1,232)**	(1,107)	(684)
Other	**178**	111	(190)
Net cash used in continuing operations	**(3,399)**	(5,699)	(2,220)
Net Cash Used in Financing Activities	**(3,399)**	(5,699)	(2,220)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**125**	24	(9)
Net Change in Cash and Cash Equivalents	**897**	183	165
Cash and cash equivalents at beginning of year	**490**	307	142
Cash and Cash Equivalents at End of Year	$ **1,387**	490	307

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

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, 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								222			222
Unrealized loss on securities								(3)			(3)
Hedging activities								(35)			(35)
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 under incentive compensation and other benefit plans	443,591	(872,440)	(771,479)		53	39	27			(39)	80
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								786			786
Unrealized gain on securities								4			4
Hedging activities								27			27
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
Net income										**8,129**	**8,129**
Other comprehensive income (loss)											
Minimum pension liability adjustment								**1**			**1**
Foreign currency translation								**777**			**777**
Unrealized gain on securities								**1**			**1**
Hedging activities								**(8)**			**(8)**
Comprehensive income											**8,900**
Cash dividends paid on common stock										**(1,232)**	**(1,232)**
Distributed under incentive	**10,779,734**		**(1,209,904)**		**693**		**41**		**(76)**		**658**

compensation and other benefit plans											
Recognition of unearned compensation									**34**		**34**
Other										**(3)**	**(3)**
December 31, 2004	**718,864,831**	**-**	**24,091,410**	**$ 7**	**26,054**	**-**	**(816)**	**1,592**	**(242)**	**16,128**	**42,723**

See Notes to Consolidated Financial Statements.

Note 1—Accounting Policies

- **Consolidation Principles and Investments—**Our consolidated financial statements include the accounts of majority-owned, controlled subsidiaries and variable interest entities where we are the primary beneficiary. The equity method is used to account for investments in affiliates in which we exert significant influence over the affiliates' operating and financial policies. 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.

- **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.

- **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.

- **Reclassification—**Certain amounts in the 2003 and 2002 financial statements have been reclassified to conform to the 2004 presentation.

- **Revenue Recognition—**Revenues associated with sales of crude oil, natural gas, natural gas liquids, petroleum and chemical products, and other items are recognized when title passes to the customer, which is when the risk of ownership passes to the purchaser and physical delivery of goods occurs, either immediately or within a fixed delivery schedule that is reasonable and customary in the industry. Revenues include the sales portion of transactions commonly called buy/sell contracts, in which physical commodity purchases and sales are simultaneously contracted with the same counterparty to either obtain a different quality or grade of refinery feedstock supply, reposition a commodity (for example, where we enter into a contract with a counterparty to sell refined products or natural gas volumes at one location and purchase similar volumes at another location closer to our wholesale customer), or both.

  At its November 2004 meeting, the Emerging Issues Task Force (EITF) discussed Issue No. 04-13, "Accounting for Purchases and Sales of Inventory with the Same Counterparty," which addresses accounting issues that arise when one company both sells inventory to and buys inventory from another company in the same line of business. The purchase and sale transactions may be pursuant to a single contractual arrangement or separate contractual arrangements and the inventory purchased or sold may be in the form of raw material, work-in progress, or finished goods. At issue is whether both the revenue and inventory/cost of sales should be recorded at fair value or whether the transactions should be classified as nonmonetary exchanges subject to the fair value exception of Accounting Principles Board (APB) Opinion No. 29, "Accounting for Nonmonetary Transactions." This draft encompasses our buy/sell transactions as described above. These transactions have the same general terms and conditions as typical commercial contracts including: separate title transfer, transfer of risk of loss, separate gross billing and cash settlement for both the buy and sell sides of the transaction, and non-performance by one party does not relieve the other party of its obligation to perform (except in events of force majeure). We account for such transactions at fair value based on the guidance contained in the following:

- APB Opinion No. 29, "Accounting for Nonmonetary Transactions."
- EITF Issue No. 99-19, "Reporting Revenue Gross as a Principal versus Net as an Agent."
- EITF Issue No. 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities."
- EITF Issue No. 03-11, "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not 'Held for Trading Purposes' as Defined in Issue No. 02-3."
- Derivatives Implementation Group Statement 133 Implementation Issue No. K1, "Miscellaneous: Determining Whether Separate Transactions Should be Viewed as a Unit."
- Financial Accounting Standards Board (FASB) Interpretation No. 39, "Offsetting of Amounts Related to Certain Contracts – an interpretation of APB Opinion No. 10 and FASB Statement No. 105."

Depending on the EITF's conclusions on this issue, it is possible that we could have to decrease sales and other operating revenues for 2004, 2003 and 2002 by $15,492 million, $11,673 million and $4,371 million, respectively, with a corresponding decrease in purchased crude oil, natural gas and products on our consolidated income statement. We believe any impact to our income from continuing operations and net income would result from LIFO inventory and would not be material to our financial statements.

Our Commercial organization uses commodity derivative contracts (such as futures and options) in various markets to optimize the value of our supply chain and 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. See Note 1—Accounting Policies—Derivative Instruments, for additional information on our accounting for, and reporting of, commodity derivative contracts.

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 to be non-recoverable through remaining production, are recognized as accounts receivable or accounts payable, as appropriate. Cumulative differences between volumes sold and entitlement volumes are generally 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.

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, natural gas and products. Freight costs billed to customers are recorded as a component of revenue.

- **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.

- **Derivative Instruments—**All derivative instruments are recorded on the balance sheet at fair value in either accounts and notes receivable, prepaid expenses and other current assets, other assets, accounts payable, other accruals, 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 accounted for as hedges under Statement of Financial Accounting Standard (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities," 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, natural gas 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 of a sufficient quantity to justify completion of the find as a producing well. If economically recoverable reserves are not found, exploratory well costs are expensed as dry holes. Exploratory wells in areas not requiring major capital expenditures are evaluated for economic viability within one year of well completion. This determination of the success of drilling results corresponds with the time period of reporting proved oil and gas reserves for the find. Exploratory wells that discover economic reserves that are in areas where a major infrastructure 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 drilling work in the area, remain capitalized as long as the additional exploratory drilling work is under way or firmly planned. In these situations, the well is considered to have found economic reserves if recoverable reserves have been found of a sufficient quantity to justify completion of the find as a producing well, assuming that the major infrastructure capital expenditure had already been made. Once all additional exploratory drilling and testing work has been completed on projects requiring major infrastructure capital expenditures, the economic viability of the overall project is evaluated within one year of the last exploratory well completion. If considered to be economically viable, internal company approvals are then obtained to move the project into the development stage. Often, the ability to move the project into the development phase and record proved reserves is dependent on obtaining permits and government or co-venturer approvals, the timing of which is ultimately beyond our control. Exploratory well costs remain suspended as long as the company is actively pursuing such approvals and permits, and believes they will be obtained. Once all required approvals and permits have been obtained, the projects are moved into development stage, which corresponds with the time period of reporting proved oil and gas reserves for the find. For complex exploratory discoveries, it is not unusual to have exploratory wells remain suspended on the balance sheet for several years while we perform additional drilling work on the potential oil and gas field, or we seek government or co-venturer approval of development plans or seek environmental permitting.

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 investment in the near term.

See Note 9—Properties, Plants and Equipment, for additional information on suspended wells.

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.

- **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.

- **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 within our Exploration and Production segment and our Refining and Marketing segment 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 and reported as Property Impairments in the periods in which the determination of impairment is made. 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. Additionally, when probable reserves exist, an appropriate risk-adjusted amount of these reserves may be included in the impairment calculation. 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, SFAS No. 69, "Disclosures about Oil and Gas Producing Activities," requires inclusion of only proved reserves and the use of prices and costs at the balance sheet date, with no projection for future changes in assumptions.

n **Impairment of Investments in Non-Consolidated Companies—**Investments in non-consolidated companies are assessed for impairment whenever changes in the facts and circumstances indicate a loss in value has occurred, which is other than a temporary decline in value. The fair value of the impaired investment is based on quoted market prices, if available, or upon the present value of expected future cash flows using discount rates commensurate with the risks of the investment.

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

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 that 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—**We record the fair value of legal obligations to retire and remove long-lived assets in the period in which the obligation is incurred (typically when the asset is installed at the production location). When the liability is initially recorded, we capitalize this 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, and the capitalized cost in properties, plants and equipment is depreciated over the useful life of the related asset. 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.

- **Guarantees—**The fair value of a guarantee is determined and recorded as a liability at the time the guarantee is given. The initial liability is subsequently reduced as we are released from exposure under the guarantee. We amortize the guarantee liability over the relevant time period, if one exists, based on the facts and circumstances surrounding each type of guarantee. In cases where the guarantee term is indefinite, we reverse the liability when we have information that the liability is essentially relieved or amortize it over an appropriate time period as the fair value of our guarantee exposure declines over time. We amortize the guarantee liability to the related income statement line item based on the nature of the guarantee. When it becomes probable that we will have to perform on a guarantee, we accrue a separate liability, if it is reasonably estimable, based on the facts and circumstances at that time.

- **Stock-Based Compensation—**Effective January 1, 2003, we voluntarily adopted the fair-value accounting method prescribed by SFAS No. 123, "Accounting for Stock-Based Compensation." We used the prospective transition method, 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 APB Opinion 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 Opinion 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:

	Millions of Dollars		
	2004	2003	2002
Net income (loss), as reported	**$ 8,129**	4,735	(295)
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects	**93**	50	74
Deduct: Total stock-based employee compensation expense determined under fair-value based method for all awards, net of related tax effects	**106**	78	135
Pro forma net income (loss)	**$ 8,116**	4,707	(356)
Earnings per share:			
Basic—as reported	**$ 11.77**	6.96	(.61)
Basic—pro forma	**11.75**	6.92	(.74)
Diluted—as reported	**11.60**	6.91	(.61)
Diluted—pro forma	**11.58**	6.87	(.73)

- **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.

- **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 are excluded from the daily weighted-average number of common shares outstanding in both calculations.

- **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 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 increases for the change in its present value, while the capitalized cost depreciates 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). Excluding the cumulative-effect benefit, application of the new accounting principle increased income from continuing operations and net income for 2003 by $32 million, or $.05 per basic and diluted share, compared with the previous accounting method.

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 excluded it from our SFAS No. 143 estimates.

During 2004 and 2003, our overall asset retirement obligation changed as follows:

	Millions of Dollars	
	2004	2003
Opening balance at January 1	**$ 2,685**	2,110
Accretion of discount	**146**	118
New obligations	**141**	43
Spending on existing obligations	**(59)**	(62)
Property dispositions	**(20)**	(95)
Foreign currency translation	**180**	109
Adjustment due to repeal of Norway Removal Grant Act	-	414
Other adjustments	**16**	48
Ending balance at December 31	**$ 3,089**	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, 2002.

	Millions of Dollars Except Per Share Amounts	
	2003	2002
Pro forma net income (loss)*	$ 4,590	(254)
Pro forma earnings per share		
Basic	6.75	(.53)
Diluted	6.70	(.52)

* *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.*

Consolidation of Variable Interest Entities

During 2003, the FASB issued and then revised Interpretation No. 46, “Consolidation of Variable Interest Entities,” (FIN 46(R)) to expand existing accounting guidance about when a company should include in its consolidated financial statements the assets, liabilities and activities of another entity. Effective January 1, 2003, we adopted FIN 46(R), which causes us to consolidate all variable interest entities (VIEs) where we conclude we are the primary beneficiary. In addition, we deconsolidated one entity in 2003 where we determined that we were not the primary beneficiary.

In general, a VIE is any legal structure used for business purposes that either (a) has an insufficient amount of equity to carry out its principal activities without additional subordinated financial support, (b) has a group of equity owners that are unable to make significant decisions about its activities, or (c) has a group of equity owners that do not have the obligation to absorb losses or the right to receive returns generated by its operations. FIN 46(R) requires a VIE to be consolidated by a company if that company is obligated to absorb 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 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.

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 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 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 mid-2005. At December 31, 2003, we reported these two entities could potentially be VIEs, but that we had been unable to obtain sufficient information to confirm that the entities were VIEs or to determine if we were the primary beneficiary. In the first quarter of 2004, we received the required information related to the entity associated with the first ship and determined that it was a VIE; however, because we are not the primary beneficiary we did not consolidate the entity. In regard to the first ship, the amount drawn under the guarantee facility at December 31, 2004, was less than $1 million. With regard to the second ship, we expect to have a variable interest in the associated entity once the ship is delivered to its owner in mid-2005. At that time, we will determine if the entity is a VIE, and if we are the primary beneficiary. We currently account for these agreements as guarantees and contingent liabilities. See Note 15—Guarantees for additional information.

The adoption of FIN 46(R) 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. At December 31, 2004, we continue to lease refining assets totaling $121 million, which are collateral for the debt obligations of $118 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, 2004, the fair market value of the swap was a liability of $7 million.

- Ashford Energy Capital S.A. continues to be consolidated in our financial statements under the provisions of FIN 46(R) 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 1.32 percent. The preferred return at December 31, 2004, was 3.34 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, 2004, 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, 2004, Ashford held $1.7 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(R) 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(R) required deconsolidation of the Trust, which increased debt in 2003 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(R). The effect of adopting FIN 46(R) 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(R) 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 21—Employee Benefit Plans for additional information.

Other
In December 2004, the FASB issued FASB Staff Position (FSP) FAS 109-1, "Application of FASB Statement No. 109, 'Accounting for Income Taxes,' to the Tax Deduction on Qualified Production Activities Provided by the American Jobs Creation Act 2004" and FSP No. 109-2, "Accounting and Disclosure Guidance for the Foreign Earnings Repatriation Provision within the American Jobs Creation Act of 2004." See Note 22—Taxes for additional information.

In April 2004, the FASB issued FSPs FAS 141-1 and FAS 142-1, which amended SFAS No. 141, "Business Combinations," and SFAS No. 142, "Goodwill and Other Intangible Assets," respectively, to remove mineral rights as an example of an intangible asset. In September 2004, the FASB issued FSP FAS 142-2, which confirmed that the scope exception in paragraph 8(b) of SFAS No. 142 extends to the disclosure provision for oil-and-gas producing entities.

In March 2004, the EITF reached a consensus on Issue 03-6, "Participating Securities and the Two-Class Method under FASB Statement No. 128, Earnings per Share," that explained how to determine whether a security should be considered a "participating security" and how earnings should be allocated to a participating security when using the two-class method for computing basic earnings per share. The adoption of this standard in the second quarter of 2004 did not have a material effect on our earnings per share calculations for the periods presented in this report.

In January 2004 and May 2004, the FASB issued FSPs FAS 106-1 and FAS 106-2, respectively, regarding accounting and disclosure requirements related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003. See Note 21—Employee Benefit Plans for additional information.

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 Statement 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 that were adopted effective December 2004.

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.

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.

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 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 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.

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

Merger-related items that reduced our 2004, 2003 and 2002 income from continuing operations were:

	Millions of Dollars						
	Before-Tax			After-Tax			
		2004	2003	2002	**2004**	2003	2002
Write-off of acquired in-process research and development costs	**$**	**-**	-	246	**-**	-	246
Restructuring charges (see Note 5)		**33**	240	422	**18**	131	253
Incremental seismic contract costs		**-**	-	35	**-**	-	22
Transition costs		**-**	110	55	**-**	92	36
Total	**$**	**33**	350	758	**18**	223	557

In total, these items reduced 2004, 2003 and 2002 income from continuing operations by $18 million, $223 million and $557 million, respectively ($.03 per share, $.33 per share and $1.15 per share on a diluted basis).

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

		Millions of Dollars Except Per Share Amounts
		2002
Revenues	$	81,433
Income from continuing operations		918
Net loss		(70)
Income from continuing operations per share of common stock		
Basic		1.36
Diluted		1.34
Net loss per share of common stock		
Basic		(.10)
Diluted		(.10)

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.

- Various other adjustments to conform Conoco's accounting policies to ConocoPhillips'.

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

The pro forma information does not reflect any anticipated synergies 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 entire period presented nor to be indicative of the results of operations that may be achieved by ConocoPhillips in the future.

Note 4—Discontinued Operations

During 2002, 2003 and 2004, we disposed of, or 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 27—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.

- 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 approximately 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 and brand. 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. Based on disposals completed and signed agreements as of December 31, 2003, we recognized a net additional charge in 2003 of approximately $96 million before-tax.

During the second quarter of 2004, we sold our Mobil-branded marketing assets on the East Coast in two separate transactions. Assets in these packages included approximately 100 company-owned and operated sites, and contracts with independent dealers and marketers covering an additional 350 sites. As a result of these and other transactions during 2004, we recorded a net before-tax gain on asset sales of $178 million in 2004. We also recorded additional impairments in 2004 totaling $96 million before-tax.

Of the approximately 270 sites remaining to be sold at December 31, 2004, approximately 200 sites are under contracts expected to close in 2005.

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

	Millions of Dollars		
	2004	2003	2002
Sales and other operating revenues from discontinued operations	**$ 1,104**	8,076	7,406
Income (loss) from discontinued operations before-tax	**$ 20**	317	(1,387)
Income tax expense (benefit)	**(2)**	80	(394)
Income (loss) from discontinued operations	**$ 22**	237	(993)

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

	Millions of Dollars	
	2004	2003
Assets		
Net properties, plants and equipment	**$ 193**	857
Other assets	**1**	7
Assets of discontinued operations	**$ 194**	864
Liabilities		
Deferred income taxes, other liabilities and deferred credits	**$ 103**	179
Liabilities of discontinued operations	**$ 103**	179

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.

Included in the total accruals of $770 million was $172 million related to pension and other postretirement 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. At the end of 2002, approximately 775 employees had been terminated. Changes in the 2002 severance related accrual balance is 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 to 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 consisted of severance-related benefits to be provided to approximately 3,900 employees worldwide, most of whom were in the United States, as well as other merger-related expenses. At the end of 2003 approximately 2,225 employees had been terminated.

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

In 2004, we recorded additional accruals of $46 million, of which $33 million was reflected in the consolidated financial statements as selling, general and administrative expense and production and operating expense, and $13 million was reflected as foreign currency translation adjustment. Included in the total accrual of $46 million was a $4 million expense related to pension and postretirement benefits. A roll-forward of activity during 2004 is provided below for the non-pension portion of the accruals, which primarily consisted of severance-related benefits to be provided based on agreed upon payment schedules to approximately 3,950 employees worldwide, most of whom were in the United States, as well as other merger-related expenses.

	Millions of Dollars			
	Reserve at December 31, 2003	Twelve Months 2004 Accruals	Payments	Reserve at December 31, 2004
Conoco	$ 83	(12)	(61)	10
Phillips	164	54	(139)	79
Total	$ 247	42	(200)	89

The ending accrual balance at December 31, 2004, of $89 million is expected to be extinguished within one year, except for $54 million, which is classified as long-term. Approximately 950 employees were terminated during 2004, and all 3,950-employee terminations under the restructuring program have now been completed.

Note 6—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.

Table of Contents

Note 7—Inventories

Inventories at December 31 were:

	Millions of Dollars	
	2004	2003
Crude oil and petroleum products	$ **3,147**	3,467
Materials, supplies and other	**519**	490
	$ **3,666**	3,957

Inventories valued on a LIFO basis totaled $2,988 million and $3,224 million at December 31, 2004 and 2003, respectively. The remainder of our inventories is valued under various methods, including FIFO and weighted average. The excess of current replacement cost over LIFO cost of inventories amounted to $2,220 million and $1,421 million at December 31, 2004 and 2003, respectively.

During 2004, certain inventory quantity reductions caused a liquidation of LIFO inventory values. This liquidation increased net income by $62 million, of which $54 million was attributable to our R&M segment. In 2003, a liquidation of LIFO inventory values increased income from continuing operations by $24 million, of which $22 million was attributable to our R&M segment.

Note 8—Investments and Long-Term Receivables

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

	Millions of Dollars	
	2004	2003
Investment in and advances to affiliated companies	$ **9,466**	6,258
Long-term receivables	**463**	476
Other investments	**479**	524
	$ **10,408**	7,258

At December 31, 2004, retained earnings included $1,264 million related to the undistributed earnings of affiliated companies, and distributions received from affiliates were $1,035 million, $496 million and $313 million in 2004, 2003 and 2002, respectively.

Equity Investments

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

- LUKOIL—10 percent ownership interest accounted for under the equity method because we concluded that the facts and circumstances surrounding our ownership interest indicate that we have an ability to exercise significant influence over its operating and financial policies—explores for and produces crude oil, natural gas, and natural gas liquids; refines, markets and transports crude oil and petroleum products; and is headquartered in Russia.

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

- Hamaca Holding LLC—57.1 percent non-controlling ownership interest accounted for under the equity method 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—produces heavy oil and in fourth quarter 2004 began producing on-specification medium-grade crude oil for export.

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

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

- Malaysian Refining Company (MRC)—47 percent ownership interest—refines crude oil and sells petroleum products.

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

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

	Millions of Dollars		
	2004	2003	2002
Revenues	$ **45,053**	29,777	16,843
Income before income taxes	**5,549**	2,033	715
Net income	**4,478**	1,495	674
Current assets	**20,685**	9,000	8,526
Noncurrent assets	**53,509**	33,695	24,351
Current liabilities	**15,386**	8,367	7,601
Noncurrent liabilities	**14,553**	11,303	13,340

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.

LUKOIL
LUKOIL is an international, integrated energy company headquartered in Russia, with worldwide petroleum exploration and production, and petroleum refining, marketing, supply and transportation. In September 2004, we made a joint announcement with LUKOIL, of an agreement to form a broad-based strategic alliance, whereby we would become a strategic equity investor in LUKOIL. Together, we also announced our intention to form a joint venture between the two companies to develop resources in the northern part of Russia’s Timan Pechora oil and gas province and the intention of the two companies to jointly seek the right to develop the West Qurna oil field in Iraq.

In the announcement, we disclosed that we were the successful bidder in an auction of 7.6 percent of LUKOIL's authorized and issued ordinary shares held by the Russian government for a price of $1,988 million, or $30.76 per share. The transaction closed on October 7, 2004. We increased our ownership in LUKOIL to 10 percent by the end of 2004 through open market purchases. Under the Shareholder Agreement between the two companies, we had the right to nominate a representative to the LUKOIL Board of Directors (Board). During the January 24, 2005, extraordinary general meeting of LUKOIL shareholders, all charter amendments reflected in the Shareholder Agreement were passed and ConocoPhillips' nominee was elected to LUKOIL's Board. In addition, the Shareholder Agreement allows us to increase our ownership interest in LUKOIL to 20 percent and limits our ability to sell our LUKOIL shares for a period of four years, except in certain circumstances. Once we reach 12.5 percent ownership, we have the right to nominate a second representative to the LUKOIL Board.

Under the terms of the joint-venture arrangements, we will pay an acquisition price to LUKOIL of approximately $500 million for a 30 percent economic interest in a joint venture to develop oil and gas resources in the northern part of Russia's Timan-Pechora province. Under the joint-venture arrangements, we will have a 50 percent voting interest. The exact amount of the acquisition price will be established at closing, which is anticipated in the first half of 2005.

Our equity share of the results of LUKOIL for the period from October 7, 2004, to December 31, 2004, has been estimated because LUKOIL's accounting cycle close and preparation of U.S. GAAP financial statements occurs subsequent to our accounting cycle close. This estimate is based on market indicators and historical production trends of LUKOIL, and other factors. Any difference between the estimated and actual results for this period will be included in our results for 2005. At December 31, 2004, the book value of our ordinary share investment in LUKOIL was $2,723 million. Our 10 percent share of the net assets of LUKOIL was estimated to be $2,064 million. This basis difference is $659 million, a majority of which is being amortized, on a unit-of-production basis. Included in net income for 2004, was after-tax expense of $11 million, representing the amortization of this basis difference. On December 31, 2004, the closing price of LUKOIL shares on the London Stock Exchange was $30.75 per share, making the aggregate total market value of our LUKOIL investment $2,613 million at that date.

Duke Energy Field Services, LLC

DEFS owns and operates gas plants, gathering systems, storage facilities and fractionation plants. At December 31, 2004, the book value of our common investment in DEFS was $242 million. Our 30.3 percent share of the net assets of DEFS was $814 million. This basis difference of $572 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 2004, 2003 and 2002 was after-tax income of $36 million, $36 million and $35 million, respectively, representing the amortization of the basis difference.

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.

Chevron Phillips Chemical Company LLC
CPChem manufactures and markets petrochemicals and plastics. At December 31, 2004, the book value of our investment in CPChem was $2,140 million. Our 50 percent share of the total net assets of CPChem was $1,988 million. This basis difference of $152 million is being amortized through 2020, consistent with the remaining estimated useful lives of CPChem properties, plants and equipment.

During 2004, we received two distributions from CPChem totaling $87.5 million, redeeming a portion of our preferred member principal, leaving $37.5 million as our remaining preferred member interest.

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 9—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					
	2004			2003		
	Gross PP&E	Accum. DD&A	Net PP&E	Gross PP&E	Accum. DD&A	Net PP&E
E&P	**$ 48,105**	**13,612**	**34,493**	42,358	10,837	31,521
Midstream	**589**	**120**	**469**	944	87	857
R&M	**18,402**	**4,048**	**14,354**	16,469	2,870	13,599
LUKOIL Investment	-	-	-	-	-	-
Chemicals	-	-	-	-	-	-
Emerging Businesses	**940**	**26**	**914**	1,013	214	799
Corporate and Other	**1,115**	**443**	**672**	1,055	403	652
	$ 69,151	**18,249**	**50,902**	61,839	14,411	47,428

PP&E is recorded at cost. 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 increases for the change in its present value, while the capitalized cost depreciates over the useful life of the related asset. Application of this new accounting principle initially increased net PP&E $1.2 billion.

Suspended Wells
In September 2004, the EITF discussed Issue No. 04-9, "Accounting for Suspended Well Costs," as it relates to SFAS No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies." SFAS No. 19 requires that the costs of exploratory wells be capitalized, or "suspended," on the balance sheet, pending a determination of whether potentially economic oil and gas reserves have been discovered. The discussion centered on whether certain circumstances would permit the continued capitalization of the costs for an exploratory well beyond one year, in the absence of plans for another exploratory well. The EITF removed the issue from its agenda, and requested that the FASB consider an amendment to SFAS No. 19 to clarify when it is permissible to continue to capitalize exploratory well costs beyond one year if (a) the well had found a sufficient quantity of reserves to justify its completion as a producing well, assuming the required capital expenditures would be made, and (b) the company was making sufficient progress assessing the reserves and the economic and operating viability of the project. In February 2005, the FASB posted FASB Staff Position (FSP) FAS No. 19-a, "Accounting for Suspended Well Costs," on its Web site for comment. The proposed FSP provides for continued capitalization past one year if a company is making sufficient progress on assessing the reserves and the economic and operating viability of the project. The proposed FSP also provides disclosure requirements about capitalized exploratory well costs. We estimate that if the proposed FSP were adopted prospectively on January 1, 2002, net income would not have changed in 2004, 2003, or 2002. We believe that the adoption of the FSP as proposed would not result in the write-off of any well suspended as of December 31, 2004. We plan to continue to monitor the deliberations of the FASB on this issue.

The following table reflects the net changes in suspended exploratory well costs during 2004, 2003 and 2002.

	Millions of Dollars		
	2004	2003	2002
Beginning balance at January 1	**$ 403**	221	189
Additions pending the determination of proved reserves	**142**	217	69
Reclassifications to proved properties	**(112)**	(6)	(3)
Charged to dry hole expense	**(86)**	(29)	(34)
Ending balance at December 31	**$ 347**	403	221

Included in total suspended well costs at year-end 2004 was $70 million related to eight exploratory wells in areas where major capital expenditures will be required and no further exploratory drilling is planned, but for which we are actively pursuing those activities necessary to classify the reserves as proved. These costs were suspended between 1999 and 2003. At year-end 2004, we were awaiting government approval of the development plan for the Bohai Bay Phase II project in China. Suspended well costs associated with this project represented $42 million of the $70 million total. This project was approved by the government in early 2005, which will allow us to book proved reserves in 2005, at which time the suspended well costs will be reclassified as part of the capitalized costs of the project. The remaining $28 million related to projects where infrastructure decisions are dependent on environmental permitting and production capacity, or where we are continuing to assess reserves and their potential development. At December 31, 2004, we did not have any amounts suspended that were associated with areas not requiring major capital expenditures before production could begin, where more than one year had elapsed since the completion of drilling.

Note 10—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, 2002	$ 15	2,350	12,079	14,444
Valuation and other adjustments	3	7	630	640
Allocated to reporting units	11,166	1,543	(12,709)	-
Balance at December 31, 2003	$ 11,184	3,900	-	15,084
Goodwill allocated to asset sales	**(38)**	**-**	**-**	**(38)**
Tax and other adjustments	**(56)**	**-**	**-**	**(56)**
Balance at December 31, 2004	**$ 11,090**	**3,900***	**-**	**14,990**

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

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, 2004			
Refining technology related	**$ 109**	**24**	**85**
Other*	**76**	**29**	**47**
	$ 185	**53**	**132**
Balance at December 31, 2003			
Refining technology related	$ 101	9	92
Other*	57	29	28
	$ 158	38	120

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

Indefinite-Lived Intangible Assets	
Balance at December 31, 2004	
Tradenames and trademarks	**$ 637**
Refinery air and operating permits	**274**
Other*	**53**
	$ 964
Balance at December 31, 2003	
Tradenames and trademarks	$ 604
Refinery air and operating permits	315
Other*	46
	$ 965

**Primarily pension related.*

Amortization expense related to the intangible assets above for the years ended December 31, 2004 and 2003, was $18 million and $17 million, respectively. The estimated amortization expense for the next five years is approximately $20 million per year.

Table of Contents

In 2004, we reduced the carrying value of indefinite-lived intangible assets related to refinery air emission credits. This impairment totaled $41 million before-tax, $26 million after-tax, and was recorded in the property impairments line of the consolidated income statement. The impairment was related to the reduced market value of certain air credits. We also impaired an intangible asset related to a marketing brand name. These intangible assets are included in the R&M segment.

Note 11—Property Impairments

During 2004, 2003 and 2002, we recognized the following impairment charges:

	Millions of Dollars		
	2004	2003	2002
E&P			
United States	$ **18**	65	12
International	**49**	180	37
Midstream	**38**	-	-
R&M			
Intangible assets	**42**	-	102
Other	**17**	2	26
Corporate and Other	-	5	-
	$ **164**	252	177

2004
The E&P segment recognized property impairments totaling $67 million in 2004, primarily related to the write-down to market value of properties planned for disposition and for properties failing to meet recoverability tests. The Midstream segment also recognized property impairments related to planned asset dispositions.

In R&M, we reduced the carrying value of certain indefinite-lived intangible assets. See Note 10—Goodwill and Intangibles for additional information. Other impairments in R&M during 2004 primarily were related to assets planned for disposition.

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
The E&P segment recognized impairments of $49 million in 2002, triggered by asset sales and evaluation of development drilling results.

We initiated a plan in late 2002 to sell a substantial portion of our R&M retail sites. The planned dispositions resulted in a reduction of the amount of gasoline volumes marketed under our “76” trademark. As a result, the carrying value of the “76” trademark 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 property impairments included in discontinued operations.

Note 12—Asset Retirement Obligations and Accrued Environmental Costs

Asset retirement obligations and accrued environmental costs at December 31 were:

	Millions of Dollars	
	2004	2003
Asset retirement obligations	**$ 3,089**	2,685
Accrued environmental costs	**1,061**	1,119
Total asset retirement obligations and accrued environmental costs	**4,150**	3,804
Asset retirement obligations and accrued environmental costs due within one year*	**(256)**	(201)
Long-term asset retirement obligations and accrued environmental costs	**$ 3,894**	3,603

**Classified as a current liability on the balance sheet, under the caption other accruals.*

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, 2004 and 2003, were $1,061 million and $1,119 million, respectively. The 2004 decrease in total accrued environmental costs is due primarily to payments on accrued environmental costs, partially offset by new accruals and accretion.

We had accrued environmental costs of $606 million and $625 million at December 31, 2004 and 2003, 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. We had also accrued in Corporate and Other $337 million and $367 million of environmental costs associated with non-operating sites at December 31, 2004 and 2003, respectively. In addition, $118 million and $127 million were included at December 31, 2004 and 2003, 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 $863 million at December 31, 2004. The expected future undiscounted payments related to the portion of the accrued environmental costs that have been discounted are: $114 million in 2005, $137 million in 2006, $103 million in 2007, $97 million in 2008, $94 million in 2009, and $443 million for all future years after 2009.

Table of Contents

Note 13—Debt

Long-term debt at December 31 was:

	Millions of Dollars	
	2004	2003
9 3/8% Notes due 2011	**$ 350**	350
8.75% Notes due 2010	**1,350**	1,350
8.5% Notes due 2005	**-**	1,150
8.125% Notes due 2030	**600**	600
8% Junior Subordinated Debentures due 2037	**361**	361
7.9% Notes due 2047	**100**	100
7.8% Notes due 2027	**300**	300
7.68% Notes due 2012	**54**	59
7.625% Notes due 2006	**240**	240
7.25% Notes due 2007	**200**	200
7.25% Notes due 2031	**500**	500
7.125% Debentures due 2028	**300**	300
7% Debentures due 2029	**200**	200
6.95% Notes due 2029	**1,900**	1,900
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
5.90% Notes due 2032	**600**	600
5.847% Notes due 2006	**118**	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 2009 at 2.29% at year-end 2004 and 1.05% - 1.08% at year-end 2003	**544**	709
Industrial Development bonds at 1.47% - 6.1% at year-end 2004 and 1.1% - 6.1% at year-end 2003	**256**	256
Guarantee of savings plan bank loan payable at 2.8375% at year-end 2004 and 1.4375% at year-end 2003	**253**	275
Note payable to Merey Sweeny, L.P. at 7%	**141**	131
Marine Terminal Revenue Refunding Bonds at 1.8% at year-end 2004 and 2.0% at year-end 2003	**265**	265
Other notes payable	**50**	52
Debt at face value	**14,432**	17,124
Capitalized leases	**56**	60
Net unamortized premiums and discounts	**514**	596
Total debt	**15,002**	17,780
Notes payable and long-term debt due within one year	**(632)**	(1,440)
Long-term debt	**$ 14,370**	16,340

Maturities inclusive of net unamortized premiums and discounts in 2005 through 2009 are: $632 million (included in current liabilities), $1,674 million, $654 million, $86 million and $1,104 million, respectively.

Effective October 12, 2004, we entered into two new revolving credit facilities totaling $5 billion to replace our previously existing $1.5 billion 364-day facility that was set to expire on October 13, 2004; two revolving credit facilities totaling $2 billion expiring in October 2006; and a $500 million facility expiring in October 2008. The two new facilities include a $2.5 billion four-year facility expiring in October 2008 and a $2.5 billion five-year facility expiring in October 2009. Both facilities are available for use as direct bank borrowings or as support for our $5 billion commercial paper program. In addition, the five-year facility may be used to support issuances of letters of credit totaling up to $750 million. The facilities are broadly syndicated among financial institutions and do not contain any material adverse change provisions or any covenants requiring maintenance of specified financial ratios or ratings. The credit agreements do contain a cross-default provision relating to our, or any of our consolidated subsidiaries', failure to pay principal or interest on other debt obligations of $200 million or more. At December 31, 2004, we had no outstanding borrowings under these facilities, but had $544 million in commercial paper outstanding and $173 million in letters of credit had been issued.

One of our Norwegian subsidiaries had two $300 million revolving credit facilities that expired in June 2004, which were not renewed.

Credit facility borrowings may bear interest at a margin above rates offered by certain designated banks in the London interbank market or at a margin above the overnight federal funds rate 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.

During 2004, we reduced our commercial paper balance outstanding from $709 million at December 31, 2003, to $544 million at December 31, 2004. Also in 2004, we paid off the $1,350 million aggregate principal amount of our 5.90% Notes due 2004 when they matured in April, and in August, we redeemed the $1,150 million aggregate principal amount of our 8.5% Notes due 2005 at a premium of $58 million plus accrued interest. The payments were funded primarily with cash from operating activities. In addition, we have given notice to redeem in March 2005 our $400 million 3.625% Notes due 2007.

On October 14, 2004, we amended and restated the ConocoPhillips Savings Plan term loan. This loan will require repayment in semi-annual installments beginning in 2009 and continuing through 2015. Under this loan, any participating bank in the syndicate of lenders may cease to participate on December 4, 2009, by giving not less than 180 days' prior notice to the ConocoPhillips Savings Plan and the company. At December 31, 2004, $253 million was outstanding under this term loan. 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 21—Employee Benefit Plans for additional discussion of the ConocoPhillips Savings Plan.

Note 14—Sales of Receivables

At December 31, 2004, certain credit card and trade receivables had been sold to a Qualifying Special Purpose Entity (QSPE) in a revolving-period securitization arrangement. This arrangement provided for us to sell, and the QSPE to purchase, certain receivables and for the QSPE to then issue beneficial interests of up to $1.2 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 QSPE because it meets 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.

At December 31, 2004 and 2003, the QSPE had issued beneficial interests to the bank-sponsored entities of $480 million and $1.2 billion, respectively. The receivables transferred to the QSPE met the isolation and other requirements of SFAS No. 140 to be accounted for as sales and were accounted for accordingly.

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 $3.2 billion at December 31, 2004, and $1.3 billion at December 31, 2003. We also retain servicing responsibility related to the sold receivables, which gives us certain rights and abilities, the fair value of which approximates the fair value of the liability incurred for continuing to service the receivables. The carrying value of our subordinated beneficial interests in the QSPE approximates fair market value due to the very short term of the underlying assets, which makes fair value stress testing for disclosure purposes unnecessary.

Total QSPE cash flows received from and paid under the securitization arrangements were as follows:

	Millions of Dollars	
	2004	2003
Receivables sold at beginning of year	**$ 1,200**	1,323
New receivables sold	**7,155**	25,201
Cash collections remitted	**(7,875)**	(25,324)
Receivables sold at end of year	**$ 480**	1,200
Discounts and other fees paid on revolving balances	**$ 6**	19

The decrease in cash flow activity in 2004 was primarily due to reductions in the average level of beneficial interests issued to the bank-sponsored entities.

At December 31, 2003, we had sold $226 million of receivables under factoring arrangements. We retained servicing responsibility related to those sold receivables, which gave us certain benefits, the fair value of which approximated the fair value of the liability incurred for continuing to service the receivables. At December 31, 2004, we had no receivables outstanding under similar arrangements.

Note 15—Guarantees

At December 31, 2004, 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

- In May 2004, the Merey Sweeny, L.P. (MSLP) joint-venture project at the Sweeny refinery in Old Ocean, Texas, achieved completion certification. As a result, the previously disclosed construction completion guarantee related to the debt and bond-financing arrangements secured by MSLP expired and the debt became non-recourse to ConocoPhillips.

- We 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 $410 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 be non-recourse upon startup and completion certification.

Guarantees of Joint-Venture Debt

- At December 31, 2004, we had guarantees of about $250 million outstanding for our portion of joint-venture debt obligations, which have terms of up to 20 years. Payment would be required if a joint venture defaults on its debt obligations. Included in these outstanding guarantees was $95 million associated with the Polar Lights Company joint venture in Russia.

Other Guarantees

- The MSLP joint-venture project agreement requires the partners in the venture to pay cash calls to cover operating expenses in the event that the venture does not have enough cash to cover operating expenses after setting aside the amount required for debt service over the next 20 years. Although there is no maximum limit stated in the agreement, the intent is to cover short-term cash deficiencies should they occur. Our maximum potential future payments under the agreement are currently estimated to be $100 million, assuming such a shortfall exists at some point in the future due to an extended operational disruption. If such an operational disruption did occur, MSLP has business interruption insurance and would be entitled to insurance proceeds subject to deductibles and certain limits.

- In February 2003, we entered into two agreements establishing separate guarantee facilities of $50 million each for two liquefied natural gas ships. 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 guarantee facilities.

  At the time of the agreement, 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 mid-2005. With respect to the first ship, the amount drawn under the guarantee facility at December 31, 2004, was less than $1 million.

- We have other guarantees totaling $340 million, which consist primarily of dealer and jobber loan guarantees to support our marketing business, a guarantee to fund the short-term cash liquidity deficits of a lubricants joint venture, a guaranteed revenue deficiency payment to a pipeline joint venture, two small construction completion guarantees, a guarantee supporting a lease assignment on a corporate aircraft, a guarantee associated with a pending lawsuit and guarantees of the lease payment obligations of a joint venture. The carrying amount recorded for these other guarantees, as of December 31, 2004, was $19 million. These guarantees generally extend up to 15 years and payment would only be required if the dealer, jobber or lessee goes into default, if the lubricants joint venture has cash liquidity issues, if the pipeline joint venture has revenue below a certain threshold, if construction projects are not completed, if guaranteed parties default on lease payments, 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. 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. 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 arrangements.

- During 2003 and 2004, 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 terms of these indemnifications vary greatly. The majority of these indemnifications are related to environmental issues, the term is generally indefinite and the maximum amount of future payments is generally unlimited. The carrying amount recorded for these indemnifications, as of December 31, 2004, was $236 million. We amortize the indemnification liability over the relevant time period, if one exists, based on the facts and circumstances surrounding each type of indemnity. In cases where the indemnification term is indefinite, we will reverse the liability when we have information that the liability is essentially relieved or amortize the liability over an appropriate time period as the fair value of our indemnification exposure declines. 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 were $119 million of environmental accruals for known contamination that is included in asset retirement obligations and accrued environmental costs at December 31, 2004. For additional information about environmental liabilities, see Note 12—Asset Retirement and Obligations and Accrued Environmental Costs, and Note 16—Contingencies and Commitments.

- 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.

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 likelihood that the triggering event will occur, the potential cost 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 might have to be paid under indemnity obligations stemming from our agreements that existed prior to December 31, 2002. The carrying amount recorded for these indemnifications, as of December 31, 2004, was $237 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 12—Asset Retirement Obligations and Accrued Environmental Costs, and Note 16—Contingencies and Commitments.

Note 16—Contingencies and Commitments

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', results of 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 12—Asset Retirement Obligations and Accrued Environmental Costs for a summary of our accrued environmental liabilities.

Legal Proceedings—We apply our knowledge, experience, and professional judgment to the specific characteristics of our cases, employing a litigation management process to manage and monitor the legal proceedings against us. Our process facilitates the early evaluation and quantification of potential exposures in individual cases. This process also enables us to track trial settings, as well as the status and pace of settlement discussions in individual matters. Based on our professional judgment and experience in using these litigation management tools and available information about current developments in all our cases, we believe that there is only a remote likelihood 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.

Other Contingencies—We have contingent liabilities resulting from throughput agreements with pipeline and processing companies not associated with financing arrangements. 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 ConocoPhillips. In addition, we have performance obligations that are secured by unused letters of credit and various purchase commitments for materials, supplies, services and items of permanent investment incident to the ordinary conduct of business.

Long-Term Throughput Agreements and Take-or-Pay Agreements—We have certain throughput agreements and take-or-pay agreements that are in support of financing arrangements. The agreements typically provide for natural gas or crude oil transportation to be used in the ordinary course of the company's business. The aggregate amounts of estimated payments under these various agreements are 2005—$92 million; 2006—$98 million; 2007—$98 million; 2008—$98 million; 2009—$98 million; and 2010 and after—$553 million. Total payments under the agreements were $86 million in 2004, $64 million in 2003 and $18 million in 2002.

Note 17—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 organization 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, 2004, were $479 million and $322 million, respectively, and appear as accounts and notes receivables, prepaid expenses and other current assets, other assets, accounts payable, other accruals, 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.

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, which we continue to hold, have qualified for and 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 has been 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 organization 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.

- 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, 2004, 2003 and 2002, the gains or losses from this activity were not material to our cash flows or income from continuing operations.

At December 31, 2004, 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 commercial paper, 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	
	2004	2003	**2004**	2003
Financial assets				
Foreign currency derivatives	$ **96**	44	**96**	44
Interest rate derivatives	**19**	13	**19**	13
Commodity derivatives	**364**	283	**364**	283
Financial liabilities				
Total debt, excluding capital leases	**14,946**	17,720	**16,126**	18,905
Mandatorily redeemable other minority interests and preferred securities	**-**	141	**-**	142
Interest rate derivatives	**17**	13	**17**	13
Foreign currency derivatives	**6**	5	**6**	5
Commodity derivatives	**299**	250	**299**	250

Note 18—Preferred Stock and Other Minority Interests

Company-Obligated Mandatorily Redeemable Preferred Securities of Phillips 66 Capital Trusts

In 1997, we formed a statutory business trust, Phillips 66 Capital II (Trust II), with ConocoPhillips owning all of the common securities of the trust. The sole purpose of the trust was to issue preferred securities to outside investors, investing the proceeds thereof in an equivalent amount of subordinated debt securities of ConocoPhillips. The trust was established to raise funds for general corporate purposes.

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). 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 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(R), Trust II was deconsolidated because we were not the primary beneficiary. This had the effect of increasing consolidated debt by $361 million, since the Subordinated Debt Securities II were no longer eliminated in consolidation. It also removed the $350 million of mandatorily redeemable preferred securities from our consolidated balance sheet. Prior to the adoption of FIN 46(R), 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

In July 2004, we retired the minority interest in Conoco Corporate Holdings L.P. The minority limited partner in Conoco Corporate Holdings L.P., a limited-life entity, was entitled to a cumulative annual 7.86 percent priority return on its investment. That net minority interest was $141 million at December 31, 2003.

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 1.32 percent. The preferred return at December 31, 2004 and 2003, was 3.34 percent and 2.48 percent, respectively. At December 31, 2004 and 2003, the minority interest was $504 million and $496 million, respectively. Ashford Energy Capital S.A. continues to be consolidated in our financial statements under the provisions of FIN 46(R) because we are the primary beneficiary. See Note 2—Changes in Accounting Principles for additional information.

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 6—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, 2004.

Note 19—Preferred Share Purchase Rights

In 2002, 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 have certain anti-takeover effects. The rights will cause substantial dilution to a person or group that attempts to acquire ConocoPhillips on terms not approved by the Board of Directors. However, since the rights may either be redeemed or otherwise made inapplicable by ConocoPhillips prior to an acquiror obtaining beneficial ownership of 15 percent or more of ConocoPhillips' common stock, the rights should not interfere with any merger or business combination approved by the Board of Directors prior to that occurrence. 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. If an acquiror obtains 15 percent or more of ConocoPhillips' common stock, then each right will be adjusted so that it will entitle the holder (other than the acquiror, whose rights will become void) to purchase, for the then exercise price, a number of shares of ConocoPhillips' common stock equal in value to two times the exercise price of the right. In addition, the rights enable holders to 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 20—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 imposed on us 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, 2004, future minimum rental payments due under non-cancelable leases, including those associated with discontinued operations, were:

	Millions of Dollars
2005	$ 476
2006	424
2007	356
2008	311
2009	237
Remaining years	1,009
Total	2,813
Less income from subleases	336*
Net minimum operating lease payments	$ 2,477

**Includes $166 million related to railroad cars subleased to CPChem, a related party.*

Operating lease rental expense from continuing operations for the years ended December 31 was:

	Millions of Dollars		
	2004	2003**	2002
Total rentals*	**$ 521**	471	541
Less sublease rentals	**42**	40	21
	$ 479	431	520

* *Includes $27 million, $31 million and $12 million of contingent rentals in 2004, 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.*

** *Revised.*

Note 21—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	
	2004		2003		**2004**	2003
	U.S.	**Int'l.**	U.S.	Int'l.		
Change in Benefit Obligation						
Benefit obligation at January 1	**$ 3,020**	**2,075**	3,079	1,501	**1,004**	919
Service cost	**150**	**69**	131	61	**23**	17
Interest cost	**176**	**114**	197	89	**58**	61
Plan participant contributions	**-**	**2**	-	1	**32**	27
Plan amendments	**-**	**2**	-	54	**-**	-
Actuarial (gain) loss	**129**	**31**	187	268	**(134)**	46
Benefits paid	**(374)**	**(84)**	(571)	(60)	**(73)**	(72)
Curtailment	**-**	**-**	(3)	(5)	**-**	-
Recognition of termination benefits	**-**	**3**	-	9	**-**	-
Foreign currency exchange rate change	**-**	**197**	-	157	**3**	6
Benefit obligation at December 31	**$ 3,101**	**2,409**	3,020	2,075	**913**	1,004
Accumulated benefit obligation portion of above at December 31	**$ 2,436**	**2,078**	2,379	1,764		
Change in Fair Value of Plan Assets						
Fair value of plan assets at January 1	**$ 1,460**	**1,303**	1,233	1,027	**7**	11
Actual return on plan assets	**198**	**129**	228	133	**1**	2
Company contributions	**417**	**139**	570	91	**37**	39
Plan participant contributions	**-**	**2**	-	1	**32**	27
Benefits paid	**(374)**	**(84)**	(571)	(60)	**(73)**	(72)
Foreign currency exchange rate change	**-**	**138**	-	111	**-**	-
Fair value of plan assets at December 31	**$ 1,701**	**1,627**	1,460	1,303	**4**	7

	Millions of Dollars					
	Pension Benefits				Other Benefits	
	2004		2003		**2004**	2003
	U.S.	**Int'l.**	U.S.	Int'l.		
Funded Status						
Excess obligation	$ **(1,400)**	**(782)**	(1,560)	(772)	**(909)**	(997)
Unrecognized net actuarial loss	**524**	**341**	554	369	**(45)**	100
Unrecognized prior service cost	**23**	**57**	26	53	**92**	111
Total recognized amount in the consolidated balance sheet	$ **(853)**	**(384)**	(980)	(350)	**(862)**	(786)
Components of above amount:						
Prepaid benefit cost	$ **-**	**71**	-	73	**-**	-
Accrued benefit liability	**(872)**	**(569)**	(999)	(538)	**(862)**	(786)
Intangible asset	**4**	**48**	5	40	**-**	-
Accumulated other comprehensive loss	**15**	**66**	14	75	**-**	-
Total recognized	$ **(853)**	**(384)**	(980)	(350)	**(862)**	(786)
Weighted-Average Assumptions Used to Determine Benefit Obligations at December 31						
Discount rate	**5.75%**	**5.50**	6.00	5.45	**5.75**	6.00
Rate of compensation increase	**4.00**	**3.80**	4.00	3.55	**4.00**	4.00
Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for years ended December 31						
Discount rate	**6.00%**	**5.45**	6.75	5.85	**6.00**	6.75
Expected return on plan assets	**7.00**	**7.00**	7.05	7.45	**7.00**	5.50
Rate of compensation increase	**4.00**	**3.55**	4.00	3.80	**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 2004, we recorded a benefit to other comprehensive income related to minimum pension liability adjustments totaling $8 million ($1 million net of tax), resulting in accumulated other comprehensive loss due to minimum pension liability adjustments at December 31, 2004, of $81 million ($60 million net of tax). During 2003, we recorded a benefit to other comprehensive income 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).

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 $4,893 million, $4,015 million, and $2,914 million at December 31, 2004, respectively, and $4,489 million, $3,661 million, and $2,415 million at December 31, 2003, respectively.

For our unfunded non-qualified supplemental key employee pension plans, the projected benefit obligation and the accumulated benefit obligation were $219 million and $162 million, respectively, at December 31, 2004, and were $237 million and $177 million, respectively, at December 31, 2003.

	Millions of Dollars								
	Pension Benefits						Other Benefits		
	2004		2003		2002		**2004**	2003	2002
	U.S.	**Int'l.**	U.S.	Int'l.	U.S.	Int'l.			
Components of Net Periodic Benefit Cost									
Service cost	**$ 150**	**69**	131	61	75	32	**23**	17	9
Interest cost	**176**	**114**	197	89	133	48	**58**	61	31
Expected return on plan assets	**(105)**	**(92)**	(90)	(78)	(73)	(49)	**-**	-	(1)
Amortization of prior service cost	**4**	**7**	4	5	5	2	**19**	19	8
Recognized net actuarial loss	**52**	**40**	70	17	48	7	**10**	6	3
Net periodic benefit cost	**$ 277**	**138**	312	94	188	40	**110**	103	50

We recognized pension settlement losses of $13 million and special termination benefits of $3 million in 2004. 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.

In determining net pension and other postretirement benefit costs, we 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 2005 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 2004 amounts:

	Millions of Dollars	
	One-Percentage-Point	
	Increase	Decrease
Effect on total of service and interest cost components	$ 2	(1)
Effect on the postretirement benefit obligation	16	(12)

In December 2003, the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (Act) was signed into law. The Act introduced a prescription drug benefit under Medicare (Medicare Part D), as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D. In May 2004, the FASB released Staff Position FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement, and Modernization Act of 2003," which required that we reflect the effect of the Act in our third-quarter 2004 financial statements. We determined, based on available regulatory guidance, that the prescription drug benefits provided by our retiree medical plan are not actuarially equivalent to the Medicare Part D benefit. Consequently, the federal subsidy will have no impact on the calculation of our medical plan liability or expense. We continue to evaluate the impact of the legislation on our benefit plan design.

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, 2004 and 2003, there were no shares of company stock included in plan assets. 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 2005, we expect to contribute approximately $410 million to our domestic qualified and non-qualified benefit plans and $140 million to our international qualified and non-qualified benefit plans.

A portion of U.S. pension plan assets is 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. At December 31, 2004, the participating interest in the annuity contract was valued at $186 million and consisted of $402 million in debt securities and $70 million in equity securities, less $286 million for the accumulated benefit obligation covered by the contract. At December 31, 2003, the participating interest was valued at $169 million and consisted of $406 million in debt securities and $63 million in equity securities, less $300 million for the accumulated benefit obligation. 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.

In the United States, plan asset allocation is managed on a gross asset basis, which includes the market value of all investments held under the insurance annuity contract. On this basis, weighted-average asset allocation is as follows:

	Pension					
	U.S.			International		
	2004	2003	Target	**2004**	2003	Target
Asset Category						
Equity securities	**64%**	55	57	**51**	48	53
Debt securities	**34**	42	37	**43**	46	41
Real estate	**1**	1	4	**1**	1	3
Other	**1**	2	2	**5**	5	3
	100%	100	100	**100**	100	100

The above asset allocations are all within guidelines established by plan fiduciaries.

Treating the participating interest in the annuity contract as a separate asset category results in the following weighted-average asset allocations:

	Pension			
	U.S.		International	
	2004	2003	**2004**	2003
Asset Category				
Equity securities	**70%**	62	**51**	48
Debt securities	**16**	22	**43**	46
Participating interest in annuity contract	**11**	12	**-**	-
Real estate	**1**	1	**1**	1
Other	**2**	3	**5**	5
	100%	100	**100**	100

The following benefit payments, which are exclusive of amounts to be paid from the participating annuity contract and which reflect expected future service, as appropriate, are expected to be paid:

	Millions of Dollars		
	Pension Benefits		
	U.S.	Int'l.	Other Benefits
2005	$ 162	75	52
2006	175	80	52
2007	198	84	53
2008	233	88	54
2009	251	93	55
2010-2014	1,771	560	304

Defined Contribution Plans
Most U.S. employees (excluding retail service station employees) are eligible to participate in the ConocoPhillips Savings Plan (CPSP). Employees can deposit up to 30 percent of their pay in the thrift feature of the CPSP to a choice of approximately 30 investment funds. ConocoPhillips matches $1 for each $1 deposited, up to 1.25 percent of pay. Company contributions charged to expense for the CPSP and predecessor plans, excluding the stock savings feature (discussed below), were $17 million in 2004, $19 million in 2003, and $40 million in 2002.

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 2005 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. The debt was refinanced during 2004; however, there was no change to the stock allocation schedule.

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 $88 million, $76 million and $39 million in 2004, 2003 and 2002, respectively, all of which was compensation expense. In 2004, 2003 and 2002, respectively, we made cash contributions to the CPSP of $0.5 million, $0.2 million and $2 million. In 2004, 2003 and 2002, we contributed 1,209,904 shares, 1,483,780 shares and 771,479 shares, respectively, of company common stock from the Compensation and Benefits Trust. The shares had a fair market value of $92 million, $80 million and $41 million, respectively. Dividends used to service debt were $27 million in 2004 and $28 million each in 2003 and 2002. These dividends reduced the amount of compensation expense recognized each period. Interest incurred on the CPSP debt in 2004, 2003 and 2002 was $5 million, $5 million and $7 million, respectively.

The total CPSP stock savings feature shares as of December 31 were:

	2004	2003
Unallocated shares	**6,519,634**	7,077,880
Allocated shares	**9,863,736**	10,312,220
Total shares	**16,383,370**	17,390,100

The fair value of unallocated shares at December 31, 2004, and 2003, was $566 million and $464 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 2004 and 2003, and was not significant in 2002 because the majority of these plans were acquired in the merger.

Stock-Based Compensation Plans
The 2004 Omnibus Stock and Performance Incentive Plan (the Plan) was approved by shareholders in May 2004. Over its 10-year life, the Plan allows the issuance of up to 35 million shares of our common stock for compensation to our employees, directors and consultants. The Plan replaced three heritage plans previously available to the company. Shares remaining available under the previous plans will be used to offset the 35 million shares noted above, so that no more than 35 million shares may be issued under the Plan. After approval of the Plan, the heritage plans were no longer used for further awards. Of the 35 million shares available for issuance under the Plan, the number of shares of common stock available for incentive stock options will be 20 million shares, and no more than 20 million shares may be used for awards in stock.

Shares of company stock awarded to employees under the Plan and the heritage plans were:

	2004	2003	2002
Shares	**1,898,781**	260,677	1,090,082
Weighted-average fair value	**$ 70.14**	48.75	57.84

Stock options granted under provisions of the Plan 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.

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.

Table of Contents

A summary of our stock option activity follows:

	Options	Weighted-Average Exercise Price
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
Granted	**2,176,104**	**65.69**
Exercised	**(10,712,699)**	**42.44**
Forfeited	**(161,021)**	**51.45**
Outstanding at December 31, 2004	**37,131,961**	**$ 51.94**

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:

	2004	2003	2002
Average grant date fair value of options	**$ 14.26**	9.95	11.67
Assumptions used			
Risk-free interest rate	**3.5%**	3.4	4.1
Dividend yield	**2.5%**	3.3	3.0
Volatility factor	**24.2%**	25.9	26.2
Expected life (years)	**6**	6	6

Options Outstanding at December 31, 2004

		Weighted-Average	
Exercise Prices	Options	Remaining Lives	Exercise Price
$12.17 to $45.88	**6,184,101**	**3.15 years**	**$ 41.30**
$46.29 to $52.25	**17,155,562**	**6.44 years**	**48.51**
$52.66 to $90.37	**13,792,298**	**6.86 years**	**60.98**

Options Exercisable at December 31

	Exercise Prices	Options	Weighted-Average Exercise Price
2004	**$12.17 to $45.88**	**6,172,805**	**$41.33**
	$46.29 to $52.25	**12,015,468**	**48.55**
	$52.66 to $65.62	**11,817,211**	**60.28**
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

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 2004 and 2003, shares transferred out of the CBT were 1,209,904 and 1,483,780, respectively. At December 31, 2004, 24.1 million shares remained in the CBT. All shares are required to be transferred out of the CBT by January 1, 2021.

Note 22—Taxes

Taxes charged to income from continuing operations were:

	Millions of Dollars		
	2004	2003	2002
Taxes Other Than Income Taxes			
Excise	**$ 16,397**	13,738	6,246
Property	**305**	290	244
Production	**499**	413	303
Payroll	**160**	149	99
Environmental	**12**	7	5
Other	**114**	82	40
	$ 17,487	14,679	6,937
Income Taxes			
Federal			
Current	**$ 1,616**	536	64
Deferred	**719**	637	56
Foreign			
Current	**3,468**	2,559	1,188
Deferred	**190**	(161)	114
State and local			
Current	**256**	136	57
Deferred	**13**	37	(36)
	$ 6,262	3,744	1,443

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	
	2004	2003*
Deferred Tax Liabilities		
Properties, plants and equipment, and intangibles	**$ 11,650**	10,551
Investment in joint ventures	**1,024**	1,092
Inventory	**364**	356
Partnership income deferral	**523**	417
Other	**660**	491
Total deferred tax liabilities	**14,221**	12,907
Deferred Tax Assets		
Benefit plan accruals	**1,244**	1,199
Asset retirement obligations and accrued environmental costs	**1,684**	1,585
Deferred state income tax	**250**	227
Other financial accruals and deferrals	**410**	372
Alternative minimum tax carryforwards	**-**	317
Loss and credit carryforwards	**1,167**	1,183
Other	**141**	182
Total deferred tax assets	**4,896**	5,065
Less valuation allowance	**968**	879
Net deferred tax assets	**3,928**	4,186
Net deferred tax liabilities	**$ 10,293**	8,721

**Certain amounts reclassified to conform with 2004 presentation.*

Current assets, long-term assets, current liabilities and long-term liabilities included deferred taxes of $85 million, $52 million, $45 million and $10,385 million, respectively, at December 31, 2004, and $-0-million, $53 million, $209 million and $8,565 million, respectively, at December 31, 2003.

We have loss and credit carryovers in multiple taxing jurisdictions. These attributes generally expire between 2005 and 2016 with some carryovers having indefinite carryforward periods.

Valuation allowances have been established for certain 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 2004, valuation allowances increased $89 million. This reflects increases of $260 million primarily related to foreign tax loss carryforwards, partially offset by decreases of $171 million, primarily related to foreign and state tax loss carryforwards that have expired or that have been utilized. The balance includes valuation allowances for certain deferred tax assets of $204 million, for which subsequently recognized tax benefits, if any, will be allocated to goodwill. 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.

In October 2004, the American Jobs Creation Act of 2004 was signed into law. The legislation introduced a special one-time provision allowing earnings of controlled foreign companies to be repatriated at a reduced tax rate. At this point, our investigation into our response to the legislation is preliminary, as we await additional and final clarifying legislation and guidance from the government. Because of the uncertainties related to this legislation, and as provided by FASB FSP No. 109-2, we elected to defer our decision on potentially altering our current plans on permanently reinvesting in certain foreign subsidiaries and foreign corporate joint ventures. We expect final guidance to be issued and our investigation into our response to the legislation to be completed late in 2005.

At December 31, 2004 and 2003, income considered to be permanently reinvested in certain foreign subsidiaries and foreign corporate joint ventures totaled approximately $2,091 million and $1,686 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.

Another provision of the American Jobs Creation Act of 2004 was a special deduction for qualifying manufacturing activities. This benefit will be recognized in the year the benefit is earned and did not impact our assessment of the need for potential valuation allowances.

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		
	2004	2003	2002	**2004**	2003	2002
Income from continuing operations before income taxes						
United States	**$ 7,587**	4,137	605	**52.8%**	49.6	28.3
Foreign	**6,782**	4,200	1,536	**47.2**	50.4	71.7
	$ 14,369	8,337	2,141	**100.0**	100.0	100.0
Federal statutory income tax	**$ 5,029**	2,918	749	**35.0%**	35.0	35.0
Foreign taxes in excess of federal statutory rate	**1,138**	792	680	**7.9**	9.5	31.8
Domestic tax credits	**(85)**	(25)	(77)	**(.6)**	(.3)	(3.6)
Write-off of acquired in-process research and development costs	**-**	-	86	**-**	-	4.0
State income tax	**175**	112	14	**1.2**	1.3	.6
Other	**5**	(53)	(9)	**.1**	(.6)	(.4)
	$ 6,262	3,744	1,443	**43.6**	44.9	67.4

Our 2004 tax expense was reduced by $72 million due to the remeasurement of deferred tax liabilities from the 2003 Canadian graduated tax rate reduction and a 2004 Alberta provincial tax rate change. 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.

Note 23—Other Comprehensive Income

The components and allocated tax effects of other comprehensive income (loss) follow:

	Millions of Dollars		
	Before-Tax	Tax Expense (Benefit)	After-Tax
2004			
Minimum pension liability adjustment	**$ 10**	**9**	**1**
Unrealized gain on securities	**2**	**1**	**1**
Foreign currency translation adjustments	**904**	**127**	**777**
Hedging activities	**4**	**12**	**(8)**
Other comprehensive income	**$ 920**	**149**	**771**
2003			
Minimum pension liability adjustment	$ 271	103	168
Unrealized gain on securities	6	2	4
Foreign currency translation adjustments*	992	206	786
Hedging activities	39	12	27
Other comprehensive income	$ 1,308	323	985
2002			
Minimum pension liability adjustment	$ (149)	(56)	(93)
Unrealized loss on securities	(3)	-	(3)
Foreign currency translation adjustments	263	41	222
Hedging activities	(35)	-	(35)
Other comprehensive income	$ 76	(15)	91

**Before-tax and tax expense amounts revised.*

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 considered permanent in duration.

Accumulated other comprehensive income in the equity section of the balance sheet included:

	Millions of Dollars	
	2004	2003
Minimum pension liability adjustment	**$ (67)**	(68)
Foreign currency translation adjustments	**1,662**	885
Unrealized gain on securities	**6**	5
Deferred net hedging loss	**(9)**	(1)
Accumulated other comprehensive income	**$ 1,592**	821

Table of Contents

Note 24—Cash Flow Information

	Millions of Dollars		
	2004	2003	2002
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(R)	**-**	940	-
Increase in long-term debt through the implementation and continuing application of FIN 46(R)	**-**	2,774	-
Increase in assets of discontinued operations held for sale related to implementation of FIN 46(R)	**-**	726	-
The merger by issuance of stock	**-**	-	15,974
Investment in properties, plants and equipment of businesses through the assumption of non-cash liabilities	**-**	-	181
Cash Payments			
Interest	**$ 560**	839	441
Income taxes	**4,754**	2,909	1,363

Note 25—Other Financial Information

	Millions of Dollars Except Per Share Amounts		
	2004	2003	2002
Interest			
Incurred			
Debt	$ **878**	1,061	740
Other	**98**	110	58
	976	1,171	798
Capitalized	**(430)**	(327)	(232)
Expensed	$ **546**	844	566
Research and Development Expenditures—expensed	$ **126**	136	355*
**Includes $246 million of in-process research and development expenses related to the merger.*			
Advertising Expenses*	$ **101**	70	37
**Deferred amounts at December 31 were immaterial in all three years.*			
Shipping and Handling Costs*	$ **947**	853	612
**Amounts included in E&P production and operating expenses.*			
Cash Dividends paid per common share	$ **1.79**	1.63	1.48
Foreign Currency Transaction Gains (Losses)—after-tax			
E&P	$ **(13)**	(50)	(34)
Midstream	**(1)**	-	-
R&M	**12**	18	9
Emerging Businesses	-	(1)	-
Corporate and Other	**44**	67	21
	$ **42**	34	(4)

Note 26—Related Party Transactions

Significant transactions with related parties were:

	Millions of Dollars		
	2004	2003	2002
Operating revenues (a)	$ **5,293**	3,812	1,554
Purchases (b)	**4,014**	3,367	1,580
Operating expenses and selling, general and administrative expenses (c)	**693**	510	248
Net interest (income) expense (d)	**39**	34	2

(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 and Getty Petroleum Marketing Inc. (a subsidiary of LUKOIL). Also, we charge several of our affiliates including CPChem, MSLP and Hamaca Holding LLC 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 upgraded 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 and a price upgrade to MSLP for heavy crude processing.

(c) We pay processing fees to various affiliates. Additionally, we pay crude oil transportation fees to pipeline equity companies.

(d) We pay and/or receive interest to/from various affiliates including the receivables securitization QSPE.

Elimination of our equity percentage share of profit or loss included in our inventory at December 31, 2004, 2003, and 2002, 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, 2004, 2003, and 2002, on the revenues from related parties described above were not material.

Note 27—Segment Disclosures and Related Information

We have organized our reporting structure based on the grouping of similar products and services, resulting in six operating segments:

1) E&P—This segment primarily explores for, produces and markets crude oil, natural gas, and natural gas liquids on a worldwide basis. At December 31, 2004, 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 purchases, refines, markets and transports crude oil and petroleum products, mainly in the United States, Europe and Asia. At December 31, 2004, 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) LUKOIL Investment—This segment represents our investment in the ordinary shares of LUKOIL, an international, integrated oil and gas company headquartered in Russia. In October 2004, we closed on a transaction to acquire 7.6 percent of LUKOIL's shares held by the Russian government. During the remainder of 2004, we increased our ownership to 10 percent.

5) 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.

6) 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.

Corporate and Other includes general corporate overhead; 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 in 2002; 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.

Table of Contents

Analysis of Results by Operating Segment

	Millions of Dollars		
	2004	2003	2002
Sales and Other Operating Revenues			
E&P			
United States	**$ 23,805**	18,521	7,222
International	**16,960**	12,964	4,850
Intersegment eliminations-U.S.	**(2,841)**	(2,439)	(1,304)
Intersegment eliminations-international	**(3,732)**	(3,202)	(484)
E&P	**34,192**	25,844	10,284
Midstream			
Total sales	**4,020**	4,735	2,049
Intersegment eliminations	**(987)**	(1,431)	(510)
Midstream	**3,033**	3,304	1,539
R&M			
United States	**72,962**	55,734	39,534
International	**25,141**	19,504	5,630
Intersegment eliminations-U.S.	**(431)**	(327)	(296)
Intersegment eliminations-international	**(26)**	(13)	-
R&M	**97,646**	74,898	44,868
LUKOIL Investment	**-**	-	-
Chemicals	**14**	14	13
Emerging Businesses	**177**	178	36
Corporate and Other	**14**	8	8
Consolidated sales and other operating revenues	**$ 135,076**	104,246	56,748
Depreciation, Depletion, Amortization and Impairments			
E&P			
United States	**$ 1,126**	1,172	999
International	**1,859**	1,736	735
Total E&P	**2,985**	2,908	1,734
Midstream	**80**	54	19
R&M			
United States	**657**	551	564
International	**175**	140	50
Total R&M	**832**	691	614
LUKOIL Investment	**-**	-	-
Chemicals	**-**	-	-
Emerging Businesses	**8**	10	4
Corporate and Other	**57**	74	29
Consolidated depreciation, depletion, amortization and impairments	**$ 3,962**	3,737	2,400

	Millions of Dollars		
	2004	2003	2002
Equity in Earnings of Affiliates			
E&P			
United States	$ **21**	27	29
International	**520**	289	162
Total E&P	**541**	316	191
Midstream	**265**	138	46
R&M			
United States	**245**	89	43
International	**110**	5	-
Total R&M	**355**	94	43
LUKOIL Investment	**74**	-	-
Chemicals	**307**	(6)	(16)
Emerging Businesses	**(7)**	-	(3)
Corporate and Other	-	-	-
Consolidated equity in earnings of affiliates	$ **1,535**	542	261
Income Taxes			
E&P			
United States	$ **1,583**	1,231	473
International	**3,349**	2,269	1,337
Total E&P	**4,932**	3,500	1,810
Midstream	**137**	83	42
R&M			
United States	**1,234**	652	90
International	**197**	64	(11)
Total R&M	**1,431**	716	79
LUKOIL Investment	-	-	-
Chemicals	**64**	(12)	(18)
Emerging Businesses	**(52)**	(51)	(38)
Corporate and Other	**(250)**	(492)	(432)
Consolidated income taxes	$ **6,262**	3,744	1,443
Net Income (Loss)			
E&P			
United States	$ **2,942**	2,374	1,156
International	**2,760**	1,928	593
Total E&P	**5,702**	4,302	1,749
Midstream	**235**	130	55
R&M			
United States	**2,126**	990	138
International	**617**	282	5
Total R&M	**2,743**	1,272	143
LUKOIL Investment	**74**	-	-
Chemicals	**249**	7	(14)
Emerging Businesses	**(102)**	(99)	(310)*
Corporate and Other	**(772)**	(877)	(1,918)
Consolidated net income (loss)	$ **8,129**	4,735	(295)

**Includes a non-cash $246 million write-off of acquired in-process research and development costs.*

	Millions of Dollars		
	2004	2003	2002
Investments In and Advances To Affiliates			
E&P			
United States	$ **188**	133	156
International	**2,522**	2,351	2,184
Total E&P	**2,710**	2,484	2,340
Midstream	**413**	394	318
R&M			
United States	**752**	777	762
International	**667**	517	416
Total R&M	**1,419**	1,294	1,178
LUKOIL Investment	**2,723**	-	-
Chemicals	**2,179**	2,059	2,050
Emerging Businesses	**1**	2	-
Corporate and Other	**21**	25	14
Consolidated investments in and advances to affiliates	$ **9,466**	6,258	5,900

Total Assets			
E&P			
United States	$ **16,105**	15,262	14,196
International	**26,481**	22,458	19,526
Goodwill	**11,090**	11,184	15
Total E&P	**53,676**	48,904	33,737
Midstream	**1,293**	1,736	1,931
R&M			
United States	**19,180**	17,172	16,718
International	**5,834**	5,020	4,117
Goodwill	**3,900**	3,900	2,350
Total R&M	**28,914**	26,092	23,185
LUKOIL Investment	**2,723**	-	-
Chemicals	**2,221**	2,094	2,095
Emerging Businesses	**972**	843	737
Corporate and Other	**3,062**	2,786	15,151*
Consolidated total assets	$ **92,861**	82,455	76,836

**Includes goodwill that had not yet been allocated to reporting units of $12,079 million.*

Capital Expenditures and Investments*			
E&P			
United States	$ **1,314**	1,418	1,205
International	**3,935**	3,090	2,071
Total E&P	**5,249**	4,508	3,276
Midstream	**7**	10	5
R&M			
United States	**1,026**	860	676
International	**318**	319	164
Total R&M	**1,344**	1,179	840
LUKOIL Investment	**2,649**	-	-
Chemicals	-	-	60
Emerging Businesses	**75**	284	122
Corporate and Other	**172**	188	85
Consolidated capital expenditures and investments	$ **9,496**	6,169	4,388

**Includes dry hole costs.*

Additional information on items included in Corporate and Other (on a before-tax basis unless otherwise noted):

	Millions of Dollars		
	2004	2003	2002
Interest income	**$ 47**	56	21
Interest and debt expense	**546**	844	566
Significant non-cash items			
Impairments included in discontinued operations	**96**	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
2004						
Sales and Other						
Operating Revenues*	**$ 96,449**	**3,975**	**14,828**	**3,653**	**16,171**	**135,076**
Long-Lived Assets**	**$ 30,255**	**4,742**	**6,076**	**4,727**	**14,568**	**60,368**
2003						
Sales and Other						
Operating Revenues*	$ 74,768	3,068	11,632	2,735	12,043	104,246
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

**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 28—New Accounting Standards and Emerging Issues

New Accounting Standards
In December 2004, the FASB issued SFAS No. 153, “Exchange of Nonmonetary Assets an amendment of APB Opinion No. 29.” This amendment eliminates the APB Opinion No. 29 exception for nonmonetary exchanges of similar productive assets and replaces it with an exception for exchanges of nonmonetary assets that do not have commercial substance. This Statement is effective on a prospective basis beginning July 1, 2005. We continue to evaluate this standard.

Also in December 2004, the FASB issued SFAS No. 123 (revised 2004), “Share-Based Payment,” (SFAS 123(R)), which supercedes APB Opinion No. 25, “Accounting for Stock Issued to Employees,” and replaces SFAS No. 123, “Accounting for Stock-Based Compensation,” that we adopted at the beginning of 2003. SFAS 123(R) prescribes the accounting for a wide range of share-based compensation arrangements, including share options, restricted share plans, performance-based awards, share appreciation rights, and employee share purchase plans, and generally requires the fair value of share-based awards to be expensed in the income statement. We are studying the provisions of this new pronouncement to determine the impact, if any, on our financial statements. For more information on our adoption of SFAS No. 123 and its effect on net income, see Note 1—Accounting Policies.

In November 2004, the FASB issued SFAS No. 151, “Inventory Costs an amendment of ARB No. 43, Chapter 4.” This Statement requires that items, such as idle facility expense, excessive spoilage, double freight, and re-handling costs, be recognized as a current-period charge. We are required to implement this Statement in the first quarter of 2006. We are analyzing the provisions of this standard to determine the effects, if any, on our financial statements.

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. The Statement, already effective for contracts created or modified after May 31, 2003, was originally intended to become effective July 1, 2003, for all contracts existing at May 31, 2003. However, on November 7, 2003, the FASB issued an indefinite deferral of certain provisions of SFAS No. 150. We continue to monitor and assess the FASB’s modifications of SFAS No. 150, but do not anticipate any material impact to our financial statements.

Emerging Issues

At a November 2004 meeting, the EITF discussed Issue No. 04-13, “Accounting for Purchases and Sales of Inventory with the Same Counterparty,” which addresses accounting issues that arise when one company both sells inventory to and buys inventory from another company in the same line of business. For additional information, see the Revenue Recognition section of Note 1—Accounting Policies.

The FASB is currently reviewing the accounting guidance provided in SFAS No. 19, “Financial Accounting and Reporting by Oil and Gas Producing Companies,” relating to exploratory costs that have been capitalized, or “suspended,” on the balance sheet, pending a determination of whether potential economic oil and gas reserves have been discovered. For additional information, see Note 9—Properties, Plants and Equipment.

In June 2004, the FASB published the Exposure Draft, “Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143.” This interpretation clarifies that an entity is required to recognize a liability for a legal obligation to perform asset retirement activities when the retirement is conditional on a future event if the liability’s fair value can be reasonably estimated. If the liability’s fair value cannot be reasonably estimated, then the entity must disclose (a) a description of the obligation, (b) the fact that a liability has not been recognized because the fair value cannot be reasonably estimated, and (c) the reasons why the fair value cannot be reasonably estimated. Depending on the FASB’s conclusions on this issue, it is possible that we would need to reconsider our asset retirement obligations and related disclosures for certain of our downstream assets (primarily refineries).

Note 29—Subsequent Events

On February 4, 2005, we announced a stock repurchase program that provides for the repurchase of up to $1 billion of the company's common stock over a period of up to two years. The program will serve as a means of offsetting dilution to shareholders from the company's stock-based compensation programs. Acquisitions for the share repurchase program will be made at management's discretion at prevailing prices, subject to market conditions and other factors. Purchases may be increased, decreased or discontinued at any time without prior notice. Shares of stock repurchased under the plan will be held as treasury shares.

We participated in negotiations throughout 2004 with the U.S. Environmental Protection Agency (EPA), U.S. Department of Justice (DOJ), the states of Louisiana, Illinois, Pennsylvania, New Jersey, and the Northwest Clean Air Agency (the state of Washington) to settle allegations arising out of the EPA's national enforcement initiative, as well as other related Clean Air Act regulation issues. In January 2005, we entered into a consent decree with the United States and the local agency and states named above. In the consent decree, we agreed to reduce air emissions from refineries in Washington, California, Texas, Louisiana, Illinois, Pennsylvania, and New Jersey over the next eight years. We plan to spend an estimated $525 million over that time period to install control technology and equipment to reduce emissions from stacks, vents, valves, heaters, boilers, and flares.

On February 24, 2005, ConocoPhillips and Duke Energy Corporation (Duke) agreed to terms to restructure their respective ownership levels in DEFS, which would cause DEFS to become a jointly controlled venture, owned 50 percent by each company. This restructuring has been approved by the Boards of Directors of both owners. We will increase our current 30.3 percent ownership in DEFS to 50 percent through a series of direct and indirect transfers of Midstream assets from ConocoPhillips to Duke, a disproportionate cash distribution to Duke from the sale of DEFS' general partner interest in TEPPCO Partners, L.P., and a final cash payment to Duke of approximately $200 million, which we expect to fund from our general liquidity resources. The restructuring is expected to close in the second quarter of 2005, subject to normal regulatory approvals. Once completed, our Midstream segment will consist primarily of our 50 percent equity method interest in DEFS.

Oil and Gas Operations (Unaudited)

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.

These disclosures include information about our consolidated oil and gas activities and our proportionate share of our equity affiliates’ oil and gas activities, covering both those in our Exploration & Production segment, as well as in our LUKOIL Investment segment. As a result, amounts reported as Equity Affiliates in Oil and Gas Operations may differ from those shown in the individual segment disclosures reported elsewhere in this report. The data included for the LUKOIL Investment segment reflects the company’s estimated share of LUKOIL’s amounts. Because LUKOIL’s accounting cycle close and preparation of U.S. GAAP financial statements occurs subsequent to our accounting cycle close, our equity share of financial information and statistics for 2004 from our LUKOIL investment are an estimate. Our estimated year-end 2004 reserves related to our equity investment in LUKOIL were based on LUKOIL’s year-end 2003 reserves without any provision for potential 2004 reserve additions, and included adjustments to conform to ConocoPhillips’ reserve policy and provide for estimated 2004 production. Other financial information and statistics were based on market indicators, historical production trends of LUKOIL, and other factors. Any differences between the estimate and actual financial information and statistics will be recorded in a subsequent period.

The information about our proportionate share of equity affiliates is necessary for a full understanding of our operations because equity affiliate operations are an integral part of the overall success of our oil and gas operations.

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. In these supplemental oil and gas disclosures, when we use equity accounting for operations that have proved reserves, these operations are not included in the consolidated operations information. Instead, they are shown separately and designated as Equity Affiliates. Prior to 2004, Equity Affiliates consisted of two heavy-oil projects in Venezuela, an oil development project in northern Russia, and a heavy-oil project in Canada. In addition, 2004 included certain operations related to our investment in LUKOIL. Equity Affiliate operations at the end of 2004 would geographically be classified as Other Areas.

Amounts in 2002 were impacted by the merger of Conoco and Phillips (the merger) in late August 2002.

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**
Developed and Undeveloped									
End of 2001	1,631	105	1,736	619	158*	2	101	**2,616**	**660**
Revisions	32	(8)	24	(31)	(28)	5	(4)	**(34)**	**(27)**
Improved recovery	46	1	47	7	-	-	-	**54**	-
Purchases	-	132	132	405	124	101	99	**861**	**733**
Extensions and discoveries	14	6	20	6	9	1	13	**49**	**4**
Production	(120)	(14)	(134)	(72)	(9)	(5)	(15)	**(235)**	**(13)**
Sales	-	(2)	(2)	(20)	-	(13)	(1)	**(36)**	-
End of 2002	1,603	220	1,823	914	254**	91	193	**3,275**	**1,357**
Revisions	35	(5)	30	15	40	(9)	(4)	**72**	**48**
Improved recovery	15	1	16	47	-	-	1	**64**	-
Purchases	-	-	-	-	5	-	-	**5**	**1**
Extensions and discoveries	19	4	23	4	10	223	10	**270**	**8**
Production	(119)	(19)	(138)	(106)	(24)	(11)	(27)	**(306)**	**(37)**
Sales	-	(15)	(15)	(9)	(21)	(20)	(25)	**(90)**	-
End of 2003	1,553	186	1,739	865	264	274	148	**3,290**	**1,377**
Revisions	31	(4)	27	28	8	(219)	(5)	**(161)**	**(88)**
Improved recovery	16	1	17	1	14	-	-	**32**	-
Purchases	-	-	-	-	-	-	-	**-**	**783**
Extensions and discoveries	46	6	52	55	4	1	186	**298**	-
Production	(110)	(19)	(129)	(98)	(35)	(9)	(21)	**(292)**	**(54)**
Sales	-	-	-	-	-	-	-	**-**	**(36)**
End of 2004	1,536	170	1,706	851	255	47	308	**3,167**	**1,982**
Developed									
End of 2001	1,275	91	1,366	534	13	2	83	**1,998**	**47**
End of 2002	1,335	169	1,504	713	55	81	168	**2,521**	**378**
End of 2003	1,365	163	1,528	454	95	51	137	**2,265**	**529**
End of 2004	1,415	148	1,563	429	207	46	121	**2,366**	**1,115**

**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.*

- Revisions in 2004 in Canada were primarily related to Surmont as a result of low December 31, 2004, bitumen values.

- Purchases in 2004 were associated with LUKOIL. Purchases in 2002 were primarily related to the merger.

- Extensions and discoveries in Other Areas in 2004 were primarily attributable to Kashagan in Kazakhstan and in 2003 were primarily related to Surmont in Canada. Surmont uses Steam Assisted Gravity Drainage, an improved recovery method.

- 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 258 million barrels at the end of 2004. 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.

Table of Contents

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**
Developed and Undeveloped									
End of 2001	3,161	3,018	6,179	1,417	317*	55	716	**8,684**	**145**
Revisions	(27)	(70)	(97)	(20)	(60)	16	(15)	**(176)**	-
Improved recovery	5	1	6	14	-	-	-	**20**	-
Purchases	-	1,862	1,862	2,583	1,856	1,241	206	**7,748**	**17**
Extensions and discoveries	2	225	227	43	6	21	414	**711**	**1**
Production	(147)	(340)	(487)	(226)	(49)	(59)	(19)	**(840)**	**(2)**
Sales	(5)	(1)	(6)	(4)	-	(97)	(161)	**(268)**	-
End of 2002	2,989	4,695	7,684	3,807	2,070**	1,177	1,141	**15,879**	**161**
Revisions	75	(140)	(65)	17	(79)	(51)	-	**(178)**	**65**
Improved recovery	6	1	7	51	-	-	1	**59**	-
Purchases	-	39	39	-	60	-	-	**99**	-
Extensions and discoveries	-	254	254	65	1,371	90	85	**1,865**	**5**
Production	(148)	(477)	(625)	(462)	(121)	(159)	(35)	**(1,402)**	**(5)**
Sales	-	(114)	(114)	(60)	(295)	(15)	(4)	**(488)**	-
End of 2003	2,922	4,258	7,180	3,418	3,006	1,042	1,188	**15,834**	**226**
Revisions	551	141	692	(87)	804	29	(46)	**1,392**	-
Improved recovery	-	1	1	-	5	-	-	**6**	-
Purchases	-	4	4	-	-	-	-	**4**	**666**
Extensions and discoveries	23	298	321	382	79	66	122	**970**	-
Production	(152)	(465)	(617)	(428)	(121)	(159)	(41)	**(1,366)**	**(9)**
Sales	-	(3)	(3)	-	-	(3)	-	**(6)**	**(21)**
End of 2004	3,344	4,234	7,578	3,285	3,773	975	1,223	**16,834**	**862**
Developed									
End of 2001	2,969	2,684	5,653	1,053	245	45	491	**7,487**	**3**
End of 2002	2,806	4,302	7,108	3,278	832	1,098	517	**12,833**	**28**
End of 2003	2,763	3,968	6,731	2,748	1,342	971	596	**12,388**	**123**
End of 2004	3,194	3,989	7,183	2,467	1,520	934	522	**12,626**	**325**

**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.*

- 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.

- Revisions in 2004 in Asia Pacific were primarily related to Indonesia.

- Purchases in 2004 were primarily attributable to LUKOIL. Purchases in 2002 were related to the merger.

- Extensions and discoveries in 2004 in Other Areas were primarily attributable to Kashagan in Kazakhstan, and in the European North Sea attributable to the United Kingdom. Extensions and discoveries in Asia Pacific in 2003 were primarily attributable to the Bayu-Undan project in the Timor Sea.

- Natural gas reserves are computed at 14.65 pounds per square inch absolute and 60 degrees Fahrenheit.

Table of Contents

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**
Developed and Undeveloped									
End of 2001	164	93	257	36	75*	-	16	**384**	-
Revisions	(4)	5	1	(1)	(11)	-	-	**(11)**	-
Improved recovery	-	1	1	-	-	-	-	**1**	-
Purchases	-	80	80	14	20	38	1	**153**	-
Extensions and discoveries	-	4	4	-	-	1	-	**5**	-
Production	(9)	(9)	(18)	(3)	-	(2)	(1)	**(24)**	-
Sales	-	-	-	-	-	(2)	(1)	**(3)**	-
End of 2002	151	174	325	46	84**	35	15	**505**	-
Revisions	(2)	35	33	3	(5)	(1)	1	**31**	-
Improved recovery	-	-	-	2	-	-	-	**2**	-
Purchases	-	-	-	-	3	-	-	**3**	-
Extensions and discoveries	-	2	2	-	10	2	-	**14**	-
Production	(8)	(17)	(25)	(5)	-	(4)	(1)	**(35)**	-
Sales	-	(1)	(1)	-	(13)	(2)	-	**(16)**	-
End of 2003	141	193	334	46	79	30	15	**504**	-
Revisions	20	(98)	(78)	7	(5)	(1)	(10)	**(87)**	-
Improved recovery	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-
Extensions and discoveries	-	1	1	1	-	1	-	**3**	-
Production	(8)	(8)	(16)	(6)	(3)	(4)	(1)	**(30)**	-
Sales	-	-	-	-	-	-	-	-	-
End of 2004	153	88	241	48	71	26	4	**390**	-
Developed									
End of 2001	163	92	255	31	-	-	16	**302**	-
End of 2002	151	166	317	40	-	30	15	**402**	-
End of 2003	141	188	329	26	-	27	15	**397**	-
End of 2004	153	82	235	34	71	25	4	**369**	-

**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.*

- Natural gas liquids reserves include estimates of natural gas liquids to be extracted from our leasehold gas at gas processing plants or facilities.

- Purchases in 2002 were related to the merger.

Table of Contents

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**
2004									
Sales	$4,378	2,568	6,946	4,215	1,777	1,214	704	**14,856**	**867**
Transfers	121	832	953	1,255	71	-	75	**2,354**	**481**
Other revenues	4	(36)	(32)	9	10	116	19	**122**	**33**
Total revenues	4,503	3,364	7,867	5,479	1,858	1,330	798	**17,332**	**1,381**
Production costs	803	689	1,492	561	233	306	169	**2,761**	**406**
Exploration expenses	82	101	183	85	106	112	211	**697**	**5**
Depreciation, depletion and amortization	426	586	1,012	1,095	275	349	43	**2,774**	**137**
Property impairments	6	12	18	2	-	47	-	**67**	**-**
Transportation costs	598	241	839	296	48	43	2	**1,228**	**65**
Other related expenses	14	43	57	20	(2)	4	21	**100**	**39**
Accretion	21	21	42	72	6	14	2	**136**	**1**
	2,553	1,671	4,224	3,348	1,192	455	350	**9,569**	**728**
Provision for income taxes	888	584	1,472	2,233	477	127	420	**4,729**	**108**
Results of operations for producing activities	1,665	1,087	2,752	1,115	715	328	(70)	**4,840**	**620**
Other earnings	167	23	190	102	(2)	130*	(45)	**375**	**(59)**
Net income (loss)	$1,832	1,110	2,942	1,217	713	458	(115)	**5,215**	**561**
2003									
Sales	$3,564	2,488	6,052	3,860	1,005	1,066	677	**12,660**	**423**
Transfers	103	545	648	903	16	-	77	**1,644**	**266**
Other revenues	(11)	93	82	(4)	33	43	10	**164**	**34**
Total revenues	3,656	3,126	6,782	4,759	1,054	1,109	764	**14,468**	**723**
Production costs	792	656	1,448	611	172	280	159	**2,670**	**184**
Exploration expenses	56	143	199	121	52	94	127	**593**	**2**
Depreciation, depletion and amortization	436	571	1,007	956	163	326	40	**2,492**	**104**
Property impairments	-	65	65	160	-	5	-	**230**	**-**
Transportation costs	666	188	854	270	40	40	23	**1,227**	**20**
Other related expenses	7	78	85	29	14	93	55	**276**	**27**
Accretion	25	18	43	50	5	11	2	**111**	**2**
	1,674	1,407	3,081	2,562	608	260	358	**6,869**	**384**
Provision for income taxes	595	502	1,097	1,538	225	57	362	**3,279**	**83**
Results of operations for producing activities	1,079	905	1,984	1,024	383	203	(4)	**3,590**	**301**
Other earnings	223	25	248	46	2	67*	(46)	**317**	**(46)**
Cumulative effect of accounting change	143	(1)	142	20	-	(8)	(12)	**142**	**(2)**
Net income (loss)	$1,445	929	2,374	1,090	385	262	(62)	**4,049**	**253**
2002									
Sales	$2,997	927	3,924	1,194	347	360	400	**6,225**	**180**
Transfers	102	401	503	1,315	-	-	-	**1,818**	**62**
Other revenues	(2)	3	1	63	7	7	14	**92**	**12**
Total revenues	3,097	1,331	4,428	2,572	354	367	414	**8,135**	**254**
Production costs	769	444	1,213	343	76	118	114	**1,864**	**57**
Exploration expenses	101	108	209	67	45	32	231	**584**	**-**
Depreciation, depletion and amortization	552	334	886	480	59	105	26	**1,556**	**30**
Property impairments	4	8	12	41	-	-	-	**53**	**-**
Transportation costs	681	87	768	125	10	-	5	**908**	**8**
Other related expenses	23	16	39	75	1	14	11	**140**	**12**
	967	334	1,301	1,441	163	98	27	**3,030**	**147**
Provision for income taxes	294	66	360	981	79	49	196	**1,665**	**(18)**
Results of operations for producing activities	673	268	941	460	84	49	(169)	**1,365**	**165**
Other earnings	197	18	215	10	(2)	24*	(4)	**243**	**(24)**
Net income (loss)	$ 870	286	1,156	470	82	73	(173)	**1,608**	**141**

** Includes $126 million, $63 million and $27 million in 2004, 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.*

- Results of operations for producing activities consist of all the activities within the E&P organization, as well as producing activities within the LUKOIL Investment segment, 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 our Midstream segment, downstream petroleum and chemical activities, as well as general corporate administrative expenses and interest.

- Transfers are valued at prices that approximate market.

- Other revenues include gains and losses from asset sales, including net gains of approximately $72 million in 2004; certain amounts resulting from the purchase and sale of hydrocarbons; and other miscellaneous income.

- 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.

- 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 and 2003 included $77 million and $34 million, respectively, for the impairment of our investment in deepwater Block 34, offshore Angola. The impairment resulted from unsuccessful drilling results in May 2002 and December 2003. Expenses in 2004 included approximately $70 million of dry hole expenses associated with Zafar-Mashal in Azerbaijan.

- Depreciation, depletion and amortization (DD&A) in Results of Operations differs from that shown for total E&P in Note 27—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.

- 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.

- 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.

- Other related expenses include foreign currency gains and losses, and other miscellaneous expenses.

- n 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. Included in 2004 is a $72 million benefit related to the remeasurement of deferred tax liabilities from the 2003 Canadian graduated tax rate reduction and a 2004 Alberta provincial tax rate change.

- n Other earnings consist of certain activities within the E&P and LUKOIL Investment segments 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, crude oil and gas marketing activities, and downstream operations.

Table of Contents

n Statistics

Net Production	**2004**	2003	2002
	Thousands of Barrels Daily		
Crude Oil			
Alaska	**298**	325	331
Lower 48	**51**	54	40
United States	**349**	379	371
European North Sea	**271**	290	196
Asia Pacific	**94**	61	24
Canada	**25**	30	13
Other areas	**58**	72	43
Total consolidated	**797**	832	647
Equity affiliates	**146**	102	35
Natural Gas Liquids*			
Alaska	**23**	23	24
Lower 48	**26**	25	8
United States	**49**	48	32
European North Sea	**14**	9	8
Asia Pacific	**9**	-	-
Canada	**10**	10	4
Other areas	**2**	2	2
Total consolidated	**84**	69	46

** Represents amounts extracted attributable to E&P operations (see natural gas liquids reserves for further discussion). Includes for 2004, 2003 and 2002, 14,000, 15,000, and 14,000 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	**165**	184	175
Lower 48	**1,223**	1,295	928
United States	**1,388**	1,479	1,103
European North Sea	**1,119**	1,215	595
Asia Pacific	**301**	318	137
Canada	**433**	435	165
Other areas	**71**	63	43
Total consolidated	**3,312**	3,510	2,043
Equity affiliates	**18**	12	4

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

		2004	2003	2002
Average Sales Price				
Crude Oil Per Barrel				
Alaska	$	**38.47**	28.87	23.75
Lower 48		**36.95**	28.76	24.48
United States		**38.25**	28.85	23.83
European North Sea		**37.42**	28.83	25.24
Asia Pacific		**38.33**	27.87	26.33
Canada		**32.92**	25.06	22.87
Other areas		**36.05**	27.68	24.76
Total international		**37.18**	28.27	25.16
Total consolidated		**37.65**	28.54	24.39
Equity affiliates		**25.52**	19.01	18.41
Average Sales Price				
Natural Gas Liquids Per Barrel				
Alaska	$	**38.64**	29.04	23.48
Lower 48		**28.14**	20.02	15.66
United States		**31.05**	22.30	20.00
European North Sea		**26.97**	21.34	17.38
Asia Pacific		**34.94**	-	-
Canada		**30.77**	23.93	20.39
Other areas		**7.24**	7.24	7.23
Total international		**28.96**	21.39	17.47
Total consolidated		**30.02**	21.95	18.93
Average Sales Price				
Natural Gas (Lease) Per Thousand Cubic Feet				
Alaska	$	**2.35**	1.76	1.85
Lower 48		**5.46**	4.81	2.79
United States		**5.33**	4.67	2.75
European North Sea		**4.09**	3.60	3.00
Asia Pacific		**3.93**	3.56	2.34
Canada		**5.00**	4.48	3.03
Other areas		**.69**	.58	.48
Total international		**4.14**	3.69	2.79
Total consolidated		**4.62**	4.08	2.77
Equity affiliates		**.78**	4.44	2.71
Average Production Costs Per Barrel of Oil Equivalent				
Alaska	$	**6.30**	5.73	5.48
Lower 48		**6.70**	6.10	6.00
United States		**6.48**	5.89	5.66
European North Sea		**3.25**	3.34	3.10
Asia Pacific		**4.16**	4.13	4.45
Canada		**7.80**	6.82	7.26
Other areas		**6.43**	5.16	5.99
Total international		**4.31**	4.12	3.99
Total consolidated		**5.26**	4.92	4.94
Equity affiliates		**7.44**	4.85	4.38

Table of Contents

	2004	2003	2002
Depreciation, Depletion and Amortization Per Barrel of Oil Equivalent			
Alaska	$ **3.34**	3.15	3.94
Lower 48	**5.70**	5.31	4.52
United States	**4.39**	4.10	4.14
European North Sea	**6.35**	5.22	4.34
Asia Pacific	**4.91**	3.92	3.46
Canada	**8.90**	7.94	6.46
Other areas	**1.64**	1.30	1.37
Total international	**5.99**	5.01	4.11
Total consolidated	**5.29**	4.59	4.13
Equity affiliates	**2.51**	2.74	2.30

Net Wells Completed (1)	Productive			Dry		
	2004	2003	2002	**2004**	2003	2002
Exploratory(2)						
Alaska	**4**	-	-	**2**	1	4
Lower 48	**38**	35	29	**8**	23	6
United States	**42**	35	29	**10**	24	10
European North Sea	**2**	1	*	*****	2	2
Asia Pacific	*****	-	*	**6**	2	7
Canada	**52**	72	19	**26**	16	2
Other areas	**1**	-	2	**2**	*	*
Total consolidated	**97**	108	50	**44**	44	21
Equity affiliates(3)	**2**	23	3	**1**	6	1
Includes step-out wells of:	***89***	*130*	*51*	***34***	*39*	*9*
Development						
Alaska	**37**	39	48	-	1	1
Lower 48	**400**	283	283	**4**	7	14
United States	**437**	322	331	**4**	8	15
European North Sea	**11**	12	11	-	-	-
Asia Pacific	**16**	19	9	-	2	-
Canada	**323**	114	20	**4**	5	1
Other areas	**4**	11	4	-	-	*
Total consolidated	**791**	478	375	**8**	15	16
Equity affiliates (3)	**50**	98	49	*****	3	1

(1)Excludes farmout arrangements.
(2)Includes step-out wells, as well as other types of exploratory wells. Step-out exploratory wells are wells drilled in areas near or offsetting current production, for which we cannot demonstrate with certainty that there is continuity of production from an existing productive formation. These are classified as exploratory wells because we cannot attribute proved reserves to these locations.
(3)Excludes LUKOIL.
**Our total proportionate interest was less than one.*

Wells at Year-End 2004

	In Progress *(1)*		Productive *(2)* Oil		Productive *(2)* Gas	
	Gross	Net	Gross	Net	Gross	Net
Alaska	**11**	**7**	**1,582**	**703**	**28**	**19**
Lower 48	**237**	**133**	**9,354**	**3,075**	**16,837**	**9,225**
United States	**248**	**140**	**10,936**	**3,778**	**16,865**	**9,244**
European North Sea	**19**	**7**	**550**	**101**	**263**	**89**
Asia Pacific	**31**	**19**	**384**	**178**	**76**	**38**
Canada	**30**	**21**	**2,334**	**1,446**	**5,457**	**3,123**
Other areas	**25**	**5**	**526**	**140**	**1**	*****
Total consolidated	**353**	**192**	**14,730**	**5,643**	**22,662**	**12,494**
Equity affiliates *(3)*	**3**	**1**	**487**	**222**	**12**	**2**

(1) Includes wells that have been temporarily suspended.
(2) Includes 3,486 gross and 1,874 net multiple completion wells.
(3) Excludes LUKOIL.
* *Our total proportionate share is less than one.*

Acreage at December 31, 2004

	Thousands of Acres Gross	Thousands of Acres Net
Developed		
Alaska	**606**	**297**
Lower 48	**5,259**	**3,130**
United States	**5,865**	**3,427**
European North Sea	**1,178**	**341**
Asia Pacific	**4,538**	**1,993**
Canada	**2,439**	**1,594**
Other areas	**540**	**103**
Total consolidated	**14,560**	**7,458**
Equity affiliates*	**256**	**109**
Undeveloped		
Alaska	**3,032**	**1,793**
Lower 48	**3,930**	**1,913**
United States	**6,962**	**3,706**
European North Sea	**4,659**	**1,425**
Asia Pacific	**27,516**	**17,494**
Canada	**13,235**	**7,659**
Other areas	**22,346**	**5,009**
Total consolidated	**74,718**	**35,293**
Equity affiliates*	**641**	**317**

* *Excludes LUKOIL.*

Table of Contents

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**
2004									
Unproved property acquisition	$ 2	8	10	-	212	12	14	**248**	**66**
Proved property acquisition	11	10	21	-	-	16	1	**38**	**1,923**
	13	18	31	-	212	28	15	**286**	**1,989**
Exploration	62	79	141	79	123	149	219	**711**	**6**
Development	490	598	1,088	1,029	483	371	286	**3,257**	**390**
	$ 565	695	1,260	1,108	818	548	520	**4,254**	**2,385**
2003									
Unproved property acquisition	$ 10	7	17	-	3	-	64	**84**	**-**
Proved property acquisition	-	6	6	(92)	27	20	(43)	**(82)**	**(10)**
	10	13	23	(92)	30	20	21	**2**	**(10)**
Exploration	65	164	229	105	101	152	167	**754**	**12**
Development	386	693	1,079	1,075	844	197	194	**3,389**	**333**
	$ 461	870	1,331	1,088	975	369	382	**4,145**	**335**
2002									
Unproved property acquisition	$ 9	315	324	679	388	559	194	**2,144**	**-**
Proved property acquisition	-	3,420	3,420	3,719	1,385	2,003	97	**10,624**	**1,671**
	9	3,735	3,744	4,398	1,773	2,562	291	**12,768**	**1,671**
Exploration	93	112	205	61	55	58	202	**581**	**1**
Development	434	409	843	406	787	46	122	**2,204**	**467**
	$ 536	4,256	4,792	4,865	2,615	2,666	615	**15,553**	**2,139**

n Costs incurred include capitalized and expensed items.

n Acquisition costs include the costs of acquiring proved and unproved oil and gas properties. Equity affiliate acquisition costs in 2004 were primarily related to LUKOIL. Some of these costs have been temporarily assigned as unproved property acquisitions while the purchase price allocation is being finalized. Once the final purchase price allocation is completed, certain amounts will be reclassified between proved and unproved property acquisition costs. Proved property acquisition costs in 2003 included net negative merger-related adjustments totaling $178 million. Acquisition costs in 2002 related primarily to the merger.

n Exploration costs include geological and geophysical expenses, the cost of retaining undeveloped leaseholds, and exploratory drilling costs.

n 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.

n 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.

n 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.

Table of Contents

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**
2004									
Proved properties	$ 8,263	8,091	16,354	13,476	4,477	3,322	1,759	**39,388**	**5,380**
Unproved properties	821	244	1,065	153	765	805	433	**3,221**	**66**
	9,084	8,335	17,419	13,629	5,242	4,127	2,192	**42,609**	**5,446**
Accumulated depreciation, depletion and amortization	2,610	2,985	5,595	5,145	704	1,057	585	**13,086**	**244**
	$ 6,474	5,350	11,824	8,484	4,538	3,070	1,607	**29,523**	**5,202**
2003									
Proved properties	$ 7,664	7,388	15,052	11,534	3,778	2,700	918	**33,982**	**3,252**
Unproved properties	936	458	1,394	509	699	658	1,059	**4,319**	**-**
	8,600	7,846	16,446	12,043	4,477	3,358	1,977	**38,301**	**3,252**
Accumulated depreciation, depletion and amortization	2,166	2,481	4,647	4,261	421	561	602	**10,492**	**161**
	$ 6,434	5,365	11,799	7,782	4,056	2,797	1,375	**27,809**	**3,091**

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 and LUKOIL Investment segments, excluding pipeline and marine operations, liquefied natural gas operations, a Canadian Syncrude operation, crude oil and natural gas marketing activities, and downstream operations.

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.

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.

Table of Contents

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**
2004									
Future cash inflows	$64,251	31,955	96,206	51,184	22,249	8,091	12,907	**190,637**	**56,171**
Less:									
Future production and transportation costs	26,956	8,312	35,268	11,953	4,897	2,591	4,016	**58,725**	**20,835**
Future development costs	4,163	2,005	6,168	7,794	1,064	575	1,492	**17,093**	**2,334**
Future income tax provisions	11,698	7,233	18,931	19,850	5,683	1,139	4,054	**49,657**	**10,711**
Future net cash flows	21,434	14,405	35,839	11,587	10,605	3,786	3,345	**65,162**	**22,291**
10 percent annual discount	10,318	7,050	17,368	3,887	4,291	1,403	2,725	**29,674**	**14,081**
Discounted future net cash flows	$ 11,116	7,355	18,471	7,700	6,314	2,383	620	**35,488**	**8,210**
2003									
Future cash inflows	$54,351	29,865	84,216	41,125	18,277	10,107	5,075	**158,800**	**32,622**
Less:									
Future production and transportation costs	21,557	7,559	29,116	10,429	4,480	3,974	2,068	**50,067**	**5,823**
Future development costs	4,104	1,404	5,508	5,358	1,163	1,111	283	**13,423**	**1,510**
Future income tax provisions	9,879	6,955	16,834	15,616	4,487	1,084	2,176	**40,197**	**8,049**
Future net cash flows	18,811	13,947	32,758	9,722	8,147	3,938	548	**55,113**	**17,240**
10 percent annual discount	9,323	7,158	16,481	3,234	3,348	1,703	152	**24,918**	**11,061**
Discounted future net cash flows	$ 9,488	6,789	16,277	6,488	4,799	2,235	396	**30,195**	**6,179**
2002									
Future cash inflows	$54,497	28,679	83,176	41,280	16,581	8,076	6,073	**155,186**	**32,983**
Less:									
Future production and transportation costs	26,035	7,763	33,798	7,974	3,764	1,885	1,639	**49,060**	**4,992**
Future development costs	2,927	1,168	4,095	2,989	1,821	617	428	**9,950**	**1,698**
Future income tax provisions	7,665	6,365	14,030	20,075	3,917	2,361	2,995	**43,378**	**8,501**
Future net cash flows	17,870	13,383	31,253	10,242	7,079	3,213	1,011	**52,798**	**17,792**
10 percent annual discount	9,097	6,759	15,856	3,998	3,272	1,422	458	**25,006**	**11,585**
Discounted future net cash flows	$ 8,773	6,624	15,397	6,244	3,807*	1,791	553	**27,792**	**6,207**

** Includes $139 million attributable to a consolidated subsidiary in which there is a 10 percent minority interest.*
Excludes discounted future net cash flows from Canadian Syncrude of $1,302 million in 2004, $1,048 million in 2003 and $869 million in 2002.

Table of Contents

Sources of Change in Discounted Future Net Cash Flows

	Millions of Dollars					
	Consolidated Operations			Equity Affiliates		
	2004	2003	2002	**2004**	2003	2002
Discounted future net cash flows at the beginning of the year	**$ 30,195**	27,792	8,995	**6,179**	6,207	996
Changes during the year						
Revenues less production and transportation costs for the year	**(13,221)**	(10,407)	(5,271)	**(877)**	(485)	(177)
Net change in prices, and production and transportation costs	**14,133**	4,436	15,566	**1,415**	(867)	2,734
Extensions, discoveries and improved recovery, less estimated future costs	**3,724**	3,237	1,284	**-**	31	22
Development costs for the year	**3,257**	3,389	2,204	**390**	333	467
Changes in estimated future development costs	**(2,542)**	(3,151)	(1,843)	**(81)**	(193)	(108)
Purchases of reserves in place, less estimated future costs	**8**	203	22,161	**3,208**	4	4,781
Sales of reserves in place, less estimated future costs	**(19)**	(1,722)	(563)	**(183)**	-	(16)
Revisions of previous quantity estimates*	**424**	83	(185)	**(1,301)**	202	(712)
Accretion of discount	**4,782**	4,738	1,540	**832**	852	177
Net change in income taxes	**(5,253)**	1,597	(16,096)	**(1,372)**	95	(1,957)
Other	**-**	-	-	**-**	-	-
Total changes	**5,293**	2,403	18,797	**2,031**	(28)	5,211
Discounted future net cash flows at year-end	**$ 35,488**	30,195	27,792	**8,210**	6,179	6,207

**Includes amounts resulting from changes in the timing of production.*

- 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.
- 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.
- The accretion of discount is 10 percent of the prior year's discounted future cash inflows, less future production, transportation and development costs.
- The net change in income taxes is the annual change in the discounted future income tax provisions. The 2003 and 2002 amounts have been revised due to the correction of disclosure calculations.

Selected Quarterly Financial Data (Unaudited)

	Millions of Dollars				Per Share of Common Stock			
					Income Before Cumulative Effect of Changes in Accounting Principles		Net Income	
	Sales and Other Operating Revenues*	Income from Continuing Operations Before Income Taxes	Income Before Cumulative Effect of Changes in Accounting Principles	Net Income	Basic	Diluted	Basic	Diluted
2004								
First	**$ 29,813**	**2,964**	**1,616**	**1,616**	**2.36**	**2.33**	**2.36**	**2.33**
Second	**31,528**	**3,470**	**2,075**	**2,075**	**3.01**	**2.97**	**3.01**	**2.97**
Third	**34,350**	**3,660**	**2,006**	**2,006**	**2.90**	**2.86**	**2.90**	**2.86**
Fourth	**39,385**	**4,275**	**2,432**	**2,432**	**3.50**	**3.44**	**3.50**	**3.44**
2003								
First	$ 26,954	2,569	1,316	1,221	1.94	1.93	1.80	1.79
Second	25,331	1,781	1,187	1,187	1.75	1.73	1.75	1.73
Third	26,116	2,310	1,306	1,306	1.92	1.90	1.92	1.90
Fourth	25,845	1,677	1,021	1,021	1.50	1.48	1.50	1.48

**Includes excise taxes on petroleum products sales. Certain quarterly amounts have been reclassified to conform to current presentation.*

Supplementary Information—Condensed Consolidating Financial Information

We have various cross guarantees among ConocoPhillips, ConocoPhillips Holding Company, and ConocoPhillips Company with respect to publicly held debt securities. ConocoPhillips Company 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 its publicly held debt securities. 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 information presents the results of operations, financial position and cash flows for:

- ConocoPhillips, ConocoPhillips Holding Company, and 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.

- The consolidating adjustments necessary to present ConocoPhillips' results on a consolidated basis.

This condensed consolidating financial information should be read in conjunction with the accompanying consolidated financial statements and notes. Certain amounts in 2003 have been reclassified to conform to the current year presentation.

Effective January 1, 2005, ConocoPhillips Holding Company was merged into ConocoPhillips Company. This new structure will be reflected in the condensed consolidating financial information included in our Quarterly Report on Form 10-Q for the first quarter of 2005.

Income Statement	ConocoPhillips	ConocoPhillips Holding Company	ConocoPhillips Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
	Millions of Dollars					
	Year Ended December 31, 2004					
Revenues						
Sales and other operating revenues	$ -	-	89,602	45,474	-	135,076
Equity in earnings of affiliates	8,111	7,976	5,995	1,265	(21,812)	1,535
Other income	1	-	180	124	-	305
Intercompany revenues	72	572	1,729	7,303	(9,676)	-
Total revenues	8,184	8,548	97,506	54,166	(31,488)	136,916
Costs and Expenses						
Purchased crude oil, natural gas and products	-	-	74,125	24,326	(8,269)	90,182
Production and operating expenses	-	1	4,062	3,346	(37)	7,372
Selling, general and administrative expenses	10	-	1,369	764	(15)	2,128
Exploration expenses	-	-	87	617	(1)	703
Depreciation, depletion and amortization	-	-	1,138	2,660	-	3,798
Property impairments	-	-	71	93	-	164
Taxes other than income taxes	-	-	6,188	11,299	-	17,487
Accretion on discounted liabilities	-	-	40	131	-	171
Interest and debt expense	92	365	1,199	244	(1,354)	546
Foreign currency transaction (gains) losses	-	-	(4)	(32)	-	(36)
Minority interests and preferred dividend requirements of capital trusts	-	-	-	32	-	32
Total Costs and Expenses	102	366	88,275	43,480	(9,676)	122,547
Income from continuing operations before income taxes and subsidiary equity transactions	8,082	8,182	9,231	10,686	(21,812)	14,369
Gain on subsidiary equity transactions	-	-	-	-	-	-
Income from continuing operations before income taxes	8,082	8,182	9,231	10,686	(21,812)	14,369
Provision for income taxes	(25)	71	1,338	4,878	-	6,262
Income from continuing operations	8,107	8,111	7,893	5,808	(21,812)	8,107
Income (loss) from discontinued operations	22	22	22	91	(135)	22
Income (loss) before cumulative effect of changes in accounting principles	8,129	8,133	7,915	5,899	(21,947)	8,129
Cumulative effect of changes in accounting principles	-	-	-	-	-	-
Net Income	$ 8,129	8,133	7,915	5,899	(21,947)	8,129

Income Statement	Millions of Dollars					
	Year Ended December 31, 2003					
	ConocoPhillips	ConocoPhillips Holding Company	ConocoPhillips Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Revenues						
Sales and other operating revenues	$ -	-	65,851	38,395	-	104,246
Equity in earnings of affiliates	4,576	4,392	3,244	523	(12,193)	542
Other income	-	-	205	104	-	309
Intercompany revenues	136	600	3,005	4,876	(8,617)	-
Total revenues	4,712	4,992	72,305	43,898	(20,810)	105,097
Costs and Expenses						
Purchased crude oil, natural gas and products	-	-	55,836	19,105	(7,466)	67,475
Production and operating expenses	-	-	3,863	3,365	(84)	7,144
Selling, general and administrative expenses	18	-	1,346	829	(14)	2,179
Exploration expenses	-	-	170	431	-	601
Depreciation, depletion and amortization	-	-	612	2,873	-	3,485
Property impairments	-	-	43	209	-	252
Taxes other than income taxes	-	-	4,411	10,268	-	14,679
Accretion on discounted liabilities	-	-	37	108	-	145
Interest and debt expense	117	316	1,267	197	(1,053)	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	67,544	37,410	(8,617)	96,788
Income from continuing operations before income taxes and subsidiary equity transactions	4,577	4,676	4,761	6,488	(12,193)	8,309
Gain on subsidiary equity transactions	-	-	-	28	-	28
Income from continuing operations before income taxes	4,577	4,676	4,761	6,516	(12,193)	8,337
Provision for income taxes	(16)	100	444	3,216	-	3,744
Income from continuing operations	4,593	4,576	4,317	3,300	(12,193)	4,593
Income (loss) from discontinued operations	237	237	237	787	(1,261)	237
Income (loss) before cumulative effect of changes in accounting principles	4,830	4,813	4,554	4,087	(13,454)	4,830
Cumulative effect of changes in accounting principles	(95)	(95)	(95)	(255)	445	(95)
Net Income	$ 4,735	4,718	4,459	3,832	(13,009)	4,735

Income Statement	ConocoPhillips	ConocoPhillips Holding Company	ConocoPhillips Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
	Millions of Dollars					
	Year Ended December 31, 2002					
Revenues						
Sales and other operating revenues	$ -	-	36,362	20,386	-	56,748
Equity in earnings of affiliates	453	416	1,631	254	(2,493)	261
Other income	-	-	(30)	222	-	192
Intercompany revenues	16	191	2,926	3,883	(7,016)	-
Total revenues	469	607	40,889	24,745	(9,509)	57,201
Costs and Expenses						
Purchased crude oil, natural gas and products	-	-	33,740	10,454	(6,337)	37,857
Production and operating expenses	-	9	2,432	2,308	(85)	4,664
Selling, general and administrative expenses	2	-	1,523	429	(4)	1,950
Exploration expenses	-	-	130	462	-	592
Depreciation, depletion and amortization	-	-	898	1,325	-	2,223
Property impairments	-	-	-	177	-	177
Taxes other than income taxes	-	-	720	6,217	-	6,937
Accretion on discounted liabilities	-	-	11	11	-	22
Interest and debt expense	29	119	873	135	(590)	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	40,335	21,582	(7,016)	55,060
Income from continuing operations before income taxes and subsidiary equity transactions	438	479	554	3,163	(2,493)	2,141
Gain on subsidiary equity transactions	-	-	-	-	-	-
Income from continuing operations before income taxes	438	479	554	3,163	(2,493)	2,141
Provision for income taxes	(5)	26	(226)	1,648	-	1,443
Income from continuing operations	443	453	780	1,515	(2,493)	698
Income (loss) from discontinued operations	(1,043)	(1,043)	(1,121)	(789)	3,003	(993)
Income (loss) before cumulative effect of changes in accounting principles	(600)	(590)	(341)	726	510	(295)
Cumulative effect of changes in accounting principles	-	-	-	-	-	-
Net Income (Loss)	$ (600)	(590)	(341)	726	510	(295)

Balance Sheet	Millions of Dollars At December 31, 2004 ConocoPhillips	ConocoPhillips Holding Company	ConocoPhillips Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Assets						
Cash and cash equivalents	$ -	-	879	508	-	1,387
Accounts and notes receivable	712	20	13,999	15,704	(21,647)	8,788
Inventories	-	-	2,367	1,299	-	3,666
Prepaid expenses and other current assets	20	9	371	586	-	986
Assets of discontinued operations held for sale	-	-	150	44	-	194
Total Current Assets	732	29	17,766	18,141	(21,647)	15,021
Investments and long-term receivables	38,194	47,065	52,359	17,313	(144,523)	10,408
Net properties, plants and equipment	-	-	16,618	34,284	-	50,902
Goodwill	-	-	14,990	-	-	14,990
Intangibles	-	-	747	349	-	1,096
Other assets	17	-	124	303	-	444
Total Assets	$ 38,943	47,094	102,604	70,390	(166,170)	92,861
Liabilities and Stockholders’ Equity						
Accounts payable	$ 7	246	20,374	10,151	(21,647)	9,131
Notes payable and long-term debt due within one year	544	13	14	61	-	632
Accrued income and other taxes	-	-	360	2,794	-	3,154
Employee benefit obligations	-	-	646	569	-	1,215
Other accruals	20	38	450	843	-	1,351
Liabilities of discontinued operations held for sale	-	-	(10)	113	-	103
Total Current Liabilities	571	297	21,834	14,531	(21,647)	15,586
Long-term debt	1,994	2,892	5,271	4,213	-	14,370
Asset retirement obligation and accrued environmental costs	-	-	890	3,004	-	3,894
Deferred income taxes	(1)	(39)	3,018	7,415	(8)	10,385
Employee benefit obligations	-	-	1,808	607	-	2,415
Other liabilities and deferred credits	8	6,361	26,512	20,367	(50,865)	2,383
Total Liabilities	2,572	9,511	59,333	50,137	(72,520)	49,033
Minority interests	-	(12)	6	1,111	-	1,105
Retained earnings	9,592	9,598	16,613	14,094	(33,769)	16,128
Other stockholders’ equity	26,779	27,997	26,652	5,048	(59,881)	26,595
Total	$ 38,943	47,094	102,604	70,390	(166,170)	92,861

Table of Contents

Balance Sheet	Millions of Dollars At December 31, 2003 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	1,185	-	10,893	13,951	(21,024)	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	-	-	591	273	-	864
Total Current Assets	1,193	7	14,719	16,297	(21,024)	11,192
Investments and long-term receivables	29,640	37,922	46,685	16,933	(123,922)	7,258
Net properties, plants and equipment	-	-	16,495	30,933	-	47,428
Goodwill	-	-	15,046	38	-	15,084
Intangibles	-	-	743	342	-	1,085
Other assets	20	-	92	296	-	408
Total Assets	$ 30,853	37,929	93,780	64,839	(144,946)	82,455
Liabilities and Stockholders' Equity						
Accounts payable	$ -	2	19,371	8,550	(21,024)	6,899
Notes payable and long-term debt due within one year	-	1,350	70	20	-	1,440
Accrued income and other taxes	38	96	625	1,917	-	2,676
Employee benefit obligations	-	-	670	676	-	1,346
Other accruals	20	45	557	849		1,471
Liabilities of discontinued operations held for sale	-	-	179	-	-	179
Total Current Liabilities	58	1,493	21,472	12,012	(21,024)	14,011
Long-term debt	2,704	2,938	6,394	4,304	-	16,340
Asset retirement obligation and accrued environmental costs	-	-	930	2,673	-	3,603
Deferred income taxes	-	(33)	2,575	6,031	(8)	8,565
Employee benefit obligations	-	-	1,828	617	-	2,445
Other liabilities and deferred credits	-	5,961	25,290	21,460	(50,428)	2,283
Total Liabilities	2,762	10,359	58,489	47,097	(71,460)	47,247
Minority interests	-	(12)	5	849	-	842
Retained earnings	2,695	1,399	9,418	10,875	(15,153)	9,234
Other stockholders' equity	25,396	26,183	25,868	6,018	(58,333)	25,132
Total	$ 30,853	37,929	93,780	64,839	(144,946)	82,455

Statement of Cash Flows	ConocoPhillips	ConocoPhillips Holding Company	ConocoPhillips Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
	Millions of Dollars					
	Year Ended December 31, 2004					
Cash Flows From Operating Activities						
Net cash provided by (used in) continuing operations	$ 406	(165)	7,547	5,327	(1,117)	11,998
Net cash provided by (used in) discontinued operations	-	-	(360)	321	-	(39)
Net Cash Provided by (Used in) Operating Activities	406	(165)	7,187	5,648	(1,117)	11,959
Cash Flows From Investing Activities						
Acquisitions, net of cash acquired	-	-	-	-	-	-
Cash consolidated from adoption and application of FIN 46(R)	-	-	-	11	-	11
Capital expenditures and investments, including dry holes	-	-	(4,717)	(7,652)	2,873	(9,496)
Proceeds from asset dispositions	-	-	1,276	537	(222)	1,591
Long-term advances/loans to affiliates and other investments	(786)	-	(1,922)	(2)	2,543	(167)
Collection of advances/loans to affiliates	1,359	1,198	435	(150)	(2,568)	274
Net cash used in continuing operations	573	1,198	(4,928)	(7,256)	2,626	(7,787)
Net cash used in discontinued operations	-	-	(1)	-	-	(1)
Net Cash Used in Investing Activities	573	1,198	(4,929)	(7,256)	2,626	(7,788)
Cash Flows From Financing Activities						
Issuance of debt	-	1,676	786	81	(2,543)	-
Repayment of debt	(170)	(2,709)	(2,432)	(32)	2,568	(2,775)
Redemption of preferred stock of subsidiaries	-	-	-	-	-	-
Issuance of company common stock	430	-	-	-	-	430
Dividends paid on common stock	(1,232)	-	-	(1,117)	1,117	(1,232)
Other	(7)	-	-	2,836	(2,651)	178
Net Cash Provided by (Used in) Financing Activities	(979)	(1,033)	(1,646)	1,768	(1,509)	(3,399)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	-	-	(2)	127	-	125
Net Change in Cash and Cash Equivalents	-	-	610	287	-	897
Cash and cash equivalents at beginning of year	-	-	268	222	-	490
Cash and Cash Equivalents at End of Year	$ -	-	878	509	-	1,387

Statement of Cash Flows	Millions of Dollars					
	Year Ended December 31, 2003					
	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)	6,013	(482)	(3,144)	9,167
Net cash provided by (used in) discontinued operations	-	-	(944)	1,133	-	189
Net Cash Provided by (Used in) Operating Activities	7,757	(977)	5,069	651	(3,144)	9,356
Cash Flows From Investing Activities						
Acquisitions, net of cash acquired	-	-	-	-	-	-
Cash consolidated from adoption and application of FIN 46(R)	-	-	-	225	-	225
Capital expenditures and investments, including dry holes	-	(44)	(4,892)	(3,626)	2,393	(6,169)
Proceeds from asset dispositions	3	-	1,508	1,151	(3)	2,659
Long-term advances/loans to affiliates and other investments	(5,950)	72	(2,297)	(30)	8,142	(63)
Collection of advances/loans to affiliates	-	-	25	61	-	86
Net cash used in continuing operations	(5,947)	28	(5,656)	(2,219)	10,532	(3,262)
Net cash used in discontinued operations	-	-	(58)	(178)	-	(236)
Net Cash Used in Investing Activities	(5,947)	28	(5,714)	(2,397)	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)	-	34	2,469	(2,390)	111
Net Cash Provided by (Used in) Financing Activities	(1,810)	949	791	1,759	(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

Table of Contents

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	(3,021)	6,019	(2,201)	4,776
Net cash provided by (used in) discontinued operations	-	-	840	(638)	-	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 and application of FIN 46(R)	-	-	-	-	-	-
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/loans to affiliates and other investments	(4,344)	(1,200)	(5,237)	(5,491)	16,103	(169)
Collection of advances/loans to affiliates	-	-	47	30	-	77
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

Item 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

Item 9A. CONTROLS AND PROCEDURES

As of December 31, 2004, with the participation of our management, our Chairman, 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 Chairman, 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, 2004.

During the second quarter of 2004, we implemented the first phase of the Supply Trading Analysis & Reporting (STAR) information system. STAR now handles the contracting, scheduling, and business analysis reporting for a portion of the motor fuels, distillates and heavy intermediate product business. In a future phase scheduled for 2005, the remaining portion of these commodity streams will be moved into the system.

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.

Management’s Annual Report on Internal Control Over Financial Reporting

This report is included in Item 8 on page 99 and is incorporated herein by reference.

Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting

This report is included in Item 8 on page 101 and is incorporated herein by reference.

Item 9B. OTHER INFORMATION

None.

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, 2005 (2005 Proxy Statement), is incorporated herein by reference.* Information regarding the executive officers appears in Part I of this report on pages 38 and 39.

Code of Business Conduct and Ethics for Directors and Employees

We have 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 web site at *www.conocophillips.com* (accessed through the “About ConocoPhillips” link on the home page). 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 web site located at *www.conocophillips.com*.

Item 11. EXECUTIVE COMPENSATION

Information presented under the following headings in the 2005 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 AND RELATED STOCKHOLDER MATTERS

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 2005 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 2005 Proxy Statement is incorporated herein by reference.

Item 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information presented under the heading “Proposal To Ratify the Appointment of Ernst & Young LLP” in the 2005 Proxy Statement is incorporated herein by reference.

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* *Except for information or data specifically incorporated herein by reference under Items 10 through 14, other information and data appearing in the 2005 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.*

PART IV

Item 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(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 98 are filed as part of this annual report.

2. Exhibits

The exhibits listed in the Index to Exhibits, which appears on pages 201 through 204, are filed as a part of this annual report.

CONOCOPHILLIPS

(Consolidated)

SCHEDULE II—VALUATION AND QUALIFYING ACCOUNTS

	Millions of Dollars				
		Additions			
Description	Balance At January 1	Charged to Expense	Other	Deductions	Balance At December 31
			(a)		
2004					
Deducted from asset accounts:					
Allowance for doubtful accounts and notes receivable	**$ 43**	**20**	**-**	**8(b)**	**55**
Deferred tax asset valuation allowance	**879**	**260**	**-**	**171**	**968**
Included in other liabilities:					
Employee termination benefits	**247**	**29**	**13**	**200(d)**	**89**
2003					
Deducted from asset accounts:					
Allowance for doubtful accounts and notes receivable	$ 48	29	-	34(b)	43
Deferred tax asset valuation allowance	608	471	-	200	879
Included in other liabilities:					
Employee termination benefits	375	122	110(c)	360(d)	247
2002					
Deducted from asset accounts:					
Allowance for doubtful accounts and notes receivable	$ 33	21	13(c)	19(b)	48
Deferred tax asset valuation allowance	263	102	251(c)	8	608
Included in other liabilities:					
Employee termination benefits	-	301	297(c)	223(d)	375

(a) Represents acquisitions/dispositions and the effect of translating foreign financial statements.

(b) Amounts charged off less recoveries of amounts previously charged off.

(c) Included in the merger purchase price allocation.

(d) 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 4, 2005 (incorporated by reference to Exhibit 99.1 to the Current Report of ConocoPhillips on Form 8-K filed on February 10, 2005; File No. 001-32395).
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 percent 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.
10.1	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).
10.2	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).
10.3	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).

Exhibit Number	Description
10.4	Incentive Compensation Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10(g) to the Annual Report of ConocoPhillips Company on Form 10-K for the year ended December 31, 1999; File No. 1-720).
10.5	Principal Corporate Officers Supplemental Retirement Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10(h) to the Annual Report of ConocoPhillips Company on Form 10-K for the year ended December 31, 1995; File No. 1-720)
10.6	Phillips Petroleum Company Supplemental Executive Retirement Plan (incorporated by reference to Exhibit 10(n) to the Annual Report of ConocoPhillips Company on Form 10-K for the year ended December 31, 2000; File No. 1-720).
10.7	Non-Employee Director Retirement Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.18 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.8	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).
10.9	Key Employee Missed Credited Service Retirement Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10(s) to the Annual Report of ConocoPhillips Company on Form 10-K for the year ended December 31, 2000; File No. 1-720).
10.10	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).
10.11	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).
10.12	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).
10.13	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).
10.14	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).
10.15	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).

Table of Contents

Exhibit Number	Description
10.16	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).
10.17	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).
10.18	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).
10.19	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).
10.20	Letter Agreement, dated as of April 12, 2002, between Holding and Jim W. Nokes (incorporated by reference to Exhibit 10.2 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarterly period ended September 30, 2002; File No. 000-49987).
10.21	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).
10.21.1	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).
10.22	ConocoPhillips Directors' Charitable Gift Program (incorporated by reference to Exhibit 10.40 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2003; File No. 000-49987).
10.23	ConocoPhillips Matching Gift Plan for Directors and Executives (incorporated by reference to Exhibit 10.41 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2003; File No. 000-49987).
10.24	Key Employee Deferred Compensation Plan of ConocoPhillips (incorporated by reference to Exhibit 10.42 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2003; File No. 000-49987).
10.25	ConocoPhillips Key Employee Change in Control Severance Plan (incorporated by reference to Exhibit 10.1 of the Quarterly Report of ConocoPhillips on Form 10-Q for the quarterly period ended September 30, 2004; File No. 000-49987).
10.26	ConocoPhillips Executive Severance Plan (incorporated by reference to Exhibit 10.2 of the Quarterly Report of ConocoPhillips on Form 10-Q for the quarterly period ended September 30, 2004; File No. 000-49987).

Exhibit Number	Description
10.27	Summary of 2005 Non-employee Director Compensation (incorporated by reference to Item 1.01 of the Current Report of ConocoPhillips on Form 8-K filed on December 13, 2004; File No. 001-32395).
10.28	Description of 2005 Named Executive Officer Stock Option Awards (incorporated by reference to Item 1.01 of the Current Report of ConocoPhillips on Form 8-K filed on February 10, 2005; File No. 001-32395).
10.29	Description of Variable Cash Incentive Program awards for the year ended December 31, 2004 (incorporated by reference to Item 1.01 of the Current Report of ConocoPhillips on Form 8-K filed on February 11, 2005; File No. 001-32395).
10.30	2004 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Appendix C of ConocoPhillips' Proxy Statement on Schedule 14A relating to the 2004 Annual Meeting of Shareholders; File No. 000-49987).
10.31	Description of Named Executive Officer Salaries.
10.32	Description of ConocoPhillips Performance Share Program (incorporated by reference to Item 1.01 of the Current Report of ConocoPhillips on Form 8-K filed on February 10, 2005; File No. 001-32395).
12	Computation of Ratio of Earnings to Fixed Charges.
21	List of Principal Subsidiaries of ConocoPhillips.
23	Consent of Independent Registered Public Accounting Firm.
31.1	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.
31.2	Certification of 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.

Table of Contents

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, 2005	/s/ J. J. Mulva *J. J. Mulva* Chairman of the Board of Directors, 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, 2005, on behalf of the registrant by the following officers in the capacity indicated and by a majority of directors.

Signature	Title
/s/ J. J. Mulva *J. J. Mulva*	Chairman of the Board of Directors, 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)

/s/ Richard H. Auchinleck *Richard H. Auchinleck*	Director
/s/ Norman R. Augustine *Norman R. Augustine*	Director
/s/ James E. Copeland, Jr. *James E. Copeland, Jr.*	Director
/s/ Kenneth M. Duberstein *Kenneth M. Duberstein*	Director
/s/ Ruth R. Harkin *Ruth R. Harkin*	Director
/s/ Larry D. Horner *Larry D. Horner*	Director
/s/ Charles C. Krulak *Charles C. Krulak*	Director
/s/ Frank A. McPherson *Frank A. McPherson*	Director
/s/ William K. Reilly *William K. Reilly*	Director
/s/ William R. Rhodes *William R. Rhodes*	Director
/s/ J. Stapleton Roy *J. Stapleton Roy*	Director
/s/ Victoria J. Tschinkel *Victoria J. Tschinkel*	Director
/s/ Kathryn C. Turner *Kathryn C. Turner*	Director

EXHIBIT 10.31

Effective March 1, 2005, the annual salaries for our named executive officers will be as follows:

- J.J. Mulva — $1,500,000
- J.W. Nokes — $852,000
- W.B. Berry — $725,000
- J.A. Carrig — $659,000
- J.E. Lowe — $546,000

Exhibit 12

CONOCOPHILLIPS AND CONSOLIDATED SUBSIDIARIES
TOTAL ENTERPRISE
Computation of Ratio of Earnings to Fixed Charges

	Millions of Dollars				
	Years Ended December 31				
	2004	2003	2002 (Unaudited)	2001	2000
Earnings Available for Fixed Charges					
Income from continuing operations before income taxes	$ 14,369	8,337	2,141	3,241	3,748
Distributions less than equity in earnings of fifty-percent-or-less-owned companies	(780)	(52)	3	58	(30)
Fixed charges, excluding capitalized interest*	758	1,019	850	501	481
	$ 14,347	9,304	2,994	3,800	4,199
Fixed Charges					
Interest and expense on indebtedness, excluding capitalized interest	$ 546	844	566	338	369
Capitalized interest	430	327	232	231	174
Preferred dividend requirements of subsidiary and capital trusts	—	—	38	53	53
Interest portion of rental expense	174	149	181	90	42
Interest expense relating to guaranteed debt of fifty-percent-or-less-owned companies	9	1	16	—	—
Interest expense relating to guaranteed debt of greater than fifty-percent-owned companies	—	—	3	—	—
	$ 1,159	1,321	1,036	712	638
Ratio of Earnings to Fixed Charges	12.4	7.0	2.9	5.3	6.6

* *Includes amortization of capitalized interest totaling approximately $29 million in 2004, $25 million in 2003, $46 million in 2002, $20 million in 2001, and $17 million in 2000.*

Earnings available for fixed charges include, if any, the company’s equity in losses of companies owned less than fifty percent and having debt for which the company is contingently liable. Fixed charges include the company’s proportionate share, if any, of interest relating to the contingent debt.

Earnings available for fixed charges include, if any, 100 percent of the losses of companies owned greater than fifty percent that have debt for which the company is contingently liable. Fixed charges include 100 percent of interest and capitalized interest, if any, relating to the contingent debt.

Exhibit 21

SUBSIDIARY LISTING OF CONOCOPHILLIPS

Company Name	Incorporation Location
Alpine Pipeline Company	Delaware
Arizona-Florida Land & Cattle Company	Florida
Asamera Algeria Limited	Alberta
Asamera Minerals (U.S.) Inc.	Colorado
Asamera Oil (U.S.) Inc.	Montana
Asamera Resources Inc.	Nevada
Ashford Energy Capital S.A.	Luxembourg
Australian Hydrocarbons Inc.	Delaware
AZL Resources, Inc.	Arizona
Aztec Catalyst Company	Delaware
Border Resources Ltd.	England
Brandywine Industrial Gas Inc.	Delaware
BVLC, Inc.	California
C.S. Land, Inc.	California
Calcasieu Properties L.L.C.	Delaware
Catoire S.A.	Belgium
CGP Developments Cajun Cogen LLC	Delaware
CGP Servicios Energeticos de Altamira, S. de R. L. de C. V.	Mexico
Clearwater Ltd.	Bermuda
Cliffe Storage Limited	England
Clyde Petroleum (Exploration) Ltd.	England
Clyde Petroleum (Investments) Limited	England
Clyde Petroleum (Management) Limited	England
Clyde Petroleum Limited	Scotland
COMAP, Inc.	Delaware
Conoco (Thailand) Company, Limited	Thailand
Conoco A.G.	Switzerland
Conoco Africa Inc.	Delaware
Conoco Arabia Holding Ltd.	British Virgin Islands
Conoco Asia Ltd.	Bermuda
Conoco Asia Pacific Ltd.	Delaware
Conoco Asia Pacific Sdn. Bhd.	Malaysia
Conoco Central Europe Inc.	Delaware
Conoco Cevolution Europe B.V.	The Netherlands
Conoco Colombia Ltd	Bermuda
Conoco Coral Inc.	Delaware
Conoco Deepwater Construction LLC	Delaware
Conoco Denmark Inc.	Delaware
Conoco Development Company	Delaware
Conoco Development II Inc.	Delaware
Conoco Development Services Inc.	Delaware
Conoco do Brasil Ltda.	Brazil
Conoco Drilling Inc.	Delaware

Company Name	Incorporation Location
Conoco Egypt Inc.	Delaware
Conoco Energy Holdings Ltd.	Bermuda
Conoco Energy Holdings Nigeria Ltd.	Bermuda
Conoco Energy Nigeria Limited	Nigeria
Conoco Energy Services Company	Delaware
Conoco Energy Ventures Inc.	Delaware
Conoco Equity Investments Inc.	Delaware
Conoco Exploration & Production B.V.	The Netherlands
Conoco Exploration & Production Nigeria Limited	Nigeria
Conoco Foreign Sales Corporation	Barbados
Conoco Frontier Ltd.	Bermuda
Conoco Funding Company	Nova Scotia
Conoco Geisum Inc.	Delaware
Conoco Global Energy Company	Delaware
Conoco Global Power (U.K.) Limited	England
Conoco Global Power Assets Inc.	Delaware
Conoco Global Power Assets Sabine Inc.	Delaware
Conoco Global Power de Mexico, S. de R. L. de C. V.	Mexico
Conoco Global Power Developments Espana SRL	Spain
Conoco Global Power Developments Inc.	Delaware
Conoco Global Power Development-Sabine Inc.	Delaware
Conoco Global Power Europe Limited	Delaware
Conoco Holdings Ltd.	Bermuda
Conoco Investment AG	Switzerland
Conoco Jet (Malaysia) Sdn. Bhd.	Malaysia
Conoco Khazar Ltd.	Bermuda
Conoco Lagia Offshore, Inc.	Delaware
Conoco Lubricant (India) Private Limited	India
Conoco Lubricants (Malaysia) Sdn. Bhd.	Malaysia
Conoco Mexico Ltd.	Bermuda
Conoco Nila Holding Ltd.	British Virgin Islands
Conoco Nordic Holdings AB	Sweden
Conoco Nordic Limited	Bermuda
Conoco Northland Ltd.	Bermuda
Conoco Norway Properties Inc.	Delaware
Conoco NW Natuna Exploration & Production Ltd.	Bermuda
Conoco NW Natuna Holding Ltd.	British Virgin Islands
Conoco Offshore Pipe Line Company	Delaware
Conoco Orinoco Inc.	Delaware
Conoco Peru Ltd.	Bermuda
Conoco PETCOKE Far East Ltd.	Delaware
Conoco Petroleum Nigeria Limited	Nigeria
Conoco Petroleum Operations Inc.	Delaware
Conoco Resources Holding B.V.	The Netherlands
Conoco Services Ltd.	Bermuda
Conoco Shale Oil Inc.	Delaware

Company Name	Incorporation Location
Conoco Shipping & Marine Development L.L.C.	Marshall Islands
Conoco Shipping Company	Liberia
Conoco Shipping Norge Nr. 3 AS	Norway
Conoco Singapore Operations Pte. Limited	Singapore
Conoco South Sokang Natuna B.V.	The Netherlands
Conoco Specialty Products Limited	England
Conoco Syria DEZ Gas Ltd.	Bermuda
Conoco Syria Ltd.	Bermuda
Conoco Tobong Holding Ltd.	British Virgin Islands
Conoco Tobong Natuna B.V.	The Netherlands
Conoco Trading Company	Delaware
Conoco Trinidad Inc.	Delaware
Conoco U.K. Properties Inc.	Delaware
Conoco Venezuela C.A.	Venezuela
Conoco Venezuela E&P Ltd.	Bermuda
Conoco Venezuela Holding C.A.	Venezuela
Conoco Venezuela Ltd.	Bermuda
Conoco Warim B.V.	The Netherlands
ConocoPhillips (03-21) Pty Ltd	Western Australia
ConocoPhillips (03-12) Pty Ltd	Victoria, Australia
ConocoPhillips (03-13) Pty Ltd	Western Australia
ConocoPhillips (03-19) Pty Ltd	Victoria, Australia
ConocoPhillips (03-16) Pty Ltd	Western Australia
ConocoPhillips (03-20) Pty Ltd	Western Australia
ConocoPhillips (Aceh) Ltd.	Bermuda
ConocoPhillips (AIB) Ltd.	Bermuda
ConocoPhillips (Banyumas) Ltd.	Bermuda
ConocoPhillips (BTC) Ltd.	Cayman Islands
ConocoPhillips (GIB) Ltd.	Bermuda
ConocoPhillips (Glen) Limited	England
ConocoPhillips (Grissik) Ltd.	Bermuda
ConocoPhillips (Kakap) Ltd.	Bermuda
ConocoPhillips (Ketapang) Ltd.	Bermuda
ConocoPhillips (East Malaysia) Ltd.	Bermuda
ConocoPhillips (Pangkah) Ltd.	Bermuda
ConocoPhillips (Ramba) Ltd.	Bermuda
ConocoPhillips (Sakakemang) Ltd.	Bermuda
ConocoPhillips (South Jambi) Ltd.	Bermuda
ConocoPhillips (Tungkal) Ltd.	Bermuda
ConocoPhillips (U.K.) Alpha Limited	England
ConocoPhillips (U.K.) Beta Limited	England
ConocoPhillips (U.K.) Cuu Long Limited	United Kingdom
ConocoPhillips (U.K.) Eta Limited	England
ConocoPhillips (U.K.) Finance Limited	England
ConocoPhillips (U.K.) Gama Limited	England
ConocoPhillips (U.K.) Lambda Limited	Eire

Company Name	Incorporation Location
ConocoPhillips (U.K.) Limited	England
ConocoPhillips (U.K.) Technology Limited	England
ConocoPhillips (U.K.) Theta Limited	England
ConocoPhillips (U.K.) Zeta Limited	England
ConocoPhillips 2000-E Company LLC	Delaware
ConocoPhillips Africa New Ventures Ltd.	Cayman Islands
ConocoPhillips Alaska, Inc.	Delaware
ConocoPhillips Alaska Natural Gas Corporation	Delaware
ConocoPhillips Arabia Inc.	Delaware
ConocoPhillips Arabia Limited	Cayman Islands
ConocoPhillips Arabia Ltd.	Bermuda
ConocoPhillips Arctic Inc.	Delaware
ConocoPhillips Asia Pacific Investments Ltd.	Bermuda
ConocoPhillips Asia Ventures Pty. Ltd.	Singapore
ConocoPhillips Australia Exploration Pty. Ltd.	Western Australia
ConocoPhillips Australia WA-248 Company Pty. Ltd.	Australia
ConocoPhillips Australia Gas Holdings Pty. Ltd.	Western Australia
ConocoPhillips Australia Pty. Ltd.	Western Australia
ConocoPhillips Austria GmbH	Austria
ConocoPhillips Aviation Services LLC	Texas
ConocoPhillips Bantry Bay Terminal Ltd	Ireland
ConocoPhillips Banyumas Holding Ltd.	British Virgin Islands
ConocoPhillips Bao Vang Ltd.	Cayman Islands
ConocoPhillips Barents Sea Ltd.	Cayman Islands
ConocoPhillips Belgium SA	Belgium
ConocoPhillips Block 204 UK Exploration Ltd.	Cayman Islands
ConocoPhillips Bohai Limited	Bahamas
ConocoPhillips Canada (East) Limited	Canada
ConocoPhillips Canada (North) Limited	Canada
ConocoPhillips Canada Energy Partnership	Alberta
ConocoPhillips Canada Limited	Nova Scotia
ConocoPhillips Canada Resources Corp.	Nova Scotia
ConocoPhillips Central and Eastern Europe Holdings B.V.	The Netherlands
ConocoPhillips China Inc.	Liberia
ConocoPhillips Communications Inc.	Delaware
ConocoPhillips Company	Delaware
ConocoPhillips Continental Holding GmbH	Germany
ConocoPhillips Czech Republic s.r.o.	Czech Republic
ConocoPhillips Denmark A/S	Denmark
ConocoPhillips Developments Limited	England
ConocoPhillips Developments LLC	Delaware
ConocoPhillips Eastern Hemisphere New Ventures Ltd.	Cayman Islands
ConocoPhillips Eastern Venezuela Gas Ltd.	Cayman Islands
ConocoPhillips Energy Asia Inc.	Delaware
ConocoPhillips Energy Marketing Corp.	Delaware
ConocoPhillips Enterprises Inc.	Delaware

Company Name	Incorporation Location
ConocoPhillips European Gas and Power Limited	England
ConocoPhillips European Power Limited	England
ConocoPhillips Expatriate Services Company	Delaware
ConocoPhillips Exploration Azerbaijan Ltd.	Cayman Islands
ConocoPhillips Exploration Investment, Ltd.	Cayman Islands
ConocoPhillips Exploration Kazakhstan Ltd.	Cayman Islands
ConocoPhillips Exploration Production Europe Limited	England
ConocoPhillips Finland Oy	Finland
ConocoPhillips Funding Ltd.	Bermuda
ConocoPhillips Germany GmbH	Germany
ConocoPhillips Global Funding S.a.r.l.	Luxembourg
ConocoPhillips Gulf of Paria Ltd.	Cayman Islands
ConocoPhillips Holdings Limited	England
ConocoPhillips Hungary Trading Ltd.	Hungary
ConocoPhillips ICHP Limited	England
ConocoPhillips Indonesia Inc. Ltd.	Bermuda
ConocoPhillips Indonesia Ventures Ltd.	Cayman Islands
ConocoPhillips International Holding Ltd.	British Virgin Islands
ConocoPhillips International Inc.	Delaware
ConocoPhillips International Ventures Ltd.	Bahamas
ConocoPhillips Investments Limited	England
ConocoPhillips Investments Norge AS	Norway
ConocoPhillips Ireland Limited	Ireland
ConocoPhillips Japan Ltd.	Japan
ConocoPhillips Jet AS	Norway
ConocoPhillips JPDA Pty. Ltd.	Western Australia
ConocoPhillips Latin America New Ventures Ltd.	Cayman Islands
ConocoPhillips Limited	England
ConocoPhillips LNG Ltd.	Cayman Islands
ConocoPhillips Lubricants Australia Pty. Ltd.	Australia
ConocoPhillips Maroc Ltd.	Cayman Islands
ConocoPhillips MEA Ltd.	Cayman Islands
ConocoPhillips Mexico Servicios, S.A. de C.V.	Mexico
ConocoPhillips Mexico, S.A. de C.V.	Mexico
ConocoPhillips Middle East Ltd.	Delaware
ConocoPhillips Middle East New Ventures Ltd.	Cayman Islands
ConocoPhillips New Ventures Ltd.	Cayman Islands
ConocoPhillips Nila Ltd.	Bermuda
ConocoPhillips Nordic AB	Sweden
ConocoPhillips Norge	Delaware
ConocoPhillips NZ Exploration Limited	Cayman Islands
ConocoPhillips Oil (GB) Limited	England & Wales
ConocoPhillips Oil Trading Limited	United Kingdom
ConocoPhillips Oilsands Partnership II	Alberta
ConocoPhillips Pacific LNG Ltd.	Cayman Islands
ConocoPhillips Pension Plan Trustees Limited	United Kingdom

Company Name	Incorporation Location
ConocoPhillips Petroleum Chemicals U.K. Limited	United Kingdom
ConocoPhillips Petroleum Company U.K. Limited	United Kingdom
ConocoPhillips Petroleum International Corporation Denmark	Cayman Islands
ConocoPhillips Petroleum Limited	England
ConocoPhillips Pipeline Australia Pty Ltd	Western Australia
ConocoPhillips Pipe Line Company	Delaware
ConocoPhillips Poland Sp. z o.o.	Poland
ConocoPhillips Power Operations Limited	England
ConocoPhillips Qatar GTL Exploration Ltd.	Cayman Islands
ConocoPhillips Qatar GTL Ltd.	Cayman Islands
ConocoPhillips Qatar LNG Inc.	Delaware
ConocoPhillips Qatar Ltd.	Cayman Islands
ConocoPhillips Russia Inc.	Delaware
ConocoPhillips Russia Ventures Ltd.	Cayman Islands
ConocoPhillips Sabah Ltd.	Bermuda
ConocoPhillips Sakakemang Holding Ltd.	British Virgin Islands
ConocoPhillips Shipping LLC	Delaware
ConocoPhillips Shipping Norge A/S	Norway
ConocoPhillips Shipping Norge Nr. 2 AS	Norway
ConocoPhillips Shtokman Inc.	Delaware
ConocoPhillips Skandinavia AS	Norway
ConocoPhillips Slovakia s.r.o.	Slovak Republic
ConocoPhillips South Sokang Holding Ltd.	British Virgin Islands
ConocoPhillips South Sokang Ltd.	Bermuda
ConocoPhillips Specialty Products Inc.	Delaware
ConocoPhillips Specialty Products Inc.-CIS	Delaware
ConocoPhillips STL Pty Ltd.	Western Australia
ConocoPhillips Surmont Partnership	Alberta
ConocoPhillips Tempe HQ Company LLC	Delaware
ConocoPhillips Timan-Pechora Inc.	Delaware
ConocoPhillips Tobong Ltd.	Bermuda
ConocoPhillips Transportation Alaska, Inc.	Delaware
ConocoPhillips Treasury Limited	England
ConocoPhillips Vietnam AS	Norway
ConocoPhillips Warim Ltd.	Bermuda
ConocoPhillips Western Canada Partnership	Alberta
ConocoPhillips Whitegate Refinery Limited	Ireland
ConocoPhillips Worldwide LNG, Ltd.	Cayman Islands
ConocoPhillips WQ Ltd.	Cayman Islands
ConocoPhillips Z&M Ltd.	Cayman Islands
Cono-Services Inc.	Delaware
Conoven Holding Ltd.	British Virgin Islands
Continental Mid Delta Petroleum Company	Delaware
Continental Netherlands Oil Company B.V.	The Netherlands
Continental Oil Company	Delaware
Continental Oil Company (Nederland) B.V.	The Netherlands

Company Name	Incorporation Location
Continental Oil Company Inc.	Canada
Continental Oil Company Limited	England
Continental Oil Company of Libya	Delaware
Continental Oil Company of Niger	Delaware
Continental Oil Company of Nigeria	Delaware
Continental Pipe Line Company	Delaware
COP Holdings Limited	England
COP Energy Technologies LLC	Delaware
Crestar Energy Holdings Ltd.	Bermuda
Crusader (Ireland) Pty. Ltd.	Australia
Crusader Inc.	Delaware
CSPL Holdings Limited	England
Danube Ltd.	Bermuda
Darwin LNG Pty. Ltd.	Western Australia
Davis Point Pipeline Company	California
Diablo Service Corporation	California
Douglas Oil Company of California	California
Douglas Stations, Inc.	Delaware
Du Pont E&P No. 1 B.V.	The Netherlands
Dubai Marketing Company Ltd.	Delaware
Dubai Petroleum Company	Delaware
Eagle Sun Company Limited	Liberia
Emerald Shipping Corporation	Delaware
Emet Pty. Ltd.	Victoria, Australia
F.P.S.O. Development Ltd.	Bermuda
Fas-Gas Retail Services Co. of Texas	Texas
Four Star Beverage Company Inc.	Texas
Four Star Holding Company, Inc.	Texas
Frontier Deepwater Drilling Inc.	Delaware
GCF Midstream Holdings LLC	Delaware
GCRL Energy Ltd.	Colorado
GCRL Holdings Inc.	Delaware
GCRL International Limited	Alberta
Glen Petroleum Limited	England
Gulf Alberta Pipe Line Company Limited	Alberta
Gulf Canada Hibernia Ltd.	Canada
Gulf Canada Limited	Canada
Gulf Canada Properties Limited	Canada
Gulf Canada Tunisia Ltd.	Alberta
Gulf Energy Asia Pte Ltd.	Singapore
Gulf Expro Limited	Scotland
Gulf of Mexico Oil and Gas Properties LLC	Delaware
Gulf Petroleum (Australia) Pty Ltd.	Australia
Gulf Resources (Calik) Ltd.	Alberta
Gulf Resources (Halmahera) Ltd.	Alberta
Gulf Resources (Merangin) Ltd.	Alberta

Company Name	Incorporation Location
Gulf Resources (NW Natuna) Ltd.	Alberta
Gulf Resources (Sakala Timur) Ltd.	Alberta
Gulf Resources (West Natuna) Ltd.	Alberta
Gulf Transasia Ltd.	Barbados
Hotel Phillips Management Company	Oklahoma
Immingham CHP LLP	England
Immingham Energy Limited	England
Interkraft Handel GmbH	Germany
International Energy Insurance Limited	Bermuda
International Energy Limited	Bahamas
International Petroleum Holdings LLC	Delaware
International Petroleum Sales Inc.	Panama
IRC Pension Trust Limited	Ireland
JET Petrol Limited	Northern Ireland
Jet Petroleum Limited	England
Jet Tankstellen-Betriebs-GmbH	Germany
Jet/Jiffy Shops Limited	Thailand
Jiffy Limited	England
Kayo Oil Company	Delaware
Kenai LNG Corporation	Delaware
Kenai Tankers LLC	Delaware
Koala Smokeless Fuels Ltd.	Australia
Kuparuk Pipeline Company	Delaware
Lantri Investments B.V.	The Netherlands
Leland Energy Partnership	Alberta
Linden Urban Renewal Limited Partnership	New Jersey
Lobo Inc.	Delaware
Lobo Pipeline Company L.P.	Delaware
Longhorn Pipeline Company	Delaware
Louisiana Gas System Inc.	Delaware
Lubricantes 76 Mexico, S.A. de C.V.	Mexico
Maspher Investments B.V.	The Netherlands
McKinney’s Gas Services, Inc.	Delaware
Morgan Hydrocarbons Inc.	Canada
Morgan Hydrocarbons International Inc.	Canada
Norske ConocoPhillips AS	Norway
North Gillette Coal Company	Nevada
Oliktok Pipeline Company	Delaware
Pacific Pipelines, Inc	Delaware
Peerless Insurance Company Limited	Barbados
Petco Enterprises Ltd.	Japan
Petrex S.A.	Belgium
Petroleum Transmission Company	Canada
Petroz (International) Pty Ltd	Queensland, Australia
Petroz (Timor Sea) Pty Ltd	Western Australia
Petroz (ZOCA 91-08) Pty Ltd	Queensland, Australia
Petroz Bentu LDC	Cayman Islands

Company Name	Incorporation Location
Petroz Korinci Baru LDC	Cayman Islands
Petroz N.L.	Australia
Petroz LNG Pty Ltd	Australia
Phillips (Brass) Limited	Cayman Islands
Phillips 66 Capital I	Delaware
Phillips 66 Capital III	Delaware
Phillips 66 Capital IV	Delaware
Phillips 66 Capital V	Delaware
Phillips 66 Capital VI	Delaware
Phillips Alpine Alaska, Inc.	Delaware
Phillips Angola Offshore Ltd.	Cayman Islands
Phillips Australasia Exploration Co.	Liberia
Phillips Block 250 Nigeria Ltd.	Nigeria
Phillips Caspian, Ltd.	Liberia
Phillips Chemical Holdings Company	Delaware
Phillips Coal Company	Nevada
Phillips Deepwater Africa Exploration, Ltd.	Cayman Islands
Phillips Deepwater Exploration Nigeria Limited	Nigeria
Phillips Exploration Angola, Ltd.	Liberia
Phillips Exploration Azerbaijan, Ltd.	Cayman Islands
Phillips Exploration Nigeria Limited	Nigeria
Phillips Gas Company	Delaware
Phillips Gas Company Shareholder, Inc.	Delaware
Phillips Gas Investment Company	Delaware
Phillips Gas Pipeline Company	Delaware
Phillips Gas Supply Corporation	Delaware
Phillips Indonesia Inc.	Delaware
Phillips Internacional Quimicos Ltda.	Brazil
Phillips International Investments, Inc.	Delaware
Phillips Investment Company	Nevada
Phillips LNG Middle East Ltd.	Cayman Islands
Phillips LNG Technology Services Company	Delaware
Phillips Mexico LNG, LLC	Delaware
Phillips New Ventures, Ltd.	Cayman Islands
Phillips Oil Company (Nigeria) Ltd.	Nigeria
Phillips Oil Company Australia	Liberia
Phillips Petroleum Africa, Ltd.	Liberia
Phillips Petroleum Arabia, Ltd.	Liberia
Phillips Petroleum Argentina S.A.	Argentina
Phillips Petroleum Canada Ltd.	New Brunswick
Phillips Petroleum Company Algeria	Delaware
Phillips Petroleum Company Andes	Delaware
Phillips Petroleum Company Cameroon	Delaware
Phillips Petroleum Company Indonesia	Delaware
Phillips Petroleum Company Ireland	Delaware
Phillips Petroleum Company Kuwait	Cayman Islands
Phillips Petroleum Company Niugini	Delaware

Company Name	Incorporation Location
Phillips Petroleum Company Western Hemisphere	Delaware
Phillips Petroleum Company ZOC Pty. Ltd.	Australia
Phillips Petroleum do Brasil Ltda.	Brazil
Phillips Petroleum Europe Exploration Ltd.	Liberia
Phillips Petroleum Greenland A/S	Greenland
Phillips Petroleum International Corporation	Delaware
Phillips Petroleum International Corporation Venezuela	Liberia
Phillips Petroleum International Investment Company	Delaware
Phillips Petroleum International Ventures Corporation	Panama
Phillips Petroleum Kazakhstan, Ltd.	Liberia
Phillips Petroleum Kuwait, Ltd.	Liberia
Phillips Petroleum Latin America, Ltd.	Liberia
Phillips Petroleum Management Corporation	Panama
Phillips Petroleum Middle East, Ltd.	Liberia
Phillips Petroleum Resources, Ltd.	Delaware
Phillips Petroleum Russia, Ltd.	Delaware
Phillips Petroleum Timor Sea Inc.	Delaware
Phillips Petroleum Timor Sea Pty. Ltd.	New South Wales, Australia
Phillips Pt. Arguello Production Company	Delaware
Phillips Retail Marketing Company	Delaware
Phillips STL Ventures Inc.	Delaware
Phillips Texas Pipeline Company, Ltd.	Texas
Phillips Utility Gas Corporation	Delaware
Pioneer Investments Corp.	Delaware
Pioneer Pipeline Company	Delaware
Polar Tankers Spill Response Company	Delaware
Polar Tankers, Inc	Delaware
Pontoon (Timor Sea) Pty Ltd	Western Australia
Pontoon N.L.	Western Australia
Power Tex Joint Venture	Delaware
Projet Malaysia Sdn. Bhd.	Malaysia
Proteina Brasileira Ltda.	Brazil
PT. ConocoPhillips Downstream Indonesia	Indonesia
R.A.Z. Properties, Inc.	California
Raptor Facilities Inc.	Delaware
Raptor Gas Transmission LLC	Delaware
Raptor Natural Pipeline LLC	New Mexico
Raptor Natural Plains Marketing LLC	Delaware
Rocky Mountain Investment & Antique Company	Wyoming
Salt Lake Terminal Company	Delaware
San Jacinto Eastern Corp.	Delaware
San Jacinto Service Company	Delaware
San Pablo Bay Pipeline Company	Delaware
San Pablo Bay Pipeline Company LLC	Delaware
Seagas Pipeline Company	Delaware
Seaway Products Pipeline Company	Texas

Company Name	Incorporation Location
Seminole Fertilizer Corporation	Delaware
Smartshop NV	Belgium
Smile Loyalty Limited	England
Sooner Insurance Company	Vermont
Southern Energy UK Generation Limited	England
Springtime Holdings Limited	Cayman Islands
Stampeder Acquisition (No. 2) Ltd.	Canada
Stampeder Acquisition Ltd.	Alberta
Stampeder Exploration Ltd.	Alberta
Sweeny Coker Investor Sub, Inc.	Delaware
Terminal de Gas Natural Licuado de Rosarito TGNLR, S. de R.L. de C.V.	Mexico
The Largo Company	Delaware
The Standard Shale Products Company	Colorado
Tosco Canada Ltd.	Yukon Territory
Tosco Europe Limited	United Kingdom
Tosco Trading, Transportation and Supply, Inc.	Delaware
Trilogy France Corporation	Novia Scotia
TS, Inc.	Georgia
Union Pipeline Company (California)	California
Unocal Expresslube, Inc.	Illinois
Wabiskaw Explorations Ltd.	Canada
WesTTex 66 Pipeline Company	Delaware
World Wide Transport, Inc.	Liberia
3072496 Nova Scotia Company	Nova Scotia
349910 Alberta Inc.	Alberta
362084 Alberta Inc.	Alberta
3793885 Canada Ltd.	Canada
534404 Alberta Ltd.	Alberta
625894 Alberta Inc.	Alberta
66 Pipe Line Company	Delaware
942819 Alberta Ltd.	Alberta

Certain subsidiaries are omitted since such subsidiaries considered in the aggregate do not constitute a significant subsidiary.

Exhibit 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference of our reports dated February 25, 2005, with respect to the consolidated financial statements, condensed consolidating financial information, and schedule of ConocoPhillips, ConocoPhillips management's assessment of the effectiveness of internal control over financial reporting, and the effectiveness of internal control over financial reporting of ConocoPhillips, included in this Annual Report (Form 10-K) for the year ended December 31, 2004, in the following registration statements and related prospectus.

ConocoPhillips Form S-3	File No. 333-101187
ConocoPhillips Form S-8	File No. 333-98681

/s/ Ernst & Young LLP

Houston, Texas
February 25, 2005

Exhibit 31.1

CERTIFICATION

I, J. J. Mulva, certify that:

1. I have reviewed this annual report on Form 10-K of ConocoPhillips;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2005

/s/ J. J. Mulva

J. J. Mulva
Chairman, President and Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, John A. Carrig, certify that:

1. I have reviewed this annual report on Form 10-K of ConocoPhillips;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2005

/s/ John A. Carrig

John A. Carrig
Executive Vice President, Finance, and
Chief Financial Officer

Exhibit 32

CERTIFICATIONS PURSUANT TO 18 U.S.C. SECTION 1350

In connection with the Annual Report of ConocoPhillips (the company) on Form 10-K for the period ended December 31, 2004, as filed with the U.S. Securities and Exchange Commission on the date hereof (the Report), each of the undersigned hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to their knowledge:

(1) The Report fully complies with the requirements of Sections 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the company.

Date: February 25, 2005

/s/ J. J. Mulva

J. J. Mulva
Chairman, President and Chief Executive Officer

/s/ John A. Carrig

John A. Carrig
Executive Vice President, Finance, and Chief Financial Officer