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

Form 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended **December 31, 2005**

OR

o **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 if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
☒ Yes o No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
o Yes ☒ No

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 o 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 a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):
Large accelerated filer ☒ Accelerated filer o Non-accelerated filer o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). o Yes ☒ No

The aggregate market value of common stock held by non-affiliates of the registrant on June 30, 2005, the last business day of the registrant's most recently completed second fiscal quarter, based on the closing price on that date of $57.49, was $79.98 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 791,235 and 47,116,283 shares, respectively, in determining the aggregate market value.

The registrant had 1,378,526,988 shares of common stock outstanding at January 31, 2006.

Documents incorporated by reference:
Portions of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 10, 2006 (Part III)

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PART I

Unless otherwise indicated, "the company," "we," "our," "us," and "ConocoPhillips" are used in this report to refer to the businesses of ConocoPhillips and its consolidated subsidiaries. "Conoco" and "Phillips" are used in this report to refer to the individual companies prior to the merger date of August 30, 2002. Items 1 and 2, Business and Properties, contain forward-looking statements including, without limitation, statements relating to the company's plans, strategies, objectives, expectations, and intentions, 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," "should," "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 98.

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. 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 and Phillips were renamed, but for ease of reference, those companies will be referred to respectively in this document as Conoco and Phillips.

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 primarily consists of our 50 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 OAO LUKOIL (LUKOIL), an international, integrated oil and gas company headquartered in Russia. Our investment was 16.1 percent at December 31, 2005.
- **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 Chevron 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, 2005, ConocoPhillips employed approximately 35,600 people.

SEGMENT AND GEOGRAPHIC INFORMATION

For operating segment and geographic information, see Note 26—Segment Disclosures and Related Information in the Notes to Consolidated Financial Statements, which is incorporated herein by reference.

EXPLORATION AND PRODUCTION (E&P)

At December 31, 2005, our E&P segment represented 57 percent of ConocoPhillips' total assets, while contributing 62 percent of net income.

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, 2005, 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 financial results or statistics from our equity investment in the ordinary shares of 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. However, our share of LUKOIL is included in the supplemental oil and gas operations disclosures on pages 170 through 185.

The information listed below appears in the supplemental oil and gas operations disclosures 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 2005, E&P's worldwide production, including its share of equity affiliates' production other than LUKOIL, averaged 1,543,000 barrels-of-oil-equivalent (BOE) per day, about the same as the 1,542,000 BOE per day averaged in 2004. During 2005, 633,000 BOE per day were produced in the United States, a slight increase from 629,000 BOE per day in 2004. Production from our international E&P operations averaged 910,000 BOE per day in 2005, a slight decrease from 913,000 BOE per day in 2004. In addition, our Canadian Syncrude mining operations had net production of 19,000 barrels per day in 2005, compared with 21,000 barrels per day in 2004. Benefiting 2005 production was the startup of the

Hamaca upgrader in Venezuela in the fourth quarter of 2004; the Bayu-Undan field in the Timor Sea, which was still ramping up during 2004; and a full year's production from the Magnolia field in the Gulf of Mexico, which continued to ramp-up during 2005. These benefits were offset by scheduled and unscheduled maintenance and normal field production declines. 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 38 percent in 2005, from $36.06 per barrel to $49.87 per barrel. E&P's annual average worldwide natural gas sales price also increased, from $4.61 per thousand cubic feet in 2004 to $6.30 per thousand cubic feet in 2005.

E&P—U.S. OPERATIONS

In 2005, U.S. E&P operations contributed 40 percent of E&P's worldwide liquids production and 42 percent of natural gas production, the same as in 2004.

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 102,100 barrels per day in 2005, compared with 109,600 barrels per day in 2004, while natural gas liquids production averaged 18,500 barrels per day in 2005, compared with 22,100 barrels per day in 2004.

Prudhoe Bay satellite fields, including Aurora, Borealis, Polaris, Midnight Sun, and Orion, produced 14,500 net barrels per day of crude oil in 2005, compared with 14,600 net barrels per day in 2004. 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 15,200 barrels per day in 2005, compared with 17,800 barrels per day in 2004, while natural gas liquids production averaged 1,000 barrels per day in 2005, the same as 2004. 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 lower production tax rate that was intended to encourage development of these marginal deposits. Accordingly, beginning in February 2005, the production tax for these satellite fields is the same 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 55.3 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 64,600 barrels per day in 2005, compared with 67,900 barrels per day in 2004.

Other fields within the Greater Kuparuk Area produced 16,000 net barrels per day of crude oil in 2005, compared with 19,300 net barrels per day in 2004, primarily from the Tarn, Tabasco, and Meltwater satellites. We have a 55.4 percent interest in Tarn and Tabasco and a 55.5 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 5,300 barrels per day in 2005, compared with 5,500 barrels per day in 2004. 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 Kuparuk drill site, and Drill Site 1J, which is the first stand-alone West Sak drill site. Drill Site 1E started up in July 2004, and its 13-well drilling program was completed in late 2005. The 1J drilling program, consisting of 31 wells, began in 2005, with first production in October 2005. Peak production is expected in 2007. In evaluation of other areas for possible West Sak development, two successful appraisal wells were completed in 2005.

Western North Slope
The Alpine field, located west of the Kuparuk field, began production in November 2000. In 2005, the field produced at a net rate of 76,600 barrels of oil per day, compared with 63,500 barrels per day in 2004. The increased production was the result of the capacity expansion projects discussed below. We are the operator and hold a 78 percent interest in Alpine.

During 2004, the Alpine Capacity Expansion Phase I project 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 handling 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 of produced water. Phase II was completed in 2005, after which Alpine's crude oil production capacity was further expanded by approximately 30,000 gross barrels per day with increased seawater injection rates to boost reservoir pressure.

In November 2004, the U.S. Department of Interior Bureau of Land Management (BLM) issued a favorable Environmental Impact Statement (EIS) Record of Decision to develop future Alpine satellites. Subsequently, 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 National Petroleum Reserve—Alaska (NPR-A). A final decision to move forward on these additional 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 2005 averaged 105 million cubic feet per day of natural gas, compared with 94 million cubic feet per day in 2004. 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 57 million cubic feet per day of natural gas in 2005, compared with 63 million cubic feet per day in 2004. Gas from the Beluga River field is sold to local utilities and industrial consumers, and is 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, utilizing two LNG tankers for transport. We sold 42.8 net billion cubic feet of LNG to Japan in 2005, compared with 38.6 net billion cubic feet in 2004.

Exploration
During 2005, we drilled five North Slope exploration and appraisal wells. This activity included two wildcat wells in the NPR-A, one infrastructure-led exploration (ILX) well near the Alpine field, and two appraisal wells in the West Sak field. The two NPR-A wells and the ILX well were classified as dry holes, but the data gathered is being further evaluated for a future development opportunity. Additionally, we completed an evaluation of the economic viability of exploration and appraisal wells drilled in prior years, and classified five wells as dry holes.

We were also the successful bidder acquiring 66,262 gross and net acres at the Minerals Management Service oil and gas lease sale in the Beaufort Sea held on March 30, 2005. Furthermore, we acquired 21,320 gross and net acres directly from another company in July 2005. As a result of acquiring this additional acreage, we had under lease approximately 1.7 million net undeveloped acres (onshore and offshore) as of December 31, 2005, in Alaska.

Transportation
We transport the petroleum liquids produced 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. A project to upgrade TAPS' pump stations began in 2004 and is expected to be completed in 2006. 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.

We continue to evaluate a gas pipeline project to deliver natural gas from Alaska's North Slope to the Lower 48. The Alaska Natural Gas Pipeline Act was passed by the U.S. 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 federal tax legislation granting seven-year depreciation for the Alaska portion of the pipeline and confirming the existing 15 percent enhanced oil recovery tax credit would apply to the gas treatment plant. In October 2005, we announced that we reached an agreement in principle with the state of Alaska on the base fiscal contract terms for an Alaskan natural gas pipeline project. In early 2006, the state of Alaska announced that they had reached an agreement in principle with all the co-venturers in the project. Once a final form of agreement is reached among all the parties, it will be subject to final approval by the Alaska State Legislature before it can be executed. Additional agreements for the gas to transit Canada will also be required.

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 through 2004: the *Polar Resolution* in 2002; the *Polar Discovery* in 2003; and the *Polar Adventure* in 2004. These 140,000-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 in 2006, although contractual and hurricane-related issues may further delay delivery of this last vessel.

Lower 48 States
Gulf of Mexico
At year-end 2005, our portfolio of producing properties in the Gulf of Mexico included four fields operated by us and five fields operated by our co-venturers.

We operate and hold a 75 percent interest in the Magnolia field in Garden Banks 783 and 784. The Magnolia field is developed from a tension-leg platform in 4,700 feet of water. Production from Magnolia began in December 2004. Well completion activities continued throughout 2005, and will continue into mid-2006. Net production from Magnolia averaged 18,700 barrels per day of liquids and 43 million cubic feet per day of natural gas in 2005. Hurricanes shut in Magnolia for approximately 20 days in 2005, but only caused minimal damage.

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 the unitized area in 2005 averaged 13,500 barrels per day of liquids and 16 million cubic feet per day of natural gas, compared with 21,000 barrels per day of liquids and 30 million cubic feet per day of natural gas in 2004. The lower 2005 average daily production rate was due to Ursa/Princess being shut in, or significantly curtailed, for approximately 85 days in 2005 for hurricanes and repairs to infrastructure following hurricane Katrina. Ursa/Princess resumed production at a curtailed rate in mid-November 2005, and returned to full production in late-December 2005.

We have a 16.8 percent interest in the K2 field. K2 is a subsea development located in Green Canyon Block 562. First production began in May 2005, and our net production averaged 700 BOE per day in 2005. Hurricanes shut in K2 for approximately 22 days in 2005, but caused no damage to the field. Drilling and completion activities will continue into early 2006, with peak net production of 6,000 BOE per day expected in 2006.

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 the onshore Upper Texas Gulf Coast, East Texas and North Louisiana areas. 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 traded in early 2005 for additional interests in Texas properties that integrate well with our existing assets.

Activities in 2005 primarily were centered on continued optimization and development of these assets. Combined production from Lower 48 onshore fields in 2005 averaged a net 1,147 million cubic feet per day of natural gas and 54,900 barrels per day of liquids, compared with 1,184 million cubic feet per day of natural gas and 54,100 barrels per day of liquids in 2004.

E&P—NORTHWEST EUROPE

In 2005, E&P operations in Northwest Europe contributed 27 percent of E&P's worldwide liquids production, compared with 29 percent in 2004. Northwest Europe operations contributed 31 percent of natural gas production in 2005, compared with 34 percent in 2004. Our Northwest European assets are principally located in the Norwegian and U.K. sectors of the North Sea.

Norway
The Greater Ekofisk Area is located approximately 200 miles offshore Norway in the center of the North Sea. The Greater Ekofisk Area is comprised of four producing fields: Ekofisk, Eldfisk, Embla, and Tor. The Ekofisk complex serves as a hub for petroleum operations in the area, with surrounding developments utilizing the Ekofisk infrastructure. Net production in 2005 from the Greater Ekofisk Area was 124,800 barrels of liquids per day and 122 million cubic feet of natural gas per day, compared with 127,400 barrels of liquids per day and 125 million cubic feet of natural gas per day in 2004. 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 Greater Ekofisk Area. The project consists of two interrelated components: construction of a new platform, Ekofisk 2/4M, and modification of the existing Ekofisk and Eldfisk complexes to increase processing capacity. Construction began in 2003, and production from the new 2/4M platform commenced in October 2005.

We also have ownership interests in other producing fields in the Norwegian sector of the 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 81,900 barrels of liquids per day and 150 million cubic feet of natural gas per day in 2005, compared with 87,700 barrels of liquids per day and 176 million cubic feet of natural gas per day in 2004.

We and our co-venturers received approval from Norwegian authorities in 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.

In 2005, approval was received from the Norwegian and U.K. authorities to proceed with a further development of the Statfjord area. The project, named the "Statfjord Late-Life Project," is a gas recovery project, with production startup targeted for the late-2007 time frame. We have a combined Norway/U.K. 15.2 percent interest in this 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
Four exploration wells were completed in 2005. Three near-field exploration wells were drilled in the Oseberg and Troll licences, one of which was successful. An additional well was drilled in the Voring Basin and tested hydrocarbons. Although the well was expensed as a dry hole, we plan to conduct further appraisal. A further near-field well was started in 2005, located within the Troll license, with operations continuing into 2006.

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 315 million cubic feet of natural gas per day and 13,100 barrels of liquids per day in 2005, compared with 347 million cubic feet of natural gas per day and

15,500 barrels of liquids per day in 2004. 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: Callanish and Brodgar. 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 was completed in the fourth quarter of 2005, 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 123 million cubic feet of natural gas per day in 2005, compared with 14,100 barrels of liquids per day and 118 million cubic feet of natural gas per day in 2004.

We continue to supply gas from J-Block to Enron Capital and Trade Resources Limited (Enron Capital), which was placed in Administration in the United Kingdom in November 2001. We have 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 15 producing gas fields in the southern North Sea, in the Rotliegendes and Carboniferous areas. Net production in 2005 averaged 278 million cubic feet per day of natural gas and 1,200 barrels of liquids per day, compared with 306 million cubic feet per day of natural gas and 1,400 barrels per day of liquids in 2004.

In 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 began in September 2005, with net production expected to increase as development drilling continues. Initially, the development consists of three wells from a six-slot wellhead platform. We are the operator of the Saturn Unit Area with a 42.9 percent interest.

In 2005, we received U.K. government approval for the Munro development. First production from Munro was achieved in August 2005, from a single well platform that is tied into the Caister-Murdoch System infrastructure. 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 35,400 barrels of liquids per day and 34 million cubic feet of natural gas per day in 2005, compared with 38,800 barrels of liquids per day and 47 million cubic feet of natural gas per day in 2004.

We have a 24 percent interest in the Clair field development in the Atlantic Margin. First production from Clair began in early 2005, with plateau production expected in 2007. The Clair development includes a conventional platform with production and process topsides facilities supported by a fixed-steel jacket. Oil

from the field is exported to the Sullom Voe terminal in Shetland via pipeline, while natural gas is carried through a spur line into the Magnus enhanced oil recovery trunk line.

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, and our reverse-flow rights provide an 85 million net cubic feet of natural gas import capability to the United Kingdom.

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 four exploration wells and one appraisal well in 2005. Drilling operations have been concluded on one well in the southern North Sea and another in the J-Block area, both of which were successful. Three further wells were started in 2005, one in the Britannia area, one in the J-Block area, and one adjacent to the Clair field in the Atlantic Margin. Operation on these wells continued into 2006.

Denmark
Exploration
We hold two exploration licenses in Denmark: 5/98 (Hejre) and 4/98 (Svane). Drilling and testing of an appraisal well, adjacent to a 2001 discovery in the Hejre license, was completed in 2005. The well was successful.

E&P—CANADA

In 2005, E&P operations in Canada contributed 3 percent of E&P’s worldwide liquids production (excluding Syncrude production), compared with 4 percent in 2004. Canadian operations contributed 13 percent of natural gas production in 2005, the same as in 2004.

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, including a coalbed methane program in the central region. The south region has shallow gas and medium-to-heavy oil. Production from these oil and gas operations in western Canada averaged a net 32,300 barrels per day of liquids and 425 million cubic feet per day of natural gas in 2005, compared with 35,000 barrels per day of liquids and 433 million cubic feet per day of natural gas in 2004.

Surmont
The Surmont lease is located approximately 35 miles south of Fort McMurray, Alberta. We own a 50 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. Consistent with our practice and in accordance with U.S. Securities and Exchange Commission guidelines, we use year-end prices for hydrocarbon reserve estimation. Due to low Canadian

bitumen values at December 31, 2005, we did not record any proved crude oil reserves for the Surmont project in 2005. The Surmont project remains an economically viable and important component of our 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 2013. We anticipate processing our share of the heavy oil produced as a feedstock in our U.S. refineries.

Parsons Lake/Mackenzie Gas Project
We are working with three other energy companies, as members of the Mackenzie Delta Producers’ Group, on the development of the Mackenzie Valley pipeline and gathering system, which is proposed to transport onshore gas production from the Mackenzie Delta in northern Canada to established markets in North America. Our interest in the pipeline and gathering system varies by component, averaging approximately 18 percent. We have 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. Considerable progress on several issues, including socio-economic responsibility, and benefits and access agreements with four of the five aboriginal groups, have resulted in the decision by the project proponents to proceed to the regulatory hearings. The National Energy Board started hearings on January 25, 2006. First production from Parsons Lake is expected in 2011.

Exploration
We hold exploration acreage in four areas of Canada: offshore eastern Canada, the foothills of western Alberta, the Mackenzie Delta/Beaufort Sea, and the Arctic Islands. In eastern Canada, we operate eight contiguous exploration licenses in the deepwater Laurentian basin. Recent exploratory activity in the Laurentian basin included a 2D seismic survey in 2004, and two 3D seismic programs completed in September 2005. In the Mackenzie Delta, we participated in an appraisal well to follow-up the Umiak discovery from 2004. Oil and gas flowed during testing of the discovery well and the appraisal well. Plans to commercialize this discovery will be integrated into the broader Parsons Lake Development project.

In the foothills, we drilled three wildcat exploratory wells in 2005. One well is being tied-in for production. The remaining two are being tested. Throughout the rest of the Western Canadian Sedimentary basin, we participated in the drilling of approximately 70 low-risk wells near our producing assets.

Elsewhere in the frontiers regions, we hold varying equity interests in discoveries along the Labrador Shelf and in the Arctic Islands. Further exploration in these basins is contemplated as distribution methods for natural gas become more certain.

Other Canadian Operations
Syncrude Canada Ltd.
We own a 9.0 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, with an auxiliary mining and extraction facility approximately 20 miles from the Mildred Lake plant. Syncrude Canada Ltd. holds eight oil sands leases and the associated surface rights, of which our share is approximately 23,000 net acres. Our net share of production averaged 19,100 barrels per day in 2005, compared with 21,000 barrels per day in 2004.

The development of the Stage III expansion-mining project continued in 2005, which is expected to increase our Syncrude production. The Aurora North Train II mine was completed and started up in the fourth quarter of 2003 and the SW Quadrant Replacement Mine was also completed and became operational by year-end 2005. 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 2005, E&P operations in South America were focused on our operations in Venezuela. South American operations contributed 11 percent of E&P’s worldwide liquids production in 2005, compared with 9 percent in 2004.

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 project is an integrated operation that produces heavy crude oil from reserves in 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 operated by PDVSA in Venezuela. Our net production was 50,200 barrels of heavy crude oil per day in 2005, compared with 59,600 barrels per day in 2004, and is included in equity affiliate production.

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 is operated by Petrolera Ameriven on behalf of the owners. The other participants in Hamaca are PDVSA and Chevron Corporation, each owning 30 percent. 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 56,100 barrels per day of heavy crude oil in 2005, compared with 32,600 barrels per day in 2004, 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.

Gulf of Paria
In March 2005, a development plan addendum for Phase I of the Corocoro field in the Gulf of Paria was approved by the Venezuelan government. This addendum addressed revisions to the original development plan approved in 2003. The wellhead platform was installed in late 2005, and the drilling program is expected to begin in the second quarter of 2006. First production from the central processing facility is targeted for 2008, with the possibility of production from an interim processing facility in 2007. We operate the field with a 32.2 percent interest.

Plataforma Deltana Block 2

We have a 40 percent interest in Plataforma Deltana Block 2. The block is operated by our co-venturer 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. PDVSA has the option to enter the project with a 35 percent interest, which would proportionately reduce our interest in the project to 26 percent.

E&P—ASIA PACIFIC

In 2005, E&P operations in the Asia Pacific area contributed 12 percent of E&P's worldwide liquids production and 11 percent of natural gas production, compared with 10 percent and 9 percent in 2004, respectively.

Indonesia
We operate nine Production Sharing Contracts (PSCs) in Indonesia and have a non-operator interest in two 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 2005 averaged a net 298 million cubic feet per day of natural gas and 15,100 barrels per day of oil, compared with 250 million cubic feet per day of natural gas and 15,400 barrels per day of oil in 2004.

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. In October 2005, natural gas export sales began from the Belanak field. 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 25 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. In October 2005, we purchased an additional 3 percent interest in the Pangkah PSC, bringing our ownership to its current 25 percent.

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 a non-operator interest in the Banyumas PSC in Java. During 2005, we sold our interests in 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 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 majority-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 2004, 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 the 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 three exploration and appraisal wells were drilled during 2005, of which one was successful. In the Ketapang PSC, an appraisal well of the Bukit Tua field, completed in 2005, provided data for progressing a development plan, which was submitted to the government of Indonesia in December 2005. In August 2005, the government of Indonesia awarded us a 100 percent interest in the Amborip VI exploration block in Papua Offshore, for which we expect to sign a PSC in early 2006.

China
Our combined net production of crude oil from the Xijiang facilities averaged 10,600 barrels per day in 2005, compared with 10,400 barrels per day in 2004. The Xijiang development consists of two 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 2005, the field produced 12,600 net barrels of oil per day, compared with 15,000 net barrels per day in 2004. We have a 49 percent interest, with the remainder held by the China National Offshore Oil Corporation. The Phase I development utilizes one manned wellhead platform and a leased 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 approved by the Chinese government in January 2005. Detailed design engineering, procurement and construction activities have begun on the second phase of development, which are planned to include five wellhead platforms, central processing facilities and a new FPSO. The first wellhead platform of Phase II is expected to be put into production in 2007, and production through the new FPSO is expected by early 2009.

Vietnam
Our ownership interest in Vietnam is centered around the Cuu Long Basin in the South China Sea, and consists of two primarily oil producing blocks, two exploration blocks, and one gas pipeline transportation system.

We have a 23.3 percent interest in Block 15-1 in the Cuu Long Basin. First production began in the fourth quarter of 2003 with the startup of the Su Tu Den development. Net production in 2005 was 15,100 barrels of oil per day, compared with 20,800 barrels per day in 2004. The oil is being processed through a one-million-barrel FPSO vessel.

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. Su Tu Vang is located approximately four miles south of Su Tu Den, and is now being developed. First oil production is targeted for 2008. In addition, successful appraisal of the Su Tu Den Northeast and Su Tu Trang fields within Block 15-1 continued in 2005.

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 2005 was 14,500 barrels of liquids per day and 18 million cubic feet per day of natural gas, compared with 11,800 barrels per day and 16 million cubic feet per day in 2004. Development of the central part of the field was completed in 2005, with first production in June.

Transportation
We own a 16.3 percent interest in the Nam Con Son natural gas pipeline. This 244-mile transportation system links gas supplies from the Nam Con Son Basin to gas markets in southern Vietnam.

Exploration
During 2005, we and our co-venturers successfully completed an exploration well in the Su Tu Nau field, located in the north corner of Block 15-1. Su Tu Nau is our fifth field discovery in Block 15-1, following Su Tu Den, Su Tu Vang, Su Tu Den Northeast, and Su Tu Trang.

Two successful appraisal wells were drilled in the Su Tu Trang field in 2005, a gas condensate field discovered in 2003 in the southeast area of the Block 15-1.

We also own interests in offshore Blocks 5-3, 133 and 134.

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 is re-injected into the reservoir. This phase began production in February 2004, and averaged a net rate of 47,800 barrels of liquids per day in

2005, compared with 28,100 barrels per day in 2004. Development drilling concluded at the end of March 2005. A major maintenance shutdown was performed during 2005.

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 2005, construction of the LNG facility proceeded, as did the laying of the pipeline. Following commissioning of the pipeline, limited natural gas production from the Bayu-Undan field began flowing into the pipeline in August 2005, to support the commissioning of the LNG plant. The first LNG cargo was loaded in February 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, increasing to approximately 260 million cubic feet per day by 2009.

Elang/Kakatua/Kakatua North
During 2005, we continued to produce ultra-light crude oil from these fields at a combined average net rate of 1,400 barrels per day, compared with 1,700 barrels per day in 2004. We are the operator with an interest of 57.4 percent.

Greater Sunrise
We and our co-venturers continued to evaluate commercial development options and LNG markets in the Asia Pacific region and the North American West Coast during 2005. The focus in 2005 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. In December 2005, we were notified that agreement had been reached between the governments of Australia and Timor-Leste with respect to Sunrise. The agreement was signed on January 12, 2006, but needs to be ratified by the respective parliaments. Commercial progress on the project will require further clarification on fiscal and jurisdictional issues with the respective governments. 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 2005, our net share of production was 34 million cubic feet of natural gas per day.

Exploration

During 2005, we announced a discovery in the Caldita No. 1 exploration well in the NT/P 61 license located offshore Northern Territory Australia. Technical evaluation to assess the further appraisal and development of the Caldita discovery is under way. Appraisal work likely will include acquiring and interpreting 3D seismic data, and drilling one or more appraisal wells to define the size and quality of the natural gas accumulation. In October 2005, we were awarded the NT/P 69 license located adjacent to NT/P 61. We are operator of the NT/P 61 and the NT/P 69 licenses, with a 60 percent interest in each.

Malaysia

Exploration

We have interests in deepwater Blocks G and J located off the east Malaysian state of Sabah. 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. The field was successfully appraised during 2004 and 2005, and is moving toward field development. In 2004, we successfully completed the drilling of the Malikai discovery in Block G. Appraisal of this discovery is scheduled to continue into 2006. In 2005, we had two additional Block G discoveries—Ubah and Pisagan. Appraisal of these discoveries is scheduled to occur in 2006 and 2007. We have a 35 percent interest in Block G.

During the first quarter of 2005, we announced that we and our co-venturers had signed a production sharing contract with PETRONAS, the Malaysian national oil company, for the appraisal and development of the Kebabangan oil field in Block J. The KBB #4 appraisal well was drilled and deemed unsuccessful in expanding the commercial size of this oil field, and a leasehold impairment was recorded during the fourth quarter of 2005. Development opportunities are being reviewed with co-venturers, and a development proposal is expected to be made to PETRONAS in 2006. We have a 40 percent interest in the oil rights of Kebabangan field.

E&P—AFRICA AND THE MIDDLE EAST

Nigeria

At year-end 2005, we were producing from four onshore Oil Mining Leases (OMLs), in which we have a 20 percent non-operator interest. These leases produced a net 28,900 barrels of liquids per day and 84 million cubic feet of natural gas per day in 2005, compared with 30,500 barrels per day and 71 million cubic feet per day in 2004. In 2005, 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 in Kwale, Nigeria. The plant came online in March 2005, and supplies electricity to Nigeria's national electricity supplier. The plant consumes 68 million gross cubic feet per day of natural gas, sourced from proved natural gas reserves in the OMLs.

In October 2003, ConocoPhillips, the Nigerian National Petroleum Corporation (NNPC), and two other co-venturers 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 formed an incorporated joint venture, Brass LNG Limited, to undertake the project. The front-end engineering and design work are expected to be completed in 2006, and will be the basis for commercial development of the facility, which could be operational as early as 2010.

Exploration

We also have production sharing contracts on deepwater Nigeria Oil Prospecting Licenses (OPLs), with a contractor interest on OPL 318 of 35 percent, OPL 248 of 72 percent, OPL 220 of 47.5 percent, and on OPL 214 of 20 percent. We operate all the OPLs except OPL 214. OPL 250 was relinquished in November 2005. OPL 220 has been converted into a Producing License, OML 131, subject to final government approval. The first exploration well on OPL 214 was drilled in 2005 and temporarily abandoned. On OPL 318, drilling commenced on the third and final exploration well in November 2005. The well did not encounter any significant accumulation of hydrocarbons, and was written off to dry hole expense in 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 us 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 drilled an appraisal well and a further exploratory well in 2005. The Londji Marine No. 1 and Coco Marine No. 2 wells were drilled consecutively starting in June 2005, with the Coco Marine No. 2 encountering some hydrocarbon producing zones. Both wells were plugged and abandoned as dry holes. We continue to evaluate the block, on which our interest expires in March 2007 unless extended.

Libya

In late-December 2005, we announced that, in conjunction with our co-venturers, we reached agreement with the Libyan National Oil Corporation on the terms under which we would return to our former oil and natural gas production operations in the Waha concessions in Libya. ConocoPhillips and Marathon Oil Corporation each hold a 16.33 percent interest, Amerada Hess Corporation holds an 8.16 percent interest, and the Libyan National Oil Corporation holds the remaining 59.16 percent interest. The concessions currently produce approximately 350,000 barrels of oil per day, and encompass nearly 13 million acres located in the Sirte Basin. The fiscal terms of the agreement are similar to the terms in effect at the time of the suspension of the co-venturers' activities in 1986, and include a 25-year extension of the concessions to 2031-2034.

As a result of the transaction, we added 238 million barrels of crude oil to our net proved reserves in 2005. Based on a current gross production estimate of 350,000 barrels of oil per day, we expect our entitlement to be approximately 45,000 net barrels of oil per day in 2006. In accordance with our policy of accounting for E&P production on the sales rather than the entitlements method, revenue and production from our working interest share of Libyan operations will be based on actual volumes sold by us during a period. We currently have, and expect to continue to build, a crude oil underlift position in the near term, from selling less than our entitlement. We expect to begin make-up of our underlift position in 2006.

Qatar

Qatargas 3

Qatargas 3 is an integrated project, jointly owned by Qatar Petroleum (68.5 percent), ConocoPhillips (30 percent) and Mitsui & Co., Ltd. (1.5 percent). The project comprises upstream natural gas production facilities to produce approximately 1.4 billion gross cubic feet per day of natural gas from Qatar's North field over the 25-year life of the project. The project also includes a 7.8-million-gross-ton-per-year LNG facility. The LNG will be shipped from Qatar in a fleet of large LNG vessels, and is destined for sale primarily in the United States. The first LNG cargos are expected to be delivered from Qatargas 3 in 2009.

The onshore Engineering, Procurement and Construction (EPC) contract for Qatargas 3 was awarded in late-December 2005. The EPC contract covers the engineering, procurement, and construction of onshore facilities for the LNG facility. The EPC contract marks the final investment decision for the project, with all definitive agreements signed and financing completed.

In order to capture cost savings, Qatargas 3 will execute the development of the onshore and offshore assets as a single integrated project with Qatargas 4, a joint venture between Qatar Petroleum and Royal Dutch Shell plc. This includes the joint development of offshore facilities situated in a common offshore block in the North field, as well as the construction of two identical LNG process trains, and associated gas treating facilities for both the Qatargas 3 and Qatargas 4 joint ventures.

Gas-to-Liquids
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. Preliminary engineering and design studies have been completed. In April 2005, the Qatar Minister of Petroleum stated that there would be a postponement of new GTL projects in order to further study impacts on infrastructure, shipping and contractors, and to ensure that the development of its gas resources occurs at a sustainable rate. Work continues with the Qatar authorities on the appropriate timing of the project to meet the objectives of Qatar and ConocoPhillips.

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

Iraq
We have the right to cooperate with LUKOIL to obtain the Iraqi government's confirmation of LUKOIL's rights under its production sharing agreement (PSA) relating to the West Qurna field. Subject to obtaining such confirmation and the consents of governmental authorities and the parties to the contract, we have the right 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 12,900 barrels of oil per day in 2005, compared with 13,300 barrels per day in 2004, and is included in equity affiliate production.

NMNG
On June 30, 2005, ConocoPhillips and LUKOIL created the OOO Naryanmarneftegaz (NMNG) joint venture to develop resources in the northern part of Russia's Timan-Pechora province. We have a 30 percent ownership interest with a 50 percent governance interest in the joint venture. We use the equity method of accounting for this joint venture. We are working with LUKOIL to finalize the development plan for the Yuzhno Khylchuyu (YK) field, award major contracts and start construction, with a target of starting up the field in late 2007.

Production from the NMNG joint-venture fields is transported via pipeline to LUKOIL's existing terminal at Varandey Bay on the Barents Sea and then shipped via tanker to international markets. LUKOIL intends to complete an expansion of the terminal's capacity in late 2007 to accommodate production from the YK field, with ConocoPhillips participating in the design and financing of the terminal expansion.

Other
In late 2004, we signed a Memorandum of Understanding with Gazprom to undertake a joint study on the development of the Shtokman natural gas field in the Barents Sea. In September 2005, we were notified that we were included on the "short list" of candidates to participate in the Shtokman LNG project. We are currently engaged in a joint feasibility study with Gazprom and the other candidates. Gazprom has indicated they will make their final partner selection in the March/April 2006 time frame.

Caspian Sea
In the North Caspian Sea, we have a 9.26 percent interest in the Republic of Kazakhstan's North Caspian Sea Production Sharing Agreement (NCSPSA), which includes the Kashagan field. In March 2005, agreement was reached with the Republic of Kazakhstan to conclude the sale of BG International's interest in the NCSPSA to several of the remaining partners and for the subsequent sale of one-half of the acquired interests to KazMunayGas. This agreement increased our ownership interest from 8.33 percent to 9.26 percent.

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. The first phase of field development currently being executed includes the construction of three artificial drilling islands for more than 60 wells, barges with processing facilities and living quarters, and pipelines to carry products onshore to oil, gas and sulphur plants. The initial production phase of the contract is for 20 years, with options to extend the agreement an additional 20 years.

Transportation
We have a 2.5 percent interest in the Baku-Tbilisi-Ceyhan (BTC) pipeline. This 1,760 kilometer pipeline will transport crude oil from the Caspian region through Azerbaijan, Georgia and Turkey, for tanker loadings at the Mediterranean port of Ceyhan. The BTC pipeline is expected to be operational by mid-2006.

Exploration
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. The Aktote prospect and the Kashagan Southwest prospect were announced as discoveries in 2003, and in 2004, the Kairan prospect was announced as a discovery. With the successful test on Kairan, the Exploration Period under the NCSPSA came to a close.

In 2005, appraisal of these discoveries continued. An appraisal well was drilled on Kalamkas More, and 3D seismic operations were carried out on the Kairan and Aktote prospects during 2005.

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. In 2005, we executed an option to secure 0.3 billion cubic feet per day of capacity in a subsequent expansion of the facility, which is subject to certain regulatory approvals and commercial decisions to proceed.

We are pursuing three other proposed U.S. 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 is in various stages of the regulatory permitting process.

During 2005, we signed a Memorandum of Understanding with Essent Energie B.V. to study the feasibility of developing an LNG import terminal in the Netherlands. The companies identified a potential project site at the Port of Eemshaven, and completed the feasibility study, which resulted in a recommendation to proceed to the next phase of more detailed engineering. A final investment decision could be made as early as 2007, subject to the economic outlook and the receipt of the necessary permits. If the outcome of these procedures is positive, the operation of the terminal could start in 2010.

During 2005, we, along with the other Norsea Pipeline Limited shareholders, made an application to obtain planning permission for an LNG regasification facility and combined heat and power plant at the Norsea Pipeline Limited existing oil terminal site at Teesside, United Kingdom. The planning permission process is expected to be complete by mid-2007.

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 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 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.

Burlington Resources Acquisition
On the evening of December 12, 2005, ConocoPhillips and Burlington Resources Inc. announced they had signed a definitive agreement under which ConocoPhillips would acquire Burlington Resources Inc. The transaction has a preliminary value of $33.9 billion. This transaction is expected to close on March 31, 2006, subject to approval by Burlington Resources shareholders at a special meeting set for March 30, 2006.

Under the terms of the agreement, Burlington Resources shareholders will receive $46.50 in cash and 0.7214 shares of ConocoPhillips common stock for each Burlington Resources share they own. This represents a transaction value of $92 per share, based on the closing of ConocoPhillips shares on Friday, December 9, 2005, the last unaffected day of trading prior to the announcement.

Burlington Resources is an independent exploration and production company, and holds a substantial position in North American natural gas reserves and production. At year-end 2004, as reported in its Annual Report on Form 10-K, Burlington Resources had proved worldwide natural gas reserves of 8,226 billion cubic feet, including 5,076 billion cubic feet in the United States and 2,330 billion cubic feet in Canada. Worldwide, Burlington Resources had 630 million barrels of crude oil and natural gas liquids combined, with 483 million barrels in the United States and 72 million barrels in Canada. During 2004, Burlington Resources' worldwide net natural gas production averaged 1,914 million cubic feet per day, while its net liquids production averaged 151,000 barrels per day.

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, 2005. No difference exists between our estimated total proved reserves for year-end 2004 and year-end 2003, which are shown in this filing, and estimates of these reserves shown in a filing with another federal agency in 2005.

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 278 million barrels of crude oil in the future, including 0.9 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, Canada, 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 our natural gas delivery commitment relates to proved undeveloped reserves in Indonesia, a portion of which 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

At December 31, 2005, our Midstream segment represented 2 percent of ConocoPhillips' total assets, while contributing 5 percent of net income.

Our Midstream business is primarily conducted through our 50 percent equity investment in Duke Energy Field Services, LLC (DEFS). In July 2005, ConocoPhillips and Duke Energy Corporation (Duke) restructured their respective ownership levels in DEFS, which resulted in DEFS becoming a jointly controlled venture, owned 50 percent by each company. This restructuring increased our ownership in DEFS to 50 percent, from 30.3 percent, through a series of direct and indirect transfers of certain Canadian Midstream assets from DEFS to Duke, a disproportionate cash distribution from DEFS to Duke from the sale of DEFS' interest in TEPPCO, and a combined payment by ConocoPhillips to Duke and DEFS of approximately $840 million. The Empress plant in Canada was not included in the initial transaction as originally anticipated due to weather-related damage. However, the Empress plant was sold to Duke on August 1, 2005, for approximately $230 million.

The Midstream business purchases raw natural gas from producers and gathers 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 2005, including our share of DEFS', was 195,000 barrels per day, compared with 194,000 barrels per day in 2004.

DEFS markets a portion of its natural gas liquids to ConocoPhillips and Chevron Phillips Chemical Company LLC (a joint venture between ConocoPhillips and Chevron Corporation) 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, 2005, DEFS owned or operated 54 natural gas liquids extraction plants, 11 natural gas liquids fractionation plants, and its gathering and transmission systems included approximately 56,000 miles of pipeline. In 2005, DEFS' raw natural gas throughput averaged 5.9 billion cubic feet per day, and natural gas liquids extraction averaged 353,000 barrels per day, compared with 5.9 billion cubic feet per day and 356,000 barrels per day, respectively, in 2004 (2004 amounts were restated to reflect discontinued operations within DEFS). DEFS' assets are primarily located in the Gulf Coast area, West Texas, Oklahoma, the Texas Panhandle, and the Rocky Mountain area.

Outside of DEFS, our U.S. natural gas liquids business included the following assets as of December 31, 2005:

- 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 in Texas and Louisiana.
- 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).

We also own a 39 percent equity interest in Phoenix Park Gas Processors Limited (Phoenix Park), a joint venture primarily with the National Gas Company of Trinidad and Tobago Limited. Phoenix Park processes gas in Trinidad and markets natural gas liquids throughout the Caribbean and into the U.S. Gulf Coast. Its facilities include a 1.35-billion-cubic-feet-per-day gas processing plant and a natural gas liquids fractionator that was expanded from 46,000 to 70,000 barrels per day in the fourth quarter of 2005. Our share of natural gas liquids extracted averaged 6,100 barrels per day in 2005, the same as in 2004.

In Syria, operations were transferred to the Syrian Gas Company at the end of the service contract on December 31, 2005. Final administrative requirements associated with closing out the service contract will be undertaken during the first half of 2006. We have no plans to make additional investments in operations in Syria.

REFINING AND MARKETING (R&M)

At December 31, 2005, our R&M segment represented 29 percent of ConocoPhillips' total assets, while contributing 31 percent of net income.

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). Accordingly, 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 procures feedstocks for R&M's refineries, facilitates supplying a portion of the gas and power needs of the R&M facilities, and supplies petroleum products to our marketing operations. Commercial has buyers, traders and marketers in offices in Houston, London, Singapore and Calgary.

We are planning to spend $4 billion to $5 billion over the period 2006 through 2011 to increase our U.S. refining system's ability to process heavy-sour crude oil and other lower-quality feedstocks. These investments are expected to incrementally increase refining capacity and clean products yield at our existing facilities, while providing competitive returns.

UNITED STATES

Refining

At December 31, 2005, we owned and operated 12 crude oil refineries in the United States, having an aggregate crude oil throughput capacity of 2,182,000 barrels per day.

				Crude Throughput Capacity (MB/D)	
Refinery	Location		Region	At December 31 2005	Effective January 1 2006
Bayway	Linden	New Jersey	East Coast	238	238
Trainer	Trainer	Pennsylvania	East Coast	185	185
				423	423
Alliance	Belle Chase	Louisiana	Gulf Coast	247	247
Lake Charles	Westlake	Louisiana	Gulf Coast	239	239
Sweeny	Old Ocean	Texas	Gulf Coast	229	247
				715	733
Wood River	Roxana	Illinois	Central	306	306
Ponca City	Ponca City	Oklahoma	Central	187	187
Borger	Borger	Texas	Central	146	146
				639	639
Billings	Billings	Montana	West Coast	58	58
Los Angeles	Carson/Wilmington	California	West Coast	139	139
San Francisco	Santa Maria/Rodeo	California	West Coast	115	120
Ferndale	Ferndale	Washington	West Coast	93	96
				405	413
				2,182	2,208

East Coast Region

Bayway Refinery

The Bayway refinery is located on the New York Harbor in Linden, New Jersey. The refinery has a crude oil processing capacity of 238,000 barrels per day, and processes mainly light low-sulfur crude oil. Crude oil is supplied to the refinery by tanker, primarily from the North Sea, Canada 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.

Trainer Refinery

The Trainer refinery is located on the Delaware River in Trainer, Pennsylvania. The refinery has a crude oil processing capacity of 185,000 barrels per day, and processes mainly light low-sulfur crude oil. 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 is located on the Mississippi River in Belle Chasse, Louisiana. The refinery has a crude oil processing capacity of 247,000 barrels per day, and processes mainly light low-sulfur crude oil. Alliance receives domestic crude oil from the Gulf of Mexico via pipeline, and foreign 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.

The Alliance refinery was shutdown in anticipation of Hurricane Katrina in late-August 2005, then remained shut down as a result of flooding and damages sustained during the hurricane. Removal of water from the site was completed by October, and repair work began. The refinery began partial operation in late-January 2006, and is expected to return to full operations around the end of the first quarter of 2006.

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, and processes mainly heavy, high-sulfur, low-sulfur and acidic crude oil. The refinery receives domestic and foreign crude oil, with a majority of its foreign crude oil being heavy Venezuelan and Mexican crude oil 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. Construction of an S Zorb™ Sulfur Removal Technology unit to produce low-sulfur gasoline was completed and began operation in late 2005.

The Lake Charles facilities include a specialty coker and calciner that manufacture graphite petroleum coke, which is supplied to the steel industry. 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 and Penreco, joint ventures that are part of our Specialty Businesses function within R&M.

The Lake Charles refinery was shutdown in anticipation of Hurricane Rita in September 2005, resumed operations in mid-October, and returned to full operations in November.

Sweeny Refinery
The Sweeny refinery is located in Old Ocean, Texas. Effective January 1, 2005, the crude oil processing capacity was increased by 13,000 barrels per day, and effective January 1, 2006, it was further increased by 18,000 barrels per day. Both increases were a result of incremental debottlenecking. As a result, the refinery's current crude oil processing capacity is 247,000 barrels per day. The refinery 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.

The Sweeny refinery was shutdown in anticipation of Hurricane Rita in September 2005, and resumed operations by October.

<u>Central Region</u>
Wood River Refinery
The Wood River refinery is located on the east side of the Mississippi River in Roxana, Illinois. It is R&M's largest refinery, with a crude oil processing capacity of 306,000 barrels per day. The refinery processes a mix of both light low-sulfur and heavy high-sulfur crude oil. The refinery receives domestic and foreign crude oil by various pipelines. The refinery produces a high percentage of transportation fuels, such as gasoline, diesel and jet fuel. Other products include petrochemical feedstocks (benzene and propylene) and asphalt. Through an off-take agreement, a significant portion of its gasoline and diesel is sold to a third party for delivery via pipelines into the upper Midwest, including the Chicago, Illinois, and Milwaukee, Wisconsin, metropolitan areas. The remaining refined products are distributed to customers in the Midwest by pipeline, truck, barge and railcar.

In November 2005, we announced plans to install our proprietary S Zorb™ Sulfur Removal Technology (SRT) at the refinery. The new 32,000-barrel-per-day S Zorb SRT unit is targeted for completion in early 2007.

Ponca City Refinery
The Ponca City refinery is located in Ponca City, Oklahoma. The refinery 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 crude oil are delivered by pipeline from the Gulf of Mexico, Oklahoma, Kansas, Texas and Canada. The refinery produces 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, and the complex includes a natural gas liquids fractionation facility. The crude oil processing capacity of the refinery is 146,000 barrels per day, and the natural gas liquids fractionation capacity is 45,000 barrels per day. The refinery processes mainly light-sour and medium-sour crude oil. It 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 company-owned 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, Colorado, and the Midcontinent region.

During 2005, construction began on a 25,000-barrel-per-day coker at the Borger refinery, with an estimated completion date in the second quarter of 2007. This project will allow the refinery to comply with clean fuel regulations for ultra-low-sulfur diesel and low-sulfur gasoline, as well as comply with required reductions of sulfur dioxide emissions. Additional project benefits include improved operating performance by adding additional upgrading capability, improved utilization, and capability to process heavy Canadian crude oil.

<u>West Coast Region</u>

Billings Refinery
The Billings refinery is located in Billings, Montana. The refinery has a crude oil processing capacity of 58,000 barrels per day, and processes a mixture of Canadian heavy, high-sulfur crude, plus domestic high-sulfur and low-sulfur crude oil, 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. 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 crude oil. The refinery receives domestic crude oil via pipeline from California, and both foreign and domestic crude oil by tanker through a third-party terminal in the Port of Long Beach. 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.

In late 2005, we entered into an agreement to utilize a proposed facility to provide waterborne crude oil receipt capacity in the Los Angeles harbor. This facility, which is expected to be operational in late 2007 or 2008, will allow the refinery to increase its proportion of waterborne crude oil versus California crude oil and accept crude oil from very large tankers.

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. Effective April 1, 2005, the refinery's crude oil processing capacity was increased by 9,000 barrels per day as a result of a project implementation related to clean fuels, and effective January 1, 2006, it was further increased by 5,000 barrels per day due to incremental debottlenecking. As a result, the refinery's current crude oil processing capacity is 120,000 barrels per day. The refinery processes mainly heavy, high-sulfur crude oil. 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, and both foreign and domestic crude oil by tanker. Semi-refined liquid products from the Santa Maria facility are sent by pipeline to the Rodeo facility for upgrading into 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 is located on Puget Sound in Ferndale, Washington. Effective January 1, 2006, the refinery's crude oil processing capacity was increased by 3,000 barrels per day as a result of incremental debottlenecking. As a result, the refinery's current crude oil processing capacity is 96,000 barrels per day. The refinery primarily receives crude oil from the Alaskan North Slope, with secondary sources supplied from 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. 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 11,800 outlets in 49 states. The majority of these sites utilize the Conoco, Phillips 66 or 76 brands.

<u>Wholesale</u>
In our wholesale operations, we utilize a network of marketers and dealers operating approximately 10,800 outlets. We place a strong emphasis on the wholesale channel of trade because of its lower capital requirements. 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.

<u>Retail</u>
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, Breakplace, or Circle K brand convenience stores.

At December 31, 2005, CFJ Properties, our 50/50 joint venture with Flying J, owned and operated 100 truck travel plazas that carry the Conoco and/or Flying J brands.

Transportation

<u>Pipelines and Terminals</u>
At December 31, 2005, we had approximately 29,000 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.

In November 2005, we entered into a Memorandum of Understanding which commits us to ship crude oil on the proposed Keystone oil pipeline, and gives us the right to acquire up to a 50 percent ownership interest in the pipeline, subject to certain conditions being met. The Keystone pipeline is intended to transport approximately 435,000 barrels per day of crude oil from Hardisty, Alberta, to Patoka, Illinois, through a 1,840-mile pipeline system. In addition to approximately 1,100 miles of new pipeline in the United States, the Canadian portion of the proposed project includes the construction of approximately 220 miles of new pipeline and the conversion of approximately 540 miles of existing pipeline facilities from natural gas to crude oil transmission. The Keystone pipeline, upon receipt of the necessary shipper support and appropriate regulatory approvals in Canada and the United States, is expected to be in service in 2009. We expect to utilize the Keystone pipeline to integrate our upstream assets in Canada with our Wood River refinery in Illinois.

Tankers
At December 31, 2005, we had under charter 15 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, 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. During 2005, we sold our interest in Venco, a coke calcining joint venture in which we had a 50 percent interest.

INTERNATIONAL

Refining

At December 31, 2005, 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.

				Crude Throughput Capacity (MB/D)	
Refinery	Location		Ownership Interest	At December 31 2005	Effective January 1 2006
Humber	N. Lincolnshire	United Kingdom	100.00%	221	221
Whitegate	Cork	Ireland	100.00%	71	71
MiRO	Karlsruhe	Germany	18.75%	53	56
CRC	Litvinov/Kralupy	Czech Republic	16.33%	27	27
Melaka	Melaka	Malaysia	47.00%	56	58
				428	433

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 crude oil. 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 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 Europe and the United States. We also operate a crude oil and products storage complex with a 7.5-million-barrel capacity, facilitated by an offshore mooring buoy, 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. Effective January 1, 2006, the refinery's capacity was increased by 14,000 barrels per day, with our share being an increase of 3,000 barrels per day, due to incremental debottlenecking. 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 Ceská rafinérská, a.s. (CRC), we have a 16.33 percent ownership in two refineries in the Czech Republic, giving us a net capacity share of 27,000 barrels per day. 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 produces a high yield of transport fuels and petrochemical feedstocks, and 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. The Kralupy refinery has a high yield of transportation 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. Effective January 1, 2006, the refinery's capacity was increased by 4,000 barrels per day, with our share being an increase of 2,000 barrels per day, due to incremental debottlenecking. Crude oil processed by the refinery is sourced mostly from the Middle East. The refinery produces a full range of refined petroleum products. The refinery capitalizes on our proprietary coking technology to upgrade low-cost feedstocks to higher-margin products. Our share of refined products is distributed by truck to "ProJET" retail sites in Malaysia, or transported by sea, primarily to Asian markets.

Refinery Acquisition
In November 2005, we executed a definitive agreement for the cash purchase of the Wilhelmshaven refinery in Wilhelmshaven, Germany. The purchase includes the 275,000-barrel-per-day refinery, a marine terminal, rail and truck loading facilities and a tank farm, as well as another entity that provides commercial and administrative support to the refinery. The purchase is expected to be completed during the first quarter of 2006, subject to satisfaction of closing conditions, including obtaining the necessary governmental approvals and regulatory permits. The acquisition is expected to provide a foundation for strengthening the company's ability to supply products to key export markets.

Our current plans include a deep conversion project for the refinery, moving it from a low-complexity facility to a high-complexity facility. This proposed project would allow the refinery to run a more advantaged crude slate, including Russian-export blends, while increasing overall conversion and reducing operating costs.

The addition of the Wilhelmshaven refinery would increase our overall European refining capacity by approximately 74 percent, from 372,000 barrels per day at year-end 2005 to 647,000 barrels per day.

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, low-price, high-volume 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, a joint venture, in which we have an equity interest, markets products in Switzerland under the "Coop" brand name. During 2005, we sold our equity interest in a joint venture that marketed products in Turkey. We also sell a portion of our Ireland refinery output to inland Irish markets.

As of December 31, 2005, R&M had approximately 2,110 marketing outlets in its European operations, of which approximately 1,530 were company-owned, and 580 were dealer-owned. Through our joint-venture operations in Switzerland, we also have interests in 168 additional sites. The company's largest branded site networks are in Germany and the United Kingdom, which account for approximately 60 percent of our total European branded units.

As of December 31, 2005, R&M had 145 marketing outlets in our wholly owned Thailand operations in Asia. In addition, through a joint venture in Malaysia, 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. We are currently in the process of transitioning our Malaysian retail business from mostly company-operated sites to dealer-operated sites, and the fuel will still be branded "ProJET."

LUKOIL INVESTMENT

At December 31, 2005, our LUKOIL Investment segment represented 5 percent of ConocoPhillips' total assets, while contributing 5 percent of net income.

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.

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, and by year-end 2005, we had increased our ownership to 16.1 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. 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, 2005, was 1,442 million BOE.

As reported in LUKOIL's 2004 annual report, the majority of its 2004 upstream oil production was sourced within Russia, with 65 percent from the western Siberia region, 14 percent from the Timan-Pechora region and 12 percent from the Urals region. Outside of Russia, LUKOIL has oil production in Kazakhstan and Egypt, and has exploratory or other projects under way in Kazakhstan, Colombia, Azerbaijan, Uzbekistan, Iran, Saudi Arabia and Iraq. Downstream, LUKOIL has eight refineries with a net crude oil throughput capacity of approximately 1.2 million barrels per day. 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

At December 31, 2005, our Chemicals segment represented 2 percent of ConocoPhillips' total assets, while contributing 2 percent of net income.

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

CPChem's business is structured around three primary operating segments: Olefins & Polyolefins, Aromatics & Styrenics, and Specialty Products. The Olefins & Polyolefins segment produces and markets ethylene, propylene, and other olefin products, which are primarily consumed within CPChem for the production of polyethylene, normal alpha olefins (NAO), polypropylene, and polyethylene pipe. The Aromatics & Styrenics segment manufactures and markets aromatics products, such as benzene, styrene, paraxylene and cyclohexane. This segment also manufactures and markets polystyrene, as well as styrene-butadiene copolymers. The Specialty Products segment manufactures and markets a variety of specialty chemical products, including organosulfur chemicals, solvents, catalysts, drilling chemicals, mining chemicals and high-performance polyphenylene sulfide polymers and compounds.

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 production plant and eight plastic pipe production 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 production 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," was completed in 2003. CPChem has signed an agreement for the development of a second complex to be built in Mesaieed, called "Q-Chem II." The facility will be designed to produce polyethylene and normal alpha olefins, on a site adjacent to the Q-Chem complex. In connection with this project, CPChem and Qatar Petroleum entered into a separate agreement with Total Petrochemicals and Qatar Petrochemical Company Ltd., establishing a joint venture to develop an ethylene cracker in Ras Laffan Industrial City, Qatar. The cracker will provide ethylene feedstock via pipeline to the planned polyethylene and normal alpha olefins plants. Construction began in late 2005, with operational startup of both projects anticipated in late 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, which began in the fourth quarter of 2004, is in conjunction with an expansion of SCP's benzene plant, together called the "JCP Project." Operational startup is anticipated in late 2007.

EMERGING BUSINESSES

At December 31, 2005, our Emerging Businesses segment represented 1 percent of ConocoPhillips' total assets.

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 for two years through early 2005. Sufficient data was collected to enable further technology and design modifications to be tested on a pilot plant scale in 2005 and 2006.

Technology Solutions
Our Technology Solutions businesses develop 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™, IMP™, SOFT™), 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 to support the company's E&P and R&M strategies and business objectives. The projects that are primarily in place to 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.

Immingham CHP, a 730-megawatt, gas-fired combined heat and power plant in North Lincolnshire, United Kingdom, was placed in commercial operations in October 2004. 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. Development work on Immingham Phase 2 began with the award of a contract for front-end engineering and securing of additional connection availability to the U.K. grid. The final decision to proceed with Phase 2 will be made later in 2006.

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 19, 2005, issue of the *Oil & Gas Journal*, our E&P segment had, on a BOE basis, the eighth-largest total of worldwide proved 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' principal 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 19, 2005, issue of the *Oil & Gas Journal*, our R&M segment had the second-largest U.S. refining capacity of 13 large refiners of petroleum products, after giving consideration to the recent merger of Valero Energy Corporation and Premcor Inc. Worldwide, it ranked sixth 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 2005 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 2005, we held a total of 1,804 active patents in 70 countries worldwide, including 732 active U.S. patents. During 2005, we received 55 patents in the United States and 148 foreign patents. Our products and processes generated licensing revenues of $42 million in 2005. 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 $125 million, $126 million and $136 million in 2005, 2004 and 2003, respectively.

The environmental information contained in Management's Discussion and Analysis of Financial Condition and Results of Operations on pages 85 through 88 under the caption, "Environmental," is incorporated herein by reference. It includes information on expensed and capitalized environmental costs for 2005 and those expected for 2006 and 2007.

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 Web site at *http://www.sec.gov.*

Item 1A. RISK FACTORS

You should carefully consider the following risk factors in addition to the other information included in this Annual Report on Form 10-K. Each of these risk factors could adversely affect our business, operating results and financial condition, as well as adversely affect the value of an investment in our common stock.

A substantial or extended decline in crude oil, natural gas and natural gas liquids prices, as well as refining margins, would reduce our operating results and cash flows, and could impact our future rate of growth and the carrying value of our assets.

Prices for crude oil, natural gas and natural gas liquids fluctuate widely. Our revenues, operating results and future rate of growth are highly dependent on the prices we receive for our crude oil, natural gas, natural gas liquids and refined products. Historically, the markets for crude oil, natural gas, natural gas liquids and refined products have been volatile and may continue to be volatile in the future. Many of the factors influencing the prices of crude oil, natural gas, natural gas liquids and refined products are beyond our control. These factors include, among others:

- Worldwide and domestic supplies of, and demand for, crude oil, natural gas, natural gas liquids and refined products.
- The cost of exploring for, developing, producing, refining and marketing crude oil, natural gas, natural gas liquids and refined products.
- Changes in weather patterns and climatic changes.
- The ability of the members of OPEC and other producing nations to agree to and maintain production levels.
- The worldwide military and political environment, uncertainty or instability resulting from an escalation or additional outbreak of armed hostilities or further acts of terrorism in the United States, or elsewhere.
- The price and availability of alternative and competing fuels.
- Domestic and foreign governmental regulations and taxes.
- General economic conditions worldwide.

The long-term effects of these and other conditions on the prices of crude oil, natural gas, natural gas liquids and refined products are uncertain. Generally, our policy is to remain exposed to market prices of commodities; however, management may elect to hedge the price risk of our crude oil, natural gas, natural gas liquids and refined products.

Lower crude oil, natural gas, natural gas liquids and refined products prices may reduce the amount of these commodities that we can produce economically, which may reduce our revenues, operating income and cash flows. Significant reductions in commodity prices could require us to reduce our capital expenditures and impair the carrying value of our assets.

Estimates of crude oil and natural gas reserves depend on many factors and assumptions, including various assumptions that are based on conditions in existence as of the dates of the estimates. Any material changes in those conditions or other factors affecting those assumptions could impair the quantity and value of our crude oil and natural gas reserves.

The proved crude oil and natural gas reserve information relating to us included in this annual report has been derived from engineering estimates prepared by our personnel. The estimates were calculated using crude oil and natural gas prices in effect as of December 31, 2005, as well as other conditions in existence as of that date. Any significant future price changes will have a material effect on the quantity and present value of our proved reserves. Future reserve revisions could also result from changes in, among other things, governmental regulation.

Reserve estimation is a subjective process that involves estimating volumes to be recovered from underground accumulations of crude oil and natural gas that cannot be directly measured. Estimates of economically recoverable crude oil and natural gas reserves and of future net cash flows depend upon a number of variable factors and assumptions, including:

- Historical production from the area, compared with production from other comparable producing areas.
- The assumed effects of regulations by governmental agencies.
- Assumptions concerning future crude oil and natural gas prices.
- Assumptions concerning future operating costs, severance and excise taxes, development costs and workover and remedial costs.

As a result, different petroleum engineers, each using industry-accepted geologic and engineering practices and scientific methods, may produce different estimates of reserves and future net cash flows based on the same available data. Because of the subjective nature of crude oil and natural gas reserve estimates, each of the following items may differ materially from the amounts or other factors estimated:

- The amount and timing of crude oil and natural gas production.
- The revenues and costs associated with that production.
- The amount and timing of future development expenditures.

The discounted future net revenues from our reserves should not be considered as the market value of the reserves attributable to our properties. As required by rules adopted by the SEC, the estimated discounted future net cash flows from our proved reserves, as described in the supplemental oil and gas operations disclosures on pages 183 through 185, are based generally on prices and costs as of the date of the estimate, while actual future prices and costs may be materially higher or lower.

In addition, the 10 percent discount factor, which SEC rules require to be used to calculate discounted future net revenues for reporting purposes, is not necessarily the most appropriate discount factor based on our cost of capital and the risks associated with our business and the crude oil and natural gas industry in general.

If we are unsuccessful in acquiring or finding additional reserves, our future crude oil and natural gas production would decline, thereby reducing our cash flows and results of operations, negatively impacting our financial condition.

The rate of production from crude oil and natural gas properties generally declines as reserves are depleted. Except to the extent that we acquire additional properties containing proved reserves, conduct successful exploration and development activities, or, through engineering studies, identify additional or secondary recovery reserves, our proved reserves will decline materially as we produce crude oil and natural gas. Accordingly, to the extent that we are not successful in replacing the crude oil and natural gas we produce

with good prospects for future production, our business will decline. Creating and maintaining an inventory of projects depends on many factors, including:

- Obtaining rights to explore, develop and produce crude oil and natural gas in promising areas.
- Drilling success.
- The ability to complete long lead-time, capital-intensive projects timely and on budget.
- Efficient and profitable operation of mature properties.

We may not be able to find or acquire additional reserves at acceptable costs.

Crude oil price increases and environmental regulations may reduce our refined product margins.

The profitability of our R&M segment depends largely on the margin between the cost of crude oil and other feedstocks we refine and the selling prices we obtain for refined products. Our overall profitability could be adversely affected by the availability of supply and rising crude oil and other feedstock prices that we do not recover in the marketplace. Refined product margins historically have been volatile and vary with the level of economic activity in the various marketing areas, the regulatory climate, logistical capabilities and the available supply of refined products.

In addition, environmental regulations, particularly the 1990 amendments to the Clean Air Act, have imposed, and are expected to continue to impose, increasingly stringent and costly requirements on our refining and marketing operations, which may reduce refined product margins.

We will continue to incur substantial capital expenditures and operating costs as a result of compliance with, and changes in, environmental laws and regulations, and, as a result, our profitability could be materially reduced.

Our businesses are subject to numerous laws and regulations relating to the protection of the environment. These laws and regulations continue to increase in both number and complexity and affect our operations with respect to, among other things:

- The discharge of pollutants into the environment.
- The handling, use, storage, transportation, disposal and clean-up of hazardous materials and hazardous and non-hazardous wastes.
- The dismantlement, abandonment and restoration of our properties and facilities at the end of their useful lives.

We have incurred and will continue to incur substantial capital, operating and maintenance, and remediation expenditures as a result of these laws and regulations. To the extent these expenditures, as with all costs, are not ultimately reflected in the prices of our products and services, our operating results will be adversely affected. The specific impact of these laws and regulations on us and our competitors may vary depending on a number of factors, including the age and location of operating facilities, marketing areas and production processes. We may also be required to make material expenditures to:

- Modify operations.
- Install pollution control equipment.
- Perform site cleanups.

- Curtail operations.

We may become subject to liabilities that we currently do not anticipate in connection with new, amended or more stringent requirements, stricter interpretations of existing requirements or the future discovery of contamination. In addition, any failure by us to comply with existing or future laws could result in civil or criminal fines and other enforcement actions against us.

Our, and our predecessors’, operations also could expose us to civil claims by third parties for alleged liability resulting from contamination of the environment or personal injuries caused by releases of hazardous substances.

Environmental laws are subject to frequent change and many of them have become more stringent. In some cases, they can impose liability for the entire cost of cleanup on any responsible party, without regard to negligence or fault, and impose liability on us for the conduct of others or conditions others have caused, or for our acts that complied with all applicable requirements when we performed them.

Please read “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Contingencies—Environmental” in Item 7 of this annual report.

Worldwide political and economic developments could damage our operations and materially reduce our profitability and cash flows.

Local political and economic factors in international markets could have a material adverse effect on us. Approximately 65 percent of our crude oil, natural gas and natural gas liquids production in 2005 was derived from production outside the United States, and 66 percent of our proved reserves, as of December 31, 2005, were located outside the United States.

There are many risks associated with operations in international markets, including changes in foreign governmental policies relating to crude oil, natural gas, natural gas liquids or refined product pricing and taxation, other political, economic or diplomatic developments, changing political conditions and international monetary fluctuations. These risks include, among others:

- Political and economic instability, war, acts of terrorism and civil disturbances.
- The possibility that a foreign government may seize our property, with or without compensation, may attempt to renegotiate or revoke existing contractual arrangements and concessions, or may impose additional taxes or royalties.
- Fluctuating currency values, hard currency shortages and currency controls.

Continued hostilities and turmoil in the world and the occurrence or threat of future terrorist attacks could affect the economies of the United States and other developed countries. A lower level of economic activity could result in a decline in energy consumption, which could cause our revenues and margins to decline and limit our future growth prospects. More specifically, our energy-related assets may be at greater risk of future terrorist attacks than other possible targets. A direct attack on our assets, or assets used by us, could have a material adverse effect on our operations, financial condition, results of operations and prospects. These risks could lead to increased volatility in prices for crude oil, natural gas, natural gas liquids and refined products and could increase instability in the financial and insurance markets, making it more difficult for us to access capital and to obtain the insurance coverage that we consider adequate.

Actions of the U.S. government through tax and other legislation, executive order and commercial restrictions could reduce our operating profitability both in the United States and abroad. The U.S. government can prevent or restrict us from doing business in foreign countries. These restrictions and those of foreign governments have in the past limited our ability to operate in, or gain access to, opportunities in various countries. Actions by both the United States and host governments have affected operations significantly in the past and will continue to do so in the future.

We also are exposed to fluctuations in foreign currency exchange rates. We do not comprehensively hedge our exposure to currency rate changes, although we may choose to selectively hedge certain working capital balances, firm commitments, cash returns from affiliates and/or tax payments. These efforts may not be successful.

Changes in governmental regulations may impose price controls and limitations on production of crude oil and natural gas.

Our operations are subject to extensive governmental regulations. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of crude oil and natural gas wells below actual production capacity in order to conserve supplies of crude oil and natural gas. Because legal requirements are frequently changed and subject to interpretation, we cannot predict the effect of these requirements.

Our operations are subject to business interruptions and casualty losses, and we do not insure against all potential losses, so we could be seriously harmed by unexpected liabilities.

Our exploration and production operations are subject to unplanned occurrences, including blowouts, explosions, fires, loss of well control, formations with abnormal pressures, spills and adverse weather. In addition, our refining, marketing and transportation operations are subject to business interruptions due to scheduled refinery turnarounds and unplanned events such as explosions, fires, pipeline interruptions, pipeline ruptures, crude oil or refined product spills, inclement weather or labor disputes. Our operations are also subject to the additional hazards of pollution, releases of toxic gas and other environmental hazards and risks, as well as hazards of marine operations, such as capsizing, collision and damage or loss from severe weather conditions. All such hazards could result in loss of human life, significant property and equipment damage, environmental pollution, impairment of operations and substantial losses to us. These hazards have adversely affected us in the past, and litigation arising from a catastrophic occurrence in the future at one of our locations may result in our being named as a defendant in lawsuits asserting potentially large claims or being assessed potentially substantial fines by governmental authorities. In addition, we are exposed to risks inherent in any business, such as terrorist attacks, equipment failures, accidents, theft, strikes, protests and sabotage, that could disrupt or interrupt operations.

We maintain insurance against many, but not all, potential losses or liabilities arising from these operating hazards in amounts that we believe to be prudent. Uninsured losses and liabilities arising from operating hazards could reduce the funds available to us for exploration, drilling, production and other capital expenditures and could materially reduce our profitability.

Our investments in joint ventures decrease our ability to manage risk.

We conduct many of our operations through joint ventures in which we may share control with our joint-venture partners. As with any joint-venture arrangement, differences in views among the joint-venture participants may result in delayed decisions or in failures to agree on major issues. There is the risk that our joint-venture partners may at any time have economic, business or legal interests or goals that are

inconsistent with those of the joint venture or us. There is also risk that our joint-venture partners may be unable to meet their economic or other obligations and that we may be required to fulfill those obligations alone. Failure by us, or an entity in which we have a joint-venture interest, to adequately manage the risks associated with any acquisitions or joint ventures could have a material adverse effect on the financial condition or results of operations of our joint ventures and, in turn, our business and operations.

We anticipate entering into additional joint ventures with other entities. We cannot assure that we will undertake such joint ventures or, if undertaken, that such joint ventures will be successful.

We may not be successful in continuing to grow through acquisitions, and any further acquisitions may require us to obtain additional financing or could result in dilution of earnings per share.

A substantial portion of our growth over the last several years has been attributable to acquisitions. Risks associated with acquisitions include those relating to:

- Diversion of management time and attention from our existing businesses and other priorities.

- Difficulties in integrating the financial, technological and management standards, processes, procedures and controls of an acquired business into those of our existing operations.
- Liability for known or unknown environmental conditions or other contingent liabilities not covered by indemnification or insurance.
- Greater than anticipated expenditures required for compliance with environmental or other regulatory standards, or for investments to improve operating results.
- Difficulties in achieving anticipated operational improvements.

We may not be successful in continuing to grow through acquisitions. In addition, the financing of future acquisitions may require us to incur additional indebtedness, which could limit our financial flexibility, or to issue additional equity, which could result in dilution of the ownership interests of existing stockholders. Any acquisitions that we do consummate may not produce the anticipated benefits or may have adverse effects on our business and operating results.

Our results of operations could be adversely affected by goodwill impairments.

As a result of mergers and acquisitions, at year-end 2005 we had approximately $15 billion of goodwill on our balance sheet. Goodwill is not amortized, but instead must be tested at least annually for impairment by applying a fair-value-based test. Goodwill is deemed impaired to the extent that its carrying amount exceeds the residual fair value of the reporting unit. Although our latest tests indicate that no goodwill impairment is currently required, future deterioration in market conditions could lead to goodwill impairments that could have a substantial negative affect on our profitability.

Item 1B. UNRESOLVED STAFF COMMENTS

None.

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 2005 and those matters previously reported in ConocoPhillips' 2004 Form 10-K and our first-, second- and third-quarter 2005 Form 10-Qs 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 2005, the Texas Commission on Environmental Quality (TCEQ) proposed an administrative penalty of $120,132 for alleged violations of the Texas Clean Air Act at the Borger refinery. The allegations relate to unexcused emission events, reporting and recordkeeping requirements, leak detection and repair, flare outages, and deviation reporting. We expect to work with the TCEQ to resolve this matter.

On October 19, 2005, the Bay Area Air Quality Management District (BAAQMD) notified us of their intent to seek civil penalties in the amount of $108,000 for 18 alleged violations of various BAAQMD regulations at our Rodeo facility and carbon plant located in the San Francisco area that occurred between February 2005 and July 2005. We are currently assessing these allegations and expect to work with the BAAQMD toward a resolution of this matter.

On October 11, 2005, the ConocoPhillips Pipe Line Company received a Notice of Probable Violation and Proposed Civil Penalty from the Department of Transportation's Pipeline and Hazardous Materials Safety Administration (DOT) alleging violation of DOT's Integrity Management Program and proposing penalties in the amount of $200,000. We responded to these allegations and expect to work with the DOT toward a resolution of this matter.

In July and August 2005, the South Coast Air Quality Management District (SCAQMD) performed inspections at our Los Angeles refinery in Wilmington and Carson, California, focusing on our leak detection and repair program for fugitive emissions as required under SCAQMD rules. The SCAQMD has informed us that they believe, as a result of these inspections, we violated certain rules related to the leak detection and repair program. We are currently working with the SCAQMD to resolve this matter.

In June 2005, the SCAQMD notified us of their intent to seek civil penalties in the amount of $401,000 for 18 alleged violations of various SCAQMD regulations at our Los Angeles refinery in Wilmington and Carson, California, and one of our tank facilities in Torrance, California. On October 27 and December 5, 2005, we entered into several settlements with the SCAQMD to resolve all the alleged violations. We paid a total civil penalty of $360,850 to the SCAQMD.

In March 2005, ConocoPhillips Pipe Line Company received a Notice of Probable Violation and Proposed Civil Penalty from DOT alleging violation of DOT operation and safety regulations at certain facilities in Kansas, Missouri, Illinois, Indiana, Wyoming and Nebraska and proposing penalties in the amount of $184,500. We are currently assessing these allegations and expect to work with the DOT toward a resolution of this matter.

From December 2004 to January 2005, the Rodeo facility experienced some exceedances of its wastewater daily-permitted-limit for copper under the National Pollutant Discharge Elimination System (NPDES) program, as administered by the San Francisco Bay Region Regional Water Quality Control Board (Water Board). The Rodeo facility self-reported the exceedances. In November 2005, we agreed with the Water Board staff to resolve these and other alleged NPDES exceedances for a civil penalty of $48,000 and supplemental environmental projects valued at $63,000. The Water Board finalized the settlement as proposed.

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 resolved this matter with the payment of civil penalties to the PSCAA in the amount of $46,000 and recognizing facility improvement credits in the amount of $115,000.

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 us, we do not believe that we are the source of the alleged spill. We are fully cooperating with the governmental authorities.

In August 2004, Polar Tankers 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 for records relating to the company's report of potential violations. We are fully cooperating with the governmental authorities.

In July 2004, Polar Tankers notified the U.S. Coast Guard of possible environmental violations onboard the vessel Polar Discovery. On June 29, 2005, the U.S. Attorney's office in Anchorage issued a subpoena to Polar Tankers for records regarding the possible environmental violations onboard that vessel. We are fully cooperating with the governmental authorities in their investigation.

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 17, 2002, the U.S. Department of Justice (DOJ) notified ConocoPhillips of various alleged violations of the NPDES permit for the Sweeny refinery. DOJ asserts that these alleged violations occurred at various times during the period from 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 matter has been resolved and the defendants, including ConocoPhillips, signed a Consent Decree and Settlement Agreement, which has been approved by the court.

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	50
William B. Berry	Executive Vice President, Exploration and Production	53
John A. Carrig	Executive Vice President, Finance, and Chief Financial Officer	54
Philip L. Frederickson	Executive Vice President, Commercial	49
Stephen F. Gates	Senior Vice President, Legal, and General Counsel	59
John E. Lowe	Executive Vice President, Planning, Strategy and Corporate Affairs	47
J. J. Mulva	Chairman, President and Chief Executive Officer	59
J. W. Nokes	Executive Vice President, Refining, Marketing, Supply and Transportation	59

**On March 1, 2006.*

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 10, 2006. 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.

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.

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 is traded on the New York Stock Exchange, under the symbol "COP."

	Stock Price*		
	High	Low	Dividends*
2005			
First	**$ 56.99**	**41.40**	**.25**
Second	**61.36**	**47.55**	**.31**
Third	**71.48**	**58.05**	**.31**
Fourth	**70.66**	**57.05**	**.31**
2004			
First	$ 35.75	32.15	.215
Second	39.50	34.29	.215
Third	42.18	35.64	.215
Fourth	45.61	40.75	.25

**The amounts in all periods reflect a two-for-one stock split effected as a 100 percent stock dividend on June 1, 2005.*

Closing Stock Price at December 31, 2005	$ 58.18
Closing Stock Price at January 31, 2006	$ 64.70
Number of Stockholders of Record at January 31, 2006*	56,562

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

Issuer Purchases of Equity Securities

				Millions of Dollars
Period	Total Number of Shares Purchased*	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs**	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs

October 1-31, 2005	6,404,478	$ 61.90	6,400,000	$ 439
November 1-30, 2005	5,591,488	65.02	5,590,000	1,076
December 1-31, 2005	7,667	60.73	—	1,076
Total	12,003,633	$ 63.35	11,990,000	

**Includes the repurchase of common shares from company employees in connection with the company's broad-based employee incentive plans.*

***On February 4, 2005, we announced a stock repurchase program that provided for the repurchase of up to $1 billion of the company's common stock over a period of up to two years, which was completed in August 2005. A second 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 was announced on August 11, 2005. A third repurchase program that provides for the repurchase of up to $1 billon of the company's common stock over a period of up to two years was announced on November 15, 2005. Acquisitions for the share repurchase programs are 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 plans are held as treasury shares.*

Item 6. SELECTED FINANCIAL DATA

	Millions of Dollars Except Per Share Amounts				
	2005	2004	2003	2002	2001
Sales and other operating revenues	$ **179,442**	135,076	104,246	56,748	24,892
Income from continuing operations	**13,640**	8,107	4,593	698	1,601
Per common share*					
Basic	**9.79**	5.87	3.37	.72	2.73
Diluted	**9.63**	5.79	3.35	.72	2.71
Net income (loss)	**13,529**	8,129	4,735	(295)	1,661
Per common share*					
Basic	**9.71**	5.88	3.48	(.31)	2.83
Diluted	**9.55**	5.80	3.45	(.31)	2.82
Total assets	**106,999**	92,861	82,455	76,836	35,217
Long-term debt	**10,758**	14,370	16,340	18,917	8,610
Mandatorily redeemable minority interests and preferred securities	**—**	—	141	491	650
Cash dividends declared per common share*	**1.18**	.895	.815	.74	.70

**The per-share amounts in all periods reflect a two-for-one stock split effected as a 100 percent stock dividend on June 1, 2005.*

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 merger of Conoco and Phillips in 2002 affects the comparability of the amounts included in the table above.

Also, see Note 3—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 26, 2006

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, and intentions, 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," "should," "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 98.

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 35,600 employees worldwide, and at year-end 2005 had assets of $107 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 primarily includes our 50 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 OAO LUKOIL (LUKOIL), an international, integrated oil and gas company headquartered in Russia. Our investment was 16.1 percent at December 31, 2005.

- 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 Chevron 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:

- Adding to our proved reserve base. We primarily add to our proved reserve base in three 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 late 2005, we signed an agreement with the Libyan National Oil Corporation under which we and our co-venturers acquired an ownership interest in the Waha concessions in Libya. As a result, we added 238 million barrels to our net proved crude oil reserves in 2005. In the three years ending December 31, 2005, our reserve replacement exceeded 100 percent, including the impact of our equity investments. The replacement rate was primarily attributable to our investment in LUKOIL, other purchases of reserves in place, and extensions and discoveries. 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 and the anticipated additional ownership interest in LUKOIL.

- Operating our producing properties and refining and marketing operations safely, consistently and in an environmentally sound manner. Safety is our first priority and we are committed to protecting the health and safety of everyone who has a role in our operations. 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 2005, our worldwide refinery capacity utilization rate was 93 percent, compared with 94 percent in 2004. The reduced utilization rate reflects the impact of hurricanes on our U.S. refining operations during 2005. Finally, we strive to conduct our operations in a manner that emphasizes our environmental stewardship.

- Controlling costs and expenses. Since we cannot control the prices of the commodity products we sell, keeping our operating and overhead costs low, within the context of our commitment to safety and environmental stewardship, is a 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.

- Selecting the appropriate projects in which to invest our capital dollars. We participate in capital-intensive industries. As a result, we must often invest significant capital dollars to explore for new oil and gas fields, develop newly discovered fields, maintain existing fields, or continue to maintain and improve our refinery complexes. We invest in those projects that are expected to provide an adequate financial return on invested dollars. However, there are often long lead times from the time we make an investment to the time that investment is operational and begins generating financial returns. Our capital expenditures and investments in 2005 totaled $11.6 billion, and we anticipate capital expenditures and investments to be approximately $11.2 billion in 2006, including our expenditures to re-enter Libya. The 2006 amount excludes any discretionary expenditures that may be made to further increase our equity investment in LUKOIL.

- 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. During 2005, we increased our investment in LUKOIL, ending the year with a 16.1 percent ownership interest. Also during 2005, we entered into an agreement to acquire Burlington Resources Inc., an independent exploration and production company with a substantial position in North American natural gas reserves and production. The transaction has a preliminary value of $33.9 billion. Under the terms of the agreement, Burlington Resources shareholders would receive $46.50 in cash and 0.7214 shares of ConocoPhillips common stock for each Burlington Resources share they own. This transaction is expected to close on March 31, 2006, subject to approval by Burlington Resources shareholders at a special meeting set for March 30, 2006.

- 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 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, or refinery margins, decline significantly for long periods of time, or when a decision to dispose of an asset leads to a write-down to its fair market value. Property impairments in 2005 totaled $42 million, compared with $164 million in 2004. 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 2005 we had $15.3 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, though non-cash, effect 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 2005, which contributed significantly to what we view as strong results from this segment. Industry crude oil prices were approximately $15 per barrel (or 36 percent) higher in 2005, compared with 2004, averaging $56.44 per barrel for West Texas Intermediate. The increase primarily was due to robust global consumption associated with the continuing global economic recovery, as well as oil supply disruptions in Iraq, and disruptions in the U.S. Gulf of Mexico due to hurricanes Katrina and Rita. In addition, there was little excess OPEC production capacity

available to replace lost supplies. Industry U.S. natural gas prices were $2.51 per million British thermal units (MMBTU) (or 41 percent) higher in 2005, compared with 2004, averaging approximately $8.64 per MMBTU for Henry Hub. Natural gas prices increased in 2005 due primarily to higher oil prices, continued concerns regarding the adequacy of U.S. natural gas supplies, and the hurricanes disrupting production and distribution in the Gulf Coast region. Looking forward, prices for both crude and natural gas are expected to decrease in 2006 from 2005 levels, while remaining strong relative to long-term historical averages.

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 50 percent equity investment in DEFS. During 2005, we increased our ownership interest in DEFS from 30.3 percent to 50 percent. During 2005, we recorded a gain of $306 million, after-tax, for our equity share of DEFS' sale of its general partnership interest in TEPPCO Partners, LP (TEPPCO).

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 2005 were stronger in comparison to 2004, resulting in improved R&M profitability. The U.S. Gulf Coast light oil spread increased 68 percent, from an average of $6.49 per barrel in 2004 to $10.92 per barrel in 2005. Key factors driving the 2005 growth in refining margins were healthy growth in demand for refined products in the United States and other countries worldwide, as well as concerns over adequate supplies due to hurricanes Katrina and Rita damaging refining and distribution infrastructure along the Gulf Coast. Our marketing margins were lower in 2005, compared with 2004, due to the market's inability to pass through higher crude and product costs.

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 2004 and all of 2005, we acquired additional shares in the open market for an additional $2.8 billion, bringing our equity ownership interest in LUKOIL to 16.1 percent by year-end 2005. We initiated this strategic investment to gain further exposure to Russia's resource potential, where LUKOIL has significant positions in proved reserves and production. We also are benefiting from an increase in proved oil and gas reserves at an attractive cost, and our E&P segment should benefit from direct participation with LUKOIL in large oil projects in the northern Timan-Pechora region of Russia, and an opportunity to potentially participate in the development of the West Qurna field in Iraq.

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. CPChem is investing in feedstock-advantaged areas in the Middle East with access to large, growing markets, such as Asia. Our financial results from Chemicals in 2005 were the strongest since the formation of CPChem in 2000, as this business line has emerged from a deep cyclical downturn that began around that time.

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, 2005, we had a debt-to-capital ratio of 19 percent, compared with 26 percent at the end of 2004. The decrease was due to a $2.5 billion reduction in debt during 2005, along with increased equity reflecting strong earnings. Upon completion of the Burlington Resources acquisition, we expect our debt-

to-capital ratio to increase into the low-30-percent range. However, we expect debt reduction to be a priority after the acquisition, allowing us to move back toward a mid-to-low-20-percent debt-to-capital ratio within three years.

RESULTS OF OPERATIONS

Consolidated Results

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

Years Ended December 31		Millions of Dollars 2005	2004	2003
Exploration and Production (E&P)	$	**8,430**	5,702	4,302
Midstream		**688**	235	130
Refining and Marketing (R&M)		**4,173**	2,743	1,272
LUKOIL Investment		**714**	74	—
Chemicals		**323**	249	7
Emerging Businesses		**(21)**	(102)	(99)
Corporate and Other		**(778)**	(772)	(877)
Net income	$	**13,529**	8,129	4,735

The improved results in 2005 and 2004 primarily were due to:

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

In addition, the improved results in 2005 also reflected our equity share of DEFS' sale of its general partner interest in TEPPCO.

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

Income Statement Analysis

2005 vs. 2004

Sales and other operating revenues increased 33 percent in 2005, while purchased crude oil, natural gas and products increased 39 percent. These increases primarily were due to higher petroleum product prices and higher prices for crude oil, natural gas, and natural gas liquids.

At its September 2005 meeting, the Emerging Issues Task Force (EITF) reached a consensus on Issue No. 04-13, "Accounting for Purchases and Sales of Inventory with the Same Counterparty," which encompasses our buy/sell transactions, and will impact our reported revenues and purchase costs. The EITF concluded that purchases and sales of inventory with the same counterparty in the same line of business should be recorded net and accounted for as nonmonetary exchanges if they are entered into "in contemplation" of one another. The new guidance is effective prospectively beginning April 1, 2006, for

new arrangements entered into, and for modifications or renewals of existing arrangements. Had this new guidance been effective for the periods included in this report, and depending on the determination of what transactions are affected by the new guidance, we would have been required to reduce sales and other operating revenues in 2005, 2004 and 2003 by $21,814 million, $15,492 million and $11,673 million, respectively, with related decreases in purchased crude oil, natural gas and products. See Note 1—Accounting Policies, in the Notes to Consolidated Financial Statements, for additional information.

Equity in earnings of affiliates increased 125 percent in 2005. The increase reflects a full year's 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 at Hamaca.
- Our chemicals joint venture, CPChem, due to higher margins.
- Our midstream joint venture, DEFS, reflecting higher natural gas liquids prices and DEFS' gain on the sale of its TEPPCO general partner interest.
- 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.

Other income increased 52 percent in 2005. The increase was mainly due to higher net gains on asset dispositions in 2005, as well as higher interest income. Asset dispositions in 2005 included the sale of our interest in coalbed methane acreage positions in the Powder River Basin in Wyoming, as well as our interests in Dixie Pipeline, Turcas Petrol A.S., and Venture Coke Company. Asset dispositions in 2004 included our interest in the Petrovera heavy-oil joint venture in Canada.

Production and operating expenses increased 16 percent in 2005. The E&P segment had higher maintenance and transportation costs; higher costs associated with new fields, including the Magnolia field in the Gulf of Mexico; negative impact from foreign currency exchange rates; and upward insurance premium adjustments. The R&M segment had higher utility costs due to higher natural gas prices, as well as higher maintenance and repair costs due to increased turnaround activity and hurricane impacts.

Depreciation, depletion and amortization (DD&A) increased 12 percent in 2005, primarily due to 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 in the Timor Sea.

We adopted Financial Accounting Standards Board (FASB) Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations—an interpretation of FASB Statement No. 143" (FIN 47), effective December 31, 2005. As a result, we recognized a charge of $88 million for the cumulative effect of this accounting change. FIN 47 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 and if the liability's fair value can be reasonably estimated. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation.

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, due to higher crude oil prices and higher production volumes.
- CPChem, due to higher volumes and margins.
- DEFS, reflecting higher natural gas liquids prices.
- Our joint-venture refinery in Melaka, Malaysia, due to improved refining margins in the Asia Pacific region.
- Merey Sweeny LLP, due to wider heavy-light crude oil differentials.

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.

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 5—Subsidiary Equity Transactions, in the Notes to Consolidated Financial Statements, for additional information.

We adopted FASB Statement of Financial Accounting Standards (SFAS) 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 FASB 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.

Segment Results

E&P

		2005	2004	2003
			Millions of Dollars	
Net Income				
Alaska	$	**2,552**	1,832	1,445
Lower 48		**1,736**	1,110	929
United States		**4,288**	2,942	2,374
International		**4,142**	2,760	1,928
	$	**8,430**	5,702	4,302
			Dollars Per Unit	
Average Sales Prices				
Crude oil (per barrel)				
United States	$	**51.09**	38.25	28.85
International		**52.27**	37.18	28.27
Total consolidated		**51.74**	37.65	28.54
Equity affiliates*		**37.79**	24.18	19.01
Worldwide E&P		**49.87**	36.06	27.52
Natural gas—lease (per thousand cubic feet)				
United States		**7.12**	5.33	4.67
International		**5.78**	4.14	3.69
Total consolidated		**6.32**	4.62	4.08
Equity affiliates*		**.26**	2.19	4.44
Worldwide E&P		**6.30**	4.61	4.08
Average Production Costs Per Barrel of Oil Equivalent**				
United States	$	**4.24**	3.70	3.60
International		**4.73**	3.96	3.88
Total consolidated		**4.51**	3.85	3.76
Equity affiliates*		**4.93**	4.14	4.16
Worldwide E&P		**4.55**	3.87	3.78
			Millions of Dollars	
Worldwide Exploration Expenses				

General administrative; geological and geophysical; and lease rentals	$	**312**	286	301
Leasehold impairment		**116**	175	133
Dry holes		**233**	242	167
	$	**661**	703	601

**Excludes our equity share of LUKOIL, which is reported in the LUKOIL Investment segment.*
***2004 and 2003 restated to exclude production, property and similar taxes.*

	2005	2004	2003
	Thousands of Barrels Daily		
Operating Statistics			
Crude oil produced			
Alaska	**294**	298	325
Lower 48	**59**	51	54
United States	**353**	349	379
European North Sea	**257**	271	290
Asia Pacific	**100**	94	61
Canada	**23**	25	30
Middle East and Africa	**53**	58	69
Other areas	—	—	3
Total consolidated	**786**	797	832
Equity affiliates*	**121**	108	102
	907	905	934
Natural gas liquids produced			
Alaska	**20**	23	23
Lower 48	**30**	26	25
United States	**50**	49	48
European North Sea	**13**	14	9
Asia Pacific	**16**	9	—
Canada	**10**	10	10
Middle East and Africa	**2**	2	2
	91	84	69
	Millions of Cubic Feet Daily		
Natural gas produced**			
Alaska	**169**	165	184
Lower 48	**1,212**	1,223	1,295
United States	**1,381**	1,388	1,479
European North Sea	**1,023**	1,119	1,215
Asia Pacific	**350**	301	318
Canada	**425**	433	435
Middle East and Africa	**84**	71	63
Total consolidated	**3,263**	3,312	3,510
Equity affiliates*	**7**	5	12
	3,270	3,317	3,522
	Thousands of Barrels Daily		
Mining operations			
Syncrude produced	**19**	21	19

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

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, 2005, 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.

2005 vs. 2004

Net income from the E&P segment increased 48 percent in 2005. The increase primarily was due to higher sales prices for crude oil, natural gas, natural gas liquids and Syncrude. In addition, increased sales volumes associated with the Magnolia and Bayu-Undan fields, as well as the Hamaca project, contributed positively to net income in 2005. Partially offsetting these items were increased production and operating costs, DD&A and taxes, as well as mark-to-market losses on certain U.K. natural gas contracts.

If crude oil and natural gas prices in 2006 do not remain at the historically strong levels experienced in 2005, E&P's earnings would be negatively impacted. See the "Business Environment and Executive Overview" section for additional discussion of crude oil and natural gas prices.

Proved reserves at year-end 2005 were 7.92 billion barrels of oil equivalent (BOE), compared with 7.61 billion BOE at year-end 2004. This excludes the estimated 1,442 million BOE and 880 million BOE included in the LUKOIL Investment segment at year-end 2005 and 2004, respectively. Also excluded, our Canadian Syncrude mining operations reported 251 million barrels of proved oil sands reserves at year-end 2005, compared with 258 million barrels at year-end 2004.

2004 vs. 2003

Net income from the E&P segment increased 33 percent in 2004, compared with 2003. 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.

U.S. E&P

2005 vs. 2004

Net income from our U.S. E&P operations increased 46 percent in 2005. The increase primarily was the result of higher crude oil, natural gas and natural gas liquids prices; higher sales volumes from the Magnolia deepwater field in the Gulf of Mexico, which began producing in late 2004; and higher gains from asset sales in 2005. These items were partially offset by:

- Higher production and operating expenses, reflecting increased transportation costs and well workover and other maintenance activity, and the impact of newly producing fields and environmental accruals.

- Higher DD&A, mainly due to increased production from the Magnolia field and other new fields.
- Higher production taxes, resulting from increased prices for crude oil and natural gas.

U.S. E&P production on a BOE basis averaged 633,000 barrels per day in 2005, compared with 629,000 barrels per day in 2004. The slight increase reflects the positive impact of a full year's production from the Magnolia field and the purchase of overriding royalty interests in the Utah and San Juan basins, mostly offset by normal field production declines, hurricane-related downtime, and the impact of asset dispositions.

2004 vs. 2003

Net income from our U.S. E&P operations increased 24 percent in 2004, compared with 2003. 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.

International E&P

2005 vs. 2004

Net income from our international E&P operations increased 50 percent in 2005. The increase primarily was the result of higher crude oil, natural gas and natural gas liquids prices. In addition, we had higher sales volumes from the Bayu-Undan field in the Timor Sea and the Hamaca project in Venezuela. These items were partially offset by:

- Higher production and operating expenses, reflecting increased costs at our Canadian Syncrude operations (including higher utility costs there) and increased costs associated with newly producing fields.
- Mark-to-market losses on certain U.K. natural gas contracts.
- Higher DD&A, mainly due to increased production from the Bayu-Undan field.
- Higher income taxes incurred by our equity affiliates at our Venezuelan heavy-oil projects.

International E&P production averaged 910,000 BOE per day in 2005, a slight decrease from 913,000 BOE per day in 2004. Production was favorably impacted in 2005 by the Bayu-Undan field and the Hamaca heavy-oil upgrader project. At the Bayu-Undan field in the Timor Sea, 2005 production was higher than that in 2004, when production was still ramping up. At the Hamaca project in Venezuela, production increased in late 2004 with the startup of a heavy-oil upgrader. These increases in production were offset by the impact of planned and unplanned maintenance, and field production declines. Our Syncrude mining operations produced 19,000 barrels per day in 2005, compared with 21,000 barrels per day in 2004.

2004 vs. 2003

Net income from our international E&P operations increased 43 percent in 2004, compared with 2003. 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's net income in 2003 also was favorably impacted by the following items:

- In Norway, the Norway Removal Grant Act (1986) was repealed, which resulted in a net after-tax benefit of $87 million.
- In the Timor Sea region, a broad ownership interest re-alignment among the co-venturers in the Bayu-Undan project and certain deferred tax adjustments resulted in an after-tax benefit of $51 million.
- In Canada, the Parliament enacted federal tax rate reductions for oil and gas producers, which resulted in a $95 million benefit upon revaluation of our deferred tax liability.

International E&P production averaged 913,000 BOE per day in 2004, down slightly from 916,000 BOE per day in 2003. 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.

Midstream

		2005	2004	2003
		Millions of Dollars		
Net Income*	**$**	**688**	235	130
**Includes DEFS-related net income:*	*$*	***591***	*143*	*72*
		Dollars Per Barrel		
Average Sales Prices				
U.S. natural gas liquids*				
Consolidated	$	**36.68**	29.38	22.67
Equity		**35.52**	28.60	22.12

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

	2005	2004	2003
	Thousands of Barrels Daily		
Operating Statistics			
Natural gas liquids extracted*	**195**	194	215
Natural gas liquids fractionated**	**168**	205	224

**Includes our share of equity affiliates, except LUKOIL, which is included in the LUKOIL Investment segment.*
***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 equity investment 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 and Trinidad.

In July 2005, ConocoPhillips and Duke Energy Corporation (Duke) restructured their respective ownership levels in DEFS, which resulted in DEFS becoming a jointly controlled venture, owned 50 percent by each company. Prior to the restructuring, our ownership interest in DEFS was 30.3 percent. This restructuring increased our ownership in DEFS through a series of direct and indirect transfers of certain Canadian Midstream assets from DEFS to Duke, a disproportionate cash distribution from DEFS to Duke from the sale of DEFS' interest in TEPPCO, and a combined payment by ConocoPhillips to Duke and DEFS of approximately $840 million. The Empress plant in Canada was not included in the initial transaction as originally anticipated due to weather-related damage. Subsequently, we sold the Empress plant to Duke in August 2005 for approximately $230 million.

2005 vs. 2004

Net income from the Midstream segment increased 193 percent in 2005. Included in the Midstream segment's 2005 net income is our share of a gain from DEFS' sale of its general partnership interest in TEPPCO. Our share of this gain, reflected in equity in earnings of affiliates, was $306 million, after-tax. In addition to this gain, our Midstream segment benefited from improved natural gas liquids prices in 2005, which increased earnings at DEFS, as well as our other Midstream operations. These positive items were partially offset by the loss of earnings from asset dispositions completed in 2004 and 2005.

Included in the Midstream segment's net income was a benefit of $17 million in 2005, compared with $36 million in 2004, representing the amortization of the excess amount of our equity interest in the net assets of DEFS over the book value of our investment in DEFS. The reduced amount in 2005 resulted from a significant reduction in the favorable basis difference of our investment in DEFS following the restructuring.

2004 vs. 2003

Net income from the Midstream segment increased 81 percent in 2004, compared with 2003. 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.

R&M

		2005	2004	2003
			Millions of Dollars	
Net Income				
United States	$	**3,329**	2,126	990
International		**844**	617	282
	$	**4,173**	2,743	1,272
			Dollars Per Gallon	
U.S. Average Sales Prices*				
Automotive gasoline				
Wholesale	$	**1.73**	1.33	1.05
Retail		**1.88**	1.52	1.35
Distillates—wholesale		**1.80**	1.24	.92

**Excludes excise taxes.*

	2005	2004	2003
		Thousands of Barrels Daily	
Operating Statistics			
Refining operations*			
United States			
Crude oil capacity**	**2,180**	2,164	2,168
Crude oil runs	**1,996**	2,059	2,074
Capacity utilization (percent)	**92%**	95	96
Refinery production	**2,186**	2,245	2,301
International			
Crude oil capacity**	**428**	437	442
Crude oil runs	**424**	396	414
Capacity utilization (percent)	**99%**	91	94
Refinery production	**439**	405	412
Worldwide			
Crude oil capacity**	**2,608**	2,601	2,610
Crude oil runs	**2,420**	2,455	2,488
Capacity utilization (percent)	**93%**	94	95
Refinery production	**2,625**	2,650	2,713
Petroleum products sales volumes			
United States			
Automotive gasoline	**1,374**	1,356	1,369
Distillates	**675**	553	575
Aviation fuels	**201**	191	180
Other products	**519**	564	492
	2,769	2,664	2,616
International	**482**	477	430
	3,251	3,141	3,046

**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 2005 and 2004 was 2,182,000 and 2,160,000 barrels per day, respectively, in the United States and 428,000 barrels per day 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, 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.

2005 vs. 2004

Net income from the R&M segment increased 52 percent in 2005, primarily due to higher worldwide refining margins. See the "Business Environment and Executive Overview" section for our view of the factors that supported the improved refining margins during 2005. Higher refining margins were partially offset by:

- Higher utility costs, mainly due to higher prices for natural gas.
- Increased turnaround costs.

- Lower production volumes and increased maintenance costs at our Gulf Coast refineries resulting from hurricanes Katrina and Rita.
- An $83 million charge for the cumulative effect of adopting FIN 47.

If refining margins decline in 2006 from the historically strong levels experienced in 2005, we would expect a corresponding decrease in R&M's earnings.

2004 vs. 2003

Net income from the R&M segment increased 116 percent in 2004, compared with 2003, 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 an accounting change (FIN 46(R)).

U.S. R&M

2005 vs. 2004

Net income from our U.S. R&M operations increased 57 percent in 2005. The increase mainly was the result of higher U.S. refining margins, partially offset by:

- Higher utility costs, mainly due to higher prices for natural gas.
- Increased turnaround costs.
- Lower production volumes and increased maintenance costs at our Gulf Coast refineries resulting from hurricanes Katrina and Rita.
- A $78 million charge for the cumulative effect of adopting FIN 47.

Our U.S. refining capacity utilization rate was 92 percent in 2005, compared with 95 percent in 2004. The 2005 rate was impacted by downtime related to hurricanes. Specifically, the Sweeny, Texas, and Lake Charles, Louisiana, refineries were shutdown in advance of Hurricane Rita. The Sweeny refinery returned to full operation by October. The Lake Charles refinery resumed operations in mid-October, and returned to full operation in November. The Alliance refinery in Belle Chase, Louisiana, was shutdown in advance

of Hurricane Katrina, and suffered flooding and damage from that storm. The refinery began partial operation in late-January 2006, and is expected to return to full operation around the end of the first quarter of 2006.

Effective January 1, 2005, the crude oil capacity at our Sweeny, Texas, refinery was increased by 13,000 barrels per day, as a result of incremental debottlenecking. Effective April 1, 2005, we increased the crude oil processing capacity at our San Francisco, California, refinery by 9,000 barrels per day as a result of a project implementation related to clean fuels.

2004 vs. 2003

Net income from our U.S. R&M operations increased 115 percent in 2004, compared with 2003, 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 an 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.

International R&M

2005 vs. 2004

Net income from our international R&M operations increased 37 percent in 2005, primarily due to higher refining margins, along with improved refinery production volumes and increased results from marketing. These factors were partially offset by negative foreign currency exchange impacts and higher utility costs.

Our international crude oil capacity utilization rate was 99 percent in 2005, compared with 91 percent in 2004. A larger volume of turnaround activity in 2004 contributed to most of this variance.

In November 2005, we executed a definitive agreement for the cash purchase of the Wilhelmshaven refinery in Wilhelmshaven, Germany. The purchase would include the 275,000-barrel-per-day refinery, a marine terminal, rail and truck loading facilities and a tank farm, as well as another entity that provides commercial and administrative support to the refinery. The purchase is expected to be completed during the first quarter of 2006, subject to satisfaction of closing conditions, including obtaining the necessary governmental approvals and regulatory permits. The addition of the Wilhelmshaven refinery would increase our overall European refining capacity by approximately 74 percent, from 372,000 barrels per day to 647,000 barrels per day.

2004 vs. 2003

Net income from the international R&M operations increased 119 percent in 2004, compared with 2003, with the improvement primarily attributable to higher refining margins, partially offset by negative foreign currency impacts on operating costs.

LUKOIL Investment

		Millions of Dollars		
		2005	2004	2003
Net Income	$	**714**	74	—
Operating Statistics*				
Net crude oil production (thousands of barrels daily)		**235**	38	—
Net natural gas production (millions of cubic feet daily)		**67**	13	—
Net refinery crude oil processed (thousands of barrels daily)		**122**	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 purchased 7.6 percent of LUKOIL's ordinary shares held by the Russian government, and during the remainder of 2004, we increased our ownership interest to 10.0 percent. During 2005, we expended $2,160 million to further increase our ownership interest to 16.1 percent. Purchase of LUKOIL shares continued into the first quarter of 2006. The 2005 results for the LUKOIL Investment segment reflect favorable market conditions, including strong crude oil prices.

In addition to our estimate of our equity share of LUKOIL's earnings, this segment 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, and also includes 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 our LUKOIL investment include an estimate for the latest quarter presented in a period. This estimate is based on market indicators, historical production trends of LUKOIL, and other factors. Differences between the estimate and actual results are recorded in a subsequent period. This process may create volatility in quarterly trend analysis for this segment, but this volatility will be mitigated when viewing this segment's results over an annual or longer time frame.

Chemicals

		Millions of Dollars		
		2005	2004	2003
Net Income	$	**323**	249	7

The Chemicals segment consists of our 50 percent interest in Chevron Phillips Chemical Company LLC (CPChem), which we account for under the equity method. 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.

2005 vs. 2004

Net income from the Chemicals segment increased 30 percent in 2005. The increase primarily was attributable to higher margins in the ethylene and polyethylene lines of business. Ethylene margins improved for the second consecutive year and, coupled with the increase in polyethylene margins, indicates that these business lines have improved from a deep cyclical downturn that began in the 1999/2000 time frame. Partially offsetting these margin improvements were higher utility costs, reflecting increased costs of natural gas, as well as hurricane-related impacts on production and maintenance and repair costs.

2004 vs. 2003

Net income from the Chemicals segment increased $242 million in 2004, compared with 2003. The increase 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 due to higher ethylene and benzene margins, as well as increased ethylene, polyethylene and normal alpha olefins sales volumes.

Emerging Businesses

		Millions of Dollars		
		2005	2004	2003
Net Income (Loss)				
Technology solutions	$	**(16)**	(18)	(20)
Gas-to-liquids		**(23)**	(33)	(50)
Power		**43**	(31)	(5)
Other		**(25)**	(20)	(24)
	$	**(21)**	(102)	(99)

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.

2005 vs. 2004

The Emerging Businesses segment incurred a net loss of $21 million in 2005, compared with a net loss of $102 million in 2004. The improved results in 2005 reflect:

- The first full year of operations at the Immingham power plant in the United Kingdom. The plant commenced commercial operations in the fourth quarter of 2004.
- Lower costs in the gas-to-liquids business, reflecting the shut down in June 2005 of a demonstration plant in Ponca City, Oklahoma.
- Improved margins in the domestic power generation business.

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 during 2004. Prior to the initial commissioning phase, most costs associated with this project were construction activities and thus capitalized. 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.

Corporate and Other

		Millions of Dollars		
		2005	2004	2003
Net Income (Loss)				
Net interest	$	**(422)**	(514)	(632)
Corporate general and administrative expenses		**(183)**	(212)	(173)
Discontinued operations		**(23)**	22	237
Merger-related costs		**—**	(14)	(223)
Cumulative effect of accounting changes		**—**	—	(112)*
Other		**(150)**	(54)	26
	$	**(778)**	(772)	(877)

**Includes a $107 million charge related to discontinued operations, primarily related to the adoption of FIN 46(R).*

2005 vs. 2004

After-tax net interest consists of interest and financing expense, net of interest income and capitalized interest, as well as premiums incurred on the early retirement of debt. Net interest decreased 18 percent in 2005, primarily due to lower average debt levels and increased interest income. Interest income increased as a result of our higher average cash balances during 2005. These items were partially offset by increased early debt retirement fees and a lower amount of interest being capitalized in 2005, reflecting the completion of several major projects in the second half of 2004.

After-tax corporate general and administrative expenses decreased 14 percent in 2005. The decrease reflects increased allocations of management-level stock-based compensation to the operating segments, which had previously been retained at corporate. These increased corporate allocations did not have a material impact on the operating segments' results. This was partially offset by increased charitable contributions, reflecting disaster relief following the southeast Asia tsunami and Gulf of Mexico hurricanes.

Discontinued operations net income declined in 2005, reflecting asset dispositions completed during 2004 and 2005.

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 2005, mainly due to unfavorable foreign currency transaction impacts.

2004 vs. 2003

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.

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.

CAPITAL RESOURCES AND LIQUIDITY

Financial Indicators

		Millions of Dollars Except as Indicated		
		2005	2004	2003
Current ratio		**.9**	1.0	.8
Net cash provided by operating activities	$	**17,628**	11,959	9,356
Notes payable and long-term debt due within one year	$	**1,758**	632	1,440
Total debt	$	**12,516**	15,002	17,780
Minority interests	$	**1,209**	1,105	842
Common stockholders' equity	$	**52,731**	42,723	34,366
Percent of total debt to capital*		**19%**	26	34
Percent of floating-rate debt to total debt		**9%**	19	17

Capital includes total debt, 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 2005 we raised $768 million in funds from the sale of assets. During 2005, available cash was used to support our ongoing capital expenditures and investments program, repay debt, pay dividends and purchase shares of our common stock. Total dividends paid on our common stock in 2005 were $1.6 billion. During 2005, cash and cash equivalents increased $827 million to $2.2 billion.

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 2007, including our capital spending program and required debt payments. We anticipate that the cash portion of the pending acquisition of Burlington Resources Inc., approximately $17.5 billion, will be financed with a combination of short- and long-term debt and available cash. For additional information about the acquisition, see Note 28—Pending Acquisition of Burlington Resources Inc., in the Notes to Consolidated Financial Statements.

Our cash flows from operating activities increased in each of the annual periods from 2003 through 2005. Favorable market conditions played a significant role in the upward trend of our cash flows from operating activities. Excluding the Burlington Resources acquisition and absent any unusual event during 2006, we expect that market conditions will again be the most important factor affecting our 2006 operating cash flows, when compared with 2005.

Significant Sources of Capital

<u>*Operating Activities*</u>
During 2005, cash of $17,628 million was provided by operating activities, compared with cash from operations of $11,959 million in 2004. This 47 percent increase was primarily due to higher income from continuing operations and a positive impact from working capital changes, partly offset by a greater amount of undistributed equity earnings.

- Income from continuing operations increased $5,533 million, compared with 2004, primarily as a result of higher crude oil, natural gas and natural gas liquid prices, as well as improved worldwide refining margins.

- Working capital changes increased cash flow by $847 million when comparing 2005 and 2004. Contributing to the increase in cash flow from working capital changes were higher increases in accounts payable in 2005, resulting from higher commodity prices and increased capital spending.

- Undistributed equity earnings increased $997 million in 2005 over 2004, as a result of higher equity in earnings of affiliates that have not been distributed to owners.

During 2004, cash flow from operations increased $2,603 million to $11,959 million. Contributing to the improvement, compared with 2003, was an increase in income from continuing operations primarily resulting from higher crude oil, natural gas and natural gas liquids prices, as well as improved worldwide refining margins. This benefit was partly offset by a higher retained interest in receivables sold to a Qualifying Special Purpose Entity (QSPE). 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 2004 and 2005, we benefited from historically high crude oil and natural gas prices, as well as strong refining margins. The sustainability of these prices and margins is 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. Including the impact of our equity investments and after adjusting our 2003 production for assets sold in 2003 and early 2004, our BOE production has increased in each of the past three years. Going forward, based on our 2005 production level of 1.79 million BOE per day, we expect our annual production growth to average in the range of 2 percent to 4 percent over the five-year period ending in 2010. These projections are tied to projects currently scheduled to begin production or ramp-up in those years, exclude our Canadian Syncrude mining operations, and do not include any impact from our pending acquisition of Burlington Resources Inc.

Including the impact of our equity investments, our reserve replacement over the three-year period ending December 31, 2005, exceeded 100 percent. Contributing to our success during this three-year period were proved reserves added through our investment in LUKOIL, other purchases of reserves in place, and extensions and discoveries. Although it cannot be assured, going forward, we expect to more than replace our production over the next three-year period, 2006 through 2008. This expectation is based on our current slate of exploratory and improved recovery projects. It does not include any impact from our pending acquisition of Burlington Resources Inc. 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 2005 and 2003, revisions increased our reserves, while in 2004, revisions

decreased 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 44 percent, 38 percent and 76 percent of our total net additions in 2005, 2004 and 2003, respectively. During these years, we converted, on average, 16 percent per year of our proved undeveloped reserves to proved developed reserves. Of the proved undeveloped reserves we had at December 31, 2005, we estimated that the average annual conversion rate for these reserves for the following three years will be approximately 15 percent. For additional information related to the development of proved undeveloped reserves, see the discussion under the E&P section of Capital Spending. 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

Proceeds from asset sales in 2005 were $768 million. Following the merger of Conoco and Phillips in August 2002, 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 at the end of 2004 to approximately $5.0 billion since the program began. Proceeds from these asset sales were used primarily to pay off debt.

Commercial Paper and Credit Facilities

During 2005, we replaced our $2.5 billion four-year revolving credit facility that would have expired in October 2008 and our $2.5 billion five-year facility that would have expired in October 2009 with two new revolving credit facilities totaling $5 billion. Both new facilities expire in October 2010. The new facilities are available for use as direct bank borrowings or as support for the ConocoPhillips $5 billion commercial paper program, the ConocoPhillips Qatar Funding Ltd. commercial paper program, and could 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, 2005.

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 the ConocoPhillips $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, 2005, we had no commercial paper outstanding under this program, compared with $544 million of commercial paper outstanding at December 31, 2004. In December 2005, ConocoPhillips Qatar Funding Ltd. initiated a $1.5 billion commercial paper program to be used to fund commitments relating to the Qatargas 3 project. At December 31, 2005, commercial paper outstanding under this program was $32 million.

Since we had $32 million of commercial paper outstanding and had issued $62 million of letters of credit, we had access to $4.9 billion in borrowing capacity under the two revolving credit facilities as of December 31, 2005. In addition, our $2.2 billion cash balance also supported our liquidity position.

At December 31, 2005, Moody's Investor Service had a rating of A1 on our senior long-term debt; and Standard and Poors' Rating Service and Fitch had 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.

Shelf Registration

We have a universal shelf registration statement on file with the U.S. Securities and Exchange Commission, under which we have available to issue and sell a total of $5 billion of various types of debt and equity securities.

Minority Interests

At December 31, 2005, we had outstanding $1,209 million of equity in less than wholly owned consolidated subsidiaries held by minority interest owners, including a minority interest of $507 million in Ashford Energy Capital S.A. The remaining minority interest amounts are primarily related to controlled-operating joint ventures with minority interest owners. The largest of these, $682 million, was related to the Bayu-Undan liquefied natural gas project in the Timor Sea and northern Australia.

In December 2001, in order to raise funds for general corporate purposes, Conoco and Cold Spring Finance S.a.r.l. (Cold Spring) 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, 2005, was 5.37 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 on a redemption date, Ashford would require a letter of credit to support $475 million of the term loans, as of December 31, 2005, 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, 2005, Ashford held $1.8 billion of ConocoPhillips subsidiary notes and $28 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.

Off-Balance Sheet Arrangements

Receivables Monetization
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. The arrangement provided for ConocoPhillips 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. At December 31, 2004, the QSPE had issued beneficial interests to the bank-sponsored entities of $480 million. 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 held no ownership interests, nor any variable interests, in any of the bank-sponsored entities, which we have not consolidated. Furthermore, except as discussed below, we have not consolidated the QSPE because it has met 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. The receivables transferred to the QSPE have met the isolation and other requirements of SFAS No. 140 to be accounted for as sales and have been accounted for accordingly.

By January 31, 2005, all of the beneficial interests held by the bank-sponsored entities had matured; therefore, in accordance with SFAS No. 140, the operating results and cash flows of the QSPE subsequent to this maturity have been consolidated in our financial statements. The revolving-period securitization arrangement was terminated on August 31, 2005, and at this time, we have no plans to renew the arrangement. See Note 13—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, 2005 and 2004, 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 2005 and 2004. 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 redemption proceeds to the immediate redemption of the preferred securities. See Note 3—Changes in Accounting Principles and Note 17—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, 2005, 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 in Venezuela. 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 Chevron Corporation. Our interest is held through a jointly owned limited liability company, Hamaca Holding LLC, for which we use the equity method of accounting. Our equity in earnings from Hamaca Holding LLC in 2005 was $473 million. We have a 57.1 percent non-controlling ownership interest in Hamaca Holding LLC. In 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 $856 million was outstanding under these credit facilities at December 31, 2005. Of this amount, $342 million was 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.

  Although the original guaranteed project completion date of October 1, 2005, was extended because of force majeure events that occurred during the construction period, completion certification was achieved on January 9, 2006, and the project financings became non-recourse with respect to the co-venturers. The lenders under the joint financing facilities may now look only to the Hamaca project's cash flows for payment.

- *Qatargas 3:* Qatargas 3 is an integrated project to produce and liquefy natural gas from Qatar's North field. We own a 30 percent interest in the project. The other participants in the project are affiliates of Qatar Petroleum (68.5 percent) and Mitsui & Co., Ltd. (Mitsui) (1.5 percent). Our interest is held through a jointly owned company, Qatar Liquefied Gas Company Limited (3), for which we use the equity method of accounting. Qatargas 3 secured project financing of $4 billion in December 2005, consisting of $1.3 billion of loans from export credit agencies (ECA), $1.5 billion from commercial banks, and $1.2 billion from ConocoPhillips. The ConocoPhillips loan facilities have substantially the same terms as the ECA and commercial bank facilities. Prior to project completion certification, all loans, including the ConocoPhillips loan facilities, are guaranteed by the participants, based on their respective ownership interests. Accordingly, our maximum exposure to this financing structure is $1.2 billion. Upon completion certification, which is expected to be December 31, 2009, all project loan facilities, including the ConocoPhillips loan facilities, will become non-recourse to the project participants.

  At December 31, 2005, Qatargas 3 had $120 million outstanding under all the loan facilities, $36 million of which was loaned by ConocoPhillips.

- *Other:* At December 31, 2005, we had guarantees outstanding for our portion of joint-venture debt obligations, which have terms of up to 20 years. The maximum potential amount of future payments under the guarantees was approximately $190 million. Payment would be required if a joint venture defaults on its debt obligations. Included in these outstanding guarantees was $96 million associated with the Polar Lights Company joint venture in Russia.

For additional information about guarantees, see Note 14—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, 2005, was $12.5 billion. This reflects debt reductions of approximately $2.5 billion during 2005. The decline in debt primarily resulted from a reduction of $512 million in our commercial paper balance; the redemption in November of our $750 million 6.35% Notes due 2009, at a premium of $42 million plus accrued interest; the redemption in late March of our $400 million 3.625% Notes due 2007, at par plus accrued interest; and the purchase, at market prices, and retirement of $752 million of various ConocoPhillips bond issues. In conjunction with the redemption of the 6.35% Notes and the 3.625% Notes, $750 million and $400 million, respectively, of interest rate swaps were cancelled. The note redemptions, interest rate swap cancellations, and bond issue purchases resulted in after-tax losses of $92 million.

On February 4, August 11, and November 15, 2005, we announced separate stock repurchase programs, each of which provides for the purchase of up to $1 billion of the company's common stock over a period of up to two years. Acquisitions for the share repurchase programs are 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 purchased under the programs are held as treasury shares. During 2005, we purchased 32.1 million shares of our common stock, at a cost of $1.9 billion under the programs.

We entered into a credit agreement with Qatargas 3, whereby we will provide loan financing of approximately $1.2 billion for the construction of the facilities. This financing will represent 30 percent of the project's total debt financing. Through December 31, 2005, we had provided $36 million in loan financing. See the "Off-Balance Sheet Arrangements" section for additional information on Qatargas 3.

In 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. Construction began in early 2005. We do not have an ownership interest in the facility, but we do have a 50 percent interest in the general partnership managing the venture, along with contractual rights to regasification capacity of the terminal. We entered into a credit agreement with Freeport LNG, whereby we will provide loan financing of approximately $630 million for the construction of the facility. Through December 31, 2005, we had provided $212 million in loan financing, including accrued interest.

In the fall of 2004, ConocoPhillips and LUKOIL agreed to the expansion of the Varandey terminal as part of our investment in the OOO Naryanmarneftegaz (NMNG) joint venture. Production from the NMNG joint-venture fields is transported via pipeline to LUKOIL's existing terminal at Varandey Bay on the Barents Sea and then shipped via tanker to international markets. LUKOIL intends to complete an expansion of the terminal oil-throughput capacity from 30,000 barrels per day to up to 240,000 barrels per day in late 2007, with ConocoPhillips participating in the design and financing of the terminal expansion. We have an obligation to provide loan financing to Varandey Terminal Company for 30 percent of the costs of the terminal expansion, but we will have no governance or ownership interest in the terminal. Based on preliminary budget estimates from the operator, we expect our total loan obligation for the terminal expansion to be approximately $330 million. This amount will be adjusted as the design is finalized and the expansion project proceeds. Through December 31, 2005, we had provided $61 million in loan financing.

We account for our loans to Qatargas 3, Freeport LNG and Varandey Terminal Company as financial assets in the "Investments and long-term receivables" line on the balance sheet.

In February 2006, we announced a quarterly dividend of 36 cents per share, representing a 16 percent increase over the previous quarter's dividend of 31 cents per share. The dividend is payable March 1, 2006, to stockholders of record at the close of business February 21, 2006.

Contractual Obligations

The following table summarizes our aggregate contractual fixed and variable obligations as of December 31, 2005:

	Millions of Dollars				
	Payments Due by Period				
At December 31, 2005	Total	Up to 1 Year	Year 2-3	Year 4-5	After 5 Years
Debt obligations*	$ 12,469	1,751	240	1,673	8,805
Capital lease obligations	47	7	36	4	—
Total debt	12,516	1,758	276	1,677	8,805
Operating lease obligations	2,618	494	766	467	891
Purchase obligations**	85,932	33,370	7,884	5,507	39,171
Other long-term liabilities***					
Asset retirement obligations	3,901	100	359	358	3,084
Accrued environmental costs	989	199	235	137	418
Total	$ 105,956	35,921	9,520	8,146	52,369

**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 $50,744 million, of which $18,276 million are primarily* *related to the supply of crude oil to our refineries and the optimization of the supply chain, $10,649 million primarily related to natural gas for resale to customers, $9,664 million primarily related to the supply of unfractionated NGLs to fractionators, optimization of NGL assets, and for resale to customers, $3,327 million related to transportation, $3,763 million related to product purchase, $2,142 million of futures, $2,114 million related to power trades and $809 million related to the purchase side of exchange agreements; (2) $30,126 million of purchase commitments for products, mostly natural gas and natural gas liquids, from CPChem over the remaining term of 95 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 14-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 $3,516 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 2006 through 2010 time period, we expect to contribute an average of $365 million per year to our qualified and non-qualified pension and postretirement medical plans in the United States and an average of $130 million per year to our non-U.S. plans, which are expected to be in excess of required minimums in many cases. The U.S. five-year average consists of $420 million for the next three years and then approximately $275 million per year as our pension plans become better funded. Our required minimum funding in 2006 is expected to be $65 million in the United States and $95 million outside the United States; and (3) Interest—we anticipate payments of $793 million in 2006, $1,387 million for the period 2007 through 2008, $1,288 million for the period 2009 through 2010, and $7,164 million for the remaining years to total $10,632 million.*

Capital Spending

Capital Expenditures and Investments

		Millions of Dollars			
		2006 Budget*	**2005**	2004	2003
E&P					
United States—Alaska	$	861	**746**	645	570
United States—Lower 48		949	**891**	669	848
International		5,663	**5,047**	3,935	3,090
		7,473	**6,684**	5,249	4,508
Midstream		6	**839**	7	10
R&M					
United States		1,820	**1,537**	1,026	860
International		1,671	**201**	318	319
		3,491	**1,738**	1,344	1,179
LUKOIL Investment**		—	**2,160**	2,649	—
Chemicals		—	**—**	—	—
Emerging Businesses		26	**5**	75	284
Corporate and Other***		217	**194**	172	188
	$	11,213	**11,620**	9,496	6,169
United States	$	3,856	**4,207**	2,520	2,493
International		7,357	**7,413**	6,976	3,676
	$	11,213	**11,620**	9,496	6,169
Discontinued operations	$	—	**—**	1	224

**Does not include any amounts for the pending acquisition of Burlington Resources Inc.*

***Discretionary expenditures in 2006 for potential additional equity investment in LUKOIL to increase our ownership percentage up to 20 percent, from 16.1 percent at December 31, 2005, are not included in our 2006 budget amounts.*

****Excludes discontinued operations.*

Our capital spending for continuing operations for the three-year period ending December 31, 2005, totaled $27.3 billion, including a combined $4.8 billion in 2004 through 2005 relating to our purchase of a 16.1 percent interest in LUKOIL. During the three-year period, spending was primarily focused on the growth of our E&P segment, with 60 percent of total spending for continuing operations in this segment.

Excluding discretionary expenditures for potential additional investment in LUKOIL, our capital budget for 2006 is $11.2 billion. Included in this amount are $447 million in capitalized interest and $44 million that is expected to be funded by minority interests in the Bayu-Undan gas export project. We plan to direct approximately 67 percent of our 2006 capital budget to E&P and 31 percent to R&M.

E&P

Capital spending for continuing operations for E&P during the three-year period ending December 31, 2005, totaled $16.4 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.

- The acquisition of limited-term, fixed-volume overriding royalty interests in Utah and the San Juan Basin related to our natural gas production.
- 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 Ekofisk Area growth project and Alvheim project in the Norwegian North Sea.
- The Clair, CMS3, Saturn and Britannia satellite developments in the United Kingdom.
- The Kashagan field and satellite prospects in the North Caspian Sea, offshore Kazakhstan, including additional ownership interest.
- The acquisition of an interest in OOO Naryanmarneftegaz (NMNG), a joint venture with LUKOIL.
- The Bayu-Undan gas recycle and liquefied natural gas development projects in the Timor Sea and northern Australia.
- The Belanak, Suban, South Jambi, Kerisi and Hiu projects in Indonesia.
- The Peng Lai 19-3 development in China's Bohai Bay and additional Bohai Bay appraisal and satellite field prospects.
- Development projects in Block 15-1 and Block 15-2 in Vietnam.

Capital expenditures for construction of our Endeavour Class tankers, as well as for an upgrade to the Trans-Alaska Pipeline System pump stations and purchase of an additional interest in the pipeline, were also included in the E&P segment.

UNITED STATES

Alaska
During the three-year period ending December 31, 2005, 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 to be in Alaska North Slope service in 2006, although contractual and hurricane-related issues may further delay delivery of this vessel.

We continued development drilling in the Greater Kuparuk Area, the Greater Prudhoe Area, the Alpine field, including Alpine's first satellite fields—Nanuq and Fiord, and the West Sak development. In addition, we completed both Phase I and Phase II of the Alpine Capacity Expansion project. We also participated in exploratory drilling on the North Slope and acquired additional acreage during this three-year period.

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 fully complete in 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, where development drilling continued in 2005. We also began production from the K2 field in Green Canyon Block 562 in May 2005.

Onshore capital was focused on natural gas developments in the San Juan Basin of New Mexico and the Lobo Trend of South Texas, and the acquisition in 2005 of limited-term, fixed-volume overriding royalty interests in Utah and the San Juan Basin related to our natural gas production.

CANADA

In Canada, we continued with development of the Syncrude Stage III expansion-mining project in the Canadian province of Alberta, where an upgrader expansion project is expected to be fully operational in mid-2006.

We also continued with development of the Surmont heavy-oil project. During 2005, funds were also invested to acquire an additional 6.5 percent interest in Surmont, increasing our interest to 50 percent. Over the life of this 30+ year project, we anticipate that approximately 500 production and steam-injection well pairs will be drilled. In 2005, our capital expenditures associated with the development of the Surmont project, excluding the acquisition of the additional interest, were approximately $93 million.

In addition, capital expenditures were also focused on the development of our conventional crude oil and natural gas reserves in western Canada.

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.

In the Gulf of Paria, funds were invested to construct a floating storage offtake facility and to construct and install a wellhead platform in the Corocoro field. The Corocoro drilling program is expected to begin in the second quarter of 2006.

NORTHWEST EUROPE

In the U.K. and Norwegian sectors of the North Sea, funds were invested during the three-year period ending December 31, 2005, for development of the Ekofisk Area growth project, where production began in the fourth quarter of 2005; the U.K. Clair field, where production began in early 2005; the Saturn project, where production began in the third quarter of 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; the Britannia satellite fields, Callanish and Brodgar, where production is expected in 2007; and the Alvheim development project, where production is scheduled to begin 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. Funding was also provided for our share of the basic phase of the Brass liquefied natural gas (LNG) project for the front-end engineering and design and related activities to move the project to a final investment decision.

RUSSIA AND CASPIAN SEA

Russia
In June 2005, we invested funds of $512 million to acquire a 30 percent economic interest and a 50 percent voting interest in NMNG, a joint venture with LUKOIL to explore for and develop oil and gas resources in the northern part of Russia's Timan-Pechora province. The June acquisition price was based on preliminary estimates of capital expenditures and working capital. The purchase price is expected to be finalized in the first quarter of 2006.

Caspian Sea
Construction activities began in 2004 to develop the Kashagan field on the Kazakhstan shelf in the North Caspian Sea. Additional exploratory drilling through 2004 has resulted in the discovery of a total of five fields in the area. In March 2005, agreement was reached with the Republic of Kazakhstan government to conclude the sale of BG International's interest in the North Caspian Sea Production Sharing Agreement to several of the remaining partners and for the subsequent sale of one-half of the acquired interests to KazMunayGas. This agreement increased our ownership interest from 8.33 percent to 9.26 percent.

ASIA PACIFIC

Timor Sea
In the Timor Sea, we continued with development activities associated with Phase I of the Bayu-Undan 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, and development drilling concluded at the end of March 2005.

In June 2003, we received approval from the Timor Sea Designated Authority for Phase II, the development of an LNG plant near Darwin, Australia, as well as a gas pipeline from Bayu-Undan to the LNG facility. Construction activities continued through 2005, and the first LNG cargo from the facility was loaded in February 2006.

Indonesia
In Indonesia, funds were used for the completion of the Belanak field in the South Natuna Sea Block B, including the construction of the Belanak floating production, storage and offloading (FPSO) facility and associated gas plant facilities on the FPSO. Oil production began from Belanak in late 2004 and first condensate production and gas exports began in June and October 2005, respectively. Also, in Block B we began development of the Kerisi and Hiu fields. In South Sumatra, following the execution of the West Java gas sales agreement in August 2004, 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
Following approval from the Chinese government in early 2005, we began development of Phase II of the Peng Lai 19-3 oil field, as well as concurrent development of the nearby 25-6 field. 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, funds were invested for the Su Tu Den Phase I southwest area development project, where production began in the fourth quarter of 2003 and where water injection facilities were put into service in 2004. Also in Block 15-1, preliminary engineering for the nearby Su Tu Vang development began in early 2005, and approval for the development was obtained in late 2005.

On Block 15-2, we upgraded facilities at our producing Rang Dong field in 2003 and continued further development of the field, including the central part of the field, where two additional platforms and additional production and injection wells were completed in the third quarter of 2005.

2006 CAPITAL BUDGET

E&P's 2006 capital budget is $7.5 billion, 12 percent higher than actual expenditures in 2005. Twenty-four percent of E&P's 2006 capital budget is planned for the United States, with 48 percent of that slated for Alaska.

We plan to spend $861 million in 2006 for our Alaskan operations. A majority of the capital spending will fund Prudhoe Bay, Greater Kuparuk and Western North Slope operations—including two Alpine satellites 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 Ursa field and the completion of the K2 and Magnolia developments in 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 $5.7 billion of its 2006 capital budget to international projects, including payments for the acquisition of an interest in our former oil and gas production operations in Libya. The agreement for our return was signed and approved by the Libyan government in late-December 2005. In addition, funds in 2006 also will be directed to developing major long-term projects, including the Bayu-Undan gas development project in the Timor Sea; the Kashagan project in the Caspian Sea and the NMNG joint venture in northern Russia; the Britannia satellites, Ekofisk Area growth and Alvheim 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.

In late-December 2005, we announced that, in conjunction with our co-venturers, we reached agreement with the Libyan National Oil Corporation on the terms under which we would return to our former oil and natural gas production operations in the Waha concessions in Libya. ConocoPhillips and Marathon each hold a 16.33 percent interest, Amerada Hess holds an 8.16 percent interest, and the Libyan National Oil Corporation holds the remaining 59.16 percent interest. The fiscal terms of the agreement are similar to the terms in effect at the time of the suspension of the co-venturers' activities in 1986. The terms include a 25-year extension of the concessions to 2031-2034; a payment to the Libyan National Oil Corporation of $1.3 billion ($520 million net to ConocoPhillips) for the acquisition of an ownership interest in, and extension of, the concessions; and a contribution to unamortized investments made since 1986 of $530 million ($212 million net to ConocoPhillips) that were agreed to be paid as part of the 1986 standstill agreement to hold the assets in escrow for the U.S.-based co-venturers. Of the total amount to be paid by ConocoPhillips, $520 million was paid in January 2006, and the remaining $212 million is expected to be paid in December 2006.

PROVED UNDEVELOPED RESERVES

Costs incurred for the years ended December 31, 2005, 2004, and 2003, relating to the development of proved undeveloped oil and gas reserves were $3.4 billion, $2.4 billion, and $2.0 billion, respectively. During these years, we converted, on average, 16 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 2006 through 2008 are projected to be $2.9 billion, $2.2 billion, and $1.3 billion, respectively. Of our 2,515 million BOE proved undeveloped reserves at year-end 2005, we estimated that the average annual conversion rate for these reserves for the three-year period ending 2008 will be approximately 15 percent.

Approximately 80 percent of our proved undeveloped reserves at year-end 2005 were associated with nine major developments and our investment in LUKOIL. Seven of the major developments are currently producing and are expected to have proved reserves convert from undeveloped to developed over time as development activities continue and/or production facilities are expanded or upgraded, and include:

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

The remaining two major projects, Qatargas 3 in Qatar and the Kashagan field in Kazakhstan, will have undeveloped proved reserves convert to developed as these projects begin production.

Midstream
Capital spending for continuing operations for Midstream during the three-year period ending December 31, 2005, was primarily related to increasing our ownership interest in DEFS in 2005 from 30.3 percent to 50 percent.

R&M
Capital spending for continuing operations for R&M during the three-year period ending December 31, 2005, 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 $4.3 billion, representing 16 percent of our total capital spending for continuing operations.

Key projects during the three-year period included:

- Completion of a fluid catalytic cracking (FCC) unit and an S ZorbÔ Sulfur Removal Technology (S-Zorb) unit at the Ferndale refinery.
- A low sulfur gasoline project at the Ponca City refinery.
- Phase I of a low sulfur gasoline project at the Wood River refinery.
- A new S-Zorb unit at the Lake Charles refinery.
- A new FCC gasoline hydrotreater at the Alliance refinery.
- An expansion of capacity in the Seaway crude-oil pipeline.
- Integration of a crude unit and coker adjacent to our Wood River refinery.
- A new hydrotreater at the Rodeo facility of our San Francisco refinery.

The integration of the crude unit and coker purchased adjacent to our Wood River refinery enables the refinery to process additional heavier, lower-cost crude oil.

The new diesel hydrotreater at the Rodeo facility of our San Francisco refinery became operational at the end of March 2005. The new diesel hydrotreater provides the capability to produce reformulated California highway diesel over one year ahead of the June 2006 deadline.

Internationally, we continued to invest in our ongoing refining and marketing operations to upgrade and increase the profitability of our existing assets, including a replacement reformer at our Humber refinery in the United Kingdom. In November 2005, we announced the planned acquisition of the 275,000-barrel-per-day Wilhelmshaven refinery in Germany. The purchase is expected to be finalized in the first quarter of 2006.

2006 CAPITAL BUDGET

R&M's 2006 capital budget is $3.5 billion, a 101 percent increase over actual spending in 2005. Domestic spending is expected to consume 52 percent of the R&M budget.

We plan to direct about $1.5 billion of the R&M capital budget to domestic refining, of which approximately $400 million is earmarked for clean fuels projects already in progress and about $700 million is for sustaining projects related to reliability, safety and the environment. In addition, about $400 million is intended for strategic and other investments to increase crude oil capacity, expand conversion capability, improve energy efficiency and increase clean product yield. Our U.S. marketing and transportation businesses are expected to spend about $275 million.

Internationally, we plan to spend approximately $1.7 billion on our R&M operations. Of this amount, about $1.4 billion is intended for the acquisition of the Wilhelmshaven refinery in Germany, including the initial expenditures for a deep conversion project and other improvements at the refinery. The remaining international R&M capital budget is for projects to strengthen our existing assets within Europe and Asia.

Emerging Businesses

Capital spending for Emerging Businesses during the three-year period ending December 31, 2005, 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 eight-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 recent action, the EPA has proposed an even more stringent particulate-matter standard and continues to consider increased stringency for ozone requirements as well. Outcomes of the deliberations remain indeterminate.

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, 2004, we reported we had been notified of potential liability under CERCLA and comparable state laws at 64 sites around the United States. At December 31, 2005, we had resolved five of these sites, reclassified one site, and had received six new notices of potential liability, leaving 66 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 $847 million in 2005 and are expected to be about $790 million in 2006 and $850 million in 2007. Capitalized environmental costs were $1,235 million in 2005 and are expected to be about $1,000 million and $630 million in 2006 and 2007, 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, 2005.

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, 2005, our balance sheet included total accrued environmental costs related to continuing operations of $989 million, compared with $1,061 million at December 31, 2004. 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 effect 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

In May 2005, the FASB issued SFAS No. 154, "Accounting Changes and Error Corrections, a replacement of APB Opinion No. 20 and FASB Statement No. 3." Among other changes, this Statement requires retrospective application for voluntary changes in accounting principle, unless it is impractical to do so. Guidance is provided on how to account for changes when retrospective application is impractical. This Statement is effective on a prospective basis beginning January 1, 2006.

In December 2004, the FASB issued SFAS No. 123 (revised 2004), "Share-Based Payment," (SFAS 123(R)), which supercedes Accounting Principles Board 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 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. For ConocoPhillips, this Statement provided for an effective date of third-quarter 2005; however, in April 2005, the Securities and Exchange Commission approved a new rule that delayed the effective date until January 1, 2006. We adopted the provisions of this Statement on January 1, 2006, using the modified-prospective transition method, and do not expect the provisions of this new pronouncement to have a material impact 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 clarifies that items, such as abnormal idle facility expense, excessive spoilage, double freight, and handling costs, be recognized as current-period charges. In addition, the Statement requires that allocation of fixed production overheads to the costs of conversion be based on the normal capacity of the production facilities. We are required to implement this Statement in the first quarter of 2006. We do not expect this Statement to have a significant impact on our financial statements.

At the September 2005 meeting, the EITF reached a consensus on 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, in the Notes to Consolidated Financial Statements.

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 2005, 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 $512 million and the accumulated impairment reserve was approximately

$167 million. The weighted average judgmental percentage probability of ultimate failure was approximately 72 percent and the weighted average amortization period was approximately 2.9 years. If that judgmental percentage were to be raised by 5 percent across all calculations, pretax leasehold impairment expense in 2006 would increase by $6 million. The remaining $2,688 million of capitalized unproved property costs at year-end 2005 consisted of individually significant leaseholds, mineral rights held into perpetuity by title ownership, exploratory wells currently drilling, and suspended exploratory wells. Management periodically assesses individually significant leaseholds 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. Except for Surmont, which is scheduled to begin production in late 2006, management expects less than $100 million to move to proved properties in 2006. Most of the remaining value is associated with Mackenzie Delta, Alaska North Slope and Australia natural gas projects, on which we continue to work with partners and regulatory agencies in order to develop. 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 potentially economic oil and gas reserves have been discovered by the drilling effort to justify completion of the find as a producing well.

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, the well costs remain capitalized on the balance sheet as long as sufficient progress assessing the reserves and the economic and operating viability of the project is being made. The accounting notion of "sufficient progress" is a judgmental area, but the accounting rules do prohibit continued capitalization of suspended well costs on the mere chance that future market conditions will improve or new technologies will be found that would make the project's development economically profitable. 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. 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 appraisal drilling and seismic 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. In addition to reviewing suspended well balances quarterly, management continuously monitors the results of the additional appraisal drilling and seismic work and expenses the suspended well costs as a dry hole when it judges that the potential field does not warrant further investment in the near term. Criteria utilized in making this determination include evaluation of the reservoir characteristics and hydrocarbon properties, expected development costs, ability to apply existing technology to produce the reserves, fiscal terms, regulations or contract negotiations, and our required return on investment.

At year-end 2005, total suspended well costs were $339 million, compared with $347 million at year-end 2004. For additional information on suspended wells, see Note 8—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 shut down 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 2005 estimated reserves related to our LUKOIL Investment segment were based on LUKOIL's year-end 2004 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 16.1 percent equity share of LUKOIL's oil and gas proved reserves at year-end 2005 were estimated based on LUKOIL's prior year's report (adjusted for known additions, license extensions, dispositions, and public information) and included adjustments to conform to our reserve policy and provided for estimated 2005 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 2005, 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 $31.9 billion and the depreciation, depletion and amortization recorded on these assets in 2005 was approximately $2.5 billion. The estimated proved developed oil and gas reserves on these fields were 4.8 billion BOE at the beginning of 2005 and were 5.2 billion BOE at the end of 2005. The estimated proved reserves on the Canadian Syncrude assets were 258 million barrels at the beginning of 2005 and were 251 million barrels at the end of 2005. 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 2005 would have been increased by an estimated $131 million. Impairments of producing oil and gas properties in 2005, 2004 and 2003 totaled $4 million, $67million and $225 million, respectively. Of these write-downs, only $1 million in 2005, $52 million in 2004 and $19 million in 2003 were due to downward revisions of

proved reserves. The remainder of the impairments in 2003 resulted either from properties being designated as held for sale or from the repeal in 2003 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 10—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 operational sites. Our largest asset removal obligations involve removal and disposal of offshore oil and gas platforms around the world, oil and gas production facilities and pipelines in Alaska, and asbestos abatement at refineries. 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.

In addition, under the above or similar contracts, permits and regulations, we have certain obligations to complete environmental-related projects. These projects are 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. Future environmental remediation costs are difficult to estimate because they 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.

See Note 1—Accounting Policies, Note 3—Changes in Accounting Principles, Note 11—Asset Retirement Obligations and Accrued Environmental Costs, and Note 15—Contingencies and Commitments, 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 trade names, 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 that require management's judgment of the estimated fair value of these intangible assets. See Note 9—Goodwill and Intangibles, in the Notes to Consolidated Financial Statements, for additional information.

Also, in connection with the acquisition of Tosco, the merger of Conoco and Phillips, and the acquisition of an ownership interest in a producing oil business in Libya, 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 E&P segment and our R&M 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 E&P 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 R&M segment, management reporting is primarily organized based on functional areas. Because the two broad functional areas of R&M 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 R&M 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 2005, the estimated fair values of our Worldwide Exploration and Production, Worldwide Refining, and Worldwide Marketing reporting units ranged from between 17 percent to 67 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 $15.3 billion of goodwill.

During 2006, we expect to acquire Burlington Resources Inc., subject to approval of the transaction by Burlington's shareholders and appropriate regulatory agencies. We expect this acquisition to result in the accounting recognition of a material amount of additional goodwill, all of which will be associated with our Worldwide Exploration and Production reporting unit. Based on our goodwill impairment testing at year-end 2005, we anticipate that this reporting unit will have adequate capacity to absorb this additional goodwill from the Burlington transaction and will not result in an impairment.

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 and throughout 2005, we purchased additional shares of LUKOIL on the open market and reached an ownership level of 16.1 percent in LUKOIL by the end of 2005. 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.

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 beginning 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 will 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 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 2005, we recorded $756 million of equity-method earnings from our 13.1 percent weighted-average ownership level in LUKOIL. Our reported earnings for the LUKOIL Investment segment of $714 million included the above equity-method earnings, less certain expenses and taxes. At December 31, 2005, we supplementally reported an estimated 1,242 million barrels of crude oil and 1,197 billion cubic feet of natural gas proved reserves from our ownership level of 16.1 percent at year-end 2005. 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 year 2005 for purposes of our equity-method accounting. Any differences between our estimate of fourth-quarter 2005 net income and the actual LUKOIL U.S. GAAP net income will be recorded in our 2006 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 2005 would have been a pretax benefit to other comprehensive income of approximately $3,298 million. Also, $19 million of acquisition-related costs would have been expensed and $756 million of current year equity-method earnings would not have been recorded.

At the end of 2005, the cost of our investment in LUKOIL exceeded our 16.1 percent share of LUKOIL's historical U.S. GAAP balance sheet equity by an estimated $1,375 million. Under the accounting guidelines of APB Opinion No. 18, we account for the basis difference between the cost of our investment and the amount of underlying equity in the historical net assets of LUKOIL 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. The majority of the basis difference is associated with LUKOIL's developed property, plant and equipment base. The earnings we recorded for

our LUKOIL investment thus included a reduction for the amortization of this basis difference. In 2005, we completed the purchase price allocation related to our 2004 share purchases of LUKOIL.

<u>Projected Benefit Obligations</u>

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 $40 million. In determining the discount rate, we use yields on high-quality fixed income investments (including among other things, Moody's Aa corporate bond yields) with adjustments as needed to match the estimated benefit cash flows of our plans.

OUTLOOK

On the evening of December 12, 2005, ConocoPhillips and Burlington Resources Inc. announced that they had signed a definitive agreement under which ConocoPhillips would acquire Burlington Resources Inc. The transaction has a preliminary value of $33.9 billion. This transaction is expected to close on March 31, 2006, subject to approval by Burlington Resources shareholders at a special meeting set for March 30, 2006.

Under the terms of the agreement, Burlington Resources shareholders will receive $46.50 in cash and 0.7214 shares of ConocoPhillips common stock for each Burlington Resources share they own. This represents a transaction value of $92 per share, based on the closing of ConocoPhillips shares on Friday, December 9, 2005, the last unaffected day of trading prior to the announcement. We anticipate that the cash portion of the purchase price, approximately $17.5 billion, will be financed with a combination of short- and long-term debt and available cash.

Burlington Resources is an independent exploration and production company that holds a substantial position in North American natural gas reserves and production.

Upon completion of the transaction, Bobby S. Shakouls, Burlington Resources' President and Chief Executive Officer, and William E. Wade Jr., currently an independent director of Burlington Resources, will join our Board of Directors. For additional information about the acquisition, see Note 28—Pending Acquisition of Burlington Resources Inc., in the Notes to Consolidated Financial Statements.

In October 2005, we announced that we had reached an agreement in principle with the state of Alaska on the base fiscal contract terms for an Alaskan natural gas pipeline project. In early 2006, the state of Alaska announced that they had reached an agreement in principle with all the co-venturers in the project. Once the final form of agreement is reached among all the parties, it will be subject to approval by the Alaska State Legislature before it can be executed. Additional agreements for the gas to transit Canada will also be required.

In February 2006, the governor of Alaska announced proposed legislation to change the state's oil and gas production tax structure. The proposed structure would be based on a percentage of revenues less certain expenditures, and include certain incentives to encourage new investment. If approved by the legislature, the new tax structure would go into effect July 1, 2006. If enacted, we would anticipate an increase in our production taxes in Alaska, based on an initial assessment of the proposed legislation.

In addition to our participation in the LNG regasification terminal at Freeport, Texas, we are pursuing three other proposed LNG regasification terminals in the United States. 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 proposed projects is in various stages of the regulatory permitting process.

In the United Kingdom, with effect from January 1, 2006, legislation is pending to increase the rate of supplementary corporation tax applicable to U.K. upstream activity from 10 percent to 20 percent. This would result in the overall U.K. upstream corporation tax rate increasing from 40 percent to 50 percent. The earnings impact of these changes will be reflected in our financial statements when the legislation is substantially enacted, which could occur in the third quarter of 2006. Upon enactment, we expect to record a charge for the revaluing of the December 31, 2005, deferred tax liability, as well as an adjustment to our tax expense to reflect the new rate from January 1, 2006, through the date of enactment. We are currently evaluating the full financial impact of this proposed legislation on our financial statements.

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 11 percent in March 2005 did not have a significant impact on our operations there; however, future changes in the exchange rate could have a significant impact. Based on public comments by Venezuelan government officials, Venezuelan legislation could be enacted that would increase the income tax rate on foreign companies operating in the Orinoco Oil Belt from 34 percent to 50 percent. We continue to work closely with the Venezuelan government on any potential impacts to our heavy-oil projects in Venezuela.

In November 2005, the Mackenzie Gas Project (MGP) proponents elected to proceed to the regulatory hearings, which began in January 2006. This followed an earlier halting of selected data collection, engineering and preliminary contracting work due to insufficient progress on key areas critical to the project. Since that time, considerable progress has been made with respect to Canadian government socio-economic funding, regulatory process and schedule, the negotiation of benefits and access agreements with four of the five aboriginal groups in the field areas and on the pipeline route. First production from the Parsons Lake field is now expected in 2011.

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. Preliminary engineering and design studies have been completed. In April 2005, the Qatar Minister of Petroleum stated that there would be a postponement of new GTL projects in order to further study impacts on infrastructure, shipping and contractors, and to ensure that the development of its gas resources occurs at a sustainable rate. Work continues with Qatar authorities on the appropriate timing of the project to meet the objectives of Qatar and ConocoPhillips.

In R&M, the optimization of spending related to clean fuels project initiatives will be an important focus area during 2006. We expect our average refinery crude oil utilization rate for 2006 to average in the mid-nineties. This projection excludes the impact of our equity investment in LUKOIL and the pending acquisition of the Wilhelmshaven refinery in Germany.

Also in R&M, we are planning to spend $4 billion to $5 billion over the period 2006 through 2011 to increase our U.S. refining system's ability to process heavy-sour crude oil and other lower-quality feedstocks. These investments are expected to incrementally increase refining capacity and clean products yield at our existing facilities, while providing competitive returns.

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 governmen t 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 ope rations 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 the 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. Consist ent 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, 2005 and 2004, 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, 2005, 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, 2005 and 2004, was immaterial to our net income and cash flows. The VaR for instruments held for purposes other than trading at December 31, 2005 and 2004, 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			
Expected Maturity Date	Fixed Rate Maturity	Average Interest Rate	Floating Rate Maturity	Average Interest Rate
Year-End 2005				
2006	**$ 1,534**	**5.73%**	**$ 180**	**5.32%**
2007	**170**	**7.24**	**—**	**—**
2008	**27**	**6.99**	**—**	**—**
2009	**304**	**6.43**	**—**	**—**

2010		**1,280**	**8.73**		**41**	**4.51**
Remaining years		**7,830**	**6.45**		**721**	**3.71**
Total	**$**	**11,145**		**$**	**942**	
Fair value	**$**	**12,484**		**$**	**942**	
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	

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, but during 2005 we terminated the majority of these interest rate swaps as we redeemed the associated debt. This reduced the amount of debt being converted from fixed to floating by the end of 2005 to $350 million. 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 2005				
2006—variable to fixed	**$**	**116**	**5.85%**	**4.10%**
2007		—	—	—
2008		—	—	—
2009		—	—	—
2010		—	—	—
Remaining years—fixed to variable		**350**	**4.35**	**4.75**
Total	**$**	**466**		
Fair value position	**$**	**(8)**		
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		

Foreign Currency Risk

We have foreign currency exchange rate risk resulting from international operations. 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, 2005 and 2004, 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 material impact to income from an adverse hypothetical 10 percent change in the December 31, 2005 or 2004, exchange rates. The notional and fair market values of these positions at December 31, 2005 and 2004, were as follows:

		Millions of Dollars			
Foreign Currency Swaps		Notional		Fair Market Value	
		2005	2004	**2005**	2004
Sell U.S. dollar, buy euro	**$**	**492**	370	**(8)**	13
Sell U.S. dollar, buy British pound		**463**	1,253	**(12)**	14

Sell U.S. dollar, buy Canadian dollar	**517**	85	**—**	2
Sell U.S. dollar, buy Czech koruny	**—**	13	**—**	—
Sell U.S. dollar, buy Danish krone	**3**	15	**—**	—
Sell U.S. dollar, buy Norwegian kroner	**1,210**	991	**(15)**	58
Sell U.S. dollar, buy Polish zlotych	**—**	2	**—**	—
Sell U.S. dollar, buy Swedish krona	**107**	148	**1**	3
Buy U.S. dollar, sell Polish zlotych	**3**	—	**—**	—
Buy euro, sell Norwegian kroner	**2**	—	**—**	—
Buy euro, sell Swedish krona	**13**	—	**—**	—

For additional information about our use of derivative instruments, see Note 16—Financial Instruments and Derivative Contracts, in the Notes to Consolidated Financial Statements.

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, 2005. 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, 2005, 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, 2005.

/s/ J. J. Mulva	/s/ John A. Carrig
J. J. Mulva	**John A. Carrig**
Chairman, President and	Executive Vice President, Finance,
Chief Executive Officer	and Chief Financial Officer

February 26, 2006

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, 2005 and 2004, 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, 2005. 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, 2005 and 2004, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2005, 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 3 to the consolidated financial statements, in 2005 ConocoPhillips adopted Financial Accounting Standards Board (FASB) Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations — an interpretation of FASB Statement No. 143," and 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 FASB 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, 2005, 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 26, 2006 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

ERNST & YOUNG LLP

Houston, Texas
February 26, 2006

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, 2005, 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, 2005, 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, 2005, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the 2005 consolidated financial statements of ConocoPhillips and our report dated February 26, 2006 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

ERNST & YOUNG LLP

Houston, Texas
February 26, 2006

Consolidated Income Statement **ConocoPhillips**

Years Ended December 31		Millions of Dollars		
		2005	2004	2003
Revenues and Other Income				
Sales and other operating revenues *(1)(2)*	$	**179,442**	135,076	104,246
Equity in earnings of affiliates		**3,457**	1,535	542
Other income		**465**	305	309
Total Revenues and Other Income		**183,364**	136,916	105,097
Costs and Expenses				
Purchased crude oil, natural gas and products *(3)*		**124,925**	90,182	67,475
Production and operating expenses		**8,562**	7,372	7,144
Selling, general and administrative expenses		**2,247**	2,128	2,179
Exploration expenses		**661**	703	601
Depreciation, depletion and amortization		**4,253**	3,798	3,485
Property impairments		**42**	164	252
Taxes other than income taxes *(1)*		**18,356**	17,487	14,679
Accretion on discounted liabilities		**193**	171	145
Interest and debt expense		**497**	546	844
Foreign currency transaction (gains) losses		**48**	(36)	(36)
Minority interests		**33**	32	20
Total Costs and Expenses		**159,817**	122,547	96,788
Income from continuing operations before income taxes and subsidiary equity transactions		**23,547**	14,369	8,309
Gain on subsidiary equity transactions		**—**	—	28
Income from continuing operations before income taxes		**23,547**	14,369	8,337
Provision for income taxes		**9,907**	6,262	3,744
Income From Continuing Operations		**13,640**	8,107	4,593
Income (loss) from discontinued operations		**(23)**	22	237
Income before cumulative effect of changes in accounting principles		**13,617**	8,129	4,830
Cumulative effect of changes in accounting principles		**(88)**	—	(95)

Net Income	$	**13,529**	8,129	4,735
Income (Loss) Per Share of Common Stock *(dollars)(4)*				
Basic				
Continuing operations	$	**9.79**	5.87	3.37
Discontinued operations		**(.02)**	.01	.18
Before cumulative effect of changes in accounting principles		**9.77**	5.88	3.55
Cumulative effect of changes in accounting principles		**(.06)**	—	(.07)
Net Income	$	**9.71**	5.88	3.48
Diluted				
Continuing operations	$	**9.63**	5.79	3.35
Discontinued operations		**(.02)**	.01	.17
Before cumulative effect of changes in accounting principles		**9.61**	5.80	3.52
Cumulative effect of changes in accounting principles		**(.06)**	—	(.07)
Net Income	$	**9.55**	5.80	3.45
Average Common Shares Outstanding *(in thousands)(4)*				
Basic		**1,393,371**	1,381,568	1,360,980
Diluted		**1,417,028**	1,401,300	1,370,866
(1) Includes excise, value added and other similar taxes on petroleum products sales:	*$*	***17,037***	*16,357*	*13,705*
(2) Includes sales related to purchases/sales with the same counterparty:		***21,814***	*15,492*	*11,673*
(3) Includes purchases related to purchases/sales with the same counterparty:		***21,611***	*15,255*	*11,453*

(4) Per-share amounts and average number of common shares outstanding in all periods reflect a two-for-one stock split effected as a 100 percent stock dividend on June 1, 2005.
See Notes to Consolidated Financial Statements.

Consolidated Balance Sheet **ConocoPhillips**

At December 31		Millions of Dollars	
		2005	2004
Assets			
Cash and cash equivalents	$	**2,214**	1,387
Accounts and notes receivable (net of allowance of $72 million in 2005 and $55 million in 2004)		**11,168**	5,449
Accounts and notes receivable—related parties		**772**	3,339
Inventories		**3,724**	3,666
Prepaid expenses and other current assets		**1,734**	986
Assets of discontinued operations held for sale		—	194
Total Current Assets		**19,612**	15,021
Investments and long-term receivables		**15,726**	10,408
Net properties, plants and equipment		**54,669**	50,902
Goodwill		**15,323**	14,990
Intangibles		**1,116**	1,096
Other assets		**553**	444
Total Assets	$	**106,999**	92,861
Liabilities			
Accounts payable	$	**11,732**	8,727
Accounts payable—related parties		**535**	404
Notes payable and long-term debt due within one year		**1,758**	632
Accrued income and other taxes		**3,516**	3,154
Employee benefit obligations		**1,212**	1,215
Other accruals		**2,606**	1,351
Liabilities of discontinued operations held for sale		—	103
Total Current Liabilities		**21,359**	15,586
Long-term debt		**10,758**	14,370
Asset retirement obligations and accrued environmental costs		**4,591**	3,894
Deferred income taxes		**11,439**	10,385
Employee benefit obligations		**2,463**	2,415
Other liabilities and deferred credits		**2,449**	2,383
Total Liabilities		**53,059**	49,033
Minority Interests		**1,209**	1,105
Common Stockholders' Equity			
Common stock (2,500,000,000 shares authorized at $.01 par value)			
Issued (2005—1,455,861,340 shares; 2004—1,437,729,662 shares)*			
Par value*		**14**	14
Capital in excess of par*		**26,754**	26,047
Compensation and Benefits Trust (CBT) (at cost: 2005—45,932,093 shares; 2004—48,182,820 shares)*		**(778)**	(816)
Treasury stock (at cost: 2005—32,080,000 shares; 2004—0 shares)		**(1,924)**	—

Accumulated other comprehensive income		**814**	1,592
Unearned employee compensation		**(167)**	(242)
Retained earnings		**28,018**	16,128
Total Common Stockholders' Equity		**52,731**	42,723
Total	$	**106,999**	92,861

**2004 restated to reflect a two-for-one stock split effected as a 100 percent stock dividend on June 1, 2005.*
See Notes to Consolidated Financial Statements.

Consolidated Statement of Cash Flows **ConocoPhillips**

Years Ended December 31	Millions of Dollars 2005	2004	2003
Cash Flows From Operating Activities			
Income from continuing operations	$ **13,640**	8,107	4,593
Adjustments to reconcile income from continuing operations to net cash provided by continuing operations			
Non-working capital adjustments			
Depreciation, depletion and amortization	**4,253**	3,798	3,485
Property impairments	**42**	164	252
Dry hole costs and leasehold impairments	**349**	417	300
Accretion on discounted liabilities	**193**	171	145
Deferred income taxes	**1,101**	1,025	401
Undistributed equity earnings	**(1,774)**	(777)	(59)
Gain on asset dispositions	**(278)**	(116)	(211)
Other	**(139)**	(190)	(328)
Working capital adjustments*			
Increase (decrease) in aggregate balance of accounts receivable sold	**(480)**	(720)	274
Increase in other accounts and notes receivable	**(2,665)**	(2,685)	(463)
Decrease (increase) in inventories	**(182)**	360	(24)
Decrease (increase) in prepaid expenses and other current assets	**(407)**	15	(105)
Increase in accounts payable	**3,156**	2,103	345
Increase in taxes and other accruals	**824**	326	562
Net cash provided by continuing operations	**17,633**	11,998	9,167
Net cash provided by (used in) discontinued operations	**(5)**	(39)	189
Net Cash Provided by Operating Activities	**17,628**	11,959	9,356
Cash Flows From Investing Activities			
Capital expenditures and investments, including dry hole costs	**(11,620)**	(9,496)	(6,169)
Proceeds from asset dispositions	**768**	1,591	2,659
Cash consolidated from adoption and application of FIN 46(R)	**—**	11	225
Long-term advances/loans to affiliates and other	**(275)**	(167)	(63)
Collection of advances/loans to affiliates and other	**111**	274	86
Net cash used in continuing operations	**(11,016)**	(7,787)	(3,262)
Net cash used in discontinued operations	**—**	(1)	(236)
Net Cash Used in Investing Activities	**(11,016)**	(7,788)	(3,498)
Cash Flows From Financing Activities			
Issuance of debt	**452**	—	348
Repayment of debt	**(3,002)**	(2,775)	(5,159)
Repurchase of company common stock	**(1,924)**	—	—
Issuance of company common stock	**402**	430	108
Dividends paid on common stock	**(1,639)**	(1,232)	(1,107)
Other	**27**	178	111
Net cash used in continuing operations	**(5,684)**	(3,399)	(5,699)
Net Cash Used in Financing Activities	**(5,684)**	(3,399)	(5,699)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**(101)**	125	24
Net Change in Cash and Cash Equivalents	**827**	897	183
Cash and cash equivalents at beginning of year	**1,387**	490	307
Cash and Cash Equivalents at End of Year	$ **2,214**	1,387	490

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

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

Millions of Dollars

	Shares of Common Stock*			Common Stock*				Accumulated Other Comprehensive Income (Loss)	Unearned Employee Compensation	Retained Earnings	Total
	Issued	Held in Treasury	Held in CBT	Par Value	Capital in Excess of Par	Treasury Stock	CBT				
December 31, 2002	1,408,709,678	—	53,570,188	$ 14	25,171	—	(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	7,460,516		(2,967,560)		183		50				233
Recognition of unearned compensation									18		18
Other										(15)	(15)
December 31, 2003	1,416,170,194	—	50,602,628	14	25,354	—	(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 compensation and other benefit plans	21,559,468		(2,419,808)		693		41		(76)		658
Recognition of unearned compensation									34		34
Other										(3)	(3)
December 31, 2004	1,437,729,662	—	48,182,820	14	26,047	—	(816)	1,592	(242)	16,128	42,723
Net income										**13,529**	**13,529**
Other comprehensive income (loss)											
Minimum pension liability adjustment								**(56)**			**(56)**
Foreign currency translation								**(717)**			**(717)**
Unrealized loss on securities								**(6)**			**(6)**
Hedging activities								**1**			**1**
Comprehensive income											**12,751**
Cash dividends paid on common stock										**(1,639)**	**(1,639)**
Repurchase of company common stock		**32,080,000**				**(1,924)**					**(1,924)**
Distributed under incentive compensation and other benefit plans	**18,131,678**		**(2,250,727)**		**707**		**38**				**745**
Recognition of unearned compensation									**75**		**75**
December 31, 2005	**1,455,861,340**	**32,080,000**	**45,932,093**	**$ 14**	**26,754**	**(1,924)**	**(778)**	**814**	**(167)**	**28,018**	**52,731**

**All periods reflect a two-for-one stock split effected as a 100 percent stock dividend on June 1, 2005.*
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 have the ability to exert significant influence over the affiliates' operating and financial policies. The cost method is used when we do not have the ability to exert 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.

- **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.

  Buy/sell transactions have the same general terms and conditions as typical commercial contracts including: separate title transfer, transfer of risk of loss, separate 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. Because buy/sell contracts have similar terms and conditions, we and many other companies in our industry account for these purchase and sale transactions in the consolidated income statement as monetary transactions outside the scope of Accounting Principles Board (APB) Opinion No. 29, "Accounting for Nonmonetary Transactions."

  Our buy/sell transactions are similar to the "barrel back" example used in Emerging Issues Task Force (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." Using the "barrel back" example, the EITF concluded that a company's decision to

display buy/sell-type transactions either gross or net on the income statement is a matter of judgment that depends on relevant facts and circumstances. We apply this judgment based on guidance in EITF Issue No. 99-19, "Reporting Revenue Gross as a Principal versus Net as an Agent" (Issue No. 99-19), which provides indicators for when to report revenues and the associated cost of goods sold gross (i.e., on separate revenue and cost of sales lines in the income statement) or net (i.e., on the same line). The indicators for gross reporting in Issue No. 99-19 are consistent with many of the characteristics of buy/sell transactions, which support our accounting for buy/sell transactions.

We also believe that the conclusion reached by the Derivatives Implementation Group Statement 133 Implementation Issue No. K1, "Miscellaneous: Determining Whether Separate Transactions Should be Viewed as a Unit," further supports our judgment that the purchase and sale contracts should be viewed as two separate transactions and not as a single transaction.

In November 2004, the EITF began deliberating the accounting for buy/sell and related transactions as Issue No. 04-13, "Accounting for Purchases and Sales of Inventory with the Same Counterparty," and reached a consensus at its September 2005 meeting. The EITF concluded that purchases and sales of inventory, including raw materials, work-in-progress or finished goods, with the same counterparty that are entered into "in contemplation" of one another should be combined and reported net for purposes of applying APB Opinion No. 29. Additionally, the EITF concluded that exchanges of finished goods for raw materials or work-in-progress within the same line of business is not an exchange subject to APB Opinion No. 29 and should be recorded at fair value.

The new guidance is effective prospectively beginning April 1, 2006, for new arrangements entered into, and for modifications or renewals of existing arrangements. We are reviewing this guidance and believe that any impact to income from continuing operations and net income would result from changes in last-in, first-out (LIFO) inventory valuations and would not be material to our financial statements.

Had this new guidance been effective for the periods included in this report, and pending our final determination of what transactions are affected by the new guidance, we estimate that we would have been required to reduce sales and other operating revenues in 2005, 2004 and 2003 by $21,814 million, $15,492 million and $11,673 million, respectively, with related decreases in purchased crude oil, natural gas and products.

Our Commercial organization uses commodity derivative contracts (such as futures and options) in various markets to optimize the value of our supply chain and to 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.

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.

- **Shipping and Handling Costs—**Our Exploration and Production (E&P) segment includes shipping and handling costs in production and operating expenses, while the Refining and Marketing (R&M) 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 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 under various methods, including the weighted-average-cost method, and the first-in, first-out (FIFO) method, consistent with general industry practice.

- **Derivative Instruments—**All derivative instruments are recorded on the balance sheet at fair value in either prepaid expenses and other current assets, other assets, other accruals, or other liabilities and deferred credits. Recognition and classification 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 Standards (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 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 derivatives.

- **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, or "suspended," on the balance sheet pending further evaluation of whether economically recoverable reserves have been found. If economically recoverable reserves are not found, exploratory well costs are expensed as dry holes. If exploratory wells encounter potentially economic quantities of oil and gas, the well costs remain capitalized on the balance sheet as long as sufficient progress assessing the reserves and the economic and operating viability of the project is being made. 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 appraisal drilling and seismic work on the potential oil and gas field, or we seek government or co-venturer approval of development plans or seek environmental permitting. 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.

Unlike leasehold acquisition costs, there is no periodic impairment assessment of suspended exploratory well costs. In addition to reviewing suspended well balances quarterly, management continuously monitors the results of the additional appraisal drilling and seismic work and expenses the suspended well costs as a dry hole when it judges that the potential field does not warrant further investment in the near term.

See Note 8—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, three reporting units have been determined: 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.

- **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.

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

- **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.

- **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.

- **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 3—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 environmental expenditures are recorded on an undiscounted basis (unless acquired in a purchase business combination) 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 and estimable.

- **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		
		2005	2004	2003
Net income, as reported	$	**13,529**	8,129	4,735
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects		**142**	93	50
Deduct: Total stock-based employee compensation expense determined under fair-value based method for all awards, net of related tax effects		**(144)**	(106)	(78)
Pro forma net income	$	**13,527**	8,116	4,707
Earnings per share*:				
Basic—as reported	$	**9.71**	5.88	3.48
Basic—pro forma		**9.71**	5.87	3.46
Diluted—as reported		**9.55**	5.80	3.45
Diluted—pro forma		**9.55**	5.79	3.43

**Per-share amounts reflect a two-for-one stock split effected as a 100 percent stock dividend on June 1, 2005.*

Generally, our stock-based compensation programs provide accelerated vesting (i.e., a waiver of the remaining period of service required to earn an award) for awards held by employees at the time of their retirement. We recognize expense for these awards over the period of time during which the employee earns the award, accelerating the recognition of expense only when an employee actually retires (both the actual expense and the pro forma expense shown in the preceding table were calculated in this manner).

Beginning in 2006, our adoption of SFAS No. 123 (revised 2004), "Share-Based Payment" (FAS 123R), will require us to recognize stock-based compensation expense for new awards over the shorter of: 1) the service period (i.e., the stated period of time required to earn the award); or 2) the period beginning at the start of the service period and ending when an employee first becomes eligible for retirement. This will shorten the period over which we recognize expense for most of our stock-based awards granted to our employees who are already age 55 or older, but we do not expect this change to have a material effect on our financial statements. If we had used this method of recognizing expense for stock-based awards for the periods presented, the effect on net income, as reported, would not have been material.

- **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 unvested stock, unit or option awards granted under our compensation plans and vested but unexercised stock options, but only to the extent these instruments dilute net income per share. 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 non-preference 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—Common Stock Split

On April 7, 2005, our Board of Directors declared a two-for-one common stock split effected in the form of a 100 percent stock dividend, payable June 1, 2005, to stockholders of record as of May 16, 2005. The total number of authorized common shares and associated par value per share were unchanged by this action. Shares and per-share information in the Consolidated Income Statement, the Consolidated Balance Sheet, the Consolidated Statement of Changes in Common Stockholders' Equity, and the Notes to Consolidated Financial Statements are on an after-split basis for all periods presented.

Note 3—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 this accounting 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 $.02 per basic and diluted share, compared with the previous accounting method.

In March 2005, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations—an interpretation of FASB Statement No. 143" (FIN 47). 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 and if the liability's fair value can be reasonably estimated. We implemented FIN 47 effective December 31, 2005. Accordingly, there was no impact on income from continuing operations in 2005. Application of FIN 47 increased net properties, plants and equipment by $269 million, and increased asset retirement obligation liabilities by $417 million. The cumulative effect of this accounting change decreased 2005 net income by $88 million (after reduction of income taxes of $60 million).

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 involve removal and disposal of offshore oil and gas platforms around the world, oil and gas production facilities and pipelines in Alaska, and asbestos abatement at refineries.

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 and FIN 47 estimates.

During 2005 and 2004, our overall asset retirement obligation changed as follows:

	Millions of Dollars

		2005	2004
Opening balance at January 1	$	**3,089**	2,685
Accretion of discount		**165**	146
New obligations and changes in estimates of existing obligations		**494**	141
Spending on existing obligations		**(75)**	(59)
Property dispositions		**—**	(20)
Foreign currency translation		**(189)**	180
Adoption of FIN 47		**417**	—
Other adjustments		**—**	16
Ending balance at December 31	$	**3,901**	3,089

The following table presents the estimated pro forma effects of the retroactive application of the adoption of FIN 47 as if the interpretation had been adopted on the dates the obligations arose:

		Millions of Dollars Except Per Share Amounts		
		2005	2004	2003
Pro forma net income*	$	**13,600**	8,113	4,720
Pro forma earnings per share				
Basic		**9.76**	5.87	3.47
Diluted		**9.60**	5.79	3.44
Pro forma asset retirement obligations at December 31		**3,901**	3,407	2,986

Consolidation of Variable Interest Entities

**Net income of $13,529 million for 2005 has been adjusted to remove the $88 million cumulative effect of the change in accounting principle attributable to FIN 47.*

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) and we 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 2004, we finalized a transaction with Freeport LNG Development, L.P. (Freeport LNG) to participate in a liquefied natural gas (LNG) receiving terminal in Quintana, Texas. We have no ownership in Freeport LNG; however, we obtained a 50 percent interest in Freeport LNG GP, Inc., which serves as the general partner managing the venture. We entered into a credit agreement with Freeport LNG, whereby we will provide loan financing of approximately $630 million for the construction of the terminal. Through December 31, 2005, we had provided $212 million in financing, including accrued interest. We determined that Freeport LNG was a VIE, and that we were not the primary beneficiary. We account for our loan to Freeport LNG as a financial asset.

In June 2005, ConocoPhillips and OAO LUKOIL (LUKOIL) created the OOO Naryanmarneftegaz (NMNG) joint venture to develop resources in the Timan-Pechora region of Russia. We determined that NMNG was a VIE because we and our related party, LUKOIL, have disproportionate interests. We have a 30 percent ownership interest with a 50 percent governance interest in the joint venture. We determined we were not the primary beneficiary and we use the equity method of accounting for this investment. Our funding for a 30 percent ownership interest amounted to $512 million. This acquisition price was based on preliminary estimates of capital expenditures and working capital. Purchase price adjustments are expected to be finalized in the first quarter of 2006. At December 31, 2005, the book value of our investment in the venture was $630 million.

Production from the NMNG joint-venture fields is transported via pipeline to LUKOIL’s existing terminal at Varandey Bay on the Barents Sea and then shipped via tanker to international markets. LUKOIL intends to complete an expansion of the terminal’s capacity in late 2007, with ConocoPhillips participating in the design and financing of the expansion. We determined that the terminal entity, Varandey Terminal Company, is a VIE because we and our related party, LUKOIL, have disproportionate interests. We have an obligation to fund, through loans, 30 percent of the terminal’s costs, but we will have no governance or ownership interest in the terminal. We determined that we were not the primary beneficiary and account

for our loan to Varandey Terminal Company as a financial asset. Through December 31, 2005, we had provided $61 million in loan financing.

In 2003, we entered into two 20-year agreements establishing separate guarantee facilities of $50 million each for two LNG ships that were then under construction. Subject to the terms of the facilities, we will be required to make payments should the charter revenue generated by the respective ships fall below a certain specified minimum threshold, and we will receive payments to the extent that such revenues exceed those thresholds. Actual gross payments over the 20 years could exceed $100 million to the extent cash is received by us. In September 2003, the first ship was delivered to its owner and in July 2005, the second ship was delivered to its owner. We determined that both of our agreements represented a VIE, but we were not the primary beneficiary and, therefore, did not consolidate these entities. The amount drawn under the guarantee facilities at December 31, 2005, was less than $5 million for both ships. We currently account for these agreements as guarantees and contingent liabilities. See Note 14—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 were terminated. At December 31, 2005, we continue to lease refining assets totaling $116 million, which are collateral for the debt obligations of $111 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 because 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, 2005, the fair market value of the swap was a liability of $2 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. (Cold Spring) 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, 2005, was 5.37 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, 2005, 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, 2005, Ashford held $1.8 billion of ConocoPhillips subsidiary notes and $28 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 because 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 $.02 per basic and diluted share. Excluding the cumulative effect, the adoption of FIN 46(R) increased net income by $139 million, or $.10 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 20—Employee Benefit Plans for additional information.

Other

In June 2005, the FASB ratified EITF Issue No. 04-5, "Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights" (Issue No. 04-5). Issue No. 04-5 adopts a framework for evaluating whether the general partner (or general partners as a group) controls the partnership. The framework makes it more likely that a single general partner (or a general partner within a general partner group) would have to consolidate the limited partnership regardless of its ownership in the limited partnership. The new guidance was effective upon ratification for all newly formed limited partnerships and for existing limited partnership agreements that are modified. The adoption of this portion of the EITF guidance had no impact on our financial statements. The guidance is effective January 1, 2006, for existing limited partnership agreements that have not been modified. This guidance will not require any new consolidations by us for existing limited partnerships or similar activities.

In April 2005, the FASB issued FASB Staff Position (FSP) FAS 19-1, "Accounting for Suspended Well Costs" (FSP FAS 19-1), with application required in the first reporting period beginning after April 4, 2005. Under early application provisions, we adopted FSP FAS 19-1 effective January 1, 2005. The adoption of this Standard did not impact 2005 net income. See Note 8—Properties, Plants and Equipment for additional information.

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 fair value recognition of nonmonetary exchanges of similar productive assets and replaces it with an exception for exchanges of nonmonetary assets that do not have commercial substance. We adopted this guidance on a prospective basis effective July 1, 2005. There was no impact to our financial statements upon adoption.

In December 2004, the FASB issued 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 of 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 21—Income 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 No. 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 20—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.

Note 4—Discontinued Operations

During 2003, 2004 and 2005, we disposed of certain U.S. retail and wholesale marketing assets, certain U.S. refining and related assets, and certain U.S. midstream natural gas gathering and processing assets. For reporting purposes, these operations were classified as discontinued operations, and in Note 26—Segment Disclosures and Related Information, these operations were included in Corporate and Other.

During 2003 we sold:

- Our Woods Cross business unit, which included 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).
- Our Exxon-branded marketing assets in New York and New England, including contracts with independent dealers and marketers. Approximately 230 sites were included in this package.
- 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 charge in 2003 of approximately $96 million before-tax.

During 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.

During 2005, we sold the majority of the remaining assets that had been classified as discontinued and reclassified the remaining immaterial assets back into continuing operations.

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

	Millions of Dollars		
	2005	2004	2003
Sales and other operating revenues from discontinued operations	**356**	1,104	8,076
Income (loss) from discontinued operations before-tax	**(26)**	20	317
Income tax expense (benefit)	**(3)**	(2)	80
Income (loss) from discontinued operations	**(23)**	22	237

Assets of discontinued operations at December 31, 2004, were primarily properties, plants and equipment, while liabilities were primarily deferred taxes.

Note 5—Subsidiary Equity Transactions

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

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

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

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

Note 6—Inventories

Inventories at December 31 were:

		Millions of Dollars	
		2005	2004
Crude oil and petroleum products	**$**	**3,183**	3,147
Materials, supplies and other		**541**	519
	$	**3,724**	3,666

Inventories valued on a LIFO basis totaled $3,019 million and $2,988 million at December 31, 2005 and 2004, 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 $4,271 million and $2,220 million at December 31, 2005 and 2004, respectively.

During 2005, certain inventory quantity reductions caused a liquidation of LIFO inventory values. This liquidation increased net income by $16 million, of which $15 million was attributable to our R&M segment. In 2004, a liquidation of LIFO inventory values increased income from continuing operations by $62 million, of which $54 million was attributable to our R&M segment.

Note 7—Investments and Long-Term Receivables

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

		Millions of Dollars	
		2005	2004
Investment in and advances to affiliated companies*	**$**	**14,777**	9,466
Long-term receivables		**458**	463
Other investments		**491**	479
	$	**15,726**	10,408

* *The Investment in and advances to affiliated companies balance includes loans and advances of $320 million and $163 million to certain equity investment companies at December 31, 2005 and 2004, respectively.*

Equity Investments
Significant affiliated companies for which we use the equity method of accounting include:

- LUKOIL—16.1 percent ownership interest at December 31, 2005 (10.0 percent at year-end 2004). We use the equity method of accounting 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. LUKOIL 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.

- Duke Energy Field Services, LLC (DEFS)—50 percent ownership interest at December 31, 2005 (30.3 percent at year-end 2004)—owns and operates gas plants, gathering systems, storage facilities and fractionation plants.

- 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. Hamaca 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. Petrozuata produces extra heavy crude oil and upgrades it into medium grade crude oil at Jose on the northern coast of Venezuela.

- OOO Naryanmarneftegaz (NMNG)—30 percent economic interest and a 50 percent voting interest—a joint venture with LUKOIL to explore for and develop oil and gas resources in the northern part of Russia's Timan-Pechora province.

- 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 (information included for LUKOIL is based on estimates):

		Millions of Dollars		
		2005	2004	2003
Revenues	$	**96,367**	45,053	29,777
Income before income taxes		**15,059**	5,549	2,033
Net income		**11,743**	4,478	1,495
Current assets		**23,652**	20,609	8,934
Noncurrent assets		**48,181**	43,844	24,147
Current liabilities		**14,727**	15,283	8,270
Noncurrent liabilities		**15,833**	14,481	11,253

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.

At December 31, 2005, retained earnings included $3,376 million related to the undistributed earnings of affiliated companies, and distributions received from affiliates were $1,807 million, $1,035 million and $496 million in 2005, 2004 and 2003, respectively.

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 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.

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, excluding transaction costs. The transaction closed on October 7, 2004. We increased our ownership in LUKOIL to 16.1 percent by the end of 2005. 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. 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.

Our equity share of the results of LUKOIL for the current year period 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 our estimate of fourth-quarter 2005 and the actual LUKOIL U.S. GAAP net income will be reported in our 2006 equity earnings. At December 31, 2005, the book value of our ordinary share investment in LUKOIL was $5,549 million. Our 16.1 percent share of the net assets of LUKOIL was estimated to be $4,174 million. This basis difference of $1,375 million is primarily being amortized on a unit-of-production basis. Included in net income for 2005 and 2004 was after-tax expense of $43 million and $14 million, respectively, representing the amortization of this basis difference.

On December 31, 2005, the closing price of LUKOIL shares on the London Stock Exchange was $59 per share, making the aggregate total market value of our LUKOIL investment $8,069 million.

Duke Energy Field Services, LLC
DEFS owns and operates gas plants, gathering systems, storage facilities and fractionation plants. In July 2005, ConocoPhillips and Duke Energy Corporation (Duke) restructured their respective ownership levels in DEFS, which resulted in DEFS becoming a jointly controlled venture, owned 50 percent by each company. This restructuring increased our ownership in DEFS to 50 percent from 30.3 percent through a series of direct and indirect transfers of certain Canadian Midstream assets from DEFS to Duke, a disproportionate cash distribution from DEFS to Duke from the sale of DEFS' interest in TEPPCO Partners, L.P., and a combined payment by ConocoPhillips to Duke and DEFS of approximately $840 million. Our interest in the Empress plant in Canada was not included in the initial transaction as originally anticipated due to weather-related damage to the facility. Subsequently, the Empress plant was sold to Duke on August 1, 2005, for approximately $230 million. In the first quarter of 2005, as a part of equity earnings, we recorded our $306 million (after-tax) equity share of the financial gain from DEFS' sale of its interest in TEPPCO.

At December 31, 2005, the book value of our common investment in DEFS was $1,274 million. Our 50 percent share of the net assets of DEFS was $1,253 million. This basis difference of $21 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 2005, 2004 and 2003 was after-tax income of $17 million, $36 million and $36 million, respectively, representing the amortization of the basis difference.

DEFS markets a 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, 2005, the book value of our investment in CPChem was $2,158 million. Our 50 percent share of the total net assets of CPChem was $2,015 million. This basis difference of $143 million is being amortized through 2020, consistent with the remaining estimated useful lives of CPChem properties, plants and equipment.

During 2005, we received one distribution from CPChem totaling $37.5 million that redeemed the remainder of our member preferred interests.

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.

Loans to Affiliated Companies
As part of our normal ongoing business operations and consistent with normal industry practice, we invest 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. Included in such activity are loans made to certain affiliated companies. Significant loans to affiliated companies include the following:

- We entered into a credit agreement with Freeport LNG, whereby we will provide loan financing of approximately $630 million for the construction of an LNG facility. Through December 31, 2005, we had provided $212 million in loan financing, including accrued interest. See Note 3—Changes in Accounting Principles, for additional information.

- We have an obligation to provide loan financing to Varandey Terminal Company for 30 percent of the costs of a terminal expansion. Based on preliminary budget estimates from the operator, we expect our total loan obligation for the terminal expansion to be approximately $330 million. This amount will be adjusted as the design is finalized and the expansion project proceeds. Through December 31, 2005, we had provided $61 million in loan financing. See Note 3—Changes in Accounting Principles, for additional information.

- Qatargas 3 is an integrated project to produce and liquefy natural gas from Qatar's North field. We own a 30 percent interest in the project. The other participants in the project are affiliates of Qatar Petroleum (68.5 percent) and Mitsui & Co., Ltd. (Mitsui) (1.5 percent). Our interest is held through a jointly owned company, Qatar Liquefied Gas Company Limited (3), for which we use the equity method of accounting. Qatargas 3 secured project financing of $4 billion in December 2005, consisting of $1.3 billion of loans from export credit agencies (ECA), $1.5 billion from commercial banks, and $1.2 billion from ConocoPhillips. The ConocoPhillips loan facilities have substantially the same terms as the ECA and commercial bank facilities. Prior to project completion certification, all loans, including the ConocoPhillips loan facilities, are guaranteed by the participants based on their respective ownership interests. Accordingly, our maximum exposure to this financing structure is $1.2 billion. Upon completion certification, which is expected to be December 31, 2009, all project loan facilities, including the ConocoPhillips loan facilities, will become non-recourse to the project participants. At December 31, 2005, Qatargas 3 had $120 million outstanding under all the loan facilities, $36 million of which was loaned by ConocoPhillips.

Note 8—Properties, Plants and Equipment

Properties, plants and equipment (PP&E) are recorded at cost. Within the E&P segment, depreciation is on a unit-of-production basis, so depreciable life will vary by field. In the R&M segment, investments in refining assets and lubes basestock manufacturing facilities are generally depreciated on a straight-line basis over a 25-year life, pipeline assets over a 45-year life, and service station buildings and fixed improvements over a 30-year life. The company's investment in PP&E, with accumulated depreciation, depletion and amortization (Accum. DD&A), at December 31 was:

	Millions of Dollars					
	2005			2004		
	Gross PP&E	Accum. DD&A	Net PP&E	Gross PP&E	Accum. DD&A	Net PP&E
E&P	$ **53,907**	**16,200**	**37,707**	48,105	13,612	34,493
Midstream	**322**	**128**	**194**	589	120	469
R&M	**20,046**	**4,777**	**15,269**	18,402	4,048	14,354
LUKOIL Investment	**—**	**—**	**—**	—	—	—
Chemicals	**—**	**—**	**—**	—	—	—
Emerging Businesses	**865**	**61**	**804**	940	26	914
Corporate and Other	**1,192**	**497**	**695**	1,115	443	672
	$ **76,332**	**21,663**	**54,669**	69,151	18,249	50,902

Suspended Wells

In April 2005, the FASB issued FSP FAS 19-1, "Accounting for Suspended Well Costs" (FSP FAS 19-1). This FSP was issued to address whether there were circumstances that would permit the continued capitalization of exploratory well costs beyond one year, other than when further exploratory drilling is planned and major capital expenditures would be required to develop the project.

FSP FAS 19-1 requires the continued capitalization of suspended well costs if the well has found a sufficient quantity of reserves to justify its completion as a producing well and the company is making sufficient progress assessing these reserves and the economic and operating viability of the project. All relevant facts and circumstances should be evaluated in determining whether a company is making sufficient progress assessing the reserves, and FSP FAS 19-1 provides several indicators to assist in this evaluation. FSP FAS 19-1 prohibits continued capitalization of suspended well costs on the chance that market conditions will change or technology will be developed to make the project economic. We adopted FSP FAS 19-1 effective January 1, 2005. There was no impact on our consolidated financial statements from the adoption.

The following table reflects the net changes in suspended exploratory well costs during 2005, 2004 and 2003:

		Millions of Dollars		
		2005	2004	2003
Beginning balance at January 1	$	**347**	403	221
Additions pending the determination of proved reserves		**183**	142	211
Reclassifications to proved properties		**(81)**	(112)	—
Charged to dry hole expense		**(110)**	(86)	(29)
Ending balance at December 31	$	**339**	347	403

The following table provides an aging of suspended well balances at December 31, 2005, 2004 and 2003:

		Millions of Dollars		
		2005	2004	2003
Exploratory well costs capitalized for a period of one year or less	$	**183**	142	211
Exploratory well costs capitalized for a period greater than one year		**156**	205	192
Ending balance	$	**339**	347	403
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year		**15**	16	13

The following table provides a further aging of those exploratory well costs that have been capitalized for more than one year since the completion of drilling as of December 31, 2005:

		Millions of Dollars				
			Suspended Since			
Project		Total	2004	2003	2002	2001
Alpine satellite—Alaska *(1)*	$	21	—	—	21	—
Malikai—Malaysia *(2)*		10	10	—	—	—
Kashagan—Republic of Kazakhstan *(2)*		18	—	9	—	9
Kairan—Republic of Kazakhstan *(2)*		13	13	—	—	—
Aktote—Republic of Kazakhstan *(3)*		19	7	12	—	—
Gumusut—Malaysia *(3)*		24	12	12	—	—
Plataforma Deltana—Venezuela *(3)*		15	15	—	—	—
Eight projects of less than $10 million each *(2)(3)*		36	1	18	9	8
Total of 15 projects	$	156	58	51	30	17

(1) Development decisions pending infrastructure west of Alpine and construction authorization.
(2) Additional appraisal wells planned.
(3) Appraisal drilling complete; costs being incurred to assess development.

Note 9—Goodwill and Intangibles

Changes in the carrying amount of goodwill are as follows:

		Millions of Dollars		
		E&P	R&M	Total
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
Acquired (Libya—see below)		**477**	—	**477**
Tax and other adjustments		**(144)**	—	**(144)**
Balance at December 31, 2005	$	**11,423**	**3,900***	**15,323**

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

On December 28, 2005, we signed an agreement with the Libyan National Oil Corporation under which we and our co-venturers acquired an ownership interest in the Waha concessions in Libya. On December 29, 2005, the Libyan government approved the signed agreement which, in the opinion of our legal counsel, made the rights and obligations under the contract legally binding and unconditional at that date among all four parties involved. The terms included a payment to the Libyan National Oil Corporation of $520 million (net to ConocoPhillips) for the acquisition of an ownership in, and extension of, the concessions; and a contribution to unamortized investments made since 1986 of $212 million (net to ConocoPhillips) that were agreed to be paid as part of the

1986 standstill agreement to hold the assets in escrow for the U.S.-based co-venturers. The $732 million of total unconditional payment obligations were recognized as current liabilities in the "Other Accruals" line of the consolidated balance sheet. The recognition of assets acquired in the business combination was a preliminary allocation of the $732 million to properties, plants and equipment. This transaction also resulted in the recording of $477 million of goodwill, which relates to net deferred tax liabilities arising from differences between the allocated financial

bases and deductible tax bases of the acquired assets. This goodwill is not expected to be deductible for tax purposes.

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, 2005				
Refining technology related	**$**	**102**	**(31)**	**71**
Refinery air permits*		**32**	**(6)**	**26**
Other**		**87**	**(37)**	**50**
	$	**221**	**(74)**	**147**
Balance at December 31, 2004				
Refining technology related	$	109	(24)	85
Other**		76	(29)	47
	$	185	(53)	132

Indefinite-Lived Intangible Assets		
Balance at December 31, 2005		
Trade names and trademarks	**$**	**598**
Refinery air and operating permits*		**242**
Other***		**129**
	$	**969**
Balance at December 31, 2004		
Trade names and trademarks	$	637
Refinery air and operating permits		274
Other***		53
	$	964

**During 2005, U.S. regulatory actions resulted in the determination that certain U.S. refinery air emission credits totaling $32 million, which were previously classified as indefinite-lived, now have a finite useful life. At the time of that determination, and in accordance with SFAS No. 142, "Goodwill and Other Intangible Assets," amortization began on these intangible assets prospectively over their estimated remaining useful life.*
***Primarily related to seismic technology, land rights, supply and processing contracts and licenses.*
****Primarily pension related.*

Amortization expense related to the intangible assets above for the years ended December 31, 2005 and 2004, was $21 million and $18 million, respectively. The estimated amortization expense for the next five years is approximately $20 million per year.

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 10—Property Impairments

During 2005, 2004 and 2003, we recognized the following before-tax impairment charges:

		Millions of Dollars		
		2005	2004	2003
E&P				
United States	**$**	**2**	18	65
International		**2**	49	180
Midstream		**30**	38	—
R&M				
Intangible assets		**—**	42	—
Other		**8**	17	2
Corporate and Other		**—**	—	5
	$	**42**	164	252

The E&P segment's impairments were the result of the write-down to market value of properties planned for disposition, properties failing to meet recoverability tests, and, in 2003, international tax law changes affecting asset removal costs. The Midstream segment recognized property impairments related to planned asset dispositions. In R&M, we reduced the carrying value of certain indefinite-lived intangible assets in 2004. See Note 9—Goodwill and Intangibles, for additional information. Other impairments in R&M primarily were related to assets planned for disposition.

See Note 4—Discontinued Operations, for information regarding property impairments included in discontinued operations.

Note 11—Asset Retirement Obligations and Accrued Environmental Costs

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

	Millions of Dollars	
	2005	2004
Asset retirement obligations	$ **3,901**	3,089
Accrued environmental costs	**989**	1,061
Total asset retirement obligations and accrued environmental costs	**4,890**	4,150
Asset retirement obligations and accrued environmental costs due within one year*	**(299)**	(256)
Long-term asset retirement obligations and accrued environmental costs	$ **4,591**	3,894

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

Asset Retirement Obligations
For information on our adoption of SFAS No. 143 and FIN 47, and related disclosures, see Note 3—Changes in Accounting Principles.

Accrued Environmental Costs
Total environmental accruals at December 31, 2005 and 2004, were $989 million and $1,061 million, respectively. The 2005 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 $570 million and $606 million at December 31, 2005 and 2004, 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 $302 million and $337 million of environmental costs associated with non-operating sites at December 31, 2005 and 2004, respectively. In addition, $117 million and $118 million were included at December 31, 2005 and 2004, 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 $805 million at December 31, 2005. The expected future undiscounted payments related to the portion of the accrued environmental costs that have been discounted are: $149 million in 2006, $102 million in 2007, $65 million in 2008, $60 million in 2009, $61 million in 2010, and $476 million for all future years after 2010.

Note 12—Debt

Long-term debt at December 31 was:

	Millions of Dollars	
	2005	2004
9 3/8% Notes due 2011	$ **328**	350
8.75% Notes due 2010	**1,264**	1,350
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	**49**	54
7.625% Notes due 2006	**240**	240
7.25% Notes due 2007	**153**	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	**1,549**	1,900
6.65% Debentures due 2018	**297**	300
6.375% Notes due 2009	**284**	300
6.35% Notes due 2009	—	750
6.35% Notes due 2011	**1,750**	1,750
5.90% Notes due 2032	**505**	600
5.847% Notes due 2006	**111**	118
5.45% Notes due 2006	**1,250**	1,250
4.75% Notes due 2012	**897**	1,000
3.625% Notes due 2007	—	400

Commercial paper and revolving debt due to banks and others through 2010 at 4.43% at year-end 2005 and 2.29% at year-end 2004		**32**	544
Industrial Development bonds at 2.98% - 3.85% at year-end 2005 and 1.47% - 6.1% at year-end 2004		**236**	256
Guarantee of savings plan bank loan payable at 4.775% at year-end 2005 and 2.8375% at year-end 2004		**229**	253
Note payable to Merey Sweeny, L.P. at 7%		**136**	141
Marine Terminal Revenue Refunding Bonds at 3.0% at year-end 2005 and 1.8% at year-end 2004		**265**	265
Other		**151**	50
Debt at face value		**12,087**	14,432
Capitalized leases		**47**	56
Net unamortized premiums and discounts		**382**	514
Total debt		**12,516**	15,002
Notes payable and long-term debt due within one year		**(1,758)**	(632)
Long-term debt	**$**	**10,758**	14,370

Maturities inclusive of net unamortized premiums and discounts in 2006 through 2010 are: $1,758 million (included in current liabilities), $199 million, $77 million, $331 million and $1,346 million, respectively.

Effective October 5, 2005, we entered into two new revolving credit facilities totaling $5 billion to replace our previously existing $2.5 billion four-year facility expiring in October 2008 and a $2.5 billion five-year facility expiring in October 2009. The two new revolving credit facilities expire in October 2010. The

facilities are available for use as direct bank borrowings or as support for the ConocoPhillips $5 billion commercial paper program, the ConocoPhillips Qatar Funding Ltd. $1.5 billion commercial paper program, and could 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, 2005, but $62 million in letters of credit had been issued.

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 2005, we reduced the commercial paper balance outstanding under the ConocoPhillips program from $544 million at December 31, 2004, to a zero balance at December 31, 2005. In December 2005, ConocoPhillips Qatar Funding Ltd. initiated a $1.5 billion commercial paper program to be used to fund our commitments relating to the Qatargas 3 project. At December 31, 2005, commercial paper outstanding under this program totaled $32 million. Also in 2005, we redeemed our $750 million 6.35% Notes due 2009, at a premium of $42 million plus accrued interest; our $400 million 3.625% Notes due 2007, at par plus accrued interest; and we purchased, at market prices, and retired $752 million of various ConocoPhillips bond issues. In conjunction with the redemption of the 6.35% Notes and the 3.625% Notes, $750 million and $400 million, respectively, of interest rate swaps were cancelled. The note redemptions, interest rate swap cancellations, and bond issue purchases resulted in after-tax losses of $92 million.

At December 31, 2005, $229 million was outstanding under the ConocoPhillips Savings Plan term loan, which requires repayment in semi-annual installments beginning in 2010 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. 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 20—Employee Benefit Plans, for additional discussion of the ConocoPhillips Savings Plan.

Note 13—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. The arrangement provided for ConocoPhillips 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. At December 31, 2004, the QSPE had issued beneficial interests to the bank-sponsored entities of $480 million. 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 held no ownership interests, nor any variable interests, in any of the bank-sponsored entities, which we have not consolidated.

Furthermore, except as discussed below, we have not consolidated the QSPE because it has met 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. The receivables transferred to the QSPE have met the isolation and other requirements of SFAS No. 140 to be accounted for as sales and have been accounted for accordingly.

By January 31, 2005, all of the beneficial interests held by the bank-sponsored entities had matured; therefore, in accordance with SFAS No. 140, the operating results and cash flows of the QSPE subsequent to this maturity have been consolidated in our financial statements. The revolving-period securitization arrangement was terminated on August 31, 2005, and, at this time, we have no plans to renew the arrangement.

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

		Millions of Dollars	
		2005	2004
Receivables sold at beginning of year	$	**480**	1,200
New receivables sold		**960**	7,155
Cash collections remitted		**(1,440)**	(7,875)
Receivables sold at end of year	$	**—**	480
Discounts and other fees paid on revolving balances	$	**2**	6

Note 14—Guarantees

At December 31, 2005, we were liable for certain contingent obligations under various contractual arrangements as described below. We recognize a liability, at inception, for the fair value of our obligation as a guarantor for newly issued or modified guarantees. 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

- At December 31, 2005, we had a construction completion guarantee related to our share of the debt held by Hamaca Holding LLC, which was used to construct the joint-venture project in Venezuela. The maximum potential amount of future payments under the guarantee is estimated to be $350 million. The original Guaranteed Project Completion Date of October 1, 2005, was further extended because of force majeure events that occurred during the construction period. Subsequent to the balance sheet date, certified construction completion was achieved on January 9, 2006, so the guarantee was released and the debt became non-recourse to ConocoPhillips.

- In December 2005, we issued a construction completion guarantee for 30 percent of the $4.0 billion in loan facilities of Qatargas 3, which will be used to construct an LNG train in Qatar. Of the $4.0 billion in loan facilities, ConocoPhillips provided facilities of $1.2 billion. The maximum potential amount of future payments to third-party lenders under the guarantee is estimated to be $850 million, which could become payable if the full debt financing is utilized and completion of the Qatargas 3 project is not achieved. Completion certification is expected on December 31, 2009. The project financing will be non-recourse upon certified completion. At year-end 2005, the carrying value of the guarantee to the third party lenders was $11 million. For additional information, see Note 7—Investments and Long-Term Receivables.

Guarantees of Joint-Venture Debt

- At December 31, 2005, we had guarantees outstanding for our portion of joint-venture debt obligations, which have terms of up to 20 years. The maximum potential amount of future payments under the guarantees was approximately $190 million. Payment would be required if a joint venture defaults on its debt obligations. Included in these outstanding guarantees was $96 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 19 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.

- In February 2003, we entered into two agreements establishing separate guarantee facilities of $50 million each for two LNG 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. See Note 3—Changes in Accounting Principles, for additional information.

- We have other guarantees with maximum future potential payment amounts totaling $260 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, 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, 2005, was $22 million. These guarantees generally extend up to 15 years and payment would be required only if the dealer, jobber or lessee goes into default, if the lubricants joint venture has cash liquidity issues, 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 and sold assets, including 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, 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, 2005, was $446 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 $320 million of environmental accruals for known contamination that is included in asset retirement obligations and accrued environmental costs at December 31, 2005. For additional information about environmental liabilities, see Note 11—Asset Retirement Obligations and Accrued Environmental Costs, and Note 15—Contingencies and Commitments.

Note 15—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 acquired in a purchase business combination, which we record 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 11—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. In addition, we have performance obligations that are secured by letters of credit of $749 million (of which $62 million was issued under the provisions of our revolving credit facilities, and the remainder was issued as direct bank 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 2006—$109 million; 2007—$100 million; 2008—$93 million; 2009—$87 million; 2010—$80 million; and 2011 and after—$427 million. Total payments under the agreements were $88 million in 2005, $96 million in 2004 and $90 million in 2003.

Note 16—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 (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 were:

		Millions of Dollars	
		2005	2004
Derivative Assets			
Current	$	**674**	437
Long-term		**193**	42
	$	**867**	479
Derivative Liabilities			
Current	$	**1,002**	265
Long-term		**443**	57
	$	**1,445**	322

These derivative assets and liabilities appear as prepaid expenses and other current assets, other assets, other accruals, or other liabilities and deferred credits on the balance sheet.

In June 2005, we acquired two limited-term, fixed-volume overriding royalty interests in Utah and the San Juan Basin related to our natural gas production. As part of the acquisition, we assumed related commodity swaps with a negative fair value of $261 million at June 30, 2005. In late June and early July, we entered into additional commodity swaps to offset essentially all of the exposure from the assumed swaps. At December 31, 2005, the commodity swaps assumed in the acquisition had a negative fair value of $316 million, and the commodity swaps entered to offset the resulting exposure had a positive fair value of $109 million. These commodity swaps contributed to the increase in derivative assets and liabilities from December 31, 2004, to December 31, 2005, as did price movements, particularly price increases in natural gas.

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 and foreign currency derivatives, 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, but during 2005 we terminated the majority of these interest rate swaps as we redeemed the associated debt. This reduced the amount of debt being converted from fixed to floating by the end of 2005 to $350 million. 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 international operations. 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 the 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 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, 2005, 2004 and 2003, the gains or losses from this activity were not material to our cash flows or income from continuing operations.

At December 31, 2005, 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 are placed in high-quality commercial paper, money market funds and time deposits with major international banks and financial institutions. 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 IntercontinentalExchange.

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.
- Investments in LUKOIL shares: See Note 7—Investments and Long-Term Receivables, for a discussion of the carrying value and fair value of our investment in LUKOIL shares.
- Debt: The carrying amount of our floating-rate debt approximates fair value. The fair value of the fixed-rate debt 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 IntercontinentalExchange, 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 commodity derivative and financial instruments at December 31 were:

	Millions of Dollars			
	Carrying Amount		Fair Value	
	2005	2004	**2005**	2004
Financial assets				
Foreign currency derivatives	$ **5**	96	**5**	96
Interest rate derivatives	**1**	19	**1**	19

Commodity derivatives	**861**	364	**861**	364
Financial liabilities				
Total debt, excluding capital leases	**12,469**	14,946	**13,426**	16,126
Foreign currency derivatives	**39**	6	**39**	6
Interest rate derivatives	**10**	17	**10**	17
Commodity derivatives	**1,396**	299	**1,396**	299

Note 17—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 3—Changes in Accounting Principles, for additional information.

Other Minority Interests
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, 2005 and 2004, was 5.37 percent and 3.34 percent, respectively. At December 31, 2005 and 2004, the minority interest was $507 million and $504 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 3—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, $682 million at December 31, 2005, relates to the Bayu-Undan LNG project in the Timor Sea and northern Australia. See Note 5—Subsidiary Equity Transactions, for additional information.

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, 2005.

Note 18—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 19—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, 2005, future minimum rental payments due under non-cancelable leases were:

Millions

		of Dollars
2006	$	494
2007		412
2008		354
2009		259
2010		208
Remaining years		891
Total		2,618
Less income from subleases		(239)*
Net minimum operating lease payments	$	2,379

**Includes $150 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		
		2005	2004	2003
Total rentals*	$	**564**	521	471
Less sublease rentals		**(66)**	(42)	(40)
	$	**498**	479	431

**Includes $28 million, $27 million and $31 million of contingent rentals in 2005, 2004 and 2003, respectively. Contingent rentals primarily are related to retail sites and refining equipment, and are based on volume of product sold or throughput.*

Note 20—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	
	2005		2004		**2005**	2004
	U.S.	**Int'l.**	U.S.	Int'l.		
Change in Benefit Obligation						
Benefit obligation at January 1	$ **3,101**	**2,409**	3,020	2,075	**913**	1,004
Service cost	**151**	**69**	150	69	**19**	23
Interest cost	**174**	**122**	176	114	**48**	58
Plan participant contributions	**—**	**2**	—	2	**34**	32
Plan amendments	**69**	**—**	—	2	**—**	—
Actuarial (gain) loss	**378**	**232**	129	31	**(117)**	(134)
Divestitures	**—**	**(9)**	—	—	**—**	—
Benefits paid	**(170)**	**(65)**	(374)	(84)	**(83)**	(73)
Curtailment	**—**	**(3)**	—	—	**—**	—
Recognition of termination benefits	**—**	**3**	—	3	**—**	—
Foreign currency exchange rate change	**—**	**(265)**	—	197	**1**	3
Benefit obligation at December 31	$ **3,703**	**2,495**	3,101	2,409	**815**	913
Accumulated benefit obligation portion of above at December 31	$ **3,037**	**2,099**	2,436	2,078		
Change in Fair Value of Plan Assets						
Fair value of plan assets at January 1	$ **1,701**	**1,627**	1,460	1,303	**4**	7
Divestitures	**—**	**(10)**	—	—	**—**	—
Actual return on plan assets	**161**	**217**	198	129	**—**	1
Company contributions	**491**	**144**	417	139	**48**	37
Plan participant contributions	**—**	**2**	—	2	**34**	32
Benefits paid	**(170)**	**(65)**	(374)	(84)	**(83)**	(73)
Foreign currency exchange rate change	**—**	**(190)**	—	138	**—**	—
Fair value of plan assets at December 31	$ **2,183**	**1,725**	1,701	1,627	**3**	4

	Millions of Dollars					
	Pension Benefits				Other Benefits	
	2005		2004		**2005**	2004
	U.S.	**Int'l.**	U.S.	Int'l.		
Funded Status						
Excess obligation	$ **(1,520)**	**(770)**	(1,400)	(782)	**(812)**	(909)
Unrecognized net actuarial loss (gain)	**812**	**398**	524	341	**(156)**	(45)
Unrecognized prior service cost	**88**	**46**	23	57	**73**	92
Total recognized amount in the consolidated balance sheet	$ **(620)**	**(326)**	(853)	(384)	**(895)**	(862)

Components of above amount:						
Prepaid benefit cost	$ —	**69**	—	71	**—**	—
Accrued benefit liability	**(838)**	**(481)**	(872)	(569)	**(895)**	(862)
Intangible asset	**88**	**39**	4	48	**—**	—
Accumulated other comprehensive loss	**130**	**47**	15	66	**—**	—
Total recognized	$ **(620)**	**(326)**	(853)	(384)	**(895)**	(862)
Weighted-Average Assumptions Used to Determine Benefit Obligations at December 31						
Discount rate	**5.50%**	**5.05**	5.75	5.50	**5.70**	5.75
Rate of compensation increase	**4.00**	**4.35**	4.00	3.80	**4.00**	4.00
Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for years ended December 31						
Discount rate	**5.75%**	**5.50**	6.00	5.45	**5.75**	6.00
Expected return on plan assets	**7.00**	**6.85**	7.00	7.00	**7.00**	7.00
Rate of compensation increase	**4.00**	**3.80**	4.00	3.55	**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.

All of our plans use a December 31 measurement date, except for a plan in the United Kingdom, which has a September 30 measurement date.

During 2005, we recorded charges to other comprehensive income related to minimum pension liability adjustments totaling $96 million ($55 million net of tax), resulting in accumulated other comprehensive loss due to minimum pension liability adjustments at December 31, 2005, of $177 million ($115 million net of tax). During 2004, we recorded a benefit to other comprehensive income 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).

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 $5,896 million, $4,899 million, and $3,906 million at December 31, 2005, respectively, and $4,893 million, $4,015 million, and $2,914 million at December 31, 2004, respectively.

For our unfunded non-qualified supplemental key employee pension plans, the projected benefit obligation and the accumulated benefit obligation were $292 million and $227 million, respectively, at December 31, 2005, and were $219 million and $162 million, respectively, at December 31, 2004.

	Millions of Dollars								
	Pension Benefits						Other Benefits		
	2005		2004		2003		**2005**	2004	2003
	U.S.	**Int'l.**	U.S.	Int'l.	U.S.	Int'l.			
Components of Net Periodic Benefit Cost									
Service cost	$ **151**	**69**	150	69	131	61	**19**	23	17
Interest cost	**174**	**122**	176	114	197	89	**48**	58	61
Expected return on plan assets	**(126)**	**(105)**	(105)	(92)	(90)	(78)	**—**	—	—
Amortization of prior service cost	**4**	**7**	4	7	4	5	**19**	19	19
Recognized net actuarial loss (gain)	**55**	**33**	52	40	70	17	**(6)**	10	6
Net periodic benefit cost	$ **258**	**126**	277	138	312	94	**80**	110	103

We recognized pension settlement losses of $4 million and $13 million in 2005 and 2004, respectively, and special termination benefits of $3 million in 2005 and 2004. As a result of the ConocoPhillips merger, we recognized settlement losses of $120 million and special termination benefits of $9 million in 2003.

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 2006 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 2005 amounts:

	Millions of Dollars	
	One-Percentage-Point	
	Increase	Decrease
Effect on total of service and interest cost components	$ 1	(1)

Effect on the postretirement benefit obligation	15	(11)

During the third quarter of 2005, we announced that retail prescription drug coverage will be extended to heritage Phillips retirees, similar to the benefit provided to heritage Conoco and Tosco retirees. Because of this change, we measured our postretirement medical plan liability as of September 1, 2005. Also included in the September 1, 2005, measurement was a loss from lowering the discount rate by 75 basis points to 5.00 percent, a gain from favorable claims experience, and a gain from recognizing the non-taxable federal subsidy we expect to receive under Medicare Part D. In 2004, we stated that, based on the regulatory evidence available at that time, we did not believe the benefit provided under our plan would be actuarially equivalent to that offered under Medicare Part D and that we would not be entitled to receive a federal subsidy. However, because of the extension of additional prescription drug benefits to heritage Phillips retirees, recent favorable claims experience, and the additional flexibility provided in the final regulations issued by the Department of Health and Human Services earlier in 2005 regarding the submission of Medicare subsidy claims, we concluded that our plan will qualify for the subsidy. Consequently, we reduced the Accumulated Postretirement Benefit Obligation (APBO) in the September 1, 2005, measurement by $166 million for the federal subsidy and reduced expense for the period from September through December 2005 for service cost, interest cost, and the amortization of gains by $2 million, $3 million, and $5 million, respectively. Combining all of the changes included in the September 1, 2005, measurement, the medical plan's APBO decreased by $53 million, and expense for the remainder of 2005 was $7 million lower than it would have been, based on the previous measurement.

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. 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 2006, we expect to contribute approximately $415 million to our domestic qualified and non-qualified benefit plans and $115 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, 2005, the participating interest in the annuity contract was valued at $175 million and consisted of $407 million in debt securities and $71 million in equity securities, less $303 million for the accumulated benefit obligation covered by the contract. At December 31, 2004, the participating interest 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. 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		
	2005	2004	Target	**2005**	2004	Target
Asset Category						
Equity securities	**66%**	64	60	**50**	51	54
Debt securities	**32**	34	30	**38**	43	42
Real estate	**1**	1	5	**3**	1	2
Other	**1**	1	5	**9**	5	2
	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	
	2005	2004	**2005**	2004
Asset Category				
Equity securities	**72%**	70	**50**	51
Debt securities	**18**	16	**38**	43
Participating interest in annuity contract	**8**	11	**—**	—
Real estate	**1**	1	**3**	1
Other	**1**	2	**9**	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		Other Benefits	
	U.S.	Int'l.	Gross	Subsidy Receipts
2006	$ 190	66	55	6
2007	210	70	53	6
2008	243	74	59	7

2009	259	80	61	8
2010	290	84	63	8
2011-2015	2,016	508	346	48

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 32 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 $18 million in 2005, $17 million in 2004, and $19 million in 2003.

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 2006 through 2009, 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 $127 million, $88 million and $76 million in 2005, 2004 and 2003, respectively, all of which was compensation expense. In 2005, 2004 and 2003, we made cash contributions to the CPSP of less than $1 million. In 2005, 2004 and 2003, we contributed 2,250,727 shares, 2,419,808 shares and 2,967,560 shares, respectively, of company common stock from the Compensation and Benefits Trust. The shares had a fair market value of $130 million, $99 million and $89 million, respectively. Dividends used to service debt were $32 million, $27 million, and $28 million in 2005, 2004 and 2003, respectively. These dividends reduced the amount of compensation expense recognized each period. Interest incurred on the CPSP debt in 2005, 2004 and 2003 was $9 million, $5 million and $5 million, respectively.

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

	2005	2004*
Unallocated shares	**11,843,383**	13,039,268
Allocated shares	**19,095,143**	19,727,472
Total shares	**30,938,526**	32,766,740

**Reflects a two-for-one stock split effected as a 100 percent stock dividend on June 1, 2005.*

The fair value of unallocated shares at December 31, 2005, and 2004, was $689 million and $566 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 2005 and 2004.

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 70 million shares of our common stock for compensation to our employees, directors and consultants. After approval of the Plan, the heritage plans were no longer used for further awards. Of the 70 million shares available for issuance under the Plan, the number of shares of common stock available for incentive stock options will be 40 million shares, and no more than 40 million shares may be used for awards in stock.

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

	2005	2004*	2003*
Shares	**1,733,290**	2,953,016	521,354
Weighted-average fair value	**$ 48.00**	33.64	24.38

**Reflects a two-for-one stock split effected as a 100 percent stock dividend on June 1, 2005.*

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.

A summary of our stock option activity follows:

	Options*	Weighted-Average

		Exercise Price*
Outstanding at December 31, 2002	86,213,210	$ 23.83
Granted	13,439,748	24.40
Exercised	(7,394,542)	15.99
Forfeited	(599,262)	25.04
Outstanding at December 31, 2003	91,659,154	$ 24.54
Granted	4,352,208	32.85
Exercised	(21,425,398)	21.22
Forfeited	(322,042)	25.73
Outstanding at December 31, 2004	74,263,922	$ 25.97
Granted	**2,567,000**	**47.87**
Exercised	**(19,265,175)**	**24.85**
Forfeited	**(169,001)**	**34.83**
Outstanding at December 31, 2005	**57,396,746**	**$ 27.31**

**Reflects a two-for-one stock split effected as a 100 percent stock dividend on June 1, 2005.*

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:

	2005	2004	2003
Average grant date fair value of options*	**$ 10.92**	7.13	4.98
Assumptions used			
Risk-free interest rate	**3.92%**	3.5	3.4
Dividend yield	**2.50%**	2.5	3.3
Volatility factor	**22.50%**	24.2	25.9
Expected life (years)	**7.18**	6	6

**2004 and 2003 reflect a two-for-one stock split effected as a 100 percent stock dividend on June 1, 2005.*

Options Outstanding at December 31, 2005

		Weighted-Average	
Exercise Prices	Options	Remaining Lives	Exercise Price
$12.34 to $23.86	**17,009,602**	**3.98 years**	**$22.60**
$24.02 to $28.83	**19,855,349**	**5.78 years**	**25.10**
$29.03 to $67.12	**20,531,795**	**6.49 years**	**33.34**

Options Exercisable at December 31

	Exercise Prices	Options	Weighted-Average Exercise Price
2005	**$12.34 to $23.86**	**17,009,602**	**$22.60**
	$24.02 to $28.83	**15,825,692**	**25.28**
	$29.03 to $55.05	**15,736,186**	**31.14**
2004*	$6.09 to $22.94	12,345,610	$20.67
	$23.15 to $26.13	24,030,936	24.28
	$26.33 to $32.81	23,634,422	30.14
2003*	$6.08 to $20.61	14,434,454	$17.10
	$21.21 to $24.98	28,644,132	23.42
	$25.11 to $33.36	25,975,946	29.77

**Reflects a two-for-one stock split effected as a 100 percent stock dividend on June 1, 2005.*

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 58.4 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 2005 and 2004, shares transferred out of the CBT were 2,250,727 and 2,419,808, respectively. At December 31, 2005, 45.9 million shares remained in the CBT. All shares are required to be transferred out of the CBT by January 1, 2021.

Note 21—Income Taxes

Income taxes charged to income from continuing operations were:

	Millions of Dollars		
	2005	2004	2003
Income Taxes			
Federal			
Current	$ **3,434**	1,616	536
Deferred	**375**	719	637
Foreign			
Current	**5,093**	3,468	2,559
Deferred	**384**	190	(161)
State and local			
Current	**538**	256	136
Deferred	**83**	13	37
	$ **9,907**	6,262	3,744

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	
	2005	2004
Deferred Tax Liabilities		
Properties, plants and equipment, and intangibles	$ **12,737**	11,650
Investment in joint ventures	**1,146**	1,024
Inventory	**207**	364
Partnership income deferral	**612**	523
Other	**570**	660
Total deferred tax liabilities	**15,272**	14,221
Deferred Tax Assets		
Benefit plan accruals	**1,237**	1,244
Asset retirement obligations and accrued environmental costs	**1,793**	1,684
Deferred state income tax	**230**	250
Other financial accruals and deferrals	**724**	410
Loss and credit carryforwards	**936**	1,167
Other	**179**	141
Total deferred tax assets	**5,099**	4,896
Less valuation allowance	**(850)**	(968)
Net deferred tax assets	**4,249**	3,928
Net deferred tax liabilities	$ **11,023**	10,293

Current assets, long-term assets, current liabilities and long-term liabilities included deferred taxes of $363 million, $65 million, $12 million and $11,439 million, respectively, at December 31, 2005, and $85 million, $52 million, $45 million and $10,385 million, respectively, at December 31, 2004.

We have loss and credit carryovers in multiple taxing jurisdictions. These attributes generally expire between 2006 and 2018 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 2005, valuation allowances decreased $118 million. This reflects increases of $90 million primarily related to foreign tax loss carryforwards, more than offset by decreases of $134 million primarily related to U.S. capital loss carryforward utilization and decreases of $74 million related to foreign loss carryforwards (i.e. expiration, relinquishment, currency translation). The balance includes valuation allowances for certain deferred tax assets of $271 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 (Act) was signed into law. One of the provisions of the Act was a special deduction for qualifying manufacturing activities. While the legislation is still undergoing clarifications, under guidance in FSP FAS 109-1, we included the estimated impact as a current benefit, which did not have a material impact on the company’s effective tax rate, and it did not have any impact on our assessment of the need for possible valuation allowances.

The Act also included a special one-time provision allowing earnings of foreign subsidiaries to be repatriated at a reduced U.S. income tax rate. Final guidance clarifying the uncertain provisions of the law was published during the third quarter of 2005. We have completed our analysis of this provision, including the final guidance, and do not intend to change our repatriation plans.

At December 31, 2005 and 2004, income considered to be permanently reinvested in certain foreign subsidiaries and foreign corporate joint ventures totaled approximately $2,773 million and $2,091 million, respectively. Deferred income taxes have not been provided on this income, as we do not plan to initiate any action that would require the payment of income taxes. It is not practicable to estimate the amount of additional tax that might be payable on this foreign income if distributed.

The amounts of U.S. and foreign income from continuing operations before income taxes, with a reconciliation of tax at the federal statutory rate with the provision for income taxes, were:

		Millions of Dollars			Percent of Pretax Income		
		2005	2004	2003	**2005**	2004	2003
Income from continuing operations before income taxes							
United States	**$**	**12,486**	7,587	4,137	**53.0%**	52.8	49.6
Foreign		**11,061**	6,782	4,200	**47.0**	47.2	50.4
	$	**23,547**	14,369	8,337	**100.0%**	100.0	100.0
Federal statutory income tax	**$**	**8,241**	5,029	2,918	**35.0%**	35.0	35.0
Foreign taxes in excess of federal statutory rate		**1,562**	1,138	792	**6.6**	7.9	9.5
Domestic tax credits		**(55)**	(85)	(25)	**(.2)**	(.6)	(.3)
Federal manufacturing deduction		**(106)**	—	—	**(.4)**	—	—
State income tax		**404**	175	112	**1.7**	1.2	1.3
Other		**(139)**	5	(53)	**(.6)**	.1	(.6)
	$	**9,907**	6,262	3,744	**42.1%**	43.6	44.9

Our 2005 tax expense was reduced by $38 million due to the remeasurement of deferred tax liabilities from the 2003 Canadian graduated tax rate reduction. 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.

Note 22—Other Comprehensive Income (Loss)

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

		Millions of Dollars		
		Before-Tax	Tax Expense (Benefit)	After-Tax
2005				
Minimum pension liability adjustment	**$**	**(101)**	**(45)**	**(56)**
Unrealized loss on securities		**(10)**	**(4)**	**(6)**
Foreign currency translation adjustments		**(786)**	**(69)**	**(717)**
Hedging activities		**(3)**	**(4)**	**1**
Other comprehensive loss	**$**	**(900)**	**(122)**	**(778)**
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

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	
		2005	2004
Minimum pension liability adjustment	**$**	**(123)**	(67)
Foreign currency translation adjustments		**945**	1,662
Unrealized gain on securities		—	6

Deferred net hedging loss	**(8)**	(9)
Accumulated other comprehensive income	**$ 814**	1,592

Note 23—Cash Flow Information

	Millions of Dollars		
	2005	2004	2003
Non-Cash Investing and Financing Activities			
Increase in properties, plants and equipment (PP&E) resulting from our payment obligations to acquire an ownership interest in producing properties in Libya*	**$ 732**	—	—
Increase in net PP&E related to the implementation of FIN 47	**269**	—	—
Investment in PP&E of businesses through the assumption of non-cash liabilities**	**261**	—	—
Fair market value of net PP&E received in a nonmonetary exchange transaction	**138**	—	—
Company stock issued under compensation and benefit plans	**133**	99	90
Investment in equity affiliate through exchange of non-cash assets and liabilities	**109**	—	—
Increase in PP&E in exchange for related increase in asset retirement obligations associated with the initial implementation and continuing application of SFAS No. 143	**511**	150	1,229
Increase in net PP&E from incurrence of asset retirement obligations due to repeal of Norway Removal Grant Act	**—**	—	336
Increase in net PP&E related to the implementation of FIN 46(R)	**—**	—	940
Increase in long-term debt through the implementation of FIN 46(R)	**—**	—	2,774
Increase in assets of discontinued operations held for sale related to implementation of FIN 46(R)	**—**	—	726

**Payment obligations were included in the "Other accruals" line within the current liabilities section of the consolidated balance sheet.*
***See Note 16—Financial Instruments and Derivative Contracts, for additional information.*

Cash Payments			
Interest	**$ 500**	560	839
Income taxes	**8,507**	4,754	2,909

Note 24—Other Financial Information

	Millions of Dollars Except Per Share Amounts		
	2005	2004	2003
Interest			
Incurred			
Debt	**$ 807**	878	1,061
Other	**85**	98	110
	892	976	1,171
Capitalized	**(395)**	(430)	(327)
Expensed	**$ 497**	546	844
Research and Development Expenditures—expensed	**$ 125**	126	136
Advertising Expenses*	**$ 84**	101	70
**Deferred amounts at December 31 were immaterial in all three years.*			
Shipping and Handling Costs*	**$ 1,265**	947	853
**Amounts included in E&P production and operating expenses.*			
Cash Dividends paid per common share	**$ 1.18**	.895	.815
Foreign Currency Transaction Gains (Losses)—after-tax			
E&P	**$ 7**	(13)	(50)
Midstream	**7**	(1)	—
R&M	**(52)**	12	18
LUKOIL Investment	**(1)**	—	—
Chemicals	**—**	—	—
Emerging Businesses	**(1)**	—	(1)
Corporate and Other	**(42)**	44	67
	$ (82)	42	34

Note 25—Related Party Transactions

Significant transactions with related parties were:

		Millions of Dollars		
		2005	2004	2003
Operating revenues (a)	$	**7,655**	5,321	3,812
Purchases (b)		**5,994**	4,545	3,367
Operating expenses and selling, general and administrative expenses (c)		**426**	492	510
Net interest expense (d)		**48**	39	34

(a) We sell natural gas to Duke Energy Field Services, LLC (DEFS) and crude oil to the Malaysian Refining Company Sdn. Bhd. (MRC), among others, for processing and marketing. Natural gas liquids, solvents and petrochemical feedstocks are sold to Chevron Phillips Chemical Company LLC (CPChem), gas oil and hydrogen feedstocks are sold to Excel Paralubes 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 MRC. We also pay fees to various pipeline equity companies for transporting finished refined products and a price upgrade to MSLP for heavy crude processing. We purchase base oils and fuel products from Excel Paralubes for use in our refinery and specialty businesses.

(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 Phillips 66 Capital Trust II and the receivables securitization QSPE.

Elimination of our equity percentage share of profit or loss included in our inventory at December 31, 2005, 2004, and 2003, 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, 2005, 2004, and 2003, on the revenues from related parties described above were not material.

Note 26—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, 2005, 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. 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 primarily consists of our equity investment in DEFS. Through June 30, 2005, our equity ownership in DEFS was 30.3 percent. In July 2005, we increased our ownership interest to 50 percent.

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, 2005, 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 and throughout 2005, we further increased our ownership to 16.1 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; discontinued operations; restructuring charges; certain eliminations; and various other corporate activities. Corporate assets include all cash and cash equivalents.

We evaluate performance and allocate resources based on net income. Segment accounting policies are the same as those in Note 1—Accounting Policies. Intersegment sales are at prices that approximate market.

Analysis of Results by Operating Segment

		Millions of Dollars	
	2005	2004	2003
Sales and Other Operating Revenues			
E&P			
United States	$ **35,159**	23,805	18,521
International	**21,692**	16,960	12,964
Intersegment eliminations—U.S.	**(4,075)**	(2,841)	(2,439)
Intersegment eliminations—international	**(4,251)**	(3,732)	(3,202)
E&P	**48,525**	34,192	25,844
Midstream			
Total sales	**4,041**	4,020	4,735
Intersegment eliminations	**(955)**	(987)	(1,431)
Midstream	**3,086**	3,033	3,304
R&M			
United States	**97,251**	72,962	55,734
International	**30,633**	25,141	19,504
Intersegment eliminations—U.S.	**(593)**	(431)	(327)
Intersegment eliminations—international	**(11)**	(26)	(13)
R&M	**127,280**	97,646	74,898
LUKOIL Investment	**—**	—	—
Chemicals	**14**	14	14
Emerging Businesses	**524**	177	178
Corporate and Other	**13**	14	8
Consolidated sales and other operating revenues	$ **179,442**	135,076	104,246
Depreciation, Depletion, Amortization and Impairments			
E&P			
United States	$ **1,402**	1,126	1,172
International	**1,914**	1,859	1,736
Total E&P	**3,316**	2,985	2,908
Midstream	**61**	80	54
R&M			
United States	**633**	657	551
International	**193**	175	140
Total R&M	**826**	832	691
LUKOIL Investment	**—**	—	—
Chemicals	**—**	—	—
Emerging Businesses	**32**	8	10
Corporate and Other	**60**	57	74
Consolidated depreciation, depletion, amortization and impairments	$ **4,295**	3,962	3,737

		Millions of Dollars	
	2005	2004	2003
Equity in Earnings of Affiliates			
E&P			
United States	$ **19**	21	27
International	**825**	520	289
Total E&P	**844**	541	316
Midstream	**829**	265	138
R&M			
United States	**388**	245	89
International	**227**	110	5
Total R&M	**615**	355	94
LUKOIL Investment	**756**	74	—
Chemicals	**413**	307	(6)
Emerging Businesses	**—**	(7)	—
Corporate and Other	**—**	—	—
Consolidated equity in earnings of affiliates	$ **3,457**	1,535	542
Income Taxes			
E&P			
United States	$ **2,349**	1,583	1,231
International	**5,145**	3,349	2,269
Total E&P	**7,494**	4,932	3,500
Midstream	**214**	137	83
R&M			
United States	**2,124**	1,234	652
International	**212**	197	64
Total R&M	**2,336**	1,431	716
LUKOIL Investment	**25**	—	—
Chemicals	**93**	64	(12)

Emerging Businesses		**(18)**	(52)	(51)
Corporate and Other		**(237)**	(250)	(492)
Consolidated income taxes	$	**9,907**	6,262	3,744
Net Income (Loss)				
E&P				
United States	$	**4,288**	2,942	2,374
International		**4,142**	2,760	1,928
Total E&P		**8,430**	5,702	4,302
Midstream		**688**	235	130
R&M				
United States		**3,329**	2,126	990
International		**844**	617	282
Total R&M		**4,173**	2,743	1,272
LUKOIL Investment		**714**	74	—
Chemicals		**323**	249	7
Emerging Businesses		**(21)**	(102)	(99)
Corporate and Other		**(778)**	(772)	(877)
Consolidated net income	$	**13,529**	8,129	4,735

		Millions of Dollars		
		2005	2004	2003
Investments In and Advances To Affiliates				
E&P				
United States	$	**336**	188	133
International		**3,789**	2,522	2,351
Total E&P		**4,125**	2,710	2,484
Midstream		**1,446**	413	394
R&M				
United States		**662**	752	777
International		**819**	667	517
Total R&M		**1,481**	1,419	1,294
LUKOIL Investment		**5,549**	2,723	—
Chemicals		**2,158**	2,179	2,059
Emerging Businesses		**—**	1	2
Corporate and Other		**18**	21	25
Consolidated investments in and advances to affiliates	$	**14,777**	9,466	6,258
Total Assets				
E&P				
United States	$	**18,434**	16,105	15,262
International		**31,662**	26,481	22,458
Goodwill		**11,423**	11,090	11,184
Total E&P		**61,519**	53,676	48,904
Midstream		**2,109**	1,293	1,736
R&M				
United States		**20,693**	19,180	17,172
International		**6,096**	5,834	5,020
Goodwill		**3,900**	3,900	3,900
Total R&M		**30,689**	28,914	26,092
LUKOIL Investment		**5,549**	2,723	—
Chemicals		**2,324**	2,221	2,094
Emerging Businesses		**858**	972	843
Corporate and Other		**3,951**	3,062	2,786
Consolidated total assets	$	**106,999**	92,861	82,455
Capital Expenditures and Investments				
E&P				
United States	$	**1,637**	1,314	1,418
International		**5,047**	3,935	3,090
Total E&P		**6,684**	5,249	4,508
Midstream		**839**	7	10
R&M				
United States		**1,537**	1,026	860
International		**201**	318	319
Total R&M		**1,738**	1,344	1,179
LUKOIL Investment		**2,160**	2,649	—
Chemicals		**—**	—	—
Emerging Businesses		**5**	75	284
Corporate and Other		**194**	172	188

Consolidated capital expenditures and investments	$	**11,620**	9,496	6,169

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

		Millions of Dollars		
		2005	2004	2003
Interest income	$	**113**	47	56
Interest and debt expense		**497**	546	844

Geographic Information

		Millions of Dollars						
		United States	Norway	United Kingdom	Canada	Russia	Other Foreign Countries	Worldwide Consolidated
2005								
Sales and Other Operating Revenues*	$	**130,874**	**3,280**	**19,043**	**5,676**	**—**	**20,569**	**179,442**
Long-Lived Assets**	$	**33,161**	**4,380**	**5,564**	**5,328**	**6,342**	**14,671**	**69,446**
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	2,800	11,768	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	50	9,413	53,686

**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 27—New Accounting Standards

In May 2005, the FASB issued SFAS No. 154, "Accounting Changes and Error Corrections, a replacement of APB Opinion No. 20 and FASB Statement No. 3." Among other changes, this Statement requires retrospective application for voluntary changes in accounting principle, unless it is impractical to do so. Guidance is provided on how to account for changes when retrospective application is impractical. This Statement is effective on a prospective basis beginning January 1, 2006.

In December 2004, the FASB issued SFAS No. 123 (revised 2004), "Share-Based Payment," (SFAS 123(R)), which supercedes Accounting Principles Board 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 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. For ConocoPhillips, this Statement provided for an effective date of third-quarter 2005; however, in April 2005, the Securities and Exchange Commission approved a new rule that delayed the effective date until January 1, 2006. We adopted the provisions of this Statement on January 1, 2006, using the modified-prospective transition method, and do not expect the provisions of this new pronouncement to have a material impact 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 clarifies that items, such as abnormal idle facility expense, excessive spoilage, double freight, and handling costs, be recognized as current-period charges. In addition, the Statement requires that allocation of fixed production overheads to the costs of conversion be based on the normal capacity of the production facilities. We are required to implement this Statement in the first quarter of 2006. We do not expect this Statement to have a significant impact on our financial statements.

At the September 2005 meeting, the EITF reached a consensus on 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.

Note 28—Pending Acquisition of Burlington Resources Inc.

On the evening of December 12, 2005, ConocoPhillips and Burlington Resources Inc. announced they had signed a definitive agreement under which ConocoPhillips would acquire Burlington Resources Inc. The transaction has a preliminary value of $33.9 billion. This transaction is expected to close on March 31, 2006, subject to approval by Burlington Resources shareholders at a special meeting set for March 30, 2006.

Under the terms of the agreement, Burlington Resources shareholders will receive $46.50 in cash and 0.7214 shares of ConocoPhillips common stock for each Burlington Resources share they own. This represents a transaction value of $92 per share, based on the closing price of our common stock on Friday, December 9, 2005, the last unaffected day of trading prior to the announcement. We anticipate that the cash portion of the purchase price, currently estimated to be approximately $17.5 billion, will be financed with a combination of short- and long-term debt and available cash.

Burlington Resources is an independent exploration and production company, and holds a substantial position in North American natural gas reserves and production. At year-end 2004, as reported in its Annual Report on Form 10-K, Burlington Resources had proved worldwide natural gas reserves of 8,226 billion cubic feet, including 5,076 billion cubic feet in the United States and 2,330 billion cubic feet in Canada. Worldwide, Burlington Resources had 630 million barrels of crude oil and natural gas liquids combined, with 483 million barrels in the United States and 72 million barrels in Canada. During 2004, Burlington Resources' worldwide net natural gas production averaged 1,914 million cubic feet per day, while its net liquids production averaged 151 thousand barrels per day.

Upon completion of the transaction, Bobby S. Shakouls, Burlington Resources' President and Chief Executive Officer, and William E. Wade Jr., currently an independent director of Burlington Resources, will join our Board of Directors.

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 and 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 from our LUKOIL investment are estimates for 2005 and 2004. Our estimated year-end 2005 reserves related to our equity investment in LUKOIL were based on LUKOIL's year-end 2004 reserves (adjusted for known additions, license extensions, dispositions, and public information) and included adjustments to conform them to ConocoPhillips' reserve policy and provided for estimated 2005 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 for our consolidated operations include the United States (U.S.), European North Sea (Norway and the United Kingdom), Asia Pacific, Canada, Middle East and Africa, and Other Areas. In these supplemental oil and gas disclosures, where we use equity accounting for operations that have proved reserves, these operations are shown separately and designated as Equity Affiliates, and include Venezuela, and Russia and Other Areas.

- **Proved Reserves Worldwide**

Years Ended December 31	Crude Oil Millions of Barrels										
	Consolidated Operations									Equity Affiliates	
	Alaska	Lower 48	Total U.S.	European North Sea	Asia Pacific	Canada	Middle East and Africa	Other Areas	Total	Venezuela	Russia and Other Areas
Developed and Undeveloped											
End of 2002	1,603	220	1,823	914	254*	91	168	25	3,275	1,271	86
Revisions	35	(5)	30	15	40	(9)	(5)	1	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	3	5
Production	(119)	(19)	(138)	(106)	(24)	(11)	(26)	(1)	(306)	(27)	(10)
Sales	—	(15)	(15)	(9)	(21)	(20)	—	(25)	(90)	—	—
End of 2003	1,553	186	1,739	865	264	274	148	—	3,290	1,295	82
Revisions	31	(4)	27	28	8	(219)	(5)	—	(161)	(78)	(10)
Improved recovery	16	1	17	1	14	—	—	—	32	—	—
Purchases	—	—	—	—	—	—	—	—	—	—	783
Extensions and discoveries	46	6	52	55	4	1	5	181	298	—	—
Production	(110)	(19)	(129)	(98)	(35)	(9)	(21)	—	(292)	(35)	(19)
Sales	—	—	—	—	—	—	—	—	—	—	(36)
End of 2004	1,536	170	1,706	851	255	47	127	181	3,167	1,182	800
Revisions	31	6	37	34	7	4	(21)	(11)	50	(54)	60
Improved recovery	15	1	16	—	—	—	—	—	16	—	—
Purchases	—	3	3	—	—	—	238	20	261	—	515
Extensions and discoveries	31	13	44	17	49	1	4	17	132	—	60
Production	(108)	(21)	(129)	(94)	(37)	(8)	(20)	—	(288)	(39)	(91)
Sales	—	(2)	(2)	—	—	—	—	—	(2)	—	(3)
End of 2005	1,505	170	1,675	808	274	44	328	207	3,336	1,089	1,341
Developed											
End of 2002	1,335	169	1,504	713	55	81	143	25	2,521	311	67
End of 2003	1,365	163	1,528	454	95	51	137	—	2,265	452	77
End of 2004	1,415	148	1,563	429	207	46	121	—	2,366	491	624
End of 2005	1,359	158	1,517	409	202	42	326	—	2,496	472	1,013

**Includes proved reserves of 14 million barrels attributable to a consolidated subsidiary in which there was 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 Middle East and Africa in 2005 of 238 million barrels were attributable to Libya. Purchases in Russia and Other Areas in 2005 and 2004 were primarily associated with LUKOIL.

- Extensions and discoveries in Asia Pacific were primarily attributable to China in 2005. Extensions and discoveries in Other Areas were attributable to Kashagan in Kazakhstan in 2004, and in 2003 were primarily related to Surmont in Canada.

- 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 251 million barrels at the end of 2005. For internal management purposes, we view these reserves and their development as part of our total exploration and production operations. However, SEC 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.

Years Ended December 31	Natural Gas										
	Billions of Cubic Feet										
	Consolidated Operations									Equity Affiliates	
	Alaska	Lower 48	Total U.S.	European North Sea	Asia Pacific	Canada	Middle East and Africa	Other Areas	Total	Venezuela	Russia and Other Areas
Developed and Undeveloped											
End of 2002	2,989	4,695	7,684	3,807	2,070*	1,177	1,136	5	15,879	145	16
Revisions	75	(140)	(65)	17	(79)	(51)	1	(1)	(178)	61	4
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)	(1)	(4)
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	205	21
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	3	119	970	—	—
Production	(152)	(465)	(617)	(428)	(121)	(159)	(41)	—	(1,366)	(4)	(5)
Sales	—	(3)	(3)	—	—	(3)	—	—	(6)	—	(21)
End of 2004	3,344	4,234	7,578	3,285	3,773	975	1,104	119	16,834	201	661
Revisions	260	(43)	217	83	(20)	72	—	(3)	349	92	(41)
Improved recovery	—	1	1	—	—	—	—	—	1	—	—
Purchases	7	163	170	1	8	—	—	13	192	—	453
Extensions and discoveries	5	270	275	79	85	78	2	5	524	—	1,212
Production	(144)	(449)	(593)	(386)	(146)	(155)	(45)	—	(1,325)	(5)	(25)
Sales	—	(62)	(62)	—	—	—	—	—	(62)	—	—
End of 2005	3,472	4,114	7,586	3,062	3,700	970	1,061	134	16,513	288	2,260
Developed											
End of 2002	2,806	4,302	7,108	3,278	832	1,098	512	5	12,833	13	15
End of 2003	2,763	3,968	6,731	2,748	1,342	971	596	—	12,388	103	20
End of 2004	3,194	3,989	7,183	2,467	1,520	934	522	—	12,626	118	207
End of 2005	3,316	3,966	7,282	2,393	2,600	918	1,060	—	14,253	155	581

**Includes proved reserves of 10 billion cubic feet attributable to a consolidated subsidiary in which there was 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 2005 and 2004 for Alaska were primarily related to higher prices and improved performance. Revisions in 2004 in Asia Pacific were primarily related to Indonesia.

- Purchases in Lower 48 in 2005 were attributable to the acquisition of two limited-term, fixed-volume overriding royalty interests in Utah and the San Juan Basin, as well as property trades in Wyoming and Texas. Purchases in Russia and Other Areas in 2005 and 2004 were primarily attributable to LUKOIL.

- Equity extensions and discoveries in 2005 in Russia and Other Areas were primarily attributable to Qatar. 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.

Years Ended December 31	Natural Gas Liquids										
	Millions of Barrels										
	Consolidated Operations									Equity Affiliates	
	Alaska	Lower 48	Total U.S.	European North Sea	Asia Pacific	Canada	Middle East and Africa	Other Areas	Total	Venezuela	Russia and Other Areas
Developed and Undeveloped											
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	—	—	—	—	—	—	—	—	—	—	—

	Alaska	Lower 48	Total U.S.	European North Sea	Asia Pacific	Canada	Middle East and Africa	Other Areas	Total	Venezuela	Russia and Other Areas
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	—	—
Revisions	—	17	17	6	4	1	—	—	28	—	—
Improved recovery	—	—	—	—	—	—	—	—	—	—	—
Purchases	—	8	8	—	—	—	—	—	8	—	—
Extensions and discoveries	—	5	5	1	2	—	—	—	8	—	21
Production	(7)	(9)	(16)	(5)	(6)	(3)	(1)	—	(31)	—	—
Sales	—	(1)	(1)	—	—	—	—	—	(1)	—	—
End of 2005	146	108	254	50	71	24	3	—	402	—	21
Developed											
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	—	—
End of 2005	146	106	252	31	64	23	2	—	372	—	—

**Includes proved reserves of 9 million barrels attributable to a consolidated subsidiary in which there was 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.

- **Results of Operations**

Years Ended December 31	Millions of Dollars										
	Consolidated Operations									Equity Affiliates	
	Alaska	Lower 48	Total U.S.	European North Sea	Asia Pacific	Canada	Middle East and Africa	Other Areas	Total	Venezuela	Russia and Other Areas
2005											
Sales	$ 5,927	3,385	9,312	5,142	2,795	1,642	423	—	19,314	1,055	2,415
Transfers	172	1,206	1,378	2,207	26	—	640	—	4,251	455	1,003
Other revenues	2	168	170	(253)	11	40	4	—	(28)	37	1
Total revenues	6,101	4,759	10,860	7,096	2,832	1,682	1,067	—	23,537	1,547	3,419
Production costs excluding taxes	488	492	980	611	274	316	115	45	2,341	196	256
Taxes other than income taxes	537	311	848	41	26	33	18	2	968	3	1,632
Exploration expenses	120	66	186	86	139	147	69	42	669	—	56
Depreciation, depletion and amortization	443	848	1,291	1,074	329	399	53	—	3,146	140	148
Property impairments	—	1	1	(10)	—	13	—	—	4	—	—
Transportation costs	665	350	1,015	296	64	53	5	—	1,433	—	255
Other related expenses	67	48	115	28	38	(12)	32	8	209	21	5
Accretion	29	19	48	84	7	16	2	—	157	—	1
	3,752	2,624	6,376	4,886	1,955	717	773	(97)	14,610	1,187	1,066
Provision for income taxes	1,342	900	2,242	3,311	747	228	759	(19)	7,268	370	303
Results of operations for producing activities	2,410	1,724	4,134	1,575	1,208	489	14	(78)	7,342	817	763
Other earnings	141	15	156	53	7	93*	(28)	35	316	(58)	(32)
Cumulative effect of accounting change	1	(3)	(2)	(2)	—	—	—	—	(4)	—	—
Net income (loss)	$ 2,552	1,736	4,288	1,626	1,215	582	(14)	(43)	7,654	759	731
2004											
Sales	$ 4,378	2,568	6,946	4,215	1,777	1,214	704	—	14,856	470	397
Transfers	121	832	953	1,255	71	—	75	—	2,354	359	122
Other revenues	4	(36)	(32)	9	10	116	5	14	122	32	1
Total revenues	4,503	3,364	7,867	5,479	1,858	1,330	784	14	17,332	861	520
Production costs excluding taxes	430	422	852	523	216	271	120	36	2,018	154	46
Taxes other than income taxes	373	267	640	38	17	35	12	1	743	—	206
Exploration expenses	82	101	183	85	106	112	67	144	697	—	5
Depreciation, depletion and amortization	426	586	1,012	1,095	275	349	43	—	2,774	94	43
Property impairments	6	12	18	2	—	47	—	—	67	—	—
Transportation costs	598	241	839	296	48	43	2	—	1,228	8	57
Other related expenses	14	43	57	20	(2)	4	14	7	100	39	—
Accretion	21	21	42	72	6	14	2	—	136	—	1
	2,553	1,671	4,224	3,348	1,192	455	524	(174)	9,569	566	162
Provision for income taxes	888	584	1,472	2,233	477	127	514	(94)	4,729	67	41
Results of operations for producing activities	1,665	1,087	2,752	1,115	715	328	10	(80)	4,840	499	121
Other earnings	167	23	190	102	(2)	130*	(35)	(10)	375	(53)	(6)
Net income (loss)	$ 1,832	1,110	2,942	1,217	713	458	(25)	(90)	5,215	446	115

Years Ended December 31	Millions of Dollars										
	Consolidated Operations									Equity Affiliates	
	Alaska	Lower 48	Total U.S.	European North Sea	Asia Pacific	Canada	Middle East and Africa	Other Areas	Total	Venezuela	Russia and Other Areas
2003											
Sales	$3,564	2,488	6,052	3,860	1,005	1,066	649	28	12,660	351	72
Transfers	103	545	648	903	16	—	77	—	1,644	266	—
Other revenues	(11)	93	82	(4)	33	43	9	1	164	34	—
Total revenues	3,656	3,126	6,782	4,759	1,054	1,109	735	29	14,468	651	72
Production costs excluding taxes	460	426	886	574	170	256	121	30	2,037	153	5
Taxes other than income taxes	332	230	562	37	2	24	8	—	633	—	26
Exploration expenses	56	143	199	121	52	94	81	46	593	—	2
Depreciation, depletion and amortization	436	571	1,007	956	163	326	37	3	2,492	97	7
Property impairments	—	65	65	160	—	5	—	—	230	—	—
Transportation costs	666	188	854	270	40	40	18	5	1,227	12	8
Other related expenses	7	78	85	29	14	93	21	34	276	15	12
Accretion	25	18	43	50	5	11	2	—	111	2	—
	1,674	1,407	3,081	2,562	608	260	447	(89)	6,869	372	12
Provision for income taxes	595	502	1,097	1,538	225	57	366	(4)	3,279	83	—
Results of operations for producing	1,079	905	1,984	1,024	383	203	81	(85)	3,590	289	12

activities											
Other earnings	223	25	248	46	2	67*	(57)	11	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	24	(86)	4,049	241	12

**Includes $141 million, $126 million and $63 million in 2005, 2004 and 2003, respectively, for a Syncrude oil project in Canada that is defined as a mining operation by SEC 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 a net gain of approximately $152 million in 2005, certain amounts resulting from the purchase and sale of hydrocarbons, and other miscellaneous income. Also included in 2005 were losses of approximately $282 million for the mark-to-market valuation of certain U.K. gas contracts. Other revenues in 2004 included net gains of $72 million from asset sales.

- Production costs are those incurred to operate and maintain wells and related equipment and facilities used to produce petroleum liquids and natural gas. These costs also include depreciation of support equipment and administrative expenses related to the production activity.

- Taxes other than income taxes include production, property and other non-income taxes.

- 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.

- Depreciation, depletion and amortization (DD&A) in Results of Operations differs from that shown for total E&P in Note 26—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.

- 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.

- 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.

- **Statistics**

Net Production	**2005**	2004	2003
	Thousands of Barrels Daily		
Crude Oil			
Alaska	**294**	298	325
Lower 48	**59**	51	54
United States	**353**	349	379
European North Sea	**257**	271	290
Asia Pacific	**100**	94	61
Canada	**23**	25	30
Middle East and Africa	**53**	58	69
Other areas	—	—	3
Total consolidated	**786**	797	832
Venezuela	**106**	93	73
Russia and other areas	**250**	53	29
Total equity affiliates	**356**	146	102
Natural Gas Liquids*			
Alaska	**20**	23	23
Lower 48	**30**	26	25
United States	**50**	49	48
European North Sea	**13**	14	9

Asia Pacific	**16**	9	—
Canada	**10**	10	10
Middle East and Africa	**2**	2	2
Total consolidated	**91**	84	69

**Represents amounts extracted attributable to E&P operations (see natural gas liquids reserves for further discussion). Includes for 2005, 2004 and 2003, 9,000, 13,000, and 15,000 barrels daily in Alaska, respectively, that were sold from the Prudhoe Bay lease to the Kuparuk lease for reinjection to enhance crude oil production.*

	Millions of Cubic Feet Daily		
Natural Gas*			
Alaska	**169**	165	184
Lower 48	**1,212**	1,223	1,295
United States	**1,381**	1,388	1,479
European North Sea	**1,023**	1,119	1,215
Asia Pacific	**350**	301	318
Canada	**425**	433	435
Middle East and Africa	**84**	71	63
Total consolidated	**3,263**	3,312	3,510
Venezuela	**7**	4	—
Russia and other areas	**67**	14	12
Total equity affiliates	**74**	18	12

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

		2005	2004	2003
Average Sales Price				
Crude Oil Per Barrel				
Alaska	$	**52.24**	38.47	28.87
Lower 48		**45.24**	36.95	28.76
United States		**51.09**	38.25	28.85
European North Sea		**53.16**	37.42	28.83
Asia Pacific		**51.34**	38.33	27.87
Canada		**44.70**	32.92	25.06
Middle East and Africa		**52.93**	36.05	28.01
Other areas		—	—	20.22
Total international		**52.27**	37.18	28.27
Total consolidated		**51.74**	37.65	28.54
Venezuela		**38.08**	24.42	19.59
Russia and other areas		**37.39**	27.41	17.55
Total equity affiliates		**37.60**	25.52	19.01
Average Sales Price				
Natural Gas Liquids Per Barrel				
Alaska	$	**51.30**	38.64	29.04
Lower 48		**36.43**	28.14	20.02
United States		**40.40**	31.05	22.30
European North Sea		**31.25**	26.97	21.34
Asia Pacific		**40.11**	34.94	—
Canada		**42.20**	30.77	23.93
Middle East and Africa		**7.39**	7.24	7.24
Total international		**36.25**	28.96	21.39
Total consolidated		**38.32**	30.02	21.95
Average Sales Price				
Natural Gas (Lease) Per Thousand Cubic Feet				
Alaska	$	**2.75**	2.35	1.76
Lower 48		**7.28**	5.46	4.81
United States		**7.12**	5.33	4.67
European North Sea		**5.77**	4.09	3.60
Asia Pacific		**5.24**	3.93	3.56
Canada		**7.25**	5.00	4.48
Middle East and Africa		**.67**	.69	.58
Total international		**5.78**	4.14	3.69
Total consolidated		**6.32**	4.62	4.08
Venezuela		**.26**	.28	—
Russia and other areas		**.48**	.86	4.44
Total equity affiliates		**.46**	.78	4.44
Average Production Costs Per Barrel of Oil Equivalent*				
Alaska	$	**3.91**	3.37	3.33
Lower 48		**4.63**	4.11	3.96
United States		**4.24**	3.70	3.60

	2005	2004	2003
European North Sea	**3.79**	3.03	3.14
Asia Pacific	**4.31**	3.85	4.09
Canada	**8.34**	6.91	6.23
Middle East and Africa	**4.63**	4.56	4.07
Other areas	**—**	—	27.40
Total international	**4.73**	3.96	3.88
Total consolidated	**4.51**	3.85	3.76
Venezuela	**5.01**	4.48	4.66
Russia and other areas	**2.69**	2.29	.98
Total equity affiliates	**3.36**	3.67	4.16

**2004 and 2003 restated to exclude production, property and similar taxes.*

	2005	2004	2003
Depreciation, Depletion and Amortization Per Barrel of Oil Equivalent			
Alaska	$ **3.55**	3.34	3.15
Lower 48	**7.98**	5.70	5.31
United States	**5.59**	4.39	4.10
European North Sea	**6.66**	6.35	5.22
Asia Pacific	**5.17**	4.91	3.92
Canada	**10.53**	8.90	7.94
Middle East and Africa	**2.14**	1.64	1.24
Other areas	**—**	—	2.74
Total international	**6.45**	5.99	5.01
Total consolidated	**6.07**	5.29	4.59
Venezuela	**3.58**	2.74	2.95
Russia and other areas	**1.55**	2.14	1.37
Total equity affiliates	**2.14**	2.52	2.74

Net Wells Completed *(1)*	Productive			Dry		
	2005	2004	2003	**2005**	2004	2003
Exploratory *(2)*						
Alaska	**—**	4	—	**5**	2	1
Lower 48	**23**	38	35	**5**	8	23
United States	**23**	42	35	**10**	10	24
European North Sea	**1**	2	1	**—**	*	2
Asia Pacific	**7**	*	—	**3**	6	2
Canada	**26**	52	72	**7**	26	16
Middle East and Africa	**—**	1	—	**2**	—	—
Other areas	**1**	—	—	**—**	2	*
Total consolidated	**58**	97	108	**22**	44	44
Venezuela	**—**	—	—	**—**	—	—
Russia and other areas	*****	2	23	**—**	1	6
Total equity affiliates *(3)*	*****	2	23	**—**	1	6
Includes step-out wells of:	***42***	*89*	*130*	***7***	*34*	*39*
Development						
Alaska	**31**	37	39	**—**	—	1
Lower 48	**297**	400	283	**9**	4	7
United States	**328**	437	322	**9**	4	8
European North Sea	**19**	11	12	**—**	—	—
Asia Pacific	**17**	16	19	**—**	—	2
Canada	**425**	323	114	**2**	4	5
Middle East and Africa	**6**	4	6	**—**	—	—
Other areas	**—**	—	5	**—**	—	—
Total consolidated	**795**	791	478	**11**	8	15
Venezuela	**28**	33	25	**1**	—	—
Russia and other areas	**1**	17	73	**—**	—	3
Total equity affiliates (3)	**29**	50	98	**1**	*	3

(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 2005	In Progress *(1)*		Productive *(2)*			
			Oil		Gas	
	Gross	Net	Gross	Net	Gross	Net

Alaska	10	6	1,653	736	28	19
Lower 48	142	53	9,292	3,289	14,818	8,116
United States	152	59	10,945	4,025	14,846	8,135
European North Sea	25	6	558	103	273	96
Asia Pacific	29	11	397	185	84	41
Canada	58	35	1,705	1,103	6,243	3,300
Middle East and Africa	10	2	1,118	234	1	—
Other areas	19	3	—	—	—	—
Total consolidated	293	116	14,723	5,650	21,447	11,572
Venezuela	9	4	526	237	—	—
Russia and other areas	7	2	70	25	12	2
Total equity affiliates *(3)*	16	6	596	262	12	2

(1) Includes wells that have been temporarily suspended.
(2) Includes 2,537 gross and 1,253 net multiple completion wells.
(3) Excludes LUKOIL.

Acreage at December 31, 2005	Thousands of Acres			
	Developed		Undeveloped	
	Gross	Net	Gross	Net
Alaska	606	295	2,844	1,739
Lower 48	4,852	3,093	3,815	1,900
United States	5,458	3,388	6,659	3,639
European North Sea	1,019	266	3,327	981
Asia Pacific	4,542	1,994	26,627	16,321
Canada	2,445	1,612	12,233	7,225
Middle East and Africa	2,446	413	15,526	3,594
Other areas	—	—	2,616	549
Total consolidated	15,910	7,673	66,988	32,309
Venezuela	188	83	—	—
Russia and Other Areas	123	39	3,229	1,081
Total equity affiliates*	311	122	3,229	1,081

**Excludes LUKOIL.*

- **Costs Incurred**

	Millions of Dollars										
	Consolidated Operations									Equity Affiliates	
	Alaska	Lower 48	Total U.S.	European North Sea	Asia Pacific	Canada	Middle East and Africa	Other Areas	Total	Venezuela	Russia and Other Areas
2005											
Unproved property acquisition	$ 1	14	15	—	26	68	85	83	277	—	866
Proved property acquisition	16	767	783	—	6	—	569	125	1,483	—	1,881
	17	781	798	—	32	68	654	208	1,760	—	2,747
Exploration	64	74	138	109	204	163	67	56	737	—	60
Development	650	688	1,338	1,402	682	782	137	414	4,755	111	338
	$ 731	1,543	2,274	1,511	918	1,013	858	678	7,252	111	3,145
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	14	1	286	—	1,989
Exploration	62	79	141	79	123	149	58	161	711	—	6
Development	490	598	1,088	1,029	483	371	86	200	3,257	338	52
	$ 565	695	1,260	1,108	818	548	158	362	4,254	338	2,047
2003											
Unproved property acquisition	$ 10	7	17	—	3	—	50	14	84	—	—
Proved property acquisition	—	6	6	(92)	27	20	3	(46)	(82)	—	(10)
	10	13	23	(92)	30	20	53	(32)	2	—	(10)
Exploration	65	164	229	105	101	152	56	111	754	—	12
Development	386	693	1,079	1,075	844	197	110	84	3,389	270	63
	$ 461	870	1,331	1,088	975	369	219	163	4,145	270	65

- Costs incurred include capitalized and expensed items.

- Acquisition costs include the costs of acquiring proved and unproved oil and gas properties. Costs in Lower 48 relate to the acquisition of two limited-term, fixed-volume overriding royalty interests in Utah and the San Juan Basin, as well as property trades in Wyoming and Texas. Such costs in Middle East and Africa were related to our return to Libya. Equity affiliate acquisition costs in 2005 and 2004 were primarily related to LUKOIL. Some of the 2005 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.

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

- Development costs include the cost of drilling and equipping development wells and building related production facilities for extracting, treating, gathering and storing petroleum liquids and natural gas.

- Approximately $1,211 million of properties, plants and equipment adjustments related to the cumulative effect of accounting changes in connection with the implementation of SFAS No. 143, "Accounting for Asset Retirement Obligations," has been excluded from the 2003 costs incurred.

- Costs incurred for the European North Sea in 2003 included approximately $430 million of increased properties, plants and equipment related to the repeal of the Norway Removal Grant Act.

- **Capitalized Costs**

At December 31	Millions of Dollars										
	Consolidated Operations									Equity Affiliates	
	Alaska	Lower 48	Total U.S.	European North Sea	Asia Pacific	Canada	Middle East and Africa	Other Areas	Total	Venezuela	Russia and Other Areas
2005											
Proved properties	$ 8,934	9,327	18,261	13,324	5,411	4,151	1,587	1,515	44,249	3,404	4,243
Unproved properties	782	198	980	118	621	1,023	305	153	3,200	—	1,000
	9,716	9,525	19,241	13,442	6,032	5,174	1,892	1,668	47,449	3,404	5,243
Accumulated depreciation, depletion and amortization	3,083	3,665	6,748	5,583	1,053	1,533	625	38	15,580	335	202
	$ 6,633	5,860	12,493	7,859	4,979	3,641	1,267	1,630	31,869	3,069	5,041
2004											
Proved properties	$ 8,263	8,091	16,354	13,476	4,477	3,322	863	896	39,388	3,293	2,087
Unproved properties	821	244	1,065	153	765	805	208	225	3,221	—	66
	9,084	8,335	17,419	13,629	5,242	4,127	1,071	1,121	42,609	3,293	2,153
Accumulated depreciation, depletion and amortization	2,610	2,985	5,595	5,145	704	1,057	551	34	13,086	190	54
	$ 6,474	5,350	11,824	8,484	4,538	3,070	520	1,087	29,523	3,103	2,099

- 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.

- 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.

- 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.

- **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.

Discounted Future Net Cash Flows

	Millions of Dollars										
	Consolidated Operations									Equity Affiliates	
	Alaska	Lower 48	Total U.S.	European North Sea	Asia Pacific	Canada	Middle East and Africa	Other Areas	Total	Venezuela	Russia and Other Areas
2005											
Future cash inflows	$96,574	48,560	145,134	74,790	31,310	11,907	19,337	11,856	294,334	49,793	62,032
Less:											
Future production and transportation costs*	34,586	10,425	45,011	12,055	5,343	2,892	3,442	2,898	71,641	6,674	40,960
Future development costs	4,569	1,686	6,255	7,517	2,920	965	474	2,066	20,197	2,002	2,758
Future income tax provisions	20,421	12,831	33,252	37,208	9,653	2,349	13,882	2,243	98,587	13,175	3,877
Future net cash flows	36,998	23,618	60,616	18,010	13,394	5,701	1,539	4,649	103,909	27,942	14,437
10 percent annual discount	19,414	11,934	31,348	6,006	5,639	2,184	560	4,224	49,961	18,172	7,548
Discounted future net cash flows	$17,584	11,684	29,268	12,004	7,755	3,517	979	425	53,948	9,770	6,889
2004											
Future cash inflows	$64,251	31,955	96,206	51,184	22,249	8,091	5,572	7,335	190,637	33,302	22,869
Less:											
Future production and transportation costs*	26,956	8,312	35,268	11,953	4,897	2,591	1,989	2,027	58,725	5,572	15,263

Future development costs	4,163	2,005	6,168	7,794	1,064	575	260	1,232	17,093	1,287	1,047
Future income tax provisions	11,698	7,233	18,931	19,850	5,683	1,139	2,675	1,379	49,657	8,758	1,953
Future net cash flows	21,434	14,405	35,839	11,587	10,605	3,786	648	2,697	65,162	17,685	4,606
10 percent annual discount	10,318	7,050	17,368	3,887	4,291	1,403	207	2,518	29,674	11,773	2,308
Discounted future net cash flows	$11,116	7,355	18,471	7,700	6,314	2,383	441	179	35,488	5,912	2,298
2003											
Future cash inflows	$54,351	29,865	84,216	41,125	18,277	10,107	5,075	—	158,800	31,018	1,604
Less:											
Future production and transportation costs*	21,557	7,559	29,116	10,429	4,480	3,974	2,068	—	50,067	4,981	842
Future development costs	4,104	1,404	5,508	5,358	1,163	1,111	283	—	13,423	1,412	98
Future income tax provisions	9,879	6,955	16,834	15,616	4,487	1,084	2,176	—	40,197	7,957	92
Future net cash flows	18,811	13,947	32,758	9,722	8,147	3,938	548	—	55,113	16,668	572
10 percent annual discount	9,323	7,158	16,481	3,234	3,348	1,703	152	—	24,918	10,890	171
Discounted future net cash flows	$ 9,488	6,789	16,277	6,488	4,799	2,235	396	—	30,195	5,778	401

**Includes taxes other than income taxes.*

Excludes discounted future net cash flows from Canadian Syncrude of $2,159 million in 2005, $1,302 million in 2004 and $1,048 million in 2003.

Sources of Change in Discounted Future Net Cash Flows*

	Millions of Dollars					
	Consolidated Operations			Equity Affiliates		
	2005	2004	2003	**2005**	2004	2003
Discounted future net cash flows at the beginning of the year	**$ 35,488**	30,195	27,792	**8,210**	6,179	6,207
Changes during the year						
Revenues less production and transportation costs for the year**	**(18,823)**	(13,221)	(10,407)	**(2,586)**	(877)	(485)
Net change in prices, and production and transportation costs**	**46,332**	14,133	4,436	**6,555**	1,415	(867)
Extensions, discoveries and improved recovery, less estimated future costs	**3,942**	3,724	3,237	**2,201**	—	31
Development costs for the year	**4,282**	3,117	2,963	**449**	390	329
Changes in estimated future development costs	**(3,261)**	(2,402)	(2,725)	**(142)**	(81)	(189)
Purchases of reserves in place, less estimated future costs	**6,610**	8	203	**2,361**	3,208	4
Sales of reserves in place, less estimated future costs	**(306)**	(19)	(1,722)	**(34)**	(183)	—
Revisions of previous quantity estimates***	**(219)**	424	83	**1,245**	(1,301)	202
Accretion of discount	**5,728**	4,782	4,738	**1,032**	832	852
Net change in income taxes	**(25,825)**	(5,253)	1,597	**(2,632)**	(1,372)	95
Other	—	—	—	—	—	—
Total changes	**18,460**	5,293	2,403	**8,449**	2,031	(28)
Discounted future net cash flows at year-end	**$ 53,948**	35,488	30,195	**16,659**	8,210	6,179

**Certain amounts in 2004 and 2003 were reclassified to conform with the current year presentation.*

***Includes taxes other than income taxes.*

****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.

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
2005								
First	**$ 37,631**	**4,940**	**2,912**	**2,912**	**2.08**	**2.05**	**2.08**	**2.05**
Second	**41,808**	**5,432**	**3,138**	**3,138**	**2.25**	**2.21**	**2.25**	**2.21**
Third	**48,745**	**6,554**	**3,800**	**3,800**	**2.73**	**2.68**	**2.73**	**2.68**
Fourth	**51,258**	**6,621**	**3,767**	**3,679**	**2.72**	**2.68**	**2.66**	**2.61**
2004								

First	$ 29,813	2,964	1,616	1,616	1.18	1.16	1.18	1.16
Second	31,528	3,470	2,075	2,075	1.50	1.48	1.50	1.48
Third	34,350	3,660	2,006	2,006	1.45	1.43	1.45	1.43
Fourth	39,385	4,275	2,432	2,432	1.75	1.72	1.75	1.72

**Includes excise taxes on petroleum products sales.*
***Per-share amounts in all periods reflect a two-for-one stock split effected as a 100 percent stock dividend on June 1, 2005.*

Supplementary Information—Condensed Consolidating Financial Information

We have various cross guarantees between ConocoPhillips and ConocoPhillips Company with respect to publicly held debt securities. ConocoPhillips Company is wholly owned by ConocoPhillips. ConocoPhillips has fully and unconditionally guaranteed the payment obligations of ConocoPhillips Company with respect to its publicly held debt securities. Similarly, ConocoPhillips Company has 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 and ConocoPhillips Company (in each case, reflecting investments in subsidiaries utilizing the equity method of accounting).
- All other non-guarantor subsidiaries of 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.

Effective January 1, 2005, ConocoPhillips Holding Company was merged into ConocoPhillips Company. Previously reported prior period information has been restated to reflect this reorganization of companies under common control.

	Millions of Dollars				
	Year Ended December 31, 2005				
Income Statement	ConocoPhillips	ConocoPhillips Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Revenues and Other Income					
Sales and other operating revenues	$ —	121,718	57,724	—	179,442
Equity in earnings of affiliates	13,754	10,235	2,842	(23,374)	3,457
Other income (loss)	(25)	152	338	—	465
Intercompany revenues	30	2,250	9,925	(12,205)	—
Total revenues and other income	13,759	134,355	70,829	(35,579)	183,364
Costs and Expenses					
Purchased crude oil, natural gas and products	—	103,307	32,665	(11,047)	124,925
Production and operating expenses	—	4,711	3,917	(66)	8,562
Selling, general and administrative expenses	16	1,436	818	(23)	2,247
Exploration expenses	—	84	577	—	661
Depreciation, depletion and amortization	—	1,473	2,780	—	4,253
Property impairments	—	2	40	—	42
Taxes other than income taxes	—	6,065	12,533	(242)	18,356
Accretion on discounted liabilities	—	37	156	—	193
Interest and debt expense	135	833	356	(827)	497
Foreign currency transaction (gains) losses	—	(16)	64	—	48
Minority interests	—	—	33	—	33
Total Costs and Expenses	151	117,932	53,939	(12,205)	159,817
Income from continuing operations before income taxes and subsidiary equity transactions	13,608	16,423	16,890	(23,374)	23,547
Gain on subsidiary equity transactions	—	—	—	—	—
Income from continuing operations before income taxes	13,608	16,423	16,890	(23,374)	23,547
Provision for income taxes	(32)	2,669	7,270	—	9,907
Income from continuing operations	13,640	13,754	9,620	(23,374)	13,640
Loss from discontinued operations	(23)	(23)	(6)	29	(23)
Income before cumulative effect of changes in accounting principles	13,617	13,731	9,614	(23,345)	13,617
Cumulative effect of changes in accounting principles	(88)	(88)	(29)	117	(88)
Net Income	$ 13,529	13,643	9,585	(23,228)	13,529

	Millions of Dollars				
	Year Ended December 31, 2004				
Income Statement	ConocoPhillips	ConocoPhillips	All Other	Consolidating	Total Consolidated

		Company	Subsidiaries	Adjustments	
Revenues and Other Income					
Sales and other operating revenues	$ —	89,602	45,474	—	135,076
Equity in earnings of affiliates	8,111	6,077	1,265	(13,918)	1,535
Other income	1	180	124	—	305
Intercompany revenues	72	1,528	7,304	(8,904)	—
Total revenues and other income	8,184	97,387	54,167	(22,822)	136,916
Costs and Expenses					
Purchased crude oil, natural gas and products	—	74,125	24,326	(8,269)	90,182
Production and operating expenses	—	4,062	3,347	(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	791	245	(582)	546
Foreign currency transaction gains	—	(4)	(32)	—	(36)
Minority interests	—	—	32	—	32
Total Costs and Expenses	102	87,867	43,482	(8,904)	122,547
Income from continuing operations before income taxes and subsidiary equity transactions	8,082	9,520	10,685	(13,918)	14,369
Gain on subsidiary equity transactions	—	—	—	—	—
Income from continuing operations before income taxes	8,082	9,520	10,685	(13,918)	14,369
Provision for income taxes	(25)	1,409	4,878	—	6,262
Income from continuing operations	8,107	8,111	5,807	(13,918)	8,107
Income from discontinued operations	22	22	91	(113)	22
Income before cumulative effect of changes in accounting principles	8,129	8,133	5,898	(14,031)	8,129
Cumulative effect of changes in accounting principles	—	—	—	—	—
Net Income	$ 8,129	8,133	5,898	(14,031)	8,129

	Millions of Dollars Year Ended December 31, 2003				
Income Statement	ConocoPhillips	ConocoPhillips Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Revenues and Other Income					
Sales and other operating revenues	$ —	65,851	38,395	—	104,246
Equity in earnings of affiliates	4,576	3,319	523	(7,876)	542
Other income	—	205	104	—	309
Intercompany revenues	136	2,936	4,876	(7,948)	—
Total revenues and other income	4,712	72,311	43,898	(15,824)	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	914	197	(384)	844
Foreign currency transaction (gains) losses	—	(41)	5	—	(36)
Minority interests	—	—	20	—	20
Total Costs and Expenses	135	67,191	37,410	(7,948)	96,788
Income from continuing operations before income taxes and subsidiary equity transactions	4,577	5,120	6,488	(7,876)	8,309
Gain on subsidiary equity transactions	—	—	28	—	28
Income from continuing operations before income taxes	4,577	5,120	6,516	(7,876)	8,337
Provision for income taxes	(16)	544	3,216	—	3,744
Income from continuing operations	4,593	4,576	3,300	(7,876)	4,593
Income from discontinued operations	237	237	787	(1,024)	237
Income before cumulative effect of changes in accounting principles	4,830	4,813	4,087	(8,900)	4,830
Cumulative effect of changes in accounting principles	(95)	(95)	(255)	350	(95)

Net Income	$	4,735	4,718	3,832	(8,550)	4,735

Balance Sheet		Millions of Dollars At December 31, 2005 ConocoPhillips	ConocoPhillips Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Assets						
Cash and cash equivalents	$	—	613	1,601	—	2,214
Accounts and notes receivable		775	12,573	16,484	(17,892)	11,940
Inventories		—	2,345	1,379	—	3,724
Prepaid expenses and other current assets		10	1,052	672	—	1,734
Assets of discontinued operations held for sale		—	—	—	—	—
Total Current Assets		785	16,583	20,136	(17,892)	19,612
Investments and long-term receivables		49,016	49,059	19,526	(101,875)	15,726
Net properties, plants and equipment		—	18,221	36,448	—	54,669
Goodwill		—	15,323	—	—	15,323
Intangibles		—	815	301	—	1,116
Other assets		11	228	313	1	553
Total Assets	$	49,812	100,229	76,724	(119,766)	106,999
Liabilities and Stockholders' Equity						
Accounts payable	$	76	17,199	12,883	(17,891)	12,267
Notes payable and long-term debt due within one year		—	323	1,435	—	1,758
Accrued income and other taxes		—	536	2,980	—	3,516
Employee benefit obligations		—	782	430	—	1,212
Other accruals		16	995	1,595	—	2,606
Liabilities of discontinued operations held for sale		—	—	—	—	—
Total Current Liabilities		92	19,835	19,323	(17,891)	21,359
Long-term debt		1,392	6,538	2,828	—	10,758
Asset retirement obligations and accrued environmental costs		—	1,112	3,479	—	4,591
Deferred income taxes		—	3,054	8,395	(10)	11,439
Employee benefit obligations		—	1,888	575	—	2,463
Other liabilities and deferred credits		1,966	11,384	17,012	(27,913)	2,449
Total Liabilities		3,450	43,811	51,612	(45,814)	53,059
Minority interests		—	(8)	1,217	—	1,209
Retained earnings		21,482	28,177	18,557	(40,198)	28,018
Other stockholders' equity		24,880	28,249	5,338	(33,754)	24,713
Total	$	49,812	100,229	76,724	(119,766)	106,999

Balance Sheet		Millions of Dollars At December 31, 2004 ConocoPhillips	ConocoPhillips Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Assets						
Cash and cash equivalents	$	—	879	508	—	1,387
Accounts and notes receivable		767	11,742	20,995	(24,716)	8,788
Inventories		—	2,367	1,299	—	3,666
Prepaid expenses and other current assets		20	381	585	—	986
Assets of discontinued operations held for sale		—	150	44	—	194
Total Current Assets		787	15,519	23,431	(24,716)	15,021
Investments and long-term receivables		38,194	44,097	20,563	(92,446)	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	$	38,998	92,095	78,930	(117,162)	92,861
Liabilities and Stockholders' Equity						
Accounts payable	$	62	17,443	16,342	(24,716)	9,131
Notes payable and long-term debt due within one year		544	27	61	—	632
Accrued income and other taxes		—	360	2,794	—	3,154

Employee benefit obligations		—	646	569	—	1,215
Other accruals		20	488	843	—	1,351
Liabilities of discontinued operations held for sale		—	(10)	113	—	103
Total Current Liabilities		626	18,954	20,722	(24,716)	15,586
Long-term debt		1,994	8,163	4,213	—	14,370
Asset retirement obligations and accrued environmental costs		—	890	3,004	—	3,894
Deferred income taxes		(1)	2,979	7,415	(8)	10,385
Employee benefit obligations		—	1,809	606	—	2,415
Other liabilities and deferred credits		8	18,120	18,140	(33,885)	2,383
Total Liabilities		2,627	50,915	54,100	(58,609)	49,033
Minority interests		—	(6)	1,111	—	1,105
Retained earnings		9,592	14,534	18,672	(26,670)	16,128
Other stockholders' equity		26,779	26,652	5,047	(31,883)	26,595
Total	$	38,998	92,095	78,930	(117,162)	92,861

Statement of Cash Flows		Millions of Dollars Year Ended December 31, 2005 ConocoPhillips	ConocoPhillips Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Cash Flows From Operating Activities						
Net cash provided by continuing operations	$	183	15,956	11,192	(9,698)	17,633
Net cash provided by (used in) discontinued operations		—	(7)	2	—	(5)
Net Cash Provided by Operating Activities		183	15,949	11,194	(9,698)	17,628
Cash Flows From Investing Activities						
Capital expenditures and investments, including dry holes		—	(5,118)	(9,119)	2,617	(11,620)
Proceeds from asset dispositions		—	279	491	(2)	768
Long-term advances/loans to affiliates and other		—	(20,056)	(1,208)	20,989	(275)
Collection of advances/loans to affiliates and other		1,240	12,339	2,161	(15,629)	111
Net cash provided by (used in) continuing operations		1,240	(12,556)	(7,675)	7,975	(11,016)
Net cash used in discontinued operations		—	—	—	—	—
Net Cash Provided by (Used in) Investing Activities		1,240	(12,556)	(7,675)	7,975	(11,016)
Cash Flows From Financing Activities						
Issuance of debt		2,901	1,504	17,036	(20,989)	452
Repayment of debt		(1,160)	(5,115)	(12,356)	15,629	(3,002)
Repurchase of company common stock		(1,924)	—	—	—	(1,924)
Issuance of company common stock		402	—	—	—	402
Dividends paid on common stock		(1,639)	—	(9,700)	9,700	(1,639)
Other		(3)	(50)	2,697	(2,617)	27
Net Cash Used in Financing Activities		(1,423)	(3,661)	(2,323)	1,723	(5,684)
Effect of Exchange Rate Changes on Cash and Cash Equivalents		—	2	(103)	—	(101)
Net Change in Cash and Cash Equivalents		—	(266)	1,093	—	827
Cash and cash equivalents at beginning of year		—	879	508	—	1,387
Cash and Cash Equivalents at End of Year	$	—	613	1,601	—	2,214

Statement of Cash Flows		Millions of Dollars Year Ended December 31, 2004 ConocoPhillips	ConocoPhillips Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Cash Flows From Operating Activities						
Net cash provided by continuing operations	$	406	7,382	5,327	(1,117)	11,998
Net cash provided by (used in) discontinued operations		—	(360)	321	—	(39)
Net Cash Provided by Operating Activities		406	7,022	5,648	(1,117)	11,959

	ConocoPhillips	ConocoPhillips Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Cash Flows From Investing Activities					
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
Cash consolidated from adoption and application of FIN 46(R)	—	—	11	—	11
Long-term advances/loans to affiliates and other	(786)	(1,922)	(2)	2,543	(167)
Collection of advances/loans to affiliates and other	1,359	1,634	(151)	(2,568)	274
Net cash provided by (used in) continuing operations	573	(3,729)	(7,257)	2,626	(7,787)
Net cash used in discontinued operations	—	(1)	—	—	(1)
Net Cash Provided by (Used in) Investing Activities	573	(3,730)	(7,257)	2,626	(7,788)
Cash Flows From Financing Activities					
Issuance of debt	—	2,462	81	(2,543)	—
Repayment of debt	(170)	(5,141)	(32)	2,568	(2,775)
Repurchase of company common stock	—	—	—	—	—
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)	(2,679)	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	—	611	286	—	897
Cash and cash equivalents at beginning of year	—	268	222	—	490
Cash and Cash Equivalents at End of Year	$ —	879	508	—	1,387

	Millions of Dollars				
	Year Ended December 31, 2003				
Statement of Cash Flows	ConocoPhillips	ConocoPhillips Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Cash Flows From Operating Activities					
Net cash provided by (used in) continuing operations	$ 7,757	5,036	(482)	(3,144)	9,167
Net cash provided by (used in) discontinued operations	—	(944)	1,133	—	189
Net Cash Provided by Operating Activities	7,757	4,092	651	(3,144)	9,356
Cash Flows From Investing Activities					
Capital expenditures and investments, including dry holes	—	(4,936)	(3,626)	2,393	(6,169)
Proceeds from asset dispositions	3	1,508	1,151	(3)	2,659
Cash consolidated from adoption and application of FIN 46(R)	—	—	225	—	225
Long-term advances/loans to affiliates and other	(5,950)	(2,225)	(30)	8,142	(63)
Collection of advances/loans to affiliates and other	—	25	61	—	86
Net cash used in continuing operations	(5,947)	(5,628)	(2,219)	10,532	(3,262)
Net cash used in discontinued operations	—	(58)	(178)	—	(236)
Net Cash Used in Investing Activities	(5,947)	(5,686)	(2,397)	10,532	(3,498)
Cash Flows From Financing Activities					
Issuance of debt	—	4,841	3,649	(8,142)	348
Repayment of debt	(809)	(1,557)	(2,793)	—	(5,159)
Repurchase of company common stock	—	—	—	—	—
Issuance of company common stock	108	—	—	—	108
Dividends paid on common stock	(1,107)	(1,578)	(1,566)	3,144	(1,107)
Other	(2)	34	2,469	(2,390)	111
Net Cash Provided by (Used in) Financing Activities	(1,810)	1,740	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

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

None.

Item 9A. CONTROLS AND PROCEDURES

As of December 31, 2005, 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, 2005.

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 105 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 pages 107 and 108 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," "Audit and Finance Committee Report," and "Stock Ownership—Section 16(a) Beneficial Ownership Reporting Compliance" in our definitive proxy statement for the Annual Meeting of Stockholders on May 10, 2006 (2006 Proxy Statement), is incorporated herein by reference.* Information regarding the executive officers appears in Part I of this report on pages 45 and 46.

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.

Item 11. EXECUTIVE COMPENSATION

Information presented under the following headings in the 2006 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," "Stock Ownership—Holdings of Officers and Directors" and "Executive Compensation—Compensation Tables—Equity Compensation Plan Information" in the 2006 Proxy Statement is incorporated herein by reference.

Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

None.

Item 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information presented under the heading "Proposal To Ratify the Appointment of Ernst & Young LLP" in the 2006 Proxy Statement is incorporated herein by reference.

**Except for information or data specifically incorporated herein by reference under Items 10 through 14, other information and data appearing in the 2006 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 104 are filed as part of this annual report.

2. Exhibits
The exhibits listed in the Index to Exhibits, which appears on pages 200 through 203, 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 (a)	Deductions	Balance At December 31
2005					
Deducted from asset accounts:					
Allowance for doubtful accounts and notes receivable	**$ 55**	**21**	**4**	**(8)(b)**	**72**
Deferred tax asset valuation allowance	**968**	**90**	**(26)**	**(182)**	**850**
Included in other liabilities:					
Employee termination benefits	**89**	**(2)**	**(3)**	**(31)(d)**	**53**
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

(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
2.1	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")).
2.2	Agreement and Plan of Merger, dated as of December 12, 2005, by and among ConocoPhillips, Cello Acquisition Corp. and Burlington Resources Inc. (incorporated by reference to Exhibit 2.1 to the Current Report of ConocoPhillips on Form 8-K filed on December 14, 2005).
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	Shareholder Agreement, dated September 29, 2004, by and between LUKOIL and ConocoPhillips (incorporated by reference to Exhibit 99.2 of the Current Report of ConocoPhillips on Form 8-K filed on September 30, 2004; File No. 333-74798).
10.2	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).
10.3	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).

Exhibit Number	Description
10.4	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).
10.5	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).
10.6	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).
10.7	ConocoPhillips Supplemental Executive Retirement Plan.
10.8	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).
10.9	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).
10.10	Key Employee Missed Credited Service Retirement Plan of ConocoPhillips.
10.11	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).
10.12	ConocoPhillips Key Employee Supplemental Retirement Plan.
10.13.1	Defined Contribution Make-Up Plan of ConocoPhillips-Title I.
10.13.2	Defined Contribution Make-Up Plan of ConocoPhillips-Title II.

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).
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.

Exhibit Number	Description
10.18	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).
10.19	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).
10.20	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).
10.20.1	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).
10.21	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).
10.22	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).
10.23.1	Key Employee Deferred Compensation Plan of ConocoPhillips-Title I.
10.23.2	Key Employee Deferred Compensation Plan of ConocoPhillips-Title II.
10.24	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).
10.25	ConocoPhillips Executive Severance Plan.
10.26	Summary of Non-employee Director Compensation (incorporated by reference to pages 5-6 of ConocoPhillips' Proxy Statement on Schedule 14A relating to the 2005 Annual Meeting of Shareholders; File No. 001-32395).
10.27	Description of ConocoPhillips' Variable Cash Incentive Program (incorporated by reference to pages 17-19 of ConocoPhillips' Proxy Statement on Schedule 14A relating to the 2005 Annual Meeting of Shareholders; File No. 001-32395).
10.28	Description of ConocoPhillips' Performance Share Program (incorporated by reference to page 20 of ConocoPhillips' Proxy Statement on Schedule 14A relating to the 2005 Annual Meeting of Shareholders; File No. 001-32395).
10.29	Description of ConocoPhillips' Stock Option Program (incorporated by reference to page 21 of ConocoPhillips' Proxy Statement on Schedule 14A relating to the 2005 Annual Meeting of Shareholders; File No. 001-32395).

Exhibit Number	Description
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, other than the Chief Executive Officer (incorporated by reference to Item 1.01 of the Current Report of ConocoPhillips on Form 8-K filed on February 16, 2006; File No. 001-32395).
10.32	Description of salary of Chief Executive Officer (incorporated by reference to Exhibit 10.31 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2004; File No. 001-32395).
12	Computation of Ratio of Earnings to Fixed Charges.
21	List of 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.

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 26, 2006

/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 26, 2006, 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/ Harold W. McGraw III *Harold W. McGraw III*	Director
/s/ Harald J. Norvik *Harald J. Norvik*	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 10.7

ORIGINAL FOR EXECUTION
APPROVED VICE PRESIDENT HUMAN RESOURCES
EFFECTIVE JANUARY 1, 2005

CONOCOPHILLIPS
SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN

PRE-AMERICAN JOBS CREATION ACT OF 2004 (“AJCA”)
GRANDFATHERED PROVISIONS

Benefits under this Plan, formerly the Phillips Petroleum Company Supplemental Executive Retirement Plan, (the “Phillips Plan”), that commenced prior to January 1, 2005 (“AJCA-grandfathered benefits”), shall be subject exclusively to the terms and conditions of the Phillips Plan in effect or before October 3, 2004. No change in the ConocoPhillips Retirement Plan adopted subsequent to such date and no change in the Phillips Plan or in the ConocoPhillips Supplemental Executive Retirement Plan adopted after such date shall apply to an AJCA-grandfathered benefit. Provided, however, for purposes of this paragraph, benefits shall be deemed to have commenced prior to January 1, 2005 and shall be AJCA-grandfathered benefits if the relevant corporate officer or committee approved the eligible employee’s petition regarding time and form of payment before January 1, 2005 even if the benefit commenced after December 31, 2004. The “relevant corporate officer or committee” means the person or persons with the authority under the Phillips Plan to approve a petition regarding the time and form of payment.

SECTION I - PURPOSE

The purpose of the ConocoPhillips Supplemental Executive Retirement Plan (“Plan”) is to supplement the retirement benefits of Retiring eligible employees who were hired in mid- career. ConocoPhillips Company (“Company”) recognizes that from time to time, it retains the services of employee(s) after the employee has performed services at another company (or companies) for varying periods of time, in order to obtain the special skills and expertise developed by the key employee during these other periods of employment. These employees generally forego all or a portion of their potential retirement benefits upon leaving their previous employer(s). This Plan, therefore, supplements retirement benefits to at least partially compensate for the loss of retirement benefits accrued at the previous employer(s). The amount of supplemental benefit payable under this Plan is not intended to cause a Retiring eligible employee’s retirement benefit to equal or exceed a full career Retiring eligible employee’s benefit.

SECTION II - DEFINITION OF TERMS

a)	Affiliated Group	shall mean the Company plus other subsidiaries and affiliates in which it owns a 5% or more equity interest.
b)	Retirement Income Plan	is Title I of the ConocoPhillips Retirement Plan (Phillips Retirement Income Plan).
c)	Retirement (or Retire, or Retiring)	is termination of employment with the Company on or after the employee’s earliest early retirement date as defined in the Retirement Income Plan. It includes termination of employment

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		at an age below 55 only when Section V applies.
d)	Credited Service, Final Average Earnings, Normal Retirement Date, and Early Retirement Date	as determined in accordance with the provisions of the Retirement Income Plan.
e)	Total Final Average Earnings	is the average of the high 3 earnings, excluding Incentive Compensation Plan Awards, paid in consecutive years of the last 10 years prior to termination of employment plus the average of the high 3 Incentive Compensation Plan Awards for any of such last 10 years under the Incentive Compensation Plan, whether paid or deferred and shall include the value of any special awards specified by the Compensation Committee to be included for final average earnings purposes under the terms of the special awards when granted by the Compensation Committee, and shall also recognize benefits paid under Section 4.2 of the Phillips Petroleum Company Executive Severance Plan in the same manner as layoff pay is recognized under the Retirement Income Plan.
f)	Total Credited Service	is an employee’s Credited Service plus any additional months of service as calculated under the Principal Corporate Officers Supplemental Retirement Plan and Missed Credited Service as defined in sub-section (j) of Section II of Article I in the Retirement Income Plan, plus months of service by recognizing benefits paid under Section 4.2 of the Phillips Petroleum Company Executive Severance Plan in the same manner as layoff pay is recognized under the Retirement Income Plan.
g)	Plan Administrator	means the person who is the highest level officer of the Company with primary responsibility for human

resources, or such person's successor.

h) Trustee — means the trustee of the grantor trust established by the Trust Agreement between the Company and Wachovia Bank, N. A. dated as of June 1, 1998, or any successor trustee.

i) Participating Subsidiary — means a subsidiary of the Company, of which the Company beneficially owns, directly or indirectly, more than 50% of the aggregate voting power of all outstanding classes and series of stock, where such subsidiary has adopted one or more plans making participants eligible for participation in this Plan.

SECTION III - ELIGIBLE EMPLOYEES

All employees of the Company who are participants in the Retirement Income Plan and who, a) as of November 1, 1988 participated in the Incentive Compensation Plan as members of Teams I, II, III (including those individuals promoted to such levels through November 1, 1988, ie: Grade 33 or above and ICP eligible), or b) were active employee participants or were eligible to participate in the Key Employee Death Protection Plan on the date of its termination (December 31, 1986), c) are hired subsequent to November 1, 1988 and at the time of hire are recommended for participation in the Plan by the Plan Administrator, with approval by the Chief Executive Officer of the Company, or d) prior to retirement are recommended for participation in the Plan by the Plan Administrator, with approval by the Chief Executive Officer of the Company, will be eligible for benefits under this Plan.

SECTION IV - ELIGIBILITY FOR BENEFITS

An eligible employee as described in Section III, will be eligible to receive the benefit amount described in Section VI only if the results of (a) below exceed the results of (b) below where:

(a) is the lesser of the following percentages;

(i) 2.4% times the greater of the eligible employee's Credited Service or the Employee's Total Credited Service at the time of Retirement; or

(ii) the Maximum SERP Benefit Percentage shown in the schedule below based upon the eligible employee's attained age at Retirement

and, (b) is the percentage derived by multiplying 1.6% times the eligible employee's Total Credited Service at the time of Retirement.

Attained Age at Retirement	**Maximum SERP Benefit Percentage**
65	60.0%
64	58.4%
63	56.8%
62	55.2%
61	53.6%
60	52.0%
59	50.4%
58	48.8%
57	47.2%
56	45.6%
55	44.0%
54 or younger	-0-

SECTION V - SPECIAL ELIGIBILITY

An eligible employee as described in Section III who is less than age 55 and who is laid off under the Layoff Plan of Phillips Petroleum Company and/or the Supplemental Layoff Plan of Phillips Petroleum Company and/or the Enhanced Supplemental Layoff Pay Plan of Phillips Petroleum Company and/or the Phillips Layoff Plan and/or the Work Force Stabilization Plan of Phillips Petroleum Company and/or who receives benefits under the Phillips Petroleum Company Executive Severance Plan or any similar plans which may be adopted by the Company from time to time and any employee who becomes employed by a member of the Affiliated Group, other than the Company or a Participating Subsidiary, immediately after terminating employment with the Company or a Participating Subsidiary, will be eligible to receive the benefit described in Section VI if the results of (a) below exceed the results of (b) below where:

(a) is the lesser of the following percentages;

(i) 2.4% times the greater of an eligible employee's Credited Service, or the employee's Total Credited Service at the time of layoff or termination; or

(ii) the Maximum SERP Benefit Percentage shown in the schedule below based upon the eligible employee's attained age at the time of layoff or termination.

and, (b) is the percentage derived by multiplying 1.6% times the eligible employee's Total Credited Service at the time of layoff or termination.

Attained Age at the time of Layoff	Maximum SERP Benefit Percentage
54	42.4%
53	40.8%
52	39.2%
51	37.6%
50	36.0%
49	34.4%
48	32.8%
47	31.2%
46	29.6%
45	28.0%
44	26.4%
43	24.8%
42	23.2%
41	21.6%
40	20.0%
39	18.4%
38	16.8%
37	15.2%
36	13.6%
35	12.0%
34	10.4%
33	8.8%
32	7.2%
31	5.6%
30	4.0%
29	2.4%
28	0.8%

SECTION VI - BENEFIT AMOUNT

Notwithstanding anything to the contrary in this Section VI, and subject to the AJCA Grandfather Provisions of this Plan, the rules for calculating an eligible employee's benefit will be applied consistently with good faith compliance with section 409A of the Internal Revenue Code of 1986 as amended; and any provisions of this Plan to the contrary will be disregarded. An eligible employee who qualifies for benefits under this Plan in accordance with Sections IV and V will be eligible to receive retirement benefits from the Plan as follows:

A. With respect to eligible employees who commence retirement benefits on or after their Normal Retirement Date -

multiply the lesser of (a)(i) or (a) (ii) as computed in Sections IV or V, as applicable, times the greater of the employee's Final Average Earnings or the employee's Total Final Average Earnings and with the results reduced by the portion of the eligible employee's Primary Social Security benefit as determined in the same manner as such reduction is determined under the Final Average Earnings formula of the Retirement Income Plan.

B. With respect to eligible employees who commence retirement benefits at an Early Retirement Date - benefits will be calculated in the same manner as the benefits for Normal Retirement Date, as described in A. of this Section, but reduced for early retirement in the same manner as is applicable under the Retirement Income Plan.

In either A. or B. above the Retirement Income Plan calculations shall be made as if no benefit limitations were imposed by the Internal Revenue Code and no benefit reductions resulted from participation in any qualified or non-qualified Company-sponsored benefit plan, and the resulting benefit amount will be reduced by applicable retirement benefit payments for which the retiree is eligible from any of the following plans, or any other similar plan or plans, of the Company or any of its subsidiary or affiliated companies; Retirement Income Plan, Retirement Restoration Plan of Phillips Petroleum Company, Key Employee Deferred Compensation Plan of Phillips Petroleum Company, the Retirement Makeup Plan of

Phillips Petroleum Company, Principal Corporate Officers Supplemental Retirement Plan of Phillips Petroleum Company, the Phillips Petroleum Company Key Employee Death Protection Plan, the Key Employee Supplemental Retirement Plan and the Key Employee Missed Credited Service Retirement Plan.

SECTION VII - PAYMENT OF RETIREMENT BENEFITS

Subject to the AJCA Grandfather provisions of the Plan, payment of benefits to eligible employees shall be as follows:

A. The rules for payment of benefits to eligible employees listed on Schedule A attached to this plan ("Schedule A Employees") shall be as follows:

(1) The benefit shall be paid as a straight life annuity for the life of the Schedule A Employee commencing in December, 2005, or if later, six months after Separation from Service. The Plan shall pay simple interest at a rate of 3% per annum on each delayed payment from the annuity starting date to December 1, 2005.

(2) Provided, however, notwithstanding subsection A.(1), (i) a Schedule A Employee who is married may, on or before December 1, 2005, elect, in writing, to receive a 50% joint and survivor annuity with the spouse as survivor commencing in December, 2005, with the rules regarding interest being as described in subsection (1) above; and

(ii) Any Schedule A Employee may elect on or before December 1, 2005, to cancel, in writing, participation in this Plan in which case the Schedule A Employee shall receive the present value of his entire accrued benefit under this Plan on or before December 31, 2005.

B. Benefits that commence under this Plan after 2005 for an eligible employee who is not a Schedule A Employee shall be paid in a lump sum the later of the first day of the first calendar month after the day the employee becomes age 55 (or, if the Retirement Income Plan treats the Employee as turning age 55 before that birth date, on the day he is treated as being age 55) or the first day of the seventh calendar month after Separation from Service as that term is defined in section 409A of the Internal Revenue Code and regulatory guidance thereunder(excluding death) but in no event before November 1, 2006. If the applicable commencement date is the first day of the seventh calendar month after Separation from Service, the Plan shall pay simple interest at the 6 month T-Bill rate (as determined by the Plan Administrator) in effect as of the annuity starting date. Such interest shall be paid from the annuity starting date used in calculating the benefit under this Plan to the commencement date.

SECTION VIII - METHOD OF PROVIDING BENEFITS

This Plan shall be unfunded. All benefits shall be provided solely from the general assets of the Company and any rights accruing to an eligible employee under the Plan shall be those of a general creditor; provided, however, that the Company may establish a grantor trust to satisfy part or all of its Plan payment obligations so long as the plan remains unfunded for purposes of Title I of ERISA.

SECTION IX - MISCELLANEOUS PROVISIONS

(a) No right or interest of an eligible employee under this Plan shall be assignable or transferable, in whole or in part, directly or indirectly, by operation of law or otherwise (excluding devolution upon death or mental incompetency).

(b) Any claim for benefits hereunder shall be presented in writing to the Plan Administrator for consideration, grant or denial. In the event that a claim is denied in whole or in part by the Plan Administrator, the claimant, within ninety days of receipt of said claim by the Plan Administrator, shall receive written notice of denial. Such notice shall contain:

(1) a statement of the specific reason or reasons for the denial;

(2) specific references to the pertinent provisions hereunder on which such denial is based;

(3) a description of any additional material or information necessary to perfect the claim and an explanation of why such material or information is necessary; and

(4) an explanation of the following claims review procedure set forth in paragraph (c) below.

(c) Any claimant who feels that a claim has been improperly denied in whole or in part by the Plan Administrator may request a review of the denial by making written application to the Trustee. The claimant shall have the right to review all pertinent documents relating to said claim and to submit issues and comments in writing to the Trustee. Any person filing an appeal from the denial of a claim must do so in writing within sixty days after receipt of written notice of denial. The Trustee shall render a decision regarding the claim within sixty days after receipt of a request for review, unless special circumstances require an extension of time for processing, in which case a decision shall be rendered within a reasonable time, but not later than 120 days after receipt of the request for review. The decision of the Trustee shall be in writing and, in the case of the denial of a claim in whole or in part, shall set forth the same information as is required in an initial notice of denial by the Plan Administrator, other than an explanation of this claims review procedure. The Trustee shall have absolute discretion in carrying out its responsibilities to make its decision of an appeal, including the authority to interpret and construe the terms hereunder, and all interpretations, findings of fact, and the decision of the Trustee regarding the appeal shall be final, conclusive and binding on all parties.

(d) Compliance with the procedures described in paragraphs (b) and (c) shall be a condition precedent to the filing of any action to obtain any benefit or enforce any right which any individual may claim hereunder. Notwithstanding anything to the contrary in this Plan, these paragraphs (b), (c) and (d) may not be amended without the written consent of a seventy-five percent (75%) majority of Participants and Beneficiaries and such paragraphs shall survive the termination of this Plan until all benefits accrued hereunder have been paid.

(e) The Chief Executive Officer, may amend or terminate this Plan at any time if, in his or her sole judgment such amendment or termination is deemed desirable. However, such amendments may not increase the benefits payable hereunder to any Officer of the Company who is also currently a Director of the Company.

(f) No amount accrued or payable hereunder shall be deemed to be a portion of an eligible employee's compensation or earnings for the purpose of any other employee benefit plan adopted or maintained by the Company, nor shall this Plan be deemed to amend or modify the provisions of the Retirement Income Plan.

(g) Participation or nonparticipation in this Plan shall not affect any eligible employee's employment status, or confer any special rights other than those expressly stated in the Plan.

(h) Except as otherwise provided herein, the Plan shall be binding upon the Company, its successors and assigns, including but not

limited to any corporation which may acquire all or substantially all of the Company's assets and business or with or into which the Company may be consolidated or merged.

(i) The Plan shall be construed, regulated, and administered in accordance with the laws of the State of Texas except to the extent that said laws have been preempted by the laws of the United States.

SECTION X - EFFECTIVE DATE

This Plan became effective January 1, 1987. This amendment and restatement of the Plan became effective January 1, 2005.

CONOCOPHILLIPS

By: /s/ Carin S. Knickel Dated: December 20, 2005
Carin S. Knickel
Vice President, Human Resources

Exhibit 10.10

ORIGINAL FOR EXECUTION
APPROVED VICE PRESIDENT HUMAN RESOURCES
EFFECTIVE JANUARY 1, 2005

KEY EMPLOYEE MISSED CREDITED SERVICE RETIREMENT PLAN OF CONOCOPHILLIPS

PURPOSE

The purpose of the Key Employee Missed Credited Service Retirement Plan of ConocoPhillips (the "Plan") is to attract and retain key employees by restoring retirement benefits which are missing for certain periods of Company service. This Plan is intended to be and shall be administered as an unfunded benefit plan for a select group of Highly Compensated Employees.

PRE-AMERICAN JOBS CREATION ACT OF 2004 ("AJCA") GRANDFATHERED PROVISIONS

Benefits under this Plan, formerly the Key Employee Missed Credited Service Retirement Plan of Phillips Petroleum Company, (the "Phillips Plan"), that commenced prior to January 1, 2005 ("AJCA-grandfathered benefits"), shall be subject exclusively to the terms and conditions of the Phillips Plan in effect or before October 3, 2004. No change in the ConocoPhillips Retirement Plan adopted subsequent to such date and no change in the Phillips Plan or in the Key Employee Missed Credited Service Retirement Plan of ConocoPhillips adopted after such date shall apply to an AJCA-grandfathered benefit. Provided, however, for purposes of this paragraph, benefits shall be deemed to have commenced prior to January 1, 2005 and shall be AJCA-grandfathered benefits if the relevant corporate officer or committee approved the employee's petition regarding time and form of payment before January 1, 2005 even if the benefit commenced after December 31, 2004. The "relevant corporate officer or committee" means the person or persons

with the authority under the Phillips Plan to approve a petition regarding the time and form of payment.

SECTION I. Definitions.

As used in this Plan:

(a) "Board" shall mean the board of directors of the Company.

(b) "Code" shall mean the Internal Revenue Code of 1986, as amended from time to time.

(c) "Committee" shall mean the Compensation Committee of the Board of Directors of ConocoPhillips, a Delaware corporation.

(d) "Company" shall mean a company or other corporation which is a member of the control group of corporations (defined in Code Section 414(b)) of which ConocoPhillips Company is a member.

(e) "Employee" shall mean a person who is an active participant in the Retirement Plan and who qualifies as a Highly Compensated Employee who as of May 1, 1995 is classified on the Company's records as a job schedule 51 grades 32 and above, all schedule 66 job grades, or a job schedule 70L grades 07 or 08.

(f) "ERISA" shall mean the Employee Retirement Income Security Act of 1974, as amended from time to time, or any successor statute.

(g) "Foreign Plan Offset" shall mean the amounts of the vested monthly retirement income from the I.E.L. Pension Plan or foreign retirement plans maintained or sponsored by the Company which is or would be payable in the form of a single life annuity upon reaching normal retirement age under such plans. If necessary, such retirement income shall be converted into a dollar amount using the exchange rate for the effective date of the Employee's transfer onto the U.S. payroll (or the next business day rate if there is no rate for that day) as published in the Wall Street Journal, and shall be converted into a monthly

single life annuity using the actuarial standards set out in Section 5 of Article V of the Retirement Plan for a deemed commencement date as of the first day of the month of transfer into the Retirement Plan. The Foreign Plan Offset shall be limited to no more than the amount by which the Missed Credited Service Retirement Benefit of the Employee would have been increased by the Missed Credited Service Months attributable to the months of participation in the I.E.L. Pension Plan or other foreign plans.

(h) "Highly Compensated Employee" shall mean an Employee who is Highly Compensated within the meaning of ERISA Sections 3(36) and 4(b)(5) subject to Section IV.

(i) "Incentive Compensation Plan" shall mean the Incentive Compensation Plan of the Company, or the Annual Incentive Compensation Plan of Phillips Petroleum Company, or similar plan of a Participating Subsidiary, or any similar or successor plans, or all, as the context may require.

(j) "Missed Credited Service Months" shall mean the number of months during any employment period with the Company not included as Credited Service in the Retirement Plan as calculated in Section II.

(k) "Missed Credited Service Retirement Benefit" shall mean the supplemental retirement benefit that would be calculated under the Retirement Plan using as Credited Service the Missed Credited Service Months in addition to the Credited Service and using Total Final Average Earnings, without regard for Internal Revenue Service limitations relating to Code Sections 401(a)(17) or 415, and reduced by:

(1) any offset applied to the retirement benefit which would be payable at normal retirement age due to a Foreign Plan Offset or due to withdrawals or benefit commencement from the Retirement Plan or the Key Employee Supplemental Retirement Plan, made in the manner specified in the Retirement Plan, and

(2) retirement benefits payable from the Retirement Plan and from the Key

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Employee Supplemental Retirement Plan.

(l) "Participating Subsidiary" shall mean a subsidiary of the Company, of which the Company beneficially owns, directly or indirectly, more than 50% of the aggregate voting power of all outstanding classes and series of stock, where such subsidiary has adopted one or more plans making participants eligible for participation in this Plan.

(m) "Plan" shall mean the Key Employee Missed Credited Service Retirement Plan of ConocoPhillips, the terms of which are stated in and by this document.

(n) "Plan Administrator" shall mean the person who is the highest level officer of the Company with primary responsibility for human resources or such person's successor.

(o) "Retirement Plan" shall mean Title I of the ConocoPhillips Retirement Plan (the Phillips Retirement Income Plan), which is qualified under Code Section 401(a). The following terms used in the Plan shall be determined in accordance with the provisions of the Retirement Plan:

(1) Approved Leave of Absence

(2) Credited Service

(3) Non-contributory Benefits Schedule and

(4) Normal Retirement Date

(p) "Total Final Average Earnings" shall mean the average of the high 3 earnings, excluding Incentive Compensation Plan awards, paid in consecutive years of the last 11 years, including the year prior in which termination of employment occurs, plus the average of the high 3 Incentive Compensation awards for any of such last 11 years under the Incentive Compensation Plan, whether paid or deferred, and shall include the value of any special awards specified by the Committee to be included for final average earnings purposes under the terms of the special awards when granted by the Committee.

(q) "Trustee" means the trustee of the grantor trust established by the Trust Agreement

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between the Company and Wachovia Bank, N.A. dated as of June 1, 1998, or any successor trustee.

SECTION II. Eligibility for Benefits.

Each Employee shall be eligible for a Missed Credited Service Retirement Benefit as a result of Missed Credited Service Months for service with the Company (provided that the full number of months as calculated below exceeds one) during any period of employment on the direct payroll of the Company which is not included as Credited Service under the other rules of the Retirement Plan, except for months attributable to the following:

(a) Service while classified as an employee eligible for participation in the Retirement Savings Plan of Phillips Petroleum Company or its predecessor plans,

(b) Service with a company prior to its acquisition by the Company,

(c) Service while classified on Company's records as a Temporary or Intermittent employee prior to January 1, 1990,

(d) Service as a non-managerial retail marketing outlet employee,

(e) Service in a category which is specifically excluded from the Retirement Plan by the definition of Employee or by Article II of the Retirement Plan at the time the person becomes an Employee, with the exception of international expatriates and foreign nationals,

(f) Periods while on an Approved Leave of Absence,

(g) Service as an employee who has commenced retirement benefits on or after his earliest Early Retirement Date and thereafter resumes employment duties with the Company,

(h) Service associated with absence due to a strike,

(i) Periods associated with absence due to discharge, or

(j) An earlier employment period with the Company followed by an absence from employment exceeding (i) 120 months from the end of employment date if that date occurred on or before January 1, 1985, or (ii) 60 months from the end of employment date if that date occurred after January 1, 1985.

In calculating the Missed Credited Service Months under this paragraph, the beginning and ending dates of an employment period shall be deemed to be as follows:

Actual Beginning or Ending Dates	Deemed Date
December 17 through January 16	January 1
January 17 through February 16	February 1
February 17 through March 16	March 1
March 17 through April 16	April 1
April 17 through May 16	May 1
May 17 through June 16	June 1
June 17 through July 16	July 1
July 17 through August 16	August 1
August 17 through September 16	September 1
September 17 through October 16	October 1
October 17 through November 16	November 1
November 17 through December 16	December 1

For the purposes of this Plan, the number of full months during any period of employment will be determined by subtracting the beginning deemed date and actual year from the ending deemed date and actual year. The Missed Credited Service Months restored pursuant to the provisions of this Plan should be deemed to have been completed under the Non-contributory Benefits Schedule of the Retirement Plan but shall not entitle any

Employee to current service benefits, as described in Article IV of the Retirement Plan, with respect to such period.

SECTION III. Plan Benefits.

Notwithstanding anything to the contrary in this Plan, and subject to the AJCA Grandfather Provisions of this Plan, the rules for calculating an Employee's benefit under this Plan will be applied consistently with good faith compliance with section 409A of the Internal Revenue Code of 1986 as amended; and any provisions of this Plan to the contrary will be disregarded.

The present value of Supplemental payments will be made in a lump sum in the amount of the Missed Credited Service Retirement Benefit to the Employee or the Employee's surviving spouse (in the case of the death of an Employee prior to the date his benefit under this Plan would otherwise commence). If applicable, the lump sum death benefit shall be paid to the surviving spouse on the first of the month after the eligible employee's death.

SECTION IV. Form and Payment of Benefits.

Subject to the AJCA Grandfather provisions of this Plan, payment of benefits shall be as follows:

A. The rules for payment of benefits to employees listed on Schedule A attached to this plan ("Schedule A Employees") shall be as follows:

(1) The benefit shall be paid as a straight life annuity for the life of the Schedule A Employee commencing in December, 2005, or if later, six months after Separation from Service. The Plan shall pay simple interest at a rate of 3% per annum on each delayed payment from the annuity starting date to December 1, 2005.

(2) Provided, however, notwithstanding subsection A.(1),

(i) a Schedule A Employee who is married may, on or before December 1, 2005, elect, in writing, to receive a 50% joint and survivor annuity with the spouse as survivor commencing in December, 2005, with the rules regarding interest being as described in subsection (1) above; and

(ii) Any Schedule A Employee may elect on or before December 1, 2005, to cancel, in writing, participation in this Plan in which case the Schedule A Employee shall receive the present value of his entire accrued benefit under this Plan on or before December 31, 2005.

B. Benefits that commence under this Plan after 2005 to an Employee who is not a Schedule A Employee shall be paid in a lump sum on the later of the first day of the first calendar month after the day the Employee becomes age 55 (or, if the Retirement Plan treats the Employee as turning age 55 before that birth date, on the day he is treated as being age 55) or the first day of the seventh calendar month after Separation from Service as that term is defined in section 409A of the Internal Revenue Code and regulatory guidance thereunder (excluding death) but in no event before November 1, 2006. If the applicable commencement date is the first day of the seventh calendar month after Separation from Service, the Plan shall pay simple interest at the 6 month T-Bill rate (as determined by the Plan Administrator) in effect as of the annuity starting date. Such interest shall be paid from the annuity starting date used in calculating the benefit under this Plan to the commencement date.

SECTION V. Method of Providing Benefits.

All amounts payable under this Plan shall be paid solely from the general assets of the Company

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and any rights accruing to an eligible Employee or Retiree under the Plan shall be those of a general creditor; provided, however, that the Company may establish a grantor trust to satisfy part or all of its Plan payment obligations so long as the Plan remains an unfunded excess benefit plan for purposes of Title I of ERISA.

SECTION VI. Nonassignability.

The right of an Employee, or beneficiary, or other person who becomes entitled to receive payments under this Plan, shall not be assignable or subject to garnishment, attachment or any other legal process by the creditors of, or other claimants against, the Employee, beneficiary, or other such person.

SECTION VII. Administration.

(a) The Plan shall be administered by the Plan Administrator. The Plan Administrator may adopt such rules, regulations and forms as deemed desirable for administration of the Plan and shall have the discretionary authority to allocate responsibilities under the Plan to such other persons as may be designated, whether or not employee members of the Board.

(b) Any claim for benefits hereunder shall be presented in writing to the Plan Administrator for consideration, grant or denial. In the event that a claim is denied in whole or in part by the Plan Administrator, the claimant, within ninety days of receipt of said claim by the Plan Administrator, shall receive written notice of denial. Such notice shall contain:

(1) a statement of the specific reason or reasons for the denial;

(2) specific references to the pertinent provisions hereunder on which such denial is based;

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(3) a description of any additional material or information necessary to perfect the claim and an explanation of why such material or information is necessary; and

(4) an explanation of the following claims review procedure set forth in paragraph (c) below.

(c) Any claimant who feels that a claim has been improperly denied in whole or in part by the Plan Administrator may request a review of the denial by making written application to the Trustee. The claimant shall have the right to review all pertinent documents relating to said claim and to submit issues and comments in writing to the Trustee. Any person filing an appeal from the denial of a claim must do so in writing within sixty days after receipt of written notice of denial. The Trustee shall render a decision regarding the claim within sixty days after receipt of a request for review, unless special circumstances require an extension of time for processing, in which case a decision shall be rendered within a reasonable time, but not later than 120 days after receipt of the request for review. The decision of the Trustee shall be in writing and, in the case of the denial of a claim in whole or in part, shall set forth the same information as is required in an initial notice of denial by the Plan Administrator, other than an explanation of this claims review procedure. The Trustee shall have absolute discretion in carrying out its responsibilities to make its decision of an appeal, including the authority to interpret and construe the terms hereunder, and all interpretations, findings of fact, and the decision of the Trustee regarding the appeal shall be final, conclusive and binding on all parties.

(d) Compliance with the procedures described in paragraphs (b) and (c) shall be a condition

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precedent to the filing of any action to obtain any benefit or enforce any right which any individual may claim hereunder. Notwithstanding anything to the contrary in this Plan, these paragraphs (b), (c) and (d) may not be amended without the written consent of a seventy-five percent (75%) majority of Participants and Beneficiaries and such paragraphs shall survive the termination of this Plan with all benefits accrued hereunder have been paid.

SECTION VIII. Employment not Affected by Plan.

Participation or nonparticipation in this Plan shall neither adversely affect any person's employment status, or confer any special rights on any person other than those expressly stated in the Plan. Participation in the Plan by an Employee of the Company or of a Participating Subsidiary shall not affect the Company's or the Participating Subsidiary's right to terminate the Employee's employment or to change the Employee's compensation or position.

SECTION IX. Miscellaneous Provisions.

(a) The Board reserves the right to amend or terminate this Plan at any time, if, in the sole judgment of the Board, such amendment or termination is deemed desirable; provided that the Company shall remain liable for any benefits accrued under this Plan prior to the date of amendment or termination.

(b) Except as otherwise provided herein, the Plan shall be binding upon the Company, its successors and assigns, including but not limited to any corporation which may acquire all or substantially all of the Company's assets and business or with or into which the Company may be consolidated or merged.

(c) No amount accrued or payable hereunder shall be deemed to be a portion of an Employee's compensation or earnings for the purpose of any other employee benefit plan adopted or maintained by the Company, nor shall this Plan be deemed to amend or modify the provisions of the Retirement Plan.

(d) The Plan shall be construed, regulated, and administered in accordance with the laws of the State of Texas except to the extent that said laws have been preempted by the laws of the United States.

CONOCOPHILLIPS

By: /s/ Carin S. Knickel Dated: December 20, 2005

Carin S. Knickel
Vice President, Human Resources

ORIGINAL FOR EXECUTION
APPROVED BY THE VICE PRESIDENT HUMAN RESOURCES
EFFECTIVE JANUARY 1, 2005

CONOCOPHILLIPS
KEY EMPLOYEE SUPPLEMENTAL RETIREMENT PLAN

PURPOSE

The purpose of the ConocoPhillips Key Employee Supplemental Retirement Plan (the "Plan") is to attract and retain key employees by providing them with supplemental retirement benefits. This Plan is intended to be and shall be administered in part as an unfunded pension excess benefit plan within the meaning of ERISA Sections 3(36) and in part as an unfunded pension benefit plan maintained primarily for a select group of management or highly compensated employees.

PRE-AMERICAN JOBS CREATION ACT OF 2004
GRANDFATHERED PROVISIONS

Benefits under this Plan, formerly called the Key Employee Supplemental Retirement Plan of Phillips Petroleum Company (the "Phillips Plan"), that commenced prior to January 1, 2005 ("AJCA-grandfathered benefits"), shall be subject exclusively to the terms and conditions of the Phillips Plan in effect on or before October 3, 2004. No change in the ConocoPhillips Retirement Plan adopted subsequent to such date and no change in the Phillips Plan or in the ConocoPhillips Key Employee Supplemental Retirement Plan adopted after such date shall apply to an AJCA-grandfathered benefit. Provided, however, for purposes of this paragraph, benefits shall be deemed to have commenced prior to January 1, 2005 and shall be AJCA-grandfathered benefits if the relevant corporate officer or committee approved the Employee's

petition regarding time and form of payment before January 1, 2005 even if the benefits commenced after December 31, 2004. The "relevant corporate officer or committee" means the person or persons with the authority under the Phillips Plan to approve a petition regarding the time and form of payment.

SECTION I. Definitions

Terms used in this Plan shall have the same meaning they have in the relevant Title of the ConocoPhillips Retirement Plan if they are not otherwise specifically defined herein.

As used in this Plan:

(a) "Board" shall mean the board of directors of the Company.

(b) "Code" shall mean the Internal Revenue Code of 1986, as amended from time to time.

(c) "Committee" shall mean the Compensation Committee of the Board of Directors of ConocoPhillips.

(d) "Company" shall mean ConocoPhillips Company, a Delaware corporation, or a successor corporation.

(e) "ConocoPhillips" shall mean ConocoPhillips, a Delaware corporation, or a successor corporation.

(f) "Employee" shall mean a person who is an active participant or a terminated vested participant in the Retirement Plan.

(g) "ERISA" shall mean the Employee Retirement Income Security Act of 1974, as amended from time to time, or any successor statute.

(h) "Final Average Earnings" shall mean "final average earnings" as that term is defined in Title I of the ConocoPhillips Retirement Plan.

(i) "Incentive Compensation Plan" shall mean the Incentive Compensation Plan of Phillips

Petroleum Company, the Annual Incentive Compensation Plan of Phillips Petroleum Company, the Variable Cash Incentive Program of ConocoPhillips or successor plans or programs, or all, as the context may require.

(j) "KEDCP" shall mean the ConocoPhillips Key Employee Deferred Compensation Plan or a successor plan.

(k) "Participating Subsidiary" shall mean a subsidiary of ConocoPhillips of which ConocoPhillips beneficially owns, directly or indirectly, more than 80% of the aggregate voting power of all outstanding classes and series of stock, where such subsidiary has adopted one or more plans making participants eligible for participation in this Plan.

(l) "Plan" shall mean the ConocoPhillips Key Employee Supplemental Retirement Plan, the terms of which are stated in and by this document.

(m) "Plan Administrator" shall mean the person who is the highest level officer of the Company with primary responsibility for human resources, or such person's successor.

(n) “Plan-age 55” shall mean the first of the calendar month after an Employee’s age 55 or, if earlier, the date the applicable title of the Retirement Plan treats the Employee as being age 55.

(o) “Restricted Stock” shall mean shares of Stock which have certain restrictions attached to the ownership thereof.

(p) “Retirement Plan” shall mean the ConocoPhillips Retirement Plan, but not including Title III of such plan, which is qualified under Code Section 401(a).

(q) “Salary” shall mean the monthly equivalent rate of pay for an Employee before adjustments for any before-tax voluntary reductions.

(r) “Schedule A Employee” shall mean an Employee whose name appears in Schedule A attached to and made a part of this Plan.

(s) “Separation from Service” shall have the meaning given that term in Code section 409A and in regulatory guidance thereunder except that the term shall not mean death.

(t) “Stock” means shares of common stock of ConocoPhillips, par value $.01.

(u) “Title I” shall mean Title I of the ConocoPhillips Retirement Plan (Phillips Retirement Income Plan).

(v) “Title II” shall mean Title II of the ConocoPhillips Retirement Plan (Cash Balance Account).

(w) “Title III” shall mean Title III of the ConocoPhillips Retirement Plan (Tosco Pension Plan).

(x) “Title IV” shall mean Title IV of the ConocoPhillips Retirement Plan (Retirement Plan of Conoco).

(y) “Total Final Average Earnings” shall mean the sum of: (i) the average of the high 3 consecutive Annual Earnings, (including any increases under Section II(b)(bb), (ee), (ff) and (gg) of this Plan, but excluding Incentive Compensation Plan awards and any increases under Section II(b)(aa), (cc), and (dd) of this Plan), paid or deemed to be paid in the Employee’s final eleven calendar years of employment with the Company or a Participating Subsidiary including the calendar year in which the Employee’s last date of employment with the Company or a Participating Subsidiary occurs; plus (ii) the average of the high 3 Incentive Compensation Plan awards (including any increases under Section II(b)(aa), (cc), or (dd) of this Plan, but excluding any increases under Section II(b)(bb), (ee), (ff) and (gg) of this Plan) paid or deemed to be paid in the Employee’s final eleven calendar years of employment with the Company or a Participating Subsidiary including the calendar year in which the Employee’s last date of employment with the Company or Participating Subsidiary occurs. Provided, however, in determining Total Final Average

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Earnings, an Incentive Compensation Plan award (and any increases under the provisions of Section II(b) cited above) shall be taken into consideration only if the Employee to whom such award or increase applies, was at the time of the award or increase, classified in a ConocoPhillips salary grade 19 or above job or any equivalent salary grade of Phillips Petroleum Company.

(z) “Trustee” means the trustee of the grantor trust established by the Trust Agreement between the Company and Wachovia Bank, N.A. dated as of June 1, 1998, or any successor trustee.

SECTION II. Plan Accrued Benefit.

(a) An Employee shall be entitled to payments under this Plan based on an accrued benefit with the following components: (i) his Title I-related accrued benefit, (ii) his Title II-related accrued Benefit and (iii) his Title IV-related accrued benefit, each as defined below.

(b) “Title I-related accrued benefit shall mean the sum of (i), (ii) and (iii) below:

(i) The difference between the Employee’s total accrued benefit under Title I and his actual accrued benefit under Title I. For this purpose, an Employee’s “total accrued benefit under Title I” is the accrued benefit he would have if his accrued benefit under Title I were determined under the terms of Title I but with the following modifications:

(aa) Include in Annual Earnings an award under the Incentive Compensation Plan which the employee deferred under the terms of the KEDCP. Include such award in the calendar year in which the award would have been paid to the Employee if it had not been deferred.

(bb) Include in Annual Earnings salary that would have been paid to the Employee but for the fact that he voluntarily elected to defer receipt of that salary under the terms of KEDCP. Include the deferred salary in Annual Earnings in the calendar year in which the salary would have been paid had it not been deferred.

(cc) Include in Annual Earnings the initial value of a restricted stock or restricted stock unit award under the Incentive Compensation Plan. Include that value in Annual Earnings in the calendar year in which the award was granted.

(dd) Include in Annual Earnings the value of any special award specified by the Committee under the terms of the special award to be included for Annual Earnings purposes under Title I in the year in which any applicable restrictions on the award lapse or, if deferred, in the year in which any applicable restrictions would have lapsed absent an election to defer.

(ee) Disregard the limitations on compensation related to Code section 401(a)(17).

(ff) Disregard the limitation on benefits related to Code section 415.

(gg) If an Employee is eligible to receive benefits under the ConocoPhillips Executive Severance Plan or under the ConocoPhillips Key Employee Change in Control Severance Plan, include in Annual Earnings an amount determined by dividing the Employee's Salary by 4.3333 times the number of weeks or partial weeks from the date the Employee's employment ends with the Employer to the end of that calendar year. Provided, however, this subsection (gg) shall be disregarded to the extent the benefit created solely by operation of this subsection (gg) is provided under the terms of Title I.

(ii) In the case of an Employee who terminated employment on or after

February 8, 1993, the Title I-related accrued benefit shall include an additional supplemental accrued benefit calculated under the terms of Title I, but disregarding the limitation on compensation that is taken into account, using as final average earnings the difference, if any, between the Total Final Average Earnings and the Final Average Earnings used in Title I.

(iii) The Title I-related accrued benefit shall also include any benefit provided under Section IV of this Plan.

(c) "Title II-related accrued benefit" shall mean the difference between the Employee's total accrued benefit under Title II and his actual accrued benefit under Title II. For this purpose, an Employee's "total accrued benefit under Title II" is the accrued benefit he would have if his accrued benefit under Title II were determined under the terms of Title II but with the following modifications:

(i) Include in Annual Earnings an award under the Incentive Compensation Plan which the Employee deferred under the terms of the KEDCP. Include such award in the calendar month and year in which the award would have been paid to the Employee if it had not been deferred.

(ii) Include in Annual Earnings salary that would have been paid to the employee but for the fact that he voluntarily elected to defer receipt of that salary under the terms of KEDCP. Include the deferred salary in Annual Earnings in the calendar month and year in which the salary would have been paid had it not been deferred.

(iii) Include in Annual Earnings the initial value of a restricted stock or restricted stock unit award under the Incentive Compensation Plan. Include that value

in Annual Earnings in the calendar month and year in which the award was granted.

(iv) Include in Annual Earnings the value of any special award specified by the Committee under the terms of the special award to be included for Annual Earnings purposes under Title II in the year in which any applicable restrictions on the award lapse or, if deferred, in the year in which any applicable restrictions would have lapsed absent an election to defer.

(v) Disregard the limitation on compensation related to Code section 401(a)(17).

(vi) Disregard the limitation on benefits related to Code section 415.

(d) "Title IV- related accrued benefit" shall mean the difference between the Employee's total accrued benefit under Title IV and his actual accrued benefit under Title IV. For this purpose, an Employee's "total accrued benefit under Title IV" is the benefit he would have if his accrued benefit were determined under the provisions of Title IV but with the following modifications:

(i) Include in Compensation salary that would have been paid to the Employee but for the fact that he voluntarily elected to defer receipt of that salary under the terms of KEDCP or a similar predecessor program but only if such salary is not included in Compensation for purposes of calculating the Title IV accrued benefit due to the election to defer. If applicable, include the deferred salary in the calendar month and year in which the salary would have been paid had it not been deferred.

(ii) Include in Compensation any Incentive Compensation Plan award that would have been paid to the Employee but for the fact that he voluntarily

elected to defer receipt of that award under the terms of KEDCP or a similar predecessor program but only if such award is not included in Compensation for purposes of calculating the Title IV accrued benefit due to the election to defer. If applicable, include the deferred award in the calendar month and year in which the award would have been paid had it not been deferred.

(iii) Include in compensation the value of any special award specified by the Committee under the terms of the special award to be included for compensation purposes under Title IV in the calendar month and year in which any applicable restrictions on the award lapse or, if deferred, in the calendar month and year in which any applicable restrictions would have lapsed absent an election to defer.

(iv) Disregard the limitation on compensation related to Code section 401(a)(17).

(v) Disregard the limitation on benefits related to Code section 415.

(e) Each of the components of the accrued benefit under this Plan (the Title I-related accrued benefit, the Title II-related accrued benefit and the Title IV-related accrued benefit) shall be expressed as a straight life annuity starting at the age that is the normal retirement age under the applicable title of the Retirement Plan in accordance with the following rules:

(i) If the annuity starting date for the relevant Retirement Plan benefit occurs on or before the required commencement date under this Plan, the Title I-related accrued benefit, the Title II-related accrued benefit or the Title IV-related accrued benefit, as is applicable, shall first be calculated as of the Retirement Plan annuity starting date related to that component benefit and

then shall be converted actuarially to a straight life annuity payable at age 65 applying actuarial assumptions that are consistent with the relevant Title of the Retirement Plan. The component accrued benefit so calculated shall not be increased or decreased based on subsequent events.

(ii) If the annuity starting date for the relevant Retirement Plan benefit has not occurred on or before the required commencement date under this Plan, the Title I-related accrued benefit, the Title II-related accrued benefit or the Title IV-related accrued benefit, as is applicable, shall be calculated as if the relevant Retirement Plan benefit had an annuity starting date and a form of payment that is the same as the required commencement date and form of payment under this Plan. The resulting component benefit shall then be converted actuarially to an equivalent straight life annuity starting at age 65, and the component accrued benefit so calculated shall be the component accrued benefit under this Plan and shall not be increased or decreased based on subsequent events.

(f) The component accrued benefit described in subsection (e) above shall be converted to the actual benefit paid under this Plan applying the methodology specified in the applicable title of the Retirement Plan. For this purpose, the terms of the applicable title of the Retirement Plan are those in effect as of the annuity starting date used in this Plan. If the applicable title of the Retirement Plan does not provide a methodology, a reasonable methodology, as determined by the Plan Administrator, shall be used.

SECTION III. DEATH BENEFIT

(a) If a Schedule A Employee chooses a 50% joint and survivor annuity and dies after the annuity starting date of that benefit, the spouse beneficiary will be entitled to payments under this Plan that are 50% of the payments due the Schedule A Employee under this Plan during his lifetime.

(b) If an Employee who is not a Schedule A Employee dies prior to the date his accrued benefit under this Plan would otherwise commence, this Plan shall provide a death benefit if the applicable title of the Retirement Plan provides a death benefit under that circumstance. Any death benefit under this Plan shall be paid in a lump sum on the first day of the first calendar month after death. If there is a delay in payment of the lump sum, regardless of the reason, the Plan shall not make an adjustment to reflect the time value of money. In the case of a Title I-related accrued benefit for an Employee who terminated employment before September 1, 2004, the death benefit, if any, shall be converted to a present value and paid to the surviving spouse. Except as described in the preceding sentence, the death benefit shall be the present value of the Employee's entire accrued benefit under this Plan payable in accordance with the following rules:

(i) The present value shall be paid to the Employee's named primary Beneficiary or beneficiaries or, if applicable, to the Employee's named contingent beneficiary or beneficiaries if the beneficiary or beneficiaries were named in a manner acceptable to the Plan Administrator.

(ii) If the Employee had not, prior to his death, named any beneficiary in a manner acceptable to the Plan Administrator, the present value shall be paid to the Employee's estate.

(iii) The present value shall be paid in a lump sum and shall be calculated using the

first of the month after death as the annuity starting date and applying the rules described in Section II(e) and (f) of this Plan for determining the amount to be paid.

(iv) If a beneficiary makes a "qualified disclaimer" as that term is defined in Section 2518 of the Code, and the Plan Administrator receives a copy of the disclaimer within 9 months after the employee's death and before payment of the death benefit under this Plan, at the place designated by the Plan Administrator, the Plan will be administered as if the disclaiming beneficiary had died before the Employee.

SECTION IV. Special Provision for former ARCO Alaska Employees.

Notwithstanding any provisions to the contrary, in order to comply with the terms of the Board approved Master Purchase and Sale Agreement ("Sale Agreement") by which the Company acquired certain Alaskan assets of Atlantic Richfield Company, Inc. ("ARCO"), the following supplemental payments will be made:

(a) The payments which would have been received under Article XXIV – ARCO Flight Crew of Title I of the Retirement Plan for those who were classified as an Aviation Manager, Chief Pilot, Assistant Chief Pilot, Captain or Reserve Captain as of July 31, 2000 if they had been eligible for those benefits under Title I of the Retirement Plan, except that if they receive a limited social security makeup benefit from Title I of the Retirement Plan it will be offset from the benefit payable from the Plan.

(b) A final ARCO Supplemental Executive Retirement Plan (SERP) benefit will be calculated at the earlier of the time an Employee who had an ARCO SERP benefit terminates

employment or, 2 years following the ARCO/BP Amoco p.l.c. merger, April 17, 2002 ("calculation date"). The SERP benefit attributable to service through July 31, 2000 shall be paid by BP Amoco p.l.c. and the difference shall be paid by this Plan. The SERP calculation will be done as if the Employee had continued to participate in the Atlantic Richfield Retirement Plan and SERP up to the calculation date. The ARCO Annual Incentive Plan (AIP) amount used will be:

(i) If the Employee terminates employment involuntarily prior to April 17, 2002, the highest of the actual AIP in the last 3 years including the AIP target payment amount for years after 1999 or the payment received under Phillips Annual Incentive Compensation Plan.

(ii) If the Employee terminates employment voluntarily prior to April 17, 2002, or if the calculation is made as of April 17, 2002, then the AIP will include the highest 3 year average using the highest of the actual AIP, the AIP target payment amount for years after 1999, or the payment received under Phillips Annual Incentive Compensation Plan. Any benefit paid by this Plan under this Section IV (b)(ii) and the SERP benefit paid by BP Amoco p.l.c. shall offset the benefit payable from this Plan.

SECTION V. Payment of Benefits.

(a) Schedule A Employees

(i) With respect to a Schedule A Employee, the accrued benefit under this Plan shall be paid as a straight life annuity for the life of the Schedule A Employee commencing in December, 2005, or if later, six months after Separation from Service. The annuity starting date for calculating the Title I-related and

Title IV-related component annuity shall be the annuity starting date used in determining the Schedule A Employee's Title I or Title IV benefit, as applicable, and the Plan shall pay interest at a rate of 3% per annum on each delayed payment from the annuity starting date to December 1, 2005. The annuity starting date for calculating the Title II-related component annuity shall be December 1, 2005, or, if later six months after Separation from Service.

(ii) Provided, however, notwithstanding subsection (a)(i), a Schedule A Employee has the following choice or choices:

(aa) A Schedule A Employee who is married may, on or before December 1, 2005, elect, in writing, to receive a 50% joint and survivor annuity with the spouse as survivor commencing in December, 2005, with the rules regarding the annuity starting date and the payment of interest being as described in subsection (i) above; or

(bb) Any Schedule A Employee may elect on or before December 1, 2005, to cancel, in writing, participation in this Plan in which case the Schedule A Employee shall receive the present value of his entire accrued benefit under this Plan on or before December 31, 2005, and shall thereafter have no rights or benefits under this Plan. Provided, however, if a Schedule A Employee is rehired and becomes employed by the Employer after 2005, he may thereafter accrue a new benefit under this Plan unrelated to the cancelled benefit.

(aaa) For a Title I-related accrued benefit and a Title IV-related accrued benefit, the present value will be determined applying the rules regarding the annuity starting date and the payment of interest as described in subsection (a)(i).

(bbb) For a Title II-related accrued benefit, the present value shall be based on the value of the Schedule A Employee's Title II-related cash balance account as of December 1, 2005.

(ccc) If a Schedule A Employee dies after electing to cancel participation but before payment is made, the payment shall be made to his estate on or before December 31, 2005.

(iii) If a Schedule A Employee is rehired after 2005 and thereafter accrues a benefit in this Plan, he shall not be considered a Schedule A Employee with respect to such post-2005 accrued benefit.

(b) Employees other than Schedule A Employees — With respect to Employees who are not Schedule A Employees, the benefit under this Plan, shall be calculated and paid as follows:

(i) Commencement — Unless the accrued benefit has been or will be paid on account of the Employee's death as described in Section III(b), the present value of the Employee's accrued benefit shall be paid in a lump sum on the later of: the Employee's Plan-age 55 or the first day of the seventh calendar month after the Employee's Separation from Service; but in no event earlier

than November 1, 2006.

(ii) Annuity Starting Date for calculating the present value

(aa) If the applicable commencement date for a Title I-related or a Title IV-related accrued benefit is the first day of the seventh calendar month after Separation from Service, the annuity starting date used in calculating the present value shall be the later of: the Employee's Plan-age 55 or the first day of the first calendar month after the Employee's Separation from Service; and the Plan shall pay interest from the annuity starting date to the commencement date at the 6 month T-Bill rate (as determined by the Plan Administrator) in effect on the annuity starting date. If the applicable commencement date for a Title-II-related accrued benefit is the first day of the seventh calendar month after Separation from Service, the annuity starting date shall be the same as the commencement date.

(bb) Except as provided in the second sentence of this subsection (bb), if the applicable commencement date is the Employee's Plan-age 55 or November 1, 2006, the annuity starting date used in calculating the present value shall be the same as the commencement date. Provided, however, in the case of an Employee whose Separation from Service is in 2006 and whose commencement date under this Plan is November 1, 2006, the annuity starting date used in calculating the present value shall be the later of: the Employee's Plan-age 55 or the first day of the first calendar month after the Employee's Separation from Service; and the Plan shall pay simple interest from the annuity starting date to

November 1, 2006, at the 6 month T-Bill rate (as determined by the Plan Administrator) in effect on the annuity starting date.

(iii) Except as specifically provided in subsections (b)(ii)(aa) and (bb), the Plan shall not make an adjustment of the benefit to reflect the time value of money if there is delay in paying the benefit for any reason.

SECTION VI. Method of Providing Benefits.

All amounts payable under this Plan shall be paid solely from the general assets of the Company and any rights accruing to an eligible Employee or beneficiary under the Plan shall be those of a general creditor; provided, however, that the Company may establish a grantor trust to satisfy part or all of its Plan payment obligations so long as the Plan remains an unfunded excess benefit plan and or an unfunded benefit plan for a select group of management or highly compensated employees for purposes of Title I of ERISA.

SECTION VII. Nonassignability.

The right of an Employee, or beneficiary, or other person who becomes entitled to receive payments under this Plan, shall not be assignable or subject to garnishment, attachment or any other legal process by the creditors of, or other claimants against, the Employee, beneficiary, or other such person.

SECTION VIII. Administration.

(a) The Plan shall be administered by the Plan Administrator. The Plan Administrator may adopt such rules, regulations and forms as deemed desirable for administration of the Plan and shall have the discretionary authority to allocate responsibilities under the Plan to

such other persons as may be designated..

(b) Any claim for benefits hereunder shall be presented in writing to the Plan Administrator for consideration, grant or denial. In the event that a claim is denied in whole or in part by the Plan Administrator, the claimant, within ninety days of receipt of said claim by the Plan Administrator, shall receive written notice of denial. Such notice shall contain:

(1) a statement of the specific reason or reasons for the denial;

(2) specific references to the pertinent provisions hereunder on which such denial is based;

(3) a description of any additional material or information necessary to perfect the claim and an explanation of why such material or information is necessary; and

(4) an explanation of the following claims review procedure set forth in paragraph (c) below.

(c) Any claimant who feels that a claim has been improperly denied in whole or in part by the Plan Administrator may request a review of the denial by making written application to the Trustee. The claimant shall have the right to review all pertinent documents relating to said claim and to submit issues and comments in writing to the Trustee. Any person filing an appeal from the denial of a claim must do so in writing within sixty days after receipt of written notice of denial. The Trustee shall render a decision regarding the claim within sixty days after receipt of a request for review, unless special circumstances require an extension of time for processing, in which case a decision shall be rendered within a reasonable time, but not later than 120 days after receipt of the request for review. The decision of the Trustee shall be in writing and, in the case of the denial of a claim in whole or in part, shall set forth the same information as is required in an initial notice of denial by the Plan Administrator, other than an explanation of this claims review procedure. The

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Trustee shall have absolute discretion in carrying out its responsibilities to make its decision of an appeal, including the authority to interpret and construe the terms hereunder, and all interpretations, findings of fact, and the decision of the Trustee regarding the appeal shall be final, conclusive and binding on all parties.

(d) Compliance with the procedures described in paragraphs (b) and (c) shall be a condition precedent to the filing of any action to obtain any benefit or enforce any right which any individual may claim hereunder. Notwithstanding anything to the contrary in this Plan, these paragraphs (b), (c) and (d) may not be amended without the written consent of a seventy-five percent (75%) majority of Participants and Beneficiaries and such paragraphs shall survive the termination of this Plan until all benefits accrued hereunder have been paid.

SECTION IX. Employment Not Affected by Plan.

Participation or nonparticipation in this Plan shall neither adversely affect any person’s employment status, or confer any special rights on any person other than those expressly stated in the Plan. Participation in the Plan by an Employee of the Company or of a Participating Subsidiary shall not affect the Company’s or the Participating Subsidiary’s right to terminate the Employee’s employment or to change the Employee’s compensation or position.

SECTION X. Miscellaneous Provisions.

(a) The Board reserves the right to amend or terminate this Plan at any time, if, in the sole judgment of the Board, such amendment or termination is deemed desirable; provided that the Company shall remain liable for any benefits accrued under this Plan prior to the date of amendment or termination.

(b) Except as otherwise provided herein, the Plan shall be binding upon the Company, its successors and assigns, including but not limited to any corporation which may acquire all or substantially all of the Company’s assets and business or with or into which the Company may be consolidated or merged.

(c) No amount accrued or payable hereunder shall be deemed to be a portion of an Employee’s compensation or earnings for the purpose of any other employee benefit plan adopted or maintained by the Company, nor shall this Plan be deemed to amend or modify the provisions of the Retirement Plan.

(d) The Plan shall be construed, regulated, and administered in accordance with the laws of the State of Texas except to the extent that said laws have been preempted by the laws of the United States.

CONOCOPHILLIPS

By: /s/ Carin S. Knickel Dated: December 20, 2005

Carin S. Knickel
Vice President, Human Resources

Exhibit 10.13.1

ORIGINAL FOR EXECUTION
APPROVED VP, HR DECEMBER 29, 2005

DEFINED CONTRIBUTION MAKE-UP PLAN OF CONOCOPHILLIPS

TITLE I
(Effective for benefits earned and vested prior to January 1, 2005)

The Defined Contribution Make-Up Plan of ConocoPhillips is intended to provide certain specified benefits to Highly Compensated Employees whose benefits under the ConocoPhillips Savings Plan might otherwise be limited. Title I of this Plan is effective with regard to benefits earned and vested prior to January 1, 2005, while Title II of this Plan is effective with regard to benefits earned or vested after December 31, 2004. Other than earnings, gains, and losses, no further benefits shall accrue under Title I of this Plan after December 31, 2004.

This Title I of the Plan is intended (1) to be a "grandfathered" plan pursuant to Code section 409A, as enacted as part of the American Jobs Creation Act of 2004, and official guidance issued thereunder, and (2) to be "a plan which is unfunded and is maintained by an employer primarily for the purpose of providing deferred compensation for a select group of management or highly compensated employees" within the meaning of sections 201(2), 301(a)(3), and 401(a)(1) of ERISA. Notwithstanding any other provision of this Plan, this Plan shall be interpreted, operated, and administered in a manner consistent with these intentions.

Section 1. Definitions.

For purposes of the Plan, the following terms, as used herein, shall have the meaning specified:

(a) **"Affiliated Company"** shall mean ConocoPhillips and any company or other legal entity that is controlled, either directly or indirectly, by ConocoPhillips.

(b) **"Affiliated Group"** shall mean ConocoPhillips and its subsidiaries and affiliates in which it owns a 5% or more equity interest.

(c) **"Allocation Ratio"** shall mean the ratio determined by dividing (i) an amount equal to the total value of the unallocated shares of Stock allocated to Stock Savings Feature participants and beneficiaries as of a Stock Savings Feature Semiannual Allocation Date or Supplemental Allocation Date (as defined in the CPSP) by (ii) an amount equal to the total net Stock Savings Feature employee deposits used in the calculation of the Stock Savings Feature Semiannual Allocation or Supplemental Allocation (as defined in the CPSP).

(d) **"Beneficiary"** shall mean a person or persons designated by a Participant to receive, in the event of death, any unpaid portion of a Participant's Benefit from this Plan. Any Participant may designate one or more persons primarily or contingently as beneficiaries in writing upon forms supplied by and delivered to the Company, and may revoke such designations in writing. If a Participant fails to properly designate a beneficiary, then the Benefits will be paid in

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the following order of priority:
(i) Surviving spouse; then
(ii) Surviving children in equal shares; then
(iii) To the estate of the Participant.

(e) **"Benefit"** shall mean an obligation of the Company to pay amounts from this Plan.

(f) **"Board"** shall mean the Board of Directors of the Company, as it may be comprised from time to time.

(g) **"Code"** shall mean the Internal Revenue Code of 1986, as amended from time to time, or any successor statute.

(h) **"CPSP"** shall mean the ConocoPhillips Savings Plan.

(i) **"Committee"** shall mean the Compensation Committee of the Board of Directors of ConocoPhillips or any successor committee with substantially the same responsibilities.

(j) **"Company"** shall mean ConocoPhillips Company, a Delaware corporation, or any successor corporation.

(k) **"Disability"** shall mean the inability, in the opinion of the Medical Director of ConocoPhillips, of a Participant, because of an injury or sickness, to work at a reasonable occupation that is available with a member of the Affiliated Group.

(l) **"Employee"** shall mean any individual who is a salaried employee of the Company or any Participating Subsidiary.

(m) **"Exchange Act"** shall mean the Securities Exchange Act of 1934, as amended and in effect from time to time, or any successor statute.

(n) **"Highly Compensated Employee"** shall mean an Employee whose compensation exceeds the amount set forth in Code Section 401(a)(17), as amended from time to time, or who is eligible to elect a voluntary salary reduction under the provisions of the KEDCP.

(o) **"KEDCP"** shall mean the Key Employee Deferred Compensation Plan of ConocoPhillips or any similar or successor plan maintained by an Affiliated Company.

(p) **"Layoff"** or **"Laid Off"** shall mean layoff under the Phillips Layoff Plan, the Work Force Stabilization Plan of Phillips Petroleum Company, the Phillips Petroleum Company Executive Severance Plan, the Conoco Severance Pay Plan, the Conoco Inc. Key Employee Severance Plan, or any similar plan which the Company, any Participating Subsidiary, or a member of the Affiliated Group may adopt from time to time under the terms of which the Participant executes and does not revoke a general release of liability, acceptable to the Company, Participating Subsidiary, or a member of the Affiliated Group, as applicable, under such layoff plan.

(q) **"Other Obligations"** shall mean the **"**Other Obligations**"** as defined in the Amendment to and Merger of Amended and Restated Conoco Inc. Salary Deferral & Savings Restoration Plan into Key Employee Deferred Compensation Plan of ConocoPhillips and Defined Contribution Make-Up Plan of ConocoPhillips, pursuant to which a portion of the Amended

and Restated Conoco Inc. Salary Deferral & Savings Restoration Plan is merged into this Plan effective October 3, 2003.

(r) **"Participant"** shall mean an Employee who is eligible to receive a Benefit from this Plan as a result of being a Highly Compensated Employee and any person for whom a Supplemental Thrift Feature Account and/or a Supplemental Stock Savings Feature Account is maintained.

(s) **"Participating Subsidiary"** shall mean a subsidiary of ConocoPhillips, which has adopted the CPSP, and one or more Employees of which are Participants eligible to make deposits to the CPSP, or are eligible for Benefits pursuant to this Plan.

(t) **"Pay"** shall mean **"**Pay**"** as defined in the CPSP except without regard to Pay Limitations or voluntary Salary Reduction under provisions of the KEDCP.

(u) **"Pay Limitations"** shall mean the compensation limitations applicable to the CPSP that are set forth in Code section 401(a)(17), as adjusted.

(v) "**Plan Administrator"** shall mean the Manager, Compensation and Benefits, of the Company, or his successor.

(w) **"Retirement"** shall mean termination of employment with the Company, a Participating Subsidiary, or a member of the Affiliated Group that qualifies the Employee for Retirement as that term is defined in the applicable provisions of the ConocoPhillips Retirement Plan, the Retirement Plan of

Conoco, or of the applicable retirement plan of a member of the Affiliated Group. Notwithstanding the foregoing, an Employee will not be considered to be in Retirement for purposes of this Plan if he is entering Retirement under the Retirement Plan of Conoco prior to age 55, unless he had attained age 50 on or before August 30, 2002.

(x) **"Stock"** shall mean shares of common stock, $0.01 par value, issued by ConocoPhillips.

(y) **"Stock Savings Feature"** shall mean the Stock Savings Feature of the CPSP.

(z) **"Supplemental Thrift Contributions"** shall mean, (i) prior to the month in which the Participant's Pay first exceeds the Pay Limitations in a year, the same percentage of a Participant's Pay that the Participant is depositing as a Basic Deposit to the Thrift Feature for that month multiplied by the amount of the Participant's voluntary salary reduction under the KEDCP for that month, and (ii) provided the Participant is making deposits to the Thrift Feature for the month in which the Participant's Pay exceeds the Pay Limitations and each month thereafter until the end of the year, the same percentage of the Participant's Pay that the Participant was depositing as a Basic Deposit to the Thrift Feature for the month in which he or she reached the Pay Limitations for the year, multiplied by the sum of the amount of the Participant's voluntary salary reduction under the KEDCP for that month plus the amount of the Participant's Pay for that month that is in excess of the Pay Limitations for that year.

(aa) **"Supplemental Stock Savings Feature Account"** shall mean the Plan Benefit account of a Participant that reflects the portion of his or her Benefit that is intended to replace certain Stock Savings Feature benefits to which the Participant might otherwise be entitled but for the application of the Pay Limitations and/or a voluntary salary reduction under the KEDCP.

(bb) **"Supplemental Stock Savings Contributions"** shall mean (i) prior to the month in which the Participant's Pay first exceeds the Pay Limitations in a year, for each month that the Participant makes deposits to the Stock Savings Feature, 1% of the amount of the Participant's voluntary salary reduction under the KEDCP for that month, and (ii) provided the Participant is making deposits to the Stock Savings Feature in the month in which the Participant's Pay exceeds the Pay Limitations, for that month and for each month thereafter until the end of the year, 1% of the sum of the amount of the Participant's voluntary salary reduction under the KEDCP for that month plus the amount of the Participant's Pay for that month that is in excess of the Pay Limitations for that year.

(cc) **"Supplemental Thrift Feature Account"** shall mean the Plan Benefit account of a Participant which reflects the portion of his or her Benefit which is intended to replace certain Thrift Feature benefits to which the Participant might otherwise be entitled but for the application of the Pay Limitations and/or a voluntary salary reduction under the KEDCP.

(dd) **"Thrift Feature"** shall mean the Thrift Feature of the CPSP.

(ee) **"Trustee"** shall mean the trustee of the grantor trust established by the Trust Agreement between the Company (known then as Phillips Petroleum Company) and Wachovia Bank, N.A. dated as of June 1, 1998, or any successor trustee.

(ff) **"Valuation Date"** shall mean "Valuation Date" as defined in the CPSP.

Section 2. Purpose.

The purpose of this Plan is to provide supplemental benefits for those Highly Compensated Employees whose benefits under the CPSP are affected by Pay Limitations or by a voluntary reduction in salary under provisions of KEDCP. This Plan is intended to be and shall be administered as an unfunded benefit plan for those Highly Compensated Employees, who are considered to be a select group of management or highly compensated employees.

Section 3. Eligibility.

Benefits may only be granted to Highly Compensated Employees.

Section 4. Supplemental Thrift Feature Account Benefits.

For each payroll period in which Company Contributions to a Participant's account in the Thrift Feature are, or would be, limited by the Pay Limitations and/or by a voluntary salary reduction to the KEDCP, a Benefit amount shall be credited to his or her Supplemental Thrift Feature Account no later than the end of the month following the Valuation Date that Company

contributions are made to the Participant's Thrift Feature Account, or would be made to such account but for Pay Limitations. The Participant will be credited with an amount equal to the amount of his or her Supplemental Thrift Contributions each month to the same investment funds and in the same proportions as the Participant has directed his or her latest available investment allocation for Deposits to the Thrift Feature.

Section 4.1 Supplemental Thrift Feature Account Earnings

The Supplemental Thrift Feature Account shall be eligible to be invested in the same investment funds as are made available to Participants in the Thrift Feature from time to time. While such investments shall consist solely of book entries and shall not actually be invested in such funds, the book entry share value of such deemed investment funds in this Plan shall be determined to be the same share value as the actual value of shares in the investment funds of the CPSP. The amounts deemed invested in this Plan shall be valued at the same time and in the same manner as though they were actually invested in the CPSP. Also, deemed investments in the Participant's Supplemental Thrift Feature Account may be exchanged into other available investment funds in the same manner, at the same times, and subject to the same limitations as though the deemed amounts were actually invested in the CPSP. However, to the extent that earnings in the form of dividends on Company Stock in the CPSP are eligible to be passed through to the Participant, such dividends will be deemed to have been reinvested in the Company Stock Fund of this Plan, without regard to whether the Participant has made a pass through election under the CPSP.

Section 5. Supplemental Stock Savings Feature Account Benefits.

For each month in which a Semiannual Allocation or Supplemental Allocation (as defined in the CPSP) to a Participant's account in the Stock Savings Feature is, or would be, limited by the Pay Limitations and/or by a voluntary salary reduction under the KEDCP, a Benefit amount shall be credited to his or her Supplemental Stock Savings Feature Account. The amount to be credited shall be calculated in shares in the Leveraged Stock Fund of this Plan as though the Participant had made Supplemental Stock Savings Contributions and shall be equal to (i) the Participant's Supplemental Stock Savings Contributions during the applicable Allocation Period (as defined in the CPSP) multiplied by the applicable Allocation Ratio, divided by (ii) the share value for the Leveraged Stock Fund of the CPSP on the applicable Allocation Date. This amount shall be credited no later than the end of the month following the Valuation Date that the Semiannual Allocation or Supplemental Allocation to the Leveraged Stock Fund would have been made had the Participant received a Semiannual Allocation or Supplemental Allocation under the Stock Savings Feature. A share in the Leveraged Stock Fund of the Supplemental Stock Savings Feature Account shall have a value equivalent to a share in the Leveraged Stock Fund of the CPSP.

Section 5.1 Supplemental Stock Savings Account Feature Earnings

After being initially invested in the Leveraged Stock Fund account, the amounts in the Participant's Supplemental Stock Savings Feature Account shall thereafter be eligible to be invested in the same investment funds as are made available to Participants in the CPSP from time to time. While such investments shall consist solely of book entries and shall not actually be invested in such funds, the book entry share value of such deemed investment funds in this Plan shall be determined to be the same share value as the actual value of shares in the investment funds of the CPSP. The amounts deemed invested in this Plan shall be valued at the same time and in the same manner as though they were actually invested in the CPSP. Also, deemed investments in the Participant's Supplemental Stock Savings Feature Account may be exchanged into other available investment funds in the same manner, at the same times, and subject to the same limitations as though the deemed amounts were actually invested in the CPSP. However, to the extent that earnings in the form of dividends on Company Stock in the CPSP are eligible to be passed through to the Participant, such dividends will be deemed to have been reinvested in the Company Stock Fund of this Plan, without regard to whether the Participant has made a pass through election under the CPSP.

Section 6. Payment.

If a Participant terminates employment with the Affiliated Group for any reason except death, Disability, Layoff during or after the year in which the Participant reaches age 50, or Retirement, Benefits which the Participant is eligible to receive under this Plan shall be paid in one lump sum cash payment as soon as practicable following his or her termination. If a Participant dies prior to Retirement, Benefits which the Participant is eligible to receive under this Plan shall be paid in one lump sum cash payment to the Participant's Beneficiary as soon as practicable after his or her death. If a Participant Retires, is Laid off during or after the year in which the Participant reaches age 50, or becomes Disabled, Benefits which the

Participant is eligible to receive under this Plan shall be paid in one lump sum cash payment as soon as practicable following the Participant's Retirement, Layoff, determination of Disability, or termination of employment; provided that such a Participant may indicate a preference to defer part or all of such lump sum cash payment under the terms of the KEDCP.

All lump sum cash payments shall be made only as of a Valuation Date and shall be net of withholding for applicable taxes required by law.

The Chief Executive Officer of ConocoPhillips, with respect to Participants who are not subject to section 16 of the Exchange Act, and the Committee, with respect to Participants who are subject to section 16 of the Exchange Act, shall consider such indication of preference and shall respectively decide in the Chief Executive Officer's or the Committee's sole discretion whether to accept or reject the preference expressed. In the event the Chief Executive Officer or the Committee, as applicable, accepts such Participant's preference, the Participant's Benefit from this Plan shall be credited as an Award under the KEDCP as soon as practicable after the Participant's Retirement, Layoff, or the date the Participant is determined to be Disabled.

Section 7. Administration.

(a) The Plan shall be administered by the Plan Administrator. The Plan Administrator may delegate to employees of the Company or any Affiliated Company the authority to execute and deliver such instruments and documents, to do all such acts and things, and to take such other steps deemed

necessary, advisable, or convenient for the effective administration of the Plan in accordance with its terms and purpose, except that the Plan Administrator may not delegate any discretionary authority with respect to substantive decisions or functions regarding the Plan or Benefits hereunder.

(b) Any claim for benefits hereunder shall be presented in writing to the Plan Administrator for consideration, grant, or denial. In the event that a claim is denied in whole or in part by the Plan Administrator, the claimant, within ninety days of receipt of said claim by the Plan Administrator, shall receive written notice of denial. Such notice shall contain:

(1) A statement of the specific reason or reasons for the denial;

(2) Specific references to the pertinent provisions hereunder on which such denial is based;

(3) A description of any additional material or information necessary to perfect the claim and an explanation of why such material or information is necessary; and

(4) An explanation of the following claims review procedure set forth in paragraph (c) below.

(c) Any claimant who feels that a claim has been improperly denied in whole or in part by the Plan Administrator may request a review of the denial by making written application to the Trustee. The claimant shall have the right to review

all pertinent documents relating to the claim and to submit issues and comments in writing to the Trustee. Any person filing an appeal from the denial of a claim must do so in writing within sixty days after receipt of written notice of denial. The Trustee shall render a decision regarding the claim within sixty days after receipt of a request for review, unless special circumstances require an extension of time for processing, in which case a decision shall be rendered within a reasonable time, but not later than 120 days after receipt of the request for review. The decision of the Trustee shall be in writing and, in the case of the denial of a claim in whole or in part, shall set forth the same information as is required in an initial notice of denial by the Plan Administrator, other than an explanation of this claims review procedure. The Trustee shall have absolute discretion in carrying out its responsibilities to make its decision of an appeal, including the authority to interpret and construe the terms hereunder, and all interpretations, findings of fact, and the decision of the Trustee regarding the appeal shall be final, conclusive, and binding on all parties.

(d) Compliance with the procedures described in paragraphs (b) and (c) shall be a condition precedent to the filing of any action to obtain any benefit or enforce any right that any individual may claim hereunder. Notwithstanding anything to the contrary in this Plan, these paragraphs (b), (c) and (d) may not be amended without the written consent of a seventy-five percent (75%) majority of Participants and Beneficiaries and such paragraphs shall survive the termination of this Plan until all benefits accrued hereunder have been paid.

Section 8. Rights of Employees and Participants.

Nothing contained in the Plan (or in any other documents related to this Plan or to any Benefit) shall confer upon any Employee or Participant any right to continue in the employ or other service of the Company or any member of the Affiliated Group or constitute any contract or limit in any way the right of the Company or any member of the Affiliated Group to change such person's compensation or other benefits or to terminate the employment of such person with or without cause.

Section 9. Awards in Foreign Countries.

The Board or its delegate shall have the authority to adopt such modifications, procedures, and subplans as may be necessary or desirable to comply with provisions of the laws of foreign countries in which the Company or Participating Subsidiaries may operate to assure the viability of the Benefits of Participants employed in such countries and to meet the purpose of this Plan.

Section 10. Amendment and Termination.

The Board reserves the right to amend or terminate this Plan at any time, and to delegate such authority as the Board deems necessary or desirable; provided that no member of the Board who is also a Participant shall participate in any action which has the actual or potential effect of increasing his or her Benefits hereunder; and further provided, the Company shall remain liable for any Benefits accrued under this Plan prior to the date of amendment or termination.

Section 11. Unfunded Plan.

All amounts payable under this Plan shall be paid solely from the general assets of the Company and any rights accruing to a Participant under the Plan shall be those of a general creditor; provided, however, that the Company or ConocoPhillips may establish one or more grantor trusts to satisfy part or all of the Company's Plan payment obligations so long as the Plan remains unfunded for purposes of Title I of ERISA.

Section 12. Miscellaneous Provisions.

(a) No right or interest of a Participant under this Plan shall be assignable or transferable, in whole or in part, directly or indirectly, by operation of law or otherwise (excluding devolution upon death or mental incompetency), without the prior consent of the Board.

(b) This Plan shall be restated and amended effective as of October 3, 2003. Effective at that time, this Plan shall assume the Other Obligations and any other obligations, claims, benefits, rights, and duties as set forth in the Amendment to and Merger of Amended and Restated Conoco Inc. Salary Deferral & Savings Restoration Plan into Key Employee Deferred Compensation Plan of ConocoPhillips and Defined Contribution Make-Up Plan of ConocoPhillips, pursuant to which a portion of the Amended and Restated Conoco Inc. Salary Deferral & Savings Restoration Plan is merged into this Plan effective October 3, 2003. Such Other Obligations shall be deemed to be part of the Supplemental Thrift Benefit Feature account of each affected Participant and

book entries made in accordance with the investment directions for each affected Participant at such time.

(c) No amount accrued or payable hereunder shall be deemed to be a portion of an Employee's compensation or earnings for the purpose of any other employee benefit plan adopted or maintained by the Company, nor shall this Plan be deemed to amend or modify the provisions of the CPSP.

(d) This Plan shall be construed, regulated, and administered in accordance with the laws of the State of Texas except to the extent that said laws have been preempted by the laws of the United States.

(e) Except as otherwise provided herein, the Plan shall be binding upon the Company, its successors and assigns, including but not limited to any corporation which may acquire all or substantially all of the Company's assets and business or with or into which the Company may be consolidated or merged.

Executed this 29th day of December 2005, effective as of January 1, 2005, with respect to benefits earned and vested prior to January 1, 2005.

/s/ Carin S. Knickel

Carin S. Knickel
Vice President, Human Resources

ORIGINAL FOR EXECUTION
APPROVED VP, HR DECEMBER 29, 2005

**DEFINED CONTRIBUTION MAKE-UP PLAN
OF
CONOCOPHILLIPS**

**TITLE II
(Effective for benefits earned or vested after
December 31, 2004)**

The Defined Contribution Make-Up Plan of ConocoPhillips is intended to provide certain specified benefits to Highly Compensated Employees whose benefits under the ConocoPhillips Savings Plan might otherwise be limited. Title I of this Plan is effective with regard to benefits earned and vested prior to January 1, 2005, while Title II of this Plan is effective with regard to benefits earned or vested after December 31, 2004. Earnings, gains, and losses shall be allocated to the Title of the Plan to which the underlying obligations giving rise to them are allocated.

This Title II of the Plan is intended (1) to comply with Code section 409A, as enacted as part of the American Jobs Creation Act of 2004, and official guidance issued thereunder, and (2) to be "a plan which is unfunded and is maintained by an employer primarily for the purpose of providing deferred compensation for a select group of management or highly compensated employees" within the meaning of sections 201(2), 301(a)(3), and 401(a)(1) of ERISA. Notwithstanding any other provision of this Plan, this Plan shall be interpreted, operated, and administered in a manner consistent with these intentions.

Section 1. Definitions.

For purposes of the Plan, the following terms, as used herein, shall have the meaning specified:

(a) **"Affiliated Company"** shall mean any corporation or other entity that is treated as a single employer with the Company under section 414(b) or (c) of the Code.

(b) **"Affiliated Group"** shall mean the Company and its subsidiaries and affiliates in which it owns a 5% or more equity interest.

(c) **"Allocation Ratio"** shall mean the ratio determined by dividing (i) an amount equal to the total value of the unallocated shares of Stock allocated to Stock Savings Feature participants and beneficiaries as of a Stock Savings Feature Semiannual Allocation Date or Supplemental Allocation Date (as defined in the CPSP) by (ii) an amount equal to the total net Stock Savings Feature employee deposits used in the calculation of the Stock Savings Feature Semiannual Allocation or Supplemental Allocation (as defined in the CPSP).

(d) **"Beneficiary"** shall mean a person or persons designated by a Participant to receive, in the event of death, any unpaid portion of a Participant's Benefit from this Plan. Any Participant may designate one or more persons primarily or contingently as beneficiaries in writing upon forms supplied by and delivered to the Company, and may revoke such designations in writing. If a Participant fails to properly designate a beneficiary, then the Benefits will be paid in the following order of priority:
(i) Surviving spouse; then
(ii) Surviving children in equal shares; then
(iii) To the estate of the Participant.

(e) **"Benefit"** shall mean an obligation of the Company to pay amounts from this Plan.

(f) **"Board"** shall mean the Board of Directors of the Company, as it may be comprised from time to time.

(g) **"Code"** shall mean the Internal Revenue Code of 1986, as amended from time to time, or any successor statute.

(h) **"Company"** shall mean ConocoPhillips Company, a Delaware corporation, or any

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successor corporation. The Company is a subsidiary of ConocoPhillips.

(i) **"ConocoPhillips"** shall mean ConocoPhillips, a Delaware corporation, or any successor corporation. ConocoPhillips is a publicly held corporation and the parent of the Company.

(j) **"CPSP"** shall mean the ConocoPhillips Savings Plan.

(k) **"CPSP Pay"** shall mean **"**Pay**"** as defined in the CPSP.

(l) **"DCMP Pay"** shall mean **"**Pay**"** as defined in the CPSP without regard to Pay Limitations or voluntary salary reduction under provisions of the KEDCP.

(m) **"Election Form"** shall mean a written form, including one in electronic format, provided by the Plan Administrator pursuant to which a Participant may elect the time and form of payment of his or her Benefit.

(n) **“Employee”** shall mean any individual who is a salaried employee of the Company or any Participating Subsidiary.

(o) **“ERISA”** shall mean the Employee Retirement Income Security Act of 1974, as amended from time to time, or any successor statute.

(p) **“Frozen Plan”** shall mean Title I of the Defined Contribution Make-Up Plan of ConocoPhillips.

(q) **“Highly Compensated Employee”** shall mean an Employee whose DCMP Pay exceeds the amount set forth in Code Section 401(a)(17), as amended from time to time, or who is eligible to elect a voluntary salary reduction under the provisions of the KEDCP.

(r) **“Investment Options”** shall mean the investment options, as determined from time to time by the Plan Administrator, used to credit earnings, gains, and losses on Supplemental Thrift Feature Account and Supplemental Stock Savings Feature Account balances.

(s) **“KEDCP”** shall mean the Key Employee Deferred Compensation Plan of ConocoPhillips or any similar or successor plan maintained by an Affiliated Company.

(t) **“Leveraged Stock Fund”** shall mean an Investment Option under this Plan that is accounted for as if investments were made in the common stock, $0.01 par value, of ConocoPhillips, although no such actual investments need be made, with accounting entries being sufficient therefor.

(u) **“Ongoing Plan”** shall mean Title II of the Defined Contribution Make-Up Plan of

ConocoPhillips.

(v) **“Participant”** shall mean an Employee who is eligible to receive a Benefit from this Plan as a result of being a Highly Compensated Employee and any person for whom a Supplemental Thrift Feature Account and/or a Supplemental Stock Savings Feature Account is maintained.

(w) **“Participating Subsidiary”** shall mean a subsidiary of ConocoPhillips, which has adopted the CPSP, and one or more Employees of which are Participants eligible to make deposits to the CPSP, or are eligible for Benefits pursuant to this Plan.

(x) **“Pay Limitations”** shall mean the compensation limitations applicable to the CPSP that are set forth in Code section 401(a)(17), as adjusted.

(y) **“Plan”** shall mean the Defined Contribution Make-Up Plan of ConocoPhillips.

(z) **“Plan Administrator”** shall mean the Manager, Compensation and Benefits, of the Company, or his successor.

(aa) **“Plan Year”** means January 1 through December 31.

(bb) **“Separation from Service”** shall mean the date on which the Participant terminates employment with the Company and its Affiliated Companies within the meaning of Code section 409A, whether by reason of disability, retirement, or otherwise.

(cc) **“Stock”** shall mean shares of common stock, $0.01 par value, issued by ConocoPhillips.

(dd) **“Stock Savings Feature”** shall mean the Stock Savings Feature of the CPSP.

(ee) **“Supplemental Stock Savings Contributions”** shall mean an amount equal to 1% of the amount of the Participant’s DCMP Pay for a Plan Year that is in excess of the Participant’s CPSP Pay for such Plan Year.

(ff) **“Supplemental Stock Savings Feature Account”** shall mean the Plan Benefit account of a Participant that reflects the portion of his or her Benefit that is intended to replace certain Stock Savings Feature benefits to which the Participant might otherwise be entitled but for the application of the Pay Limitations and/or a voluntary salary reduction under the KEDCP.

(gg) **“Supplemental Thrift Contributions”** shall mean an amount equal to 1.25% of the amount of the Participant’s DCMP Pay for a Plan Year that is in excess of the Participant’s

CPSP Pay for such Plan Year.

(hh) **“Supplemental Thrift Feature Account”** shall mean the Plan Benefit account of a Participant which reflects the portion of his or her Benefit which is intended to replace certain Thrift Feature benefits to which the Participant might otherwise be entitled but for the application of the Pay Limitations and/or a voluntary salary reduction under the KEDCP.

(ii) **“Thrift Feature”** shall mean the Thrift Feature of the CPSP.

(jj) **“Trustee”** shall mean the trustee of the grantor trust established by the Trust Agreement between the Company (known then as Phillips Petroleum Company) and Wachovia Bank, N.A. dated as of June 1, 1998, or any successor trustee.

(kk) **“Valuation Date”** shall mean “Valuation Date” as defined in the CPSP.

Section 2. Purpose.

The purpose of this Plan is to provide supplemental benefits for those Highly Compensated Employees whose benefits under the CPSP might otherwise be affected by Pay Limitations or by a voluntary reduction in salary under provisions of KEDCP.

Section 3. Eligibility.

Benefits may only be granted to Highly Compensated Employees.

Section 4. Supplemental Thrift Feature Account Benefits.

For any payroll period in which a Highly Compensated Employee's DCMP Pay exceeds his or her CPSP Pay, a Benefit amount shall be credited to a Highly Compensated Employee's Supplemental Thrift Feature Account for the Ongoing Plan no later than the end of the month following the Valuation Date that Company contributions are made to the Highly Compensated Employee's Thrift Feature account, or would have been made to such account if the Highly Compensated

Employee had received Company contributions under the Thrift Feature. The Benefit amount so credited shall equal 1.25% of the amount by which the Highly Compensated Employee's DCMP Pay for that payroll period exceeds his or her CPSP Pay for that payroll period.

Section 4.1 Supplemental Thrift Feature Account Earnings

The Company shall periodically credit earnings, gains, and losses to a Participant's Supplemental Thrift Feature Account, until the full balance of such Account has been distributed. Earnings, gains, and losses shall be credited to a Participant's Supplemental Thrift Feature Account under this Section based on the results that would have been achieved had amounts credited to such Account been invested as soon as practicable after crediting into Investment Options selected by the Participant. The Plan Administrator shall specify procedures to allow Participants to make elections as to the deemed investment of amounts newly credited to their Supplemental Thrift Feature Accounts, as well as the deemed investment of amounts previously credited to their Supplemental Thrift Feature Accounts. Nothing in this Section or otherwise in the Plan, however, will require the Company to actually invest any amounts in such Investment Options or otherwise.

Section 5. Supplemental Stock Savings Feature Account Benefits.

For each month in which a Semiannual or Supplemental Allocation (as defined in the CPSP) is made to a Highly Compensated Employee's Stock Savings Feature Account, or would have been made to such account if the Highly Compensated Employee had received a Semiannual or Supplemental Allocation, a Benefit amount shall be credited to his or her Supplemental Stock Savings Feature Account. The Benefit amount to be credited shall be calculated in shares in the Leveraged Stock Fund of this Plan and shall be equal to (i) the Highly Compensated Employee's Supplemental Stock Savings Contributions during the applicable Allocation Period (as defined in the CPSP) multiplied by the applicable Allocation Ratio, divided by (ii) the share value for the Leveraged Stock Fund of the CPSP on the applicable Allocation Date (as defined in the CPSP).

This amount shall be credited no later than the end of the month following the Valuation Date that a Semiannual Allocation or Supplemental Allocation is made under the Stock Savings Feature, or would have been made had the Highly Compensated Employee received such a Semiannual Allocation or Supplemental Allocation under the Stock Savings Feature. A share in the Leveraged Stock Fund of this Plan shall have a value equivalent to a share in the Leveraged Stock Fund of the CPSP.

Section 5.1 Supplemental Stock Savings Feature Account Earnings

After being initially invested in the Leveraged Stock Fund account, the amounts in the Participant's Supplemental Stock Savings Feature Account shall thereafter be eligible to be invested in Investment Options selected by the Participant. The Company shall periodically credit earnings, gains and losses to a Participant's Supplemental Stock Savings Feature Account, until the full balance of such Account has been distributed. Earnings, gains, and losses shall be credited to a Participant's Supplemental Stock Savings Feature Account under this Section based on the results that would have been achieved had amounts credited to such Account been invested as soon as practicable after crediting into the Leveraged Stock Fund of this Plan or the Investment Options selected by the Participant. The Plan Administrator shall specify procedures to allow Participants to make elections as to the deemed investment of amounts previously credited to their Supplemental Stock Savings Feature Accounts. Nothing in this Section or otherwise in the Plan, however, will require the Company to actually invest any amounts in Stock or in such Investment Options or otherwise.

Section 6. Payment.

In the absence of an effective election under Section 6.1 or Section 6.2, Benefits that a Participant is eligible to receive under the Ongoing Plan (and earnings, gains, and losses thereon) shall normally be paid in one lump sum payment on the date that is six months after the date of the Participant's Separation from Service. If the Participant dies prior to his or her Separation from Service, or after his or her Separation from Service but prior to the date that the Benefits which the Participant is eligible to receive under the Ongoing Plan (and earnings, gains, and losses thereon) commence to be paid, the Benefits that the Participant is eligible to receive under the Ongoing Plan (and earnings, gains, and losses thereon) shall be paid in one lump sum cash payment to the Participant's Beneficiary on the date of the Participant's death.

Section 6.1 Payment Election by Participant.

A Participant may elect on an Election Form delivered to the Plan Administrator at a time set by the Plan Administrator (which shall be prior to the beginning of the Plan Year) to have the amounts attributable to Benefits under the Ongoing Plan that are credited to his or her Supplemental Thrift Feature Account (and earnings, gains, and losses thereon) with respect to such Plan Year and the amounts attributable to Benefits credited to his or her Supplemental Stock Savings Feature Account (and earnings, gains, and losses thereon) with respect to such Plan Year paid to the Participant in either:

(a) one lump sum payment, or

(b) annual, semi-annual, quarterly, or monthly installments, using a declining balance method, over a period ranging from one to fifteen years.

A Participant may elect to have payments commence as of the beginning of any calendar quarter that is at least one year after the date of the Participant's Separation from Service, provided that no

payment shall be made after the date that is twenty years after the date of the Participant's Separation from Service.

Section 6.2 Change in Time or Form of Payment.

A Participant may make an election to change the time or form of payment elected under Section 6.1 or the payment to be made under Section 6, but only if the following rules are satisfied:

(a) The election to change the time or form of payment may not take effect until at least twelve months after the date on which such election is made;

(b) Payment under such election may not be made earlier than at least five years from the date the payment would have otherwise been made or commenced;

(c) Such payment may commence as of the beginning of any calendar quarter;

(d) An election to receive payments in installments shall be treated as a single payment for purposes of these rules;

(e) The election may not result in an impermissible acceleration of payment prohibited under Code section 409A;

(f) No more than four such elections shall be permitted with respect to Benefits credited to a Participant's Accounts for a Plan Year; and

(g) No payment may be made after the date that is twenty (20) years after the date of the Participant's Separation from Service.

Section 6.3 Effect of Taxation.

If a portion of a Participant's Benefit (and earnings, gains, and losses thereon) is includible in income under Code section 409A, such portion shall be distributed immediately to the Participant.

Section 7. Administration.

(a) The Plan shall be administered by the Plan Administrator. The Plan Administrator may delegate to employees of the Company or any Affiliated Company the authority to execute and deliver such instruments and documents, to do all such acts and things, and to take such other steps deemed necessary, advisable, or convenient for the effective administration of the Plan in accordance with its terms and purpose, except that the Plan Administrator may not delegate any discretionary authority with respect to substantive decisions or functions regarding the Plan or Benefits hereunder.

(b) Any claim for benefits hereunder shall be presented in writing to the Plan Administrator for consideration, grant, or denial. Claimants will be notified in writing of approved claims, which will be processed as claimed. A claim is considered approved only if its approval is communicated in writing to a claimant.

(c) In the case of a denial of a claim respecting benefits paid or payable with respect to a Participant, a written notice will be furnished to the claimant within 90 days of the date on which the claim is received by the Plan Administrator. If special circumstances (such as for a hearing) require a longer period, the claimant will be notified in writing, prior to the expiration of the 90-day period, of the reasons for an extension of time; provided, however, that no extensions will be permitted beyond 90 days after the expiration of the initial 90-day period. A denial or partial denial of a claim will be dated and signed by the Plan Administrator and will clearly set forth:

(1) the specific reason or reasons for the denial;
(2) specific reference to pertinent Plan provisions on which the denial is based;
(3) a description of any additional material or information necessary for the claimant to perfect the claim and an explanation of why such material or information is necessary; and
(4) an explanation of the procedure for review of the denied or partially denied claim set forth below, including the claimant's right to bring a civil action under ERISA section 502(a) following an adverse benefit determination on review.

(d) Upon denial of a claim, in whole or in part, a claimant or his duly authorized representative will have the right to submit a written request to the Trustee for a full and fair review of the denied claim by filing a written notice of appeal with the Trustee within 60 days of the receipt by the claimant of written notice of the denial of the claim. A claimant or the claimant's authorized representative will have, upon request and free of charge, reasonable access to, and copies of, all documents, records, and other information relevant to the claimant's claim for benefits and may submit issues and comments in writing. The review will take into account all comments, documents, records, and other information submitted by the claimant relating to the claim, without regard to whether such information was submitted or considered in the initial benefit determination. If the claimant fails to file a request for review within 60 days of the denial notification, the claim will be deemed abandoned and the claimant precluded from reasserting it. If the claimant does file a request for review, his request must include a description of the issues and evidence he deems relevant. Failure to raise issues or present evidence on review will preclude those issues or evidence from being presented in any subsequent proceeding or judicial review of the claim.

(e) The Trustee will provide a prompt written decision on review. If the claim is denied on review, the decision shall set forth:

(1) the specific reason or reasons for the adverse determination;
(2) specific reference to pertinent Plan provisions on which the adverse determination is based;
(3) a statement that the claimant is entitled to receive, upon request and free of charge, reasonable access to, and copies of, all documents, records, and other information relevant to the claimant's claim for benefits; and
(4) a statement describing any voluntary appeal procedures offered by the Plan and the claimant's right to obtain the information about such procedures, as well as a statement of the claimant's right to bring an action under ERISA section 502(a).

(f) A decision will be rendered no more than 60 days after the Trustee's receipt of the request for review, except that such period may be extended for an additional 60 days if the Trustee determines that special circumstances (such as for a hearing) require such extension. If an extension of time is required, written notice of the extension will be furnished to the claimant before the end of the initial 60-day period.

(g) To the extent permitted by law, decisions reached under the claims procedures set forth in this Section shall be final and binding on all parties. No legal action for benefits under the Plan shall be brought unless and until the claimant has exhausted his remedies under this Section. In any such legal action, the claimant may only present evidence and theories which the claimant presented during the claims procedure. Any claims which the claimant does not in good faith pursue through the review stage of the procedure shall be treated as having been irrevocably waived. Judicial review of a claimant's denied claim shall be limited to a determination of whether the denial was an abuse of discretion based on the evidence and theories the claimant presented during the claims procedure.

Section 8. Rights of Employees and Participants.

Nothing contained in the Plan (or in any other documents related to this Plan or to any Benefit) shall confer upon any Employee or Participant any right to continue in the employ or other service of the Company or any member of the Affiliated Group or constitute any contract or limit in any way the right of the Company or any member of the Affiliated Group to change such person's compensation or other benefits or to terminate the employment of such person with or without cause.

Section 9. Awards in Foreign Countries.

The Board or its delegate shall have the authority to adopt such modifications, procedures, and subplans as may be necessary or desirable to comply with provisions of the laws of foreign countries in which the Company or Participating Subsidiaries may operate to assure the viability of the Benefits of Participants employed in such countries and to meet the purpose of this Plan.

Section 10. Amendment and Termination.

The Board reserves the right to amend or terminate this Plan at any time, and to delegate such authority as the Board deems necessary or desirable; provided that no member of the Board who is also a Participant shall participate in any action which has the actual or potential effect of increasing his or her Benefits hereunder; and further provided, the Company shall remain liable for any Benefits accrued under this Plan prior to the date of amendment or termination.

Section 11. Unfunded Plan.

All amounts payable under this Plan shall be paid solely from the general assets of the Company and any rights accruing to a Participant under the Plan shall be those of a general creditor; provided, however, that the Company may establish one or more grantor trusts to satisfy part or all of the Company's Plan payment obligations so long as the Plan remains unfunded for purposes of sections 201(2), 301(a)(3), and 401(a)(1) of ERISA.

Section 12. Miscellaneous Provisions.

(a) No right or interest of a Participant under this Plan shall be assignable or transferable, in whole or in part, directly or indirectly, by operation of law or otherwise (excluding devolution upon death or mental incompetency).

(b) This Ongoing Plan replaces the Frozen Plan, which was frozen effective as of December 31, 2004. The distribution of amounts that were earned and vested (within the meaning of Code section 409A and official guidance issued thereunder) under the Frozen Plan prior to

January 1, 2005 (and earnings thereon) and are exempt from the requirements of Code section 409A shall be made in accordance with the terms of the Frozen Plan as in effect on December 31, 2004.

(c) No amount accrued or payable hereunder shall be deemed to be a portion of an Employee's compensation or earnings for the purpose of any other employee benefit plan adopted or maintained by the Company, nor shall this Plan be deemed to amend or modify the provisions of the CPSP.

(d) This Plan shall be construed, regulated, and administered in accordance with the laws of the State of Texas except to the extent that said laws have been preempted by the laws of the United States.

(e) Except as otherwise provided herein, the Plan shall be binding upon the Company, its successors and assigns, including but not limited to any corporation which may acquire all or substantially all of the Company's assets and business or with or into which the Company may be consolidated or merged.

Executed this 29th day of December 2005, effective as of January 1, 2005, with respect to benefits earned or vested after December 31, 2004.

/s/ Carin S. Knickel

Carin S. Knickel
Vice President, Human Resources

Exhibit 10.17

AMENDED AND RESTATED BY APPROVAL OF
THE DIRECTORS' AFFAIRS COMMITTEE
NOVEMBER 18, 2005
RATIFIED BY APPROVAL OF
THE DIRECTORS' AFFAIRS COMMITTEE
DECEMBER 9, 2005

DEFERRED COMPENSATION PLAN FOR NON-EMPLOYEE DIRECTORS OF CONOCOPHILLIPS

(Amended and Restated Effective as of January 1, 2005)

Section 1. Purpose of the Plan

The purpose of the Deferred Compensation Plan for Non-Employee Directors ("Plan") is to provide a program whereby a member of the Board of Directors of ConocoPhillips ("Company") who is not an officer or present employee of the Company or any of its subsidiaries ("Non-Employee Director") may elect to:

1) receive the payment of part or all of the Cash Compensation payable to the Non-Employee Director ("Cash Payment"),

2) defer the payment of part or all of the Cash Compensation payable to the Non-Employee Director ("Deferred Payment"), credited into an account or accounts established from time to time for that purpose (a "Deferred Compensation Account"),

3) receive part or all of the Cash Compensation payable to the Non-Employee Director in shares of Unrestricted Stock under the terms of the 1998 Stock and Performance Incentive Plan of ConocoPhillips, the 2004 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, or a successor plan ("Unrestricted Stock Award"),

4) receive part or all of the Cash Compensation in shares of Restricted Stock or Restricted Stock Units under the terms of the 1998 Stock and Performance Incentive Plan of ConocoPhillips, the 2004 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, or a successor plan ("Restricted Stock Award"),

5) delay the lapsing of restrictions on Restricted Stock, or delay the lapsing of restrictions and settlement of Restricted Stock Units, issued prior to January 1, 2003 due to the attainment of certain ages under the terms of the Phillips Petroleum Company Stock Plan for Non-Employee Directors, and to delay the lapsing on any Restricted Stock, or the lapsing of restrictions and settlement of Restricted Stock Units, issued on or after January 1, 2003, under the terms of the 1998 Stock and Performance Incentive Plan of ConocoPhillips, the 2004 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, or a successor plan.

6) defer the value of shares of unrestricted Common Stock which would otherwise be delivered to the Non-Employee Director as a result of restrictions being lapsed on shares of Restricted Stock or when Restricted Stock Units or similar Awards have restrictions lapse and are settled due to the attainment of certain ages or at Retirement under the terms of the Phillips Petroleum Company Stock Plan for Non-Employee Directors and/or the 1998 Stock and Performance Incentive Plan of ConocoPhillips, the 2004 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, or a successor plan, or under the terms of the grant of such Awards ("Value of Restricted Stock, Restricted Stock Units or Awards"); provided, however, that this paragraph 5) shall apply to Restricted Stock, Restricted Stock Units, or similar Awards that were earned and vested on or before December 31, 2004.

The amount of total compensation which is paid to the Non-Employee Director for services rendered as a Non-Employee Director is set by resolution of the Board of Directors and is comprised of a portion paid in cash ("Cash Compensation") and a portion paid in Restricted Stock and/or Restricted Stock Units ("Stock Compensation") of ConocoPhillips common stock $.01 par value ("CP Common Stock"). Cash Compensation shall be earned for service as a Non-Employee Director over each calendar month in which the Non-Employee Director is a member of the Board of Directors of ConocoPhillips and not an officer or employee of ConocoPhillips or any of its subsidiaries. Any Cash Compensation payable as a result of assignment to a particular committee of the Board of Directors of ConocoPhillips, chairmanship of a committee, or similar duties shall be deemed to be earned for any calendar month in which the assignment, chairmanship, or similar duties exist. Stock Compensation shall be earned annually by those Non-Employee Directors who are members of the Board of Directors on the grant date of the Stock Compensation.

This Plan is amended and restated with the intention to comply with section 409A of the United States Internal Revenue Code of the Internal Revenue Code of 1986, as amended (the "IRC"), which became generally effective on January 1, 2005, and any regulations or other applicable guidance thereon, and shall be construed accordingly. It is intended that provisions of the Plan dealing with Cash Compensation or Stock Compensation earned and vested prior to January 1, 2005, shall continue as in effect prior to that date as "grandfathered" provisions and not be considered to be materially modified by this amendment and restatement. Effective times of various provisions herein are stated where necessary to delineate grandfathered provisions from those effective on January 1, 2005, designed to comply with section 409A of the IRC.

Section 2. Elections

(a) Cash Payment. For each calendar year, a Non-Employee Director may elect to have payment of part or all of the Non-Employee Director's Cash Compensation paid in cash in each month earned. On or before December 20 (or such other date in December as may be set from time to time for the orderly administration of the Plan) of each year, the election to receive Cash Compensation to be paid in the next calendar year may be made by giving written notice thereof in the manner prescribed by the Company, except that such election may be made by the end of the 30-day period after a Non-Employee Director is first elected to the Board of Directors. The election becomes irrevocable on December 31 of the calendar year prior to the year in which the Cash Compensation is to be earned. In default of a timely election otherwise, a Non-Employee Director shall receive Cash Compensation.

(b) Deferred Payment. For each calendar year, a Non-Employee Director may elect to have payment of part or all of the Non-Employee Director's Cash Compensation deferred. On or before December 20 (or such other date in December as may be set from time to time for the orderly administration of the Plan) of each year, the election to defer Cash Compensation that would otherwise be paid in the next calendar year may be made by giving written notice thereof in the manner prescribed by the Company, except that such election may be made by the end of the 30-day period after a Non-Employee Director is first elected to the Board of Directors, to be effective for any Cash Compensation for that year earned beginning the month after such election is made. The election becomes irrevocable on December 31 of the calendar year prior to the year in which the Cash Compensation is to be earned.

(c) Unrestricted Stock Award. For each calendar year, a Non-Employee Director may elect to receive Unrestricted Stock for part or all of the Cash Compensation that would otherwise be paid in the next calendar year. On or before December 20 (or such other date in December as may be set from time to time for the orderly administration of the Plan) of each year, such election to receive Unrestricted Stock instead of cash may be made by giving written notice thereof in the manner prescribed by the Company, except that such election may be made by the end of the 30-day period after a Non-Employee Director is first elected to the Board of Directors, to be effective for any Cash Compensation for that year. Such election to receive Unrestricted Stock becomes irrevocable on December 31 of the calendar year prior to the year in which the Cash Compensation is to be earned.

(d) Restricted Stock Award. For each calendar year, a Non-Employee Director may elect to receive Restricted Stock Units (or, prior to January 1, 2005, Restricted Stock) for part or all of the Cash Compensation that would otherwise be paid in the next calendar year. On or before December 20 (or such other date in December as may be set from time to time for the orderly administration of the Plan) of each year, such election to receive Restricted Stock instead of cash may be made by giving written notice thereof in the manner prescribed by the Company, except that such election may be made by the end of the 30-day period after a Non-Employee Director is first elected to the Board of Directors, to be effective for any Cash Compensation for that year earned beginning the month after such election is made. Such election to receive Restricted Stock or Restricted Stock Units becomes irrevocable on December 31 of the calendar year prior to the year in which the Cash Compensation is to be earned.

(e) Restricted Stock Lapsing or Restricted Stock Units Settled.

(i) For Restricted Stock Units issued in exchange for shares of Restricted Stock pursuant to the Exchange Offer initiated by Phillips Petroleum Company on December 17, 2001, Non-Employee Directors who are or will become 65 years of age prior to the end of that calendar year may elect to delay the lapsing of restrictions on such Restricted Stock Units that would otherwise be lapsed and to delay the receipt of shares of CP Common Stock that would otherwise be delivered in settlement of such Restricted Stock Units, based on their age under the terms of the Phillips Petroleum Company Stock Plan for Non-Employee Directors, until the day the Director retires from the Board of Directors. The Non-Employee Director must make the elections specified in this Section 2(e)(i) by giving written notice thereof in the manner prescribed by the Company on or before December 20 (or such other date in December as may be set from time to time for the orderly administration of the Plan) of that year. Such election to delay the lapsing of restrictions on Restricted Stock or the settlement of Restricted Stock Units or Awards becomes irrevocable after the date for making such election. Such election shall apply to any Restricted Stock Units granted in exchange for shares of Restricted Stock pursuant to the Exchange Offer initiated by Phillips Petroleum Company on December 17, 2001.

(ii) For Restricted Stock and/or Restricted Stock Units issued other than as described in Section 2(e)(i) above, but issued on or before March 15, 2005, Non-Employee Directors may elect to set the time and form of settlement of such Restricted Stock and/or Restricted Stock Units as CP Common Stock by elections made on or before March 15, 2005 (which such elections shall become irrevocable on March 15, 2005; provided, however, that a subsequent change in the time or form of payment may be allowed pursuant to the subsequent election provisions set forth in Section 4(b)(ii) of this Plan). Such initial elections made on or before March 15, 2005, shall be on the forms attached as Exhibits to this Plan, the terms of which are incorporated herein by reference. In the event an initial election is not timely made with regard to a particular Award of Restricted Stock and/or Restricted Stock Units described in this Section 2(e)(ii), then restrictions on such Award shall lapse on the earlier of the death or the date six months after the date of separation from service, whether by retirement, disability, or otherwise (than death), of the Non-Employee Director to whom the Award was granted. Separation from service shall mean the termination of the Non-Employee Director's service with the Board of Directors of ConocoPhillips or any successor company, and shall be interpreted to accord with the term "separation from service" as used in section 409A of the IRC. Notwithstanding anything in this Plan or on an election to the contrary, if the Plan or the election would otherwise lapse restrictions on an Award of Restricted Stock and/or Restricted Stock Units described in this Section 2(e)(ii) and settle unrestricted stock in a lump sum on the separation from service of a Non-Employee Director, such lapsing shall not occur and such settlement shall not be made until the earlier of the death of the Non-Employee Director or the date which is six months after the date of such Non-Employee Director's separation from service.

(iii) For Restricted Stock and/or Restricted Stock Units issued after March 15, 2005, Non-Employee Directors may elect to set the time and form of settlement of such restricted Stock and/or Restricted Stock Units as CP Common Stock by elections made prior to the calendar year in which such Restricted Stock and/or Restricted Stock Units are granted. Such elections shall become irrevocable on December 31 of the calendar year in which they are made; provided, however, that a subsequent change in time or form of payment may be allowed pursuant to the subsequent election provisions of Section 4(b)(ii) of this Plan. Such elections shall be on the form or forms attached as Exhibits to this Plan from time to time, the terms of which shall be incorporated herein by reference. In the event an initial election is not timely made with regard to a particular Award of Restricted Stock and/or Restricted Stock Units described in this Section 2(e)(ii), then restrictions on such Award shall lapse upon the earlier of the death or the date six months after the date of separation from service, whether by retirement, disability, or otherwise (than death), of the Non-Employee Director to whom the Award was granted. Notwithstanding anything in this Plan or on an election to the contrary, if the Plan or the election would otherwise lapse restrictions on an Award of Restricted Stock and/or Restricted Stock Units described in this Section 2(e)(iii) and settle unrestricted stock in a lump sum on the separation from service of a Non-Employee Director, such lapsing shall not occur and such settlement shall not be made until the earlier of the death of the Non-Employee Director or the date which is six

months after the date of such Non-Employee Director's separation from service.

(iv) Awards of Restricted Stock and/or Restricted Stock Units are made for services performed by the Non-Employee Director in the year in which the Award is made, not with regard to any prior year or later year service.

(f) Value of Restricted Stock and Restricted Stock Units.

(i) Each year Non-Employee Directors who were directors of Phillips Petroleum Company and who are or will become 65 years of age prior to the end of that calendar year may make an election concerning the deferral of the receipt of the value of all or part of the Common Stock which would otherwise be delivered to the Non-Employee Director as a result of restrictions being lapsed on shares of Restricted Stock or and the settlement of Restricted Stock Units or similar Awards issued prior to January 1, 2002, based on their age under the terms of the Phillips Petroleum Company Stock Plan for Non-Employee Directors.

(ii) If the Non-Employee Director who was a director of Phillips Petroleum Company has previously elected to delay the lapsing of restrictions on Restricted Stock or the settlement of Restricted Stock Units or similar Awards granted prior to January 1, 2002, until the Director retires from the Board of Directors or if restrictions are to lapse on any Restricted Stock or if Restricted Stock Units or similar Awards are to be settled at the time the Director retires from the Board of Directors, or if the Non-Employee Director Retires from the Board prior to being given an opportunity to make such election, such Non-Employee Director may make an election concerning the deferral of the receipt of the value of all or part of the Common Stock or the cash payment that would otherwise be delivered to the Non-Employee Director as a

result of restrictions being lapsed on shares of Restricted Stock or the settlement of Restricted Stock Units or Awards when the Director retires from the Board of Directors.

(iii) The Non-Employee Director must make the election specified in Sections 2 (f) (i) and (ii) herein by giving written notice on or before December 20 (or such other date in December as may be set from time to time for the orderly administration of the Plan) of the applicable year, or as soon as practicable prior to the Director's Retirement from the Board if such Director would receive shares of Common Stock or a cash payment as a result of restrictions being lapsed on shares of Restricted Stock or the settlement of Restricted Stock Units or Awards under the terms of the Phillips Petroleum Company Stock Plan for Non-Employee Directors or the 1998 Stock and Performance Incentive Plan of ConocoPhillips or the terms of the Award. Such election to defer the value of Restricted Stock or Restricted Stock Units or Awards becomes irrevocable after the date for making such election.

Section 3. Deferred Compensation Accounts

(a) Credit for Deferral. The Company will establish and maintain Deferred Compensation Accounts for each Non-Employee Director who defers Cash Compensation and/or the Value of Restricted Stock or Restricted Stock Units or Awards in which will be credited the amounts deferred for the year to which the deferral relates. Amounts deferred shall be credited as soon as practicable but not later than 30 days after the date the payment would otherwise have been made. The value of the underlying Restricted Stock or Restricted Stock Units or Awards i) for any Restricted Stock or Restricted Stock Units issued prior to

January 1, 2003 shall be the higher of (a) the average of the high and low selling prices of the Common Stock on the date the restrictions lapse or the shares are to be delivered, as applicable, or the last trading day before such date, if such date is not a trading day, or (b) the average of the high three monthly Fair Market Values of the Common Stock during the twelve calendar months preceding the month in which the restrictions lapse or the shares are to be delivered, as applicable and ii) for any Restricted Stock or Restricted Stock Units issued, including all dividends that are reinvested, on or after January 1, 2003 shall be the monthly average Fair Market Value of the calendar month preceding the month in which the restrictions lapse or the cash payment or shares are to be delivered as applicable. The monthly average Fair Market Value of the Common Stock is the average of the daily Fair Market Value of the Common Stock for each trading day of the month. The daily Fair Market Value of the Common Stock shall be deemed equal to the average of the reported highest and lowest sales prices per share of such Common Stock as reported on the composite tape of the New York Stock Exchange transactions.

(b) Designation of Investments. The amount in each Non-Employee Director's Deferred Compensation Account shall be deemed to have been invested and reinvested from time to time, in such "eligible securities" as the Non-Employee Director shall designate. Prior to or in the absence of a Non-Employee Director's designation, the Company shall designate an "eligible security" in which the Non-Employee Director's Deferred Compensation Account shall be deemed to have been invested until designation instructions are received from the Non-Employee Director. Eligible securities are those securities designated by the Chief Financial Officer of the Company. The Chief Financial Officer of the Company may include as eligible securities, stocks listed on a national securities exchange, and bonds,

notes, debentures, corporate or governmental, either listed on a national securities exchange or for which price quotations are published in The Wall Street Journal and shares issued by investment companies commonly known as "mutual funds". The Non-Employee Director's Deferred Compensation Account will be adjusted to reflect the deemed gains, losses and earnings as though the amount deferred was actually invested and reinvested in the eligible securities for the Non-Employee Director's Deferred Compensation Account.

Notwithstanding anything to the contrary in this Section 3(b), in the event the Company actually purchases or sells such securities in the quantities and at the times the securities are deemed to be purchased or sold for a Non-Employee Director's Deferred Compensation Account, the Account shall be adjusted accordingly to reflect the price actually paid or received by the Company for such securities after adjustment for all transaction expenses incurred (including without limitation brokerage fees and stock transfer taxes).

In the case of any deemed purchase not actually made by the Company, the Deferred Compensation Account shall be charged with a dollar amount equal to the quantity and kind of securities deemed to have been purchased multiplied by the fair market value of such security on the date of reference and shall be credited with the quantity and kind of securities so deemed to have been purchased. In the case of any deemed sale not actually made by the Company, the account shall be charged with the quantity and kind of securities deemed to have been sold, and shall be credited with a dollar amount equal to the quantity and kind of securities deemed to have been sold multiplied by the fair market value of such security on the date of reference. As used

herein "fair market value" means in the case of a listed security the closing price on the date of reference, or if there were no sales on such date, then the closing price on the nearest preceding day on which there were such sales, and in the case of an unlisted security the mean between the bid and asked prices on the date of reference, or if no such prices are available for such date, then the mean between the bid and asked prices to the nearest preceding day for which such prices are available.

The Treasurer may also designate a Fund Manager to provide services which may include recordkeeping, Non-Employee Director accounting, Non-Employee Director communication, payment of installments to the Non-Employee Director, tax reporting and any other services specified by the Company in agreement with the Fund Manager.

(c) Payments. A Non-Employee Director's Deferred Compensation Account shall be debited with respect to payments made from the account pursuant to this Plan as of the date such payments are made from the account. The payment shall be made as soon as practicable, but no later than 2 ½ months after the end of the calendar year in which the payment date falls.

If any person to whom a payment is due hereunder is under legal disability as determined in the sole discretion of the Chief Executive Officer, the Company shall have the power to cause the payment due such person to be made to such person's guardian or other legal representative for the person's benefit, and such payment shall constitute a full release and discharge of the Company and any fiduciary of the Plan.

(d) Statements. At least one time per year the Company or the Company's designee will furnish each Non-Employee Director a written statement setting forth the current balance in the Non-Employee Director's Deferred Compensation Account, the amounts credited or

debited to such account since the last statement and the payment schedule of deferred amounts and deemed gains, losses and earnings accrued thereon as provided by the deferred payment option selected by the Non-Employee Director.

Section 4. Deferred Payment Options

(a) Payment Options for Cash Compensation and the Value of Restricted Stock or Restricted Stock Units or Awards for Deferred Compensation Accounts Established for Amounts Earned and Vested Prior to 2005. With regard to Deferred Compensation Accounts established for Cash Compensation or Stock Compensation earned and vested prior to January 1, 2005, a Non-Employee Director, at the time an election to defer Cash Compensation or the Value of Restricted Stock or Restricted Stock Units or Awards is made, shall also specify in writing whether the Cash Compensation or the Value of Restricted Stock or Restricted Stock Units or Awards deferred by such election and any deemed gains, losses and earnings accrued thereon is to be paid in one lump sum or in annual installments of not less than 1 nor more than 10. The lump sum payment will be made or the first installment will begin as soon as practicable after the first day of the calendar quarter which is on or after the Non-Employee Director's retirement, or the Director may specify that the lump sum be paid the first day of any calendar quarter following retirement from the Board except that the date must be at least one year from the date the election is made. After a Non-Employee Director first selects a payment option, all subsequent deferrals of Cash Compensation and/or the Value of Restricted Stock or Restricted Stock Units or Awards will have the same payment option.

(b) Payment Option Revision.

(i) With regard to Deferred Compensation Accounts established for Cash Compensation or Stock Compensation earned and vested prior to January 1, 2005, a Non-Employee Director may at any time during a period beginning 365 days prior to and ending no later than December 20 (or such other date in December as may be set from time to time for the orderly administration of the Plan) prior to the date the Non-Employee Director terminates Board service due to (a) not being nominated for election to the Board; or (b) not being reelected to Board service after being so nominated; or (c) resignation from Board service as a result of the Director's disability or any reason acceptable to a majority of the remaining members of the Board of Directors ("Retires" or "Retirement"), or as soon as practicable prior to Retirement in the manner prescribed by the Company, revise such payment option and select one of the following payment options in place of such payment option:

(A) a lump sum,

(B) annual installments of not less than 1 nor more than 15,

C) semi-annual installments of not less than 1 nor more than 30, or

D) quarterly installments of not less than 1 nor more than 60, with the lump sum to be paid or first installment to commence, as soon as practicable following any date specified by the Non-Employee Director so long as such date is the first day of a calendar quarter, is on or after the Non-Employee Director's Retirement Date, is at least one year from the date the payment option was revised and is no later than five

E) years after the Non-Employee Director's Retirement Date.

(ii) With regard to Deferred Compensation Accounts established for Cash Compensation or Stock Compensation that was not both earned and vested prior to January 1, 2005, and with regard to Awards of Restricted Stock and/or Restricted Stock Units made to the Non-Employee Director (other than Awards made pursuant to the Exchange Offer initiated by Phillips Petroleum Company on December 17, 2001), a Non-Employee Director may make a subsequent change to an earlier election with regard to any such Deferred Compensation Account or Award. Such subsequent change may change either the time or the form of payment or both as to any particular Deferred Compensation Account or Award. Such subsequent change shall not become effective unless one year passes after such subsequent change is made and no event or time that would cause payment to be made under the election that is being changed has occurred. Any such subsequent change shall increase by at least five years the date on which payment will be made from the date on which payment would have been made under the election that is being changed. The Non-Employee Director is allowed to make no more than three such subsequent changes per Deferred Compensation Account or Award. With regard to a Deferred Compensation Account or Award as to which an election is in effect to take payments in installments, such installments shall be considered to be a single payment commencing on the first date an installment payment is scheduled to be made, in accordance with Proposed Treasury Regulation 1.409A-2(b)(2)(iii).

(c) Installment Amount. The amount of each installment shall be determined by dividing the

balance in the Non-Employee Director's Deferred Compensation Account as of the date the installment is to be paid, by the number of installments remaining to be paid (inclusive of the current installment) or such other installment option that may be offered.

Section 5. Death of Non-Employee Director

Upon the death of a Non-Employee Director, the Non-Employee Director's beneficiary or beneficiaries designated in accordance with Section 6 of this Plan, or, in the absence of an effective beneficiary designation, the surviving spouse, or the Estate of the deceased Non-Employee Director, in that order of priority, shall receive the beneficiary's or beneficiaries' portion of the payments in accordance with the deferred payment schedule selected by the Non-Employee Director, whether the Non-Employee Director's death occurred before or after such payments have commenced; provided, however, such payments out of a Deferred Compensation Account (established before January 1, 2005, or with regard to an Award of Restricted Stock Units that was subject to the Exchange offer initiated by Phillips Petroleum Company on December 17, 2001, may be made in a different manner if the beneficiary or beneficiaries entitled to receive such payments, due to an unanticipated emergency caused by an event beyond the control of the beneficiary or beneficiaries that results in financial hardship to the beneficiary or beneficiaries, so requests and the Vice President Human Resources gives written consent to the method of payment requested.

Section 6. Designation of Beneficiary

Each Non-Employee Director who defers under this Plan shall designate a beneficiary or beneficiaries to receive the entire balance of the Non-Employee Director's Deferred

Compensation Account by giving signed written notice of such designation in the manner prescribed by the Company. Each Non-Employee Director who has an Award of Restricted Stock and/or Restricted Stock Units shall designate a beneficiary or beneficiaries to receive any such Restricted Stock ad Restricted Stock Units by giving signed written notice of such designation in the manner provided by the Company. The Non-Employee Director may from time to time change or cancel any previous beneficiary designation in the same manner. The last written beneficiary designation received by the Company shall be controlling over any prior designation and over any testamentary or other disposition. After receipt by the Company of such written designation, it shall take effect as of the date on which it was signed by the Non-Employee Director, whether the Non-Employee Director is living at the time of such receipt, but without prejudice to the Company on account of any payment made under this Plan before receipt of such designation.

Section 7. Nonassignability

The right of a Non-Employee Director or beneficiary or other person who becomes entitled to receive payments under this Plan shall not be pledged, assigned or subject to garnishment, attachment or any other legal process by the creditors of or other claimants against the Non-Employee Director, beneficiary, or other such person.

Section 8. Administration, Interpretation and Amendment

The Plan shall be administered by the Chief Executive Officer of the Company or his designee. The decision of the Chief Executive Officer with respect to any questions arising as to the interpretation of this Plan, including the severability of any and all of the provisions thereof,

shall be final, conclusive and binding. The Company reserves the right to amend this Plan from time to time or to terminate the Plan entirely, provided, however, that no amendment may affect the balance in a Non-Employee Director’s account on the effective date of the amendment.

Section 9. Nonsegregation

Amounts deferred pursuant to this Plan and the crediting of amounts to a Non-Employee Director’s Deferred Compensation Account shall represent the Company’s unfunded and unsecured promise to pay compensation in the future. With respect to said amounts, the relationship of the Company and a Non-Employee Director shall be that of debtor and general unsecured creditor. While the Company may make investments for the purpose of measuring and meeting its obligations under this Plan such investments shall remain the sole property of the Company subject to claims of its creditors generally, and shall not be deemed to form or be included in any part of the Deferred Compensation Account.

Section 10. Funding

All amounts payable under the Plan are unfunded and unsecured benefits and shall be paid solely from the general assets of the Company and any rights accruing to the Non-Employee Director or the beneficiary under this Plan shall be those of an unsecured general creditor; provided, however, that the Company may establish a grantor trust to pay part or all of its Plan payment obligations so long as the Plan remains unfunded for federal tax purposes.

Section 11. Miscellaneous

(a) Except as otherwise provided herein, the Plan shall be binding upon the Company, its successors and assigns, including but not limited to any corporation which may acquire all or substantially all of the Company’s assets and business or with or into which the Company may be consolidated or merged.

(b) This Plan shall be construed, regulated, and administered in accordance with the laws of the State of Delaware except to the extent that said laws have been preempted by the laws of the United States.

Section 12. Continuing Directors and Noncontinuing Directors

Notwithstanding anything contained in this Plan to the contrary:

(a) Elections made by a Non-Employee Director who is a member of the board of directors (the “ConocoPhillips Board”) of ConocoPhillips (a “Continuing Director”) immediately following the closing (the “Closing”) of the transactions (the “Merger”) contemplated by the Agreement and Plan of Merger dated as of November 18, 2001 by and among Phillips Petroleum Company, CorvettePorsche Corp., Porsche Merger Corp., Corvette Merger Corp., and Conoco Inc. (the “Merger Agreement”) shall be effective for the following compensation received from ConocoPhillips with respect to service as a Continuing Director for the portion of calendar year 2002 that follows the Closing, without any action on the part of such Continuing Director, Phillips Petroleum Company, Conoco Inc., or ConocoPhillips: (i) the deferral of the receipt of Cash Compensation, (ii) the receipt of Unrestricted Stock in lieu of Cash Compensation or Stock Compensation, (iii) the receipt of Restricted Stock in lieu of Cash Compensation or Stock Compensation, (iv) the deferral of the lapsing of restrictions on Restricted Stock

that would otherwise lapse, (v) the deferral of receipt of the value of all or part of the Common Stock which would otherwise be delivered to the Continuing Director as a result of restrictions being lapsed; and (vi) the deferral of receipt of a lump sum payment from the Non-employee Director Retirement Plan.

(b) ConocoPhillips shall be the co-sponsor of this Plan and shall be the obligor hereunder with respect to compensation of Continuing Directors for services on the ConocoPhillips Board that is deferred hereunder.

(c) A Continuing Director shall not be deemed to have "retired" or otherwise terminated service as a Non-Employee Director for any purpose of this Plan solely as a result of such director's ceasing to be a director of Phillips Petroleum Company or of Conoco Inc. in connection with the Merger, and no distributions of the Continuing Directors' account balances under the Plan shall be made solely as a result of the consummation of the transactions contemplated by the Merger Agreement. For any Continuing Director, service as a member of the ConocoPhillips Board shall be treated as service as a Non-Employee Director, and "retirement" or any other termination of service from the ConocoPhillips Board shall be deemed to be a retirement or termination of service (as applicable) as a Non-Employee Director for all purposes of this Plan.

(d) Each individual who ceases to be a Non-Employee Director in connection with the Merger who is not a Continuing Director shall be deemed to have retired as of the Closing Date for purposes of this Plan (including, without limitation, for purposes of Section 4).

(e) This Plan shall be considered the continuation of the similar prior plans of deferred compensation for the non-employee directors of Phillips Petroleum Company and of

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Conoco Inc., which shall be considered to have merged into this Plan; provided, however, that for any non-employee director of Phillips Petroleum Company or of Conoco Inc. who is not a Continuing Director (including those who were not directors immediately before the Merger), the terms and conditions of the prior plan applicable to such director shall govern with regard to the benefits from that prior plan, unless explicitly provided to the contrary in this Plan.

Section 13. Effective Date of the Plan

This Plan is amended and restated effective as of January 1, 2005.

Appendix for Canadian Non-Employee Directors

Effective July 1, 2003, with regard to any Non-Employee Director who shall be a citizen of Canada, residing in and having a tax home in Canada, and not a citizen of the United States, notwithstanding anything to the contrary in this Deferred Compensation Plan for Non-Employee Directors of ConocoPhillips:

(1) Any such Non-Employee Director shall not be allowed to defer Cash Compensation into a Deferred Compensation Account or elect to take Cash Compensation in the form of Unrestricted Stock;

(2) Any such Non-Employee Director shall receive any remaining monthly Cash Compensation in 2003 in the form of Restricted Stock Units having the terms and conditions applicable to the annual Award made on January 15, 2003; except that such Restricted Stock Units shall have restrictions lapse and be settled in unrestricted shares of the Common Stock of ConocoPhillips only upon the retirement, death, or loss of office of such Non-Employee Director;

(3) Any Restricted Stock Units granted to any such Non-Employee Director on or after January 1, 2004, shall have restrictions that lapse and be settled in unrestricted shares of ConocoPhillips Common Stock only upon the retirement, death, or loss of office of such Non-Employee Director.

Appendix for Norwegian Non-Employee Directors

Effective July 1, 2003, with regard to any Non-Employee Director who shall be a citizen of Norway, residing in and having a tax home in Norway, and not a citizen of the United States, notwithstanding anything to the contrary in this Deferred Compensation Plan for Non-Employee Directors of ConocoPhillips:

(1) Any such Non-Employee Director shall not be allowed to defer Cash Compensation into a Deferred Compensation Account, elect to take Cash Compensation in the form of Unrestricted Stock, or elect to take Cash Compensation in the form of Restricted Stock and/or Restricted Stock Units;

(2) Any such Non-Employee Director shall receive any remaining monthly Cash Compensation in 2003 in the form of Restricted Stock Units having the terms and conditions applicable to the annual Award made on January 15, 2003; except that such Restricted Stock Units shall have restrictions lapse and be settled in unrestricted shares of the Common Stock of ConocoPhillips only upon the retirement, death, or loss of office of such Non-Employee Director;

(3) Any Restricted Stock Units granted to any such Non-Employee Director on or after January 1, 2004, shall have restrictions that lapse and be settled in unrestricted shares of ConocoPhillips Common Stock only upon the retirement, death, or loss of office of such Non-Employee Director.

Exhibit 10.23.1

ORIGINAL FOR EXECUTION
APPROVED VP, HR DECEMBER 29, 2005

KEY EMPLOYEE DEFERRED COMPENSATION PLAN OF CONOCOPHILLIPS

TITLE I
(Effective for benefits earned and vested prior to January 1, 2005)

PURPOSE

The purpose of the Key Employee Deferred Compensation Plan of ConocoPhillips (the "Plan") is to attract and retain key employees by providing them with an opportunity to defer receipt of cash amounts which otherwise would be paid to them under various compensation programs or plans by the Company. This Plan is the continuation of the Key Employee Deferred Compensation Plan of Phillips Petroleum Company, of the Conoco Inc. Global Variable Compensation Deferral Program, and of the portions of the Conoco Inc. Salary Deferral & Savings Restoration Plan consisting of Salary Deferral Obligations and Retiree Obligations, and all deferrals made under any of those plans, programs, or arrangements shall continue under their terms and the terms of this Plan. Title I of this Plan is effective with regard to benefits earned and vested prior to January 1, 2005, while Title II of this Plan is effective with regard to benefits earned or vested after December 31, 2004. Other than earnings, gains, and losses, no further benefits shall accrue under Title I of this Plan after December 31, 2004.

This Title I of the Plan is intended (1) to be a "grandfathered" plan pursuant to Code section 409A, as enacted as part of the American Jobs Creation Act of 2004, and official guidance issued thereunder, and (2) to be "a plan which is unfunded and is maintained by an employer primarily for the purpose of providing deferred compensation for a select group of management or highly compensated employees" within the meaning of sections 201(2), 301(a)(3), and 401(a)(1) of ERISA. Notwithstanding any other provision of this Plan, this Plan shall be interpreted, operated, and administered in a manner consistent with these intentions.

SECTION 1. Definitions.

(a) "Affiliated Group" shall mean the Company plus other subsidiaries and affiliates in which it owns, directly or through a subsidiary or affiliate, a 5% or more equity interest.

(b) "Award" shall mean the United States cash dollar amount (i) allotted to an Employee under the terms of an Incentive Compensation Plan or a Long Term Incentive Plan, or (ii) required to be credited to an Employee's Deferred Compensation Account pursuant to an Incentive Compensation Plan, the Long Term Incentive Compensation Plan, the Strategic Incentive Plan, a Long Term Incentive Plan, or any similar plans, or any administrative procedure adopted pursuant thereto, or (iii) credited as a result of a Participant's deferral of the receipt of the value of the Stock which would otherwise be delivered to an Employee in the event restrictions lapse on Restricted Stock or Restricted Stock Units or the settlement of Restricted Stock Units previously awarded or which may be awarded to the Participant pursuant to an Incentive Compensation Plan, the Long Term Incentive Compensation Plan, the Strategic Incentive Plan, a Long Term Incentive Plan, an Omnibus Securities Plan, or any similar plans, or any administrative procedure adopted pursuant thereto, or (iv) credited resulting from a lump sum distribution from any of the Company's non-qualified retirement plans and/or plans which provide for a retirement supplement, or (v) resulting from the forfeiture of Restricted Stock, required by Phillips Petroleum Company, of key employees who became employees of GPM Gas Corporation, or (vi) credited as a result of an Employee's deferral of the receipt of the lump sum cash payment from the Employee's account in the Defined Contribution Makeup Plan, or (vii) credited as a result of an Employee's voluntary reduction of Salary, or (viii) credited as a result of an Employee's deferral of a Performance Based Incentive Award, or (ix) any other amount determined by the Committee to be an Award under the Plan. Sections 2 and 3 of this Plan shall not apply with respect to Awards included under (ii), (v), and (ix) above and a participant receiving such an Award shall be deemed, with respect thereto, to have elected a Section 5(b)(i) payment option - 10 annual installments commencing about one year after retirement at age 55 or above, but subject to revision under the

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terms of this Plan.

(c) "Board of Directors" shall mean the board of directors of the Company.

(d) "Chief Executive Officer" or "CEO" shall mean the Chief Executive Officer of the Company.

(e) "Committee" shall mean the Compensation Committee of the Board of Directors.

(f) "Company" shall mean ConocoPhillips.

(g) "Conoco Inc. Global Variable Compensation Deferral Program" shall mean the Conoco Inc. Global Variable Compensation Deferral Program, prior to its merger into this Plan on October 3, 2003.

(h) "Conoco Inc. Salary Deferral & Savings Restoration Plan" shall mean the Conoco Inc. Salary Deferral & Savings Restoration Plan, prior to its merger into this Plan on October 3, 2003.

(i) "Deferred Compensation Account" shall mean an account established and maintained for each Participant in which is recorded the amounts of Awards deferred by a Participant, the deemed gains, losses, and earnings accrued thereon, and payments made therefrom all in accordance with the terms of the Plan.

(j) "Defined Contribution Makeup Plan" shall mean the Defined Contribution Makeup Plan of ConocoPhillips, or any similar plan or successor plans.

(k) "Disability" shall mean the inability, in the opinion of the Company's Medical Director, of a Participant, because of an injury or sickness, to work at a reasonable occupation that is available with the Company, a Participating Subsidiary, or another subsidiary of the Company.

(l) "Employee" shall mean any individual or Rehired Participant who satisfies the conditions of Section 5(j) who is a salaried employee of the Company or of a Participating Subsidiary who is eligible to receive an Award from an Incentive Compensation Plan, has Restricted Stock and/or Restricted Stock Units, and is classified as a ConocoPhillips salary grade 19 or above or any equivalent salary grade at a Participating Subsidiary. Employee shall also include Participants who are employed by a member of the Affiliated Group and former employees of a member of the Affiliated Group who Retire or are Laid Off and are eligible to receive a lump sum distribution from non-qualified retirement plans. Employee shall also include any individual or Rehired Participant who is hired as a salaried employee of ConocoPhillips Services Inc. on or after January 1, 2003, and is classified as a ConocoPhillips salary grade 19 or above or any equivalent salary grade at a Participating Subsidiary. Notwithstanding the foregoing, prior to October 3, 2003, Employee shall not include anyone who is classified as a Heritage Conoco Employee. On and after October 3, 2003, Employee shall include anyone who is classified as a Heritage Conoco Employee.

(m) "ERISA" shall mean the Employee Retirement Income Security Act of 1974, as amended from time to time, or any successor statute.

(n) "Exchange Act" shall mean the Securities Exchange Act of 1934, as amended and in effect from time to time, or any successor statute.

(o) "Heritage Conoco Employee" shall mean an individual employed by Conoco Inc., Conoco Pipe Line Company, or Louisiana Gas Systems Inc. prior to January 1, 2003; provided, however, that an individual who has been terminated from employment with a member of the Affiliated Group at any time and rehired by a member of the Affiliated Group after January 1, 2003, shall not be considered a Heritage Conoco Employee for purposes of this Plan.

(p) "Incentive Compensation Plan" shall mean the ConocoPhillips Variable Cash Incentive Program, the Incentive Compensation Plan of Phillips Petroleum Company, or the Annual Incentive Compensation Plan of Phillips Petroleum Company, the Special Incentive Plan for Former Tosco Executives, the Conoco Inc. Global Variable Compensation Plan, or a similar plan of a Participating Subsidiary, or any similar or successor plans, or all, as the context may require.

(q) "Layoff" or "Laid Off" shall mean an applicable termination of employment by reason of layoff under the Phillips Layoff Plan or the Phillips Work Force Stabilization Plan, an applicable Qualifying Event (without there being a Disqualifying Event) under the Conoco Severance Pay Plan, or layoff or redundancy under any other layoff or redundancy plan which the Company, any Participating Subsidiary, or any other member of the Affiliated Group may adopt from time to time. If all or any portion of the benefits under the layoff or redundancy plan are contingent on the employee's signing a general release of liability, such termination shall not be considered as a Layoff for purposes of this Plan unless the employee executes and does not revoke a general release of liability, acceptable to the Company, under the terms of such layoff or redundancy plan.

(r) "Long-Term Incentive Compensation Plan" shall mean the Long-Term Incentive Compensation Plan of Phillips Petroleum Company, which was terminated December 31, 1985.

(s) "Long-Term Incentive Plan" shall mean the ConocoPhillips Performance Share Program, the ConocoPhillips Restricted Stock Program, the Phillips Petroleum Company Long-Term Incentive Plan, or a similar or successor plan of any of them, established under an Omnibus Securities Plan.

(t) "Newhire Employee" shall mean any Employee who is hired or rehired during a calendar year.

(u) "Omnibus Securities Plan" shall mean the Omnibus Securities Plan of Phillips Petroleum Company, the 2002 Omnibus Securities Plan of Phillips Petroleum Company, the 1998 Stock and Performance Incentive Plan of ConocoPhillips, the 1998 Key Employee Stock Plan of ConocoPhillips, or a similar or successor plan of any of them.

(v) "Participant" shall mean a person for whom a Deferred Compensation Account is maintained.

(w) "Participating Subsidiary" shall mean a subsidiary of the Company, of which the Company beneficially owns, directly or indirectly, more than 50% of the aggregate voting power of all outstanding classes and series of stock, where such subsidiary has adopted one or more plans making participants eligible for participation in this Plan and one or more Employees of which are Potential Participants.

(x) "Plan Administrator" shall mean the Vice President, Human Resources of the Company, or his or her successor.

(y) "Potential Participant" shall mean a person who has received a notice specified in Section 2 or in Section 5 (h).

(z) “Rehired Participant” shall mean a Participant who, subsequent to Retirement or Layoff, is rehired by the Company, or any subsidiary of the Company, and whose employment status is classified as regular full-time or its equivalent.

(aa) “Restricted Stock” and “Restricted Stock Units” shall mean respectively shares of Stock and units each of which shall represent a hypothetical share of Stock, which have certain restrictions attached to the ownership thereof or the delivery of shares pursuant thereto.

(bb) “Retiree Obligations” shall mean obligations to former employees who have retired on

or after the earliest retirement date available under the Retirement Plan of Conoco and who are Participants in this Plan arising from deferrals made as participants in the Conoco Inc. Salary Deferral & Savings Restoration Plan prior to its merger into this Plan.

(cc) “Retirement” or “Retire” or “Retiring” shall mean termination of employment with the Company or any subsidiary of the Company on or after the earliest early retirement date at age 55 or above as defined in the ConocoPhillips Retirement Plan (or, with respect to a Heritage Conoco Employee, the Retirement Plan of Conoco) or of the applicable retirement plan of a member of the Affiliated Group.

(dd) “Retirement Income Plan” shall mean the ConocoPhillips Retirement Plan (or, with respect to a Heritage Conoco Employee, the Retirement Plan of Conoco) or a similar retirement plan of the Participating Subsidiary pursuant to the terms of which the Participant retires.

(ee) “Salary Deferral Obligations” shall mean obligations to Employees who are Participants in this Plan arising from salary deferrals made as participants in the Conoco Inc. Salary Deferral & Savings Restoration Plan prior to its merger into this Plan.

(ff) “Settlement Date” shall mean the date on which all acts under an Incentive Compensation Plan or the Long-Term Incentive Compensation Plan or actions directed by the Committee, as the case may be, have been taken which are necessary to make an Award payable to the Participant.

(gg) “Salary” shall mean the monthly equivalent rate of pay for an Employee before adjustments for any before-tax voluntary reductions.

(hh) “Stock” means shares of common stock of ConocoPhillips, par value $.01.

(ii) “Strategic Incentive Plan” shall mean the Strategic Incentive Plan portion of the 1986 Stock Plan of Phillips Petroleum Company, of the 1990 Stock Plan of Phillips Petroleum Company, of the Phillips Petroleum Company Omnibus Securities Plan, and of any successor plans of similar nature.

(jj) “Trustee” shall mean the trustee of the grantor trust established by the Trust Agreement between the Company and Wachovia Bank, N.A. dated as of June 1, 1998, or any successor trustee.

SECTION 2. Notification of Potential Participants.

(a) Incentive Compensation Plan. Each year, during October, Employees who are eligible to receive an Award in the immediately following calendar year under an Incentive Compensation Plan will be notified and given the opportunity, in a manner prescribed by the Plan Administrator, to indicate a preference concerning deferral of all or part (in one percent increments) of such Award.

(b) Restricted Stock and Restricted Stock Units Lapsing.

(i) Each year during October, Employees who are or will be 55 years of age or older prior to the end of the following calendar year will be notified and given the opportunity, in a manner prescribed by the Plan Administrator, to indicate a preference to delay the lapsing of the restrictions on part (in one percent increments) or all of the shares of Restricted Stock and/or Restricted Stock Units previously awarded or which may be awarded to the Employee under an Incentive Compensation Plan, the Long Term Incentive Compensation Plan, a Long-Term Incentive Plan, the Strategic Incentive Plan, or an Omnibus Securities Plan in the event the Compensation Committee takes action in the following calendar year to lapse restrictions on Restricted Stock and/or Restricted Stock Units and/or settle Restricted Stock Units.

(ii) Each year during October, Employees who have been granted a special Restricted Stock Award and/or Restricted Stock Unit Award will be notified and given the

opportunity, in a manner prescribed by the Plan Administrator to indicate a preference to delay the lapsing of the restrictions on part (in one percent increments) or all of the shares of Restricted Stock and/or Restricted Stock Units when the restrictions lapse on the Special Restricted Stock and/or Restricted Stock Units or the Restricted Stock Units are settled based on the terms of the Special Restricted Stock and/or Restricted Stock Unit Awards in the following year.

(iii) Such indication of preference as outlined in (i) above may be made within 60 days of the amendment of this Plan providing for the notice; provided, however, that such indication of preference must be made no later than June 6, 2003, for such Awards that would otherwise be lapsed or settled later in 2003.

(c) Restricted Stock and Restricted Stock Unit Awards Deferral.

(i) Each year during October, Employees who are or will be 55 years of age or older prior to the end of the calendar year will be notified and given the opportunity, in a manner prescribed by the Plan Administrator, to indicate a preference concerning the deferral of the receipt of the value of all or part (in one percent increments) of the Stock which would otherwise be delivered to the Employees in the event, during the following calendar year, the Compensation Committee takes action to lapse restrictions on Restricted Stock and/or Restricted Stock Units and/or settle Restricted Stock Units previously awarded or which may be awarded to the Employees under an Incentive Compensation Plan, the Long Term Incentive Compensation Plan, a Long Term Incentive Plan, the Strategic Incentive Plan, or an Omnibus Securities Plan.

(ii) Employees who have been granted a special Restricted Stock Award and/or Restricted Stock Units Award may, in the year preceding the year in which the restrictions are scheduled to lapse or the Restricted Stock Units are to be settled, indicate a preference concerning the deferral of the value of all or part (in one percent increments) of the stock which would otherwise be delivered to the Employees in the next calendar year when the restrictions lapse on the special Restricted Stock and /or

Restricted Stock Units or the Restricted Stock Units are settled based on the terms of the special Restricted Stock Awards and/or Restricted Stock Units Awards.

(iii) Employees who are Laid Off during or after the year they reach age 50 may no later than 30 days after being notified of Layoff, in the manner prescribed by the Plan Administrator, indicate a preference concerning the deferral of the receipt of the value of all or part (in one percent increments) of the Stock which would be otherwise be delivered to the Employees in the event Restricted Stock Units, which have been granted in exchange for Restricted Stock pursuant to the Exchange offer initiated by the Company on December 17, 2001, are settled.

(iv) Such indication of preference as outlined in (i) above may be made within 60 days of the amendment of this Plan providing for the notice; provided, however, that such indication of preference must be made no later than June 6, 2003, for such Awards that would otherwise be lapsed or settled later in 2003.

(d) Lump Sum Distribution from Non-Qualified Retirement Plans. With respect to the lump sum distribution permitted from the Company's non-qualified retirement plans and/or plans which provide for a retirement supplement, Employees may indicate, in a manner prescribed by the Plan Administrator, a preference concerning deferral of all or part (in one percent increments) of such lump sum distribution.

(e) Lump Sum from Defined Contribution Makeup Plan. Employees who will receive a lump sum cash payment from their account under the Defined Contribution Makeup Plan, may indicate, in a manner prescribed by the Plan Administrator, a preference concerning deferral of all or part (in one percent increments) of such payment.

(f) Salary Reduction. Annually, Employees and Newhire Employees on the U.S. dollar payroll may elect, in a manner prescribed by the Plan Administrator, a voluntary reduction of Salary for each pay period of the following calendar year, or for Newhire Employees the remainder of the calendar year in which they are hired, in which case

the Company will credit a like amount as an Award hereunder, provided that the amount of such voluntary reduction shall not be less than 1% nor more than 50% of the Employee's Salary per pay period (and may be further limited by the Plan Administrator such that the resulting salary that is paid is sufficient to satisfy all benefit plan deductions, tax deductions, elective deductions, and other deductions required to be withheld by the Company).

(g) Performance Based Incentive Award. Each year, during October, Employees who are eligible to receive a Performance Based Incentive Award in the immediately following calendar year will be notified and given the opportunity, in a manner prescribed by the Plan Administrator, to indicate a preference for the award to be paid as cash, deferred to their KEDCP account, or issued as Restricted Stock or a combination of cash, deferred compensation and Restricted Stock.

SECTION 3. Indication of Preference or Election to Defer Award.

(a) Incentive Compensation Plan. If a Potential Participant prefers to defer under this Plan all or any part of the Award to which a notice received under Section 2(a) pertains, the Potential Participant must indicate such preference, in a manner prescribed by the Plan Administrator, (i) if the Potential Participant is subject to Section 16 of the Exchange Act, to the Committee, or (ii) if the Potential Participant is not subject to Section 16 of the Exchange Act, to the CEO. The Potential Participant's preference must be received on or before October 31 of the year in which said Section 2(a) notice was received. Such indication must state the portion of the Award the Potential Participant desires to be deferred. If an indication is not received by October 31, the Potential Participant will be deemed to have elected to receive and not to defer any such Incentive Compensation Plan award.

Such indication of preference, if accepted, becomes irrevocable on November 1 of the year in which the indication is submitted to the Committee or CEO, except that, in the event of any of the following:

i) the Employee is demoted to a job classification/grade that is no longer eligible to receive an Award from an Incentive Compensation Plan,

ii) the Employee's employment status is classified to a status other than regular full-time or its equivalent, or

iii) the Employee is receiving Unavoidable Absence Benefits (UAB) pay such that the pay received is less than his/her pay had been prior to being on UAB,

the Employee can request, subject to approval by the Plan Administrator, that his/her indication of preference to defer, whether approved or not, be revoked for that Incentive Compensation Plan Award.

The Committee or CEO, as applicable, shall consider such indication of preference as submitted and shall decide whether to accept or reject the preference expressed.

(b) Restricted Stock and Restricted Stock Unit Awards Lapsing. If a Potential Participant prefers to delay the lapsing of the restrictions on part or all of the shares of Restricted Stock and/or Restricted Stock Units to which a notice received under Section 2(b) pertains, the Potential Participant must indicate such preference in a manner prescribed by the Plan Administrator, (i) if the Potential Participant is subject to Section 16 of the Exchange Act, to the Committee, or (ii) if the Potential Participant is not subject to Section 16 of the Exchange Act, to the CEO. The Potential Participant's preference must state the percentage of the shares and/or units on which the lapsing is to be delayed. If an indication is not received by October 31, the Potential Participant will be deemed to have elected to have the restrictions lapsed if the Compensation Committee takes action to lapse restrictions or as specified under the terms of the Special Restricted Stock and/or Restricted Stock Unit Awards. If the Potential Participant prefers to delay the lapsing of the restrictions on part or all of the shares of Restricted Stock or Restricted Stock Units awarded under an Incentive Compensation Plan, the Long Term Incentive Compensation Plan, a Long Term Incentive Plan, or Strategic Incentive Plan, those shares and/or units will be subject to another indication of preference in the following year. If the Potential Participant prefers to delay the lapsing of the restrictions on part or all of the shares of Restricted Stock or Restricted

Stock Units from Special Stock Awards, those shares and/or units will remain restricted and the Employee will receive a notice to indicate a preference for such shares when the Employee is or will be 55 years of age or older prior to the end of the calendar year as specified in Section 2(b)(i).

(c) Restricted Stock or Restricted Stock Unit Deferral. If a Potential Participant prefers to defer under this Plan the value of all or any part of the Restricted Stock or Restricted Stock Units to which a notice received under Section 2(c) pertains, the Potential Participant must indicate such preference, in a manner prescribed by the Plan Administrator, (i) if the Potential Participant is subject to Section 16 of the Exchange Act, to the Committee, or (ii) if the Potential Participant is not subject to Section 16 of the Exchange Act, to the CEO. The Potential Participant's preference must be received on or before October 31 of the year in which said Section 2(c) notice was received. Such indication must state the portion of the value of the Restricted Stock or Restricted Stock Units the Potential Participant desires to be deferred. If an indication is not received by October 31, the Potential Participant will be deemed to have elected to receive any shares or units for which the restrictions are lapsed. Such indication of preference becomes irrevocable on November 1 of the year in which the indication is submitted to the Committee or CEO. The Committee or CEO, as applicable, shall consider such indication of preference as submitted and shall decide whether to accept or reject the preference expressed. A deferral of the value of the Restricted Stock or Restricted Stock Units will be paid under the terms of Section 5(b)(i) hereof - 10 annual installments commencing about one year after Retirement at age 55 or above, but subject to revision under the terms of this Plan. Such approved indication of preference shall also apply to any Restricted Stock Units granted in exchange for shares of Restricted Stock pursuant to the Exchange offer initiated by the Company on December 17, 2001.

(d) Lump Sum Distribution from Non-Qualified Retirement Plans. If a Potential Participant prefers to defer under this Plan all or part of the lump sum distribution to which Section 2(d) pertains, the Potential Participant must indicate such preference, in

a manner prescribed by the Plan Administrator, (i) if the Potential Participant is subject to Section 16 of the Exchange Act, to the Committee or (ii) if the Potential Participant is not subject to Section 16 of the Exchange Act, to the CEO. The Potential Participant's preference must be received in the period beginning 90 days prior to and ending no less than 30 days prior to the date of commencement of retirement benefits under such plans. Such indication must state the portion of the lump sum distribution the Potential Participant desires to be deferred. The Committee or CEO, as applicable, shall consider such indication of preference as submitted and shall decide whether to accept or reject the preference expressed as soon as practicable. Such indication of preference, if accepted, becomes irrevocable on the date of such acceptance.

(e) Lump Sum from Defined Contribution Makeup Plan. If a Potential Participant prefers to defer under this Plan all or part of the lump sum cash payment to which Section 2(e) pertains, the Potential Participant must indicate such preference, in a manner prescribed by the Plan Administrator, (i) if the Potential Participant is subject to Section 16 of the Exchange Act, to the Committee or (ii) if the Potential Participant is not subject to Section 16 of the Exchange Act, to the CEO. The Potential Participant's preference must be received in the period beginning 365 days prior to and ending no less than 90 days prior to the Participant's retirement date at age 55 or above except that if a Potential Participant is notified of layoff during or after the year in which the Potential Participant reaches age 50, the Potential Participant's preference must be received no later than 30 days after being notified of layoff. Such indication must state the portion of the lump sum payment the Potential Participant desires to be deferred. The Committee or CEO, as applicable, shall consider such indication of preference as submitted and shall decide whether to accept or reject the preference expressed as soon as practicable. Such indication of preference, if accepted, becomes irrevocable on the date of such acceptance. A deferral of the lump sum from the Defined Contribution Makeup Plan will be paid under the terms of Section 5(b)(i) hereof - - 10 annual installments commencing about one year after Retirement at age 55 or above, but subject to revision under the terms of the Plan.

(f) Salary Reduction. If a Potential Participant elects to voluntarily reduce Salary and receive an Award hereunder in lieu thereof, the Potential Participant must make an election, in the manner prescribed by the Plan Administrator, which must be received on or before October 31 prior to the beginning of the calendar year of the elected deferral or for Newhire Employees as soon as practicable within a 30-day period after their first day of employment or reemployment. Such election must be in writing signed by the Potential Participant, and must state the amount of the salary reduction the Potential Participant elects. Such election becomes irrevocable on October 31 prior to the beginning of the calendar year or for Newhire Employees after the 30-day period after their first day of employment or reemployment, except that in the event of any of the following:

i) the Employee is demoted to a job classification/grade that is no longer eligible to receive an Award from an Incentive Compensation Plan,

ii) the Employee's employment status is classified to a status other than regular full-time or its equivalent, or

iii) the Employee is receiving Unavoidable Absence Benefits (UAB) pay such that the pay received is less than his/her pay had been prior to being on UAB,

the Employee can request, subject to approval by the Plan Benefits Administrator, that his/her election to voluntarily reduce his/her salary be revoked for the remainder of the calendar year.

An Award in lieu of voluntarily reduced salary will be paid under the terms of Section 5(b)(i) hereof - 10 annual installments commencing about one year after Retirement at age 55 or above, but subject to revision under the terms of the Plan.

(g) Performance Based Incentive Award. The Potential Participant who is eligible to receive a Performance Based Incentive Award in the immediately following calendar year, must indicate a preference, in a manner prescribed by the Plan Administrator, (i) if the Potential Participant is subject to Section 16 of the Exchange Act, to the Committee, or (ii) if the Potential Participant is not subject to Section 16 of the

Exchange Act, to the CEO. The Potential Participant's preference must be received on or before October 31 of the year in which said Section 2(g) notice was received. Such indication must state the portion of the award the Potential Participant desires to be in cash, the portion to be deferred and the portion to be in Restricted Stock. If an indication is not received by October 31 the Potential Participant will be deemed to have elected to receive the award as cash. Such indication of preference becomes irrevocable on November 1 of the year in which the indication is submitted to the Committee or CEO. The Committee or CEO, as applicable, shall consider such indication of preference as submitted and shall decide whether to accept or reject the preference expressed.

SECTION 4. Deferred Compensation Accounts.

(a) Credit for Deferral. Amounts deferred pursuant to Section 3(a) and Section 5(h)(1) will be credited to the Participant's Deferred Compensation Account as soon as practicable, but not less than 30 days after the Settlement Date of the Incentive Compensation Plan. Amounts deferred pursuant to Section 3(c) and Section 5(h)(2) will be credited, as applicable, as soon as practicable, but not later than 30 days after the date as of which the restrictions lapse at the market value of the underlying Restricted Stock or the shares represented by the Restricted Stock Units awarded under an Incentive Compensation Plan, the Long Term Incentive Compensation Plan, a Long Term Incentive Plan or a Strategic Incentive Plan Performance Period which began prior to January 1, 2003. For this purpose, the market value of the underlying Restricted Stock or the shares represented by the Restricted Stock Units, as applicable, shall be based on the higher of (i) the average of the high and low selling prices of the Stock on the date the restrictions lapse or the last trading day before the day the restrictions lapse if such date is not a trading day or (ii) the average of the high three monthly Fair Market Values of the Stock during the twelve calendar months preceding the month in which the restrictions lapse. The monthly Fair Market Value of the Stock is the average of the daily Fair Market Value of the Stock for each trading day of the month.

The market value of the underlying Restricted Stock or the shares represented by the Restricted Stock Units awarded under a Long Term Incentive Plan, under an Incentive Compensation Plan that began on or after January 1, 2003, under an Omnibus Securities Plan (with regard to awards made on or after January 1, 2003), and for the Special Stock Awards issued on October 22, 2002, shall be the monthly average Fair Market Value of the Stock during the calendar month preceding the month in which the restrictions lapse or shares are to be delivered as applicable. The monthly average Fair Market Value of the Stock is the average of the daily Fair Market Value of the Stock for each trading day of the month.

The daily Fair Market Value of the Stock shall be deemed equal to the average of the high and low selling prices of the Stock on the New York Stock Exchange.

Amounts deferred pursuant to Section 3(e) and 3(f) and Section 5(h)(3) will be credited to the Participant's Deferred Compensation Account as soon as practicable, but not later than 30 days after the cash payment would have been made had it not been deferred. Amounts deferred pursuant to other provisions of this Plan shall be credited as soon as practicable but not later than 30 days after the date the Award would otherwise be payable.

(b) Designation of Investments. The amount in each Participant's Deferred Compensation Account shall be deemed to have been invested and reinvested from time to time, in such "eligible securities" as the Participant shall designate. Prior to or in the absence of a Participant's designation, the Company shall designate an "eligible security" in which the Participant's Deferred Compensation Account shall be deemed to have been invested until designation instructions are received from the Participant. Eligible securities are those securities designated by the

Chief Financial Officer of the Company, or his successor. The Chief Financial Officer of the Company may include as eligible securities, stocks listed on a national securities exchange, and bonds, notes,

debentures, corporate or governmental, either listed on a national securities exchange or for which price quotations are published in The Wall Street Journal and shares issued by investment companies commonly known as "mutual funds". The Participant's Deferred Compensation Account will be adjusted to reflect the deemed gains, losses, and earnings as though the amount deferred was actually invested and reinvested in the eligible securities for the Participant's Deferred Compensation Account.

Notwithstanding anything to the contrary in this section 4(b), in the event the Company (or any trust maintained for this purpose) actually purchases or sells such securities in the quantities and at the times the securities are deemed to be purchased or sold for a Participant's Deferred Compensation Account, the Account shall be adjusted accordingly to reflect the price actually paid or received by the Company for such securities after adjustment for all transaction expenses incurred (including without limitation brokerage fees and stock transfer taxes).

In the case of any deemed purchase not actually made by the Company, the Deferred Compensation Account shall be charged with a dollar amount equal to the quantity and kind of securities deemed to have been purchased multiplied by the fair market value of such security on the date of reference and shall be credited with the quantity and kind of securities so deemed to have been purchased. In the case of any deemed sale not actually made by the Company, the account shall be charged with the quantity and kind of securities deemed to have been sold, and shall be credited with a dollar amount equal to the quantity and kind of securities deemed to have been sold multiplied by the fair market value of such security on the date of reference. As used in this paragraph "fair market value" means in the case of a listed security the closing price on the date of reference, or if there were no sales on such date, then the closing price on the nearest preceding day on which there were such sales, and in the case of an unlisted security the mean between the bid and asked prices on the date of reference, or if no such prices are available for such date, then the mean between the bid and asked prices to the nearest preceding day for which such prices are available.

The Chief Financial Officer of the Company may also designate a third party to provide services that may include record keeping, Participant accounting, Participant communication, payment of installments to the Participant, tax reporting, and any other services specified by the Company in agreement with such third party.

(c) Payments. A Participant's Deferred Compensation Account shall be debited with respect to payments made from the account pursuant to this Plan as of the date such payments are made from the account. The payment shall be made as soon as practicable, but no later than 30 days, after the installment payment date.

If any person to whom a payment is due hereunder is under legal disability as determined in the sole discretion of the Plan Administrator, the Plan Administrator shall have the power to cause the payment due such person to be made to such person's guardian or other legal representative for the person's benefit, and such payment shall constitute a full release and discharge of the Company, the Plan Administrator, and any fiduciary of the Plan.

(d) Statements. At least one time per year the Company or the Company's designee will furnish each Participant a written statement setting forth the current balance in the Participant's Deferred Compensation Account, the amounts credited or debited to such account since the last statement and the payment schedule of deferred Awards, and deemed gains, losses, and earnings accrued thereon as provided by the deferred payment option selected by the Participant.

SECTION 5. Payments from Deferred Compensation Accounts.

(a) Election of Method of Payment for an Incentive Compensation Plan Award. At the time a Potential Participant submits an indication of preference to defer all or any part of an Award under an Incentive Compensation Plan as provided in Section 3(a) above, the Potential Participant shall also elect in a manner prescribed by the Plan

Administrator, which of the payment options, provided for in Paragraph (b) of this Section, shall apply to the deferred portion of said Award adjusted for any deemed gains, losses, and earnings accrued thereon credited to the Participant's Deferred Compensation Account under this Plan. Subject to Paragraphs (e), (g), and (h) of this Section, if the Committee or CEO, as appropriate, accepts the Potential Participant's indication of preference, the election of the method of payment of the amount deferred shall become irrevocable.

(b) Payment Options. A Potential Participant may elect to have the deferred portion of an Incentive Compensation Plan Award adjusted for any deemed gains, losses, and earnings accrued thereon paid:

(i) *(Post-Retirement)* in 1 to 15 annual installments, in 2 to 30 semi-annual installments, or in 4 to 60 quarterly installments, the payment of the first of any of such installments to commence on the first day of the first calendar quarter which is on or after the first anniversary of (x) the Potential Participant's first day of Retirement at age 55 or above (or at age 50 or above for a Heritage Conoco Employee who was employed by Conoco Inc. or its affiliates on August 30, 2002 if such Heritage Conoco Employee is eligible for early retirement under the Retirement Plan of Conoco) or (y) the Potential Participant's first day of Layoff at age 50 or above, or

(ii) *(Date Certain)* with regard only to the deferred portion of an Incentive Compensation Award, in 1 to 15 annual installments, in 2 to 30 semi-annual installments, or in 4 to 60 quarterly installments, the payment of the first of any of such installments to commence on the first day of calendar quarter which is designated by the Participant, is at least one year after the date on which the election is made, and is not later than the 65^{th} birthday of the Participant; provided, however, that in the event of termination of employment from the Affiliated Group by a Heritage Conoco Employee who had made deferral of amounts from the Conoco Inc. Global Variable Compensation Plan, the balance

of such deferred amounts (adjusted for earnings, gains, and losses) shall be paid in a lump sum as soon as practicable after termination, notwithstanding an installment election made pursuant to this Paragraph, or

(iii) *(Pre-Retirement)* otherwise, in a lump sum paid as soon as practicable following the Participant's termination from employment with the Affiliated Group.

(iv) In the event that no election is properly and timely made with regard to the time and method of payment under Section 5(b)(i) or (ii), payment shall be made in 10 annual installments, the payment of the first of any of such installments to commence on the first day of the first calendar quarter which is on or after the first anniversary of (x) the Potential Participant's first day of Retirement at age 55 or above (or at age 50 or above for a Heritage Conoco Employee who was employed by Conoco Inc. or its affiliates on August 30, 2002 if such Heritage Conoco Employee is eligible for early retirement under the Retirement Plan of Conoco) or (y) the Potential Participant's first day of Layoff at age 50 or above.

(c) <u>Election of Method of Payment of the Value of Restricted Stock and Restricted Stock Units</u>. As provided in Section 3(c) above, a deferral of the value of all or part of the Restricted Stock or Restricted Stock Units will be considered payment option (b)(i) of this Section subject to Paragraphs (e) and (g) of this Section.

(d) <u>Election of Method of Payment of a Lump Sum Distribution from Non-Qualified Retirement Plans</u>. At the time a Potential Participant submits an indication of preference to defer all or part of the lump sum distribution as provided in Section 3(d) above, the Potential Participant shall also elect in a manner prescribed by the Plan Administrator which payment option shall apply to the deferred lump sum adjusted for any gains, losses, and earnings to be accrued thereon credited to the Participant's Deferred Compensation Account under this Plan. The payment options are annual installments of not less than 1 nor more than 15, semi-annual installments of not less

than 2 nor more than 30, or quarterly installments of not less than 4 nor more than 60. The first installment shall commence as soon as practicable after any date specified by the Potential Participant, so long as such date is the first day of a calendar quarter and is at least one year and not later than five years from the date the payout option was elected. Subject to Paragraph (g) of this Section, if the Committee or CEO, as appropriate, accepts the Potential Participant's indication of preference, the election of the method of payment of the amount deferred shall become irrevocable.

(e) <u>Payment Option Revisions</u>. If a Section 5(b)(i) payment option applies to any part of the balance of a Participant's Deferred Compensation Account, the Participant may revise such payment option as follows:

(i) <u>Prior to Retirement</u>. The Participant at any time during a period beginning 365 days prior to and ending 90 days prior to the date the Participant Retires at age 55 or above may, with respect to the total of all amounts subject to such payment option at the time of the Participant's Retirement at age 55 or above, in the manner prescribed by the Plan Administrator, revise such payment option and elect one of the payment options specified in (e)(iv) of this Section to apply to such total amount in place of such payment option.

(ii) <u>Upon Layoff</u>. If a Participant who is eligible to Retire or who is Laid Off during or after the year in which the Participant reaches age 50 is notified of Layoff, the Participant may, no later than 30 days after being notified of Layoff, in the manner prescribed by the Plan Administrator, revise such payment option and elect one of the payment options specified in (e)(iv) of this Section to apply to such total amount in place of such payment option.

(iii) <u>If Disabled</u>. The Participant may at any time during a period from the date of the beginning of the qualifying period for the Company's Long Term Disability Plan or similar plan to no later than 90 days prior to the end of such period, or within 30 days of the amendment of this Plan providing for such election, in the

manner prescribed by the Plan Administrator, revise such payment option and elect one of the payment options specified in (e)(iv) of this Section to apply to the total of all amounts subject to such payment option; provided, however, that after the payments have begun, such payments may be made in a different manner if, the Participant due to an unanticipated emergency caused by an event beyond the control of the Participant results in financial hardship to the Participant, so request and the CEO gives written consent to the method of payment requested.

(iv) <u>Payment Options After Revision</u>. If a Participant revises a Section 5(b)(i) payment option as specified in (e)(i), (e)(ii), or (e)(iii) of this Section, the Participant may select payments in annual installments of not less than 1 nor more than 15, in semi-annual installments of not less than 2 nor more than 30, or in quarterly installments of not less than 4 nor more than 60, with the first installment to commence as soon as practicable following any date specified by the Participant so long as such date is the first day of a calendar quarter, is on or after the Participant's first day of Retirement at age 55 or above or the first day the Participant is no longer an Employee following Layoff, is at least one year and no more than five years from the date the payment option was revised.

(f) Installment Amount. The amount of each installment shall be determined by dividing the balance in the Participant's Deferred Compensation Account as of the date the installment is to be paid, by the number of installments remaining to be paid (inclusive of the current installment).

(g) Death of Participant. Upon the death of a Participant, the Participant's beneficiary or beneficiaries designated in accordance with Section 6, or in the absence of an effective beneficiary designation, the surviving spouse, surviving children (natural or adopted) in equal shares, or the Estate of the deceased Participant, in that order of priority, shall receive payments in accordance with the payment option selected by the Participant, if death occurred after such payments had commenced; or if death occurred before

payments have commenced, the beneficiary may select payments in annual installments of not less than 1 nor more than 15, in semi-annual installments of not less than 2 nor more than 30, or in quarterly installments of not less than 4 nor more than 60 with the first installment to commence as soon as practicable following any date specified by the beneficiary so long as such date is the first day of a calendar quarter and is at least one year and no more than five years from the date the payment option is selected and is not later than the date the deceased Participant would have been age 65; provided, however, such payments may be made in a different manner if the beneficiary or beneficiaries entitled to receive or receiving such payments, due to an unanticipated emergency caused by an event beyond the control of the beneficiary or beneficiaries that results in financial hardship to the beneficiary or beneficiaries, so requests and the CEO gives written consent to the method of payment requested.

(h) Disability of Participant. In the event a Participant or Employee becomes disabled, the individual may, in the period from the date of the beginning of the qualifying period for the Company's Long Term Disability Plan to no later than 90 days prior to the end of such period, or within 30 days of the amendment of this Plan providing for such election, indicate a preference, in a manner prescribed by the Plan Administrator, for any of the following:

(1) To defer part or all of any Incentive Compensation Plan Award the Employee is eligible to receive in the immediately following calendar year,
(2) To defer part or all of the value of the Stock which would otherwise be delivered to the Employee when the restrictions lapse on any Restricted Stock or Restricted Stock Units or Restricted Stock Units are settled, or
(3) To defer part or all of the value from their account under the Defined Contribution Makeup Plan which would otherwise be paid as a lump sum to the Participant.

Such indications of preference shall be subject to approval by the Committee if the Potential Participant is subject to Section 16 of the Exchange Act or by the CEO if the Potential Participant is not subject to Section 16 of the Exchange Act. The Committee

or CEO, as applicable, shall consider such indication or preference as submitted and shall decide whether to accept or reject the preference expressed.

Such indications of preference, if accepted, become irrevocable on the date of such acceptance. A deferral of any amount will be paid under the terms of Section 5(b)(i) hereof - ten (10) annual installments, but subject to revision as specified under the terms of this Plan.

(i) Termination of Employment. In the event a Participant's employment with the Company, any Participating Subsidiary, or any other subsidiary of the Company terminates for any reason other than death, Retirement at age 55 or above, Disability, or Layoff during or after the year in which the Participant reaches age 50, the entire balance of the Participant's Deferred Compensation Account shall be paid to the Participant in one lump sum as soon as practicable after the date the Participant terminates employment, except that a Participant who becomes employed by a member of the Affiliated Group immediately after terminating employment with the Company or Participating Subsidiary shall not receive their benefit under the Plan until the Participant terminates employment from the Affiliated Group; provided, however, the Committee, in its sole discretion, may elect to make such payments in the amounts and on such schedule as it may determine.

(j) Rehire of Participant. In the event a Participant is a Rehired Participant, he/she will be eligible to receive notifications as specified in Section 2 and will be eligible to submit an Indication of Preference or Election to Defer as specified in Section 3, if the Participant agrees to the suspension of payments from his/her Deferred Compensation Account during the period of reemployment by the Company. Upon termination of reemployment, such payments shall resume on the same schedule as was in effect at the time the Participant previously Retired or was Laid Off.

SECTION 6. Special Provisions for Former ARCO Alaska Employees.

Notwithstanding any provisions to the contrary, in order to comply with the terms of the Master Purchase and Sale Agreement ("Sale Agreement") by which the Company acquired certain Alaskan assets of Atlantic Richfield Company ("ARCO"), a Participant who was eligible to participate in the ARCO employee benefit plans immediately prior to becoming an Employee and who was not employed by ARCO Marine, Inc. (a "former ARCO Alaska employee") may, in a manner prescribed by the Plan Administrator, indicate a preference or make an election:

(a) To reduce voluntarily salary and receive an Award in the amount of the reduction credited to, at the Employee's election, (i) an account under this Plan or (ii) for so long as the ARCO Executive Deferral Plan will accept such deferrals of salary, but not beyond December 31, 2001, an account under the ARCO Executive Deferral Plan; or

(b) To defer any Award payable to a former ARCO employee who is involuntarily terminated prior to April 18, 2002, in lieu of a target ARCO Annual Incentive Plan (AIP) award, and at the Employee's election credit the Award to (i) an account under this Plan or (ii) to the ARCO Executive Deferral Plan; or

(c) To defer the Final ARCO Supplemental Executive Retirement Plan (SERP) benefit that will be calculated as of the earlier of April 17, 2002, or the date the former ARCO employee voluntarily or involuntarily terminates employment from the Company or any Participating Subsidiary to the ARCO Executive Deferral Plan; or

(d) To defer the value of the restricted stock granted on July 31, 2000, to an account under this Plan when the restrictions lapse on July 31, 2001, July 31, 2002, and July 31, 2003; provided that such indications of preference shall be made in July of the year preceding the calendar year when the restrictions are scheduled to lapse or as soon as practicable after July 31, 2000, for the restrictions on the shares that are to be lapsed on July 31, 2001; or

(e) For a former ARCO Alaska employee who was classified as a grade 7 or 8 under ARCO's job classification system and was eligible under ARCO's Executive Deferral Plan to voluntarily reduce salary and defer the amount of the voluntary salary reduction and who was classified as a grade 31 or below at that time under Phillips Petroleum Company's job classification system, to make an annual election to voluntarily reduce salary and defer the amount of the voluntary salary reduction for salary received from July 31, 2000, through December 31, 2000, and for the five years from 2001 through 2005 and receive a salary deferral credit under this Plan.

All indications of preference in Sections 6(a), (b), and (c) are subject to approval by the Compensation Committee if the Employee is subject to Section 16 of the Exchange Act and by the CEO if the Employee is not subject to Section 16 of the Exchange Act.

SECTION 7. Designation of Beneficiary.

Each Participant shall designate a beneficiary or beneficiaries to receive the entire balance of the Participant's Deferred Compensation Account by giving signed written notice of such designation to the Plan Administrator. The Participant may from time to time change or cancel any previous beneficiary designation in the same manner. The last beneficiary designation received by the Plan Administrator shall be controlling over any prior designation and over any testamentary or other disposition. After acceptance by the Plan Administrator of such written designation, it shall take effect as of the date on which it was signed by the Participant, whether the Participant is living at the time of such receipt, but without prejudice to the Company or the CEO on account of any payment made under this Plan before receipt of such designation.

SECTION 8. Nonassignability.

The right of a Participant, or beneficiary, or other person who becomes entitled to receive payments under this Plan, shall not be assignable or subject to garnishment, attachment, or any other legal process by the creditors of, or other claimants against, the Participant,

beneficiary, or other such person.

SECTION 9. Administration.

(a) The Plan Administrator may adopt such rules, regulations, and forms as deemed desirable for administration of the Plan and shall have the discretionary authority to allocate responsibilities under the Plan to such other persons as may be designated.

(b) Any claim for benefits hereunder shall be presented in writing to the Plan Administrator for consideration, grant or denial. In the event that a claim is denied in whole or in part by the Plan Administrator, the claimant, within ninety days of receipt of said claim by the Plan Administrator, shall receive written notice of denial. Such notice shall contain:

(1) a statement of the specific reason or reasons for the denial;

(2) specific references to the pertinent provisions hereunder on which such denial is based;

(3) a description of any additional material or information necessary to perfect the claim and an explanation of why such material or information is necessary; and

(4) an explanation of the following claims review procedure set forth in paragraph (c) below.

(c) Any claimant who feels that a claim has been improperly denied in whole or in part by the Plan Administrator may request a review of the denial by making written application to the Trustee. The claimant shall have the right to review all pertinent documents relating to said claim and to submit issues and comments in writing to the Trustee. Any person filing an appeal from the denial of a claim must do so in writing within sixty days after receipt of written notice of denial. The Trustee shall render a decision regarding the claim within sixty days after receipt of a request for review, unless special circumstances require an extension of time for processing, in which case a decision shall be rendered within a reasonable time, but not later than 120 days after receipt of the request for review. The decision of the Trustee shall be in writing and, in the case of the denial of a claim in whole or in part, shall set forth the same information as is required in an initial notice of denial by the Plan Administrator, other than an explanation of this claims review procedure. The Trustee shall have absolute discretion in carrying out its responsibilities to make its decision of an appeal, including the authority to interpret and construe the terms hereunder, and all interpretations, findings of fact, and the decision of the Trustee regarding the appeal shall be final, conclusive and binding on all parties.

(d) Compliance with the procedures described in paragraphs (b) and (c) shall be a condition precedent to the filing of any action to obtain any benefit or enforce any right which any individual may claim hereunder. Notwithstanding anything to the contrary in the Plan, these paragraphs (b), (c), and (d) may not be amended without the written consent of a seventy-five percent (75%) majority of Participants and Beneficiaries and such paragraphs shall survive the termination of this Plan until all benefits accrued hereunder have been paid.

SECTION 10. Employment not Affected by Plan.

Participation or nonparticipation in this Plan shall neither adversely affect any person's employment status nor confer any special rights on any person other than those expressly stated in the Plan. Participation in the Plan by an Employee of the Company or of a Participating Subsidiary shall not affect the Company's or the Participating Subsidiary's right to terminate the Employee's employment or to change the Employee's compensation or position.

SECTION 11. Determination of Recipients of Awards.

The determination of those persons who are entitled to Awards under an Incentive Compensation Plan and any other such plans shall be governed solely by the terms and provisions of the applicable plan, and the selection of an Employee as a Potential Participant

or the acceptance of an indication of preference to defer an Award hereunder shall not in any way entitle such Potential Participant to an Award.

SECTION 12. Method of Providing Payments.

(a) Nonsegregation. Amounts deferred pursuant to this Plan and the crediting of amounts to a Participant's Deferred Compensation Account shall represent the Company's unfunded and unsecured promise to pay compensation in the future. With respect to said amounts, the relationship of the Company and a Participant shall be that of debtor and general unsecured creditor. While the Company may make investments for the purpose of measuring and meeting its obligations under this Plan such investments shall remain the sole property of the Company subject to claims of its creditors generally, and shall not be deemed to form or be included in any part of the Deferred Compensation Account.

(b) Funding. It is the intention of the Company that this Plan shall be unfunded for federal tax purposes and for purposes of Title I of ERISA; provided, however, that the Company may establish a grantor trust to satisfy part or all of its Plan payment obligations so long as the Plan remains unfunded for federal tax purposes and for purposes of Title I of ERISA.

SECTION 13. Amendment or Termination of Plan.

Subject to Paragraph 9(d), the Company reserves the right to amend this Plan from time to time or to terminate the Plan entirely, provided, however, that no amendment may affect the balance in a Participant's account on the effective date of the amendment. No Participant shall participate in a decision to amend or terminate this Plan. In the event of termination of the Plan, the Chief Executive Officer, in his sole discretion, may elect to pay to the Participant in one lump sum as soon as practicable after termination of the Plan, the balance then in the Participant's account.

SECTION 14. Miscellaneous Provisions.

(a) Except as otherwise provided herein, the Plan shall be binding upon the Company, its successors and assigns, including but not limited to any corporation which may acquire all or substantially all of the Company's assets and business or with or into which the Company may be consolidated or merged.

(b) This Plan shall be construed, regulated, and administered in accordance with the laws of the State of Texas except to the extent that said laws have been preempted by the laws of the United States.

SECTION 15. Effective Date of Existing Restatement of the Plan.

This Plan was amended and restated effective as of October 3, 2003, but with provisions added in the preamble and below to indicate the separation of Title I and Title II of the Plan to comply with Code section 409A.

Executed this 29th day of December 2005, effective as of January 1, 2005, with respect to benefits earned and vested prior to January 1, 2005.

/s/ Carin S. Knickel

Carin S. Knickel
Vice President, Human Resources

Exhibit 10.23.2

ORIGINAL FOR EXECUTION
APPROVED VP, HR DECEMBER 29, 2005

KEY EMPLOYEE DEFERRED COMPENSATION PLAN OF CONOCOPHILLIPS

TITLE II
(Effective for benefits earned or vested after December 31, 2004)

PURPOSE

The purpose of the Key Employee Deferred Compensation Plan of ConocoPhillips (the "Plan") is to attract and retain key employees by providing them with an opportunity to defer receipt of cash amounts which otherwise would be paid to them under various compensation programs or plans by the Company. Title I of this Plan is effective with regard to benefits earned and vested prior to January 1, 2005, while Title II of this Plan is effective with regard to benefits earned or vested after December 31, 2004. Earnings, gains, and losses shall be allocated to the Title of the Plan to which the underlying obligations giving rise to them are allocated.

This Title II of the Plan is intended (1) to comply with Code section 409A, as enacted as part of the American Jobs Creation Act of 2004, and official guidance issued thereunder, and (2) to be "a plan which is unfunded and is maintained by an employer primarily for the purpose of providing deferred compensation for a select group of management or highly compensated employees" within the meaning of sections 201(2), 301(a)(3), and 401(a)(1) of ERISA. Notwithstanding any other provision of this Plan, this Plan shall be interpreted, operated, and administered in a manner consistent with these intentions.

SECTION 1. Definitions.

(a) "Affiliated Company" shall mean any corporation or other entity that is treated as a single employer with the Company under section 414(b) or (c) of the Code.

(b) "Affiliated Group" shall mean the Company plus other subsidiaries and affiliates in which it owns, directly or through a subsidiary or affiliate, a 5% or more equity interest.

(c) "Award" shall mean the United States cash dollar amount (i) allotted to an Employee under the terms of an Incentive Compensation Plan or a Long Term Incentive Plan, or (ii) required to be credited to an Employee's Deferred Compensation Account pursuant to the terms of an Award or of an Incentive Compensation Plan, the Long Term Incentive Compensation Plan, the Strategic Incentive Plan, a Long Term Incentive Plan, or any similar plans, or any administrative procedure adopted pursuant thereto, or (iii) credited as a result of an Employee's voluntary reduction of Salary, or (iv) any other amount determined by the Committee to be an Award under the Plan.

(d) "Code" shall mean the Internal Revenue Code of 1986, as amended from time to time, or any successor statute.

(e) "Committee" shall mean the Compensation Committee of the Board of Directors of the Company.

(f) "Company" shall mean ConocoPhillips.

(g) "Deferred Compensation Account" shall mean an account established and maintained for each Participant in which is recorded the amounts of Awards deferred by a Participant, the deemed gains, losses, and earnings accrued thereon, and payments made therefrom all in accordance with the terms of the Plan.

(h) "Election Form" shall mean a written form, including one in electronic format, provided by the Plan Administrator pursuant to which a Participant may elect the time and form of payment of his or her Benefit.

(i) "Employee" shall mean any individual who is a salaried employee of the Company or of a Participating Subsidiary who is eligible to receive an Award from an Incentive Compensation Plan and is classified as a ConocoPhillips salary grade 19 or above or any equivalent salary grade at a Participating Subsidiary.

(j) "ERISA" shall mean the Employee Retirement Income Security Act of 1974, as amended from time to time, or any successor statute.

(k) "Heritage Conoco Employee" shall mean an individual employed by Conoco Inc., Conoco Pipe Line Company, or Louisiana Gas Systems Inc. prior to January 1, 2003; provided, however, that an individual who has been terminated from employment with a member of the Affiliated Group at any time and rehired by a member of the Affiliated Group after January 1, 2003, shall not be considered a Heritage Conoco Employee for purposes of this Plan.

(l) "Incentive Compensation Plan" shall mean the ConocoPhillips Variable Cash Incentive Program, the Incentive Compensation Plan of Phillips Petroleum Company, or the Annual Incentive Compensation Plan of Phillips Petroleum Company, the Special Incentive Plan for Former Tosco Executives, the Conoco Inc. Global Variable Compensation Plan, or a similar plan of a Participating Subsidiary, or any similar or successor plans, or all, as the context may require.

(m) “Long-Term Incentive Compensation Plan” shall mean the Long-Term Incentive Compensation Plan of Phillips Petroleum Company, which was terminated December 31, 1985.

(n) “Long-Term Incentive Plan” shall mean the ConocoPhillips Performance Share Program, the ConocoPhillips Restricted Stock Program, the Phillips Petroleum Company Long-Term Incentive Plan, or a similar or successor plan of any of them, established under an Omnibus Securities Plan.

(o) “Omnibus Securities Plan” shall mean the 2004 Omnibus Stock and Performance Incentive Plan of ConocoPhillips, the 2002 Omnibus Securities Plan of Phillips Petroleum Company, the Omnibus Securities Plan of Phillips Petroleum Company, the 1998 Stock and Performance Incentive Plan of ConocoPhillips, the 1998 Key Employee Stock Plan of ConocoPhillips, or a similar or successor plan of any of them.

(p) “Participant” shall mean a person for whom a Deferred Compensation Account is maintained.

(q) “Participating Subsidiary” shall mean a subsidiary of the Company, of which the Company beneficially owns, directly or indirectly, more than 50% of the aggregate voting power of all outstanding classes and series of stock, where such subsidiary has adopted one or more plans making participants eligible for participation in this Plan and one or more Employees of which are Potential Participants.

(r) “Plan Administrator” shall mean the Vice President, Human Resources of the Company, or his or her successor.

(s) “Potential Participant” shall mean a person who has received a notice specified in Section 2.

(t) “Restricted Stock” and “Restricted Stock Units” shall mean respectively shares of Stock and units each of which shall represent a hypothetical share of Stock, which have certain restrictions attached to the ownership thereof or the delivery of shares pursuant thereto.

(u) “Retirement” or “Retire” or “Retiring” shall mean termination of employment with the Company or any subsidiary of the Company on or after age 55 or above and on or after the earliest early retirement date as defined in applicable title of the ConocoPhillips Retirement Plan or of the applicable retirement plan of a Participating Company.

(v) “Schedule A Employee” shall mean an Employee whose name appears in Schedule A attached to and made a part of this Plan.

(w) “Separation from Service” shall mean the date on which the Participant terminates employment with the Company and its Affiliated Companies within the meaning of Code section 409A, whether by reason of death, disability, retirement, or otherwise.

(x) “Settlement Date” shall mean the date on which all acts under an Incentive Compensation Plan or the Long-Term Incentive Compensation Plan or actions directed by the Committee, as the case may be, have been taken which are necessary to make an Award payable to the Participant.

(y) “Salary” shall mean the monthly equivalent rate of pay for an Employee before adjustments for any before-tax voluntary reductions.

(z) “Stock” means shares of common stock of ConocoPhillips, par value $.01.

(aa) “Strategic Incentive Plan” shall mean the Strategic Incentive Plan portion of the 1986 Stock Plan of Phillips Petroleum Company, of the 1990 Stock Plan of Phillips Petroleum Company, of the Phillips Petroleum Company Omnibus Securities Plan, and of any successor plans of similar nature.

(bb) “Trustee” shall mean the trustee of the grantor trust established by the Trust Agreement between the Company and Wachovia Bank, N.A. dated as of June 1, 1998, or any successor trustee.

SECTION 2. Notification of Potential Participants.

(a) Incentive Compensation Plan. With regard to each year, at such times as the Plan Administrator may determine, Employees who are eligible to receive an Award in the immediately following calendar year under an Incentive Compensation Plan will be notified and given the opportunity to make an election, using the Election Form or in such other manner prescribed by the Plan Administrator, to defer all or part of such Award.

(b) Salary Reduction. With regard to each year, at such times as the Plan Administrator may determine, Employees on the U.S. dollar payroll will be notified and given the opportunity to make an election, using the Election Form or in such other manner prescribed by the Plan Administrator, to make a voluntary reduction of Salary for each pay period of the following calendar year, in which case the Company will credit a like amount as an Award hereunder, provided that the amount of such voluntary reduction shall not be less than 1% nor more than 50% of the Employee’s Salary per pay period.

SECTION 3. Election to Defer Award or Reduce Salary.

(a) Incentive Compensation Plan. If a Potential Participant elects to defer under this Plan all or any part of the Award to which a notice received under Section 2(a) pertains, the Potential Participant must make such election, using the Election Form or in such other manner prescribed by the Plan Administrator. The Potential Participant's election shall become irrevocable on December 31 of the year in which said Section 2(a) notice was received (except in the case of an election for an Award under an Incentive Compensation Plan determined by the Plan Administrator to be "performance-based compensation" under Code section 409A, the election shall become irrevocable on June 30 of the year in which said Section 2(a) notice was received), subject to the provisions Section 5(d). If an election is not properly made and timely received, the Potential Participant will be deemed to have elected to receive and not to defer any such Incentive Compensation Plan Award.

(b) Salary Reduction. If a Potential Participant elects to voluntarily reduce Salary to which a notice received under Section 2(b) pertains and receive an Award hereunder in lieu thereof, the Potential Participant must make an election, using the Election Form or in such other manner prescribed by the Plan Administrator, which must be received on or before December 31 (or such earlier time as may be prescribed by the Plan Administrator) prior to the beginning of the calendar year of the elected deferral. Such election must be in writing signed by the Potential Participant, and must state the amount of the salary reduction the Potential Participant elects. Such election becomes irrevocable on December 31 prior to the beginning of the calendar year, subject to the provisions Section 5(d). If an election is not properly made and timely received, the Potential Participant will be deemed to have elected to receive and not to defer any such Salary.

SECTION 4. Deferred Compensation Accounts.

(a) Credit for Deferral. Amounts deferred pursuant to Section 3(a) will be credited to a Deferred Compensation Account for the Participant for the calendar year in which the amounts are deferred as soon as practicable, but not less than 30 days after the Settlement Date of the Incentive Compensation Plan.

If an Award in the form of Restricted Stock or Restricted Stock Units provides that, in certain instances the Restricted Stock or Restricted Stock Units shall be cancelled and a market value in lieu thereof be credited to a Deferred Compensation Account for the Participant, then the market value shall be credited to a Deferred Compensation Account for the Participant as of the day that the Award in the form of Restricted Stock or Restricted Stock Units is cancelled. The market value of the underlying Restricted Stock or the shares represented by the Restricted Stock Units awarded under a Long Term Incentive Plan, under an Incentive Compensation Plan that began on or after January 1, 2003, under an Omnibus Securities Plan (with regard to awards made on or after January 1, 2003), and for the Special Stock Awards issued on

October 22, 2002, shall be the monthly average Fair Market Value of the Stock during the calendar month preceding the month in which the restrictions lapse or shares are to be delivered as applicable. The monthly average Fair Market Value of the Stock is the average of the daily Fair Market Value of the Stock for each trading day of the month. For Awards made prior to those times, the market value of the underlying Restricted Stock or the shares represented by the Restricted Stock Units, as applicable, shall be based on the higher of (i) the average of the high and low selling prices of the Stock on the date the restrictions lapse or the last trading day before the day the restrictions lapse if such date is not a trading day or (ii) the average of the high three monthly Fair Market Values of the Stock during the twelve calendar months preceding the month in which the restrictions lapse. The monthly Fair Market Value of the Stock is the average of the daily Fair Market Value of the Stock for each trading day of the month. The daily Fair Market Value of the Stock shall be deemed equal to the average of the high and low selling prices of the Stock on the New York Stock Exchange.

Amounts deferred pursuant to other provisions of this Plan shall be credited to a Deferred Compensation Account for the Participant for the calendar year in which such amounts are deferred as soon as practicable but not later than 30 days after the date the Award or Salary would otherwise be payable.

(b) Designation of Investments. The amount in each Deferred Compensation Account of a Participant shall be deemed to have been invested and reinvested from time to time, in such "eligible securities" as the Participant shall designate. Prior to or in the absence of a Participant's designation, the Company shall designate an "eligible security" in which the Participant's Deferred Compensation Account shall be deemed to have been invested until designation instructions are received from the Participant. Eligible securities are those securities designated by the Chief Financial Officer of the Company, or his successor. The Chief Financial Officer of the Company may include as eligible securities, stocks listed on a national securities exchange and bonds, notes, debentures, corporate or governmental, either listed on a national securities exchange

or for which price quotations are published in The Wall Street Journal and shares issued by investment companies commonly known as "mutual funds." The Deferred Compensation Accounts of a Participant will be adjusted to reflect the deemed gains, losses, and earnings as though the amount deferred was actually invested and reinvested in the eligible securities for each Deferred Compensation Account of the Participant.

Notwithstanding anything to the contrary in this section 4(b), in the event the Company (or any trust maintained for this purpose) actually purchases or sells such securities in the quantities and at the times the securities are deemed to be purchased or sold for a Deferred Compensation Account of a Participant, the Account shall be adjusted accordingly to reflect the price actually paid or received by the Company for such securities after adjustment for all transaction expenses incurred (including without limitation brokerage fees and stock transfer taxes).

In the case of any deemed purchase not actually made by the Company, the Deferred Compensation Account shall be charged with a dollar amount equal to the quantity and kind of securities deemed to have been purchased multiplied by the fair market value of such security on the date of reference and shall be credited with the quantity and kind of securities so deemed to have been purchased. In the case of any deemed sale not actually made by the Company, the account shall be charged with the quantity and kind of securities deemed to have been sold, and shall be credited with a dollar amount equal to the quantity and kind of securities deemed to have been sold multiplied by the fair market value of such security on the date of reference. As used in this paragraph "fair market value" means in the case of a listed security the closing price on the date of reference, or if there were no sales on such date, then the closing price on the nearest preceding day on which there were such sales, and in the case of an unlisted security the mean between the bid and asked prices on the date of reference, or if no such prices are available for such date, then the mean between the bid and asked prices to the nearest preceding day for which such prices are available.

The Plan Administrator may designate a third party to provide services that may include record keeping, Participant accounting, Participant communication, payment of installments to the Participant, tax reporting, and any other services specified in an agreement with such third party.

(c) Payments. A Participant's Deferred Compensation Account shall be debited with respect to payments made from the account pursuant to this Plan as of the date such payments are made from the account. The payment shall be made as soon as practicable, but no later than 2 ½ months after the end of the calendar year in which the payment date falls.

If any person to whom a payment is due hereunder is under legal disability as determined in the sole discretion of the Plan Administrator, the Plan Administrator shall have the power to cause the payment due such person to be made to such person's guardian or other legal representative for the person's benefit, and such payment shall constitute a full release and discharge of the Company, the Plan Administrator, and any fiduciary of the Plan.

(d) Statements. At least one time per year the Plan Administrator (or a third party acting for the Plan Administrator) will furnish each Participant a written statement setting forth the current balance in the Participant's Deferred Compensation Account, the amounts credited or debited to such account since the last statement and the payment schedule of deferred Awards, and deemed gains, losses, and earnings accrued thereon as provided by the deferred payment option selected by the Participant. This provision shall be deemed satisfied if the Plan Administrator (or a third party acting for the Plan Administrator) makes such information available through electronic means, such as a web site, and informing affected Participants of the availability of the information and the manner of accessing it.

SECTION 5. Payments from Deferred Compensation Accounts.

(a) Election of Method of Payment. At the time a Potential Participant submits an election to defer all or any part of an Award under an Incentive Compensation Plan as provided in Section 3(a) above or to reduce any part of salary as provided in Section 3(b) above, the Potential Participant shall also elect, using the Election Form or in such other manner prescribed by the Plan Administrator, which of the payment options, provided for in Paragraph (b) of this Section, shall apply to the deferred portion of said Award or salary adjusted for any deemed gains, losses, and earnings accrued thereon credited to the Participant's Deferred Compensation Account under this Plan. Subject to Paragraph (d) of this Section, the election of the method of payment of the amount deferred shall become irrevocable on December 31 of the year in which the applicable Section 2(a) or (b) notice was received (except in the case of an election for an Award under an Incentive Compensation Plan determined by the Plan Administrator to be "performance-based compensation" under Code section 409A, the election shall become irrevocable on June 30 of the year in which said Section 2(a) or (b) notice was received). If an election does not properly indicate a time and method of payment, the Potential Participant will be deemed to have elected to receive such payment in a single lump sum at the earlier of death or six months after Separation from Service other than by death.

(b) Payment Options. A Potential Participant may elect, using an Election Form or in such other manner prescribed by the Plan Administrator, to have the deferred portion of an Incentive Compensation Plan Award or salary adjusted for any deemed gains, losses, and earnings accrued thereon paid:

(i) *(After Separation from Service)* in 1 to 15 annual installments, in 2 to 30 semi-annual installments, or in 4 to 60 quarterly installments, the payment of the first of any of such installments to commence on the first day of the first calendar quarter which is on or after six months from the Participant's Separation from Service, subject to Paragraph (d) of this Section, or

(ii) *(Date Certain)* with regard only to the deferred portion of an Incentive

Compensation Award, in 1 to 15 annual installments, in 2 to 30 semi-annual installments, or in 4 to 60 quarterly installments, the payment of the first of any of such installments to commence on the first day of calendar quarter which is designated by the Participant, is at least one year after the date on which the election is made, and is not later than the 65th birthday of the Participant, subject to Paragraph (d) of this Section.

(iii) In the event that no election is properly and timely made with regard to the time and method of payment under Section 5(b)(i), payment shall be made on the earlier of the death or the date which is the first of the calendar quarter following six months after the date of Separation from Service, whether by retirement, disability, or otherwise (other than by death), of the Participant, subject to Paragraph (d) of this Section.

(c) Method of Payment of the Value of Restricted Stock and Restricted Stock Units. If an Award in the form of Restricted Stock or Restricted Stock Units provides that, in certain instances the Restricted Stock or Restricted Stock Units shall be cancelled and a market value in lieu thereof be credited to a Deferred Compensation Account for the Participant, payment of such Deferred Compensation Account shall be made on the earlier of the death or the date which is the first of the calendar quarter following six months after the date of Separation from Service, whether by retirement, disability, or otherwise (than death), of the Participant, subject to Paragraphs (d) of this Section.

(d) Change in Time or Form of Payment. A Participant may make an election to change the time or form of payment elected or set under Section 5 (including this Paragraph (d)), but only if the following rules are satisfied:

(1) The election to change the time or form of payment may not take effect until at least twelve months after the date on which such election is made;

(2) Payment under such election may not be made earlier than at least five years from the date the payment would have otherwise been made or commenced;

(3) Such payment may commence as of the beginning of any calendar quarter;

(4) An election to receive payments in installments shall be treated as a single payment for purposes of these rules;

(5) The election may not result in an impermissible acceleration of payment prohibited under Code section 409A;

(6) No more than four such elections shall be permitted with respect to each Deferred Compensation Account of a Participant; and

(7) No payment may be made after the date that is twenty (20) years after the date of the Participant's Separation from Service.

(e) Effect of Taxation. If a portion of a Participant's Benefit (and earnings, gains, and losses thereon) is includible in income under Code section 409A, such portion shall be distributed immediately to the Participant.

(f) Installment Amount. The amount of each installment shall be determined by dividing the balance in the Participant's Deferred Compensation Account as of the date the installment is to be paid, by the number of installments remaining to be paid (inclusive of the current installment).

(g) Death of Participant. Upon the death of a Participant, the Participant's beneficiary or beneficiaries designated in accordance with Section 8, or in the absence of an effective beneficiary designation, the surviving spouse, surviving children (natural or adopted) in equal shares, or the Estate of the deceased Participant, in that order of priority, shall receive payments in accordance with the payment option selected by the Participant or, if no payment option was properly and timely selected by the Participant with regard to a Deferred Compensation Account, upon the death of the Participant.

SECTION 6. Special Provisions for Former ARCO Alaska Employees.

Notwithstanding any provisions to the contrary, in order to comply with the terms of the

Master Purchase and Sale Agreement ("Sale Agreement") by which the Company acquired certain Alaskan assets of Atlantic Richfield Company ("ARCO"), a Participant who was eligible to participate in the ARCO employee benefit plans immediately prior to becoming an Employee and who was not employed by ARCO Marine, Inc. (a "former ARCO Alaska employee") and who was classified as a grade 7 or 8 under ARCO's job classification system and was eligible under ARCO's Executive Deferral Plan to voluntarily reduce salary and defer the amount of the voluntary salary reduction and who was classified as a grade 31 or below at that time under Phillips Petroleum Company's job classification system may, in a manner prescribed by the Plan Administrator, make an election to voluntarily reduce salary and defer the amount of the voluntary salary reduction for salary received for 2005 and receive a salary deferral credit under this Plan; provided, that all of the Plan provisions (other than eligibility to participate) shall apply to such an election.

SECTION 7. Schedule A Employees.

Notwithstanding any earlier election or indication of preference to participate in voluntary salary reductions to be deferred into the Plan in 2005 or deferrals into the Plan in 2005 of Awards under an Incentive Compensation Plan, Schedule A Employees shall have their participation in the Plan for 2005 revoked as to the salary reductions or Incentive Compensation Plan Award or both, as indicated on Schedule A to this Plan. Any such deferrals made in 2005 for such Schedule A Employees shall be returned to them (together with any earnings, gains, or losses thereon) on or before December 31, 2005.

SECTION 8. Designation of Beneficiary.

Each Participant shall designate a beneficiary or beneficiaries to receive the entire balance of the Participant's Deferred Compensation Account by giving signed written notice of such designation to the Plan Administrator. The Participant may from time to time change or cancel any previous beneficiary designation in the same manner. The last beneficiary designation received by the Plan Administrator shall be controlling over any prior designation and over any testamentary or other disposition. After acceptance by the Plan

Administrator of such written designation, it shall take effect as of the date on which it was signed by the Participant, whether the Participant is living at the time of such receipt, but without prejudice to the Company or any member of the Affiliated Group or the Plan Administrator or their respective employees and agents on account of any payment made under this Plan before receipt of such designation.

SECTION 9. Nonassignability.

The right of a Participant, or beneficiary, or other person who becomes entitled to receive payments under this Plan, shall not be assignable or subject to garnishment, attachment, or any other legal process by the creditors of, or other claimants against, the Participant, beneficiary, or other such person.

SECTION 10. Administration.

(a) The Plan shall be administered by the Plan Administrator. The Plan Administrator may delegate to employees of the Company or any Affiliated Company the authority to execute and deliver such instruments and documents, to do all such acts and things, and to take such other steps deemed necessary, advisable, or convenient for the effective administration of the Plan in accordance with its terms and purpose, except that the Plan Administrator may not delegate any discretionary authority with respect to substantive decisions or functions regarding the Plan or Benefits hereunder. The Plan Administrator may adopt such rules, regulations, and forms as deemed desirable for administration of the Plan and shall have the discretionary authority to allocate responsibilities under the Plan to such other persons as may be designated.

(b) Any claim for benefits hereunder shall be presented in writing to the Plan Administrator for consideration, grant, or denial. Claimants will be notified in writing of approved claims, which will be processed as claimed. A claim is considered approved only if its approval is communicated in writing to a claimant.

(c) In the case of a denial of a claim respecting benefits paid or payable with respect to a Participant, a written notice will be furnished to the claimant within 90 days of the date on which the claim is received by the Plan Administrator. If special circumstances (such as for a hearing) require a longer period, the claimant will be notified in writing, prior to the expiration of the 90-day period, of the reasons for an extension of time; provided, however, that no extensions will be permitted beyond 90 days after the expiration of the initial 90-day period. A denial or partial denial of a claim will be dated and signed by the Plan Administrator and will clearly set forth:

(1) the specific reason or reasons for the denial;

(2) specific reference to pertinent Plan provisions on which the denial is based;

(3) a description of any additional material or information necessary for the claimant to perfect the claim and an explanation of why such material or information is necessary; and

(4) an explanation of the procedure for review of the denied or partially denied claim set forth below, including the claimant’s right to bring a civil action under ERISA section 502(a) following an adverse benefit determination on review.

(d) Upon denial of a claim, in whole or in part, a claimant or his duly authorized representative will have the right to submit a written request to the Trustee for a full and fair review of the denied claim by filing a written notice of appeal with the Trustee within 60 days of the receipt by the claimant of written notice of the denial of the claim. A claimant or the claimant’s authorized representative will have, upon request and free of charge, reasonable access to, and copies of, all documents, records, and other information relevant to the claimant’s claim for benefits and may submit issues and comments in writing. The review will take into account all comments, documents, records, and other information submitted by the claimant relating to the claim, without regard to whether such information was submitted or considered in the initial benefit determination. If the claimant fails to file a request for review within 60 days of the denial notification, the claim will be deemed abandoned and the claimant precluded

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from reasserting it. If the claimant does file a request for review, his request must include a description of the issues and evidence he deems relevant. Failure to raise issues or present evidence on review will preclude those issues or evidence from being presented in any subsequent proceeding or judicial review of the claim.

(e) The Trustee will provide a prompt written decision on review. If the claim is denied on review, the decision shall set forth:

(1) the specific reason or reasons for the adverse determination;

(2) specific reference to pertinent Plan provisions on which the adverse determination is based;

(3) a statement that the claimant is entitled to receive, upon request and free of charge, reasonable access to, and copies of, all documents, records, and other information relevant to the claimant’s claim for benefits; and

(4) a statement describing any voluntary appeal procedures offered by the Plan and the claimant’s right to obtain the information about such procedures, as well as a statement of the claimant’s right to bring an action under ERISA section 502(a).

(f) A decision will be rendered no more than 60 days after the Trustee’s receipt of the request for review, except that such period may be extended for an additional 60 days if the Trustee determines that special circumstances (such as for a hearing) require such extension. If an extension of time is required, written notice of the extension will be furnished to the claimant before the end of the initial 60-day period.

(g) To the extent permitted by law, decisions reached under the claims procedures set forth in this Section shall be final and binding on all parties. No legal action for benefits under the Plan shall be brought unless and until the claimant has exhausted his remedies under this Section. In any such legal action, the claimant may only present evidence and theories which the claimant presented during the claims procedure. Any claims which the claimant does not in good faith pursue through the review stage of the procedure shall be treated as having been irrevocably waived. Judicial review of a claimant's denied claim shall be limited to a determination of whether the denial was an abuse of discretion based on the evidence and theories the claimant presented during the claims procedure.

SECTION 11. Employment not Affected by Plan.

Participation or nonparticipation in this Plan shall neither adversely affect any person's employment status nor confer any special rights on any person other than those expressly stated in the Plan. Participation in the Plan by an Employee of the Company or of a Participating Subsidiary shall not affect the Company's or the Participating Subsidiary's right to terminate the Employee's employment or to change the Employee's compensation or position.

SECTION 12. Determination of Recipients of Awards.

The determination of those persons who are entitled to Awards under an Incentive Compensation Plan and any other such plans shall be governed solely by the terms and provisions of the applicable plan or program, and the selection of an Employee as a Potential Participant or the acceptance of an indication of preference to defer an Award hereunder shall not in any way entitle such Potential Participant to an Award.

SECTION 13. Method of Providing Payments.

(a) Nonsegregation. Amounts deferred pursuant to this Plan and the crediting of amounts to a Participant's Deferred Compensation Account shall represent the Company's unfunded and unsecured promise to pay compensation in the future. With respect to said amounts, the relationship of the Company and a Participant shall be that of debtor and general unsecured creditor. While the Company may make investments for the purpose of measuring and meeting its obligations under this Plan such investments shall remain the sole property of the Company subject to claims of its creditors

generally, and shall not be deemed to form or be included in any part of the Deferred Compensation Account.

(b) Funding. It is the intention of the Company that this Plan shall be unfunded for federal tax purposes and for purposes of Title I of ERISA; provided, however, that the Company may establish a grantor trust to satisfy part or all of its Plan payment obligations so long as the Plan remains unfunded for federal tax purposes and for purposes of Title I of ERISA.

SECTION 14. Amendment or Termination of Plan.

The Company reserves the right to amend this Plan from time to time or to terminate the Plan entirely, provided, however, that no amendment may affect the balance in a Participant's account on the effective date of the amendment.

SECTION 15. Miscellaneous Provisions.

(a) Except as otherwise provided herein, the Plan shall be binding upon the Company, its successors and assigns, including but not limited to any corporation which may acquire all or substantially all of the Company's assets and business or with or into which the Company may be consolidated or merged.

(b) This Plan shall be construed, regulated, and administered in accordance with the laws of the State of Texas except to the extent that said laws have been preempted by the laws of the United States.

SECTION 16. Effective Date of the Restated Plan.

This Plan is amended and restated effective as of January 1, 2005.

Executed this 29th day of December 2005, effective as of January 1, 2005, with respect to benefits earned and vested prior to January 1, 2005.

/s/ Carin S. Knickel

Carin S. Knickel
Vice President, Human Resources

Exhibit 10.25

ORIGINAL FOR EXECUTION
APPROVED VICE PRESIDENT HUMAN RESOURCES
EFFECTIVE JANUARY 1, 2005

CONOCOPHILLIPS
EXECUTIVE SEVERANCE PLAN

(Amended and Restated Effective as of January 1, 2005)

Effective October 1, 2004, the Company adopted this the ConocoPhillips Executive Severance Plan (the "Plan") for the benefit of certain employees of the Company and its subsidiaries. This amendment and restatement of the Plan shall be effective January 1, 2005. Any Eligible Employee (as defined below) having a Severance Date (as defined below) prior to January 1, 2005, shall have benefits under this Plan determined in accordance with the provisions of this Plan as they existed prior to this amendment and restatement. Any Eligible Employee (as defined below) having a Severance Date (as defined below) on or after January 1, 2005, shall have benefits under this Plan determined in accordance with the provisions of this Plan pursuant to this amendment and restatement. All capitalized terms used herein are defined in Section 1 hereof. This Plan is intended to be a plan maintained primarily for the purpose of providing deferred compensation for a select group of management or highly compensated employees, within the meaning of Title I of the Employee Retirement Income Security Act of 1974, as amended and shall be interpreted in a manner consistent with such intention.

SECTION 1. DEFINITIONS. As hereinafter used:

1.1 "Board" means the Board of Directors of the Company.

1.2 "Cause" means (i) the willful and continued failure by the Eligible Employee to substantially perform the Eligible Employee's duties with the Employer (other than any such failure resulting from the Eligible Employee's incapacity due to physical or mental illness), or (ii) the willful engaging, not in good faith, by the Eligible Employee in conduct which is demonstrably injurious to the Company or any of its subsidiaries, monetarily or otherwise.

1.3 "Code" means the Internal Revenue Code of 1986, as it may be amended from time to time.

1.4 "Company" means ConocoPhillips or any successors thereto.

1.5 "Credited Compensation" of a Severed Employee means the aggregate of the Severed Employee's annual base salary plus his or her annual incentive compensation, each as further described below. For purposes of this definition, (a) annual base salary shall be determined immediately prior to the Severance Date and (b) annual incentive compensation shall be deemed to equal the Severed Employee's most recently established target (determined at one hundred percent of target) for annual incentive compensation for such employee prior to such employee's Severance Date

pursuant to the Variable Cash Incentive Program or its successor program maintained by the Employer.

1.6 "Effective Date" means, as applicable, the date first stated above as the original effective date of this Plan or the effective date of this Plan as amended and restated.

1.7 "Eligible Employee" means any employee that is a Tier 1 Employee or a Tier 2 Employee, other than those employees who are listed on Exhibit B.

1.8 "Employer" means the Company or any of its subsidiaries.

1.9 "Person" means any individual, firm, corporation, partnership, association, trust, unincorporated organization, or other entity.

1.10 "Plan" means the ConocoPhillips Executive Severance Plan, as set forth herein, as it may be amended from time to time.

1.11 "Plan Administrator" means the person or persons appointed from time to time by the Board, which appointment may be revoked at any time by the Board.

1.12 "Retirement Plans" means the ConocoPhillips Retirement Plan and the ConocoPhillips Key Employee Supplemental Retirement Plan.

1.13 "Severance" means the termination of an Eligible Employee's employment with the Employer by the Employer other than for Cause. An Eligible Employee will not be considered to have incurred a Severance if his employment is discontinued by reason of the Eligible Employee's death or a physical or mental condition causing such Eligible Employee's inability to substantially perform his duties with the Employer and entitling him or her to benefits under any long-term sick pay or disability income policy or program of the Employer. Furthermore, an Eligible Employee will not be considered to have incurred a Severance if employment with the Employer is discontinued after the Eligible Employee has been offered employment with another employer that has purchased a subsidiary or division of the Company or all or substantially all of the assets of an a subsidiary or division of the Company and the offer of employment from the other employer is at the same or greater salary and the same or greater target bonus as the Eligible Employee has at that time from the Employer. Still further, an Eligible Employee will not be considered to have incurred a Severance if employment with the Employer is discontinued and the Eligible Employee is also eligible for payments under the ConocoPhillips Key Employee Change in Control Severance Plan, effective October 1, 2004, or as subsequently amended, or under the Conoco Inc. Key Employee Severance Plan, as amended and restated effective October 1, 2001, and as subsequently amended.

1.14 "Severance Date" means the date on which an Eligible Employee incurs a Severance.

1.15 "Severance Pay" means the payment determined pursuant to Section 2.1 hereof.

1.16 "Severed Employee" means an Eligible Employee who has incurred a Severance.

1.17 "Tier 1 Employee" means any employee of the Employer who is in salary grade 26 or above (under the salary grade schedule of the Company on the Effective Date, with appropriate adjustment for any subsequent change in such salary grade schedule) on the Severance Date.

1.18 "Tier 2 Employee" means any employee of the Employer, other than a Tier 1 Employee, who is in salary grade 23 or above (under the salary grade schedule of the Company on the Effective Date, with appropriate adjustment for any subsequent change in such salary grade schedule) on the Severance Date.

SECTION 2. BENEFITS.

2.1 Subject to Section 2.7, each Severed Employee shall be entitled to receive Severance Pay equal to the sum of the amounts determined under Sections 2.1(a), (b), and (c). Furthermore, for purposes of Employer compensation plans, programs, and arrangements, each Severed Employee shall be considered to have been laid off by the Employer.

(a) The amount that is the Severed Employee's Credited Compensation, multiplied by (i) 2, in the case of a Tier 1 Employee or (ii) 1.5 in the case of a Tier 2 Employee.

(b) The amount that is the present value, determined as of the Severed Employee's Severance Date, of the increase in benefits under the Retirement Plans that would result if the Severed Employee was credited with the following number of additional years of age and service under the Retirement Plans: (i) 2, in the case of a Tier 1 Employee or (ii) 1.5, in the case of a Tier 2 Employee. Present value shall be determined based on the assumptions utilized under the ConocoPhillips Retirement Plan for purposes of determining contributions under Code Section 412 for the most recently completed plan year.

(c) The amount that is equal to either (i) or (ii), as applicable, plus either (iii) or (iv), as applicable, plus (v), if applicable, plus (vi), if applicable:

(i) If the Severed Employee was enrolled in company-sponsored medical coverage on the Severance Date, an amount equal to 6 times the difference between the COBRA participant contribution rate and the active employee contribution rate, each as of the Severance Date, for the type of coverage in which the Tier 2 Employee was enrolled.

(ii) If the Severed Employee was not enrolled in company-sponsored medical coverage on the Severance Date, an amount equal to 18 times the difference between the COBRA participant contribution rate and the active employee contribution rate, each as of the Severance Date, for PPO medical coverage.

(iii) If the Severed Employee was enrolled in company-sponsored dental coverage on the Severance Date, an amount equal to 6 times the difference between the COBRA participant contribution rate and the active employee contribution rate, each as of the Severance Date, for the type of coverage in which the Tier 2 Employee was enrolled.

(iv) If the Severed Employee was not enrolled in company-sponsored dental coverage on the Severance Date, an amount equal to 18 times the difference

between the COBRA participant contribution rate and the active employee contribution rate, each as of the Severance Date, for dental coverage (using the CP dental option coverage).

(v) In the case of a Tier 1 Employee, an amount equal to the sum of 6 times the COBRA participant contribution rate, as of the Severance Date, for PPO medical coverage plus 6 times the COBRA participant contribution rate, as of the Severance Date, for dental coverage (using the CP dental option coverage).

(vi) If any persons qualified as eligible dependents of the Severed Employee under the applicable company-sponsored medical or dental coverage in which the Severed Employee was enrolled on the Severance Date, an amount equal to the sum of the differences, for each such eligible dependent, between the COBRA eligible dependent contribution rate and the eligible dependent contribution rate for eligible dependents of active employees, each as of the Severance Date, for the medical and/or dental coverage in which the Severed Employee was enrolled on the Severance Date, as applicable, times the factor set forth in the applicable Section 2.1(c)(i) or (ii), (c)(iii) or (iv), and (c)(v); provided, that if the Severed Employee was not enrolled for medical or dental coverage, then the eligibility and amount for each dependent shall be determined as if the Severed Employee had been enrolled in the PPO medical coverage or dental coverage (using the CP dental option coverage), as applicable, on the Severance Date.

2.2 Subject to Section 2.7, Severance Pay (as well as any amount payable pursuant to Section 2.4 hereof) shall be paid to an eligible Severed Employee in a lump sum as soon a practicable after the Severance Date.

2.3 Subject to Section 2.7, for a period of (a) 24 months, in the case of a Tier 1 Employee or (b) 18 months, in the case of a Tier 2 Employee, beginning the first of the month following the termination of active employee benefits, the Company shall arrange to provide the Severed Employee and his eligible dependents certain benefits, as enumerated below, similar to those the Severed Employee and his eligible dependents had immediately prior to the Severed Employee's Severance Date. These benefits will be provided at no greater cost to the Severed Employee than active employee rates for the plan year of coverage provided the benefits continue to be offered by the Company to active employees and the Severed Employee and his eligible dependents meet the same eligibility criteria for the benefits as an active employee and dependents of an active employee. Depending on coverages prior to the Severed Employee's Severance Date, these benefits could include the following, but do not include any other benefits offered by the Company: Life Insurance, which includes Basic, Executive Basic, Supplemental, and Dependent Life; and Personal Accident Insurance. Severed employees may also continue Long Term

Care and Executive Life directly through the vendor to be paid for by the Severed Employee. Nothing herein shall prevent a Severed Employee or eligible dependents of a Severed Employee from electing to receive COBRA continuation coverage of health benefits subject to COBRA, in accordance with the applicable provisions of the law and the applicable plans. While as an active

employee the Severed Employee may have been able to make employee contributions or pay premiums for certain coverage through a pre-tax salary reduction arrangement, that will not continue after the Severed Employee's Severance Date. The cost of these benefits will not be adjusted to reflect that the Severed Employee's cost will no longer be pre-tax. All other active employee benefits, not specifically mentioned above, are excluded, although if any of the benefits specifically mentioned above are replaced with a similar benefit after the Severed Employee's Severance Date, such replacement benefits are to be considered as mentioned specifically above even though their names, terms, and conditions may have been changed. Such benefits shall not be provided (except to the extent as may be required by law) during any period when the Severed Employee is eligible to receive such benefits from another employer or from an Employer or if the Severed Employee has resumed working for an Employer. The Severed Employee is obligated to inform the Company when or if they become eligible to receive such benefits from another employer.

2.4 Each Severed Employee shall be entitled to receive the employee's full salary through the Severance Date and, subject to Section 2.7 but notwithstanding any provision of the Company's Variable Cash Incentive Program or similar annual bonus incentive plan to the contrary, a cash lump sum amount equal to a pro rata portion to the Severance Date of the aggregate value of the annual incentive compensation award to such Severed Employee for the then uncompleted fiscal year under such plan, such aggregate value being deemed to equal the Severed Employee's most recently established target (determined at one hundred percent of target) for annual incentive compensation for such employee prior to such employee's Severance Date pursuant to the Variable Cash Incentive Program (or similar annual bonus incentive plan) or its successor program maintained by the Employer.

2.5 Each party to any dispute concerning this Plan shall be responsible for that party's own legal fees and expenses; provided, however, that the arbitrator appointed pursuant to Section 3.2 of this Plan may award reasonable legal fees and expenses to an Eligible Employee if the arbitrator determines that the Company's denial of the claim of the Eligible Employee was not reasonable.

2.6 The Company shall be entitled to withhold and/or to cause to be withheld from amounts to be paid to the Severed Employee hereunder any federal, state, or local withholding or other taxes or charges which it is from time to time required to withhold.

2.7 No Severed Employee shall be eligible to receive Severance Pay or other benefits under the Plan unless he or she first executes a written release substantially in the form attached as Exhibit A hereto (or, if the Severed Employee was not a United States employee, a similar release which is in accordance with the applicable laws in the relevant jurisdiction) and, to the extent such release is revocable by its terms, only if the Severed Employee does not revoke it, and unless he or she also, at the request of the Company, executes a written agreement not to compete with the Company, with such terms and conditions as may be proposed by the Company at the time.

SECTION 3. PLAN ADMINISTRATION.

3.1 The Plan Administrator shall administer the Plan and may interpret the Plan, prescribe, amend, and rescind rules and regulations under the Plan and make all other determinations necessary or advisable for the administration of the Plan, subject to the provisions of the Plan. The Plan Administrator shall have absolute discretion and authority in carrying out its responsibilities, and all interpretations of the Plan, determinations of eligibility under the Plan, determinations to grant or deny benefits under the Plan, or findings of fact or resolutions related to the Plan and its administration that are made by the Plan Administrator shall be binding, final, and conclusive on all parties.

3.2 In the event of a claim by an Eligible Employee as to the amount or timing of any payment or benefit, such Eligible Employee shall present the reason for his or her claim in writing to the Plan Administrator. The Plan Administrator shall, within 14 days after receipt of such written claim, send a written notification to the Eligible Employee as to its disposition. Except as provided in the preceding portion of this Section 3.2, all disputes under this Plan shall be settled exclusively by binding arbitration in Houston, Texas, in accordance with the rules of the American Arbitration Association then in effect. Judgment may be entered on the arbitrator's award in any court having jurisdiction.

3.3 The Plan Administrator may delegate any of its duties hereunder to such person or persons from time to time as it may designate.

3.4 The Plan Administrator is empowered, on behalf of the Plan, to engage accountants, legal counsel, and such other personnel as it deems necessary or advisable to assist it in the performance of its duties under the Plan. The functions of any such persons engaged by the Plan Administrator shall be limited to the specified services and duties for which they are engaged, and such persons shall have no other duties, obligations or responsibilities under the Plan. Such persons shall exercise no discretionary authority or discretionary control respecting the management of the Plan. All reasonable expenses thereof shall be borne by the Employer.

SECTION 4. DURATION; AMENDMENT; AND TERMINATION.

4.1 This Plan shall be effective on the Effective Date. This Plan shall continue in effect unless and until it is terminated as provided in Section 4.2.

4.2 This Plan may be amended from time to time during its term by the Company acting through its Board of Directors or, to the extent authorized by the Board of Directors, its officers. The Company may, by action of its Board of Directors, terminate this Plan at any time.

SECTION 5. GENERAL PROVISIONS.

5.1 Except as otherwise provided herein or by law, no right or interest of any Eligible Employee under the Plan shall be assignable or transferable, in whole or in part, either directly or by operation of law or otherwise, including without limitation by execution, levy, garnishment, attachment, pledge, or in any manner; no attempted assignment or transfer thereof shall be effective; and no right or interest of any Eligible Employee under the Plan shall be liable for, or subject to, any obligation or liability of such Eligible Employee. When a payment is due under this Plan to a Severed Employee who is unable to care for his or her affairs, payment may be made directly to his or her legal guardian or personal representative.

5.2 If any Employer is obligated by law or by contract to pay severance pay, a termination indemnity, notice pay, or the like, to a Severed Employee, or if any Employer is obligated by law to provide advance notice of separation ("Notice Period") to a Severed Employee, then any Severance Pay hereunder to such Severed Employee shall be reduced by the amount of any such severance pay, termination indemnity, notice pay, or the like, as applicable, and by the amount of any compensation received during any Notice Period. This provision specifically includes any payments or obligations under the ConocoPhillips Severance Pay Plan, as effective March 13, 2004, and as subsequently amended. Furthermore, if an Eligible Employee has willful and bad faith conduct demonstrably injurious to Company or its subsidiaries, monetarily or otherwise, after receiving Severance Pay, the Company may offset an amount equal to such Severance Pay against any other amounts due from other plans or programs, unless otherwise required by law.

5.3 Neither the establishment of the Plan, nor any modification thereof, nor the creation of any fund, trust, or account, nor the payment of any benefits shall be construed as giving any Eligible Employee, or any person whomsoever, the right to be retained in the service of the Employer, and all Eligible Employees shall remain subject to discharge to the same extent as if the Plan had never been adopted.

5.4 If any provision of this Plan shall be held invalid or unenforceable, such invalidity or unenforceability shall not affect any other provisions hereof, and this Plan shall be construed and enforced as if such provisions had not been included.

5.5 This Plan shall be binding upon the heirs, executors, administrators, successors, and assigns of the parties, including each Eligible Employee, present and future, and any successor to the Employer.

5.6 The headings and captions herein are provided for reference and convenience only, shall not be considered part of the Plan, and shall not be employed in the construction of the Plan.

5.7 The Plan shall not be funded. No Eligible Employee shall have any right to, or interest in, any assets of any Employer that may be applied by the Employer to the payment of benefits or other rights under this Plan.

5.8 Any notice or other communication required or permitted pursuant to the terms hereof shall have been duly given when delivered or mailed by United States Mail, first-class, postage prepaid, addressed to the intended recipient at his, her or its last known address.

5.9 This Plan shall be construed and enforced according to the laws of the State of Delaware.

CONOCOPHILLIPS

By: /s/ Carin S. Knickel Dated: December 20, 2005
Carin S. Knickel
Vice President, Human Resources

Exhibit A

WAIVER AND RELEASE OF CLAIMS

In consideration of, and subject to, the payments to be made to me by ConocoPhillips, a Delaware corporation (the "Company") or any of its subsidiaries, pursuant to the ConocoPhillips Executive Severance Plan (the "Plan"), which I acknowledge that I would not otherwise be entitled to receive, I hereby waive any claims I may have for employment or re-employment by the Company or any subsidiary or parent of the Company after the date hereof, and I further agree to and do release and forever discharge the Company or any subsidiary or parent of the Company, and their respective past and present officers, directors, shareholders, employees, and agents from any and all claims and causes of action, known or unknown, arising out of or relating to my employment with the Company or any subsidiary or parent of the Company, or the termination thereof, including, but not limited to, wrongful discharge, breach of contract, tort, fraud, the Civil Rights Acts, Age Discrimination in Employment Act, Employee Retirement Income Security Act, Americans with Disabilities Act, or any other federal, state, or local legislation or common law relating to employment or discrimination in employment or otherwise.

Notwithstanding the foregoing or any other provision hereof, nothing in this Waiver and Release of Claims shall adversely affect (i) my rights under the Plan; (ii) my rights to benefits other than severance benefits under plans, programs, and arrangements of the Company or any subsidiary or parent of the Company which are accrued but unpaid as of the date of my termination; or (iii) my rights to indemnification under any indemnification agreement, applicable law and the certificates of incorporation and bylaws of the Company and any subsidiary or parent of the Company, and my rights under any director's and officers' liability insurance policy covering me.

I acknowledge that I have signed this Waiver and Release of Claims voluntarily, knowingly, of my own free will and without reservation or duress and that no promises or representations have been made to me by any person to induce me to do so other than the promise of payment set forth in the first paragraph above and the Company's acknowledgement of my rights reserved under the second paragraph above.

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

		Millions of Dollars				
		Years Ended December 31				
		2005	2004	2003	2002	2001
				(Unaudited)		
Earnings Available for Fixed Charges						
Income from continuing operations before income taxes	**$**	**23,547**	14,369	8,337	2,141	3,241
Distributions less than equity in earnings of fifty-percent-or-less-owned companies		**(1,785)**	(780)	(52)	3	58
Fixed charges, excluding capitalized interest*		**747**	758	1,019	850	501
	$	**22,509**	14,347	9,304	2,994	3,800
Fixed Charges						
Interest and expense on indebtedness, excluding capitalized interest	**$**	**497**	546	844	566	338
Capitalized interest		**395**	430	327	232	231
Preferred dividend requirements of subsidiary and capital trusts		**—**	—	—	38	53
Interest portion of rental expense		**188**	174	149	181	90
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	—
	$	**1,080**	1,159	1,321	1,036	712
Ratio of Earnings to Fixed Charges		**20.8**	12.4	7.0	2.9	5.3

**Includes amortization of capitalized interest totaling approximately $62 million in 2005, $29 million in 2004, $25 million in 2003, $46 million in 2002, and $20 million in 2001.*

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.

SUBSIDIARY LISTING OF CONOCOPHILLIPS

Company Name	Incorporation Location
Alpine Pipeline Company	Delaware
Arizona-Florida Land & Cattle Company	Florida
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
Beacon Port LLC	Delaware
Brandywine Industrial Gas Inc.	Delaware
Brazoria Interconnector Gas Pipeline LLC	Delaware
BVLC, Inc.	California
C.S. Land, Inc.	California
Calcasieu Properties L.L.C.	Delaware
Cello Acquisition Corp.	Delaware
CGP Servicios Energeticos de Altamira, S. de R. L. de C. V.	Mexico
Clearwater Ltd.	Bermuda
Cliffe Storage Limited	England
Clyde Petroleum (Management) Limited	England
Clyde Petroleum Limited	Scotland
COMAP, Inc.	Delaware
Compass Pass Pipeline LLC	Delaware
Compass Port LLC	Delaware
Conoco (Thailand) Company, Limited	Thailand
Conoco A.G.	Switzerland
Conoco Arabia Holding Ltd.	British Virgin Islands
Conoco Asia Ltd.	Bermuda
Conoco Asia Pacific Ltd.	Delaware
Conoco Asia Pacific Sdn. Bhd.	Malaysia
Conoco Carbon Fibers Japan, K.K.	Japan
Conoco Central Europe Inc.	Delaware
Conoco Colombia Ltd.	Bermuda
Conoco Coral Inc.	Delaware
Conoco Deepwater Construction LLC	Delaware
Conoco Denmark Inc.	Delaware
Conoco Development Services Inc.	Delaware
Conoco do Brasil Ltda.	Brazil
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 Exploration & Production B.V.	The Netherlands

Company Name	Incorporation Location
Conoco Exploration & Production Nigeria Limited	Nigeria
Conoco Foreign Sales Corporation	Barbados
Conoco Frontier Ltd.	Bermuda
Conoco Funding Company	Nova Scotia
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 Holdings Ltd.	Bermuda
Conoco Investment AG	Switzerland
Conoco Jet (Malaysia) Sdn. Bhd.	Malaysia
Conoco Khazar Ltd.	Bermuda
Conoco Lagia Offshore, Inc.	Delaware
Conoco Libya Ltd.	Bermuda
Conoco Limited	England
Conoco Lubricant (India) Private Limited	India
Conoco Lubricants (Malaysia) Sdn. Bhd.	Malaysia

Conoco Mexico Ltd.	Bermuda
Conoco Middle East Gas Co. N.V.	Netherlands Antilles
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 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
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 Holding Ltd.	British Virgin Islands
Conoco South Sokang Ltd.	Bermuda
Conoco South Sokang Natuna B.V.	The Netherlands
Conoco Specialty Products Limited	England
Conoco Syria DEZ Gas Ltd.	Bermuda

Company Name	Incorporation Location
Conoco Syria Ltd.	Bermuda
Conoco Taiwan Exploration and Production B.V.	The Netherlands
Conoco Tobong Holding Ltd.	British Virgin Islands
Conoco Tobong Natuna B.V.	The Netherlands
Conoco Trinidad Inc.	Delaware
Conoco U.K. Properties Inc.	Delaware
Conoco Venezuela C.A.	Venezuela
Conoco Venezuela Holding C.A.	Venezuela
Conoco Venezuela Ltd.	Bermuda
Conoco Warim B.V.	The Netherlands
ConocoPhillips (03-12) Pty. Ltd.	Victoria, Australia
ConocoPhillips (03-13) Pty. Ltd.	Western Australia
ConocoPhillips (03-16) Pty. Ltd.	Western Australia
ConocoPhillips (03-19) Pty. Ltd.	Victoria, Australia
ConocoPhillips (03-20) Pty. Ltd.	Western Australia
ConocoPhillips (03-21) Pty. Ltd.	Western Australia
ConocoPhillips (Aceh) Ltd.	Bermuda
ConocoPhillips (AIB) Ltd.	Bermuda
ConocoPhillips (Amborip VI) Ltd.	Cayman Islands
ConocoPhillips (Banyumas) Ltd.	Bermuda
ConocoPhillips (BTC) Ltd.	Cayman Islands
ConocoPhillips (East Malaysia) Ltd.	Bermuda
ConocoPhillips (GIB) Ltd.	Bermuda
ConocoPhillips (Glen) Limited	England
ConocoPhillips (Grissik) Ltd.	Bermuda
ConocoPhillips (Ketapang) Ltd.	Bermuda
ConocoPhillips (Pangkah) Ltd.	Bermuda
ConocoPhillips (Pasangkayu) Ltd.	Bermuda
ConocoPhillips (Ramba) Ltd.	Bermuda
ConocoPhillips (Sakakemang) Ltd.	Bermuda
ConocoPhillips (South Jambi) Ltd.	Bermuda
ConocoPhillips (Surumana) Ltd.	Cayman Islands
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
ConocoPhillips (U.K.) Limited	England
ConocoPhillips (U.K.) Technology Limited	England
ConocoPhillips (U.K.) Theta Limited	England
ConocoPhillips (U.K.) Zeta Limited	England
ConocoPhillips Africa New Ventures Ltd.	Cayman Islands
ConocoPhillips Alaska, Inc.	Delaware

ConocoPhillips Alaska Natural Gas Corporation	Delaware

Company Name	Incorporation Location
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 Assistance and Relief for Employees	Texas
ConocoPhillips Atlantic Margins Ltd.	Cayman Islands
ConocoPhillips Australia Exploration Pty. Ltd.	Western 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 N.V.	Belgium
ConocoPhillips Block 204 UK Exploration Ltd.	Cayman Islands
ConocoPhillips Bohai Limited	Bahamas
ConocoPhillips Browse Pty. Ltd.	Western Australia
ConocoPhillips Canada (East) Limited	Canada
ConocoPhillips Canada (North) Limited	Canada
ConocoPhillips Canada Energy Partnership	Alberta
ConocoPhillips Canada Limited	Nova Scotia
ConocoPhillips Canada Oilsands Limited	Alberta
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 Danmark 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
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

Company Name	Incorporation Location
ConocoPhillips Exploration Kazakhstan Ltd.	Cayman Islands
ConocoPhillips Exploration Nigeria (Alpha) Limited	Nigeria
ConocoPhillips Exploration Nigeria (Beta) Limited	Nigeria
ConocoPhillips Exploration Nigeria (Gamma) Limited	Nigeria
ConocoPhillips Exploration Production Europe Limited	England
ConocoPhillips Exploration Turkmenistan Ltd.	Cayman Islands
ConocoPhillips Finland Oy	Finland
ConocoPhillips Funding Ltd.	Bermuda
ConocoPhillips Gas Company	Delaware
ConocoPhillips Germany GmbH	Germany
ConocoPhillips Global Funding S.a.r.l.	Luxembourg
ConocoPhillips Gulf of Paria B.V.	The Netherlands
ConocoPhillips Gulf of Paria Ltd.	Cayman Islands
ConocoPhillips Holdings Limited	England
ConocoPhillips Hungary Trading Ltd.	Hungary
ConocoPhillips ICHP Limited	England

ConocoPhillips Indonesia Holding Ltd.	British Virgin Islands
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 Iraq Ltd.	Cayman Islands
ConocoPhillips Ireland Limited	Ireland
ConocoPhillips Ireland Pension Trust Limited	Ireland
ConocoPhillips Japan Ltd.	Japan
ConocoPhillips Jet AS	Norway
ConocoPhillis Jet d.o.o.	Slovenia
ConocoPhillips JPDA Pty. Ltd.	Western Australia
ConocoPhillips Latin America New Ventures Ltd.	Cayman Islands
ConocoPhillips Libya Alliance Ltd.	Cayman Islands
ConocoPhillips Libya Holding Ltd.	British Virgin Islands
ConocoPhillips Limited	England
ConocoPhillips LNG Ltd.	Cayman Islands
ConocoPhillips LNG Ventures Ltd.	Cayman Islands
ConocoPhillips Lubricants Australia Pty. Ltd.	Australia
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 E&P Ltd.	Cayman Islands
ConocoPhillips Middle East Ltd.	Delaware
ConocoPhillips Middle East New Ventures Ltd.	Cayman Islands
ConocoPhillips Netherlands B.V.	The Netherlands
ConocoPhillips New Ventures Ltd.	Cayman Islands

Company Name	Incorporation Location
ConocoPhillips Nila Holding Ltd.	British Virgin Islands
ConocoPhillips Nila Ltd.	Bermuda
ConocoPhillips Nordic AB	Sweden
ConocoPhillips Norge	Delaware
ConocoPhillips Northern Partnership	Alberta
ConocoPhillips NZ Exploration Limited	Cayman Islands
ConocoPhillips Oil Trading Limited	United Kingdom
ConocoPhillips Oilsands Partnership II	Alberta
ConocoPhillips Pacific LNG Ltd.	Cayman Islands
ConocoPhillips Pension Plan Trustees Limited	United Kingdom
ConocoPhillips Petroleum Chemicals U.K. Limited	United Kingdom
ConocoPhillips Petroleum Company U.K. Limited	United Kingdom
ConocoPhillips Petroleum Exploration II, Ltd.	Cayman Islands
ConocoPhillips Petroleum Exploration FF, Ltd.	Cayman Islands
ConocoPhillips Petroleum Exploration GG, Ltd.	Cayman Islands
ConocoPhillips Petroleum Exploration HH, Ltd.	Cayman Islands
ConocoPhillips Petroleum International Corporation Denmark	Cayman Islands
ConocoPhillips Petroleum Limited	England
ConocoPhillips Petrozuata B.V.	The Netherlands
ConocoPhillips Pipe Line Company	Delaware
ConocoPhillips Pipeline Australia Pty. Ltd.	Western Australia
ConocoPhillips Plataforma Deltana B.V.	The Netherlands
ConocoPhillips Poland Sp. z o.o.	Poland
ConocoPhillips Power Operations Limited	England
ConocoPhillips Qatar Funding 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 Southeast Asia New Ventures Ltd.	Cayman Islands
ConocoPhillips Specialty Products Inc.	Delaware

ConocoPhillips STL Pty. Ltd.	Western Australia
ConocoPhillips Surmont Partnership	Alberta
ConocoPhillips Tarakan Ltd.	Cayman Islands
ConocoPhillips Timan-Pechora Inc.	Delaware
ConocoPhillips Tobong Ltd.	Bermuda
ConocoPhillips Transportation Alaska, Inc.	Delaware

Company Name	Incorporation Location
ConocoPhillips Treasury Limited	England
ConocoPhillips Vietnam AS	Norway
ConocoPhillips WA-248 Pty. Ltd.	Australia
ConocoPhillips WA-274-P Pty. Ltd	Western Australia
ConocoPhillips WA Exploration Pty. Ltd.	Australia
ConocoPhillips W05-3/4 Pty. Ltd.	Australia
ConocoPhillips Warim Ltd.	Bermuda
ConocoPhillips Water Technology Ltd.	Cayman Islands
ConocoPhillips West Coast LNG LLC	Delaware
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.	Colorado
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
Continental Oil Company Inc.	Canada
Continental Oil Company Limited	England
Continental Oil Company of Libya	Delaware
COP Energy Technologies LLC	Delaware
COP Holdings Limited	England
CPC Investigations LLC	Delaware
Crestar Energy Holdings Ltd.	Bermuda
CRS Resources (Ecuador) LDC	Cayman Islands
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
Dubai Marketing Company Ltd.	Delaware
Dubai Petroleum Company	Delaware
Du Pont E&P No. 1 B.V.	The Netherlands
Eagle Sun Company Limited	Liberia
Emerald Shipping Corporation	Delaware
Emet Pty. Ltd.	Victoria, Australia
Ensyn Corporation	Delaware
F.P.S.O. Development Ltd.	Bermuda
Fas-Gas Retail Services Co. of Texas	Texas

Company Name	Incorporation Location
Four Star Beverage Company Inc.	Texas
Four Star Holding Company, Inc.	Texas
GCF Midstream Holdings LLC	Delaware
GCRL Energy Ltd.	Colorado
GCRL Inc.	Delaware
GCRL International Limited	Alberta
Glen Petroleum Limited	England
Gulf Alberta Pipe Line Company Limited	Alberta
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 Petroleum (Australia) Pty. Ltd.	Australia
Gulf Resources (Calik) Ltd.	Alberta
Gulf Resources (Halmahera) Ltd.	Alberta
Gulf Resources (Merangin) Ltd.	Alberta
Gulf Resources (NW Natuna) Ltd.	Alberta
Gulf Resources (Sakala Timur) Ltd.	Alberta
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
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
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
Louisiana Midstream Holdings, LLC	Delaware
Lubricantes 76 Mexico, S.A. de C.V.	Mexico
Maspher Investments B.V.	The Netherlands
Mont Belvieu Storage Caverns, LLC	Delaware

Company Name	Incorporation Location
Norske ConocoPhillips AS	Norway
North Gillette Coal Company	Nevada
Oliktok Pipeline Company	Delaware
Pacific Pipelines, Inc.	Delaware
Petco Enterprises Ltd.	Japan
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
Petroz Korinci Baru LDC	Cayman Islands
Petroz LNG Pty. Ltd.	Australia
Petroz N.L.	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 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 Shareholder, Inc.	Delaware
Phillips Gas Investment Company	Delaware
Phillips Gas Pipeline Company	Delaware
Phillips Gas Supply Corporation	Delaware
Phillips Indonesia Inc.	Delaware

Phillips International Investments, Inc.	Delaware
Phillips Investment Company	Nevada
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 Algeria, Ltd.	Cayman Islands
Phillips Petroleum Arabia, Ltd.	Liberia
Phillips Petroleum Argentina S.A.	Argentina
Phillips Petroleum Canada Ltd.	New Brunswick
Phillips Petroleum Company Cameroon	Delaware

Company Name	Incorporation Location
Phillips Petroleum Company Indonesia	Delaware
Phillips Petroleum Company Ireland	Delaware
Phillips Petroleum Company Niugini	Delaware
Phillips Petroleum Company Western Hemisphere	Delaware
Phillips Petroleum Europe Exploration Ltd.	Liberia
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 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 Texas Pipeline Company, Ltd.	Texas
Phillips Utility Gas Corporation	Delaware
Pioneer Investments Corp.	Delaware
Pioneer Pipe Line 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 Angelo Midstream Holdings, LLC	Delaware
San Pablo Bay Pipeline Company	Delaware
Seagas Pipeline Company	Delaware
Seaway Products Pipeline Company	Texas
Seminole Fertilizer Corporation	Delaware
Smartshop NV	Belgium
Smile Loyalty Limited	England
Sooner Insurance Company	Vermont

Company Name	Incorporation Location
Southeast New Mexico Midstream Holdings, LLC	Delaware
Southern Energy UK Generation Limited	England
Springtime Holdings Limited	Cayman Islands
SRW Cogeneration Limited Partnership	Delaware
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 ConocoPhillips Heritage Museums, Inc.	Oklahoma
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	Nova Scotia
Trinidad Holdings LLC	Delaware
TS, Inc.	Georgia
Unocal Expresslube, Inc.	Illinois
Wabiskaw Explorations Ltd.	Canada
WesTTex 66 Pipeline Company	Delaware
World Wide Transport, Inc.	Liberia
2435239 Nova Scotia Limited	Nova Scotia
3072496 Nova Scotia Company	Nova Scotia
349910 Alberta Inc.	Alberta
362084 Alberta Inc.	Alberta
534404 Alberta Ltd.	Alberta
625894 Alberta Inc.	Alberta
66 Pipe Line Company	Delaware
758350 Alberta Inc.	Alberta
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 26, 2006, 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, 2005, in the following registration statements and related prospectus.

ConocoPhillips Form S-3	File No. 333-101187
ConocoPhillips Form S-4	File No. 333-130967
ConocoPhillips Form S-8	File No. 333-98681
ConocoPhillips Form S-8	File No. 333-116216

/s/ Ernst & Young LLP

Houston, Texas
February 26, 2006

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 26, 2006

/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 26, 2006

/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, 2005, 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 26, 2006

/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