CONOCOPHILLIPS
Form 10-K
February 23, 2007

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

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2006

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. x 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 x 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. x 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. o

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 x 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 x No

The aggregate market value of common stock held by non-affiliates of the registrant on June 30, 2006, the last business day of the registrant s most recently completed second fiscal quarter, based on the closing price on that date of $65.53, was $107.9 billion. The registrant, solely for the purpose of this required presentation, had deemed its Board of Directors and grantor trusts to be affiliates, and deducted their stockholdings of 878,673 and 45,876,265 shares, respectively, in determining the aggregate market value.

The registrant had 1,644,099,838 shares of common stock outstanding at January 31, 2007.

Documents incorporated by reference:

Portions of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 9, 2007 (Part III)

TABLE OF CONTENTS

PART I

Unless otherwise indicated, the company, we, our, us, and ConocoPhillips are used in this report to refer to the businesses of ConocoPhillips 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, 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 96.

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, processes and markets natural gas produced by ConocoPhillips and others, and fractionates and markets natural gas liquids, primarily in the United States and Trinidad. The Midstream segment primarily consists of our 50 percent equity investment in DCP Midstream, LLC, formerly named Duke Energy Field Services, LLC.

- **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. At December 31, 2006, our ownership interest was 20 percent, based on authorized and issued shares, and 20.6 percent, based on estimated shares outstanding.

- **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).

- **Emerging Businesses** This segment includes the development of new technologies and businesses outside our normal scope of operations.

At December 31, 2006, ConocoPhillips employed approximately 38,400 people.

SEGMENT AND GEOGRAPHIC INFORMATION

For operating segment and geographic information, see Note 29 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, 2006, our E&P segment represented 68 percent of ConocoPhillips total assets, while contributing 63 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, 2006, our E&P operations were producing in the United States, Norway, the United Kingdom, the Netherlands, Canada, Nigeria, Venezuela, Ecuador, Argentina, offshore Timor Leste in the Timor Sea, Australia, China, Indonesia, Algeria, Libya, the United Arab Emirates, Vietnam, and Russia.

On March 31, 2006, we completed the $33.9 billion acquisition of Burlington Resources Inc., an independent exploration and production company that held a substantial position in North American natural gas proved reserves, production and exploratory acreage.

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 176 through 195.

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 2006, E&P s worldwide production, including its share of equity affiliates production other than LUKOIL, averaged 1,936,000 barrels-of-oil-equivalent (BOE) per day, an increase compared with the 1,543,000 BOE per day averaged in 2005. During 2006, 808,000 BOE per day were produced in the United States, an increase from 633,000 BOE per day in 2005. Production from our international E&P operations averaged 1,128,000 BOE per day in 2006, an increase compared with 910,000 BOE per day in 2005. In addition, our Canadian Syncrude mining operations had net production of 21,000 barrels per day in 2006, compared with 19,000 barrels per day in 2005. Benefiting 2006 production was the addition of volumes from the Burlington Resources assets and new production from our reentry into Libya, as well as increased production from the Bayu-Undan field in the Timor Sea, offset slightly by lower production at the Prudhoe Bay field in Alaska.

E&P s worldwide annual average crude oil sales price increased 21 percent, from $49.87 per barrel in 2005 to $60.37 per barrel in 2006. E&P s annual average worldwide natural gas sales price decreased, from $6.30 per thousand cubic feet in 2005 to $6.19 per thousand cubic feet in 2006.

E&P U.S. OPERATIONS

In 2006, U.S. E&P operations contributed 40 percent of E&P s worldwide liquids production and 44 percent of natural gas production, compared with 40 percent and 42 percent in 2005, respectively.

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 non-operator interest in all fields within the Greater Prudhoe Area.

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 re-injects natural gas into the reservoir. Our net crude oil production from the Prudhoe Bay field averaged 78,800 barrels per day in 2006, compared with 102,100 barrels per day in 2005, while natural gas liquids production averaged 16,700 barrels per day in 2006, compared with 18,500 barrels per day in 2005.

Prudhoe Bay satellite fields, including Aurora, Borealis, Polaris, Midnight Sun, and Orion, produced 12,900 net barrels per day of crude oil in 2006, compared with 14,500 net barrels per day in 2005. All Prudhoe Bay satellite fields produce through the Prudhoe Bay production facilities.

The Greater Point McIntyre Area (GPMA) primarily includes 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 11,400 barrels per day in 2006, compared with 15,200 barrels per day in 2005, while natural gas liquids production averaged 800 barrels per day in 2006, compared with 1,000 barrels per day in 2005. The bulk of GPMA 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 August 2006, a phased shutdown of the Prudhoe Bay fields was initiated due to the discovery of a leak in an oil sales line and concerns with pipeline corrosion. After completion of increased inspections and surveillance of the pipelines in the fields western operating area, the shutdown was limited to the eastern operating area pipelines. The full-year impact on our production is an estimated decrease of 9,400 barrels per day. Production from the eastern operating area resumed in October 2006, utilizing bypass lines from the Prudhoe Bay unit to a pipeline located nearby.

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. 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 re-injection. Our net crude oil production from the Kuparuk field averaged 59,900 barrels per day in 2006, compared with 64,600 barrels per day in 2005. The Kuparuk field is located about 40 miles west of Prudhoe Bay, and our ownership interest in the field is 55.3 percent.

Other fields within the Greater Kuparuk Area produced 13,400 net barrels per day of crude oil in 2006, compared with 16,000 net barrels per day in 2005, 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 8,400 barrels per day in 2006, compared with 5,300 barrels per day in 2005. We have a 52.2 percent interest in this field.

Western North Slope

The Alpine field, located west of the Kuparuk field, began production in November 2000. In 2006, the field produced at a net rate of 74,100 barrels of oil per day, compared with 76,600 barrels per day in 2005. We are the operator and hold a 78 percent interest in Alpine and the two satellite fields.

The Alpine satellite fields, Nanuq and Fiord, began production in 2006. The fields produced at a net rate of 4,300 barrels of oil per day. Plans call for the drilling of approximately 40 wells, of which 16 had been drilled by the end of 2006. Peak production is expected in 2008. The oil is processed through the existing Alpine facilities. The companies are pursuing state, local and federal permits for additional Alpine satellite developments in the National Petroleum Reserve Alaska (NPR-A), including the Qannik satellite field discovery announced in 2006. The Qannik accumulation would be the third satellite field to be developed near Alpine, and plans include developing the field from the Alpine CD 2 drill site. Production from Qannik is expected to commence by late 2008.

<u>Cook Inlet Area</u>

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, all of which are operated by us.

We have a 100 percent interest in the North Cook Inlet field. Net production in 2006 averaged 88 million cubic feet per day of natural gas, compared with 105 million cubic feet per day in 2005. 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 49 million cubic feet per day of natural gas in 2006, compared with 57 million cubic feet per day in 2005. 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 41.3 net billion cubic feet in 2006, compared with 42.8 net billion cubic feet in 2005. In January 2007, we and our co-venturer filed for a two-year extension of the Kenai LNG plant s export license with the U.S. Department of Energy. This application would extend the export license through March 31, 2011.

Exploration

In 2006, we drilled seven exploration wells. Two wells were classified as dry holes and five wells encountered commercial quantities of oil. Three of the successful wells are located in the West Sak field, one is in the Prudhoe Bay unit, and one is in the Alpine Area. We also acquired more than 2,900 square kilometers of 3D seismic and were the successful bidder in four lease sales, acquiring 27 lease blocks covering 149,815 acres.

Transportation

We transport the petroleum liquids produced on the North Slope to market through the Trans-Alaska Pipeline System (TAPS). TAPS is composed of 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. A phased startup of the project began in the first quarter of 2007. 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.

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 crude trade, chartering additional third-party-operated vessels, as necessary. Beginning with the *Polar Endeavour* in 2001, Polar Tankers has brought into service five double-hulled tankers. The fifth and final tanker, the *Polar Enterprise,* began Alaska North Slope service in February 2007.

We and our co-venturers continue to seek agreement with the Alaskan government on fiscal terms that would enable the development of a pipeline to transport natural gas from Alaska s North Slope to markets in the Lower 48 states. Alaska s new governor has stated her administration will propose a new law in the Alaska legislature and seek new proposals for development of an Alaskan gas pipeline. We expect to be actively involved in this process throughout 2007.

Lower 48 States

Gulf of Mexico

At year-end 2006, our portfolio of producing properties in the Gulf of Mexico included four operated fields and five fields operated by our co-venturers.

We operate and hold a 75 percent interest in the Magnolia field in Garden Banks Blocks 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 2006. Net production from Magnolia averaged 17,800 barrels per day of liquids and 44 million cubic feet per day of natural gas in 2006, compared with 18,700 barrels per day of liquids and 43 million cubic feet per day of natural gas in 2005.

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 2006 averaged 14,400 barrels per day of liquids and 18 million cubic feet per day of natural gas, compared with 13,500 barrels per day of liquids and 16 million cubic feet per day of natural gas in 2005.

We previously held a 16.8 percent interest in the K2 field, which was comprised of Green Canyon Blocks 562 and 563. In December 2006, the unit was expanded to include five additional blocks, and our working interest was reduced to 12.4 percent. Our net production averaged 2,300 BOE per day in 2006, compared with 700 BOE per day in 2005.

Onshore

The acquisition of Burlington Resources significantly added to our assets in the onshore Lower 48 states. Our 2006 onshore production primarily consisted of natural gas, with the majority of production located in the San Juan Basin, the Permian Basin, the Lobo Trend, and the Panhandles of Texas and Oklahoma. We also have operations in the Wind River, Williston, Anadarko, Fort Worth and Piceance Basins, as well as in the Bossier Trend and southern Louisiana. During 2006, we gained entrance into the Piceance Basin, located in northwestern Colorado, where activity is primarily focused on developing the Williams Fork Mesaverde interval.

The San Juan Basin, located in northwest New Mexico and southwest Colorado, includes the majority of our coalbed methane (CBM) production. In addition, we continue to pursue development opportunities in three conventional formations in the San Juan Basin.

In addition to our CBM production from the San Juan Basin, we also hold CBM acreage positions in the Uinta Basin in Utah and the Black Warrior Basin in Alabama.

Other onshore properties exist in Wyoming, East Texas, the Texas Gulf Coast, North Louisiana, and the Florida Panhandle.

Activities in 2006 primarily were centered on continued optimization and development of these assets. Combined production from Lower 48 onshore fields in 2006 averaged a net 1,900 million cubic feet per day of natural gas and 128,000 barrels per day of liquids, compared with 1,147 million cubic feet per day of natural gas and 54,900 barrels per day of liquids in 2005. The increase in 2006 was primarily due to the Burlington Resources acquisition.

Transportation

In June 2006, we acquired a 24 percent interest in West2East Pipeline LLC, a company holding a 100 percent interest in Rockies Express Pipeline LLC (Rockies Express). Rockies Express plans to construct a 1,633-mile natural gas pipeline from Wyoming to Ohio. This should provide us with a cost-effective means of transporting our natural gas production in the Rocky Mountain region to markets in the midwest and eastern United States. The pipeline is expected to be completed in 2009.

Exploration

In the Lower 48 states, we own undeveloped mineral interests in 7.7 million net acres and hold leases on 2.3 million undeveloped net acres. In 2006, we completed 46 gross exploration wells. Areas of focus in 2006 included the east Texas Bossier Trend and the Fort Worth Basin Barnett Trend. Other areas with active exploration drilling programs included South Texas, the Bakken Trend in the Williston Basin, and the Piceance Basin.

E&P EUROPE

In 2006, E&P operations in Europe contributed 23 percent of E&P s worldwide liquids production, compared with 27 percent in 2005. Europe operations contributed 21 percent of natural gas production in 2006, compared with 31 percent in 2005. Our European assets are principally located in the Norwegian and U.K. sectors of the North Sea. With the acquisition of Burlington Resources, we now have operations in the East Irish Sea and the Netherlands.

Norway

The Greater Ekofisk Area, located approximately 200 miles offshore Norway in the center of the North Sea, is composed 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 2006 from the Greater Ekofisk Area was 121,700 barrels of liquids per day and 123 million cubic feet of natural gas per day, compared with 124,800 barrels of liquids per day and 122 million cubic feet of natural gas per day in 2005. We are operator and hold a 35.1 percent interest in Ekofisk.

During 2006, a review of the Eldfisk and Embla field facilities and process systems resulted in reduced expectations of facility life compared to previous forecasts. We now anticipate future capital investments will be required to maintain and upgrade the facilities to continue production until the end of the license period. An evaluation is under way to determine the optimal approach for a redevelopment of the Eldfisk and Embla facilities. Pending determination and approval of capital expenditures necessary to extend facility life to the end of the license period, proved reserves were revised downward to reflect the shorter field life expectation.

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. Our net production from these and other fields in the Norwegian sector of the North Sea and the Norwegian Sea averaged 75,800 barrels of liquids per day and 147 million cubic feet of natural gas per day in 2006, compared with 81,900 barrels of liquids per day and 150 million cubic feet of natural gas per day in 2005.

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, Norwegian and U.K. authorities approved the Statfjord Late-Life Project, a Statfjord-area gas recovery project with production startup targeted for late 2007. 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 and a 2.2 percent interest in Gassled, which owns most of the Norwegian gas transportation system.

Exploration

In 2006, one appraisal well and four exploration wells were completed. The appraisal well within the Alvheim license and two of the exploration wells within the Heidrun and Oseberg licenses were successful. The other two wells in the Troll and Oseberg licenses were expensed as dry holes.

During 2006, we were awarded interests in two licenses, PL392 located in the Voering Basin and PL085D located adjacent to the Troll licenses.

United Kingdom

We have a 58.7 percent interest in the Britannia natural gas and condensate field, and own 50 percent of Britannia Operator Limited, the operator of the field. Our net production from Britannia averaged 246 million cubic feet of natural gas per day and 10,100 barrels of liquids per day in 2006, compared with 315 million cubic feet of natural gas per day and 13,100 barrels of liquids per day in 2005. Development drilling in the Britannia field is expected to continue into 2007.

We have a 75 percent interest in the Brodgar field and an 83.5 percent interest in the Callanish field. First production from these two Britannia satellite fields is targeted for 2008.

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 15,900 barrels of liquids per day and 133 million cubic feet of natural gas per day in 2006, compared with 14,100 barrels of liquids per day and 123 million cubic feet of natural gas per day in 2005.

We have various ownership interests in 15 producing gas fields in the southern North Sea, in the Rotliegendes and Carboniferous areas. Net production in 2006 averaged 309 million cubic feet per day of natural gas and 1,200 barrels of liquids per day, compared with 278 million cubic feet per day of natural gas and 1,200 barrels per day of liquids in 2005.

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. Initially, the development consisted of three wells from a wellhead platform. A fourth well, Rhea, was approved and successfully drilled in 2006. We are the operator of the Saturn Unit Area with a 42.9 percent interest.

In 2006, the U.K. government approved a plan for the development of two new Saturn satellite fields: Mimas and Tethys. Tethys first production began in February 2007. Mimas first production is targeted for April 2007. We have a 25 percent interest in the Tethys field and a 35 percent interest in the Mimas field.

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 4.84 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 26,700 barrels of liquids per day and 34 million cubic feet of natural gas per day in 2006, compared with 35,400 barrels of liquids per day and 34 million cubic feet of natural gas per day in 2005.

We have a 24 percent interest in the Clair field development in the Atlantic Margin. First production from Clair began in early 2005 from a conventional platform, with plateau production expected in 2008. Net production in 2006 averaged 6,000 barrels of liquids per day, compared with 3,200 barrels of liquids per day in 2005. Natural gas production commenced in 2006.

As part of the acquisition of Burlington Resources, we acquired and became operator of the Millom, Dalton and Calder fields in the East Irish Sea. The natural gas produced from these fields is transported onshore, processed and sold into the U.K. spot market. Net production in 2006 averaged 38 million cubic feet of natural gas per day.

Transportation

The Interconnector pipeline, which connects the United Kingdom and Belgium, facilitates marketing natural gas produced in the United Kingdom throughout Europe. Our 10 percent equity share of the Interconnector pipeline allows us to ship approximately 200 million net cubic feet of natural gas per day to markets in continental Europe, 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. In addition, we acquired 100 percent ownership of the Rivers Gas Terminal as part of the Burlington Resources acquisition.

Exploration

In 2006, we participated in three appraisal wells and eight exploration wells. With the exception of an appraisal well in the southern North Sea that has not yet reached the primary target, all wells have encountered hydrocarbons. A single exploration well has been expensed as a dry hole.

In the Atlantic Margin, and adjacent to the Clair field, operations concluded on one appraisal well, which was successfully tested. Operations continue on a second well and are expected to conclude in 2007.

In the J-Block and Britannia areas of the central North Sea, activities that originally commenced in 2005 on two exploration wells concluded in 2006. In the J-Block area, two additional exploration wells were also completed. One well is currently producing, and in September 2006, we announced the discovery of Jasmine, a new gas and condensate field, the results of which are being evaluated to determine future appraisal and development plans. All wells in the central North Sea were successful.

In the southern North Sea, four exploration wells were drilled and operations are ongoing on an appraisal well. Two of the exploration wells were successful, one was expensed as a dry hole, and evaluations are ongoing on the fourth.

Denmark

Exploration

We have varying ownership interests in three licenses, 4/98, 5/98 and 01/06 in the Danish sector of the North Sea. License 1/04, which was acquired through the acquisition of Burlington Resources, has been relinquished. License 01/06 was awarded in 2006 and is adjacent to the 5/98 license that includes the 2001 Hejre discovery. In 2006, one exploration well was drilled in license 4/98. The well encountered non-commercial quantities of hydrocarbons and was expensed as a dry hole.

Netherlands

We obtained varying non-operated production interests in the Dutch sector of the North Sea as part of the Burlington Resources acquisition, as well as interests in offshore pipelines and an onshore gas plant and terminal at Den Helder. Net production in 2006 averaged 34 million cubic feet of natural gas per day.

Exploration

In 2006, we participated in three exploration wells and one appraisal well in the southern North Sea, all of which encountered hydrocarbons. Within the JDA K15 license, one appraisal well and one exploration well were successful. Operations are in progress on the second exploration well within that license, and are expected to conclude in 2007. The third exploration well, located in the E18a license, also encountered hydrocarbons and will be further evaluated with a 2007 appraisal well.

E&P CANADA

In 2006, E&P operations in Canada contributed 5 percent of E&P s worldwide liquids production (excluding Syncrude production), compared with 3 percent in 2005. Canadian operations contributed 20 percent of E&P s worldwide natural gas production in 2006, compared with 13 percent in 2005.

Oil and Gas Operations

Western Canada

During 2006, the Burlington Resources acquisition significantly expanded our asset base in western Canada. Operations in western Canada encompass properties in Alberta, northeastern British Columbia and southern Saskatchewan. The properties in northern Alberta and northeastern British Columbia contain a mix of oil and natural gas, and are primarily accessible only in the winter. The properties in the central and foothills areas of Alberta mainly produce natural gas. As a result of declining well performance and drilling results in the Canadian Rockies Foothills area, we recorded an impairment charge in the fourth quarter of 2006. The properties in southern Alberta and southern Saskatchewan have shallow gas and medium-to-heavy oil. Net production from these oil and gas operations in western Canada averaged 50,200 barrels per day of liquids and 983 million cubic feet per day of natural gas in 2006, compared with 32,300 barrels per day of liquids and 425 million cubic feet per day of natural gas in 2005.

In September 2006, we sold the Kerrobert heavy-oil property in southwestern Saskatchewan, and in January 2007, we completed the sale of oil and natural gas producing properties and undeveloped acreage in western Canada, including oil properties in northern, central and southern Alberta and shallow gas properties in southwestern Alberta and southeastern Saskatchewan. Combined, production from these properties averaged 18,000 BOE per day in 2006.

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 2003, we received regulatory approval to develop the Surmont project from the Alberta Energy and Utilities Board. The Surmont project uses an enhanced thermal oil recovery method called steam-assisted gravity drainage (SAGD). 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-plus 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. Initial production is expected in the first half of 2007, with peak production expected in 2014. We anticipate processing our share of the heavy oil produced as a feedstock in our U.S. refineries.

Consistent with our practice and in accordance with U.S. Securities and Exchange Commission guidelines, we use year-end prices for hydrocarbon reserve estimation. Bitumen prices can be seasonal, often reaching low levels at year-end. Conversely, natural gas prices, a significant cost component of the development, can be seasonally high at year-end. Low bitumen and/or high natural gas prices at year-end 2004 and 2005 resulted in no proved reserves being reflected for the Surmont project. Bitumen and natural gas prices at December 31, 2006, were such that we were able to record 58 million barrels of proved reserves for the initial stage of the project.

EnCana Joint Venture

In October 2006, we announced a business venture with EnCana Corporation (EnCana), to create an integrated North American heavy-oil business. The transaction closed on January 3, 2007. The venture consists of two 50/50 operating joint ventures, a Canadian upstream general partnership, FCCL Oil Sands Partnership, and a U.S. downstream limited liability company, WRB Refining LLC. We plan to use the equity method of accounting for our investments in both joint ventures.

The upstream joint venture s operating assets consist of the Foster Creek and Christina Lake SAGD bitumen projects, both located in the eastern flank of the Athabasca oil sands in northeast Alberta. EnCana is the operator and managing partner of the upstream joint venture. We expect to contribute $7.5 billion, plus accrued interest, to this joint venture over a 10-year period beginning in 2007. We anticipate our share of production to be approximately 29,000 barrels per day in 2007.

See the Refining and Marketing (R&M) section for information on our downstream joint venture with EnCana.

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 Parsons Lake gas field, one of the primary fields in the Mackenzie Delta that would anchor the pipeline development. A Joint Review Panel was established by the National Energy Board, an independent federal regulatory agency in Canada, to review the Mackenzie Gas Project. The Joint Review Panel s hearings started in January 2006 and have been held at multiple locations in the Canadian North. In July 2006, the Joint Review Panel extended its schedule through April 2007. A federal court ruling in November 2006 related to a claim by an aboriginal group has the potential to further delay the regulatory process. In addition, cost estimates for the project have increased as a result of global and local market conditions. The uncertainties related to the regulatory schedule, as well as the economic impact of the cost estimate increase, have to be addressed before a decision to construct can be made and a definitive startup date for the project can be confirmed.

Exploration

We hold exploration acreage in four areas of Canada: the Western Canada Sedimentary Basin, offshore eastern Canada, the Mackenzie Delta/Beaufort Sea, and the Arctic Islands. Within the Western Canadian Sedimentary Basin, we hold exploration acreage throughout the basin, including the foothills of western Alberta and eastern British Columbia. In the foothills, we drilled 13 exploratory wells in 2006, three of which will be completed as producers, with the remaining 10 wells in various stages of testing and evaluation. In late 2006, we also began drilling one well on exploration acreage in the central Alberta Nisku prospect. Throughout the rest of western Canada, we participated in drilling approximately 75 lower risk exploration wells near our producing assets. In the Mackenzie Delta, we were successful in acquiring additional acreage following the Umiak discovery from 2004. In offshore eastern Canada, we operate eight contiguous exploration licenses in the shallow and deepwater Laurentian Basin. We hold varying interests in discoveries in the Beaufort Sea and in the Arctic Islands. Further exploration in these basins is anticipated as distribution methods for natural gas become more certain.

Other Canadian Operations

Syncrude Canada Ltd.

We own a 9 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. The development of the Stage III expansion-mining project was completed by April 2006. Our net share of production averaged 21,100 barrels per day in 2006, compared with 19,100 barrels per day in 2005.

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

E&P SOUTH AMERICA

In 2006, E&P operations in South America were focused on our operations in Venezuela. We also acquired interests in Ecuador, Argentina, Peru and Colombia, as a result of the 2006 Burlington Resources acquisition. South American operations contributed 10 percent of E&P s worldwide liquids production in 2006, compared with 11 percent in 2005.

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 49,600 barrels of heavy crude oil per day in 2006, compared with 50,200 barrels per day in 2005, 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. Net production averaged 51,400 barrels per day of heavy crude oil in 2006, compared with 56,100 barrels per day in 2005, and is included in equity affiliate production.

Gulf of Paria

In 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 development drilling began in the second quarter of 2006. Arrival of the floating storage and offloading (FSO) vessel and completion of the pipelines and the FSO mooring are expected to occur in the first quarter of 2007. Field production is expected to commence in the third quarter of 2008 upon installation of the central processing platform, with the possibility of production from an interim processing facility in mid-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 and 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. Preliminary engineering studies could begin in late 2007.

Operating Environment

See the Outlook section of Management s Discussion and Analysis of Financial Condition and Results of Operations for a discussion of developments in Venezuela that could impact our operations.

Ecuador

In Ecuador, we acquired an interest in two producing blocks as part of the Burlington Resources acquisition. We hold a 42.5 percent interest in Block 7 and a 46.25 percent interest in Block 21.

Argentina

We have a 25.7 percent interest in the producing Sierra Chata concession in Argentina as a result of the Burlington Resources acquisition.

Peru

We have varying ownership interests in four exploration blocks in Peru as a result of the Burlington Resources acquisition.

In the third quarter of 2006, we acquired a 100 percent ownership interest in exploration blocks 123 and 124 in northern Peru s Maranon Basin, covering more than 5.5 million acres.

Colombia

In Colombia, we acquired an exploration contract for a 100 percent interest in the Orquídea area of the Middle Magdalena Basin as part of the Burlington Resources acquisition. We sold our ownership interest later in 2006.

E&P ASIA PACIFIC

In 2006, E&P operations in the Asia Pacific area contributed 11 percent of E&P s worldwide liquids production and 12 percent of natural gas production, compared with 12 percent and 11 percent in 2005, 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. 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 beginning in 2007. These are U.S.-dollar-denominated, fixed-price contracts. Production from Indonesia in 2006 averaged a net 319 million cubic feet per day of natural gas and 12,400 barrels per day of oil, compared with 298 million cubic feet per day of natural gas and 15,100 barrels per day of oil in 2005.

Offshore Assets

We operate three offshore PSCs: South Natuna Sea Block B, Ketapang and Amborip VI. We also hold a non-operator interest in the Pangkah PSC, offshore East Java. In 2006, we signed the Amborip VI PSC. This block, located offshore in the Arafura Sea, was awarded to us in 2005. In 2006, the Indonesian government approved our relinquishment of the Nila PSC.

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. 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. In late 2006, gas production began from the Hiu gas field. Also in Block B, we continued development of the Kerisi field and began development of the North Belut field.

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.

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 Warim in Papua. We hold a non-operator interest in the Banyumas PSC in Java. In January 2007, we sold our 50 percent working interest in the Block A PSC in North 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 the Pangkah and Block B PSCs, seismic was acquired to support further exploration activity.

In December 2006, the Indonesian government announced we were the successful bidder on the Kuma PSC for a 60 percent interest and operatorship. The block is located in Makassar Straits between the islands of Kalimantan and Sulawesi. The PSC agreement was signed in January 2007.

China

The Xijiang development consists of two fields located approximately 80 miles south of Hong Kong in the South China Sea. The facilities include two manned platforms and an FPSO vessel. Our combined net production of crude oil from the Xijiang fields averaged 10,100 barrels per day in 2006, compared with 10,600 barrels per day in 2005.

Production from Phase I development of the Peng Lai 19-3 field in Bohai Bay Block 11-05 began in 2002. In 2006, the field produced 13,800 net barrels of oil per day, compared with 12,600 net barrels per day in 2005. 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 vessel.

In 2005, we received government approval to develop the second phase of the Peng Lai 19-3 field, as well as concurrent development through the same facilities of the nearby Peng Lai 25-6 field. 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. Offshore installation work associated with the first new wellhead platform (WHP-C) began in the third quarter of 2006. 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.

As a result of the Burlington Resources acquisition, we have interests in the Panyu and Ba Jiao Chang (BJC) fields. The Panyu development is an offshore project located approximately 36 miles southwest of the Xijiang development. The field consists of two manned platforms and a leased FPSO vessel. During 2005, Phase II of the Panyu development drilling program was initiated. Government approvals were received and work began on a facilities upgrade. In addition, a development plan for a satellite discovery was approved by the government. Since the acquisition date, the field produced 9,100 net barrels of oil per day in 2006. We have a 24.5 percent interest in the field, which is operated by the China National Offshore Oil Corporation.

The BJC gas field is located onshore, and pilot production began in 1999. Government approval of the field development was granted in 2004. At year-end 2006, 11 development wells had been drilled in the BJC field and further development was ongoing. In 2006, net gas production averaged 7 million cubic feet per day.

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. Net production in 2006 was 11,800 barrels of oil per day, compared with 15,100 barrels per day in 2005. The oil is being processed through a one-million-barrel FPSO vessel.

Development of the Su Tu Vang field continued in 2006. This field was discovered in 2001. First oil production is targeted for 2008. Preliminary engineering is under way on the Su Tu Den Northeast development, with first production anticipated in 2010. Appraisal of the Su Tu Trang and Su Tu Nau discoveries continued in 2006.

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 2006 was 13,000 barrels of liquids per day and 21 million cubic feet per day of natural gas, compared with 14,500 barrels per day and 18 million cubic feet per day in 2005.

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

A successful appraisal well was drilled in the Su Tu Trang field in 2006, a gas and condensate field discovered in 2003 in the southeast area of the Block 15-1. Further appraisal plans and potential development options for this field are currently being evaluated.

We also own interests in offshore Blocks 5-3, 133 and 134. These blocks are located in the Nam Con Son Basin.

Timor Sea and Australia

Bayu-Undan

We operate and hold a 56.7 percent interest in the Bayu-Undan field, located in the Timor Sea. The Bayu-Undan field was developed in two phases. Phase I was a gas-recycle project, where condensate and natural gas liquids were separated and removed and the dry gas was re-injected into the reservoir. This phase began production in February 2004, and averaged a net rate of 53,400 barrels of liquids per day in 2006, compared with 47,800 barrels per day in 2005. In accordance with various governance agreements, a redetermination of the ownership interest in the Bayu-Undan Joint Venture, Darwin LNG Pty Ltd and the Bayu-Undan Pipeline Joint Venture is expected to be completed in 2007. We have an almost equal ownership interest in the two underlying PSCs, and therefore, we do not expect a material change in ownership as a result of this redetermination.

Phase II involved the installation of a natural gas pipeline from the field to Darwin, Australia, 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. The LNG facility was completed and began full operation in 2006, with the first LNG cargo 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 was 200 million cubic feet per day in 2006. Production from the Bayu-Undan field is used by the Darwin LNG plant.

Elang/Kakatua/Kakatua North

During 2006, we continued to produce ultra-light crude oil from these fields at a combined average net rate of 1,100 barrels per day, compared with 1,400 barrels per day in 2005. We are the operator with an interest of 57.4 percent.

Greater Sunrise

Greater Sunrise is a gas and condensate field located in the Timor Sea. In January 2006, agreement was reached between the governments of Australia and Timor Leste concerning sharing of revenues from the anticipated development of the Greater Sunrise field. The Treaty on Certain Maritime Arrangements (CMATS), together with the 2003 International Unitisation Agreement for Greater Sunrise (IUA), provides for equal sharing of upstream government revenues generated by the project. We and our co-venturers are awaiting ratification of the CMATS by both countries, and ratification of the IUA by Timor Leste, to allow further evaluation of the development options for this field. We have a 30 percent interest in this project.

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 2006, our net share of production was 35 million cubic feet of natural gas per day, compared with 34 million cubic feet of natural gas per day in 2005.

Exploration

During 2006, the Barossa No. 1 exploration well was drilled in the NT/P 69 license located offshore Northern Territory Australia. The well provided results that further build on the 2005 Caldita No. 1 discovery well drilled in the adjacent license NT/P 61. A Caldita appraisal well drilled in early 2007 confirmed the presence of gas and water level and was charged to expense. Acquisition of 3D seismic data is currently in progress over both discoveries. We are operator of the NT/P 69 and the NT/P 61 licenses, with a 60 percent interest in each.

In 2006, we purchased acreage in Australia s western sector of the Timor Sea, covered by licenses WA-341-P, WA-343-P, and WA-344-P. We are the operator and own 100 percent interests. Further evaluation of the area, including reprocessing of 3D seismic data, is under way.

Also in 2006, we entered into farm-in agreements to acquire 51 percent interests in licenses WA-314-P and WA-315-P located in the western Timor Sea. We will participate in acquisition, processing and interpretation of seismic data and the drilling of one exploration well in each of the licenses to earn this position.

Malaysia

Exploration

We have interests in deepwater Blocks G and J located off the east Malaysian state of Sabah. The Gumusut 1 well 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. During 2006, the Gumusut and Kakap fields were unitized. ConocoPhillips has no working interest in the Kakap field, which resides in Block K. ConocoPhillips share of the combined Gumusut-Kakap unit is 33 percent.

In 2004, we successfully completed the drilling of the Malikai discovery in Block G. The field was successfully appraised in 2006. In 2005, we had two additional Block G discoveries Ubah and Pisagan. An unsuccessful well near Ubah in 2006 reduced the economic viability of a near-term Ubah development, and the Ubah well was expensed as a dry hole in 2006. These Block G discoveries are being evaluated as part of a broader area development plan. We have a 35 percent interest in Block G.

16

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 options were reviewed with co-venturers during 2006 and we decided not to pursue an oil-only development. The remaining leasehold value was impaired during the third quarter of 2006. We have a 40 percent interest in the oil rights of Kebabangan field.

E&P AFRICA AND THE MIDDLE EAST

Algeria

We have interests in three fields in Block 405a as a result of the Burlington Resources acquisition.

We operate and have a 65 percent interest in the Menzel Lejmat North (MLN) field. During 2005, the MLN Expansion Project was approved, which is designed to increase field production and reserves through additional pressure maintenance. The drilling program began in 2005 and continued in 2006.

We have a 3.73 percent interest in the Ourhoud field. Development of the waterflood program on the field continued during 2006.

We have a 16.9 percent interest in the EMK (El Merk) oil field unit, which extends into the southeastern area of Block 405a. In 2006, the partners continued engineering studies and drilling activities with the expectation of finalizing the development plan for the field and initiating engineering, procurement, and construction activities in 2007.

Libya

In late 2005, we and our co-venturers reached an 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 330,000 gross barrels of oil per day, and encompass nearly 13 million acres located in the Sirte Basin. The terms of the agreement include a 25-year extension of the concessions to 2031-2034.

Net oil production during the year averaged 50,100 barrels per day, including 3,800 barrels per day associated with the recovery of our 1986 underlift position. The underlift existing at reentry has been fully recovered.

Egypt

With the acquisition of Burlington Resources in 2006, we acquired a 50 percent non-operated interest in a concession in Egypt that includes the development of the Tao gas field and its associated facilities. Detailed engineering studies are under way for the facilities and pipelines, and plans are being developed to commence drilling in 2007.

Nigeria

At year-end 2006, 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 24,500 barrels of liquids per day and 138 million cubic feet of natural gas per day in 2006, compared with 28,900 barrels per day and 84 million cubic feet per day in 2005. In 2006, 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.

During 2006, Brass LNG Limited continued to progress front-end engineering and design work for a new LNG facility to be constructed in Nigeria s central Niger Delta. We have a 17 percent equity interest in Brass LNG Limited. In early 2006, six potential buyers signed Memorandum of Understanding agreements for the purchase of LNG produced at the Brass facility.

Exploration

We have PSCs on three deepwater Nigeria Oil Prospecting Licenses (OPLs), with an interest on OPL 318 of 35 percent, on OPL 248 of 28.8 percent, and on OPL 214 of 20 percent. We operate OPLs 318 and 248. We and our co-venturers entered into the Second Exploration Phase on OPL 214 during 2006, which extends the lease for another three years. In addition to the OPLs, we operate OML 131 with a 47.5 percent interest. We are conducting detailed evaluations of all licenses and formulating plans to drill OPL 214 and OPL 248.

Cameroon

In May 2006, we sold our ownership interest in license PH77, located offshore Cameroon.

Qatar

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.

In the second quarter of 2006, we signed an interim agreement with affiliates of ExxonMobil and Qatar Petroleum to acquire an approximate 10 percent ownership interest in a planned LNG regasification facility and associated pipeline located on the Sabine-Neches Industrial Ship Channel northwest of Sabine Pass, Texas (Golden Pass). Subject to the negotiation of definitive agreements, ConocoPhillips will also secure capacity rights in the Golden Pass LNG terminal and pipeline to manage a substantial portion of the LNG purchased from Qatargas 3. In addition to the United States, the participants in Qatargas 3 continue to evaluate other market alternatives for Qatargas 3 LNG production.

In order to capture cost savings, Qatargas 3 is executing 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. Upon completion of the Qatargas 3 and Qatargas 4 projects, production will be combined and shared.

Dubai

In Dubai, United Arab Emirates, we operate four offshore oil fields. In August 2006, we announced an agreement with the government of Dubai whereby our offshore oil concession would end effective April 2007. This action is not expected to have a material impact on our financial statements, production, or proved reserves, which were revised downward in 2006 to reflect this agreement.

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

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 12,100 barrels of oil per day in 2006, compared with 12,900 barrels per day in 2005, and is included in equity affiliate production.

NMNG

In June 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 NMNG. We use the equity method of accounting for this joint venture. NMNG is working to develop the Yuzhno Khylchuyu (YK) field.

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 oil-throughput capacity from 30,000 barrels per day to 240,000 barrels per day 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 the fourth quarter of 2006, Gazprom stated the Shtokman field will be developed exclusively by Gazprom, without any international equity partners.

Caspian

In the 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. 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 artificial drilling islands with processing facilities and living quarters, and pipelines to carry production onshore. The initial production phase of the contract is for 20 years, with options to extend the agreement an additional 20 years. First production is expected in the 2010 time frame.

Transportation

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

Exploration

In 2006, appraisal of the Kalamkas More, Kashagan Southwest, Kairan and Aktote discoveries continued. A second successful appraisal well was drilled on Kalamkas More, and initial appraisal well drilling operations were under way at year-end on Kairan.

E&P OTHER

LNG

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 is designed to have 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 the 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.

In order to deliver the natural gas from the Freeport terminal to market, we plan to construct and operate a 32-mile, 42-inch pipeline from the Freeport terminal to an interconnector near Iowa Colony, Texas. Construction is expected to begin in February 2007 and is planned for completion in early 2008 to coincide with the Freeport terminal startup.

In 2006, we withdrew our license applications under the federal Deepwater Port Act for the Compass Port and Beacon Port Terminals, which were proposed LNG regasification terminals located offshore Alabama and offshore Louisiana, respectively, in federal waters in the Gulf of Mexico. We continue to pursue a proposed LNG regasification terminal in the Port of Long Beach, California. This proposed facility would be a joint venture, and the project is seeking the necessary permits.

In Europe, we are working jointly with Essent Energie B.V. to develop an LNG regasification terminal at the Port of Eemshaven in the Netherlands. A preliminary engineering study was completed in 2006, and we submitted applications for the environmental permitting process and exemption from regulated third party access.

In 2006, we, along with the other Norsea Pipeline Limited shareholders, progressed the application to obtain planning permission for an LNG regasification facility and combined heat and power plant at the existing Norsea Pipeline Limited oil terminal site at Teesside, United Kingdom. The application is expected to be submitted to regulatory authorities in early 2007.

Commercial

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 the United States, the United Kingdom, Singapore and Canada.

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 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 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 Lower 48 states.

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, 2006. No difference exists between our estimated total proved reserves for year-end 2005 and year-end 2004, which are shown in this filing, and estimates of these reserves shown in a filing with another federal agency in 2006.

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 5.7 trillion cubic feet of natural gas and 266 million barrels of crude oil in the future, including 1 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 commitments relate to proved undeveloped reserves. See the disclosure on Proved Undeveloped Reserves in Management s Discussion and Analysis of Financial Condition and Results of Operations for information on the development of proved undeveloped reserves.

MIDSTREAM

At December 31, 2006, our Midstream segment represented 1 percent of ConocoPhillips total assets, while contributing 3 percent of net income.

Our Midstream business is primarily conducted through our 50 percent equity investment in DCP Midstream, LLC, formerly named Duke Energy Field Services, LLC (DEFS). DCP Midstream is a joint venture with Spectra Energy, the natural gas business formerly owned by Duke Energy Corporation (Duke). Effective January 2, 2007, Spectra Energy became a separate legal entity from Duke, and the name of the joint venture was changed from DEFS to DCP Midstream to reflect this change in ownership.

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

21

liquids extracted in 2006, including our share of DCP Midstream, was 209,000 barrels per day, compared with 195,000 barrels per day in 2005.

DCP Midstream 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.

DCP Midstream is headquartered in Denver, Colorado. At December 31, 2006, DCP Midstream owned or operated 52 natural gas liquids extraction plants, 10 natural gas liquids fractionation plants, and its gathering and transmission systems included approximately 56,000 miles of pipeline. In 2006, DCP Midstream s raw natural gas throughput averaged 6.0 billion cubic feet per day, and natural gas liquids extraction averaged 360,000 barrels per day, compared with 5.9 billion cubic feet per day and 353,000 barrels per day, respectively, in 2005. DCP Midstream s assets are primarily located in the following producing regions: Rocky Mountains, Midcontinent, Permian, East Texas/North Louisiana, South Texas, Central Texas, and the Gulf Coast.

Outside of DCP Midstream, our U.S. natural gas liquids business included the following assets as of December 31, 2006:

- 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 70,000-barrels-per-day natural gas liquids fractionator. Our share of natural gas liquids extracted averaged 6,400 barrels per day in 2006, compared with 6,100 barrels per day in 2005.

REFINING AND MARKETING (R&M)

At December 31, 2006, our R&M segment represented 22 percent of ConocoPhillips total assets, while contributing 29 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).

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, supplies petroleum products to our marketing operations, and markets petroleum products directly to third parties. Commercial has buyers, traders and marketers in offices in the United States, the United Kingdom, Singapore and Canada.

UNITED STATES

Refining

At December 31, 2006, we owned and operated 12 crude oil refineries in the United States, having an aggregate crude oil throughput capacity of 2,208,000 barrels per day.

				Crude Throughput Capacity (MB/D)		
Refinery	**Location**		**Region**	**At December 31 2006**	**Effective January 1 2007**	
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	247	247	
				733	733	
Borger	Borger	Texas	Central	146	124	*
Wood River	Roxana	Illinois	Central	306	153	*
Ponca City	Ponca City	Oklahoma	Central	187	187	
				639	464	
Billings	Billings	Montana	West Coast	58	58	
Ferndale	Ferndale	Washington	West Coast	96	96	
Los Angeles	Carson/Wilmington	California	West Coast	139	139	
San Francisco	Arroyo Grande/ San Francisco	California	West Coast	120	120	
				413	413	
				2,208	2,033	

**Amounts reflect the contribution of the Wood River and Borger refineries to the downstream joint venture with EnCana, effective January 1, 2007.*

23

<u>East Coast Region</u>

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, ultra low sulfur diesel and jet fuel. Other products include petrochemical feedstocks, home heating oil and residual fuel oil. The facility distributes its refined products to East Coast customers by pipeline, barge, railcar and truck. 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 and often moving feedstocks between the facilities. Trainer receives a majority of its crude oil by tanker from West Africa, Canada and the North Sea. The refinery produces a high percentage of transportation fuels, such as gasoline, diesel and jet fuel. Other products include home heating oil, residual fuel oil and liquefied petroleum gas. Refined products are primarily distributed to customers in Pennsylvania, New York and New Jersey by pipeline, barge, railcar and truck.

<u>Gulf Coast Region</u>

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. Other products include home heating oil, petrochemical feedstocks and anode petroleum coke. The majority of the refined products are distributed to customers in the southeastern and eastern United States through major common-carrier pipeline systems and by barge.

The Alliance refinery was shutdown in anticipation of Hurricane Katrina in August 2005, and remained shutdown as a result of flooding and damages sustained during the hurricane. The refinery began partial operation in January 2006 and returned to normal operations in April 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 crude oil, but also processes 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 from the Petrozuata project and Mexican crude oil, both delivered via tanker. The refinery produces a high percentage of transportation fuels, such as gasoline, off-road diesel and jet fuel, along with home heating oil. The majority of its refined products are distributed to customers by truck, railcar, barge or major common-carrier pipelines to customers in the southeastern and eastern United States. In addition, refined products can be sold into export markets through the refinery s marine terminal.

The Lake Charles facilities include a specialty coker and calciner that manufacture graphite petroleum coke, which is supplied to the steel 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.

Sweeny Refinery

The Sweeny refinery is located in Old Ocean, Texas. The refinery has a crude oil processing capacity of 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. Other products include home heating oil, petrochemical feedstocks and petroleum (fuel) coke. Refined products are distributed throughout the midwest and southeastern United States by pipeline, barge and railcar.

ConocoPhillips has a 50 percent interest in Merey Sweeny, L.P., a limited partnership that owns a 65,000-barrel-per-day delayed coker and related facilities at the Sweeny refinery. PDVSA, which owns the other 50 percent interest, supplies the refinery with Venezuelan Merey, or equivalent, Venezuelan crude oil. We are the operating partner.

Central Region

EnCana Joint Venture

In October 2006, we announced a business venture with EnCana Corporation (EnCana), to create an integrated North American heavy-oil business. The transaction closed on January 3, 2007. The venture consists of two 50/50 operating joint ventures, a Canadian upstream general partnership, FCCL Oil Sands Partnership, and a U.S. downstream limited liability company, WRB Refining LLC. We plan to use the equity method of accounting for our investments in both joint ventures. See the Exploration and Production (E&P) section for additional information on the upstream joint venture.

The downstream joint-venture assets consist of our Borger and Wood River refineries, located in Borger, Texas, and Roxana, Illinois, respectively. This joint venture plans to expand heavy-oil processing capacity at these facilities from 60,000 barrels per day to approximately 550,000 barrels per day by 2015. Total crude oil throughput at these two facilities is expected to increase from the current 452,000 barrels per day to approximately 600,000 barrels per day over the same time period. We are the operator and managing partner of this downstream joint venture. EnCana is expected to contribute $7.5 billion, plus accrued interest, to this joint venture over a 10-year period beginning in 2007. For the Borger refinery, we are entitled to 85 percent of the operating results in 2007, 65 percent in 2008, and 50 percent in all years thereafter. For the Wood River refinery, operating results are shared 50/50, effective upon formation.

Borger Refinery

The Borger refinery is located in Borger, Texas, and the complex includes a natural gas liquids fractionation facility. As discussed above, this refinery was contributed to the joint venture with EnCana on January 3, 2007. 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, high-sulfur and medium, high-sulfur 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. In addition, we have begun construction of a new vacuum unit and revamps of heavy oil and distillate hydrotreaters. These projects 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.

Wood River Refinery

The Wood River refinery is located on the east side of the Mississippi River in Roxana, Illinois. As discussed above, this refinery was contributed to the joint venture with EnCana on January 3, 2007. It has 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 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 began operations in 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. The refinery processes a mixture of light, medium and heavy crude oil. Most of the crude processed is received by pipeline from the Gulf of Mexico, Oklahoma, Kansas, Texas and Canada. The refinery produces high ratios of low-sulfur gasoline and ultra-low-sulfur diesel fuel from crude oil. Finished petroleum products are primarily shipped by company-owned and common-carrier pipelines to markets throughout the Midcontinent region.

West Coast Region

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 oil, 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, diesel and aviation fuels, as well as fuel-grade petroleum coke. Finished petroleum products from the refinery are delivered by pipeline, railcar and truck. Pipelines transport most of the refined products to markets in Montana, Wyoming, Utah, and Washington.

Ferndale Refinery

The Ferndale refinery is located on Puget Sound in Ferndale, Washington. The refinery has a crude oil processing capacity of 96,000 barrels per day. The refinery primarily receives light, low-sulfur crude oil from the Alaskan North Slope. The refinery also receives crude oil from Canada. The refinery produces transportation fuels such as gasoline and diesel. 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.

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 government-mandated oxygenate requirements. Refined products are distributed to customers in southern California, Nevada and Arizona by pipeline and truck.

San Francisco Refinery

The San Francisco refinery is composed of two linked facilities located about 200 miles apart. The Santa Maria facility is located in Arroyo Grande, California, about 200 miles south of San Francisco, while the Rodeo facility is in the San Francisco Bay area. The refinery has a crude oil processing capacity of 120,000 barrels per day. The refinery processes mainly heavy, high-sulfur crude oil. The Rodeo facility has a calciner to upgrade the value of the coke that is produced. The refinery receives crude oil from 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 a high percentage of 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 government-mandated oxygenate requirements. Refined products are distributed by pipeline, railcar, truck and barge to customers in California.

Marketing

In the United States, R&M markets gasoline, diesel fuel, and aviation fuel through approximately 10,600 outlets in 49 states. The majority of these sites utilize the Conoco, Phillips 66 or 76 brands.

Wholesale

In our wholesale operations, we utilize a network of marketers and dealers operating approximately 9,600 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 580 Phillips 66 branded locations in the United States.

Retail

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

At December 31, 2006, 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.

In December 2006, we announced our company-owned and company-operated retail outlets are expected to be divested to new or existing wholesale marketers. Of the approximately 830 retail outlets scheduled for divestiture, 330 are company-owned and company-operated. The remaining outlets are operated by dealers.

Transportation

Pipelines and Terminals

At December 31, 2006, we had approximately 30,000 miles of common-carrier crude oil, raw natural gas liquids, and petroleum products pipeline systems in the United States, including those partially owned and/or operated by affiliates. We also owned and/or operated 65 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 1,860-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. Keystone received shipper support in December 2005, securing 340,000 barrels per day of contractual support. The National Energy Board, an independent federal regulatory agency in Canada, approved the conversion of a portion of the existing pipeline from natural gas to crude oil service on February 9, 2007. Additional regulatory filings are proceeding. The targeted in-service date remains the end of 2009. We expect to utilize the Keystone pipeline to supply Canadian crude to our U.S. refineries in the central region and to transport our Canadian crude production to market.

Tankers

At December 31, 2006, 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 segment overview, 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 includes 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 also manufacture high-quality graphite and anode-grade cokes in the United States and Europe for use in the global steel and aluminum industries.

INTERNATIONAL

Refining

In May 2006, we signed a Memorandum of Understanding with the Saudi Arabian Oil Company to conduct a detailed evaluation of a proposed development of a 400,000-barrel-per-day, full-conversion refinery in Yanbu, Saudi Arabia. The refinery would be designed to process Arabian heavy crude oil and produce high-quality, ultra-low-sulfur refined products. A joint ConocoPhillips and Saudi Aramco project team are developing the front-end engineering design.

In July 2006, we announced the signing of a Memorandum of Understanding with International Petroleum Investment Company (IPIC) of Abu Dhabi to identify new upstream and downstream opportunities for joint investment. The parties also signed a Heads of Agreement to conduct a feasibility study for construction of a world scale 500,000-barrel-per-day refinery in Fujairah, United Arab Emirates. This joint feasibility study has been completed, and we are currently evaluating the results with IPIC.

At December 31, 2006, R&M owned or had an interest in seven refineries outside the United States with an aggregate crude oil capacity of 693,000 net barrels per day.

				Crude Throughput Capacity (MB/D)	
Refinery	Location		Ownership Interest	At December 31 2006	Effective January 1 2007
Humber	N. Lincolnshire	United Kingdom	100.00 %	221	221
Whitegate	Cork	Ireland	100.00 %	71	71
Wilhelmshaven	Wilhelmshaven	Germany	100.00 %	260	260
MiRO	Karlsruhe	Germany	18.75 %	56	57
CRC	Litvinov/Kralupy	Czech Republic	16.33 %	27	27
Melaka	Melaka	Malaysia	47.00 %	58	60
				693	696

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 light, low-sulfur and acidic crude oil. The refinery also processes intermediate feedstocks, mostly vacuum gas oils and residual fuel oil.

The Humber refinery is a fully integrated refinery that produces a high percentage of transportation fuels, such as gasoline and diesel. Other products include home heating oil and specialty chemicals. 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. Products produced in the refinery are mainly marketed in the United Kingdom, along with 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, low-sulfur crude oil sourced mostly from the North Sea. The refinery primarily produces transportation fuels, such as gasoline, diesel and fuel oil, which are distributed to the inland market, as well as being exported to Europe and the United States. We also operate a crude oil and products storage complex consisting of 7.5 million barrels of storage capacity and an offshore mooring buoy, located in Bantry Bay, about 80 miles southwest of the Whitegate refinery in southern Cork County.

Wilhelmshaven Refinery

On February 28, 2006, we closed the acquisition of the Wilhelmshaven refinery, located in the northern state of Lower Saxony in Germany. The purchase included the 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 Wilhelmshaven refinery has a crude oil processing capacity of 260,000 barrels per day. Crude oil processed by the refinery is low-sulfur sourced mostly from the North Sea. The Wilhelmshaven refinery primarily produces transportation fuels, fuel oil, and intermediate feedstocks, which are distributed to the inland market via truck and are also exported to Europe and the United States.

Escalating project costs worldwide led to deferral of the deep conversion project at the Wilhelmshaven refinery. This deferral will allow the company to examine alternative means of upgrading the refinery.

MiRO Refinery

The Mineraloel Raffinerie Oberrhein GmbH (MiRO) refinery in Karlsruhe, Germany, is a joint-venture refinery with a crude oil processing capacity of 302,000 barrels per day. Effective January 1, 2007, the refinery s capacity was increased by 5,000 barrels per day, with our share being an increase of 1,000 barrels per day. The increase was the result of incremental debottlenecking. We have an 18.75 percent interest in MiRO, giving us a net capacity share of 57,000 barrels per day. The refinery s crude oil feedstock includes medium-sulfur crude oil. 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 co-venturers in proportion to their respective ownership interests. The majority of refined products are distributed by truck and railcar to Germany and neighboring markets.

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 light, low-sulfur 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 oil, 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 co-venturers, with each co-venturer receiving its 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. Effective January 1, 2007, 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. The refinery has a rated crude oil processing capacity of 128,000 barrels per day, of which our share is 60,000 barrels per day. The medium, high-sulfur 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 tanker to primarily Asian markets.

Marketing

R&M has marketing operations in 15 European countries. R&M s European marketing strategy is to sell primarily through owned, leased or joint-venture retail sites using a low-cost, high-volume 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. We also sell a portion of our Ireland refinery output to inland Irish markets.

As of December 31, 2006, R&M had approximately 2,000 marketing outlets in its European operations, of which approximately 1,500 were company-owned, and 500 were dealer-owned. Through our joint-venture operations in Switzerland, we also have interests in 184 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, 2006, R&M had 147 JET branded marketing outlets in our wholly owned Thailand operations in Asia. In Malaysia, there are 40 company-owned, dealer-operated and 4 dealer-owned, dealer-operated ProJET branded retail sites. The convenience stores in Malaysia are operated by a third party under the 7-Eleven brand.

We have announced our intention to sell some of our non-strategic marketing businesses. In December 2006, we reached an agreement to sell 376 of our fueling stations in six European countries to LUKOIL. This transaction is expected to close in the second quarter of 2007.

LUKOIL INVESTMENT

At December 31, 2006, our LUKOIL Investment segment represented 6 percent of ConocoPhillips total assets, while contributing 9 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. At December 31, 2006, we had a 20 percent ownership interest, based on authorized and issued shares, and a 20.6 percent ownership interest, based on estimated shares outstanding. See Note 10 Investments, Loans and Long-Term Receivables, in the Notes to Consolidated Financial Statements, for additional information.

Under the Shareholder Agreement between the two companies, we have representation on the LUKOIL Board of Directors (Board), and LUKOIL s corporate charter requires unanimous Board consent for certain key decisions. In addition, the Shareholder Agreement limits our ownership interest in LUKOIL to

20 percent, based on authorized and issued shares, and limits our ability to sell our LUKOIL shares for a period of four years from September 29, 2004, 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, 2006, was 1,805 million BOE.

As reported in LUKOIL s 2005 annual report, the majority of its 2005 upstream oil production was sourced within Russia, with 65 percent from the western Siberia region, 14 percent from the Timan-Pechora province and 11 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 seven refineries with a net crude oil throughput capacity of approximately 1.2 million barrels per day. In addition, LUKOIL has a marketing network which extends to 18 countries, with the majority of wholesale and retail sales in Russia, the United States and Europe.

CHEMICALS

At December 31, 2006, our Chemicals segment represented 1 percent of ConocoPhillips total assets, while contributing 3 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.

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 owns a 49 percent interest in this joint venture. Construction of a second complex in Mesaieed, Q-Chem II, began in late 2005, of which CPChem also owns a 49 percent interest. The Q-Chem II facility is designed to produce polyethylene and NAO, 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 Q-Chem II plants. Operational startup of both projects is anticipated in early 2009.

In 2003, CPChem formed a 50-percent-owned joint venture company to develop an integrated styrene facility in Al Jubail, Saudi Arabia. The facility, being 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 existing benzene plant, together called the JCP Project. Operational startup is anticipated in late 2007.

EMERGING BUSINESSES

At December 31, 2006, our Emerging Businesses segment represented 1 percent of ConocoPhillips total assets, while contributing less than 1 percent of net income.

Emerging Businesses encompass the development of new technologies and businesses outside our normal scope of operations.

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.

The Immingham combined heat and power (CHP) plant, a 730-megawatt, gas-fired facility in North Lincolnshire, United Kingdom, was placed in commercial operations in October 2004. This wholly owned 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.

In October 2006, we announced we would invest approximately $400 million to expand the capacity at our Immingham CHP plant by 450 megawatts to 1,180 megawatts. 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. Commercial operation of the expansion is currently expected to start in mid-2009.

We also own a gas-fired cogeneration plant in Orange, Texas. We sold our interest in Ingleside, a gas-fired cogeneration plant in Corpus Christi in October 2006.

Gas-to-liquids (GTL)

As a result of market conditions, we have no immediate plans to further pursue GTL developments. We are, however, expanding our efforts to develop carbon-to-liquids technology focused on coal and petroleum coke.

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 ZorbTM SRT), alkylation technologies (ReVAPTM, IMPTM, SOFTTM), and

33

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.

Alternative Energy and Programs

Alternative Energy and Programs 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. ConocoPhillips is interested in the production of biofuels. We have recently commercialized the production of renewable diesel, a new type of renewable fuel that utilizes existing infrastructure. We have also formed a research relationship with Iowa State University to develop new methods for producing second-generation biofuels.

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 publicly available year-end 2005 reserves statistics, we had, on a BOE basis, the fifth-largest total of worldwide proved reserves of non-government-controlled companies, after giving consideration to the 2006 acquisition of Burlington Resources. 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 DCP Midstream 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. DCP Midstream is a large producer of natural gas liquids in the United States. DCP Midstream s 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 18, 2006, issue of the *Oil & Gas Journal*, our R&M segment had the second-largest U.S. refining capacity of 15 large refiners of petroleum products. Worldwide, it ranked fourth 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 2006 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 2006, we held a total of 1,751 active patents in 70 countries worldwide, including 706 active U.S. patents. During 2006, we received 57 patents in the United States and 77 foreign patents. Our products and processes generated licensing revenues of $35 million in 2006. 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 $117 million, $125 million, and $126 million in 2006, 2005, and 2004, 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 2006 and those expected for 2007 and 2008.

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. 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 spending, our share repurchase programs, our debt reduction programs, or 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, 2006, 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 176 through 195, 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 we are unsuccessful 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 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 2006 was derived from production outside the United States, and 61 percent of our proved reserves, as of December 31, 2006, 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., state and local governments 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 our joint-venture partners may be unable to meet their economic or other obligations and 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 integrating and optimizing assets acquired in recent acquisitions.

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.

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 2006 and those matters previously reported in ConocoPhillips 2005 Form 10-K and our first-, second- and third-quarter 2006 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 proceedings 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.

New Matters

On November 9, 2006, the Bay Area Air Quality Management District (BAAQMD) issued a demand to settle 33 Notices of Violation (NOVs) dated between October 2005 and October 2006. The NOVs allege violations of various BAAQMD regulations or permit requirements at our San Francisco area refinery. BAAQMD s initial demand is to settle all 33 NOVs for $219,000. We are working with BAAQMD to resolve this matter.

In December 2005, routine tests at our refinery in Lake Charles, Louisiana, revealed that certain particulate matter emissions did not meet established limits. The refinery has been working diligently to resolve this issue and expects to be in full compliance with all applicable particulate matter emission limits by the second quarter of 2007. The Environmental Protection Agency (EPA) and Louisiana Department of Environmental Quality have been kept informed of the refinery s remedial actions. The refinery will continue to work with the agencies to resolve any issues or enforcement actions.

In December 2005, ConocoPhillips Canada, Limited (COPC) was charged with five counts under the Environmental Protection and Enhancement Act of Alberta relating to a pipeline leak in Central Alberta that occurred in January 2004. The charges allege that COPC released a substance into the environment that could or did have a significant adverse effect and allege that COPC failed to contain and report the release when it was first detected. We have now received disclosure of the provincial government s case. We have met with government counsel and are exploring the prospect of resolution of this matter. A trial is scheduled to commence on February 27, 2007.

Matters Previously Reported

In September 2006, the San Luis Obispo Air Pollution Control District (SLOAPCD) issued a demand to settle four NOVs issued between May and August 2006 with respect to our Santa Maria facility, a part of our San Francisco area refinery. The NOVs allege we: exceeded green coke feed limit on 17 separate days; failed to timely submit a second quarter 2006 report; failed to sample and analyze certain air emissions; and exceeded carbon plant pressure limits for three days. SLOAPCD s initial monetary demand is $143,000 to settle all four NOVs. We are working with SLOAPCD to resolve this matter.

BAAQMD has notified us of its intent to seek civil penalties for several pending NOVs issued between August 2005 and July 2006 alleging violations of various BAAQMD regulations at the Rodeo facility of our San Francisco refinery. The BAAQMD has not yet specified a penalty for these alleged violations. However, we are currently assessing these allegations and expect to work with the BAAQMD toward a resolution of these NOVs.

On March 28, 2006, the Texas Commission on Environmental Quality (TCEQ) issued a revised draft agreed order relating to alleged air quality and solid waste violations at our Borger refinery. The order addresses several categories of air quality violations including emission events, violation of permit conditions, and failure to pay emission fees, and a single solid waste violation for improper classification and disposal of waste. The order proposes a penalty of $160,406. We are currently evaluating the proposed order and anticipate working with TCEQ to resolve the matter.

On December 16, 2005, our Bayway refinery experienced a hydrocarbon spill to the Rahway River and Arthur Kill. As a result of this spill, we received a draft Order on Consent (Order) from the state of New York, and are also negotiating similar settlements with the state of New Jersey and the federal government. The final settlement with New York included a civil penalty of $75,000 of which $25,000 was suspended because we also agreed to do a beach cleanup project. Settlement discussions with the State of New Jersey and the federal government are ongoing.

In December 2005, the 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 Title V permit reporting. We expect to work with the TCEQ to resolve 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. The penalty payment has been made and this matter has been resolved.

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 responded to these allegations and expect to work with the DOT toward a resolution of this matter.

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.

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	51
William B. Berry	Executive Vice President, Exploration and Production Europe, Asia, Africa and Middle East	54
John A. Carrig	Executive Vice President, Finance, and Chief Financial Officer	55
Philip L. Frederickson	Executive Vice President, Planning, Strategy and Corporate Affairs	50
James L. Gallogly	Executive Vice President, Refining, Marketing and Transportation	54
Stephen F. Gates	Senior Vice President, Legal, and General Counsel	60
Randy L. Limbacher	Executive Vice President, Exploration and Production Americas	48
John E. Lowe	Executive Vice President, Commercial	48
James J. Mulva	Chairman, President and Chief Executive Officer	60

**On March 1, 2007.*

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 9, 2007. 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 Europe, Asia, Africa and Middle East, of ConocoPhillips effective April 1, 2006, having previously served as ConocoPhillips Executive Vice President, Exploration and Production, since 2003. He 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.

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.

Philip L. Frederickson was appointed Executive Vice President, Planning, Strategy and Corporate Affairs of ConocoPhillips effective April 1, 2006, having previously served as Executive Vice President, Commercial of ConocoPhillips since completion of the merger. Prior to the merger, he was Conoco s Senior Vice President of Corporate Strategy and Business Development since 2001.

44

James L. Gallogly was appointed Executive Vice President, Refining, Marketing and Transportation of ConocoPhillips effective April 1, 2006, having previously served as President and Chief Executive Officer of Chevron Phillips Chemical Company LLC since 2000.

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.

Randy L. Limbacher was appointed Executive Vice President, Exploration and Production Americas of ConocoPhillips effective April 1, 2006, having previously served as Executive Vice President and Chief Operating Officer of Burlington Resources since 2002. He served as Senior Vice President, Production of Burlington Resources since 2001.

John E. Lowe was appointed Executive Vice President, Commercial of ConocoPhillips effective April 1, 2006, having previously served as Executive Vice President, Planning, Strategy and Corporate Affairs of ConocoPhillips since completion of the merger. Prior to the merger, he was Phillips Senior Vice President, Corporate Strategy and Development since 2001.

James 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.

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
2006			
First	**$ 66.25**	**58.01**	**.36**
Second	**72.50**	**57.66**	**.36**
Third	**70.75**	**56.55**	**.36**
Fourth	**74.89**	**54.90**	**.36**
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

Closing Stock Price at December 31, 2006	$ 71.95
Closing Stock Price at January 31, 2007	$ 66.41
Number of Stockholders of Record at January 31, 2007*	66,202

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

46

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased*	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs**	Millions of Dollars Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs
October 1-31, 2006	1,438,711	$ 60.22	1,438,124	$ 314
November 1-30, 2006	1,701,095	63.13	1,697,630	207
December 1-31, 2006	1,354,740	70.97	1,346,075	112
Total	4,494,546	$ 64.56	4,481,829	

**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 providing 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, and was completed in April 2006. 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. On January 12, 2007, we announced a stock repurchase program that provides for the repurchase of up to $1 billion of the company s common stock. On February 9, 2007, we announced plans to purchase $4 billion of our common stock in 2007, including the $1 billion announced on January 12, 2007. 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.*

47

Item 6. SELECTED FINANCIAL DATA

	Millions of Dollars Except Per Share Amounts				
	2006	**2005**	**2004**	**2003**	**2002**
Sales and other operating revenues	**$ 183,650**	179,442	135,076	104,246	56,748
Income from continuing operations	**15,550**	13,640	8,107	4,593	698
Per common share					
Basic	**9.80**	9.79	5.87	3.37	.72
Diluted	**9.66**	9.63	5.79	3.35	.72
Net income (loss)	**15,550**	13,529	8,129	4,735	(295)
Per common share					
Basic	**9.80**	9.71	5.88	3.48	(.31)
Diluted	**9.66**	9.55	5.80	3.45	(.31)
Total assets	**164,781**	106,999	92,861	82,455	76,836
Long-term debt	**23,091**	10,758	14,370	16,340	18,917
Mandatorily redeemable minority interests and preferred securities				141	491
Cash dividends declared per common share	**1.44**	1.18	.895	.815	.74

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

- The merger of Conoco and Phillips in 2002.
- The acquisition of Burlington Resources in 2006.

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

48

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

February 22, 2007

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 c 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 96.

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 38,400 employees worldwide, and at year-end 2006 had assets of $165 billion. Our stock is listed on the New York Stock Exchange under the symbol COP.

On March 31, 2006, we completed the $33.9 billion acquisition of Burlington Resources Inc., an independent exploration and production company that held a substantial position in North American natural gas proved reserves, production and exploratory acreage. This acquisition added approximately 2 billion barrels of oil equivalent to our proved reserves. The acquisition is reflected in our results of operations beginning in the second quarter of 2006.

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, processes and markets natural gas produced by ConocoPhillips and others, and fractionates and markets natural gas liquids, primarily in the United States and Trinidad. The Midstream segment primarily consists of our 50 percent equity investment in DCP Midstream, LLC, formerly named Duke Energy Field Services, LLC.

- 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. At December 31, 2006, our ownership interest, based on authorized and issued shares, was 20 percent, and 20.6 percent based on estimated shares outstanding.

- 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).

- Emerging Businesses This segment includes the development of new technologies and businesses outside our normal scope of operations.

Crude oil and natural gas prices, along with refining margins, are the most significant factors 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 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 improve 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. Although it cannot be assured, 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. The acquisition of Burlington Resources in March of 2006 added approximately 2 billion barrels of oil equivalent to our proved reserves, and through our investments in LUKOIL over the past three years we purchased about 1.9 billion barrels of oil equivalent. In the three years ending December 31, 2006, our reserve replacement was 254 percent, including the impact of the Burlington Resources acquisition and our additional equity investment 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 and the communities in which we operate. Maintaining high utilization rates at our refineries and minimizing downtime in producing fields enable us to capture the value available in the market in terms of prices and margins. During 2006, our worldwide refinery capacity utilization rate was 92 percent, compared with 93 percent in 2005. The reduced utilization rate reflects both scheduled downtime and unplanned weather-related downtime. Concerning the environment, we strive to conduct our operations in a manner consistent with our environmental stewardship principles.

- Controlling costs and expenses. Since we cannot control the prices of the commodity products we sell, controlling operating and overhead costs and prudently managing our capital program, within the context of our commitment to safety and environmental stewardship, are high priorities. 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 managing operating and overhead costs are critical to maintaining competitive positions in our industries, cost control is a component of our variable compensation programs. With the rise in commodity prices over the last several years, and the subsequent increase in industry-wide spending on capital and major maintenance programs, we and other energy companies are experiencing inflation for the costs of certain goods and services in excess of general worldwide inflationary trends. Such costs include rates for drilling rigs, steel and other raw materials, as well as costs for skilled labor. While we work to manage the effect these inflationary pressures have on our costs, our capital program has been impacted by these factors, and certain projects have been delayed. Our capital program may be further impacted by these factors going forward.

• 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 2006 totaled $15.6 billion, and we anticipate capital expenditures and investments to be approximately $12.3 billion in 2007.

• 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 strategic plans 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 2005 and 2006, we increased our investment in LUKOIL, ending the year with a 20 percent ownership interest, based on authorized and issued shares. During 2006, we completed the $33.9 billion acquisition of Burlington Resources. Also during 2006, we announced the commencement of an asset rationalization program to evaluate our asset base to identify those assets that may no longer fit into our strategic plans or those that could bring more value by being monetized in the near term. This program generated proceeds of $1.5 billion through January 31, 2007. We expect this rationalization program to result in proceeds from asset dispositions of $3 billion to $4 billion. In December 2006, we announced a program to dispose of our company-owned U.S. retail marketing outlets to new or existing wholesale marketers.

• 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, natural gas and natural gas liquids prices and production, 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 2006 totaled $383 million, compared with $42 million in 2005. 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 2006 we had $31.5 billion of goodwill on our balance sheet, after reclassifying $340 million to current assets and recording an impairment of $230 million related to assets held for sale. 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.

• Effective Tax Rate. Our operations are located in countries with different tax rates and fiscal structures. Accordingly, even in a stable commodity price and fiscal/regulatory environment, our overall effective tax rate can vary significantly between periods based on the mix of pre-tax earnings within our global operations.

- Fiscal and Regulatory Environment. As commodity prices and refining margins improved over the last several years, certain governments have responded with changes to their fiscal take. These changes have generally negatively impacted our results of operations, and further changes to government fiscal take could have a negative impact on future 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. Industry crude oil prices for West Texas Intermediate were higher in 2006 compared with 2005, averaging $66.00 per barrel in 2006, an increase of 17 percent. The increase was primarily due to growth in global consumption associated with continuing economic expansions and limited spare capacity from major exporting countries. Industry natural gas prices for Henry Hub decreased during 2006 to $7.24 per million British thermal units (MMBTU), down 16 percent, compared with the 2005 average of $8.64 per MMBTU, primarily due to high storage levels and moderate weather.

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 DCP Midstream. During 2005, we increased our ownership interest in DCP Midstream from 30.3 percent to 50 percent, and we recorded a gain of $306 million, after-tax, for our equity share of DCP Midstream s sale of its general partnership interest in TEPPCO Partners, LP (TEPPCO). An adjustment recorded in 2006 increased this gain by $24 million. DCP Midstream s natural gas liquids prices increased 11 percent in 2006, generally tracking the increase in crude oil prices.

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. Industry refining margins in the United States were stronger overall in comparison to 2005, contributing to improved R&M profitability. Key factors contributing to the stronger refining margins in 2006 were high U.S. gasoline and distillate demand. Industry marketing margins in the United States were stronger in 2006, compared with those in 2005, as the market did not encounter the steep product cost increases experienced in 2005 due to hurricanes.

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 from the Russian government for approximately $2 billion. During the remainder of 2004, all of 2005 and 2006, we invested an additional $5.5 billion, bringing our equity ownership interest in LUKOIL to 20 percent by year-end 2006, based on authorized and issued shares. 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 province 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 2006 financial results from Chemicals 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. The businesses in this segment focus on staying current on new technologies to support our primary segments. They also pursue technologies involving heavy oils, biofuels, and alternative energy sources. Some of these technologies may have the potential to become important drivers of profitability in future years.

RESULTS OF OPERATIONS

Consolidated Results

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

	Millions of Dollars		
Years Ended December 31	**2006**	**2005**	**2004**
Exploration and Production (E&P)	**$ 9,848**	8,430	5,702
Midstream	**476**	688	235
Refining and Marketing (R&M)	**4,481**	4,173	2,743
LUKOIL Investment	**1,425**	714	74
Chemicals	**492**	323	249
Emerging Businesses	**15**	(21)	(102)
Corporate and Other	**(1,187)**	(778)	(772)
Net income	**$ 15,550**	13,529	8,129

2006 vs. 2005

The improved results in 2006 were primarily the result of:

- Higher crude oil prices in the E&P segment.
- The inclusion of Burlington Resources in our results of operations for the E&P segment.
- Improved refining margins and volumes and marketing margins in the R&M segment s U.S. operations.
- Increased equity earnings from our investment in LUKOIL due to an increase in our ownership percentage and higher estimated commodity prices and volumes.
- The recognition in 2006 of business interruption insurance recoveries attributable to hurricanes in 2005.

These items were partially offset by:

- The impairment of certain assets held for sale in the R&M and E&P segments.
- Lower natural gas prices in the E&P segment.
- Higher interest and debt expense resulting from higher average debt levels due to the Burlington Resources acquisition.
- Decreased net income from the Midstream segment, reflecting the inclusion of our equity share of DCP Midstream s gain on the sale of the general partner interest in TEPPCO in our 2005 results.

53

2005 vs. 2004

The improved results in 2005, compared with 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.
- Increased equity earnings from our investment in LUKOIL.
- Our equity share of DCP Midstream s gain on the sale of its general partner interest in TEPPCO in 2005.

Income Statement Analysis

2006 vs. 2005

Sales and other operating revenues increased 2 percent in 2006, while purchased crude oil, natural gas and products decreased 5 percent. The increase in sales and other operating revenues was primarily due to higher realized prices for crude oil and petroleum products, as well as higher sales volumes associated with the Burlington Resources acquisition. These increases were mostly offset by decreases associated with the implementation of Emerging Issues Task Force Issue No. 04-13, Accounting for Purchases and Sales of Inventory with the Same Counterparty. The decrease in purchased crude oil, natural gas and products was primarily the result of the implementation of Issue No. 04-13. See Note 2 Changes in Accounting Principles, in the Notes to Consolidated Financial Statements, for additional information on the impact of this Issue on our income statement.

Equity in earnings of affiliates increased 21 percent in 2006. The increase reflects improved results from:

- LUKOIL, resulting from an increase in our ownership percentage, as well as higher estimated crude oil and petroleum products prices and volumes, and a net benefit from the alignment of our estimate of LUKOIL s fourth quarter 2005 net income to LUKOIL s reported results.
- Our chemicals joint venture, CPChem, due to higher margins and volumes, as well as the recognition of a business interruption insurance net benefit.

These increases were offset partially by the inclusion of our equity share of DCP Midstream s gain on the sale of the general partner interest in TEPPCO in our 2005 results.

Other income increased 47 percent during 2006, primarily due to the recognition in 2006 of recoveries on business interruption insurance claims attributable to losses sustained from hurricanes in 2005. In addition, interest income was higher in 2006. These increases were partially offset by higher net gains on asset dispositions recorded in 2005.

Production and operating expenses increased 22 percent in 2006. The increase was primarily due to the acquired Burlington Resources assets, increased production at the Bayu-Undan field associated with the Darwin liquefied natural gas (LNG) project in Australia, the first year of production in Libya, and the acquisition of the Wilhelmshaven refinery in Germany.

Exploration expenses increased 26 percent in 2006, primarily due to the Burlington Resources acquisition.

Depreciation, depletion and amortization (DD&A) increased 71 percent during 2006. The increase was primarily the result of the addition of Burlington Resources assets in E&P s depreciable asset base. In addition, the acquisition of the Wilhelmshaven refinery increased DD&A recorded by the R&M segment.

Impairments were $683 million in 2006, compared with $42 million in 2005. The increase primarily relates to the impairment in 2006 of certain assets held for sale in the R&M and E&P segments, comprised of properties, plants and equipment, trademark intangibles and goodwill. We also recorded an impairment charge in the E&P segment associated with assets in the Canadian Rockies Foothills area, as a result of declining well performance and drilling results. See Note 13 Impairments, in the Notes to Consolidated Financial Statements, for additional information.

Interest and debt expense increased from $497 million in 2005 to $1,087 million in 2006, primarily due to higher average debt levels as a result of the financing required to partially fund the acquisition of Burlington Resources.

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.

Equity in earnings of affiliates increased 125 percent in 2005, compared with 2004. 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 benefiting both ventures, and higher production volumes at Hamaca.
- Our chemicals joint venture, CPChem, due to higher margins.
- Our midstream joint venture, DCP Midstream, reflecting higher natural gas liquids prices and DCP Midstream s 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, compared with 2004. 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, compared with 2004. 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, compared with 2004, 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.

Restructuring Program

As a result of the Burlington Resources acquisition, we implemented a restructuring program in March 2006 to capture the synergies of combining the two companies. Under this program, which is expected to be completed by the end of March 2008, we recorded accruals totaling $230 million for employee severance payments, site closings, incremental pension benefit costs associated with the workforce reductions, and employee relocations. Approximately 600 positions have been identified for elimination, most of which are in the United States. Of the total accrual, $224 million is reflected in the Burlington Resources purchase price allocation as an assumed liability, and $6 million ($4 million after-tax) related to ConocoPhillips is reflected in selling, general and administrative expenses. Included in the total accruals of $230 million is $12 million related to pension benefits to be paid in conjunction with other retirement benefits over a number of future years. See Note 6 Restructuring, in the Notes to Consolidated Financial Statements, for additional information.

56

Segment Results

E&P

	2006	2005	2004
	Millions of Dollars		
Net Income			
Alaska	$ **2,347**	2,552	1,832
Lower 48	**2,001**	1,736	1,110
United States	**4,348**	4,288	2,942
International	**5,500**	4,142	2,760
	$ **9,848**	8,430	5,702
	Dollars Per Unit		
Average Sales Prices			
Crude oil (per barrel)			
United States	$ **61.09**	51.09	38.25
International	**63.38**	52.27	37.18
Total consolidated	**62.39**	51.74	37.65
Equity affiliates*	**46.01**	37.79	24.18
Worldwide E&P	**60.37**	49.87	36.06
Natural gas (per thousand cubic feet)			
United States	**6.11**	7.12	5.33
International	**6.27**	5.78	4.14
Total consolidated	**6.20**	6.32	4.62
Equity affiliates*	**.30**	.26	2.19
Worldwide E&P	**6.19**	6.30	4.61
Natural gas liquids (per barrel)			
United States	**40.35**	40.40	31.05
International	**42.89**	36.25	28.96
Total consolidated	**41.50**	38.32	30.02
Equity affiliates*			
Worldwide E&P	**41.50**	38.32	30.02
Average Production Costs Per Barrel of Oil Equivalent			
United States	$ **5.43**	4.24	3.70
International**	**5.65**	4.58	3.86
Total consolidated**	**5.55**	4.43	3.79
Equity affiliates*	**5.83**	4.93	4.14
Worldwide E&P**	**5.57**	4.47	3.81

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

***Prior years restated to reflect reclassification of certain costs to conform to current year presentation.*

	Millions of Dollars		
Worldwide Exploration Expenses			
General administrative; geological and geophysical; and lease rentals	$ **483**	312	286
Leasehold impairment	**157**	116	175
Dry holes	**194**	233	242
	$ **834**	661	703

57

	2006	2005	2004
	Thousands of Barrels Daily		
Operating Statistics			
Crude oil produced			
Alaska	**263**	294	298
Lower 48	**104**	59	51
United States	**367**	353	349
Europe	**245**	257	271
Asia Pacific	**106**	100	94
Canada	**25**	23	25
Middle East and Africa	**106**	53	58
Other areas	**7**		
Total consolidated	**856**	786	797
Equity affiliates*	**116**	121	108
	972	907	905
Natural gas liquids produced			
Alaska	**17**	20	23
Lower 48	**62**	30	26
United States	**79**	50	49
Europe	**13**	13	14
Asia Pacific	**18**	16	9
Canada	**25**	10	10
Middle East and Africa	**1**	2	2
	136	91	84
	Millions of Cubic Feet Daily		
Natural gas produced**			
Alaska	**145**	169	165
Lower 48	**2,028**	1,212	1,223
United States	**2,173**	1,381	1,388
Europe	**1,065**	1,023	1,119
Asia Pacific	**582**	350	301
Canada	**983**	425	433
Middle East and Africa	**142**	84	71
Other areas	**16**		
Total consolidated	**4,961**	3,263	3,312
Equity affiliates*	**9**	7	5
	4,970	3,270	3,317
	Thousands of Barrels Daily		
Mining operations			
Syncrude produced	**21**	19	21

**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, 2006, our E&P operations were producing in the United States, Norway, the United Kingdom, the Netherlands, Canada, Nigeria, Venezuela, Ecuador, Argentina, offshore Timor Leste in the Timor Sea, Australia, China, Indonesia, Algeria, Libya, the United Arab Emirates, Vietnam, and Russia.

2006 vs. 2005

Net income from the E&P segment increased 17 percent in 2006. The increase was primarily due to higher realized crude oil prices and, to a lesser extent, higher sales prices for natural gas liquids and Syncrude. In addition, increased sales volumes, primarily the result of the Burlington Resources acquisition, contributed positively to net income in 2006. These items were partially offset by lower realized natural gas prices, higher exploration expenses, the negative impacts of changes in tax laws, and asset impairments.

If crude oil prices in 2007 do not remain at the levels experienced in 2006, and if costs continue to increase, the E&P segment s earnings would be negatively impacted. See the Business Environment and Executive Overview section for additional information on industry crude oil and natural gas prices and inflationary cost pressures.

Proved reserves at year-end 2006 were 9.36 billion barrels of oil equivalent (BOE), compared with 7.92 billion BOE at year-end 2005. This excludes the estimated 1,805 million BOE and 1,442 million BOE included in the LUKOIL Investment segment at year-end 2006 and 2005, respectively. Also excluded is our share of Canadian Syncrude mining operations, which was 243 million barrels of proved oil sands reserves at year-end 2006, compared with 251 million barrels at year-end 2005.

U.S. E&P

Net income from our U.S. E&P operations increased slightly in 2006, primarily resulting from higher crude oil prices, as well as increased crude oil, natural gas, and natural gas liquids production in the Lower 48 states, reflecting the Burlington Resources acquisition. These increases were partially offset by lower natural gas prices, higher exploration expenses, lower production levels in Alaska, and higher production taxes in Alaska.

In August 2006, the state of Alaska enacted new production tax legislation, retroactive to April 1, 2006. The new legislation results in a higher production tax structure for ConocoPhillips.

U.S. E&P production on a BOE basis averaged 808,000 barrels per day in 2006, compared with 633,000 barrels per day in 2005. Production was favorably impacted in 2006 by the addition of volumes from the Burlington Resources assets, offset slightly by decreases in production levels in Alaska. Production in Alaska was negatively impacted by operational shut downs and weather-related transportation delays.

International E&P

Net income from our international E&P operations increased 33 percent in 2006, reflecting higher crude oil, natural gas, and natural gas liquids prices and production, as well as higher levels of LNG production from the Darwin LNG facility associated with the Bayu-Undan field in the Timor Sea. These increases were offset partially by increased exploration expenses and a $93 million after-tax impairment charge associated with assets in the Canadian Rockies Foothills area. In addition, the increases to net income were partially offset by the negative impacts of tax law changes.

The following international tax legislation was enacted during 2006:

- In the United Kingdom, the rate of supplementary corporation tax applicable to U.K. upstream activity increased in July 2006 from 10 percent to 20 percent, retroactive to January 1, 2006, which increased the U.K. upstream corporation tax from 40 percent to 50 percent. This resulted in additional tax expense during 2006 of approximately $470 million, comprised of approximately $250 million for revaluing beginning deferred tax liability balances, and approximately $220 million to reflect the new rate from January 1, 2006.

- In Canada, the Alberta government reduced the Alberta corporate income tax rate from 11.5 percent to 10 percent, effective April 2006. In addition, the Canadian federal government announced federal tax rate reductions whereby the federal tax rate will decline by 2 percent over the period 2008 to 2010 and the 1.12 percent federal surtax will be eliminated in 2008. As a result of these tax rate reductions, we recorded a one-time favorable adjustment in the E&P segment of $401 million to our deferred tax liability in the second quarter of 2006.

- The China Ministry of Finance enacted a Special Levy on Earnings from Petroleum Enterprises, effective March 26, 2006. The special levy, which is based on the cost recovery price of crude oil, starts at a rate of 20 percent of the excess price when crude oil prices exceed $40 per barrel, and increases 5 percent for every corresponding $5 per barrel increase in the cost recovery price. Once the cost recovery price reaches $60 per barrel, a maximum levy rate of 40 percent is applied. This special levy resulted in a negative impact to earnings of $41 million in 2006.

- The Venezuelan government enacted an extraction tax of 33.33 percent with an effective date of May 29, 2006. The tax is calculated based on the value of oil extracted, less royalty payments. This extraction tax resulted in a reduction in our equity earnings of $113 million in 2006. An increase in the Venezuelan income tax rate from 34 percent to 50 percent for heavy-oil projects was enacted in the third quarter of 2006, and became effective with the tax year beginning January 1, 2007. Had this new rate been in effect in 2006, our equity earnings would have been reduced by an estimated $205 million.

- The Algerian government enacted an exceptional profits tax with an effective date of August 1, 2006. In general, the exceptional profits tax applies to all calendar months during which the monthly arithmetic average of the high and low Brent price is greater than $30 per barrel. The tax rate is determined by reference to a price coefficient, the calculation of which is prescribed in the legislation. For 2006, the rate of the tax was 6.2 percent. The resulting negative impact on earnings in 2006 was approximately $36 million, including a rate adjustment effected in respect of the deferred tax provision.

International E&P production averaged 1,128,000 BOE per day in 2006, an increase of 24 percent from 910,000 BOE per day in 2005. Production was favorably impacted in 2006 by the addition of Burlington Resources assets, higher gas production at Bayu-Undan associated with the Darwin LNG ramp-up in Australia, and the 2006 reentry into Libya. Our Syncrude mining operations produced 21,000 barrels per day in 2006, compared with 19,000 barrels per day in 2005.

2005 vs. 2004

Net income from the E&P segment increased 48 percent in 2005, compared with 2004. 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.

60

U.S. E&P

Net income from our U.S. E&P operations increased 46 percent in 2005, compared with 2004. 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 Utah and the San Juan Basin, mostly offset by normal field production declines, hurricane-related downtime, and the impact of asset dispositions.

International E&P

Net income from our international E&P operations increased 50 percent in 2005, compared with 2004. 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, 2005 production was higher than in 2004, when production was still ramping up. At the Hamaca project, 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.

Midstream

	2006	2005	2004
	Millions of Dollars		
Net Income*	**$ 476**	688	235
**Includes DCP Midstream-related net income:*	***$ 385***	*591*	*143*
	Dollars Per Barrel		
Average Sales Prices			
U.S. natural gas liquids*			
Consolidated	**$ 40.22**	36.68	29.38
Equity	**39.45**	35.52	28.60

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

	Thousands of Barrels Daily		
Operating Statistics			
Natural gas liquids extracted*	**209**	195	194
Natural gas liquids fractionated**	**144**	168	205

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

***Excludes DCP Midstream.*

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 DCP Midstream, LLC, formerly named Duke Energy Field Services, LLC, 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 DCP Midstream, which resulted in DCP Midstream becoming a jointly controlled venture, owned 50 percent by each company. Prior to the restructuring, our ownership interest in DCP Midstream was 30.3 percent. This restructuring increased our ownership in DCP Midstream through a series of direct and indirect transfers of certain Canadian Midstream assets from DCP Midstream to Duke, a disproportionate cash distribution from DCP Midstream to Duke from the sale of DCP Midstream s interest in TEPPCO Partners, L.P. (TEPPCO), and a combined payment by ConocoPhillips to Duke and DCP Midstream 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.

2006 vs. 2005

Net income from the Midstream segment decreased 31 percent in 2006, primarily due to the gain from the sale of DCP Midstream s interest in TEPPCO included in 2005 results. Our net share of this gain was $306 million on an after-tax basis. This decrease was partially offset by a $24 million positive tax adjustment recorded in 2006 to the gain recorded in 2005 on the sale of DCP Midstream s interest in TEPPCO, as well as higher natural gas liquids prices and an increased ownership interest in DCP Midstream.

2005 vs. 2004

Net income from the Midstream segment increased 193 percent in 2005, compared with 2004. Included in the Midstream segment s 2005 net income is a $306 million gain, representing our share of DCP Midstream s gain on the sale of its general partnership interest in TEPPCO. In addition, our Midstream segment benefited from improved natural gas liquids prices in 2005, which increased earnings at DCP Midstream, 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 DCP Midstream over the book value of our investment in DCP Midstream. The reduced amount in 2005 resulted from a significant reduction in the favorable basis difference of our investment in DCP Midstream following the restructuring.

R&M

	2006	2005	2004
	Millions of Dollars		
Net Income			
United States	**$ 3,915**	3,329	2,126
International	**566**	844	617
	$ 4,481	4,173	2,743

	Dollars Per Gallon		
U.S. Average Sales Prices*			
Automotive gasoline			
Wholesale	**$ 2.04**	1.73	1.33
Retail	**2.18**	1.88	1.52
Distillates wholesale	**2.11**	1.80	1.24

**Excludes excise taxes.*

	Thousands of Barrels Daily		
Operating Statistics			
Refining operations*			
United States			
Crude oil capacity**	**2,208**	2,180	2,164
Crude oil runs	**2,025**	1,996	2,059
Capacity utilization (percent)	**92 %**	92	95
Refinery production	**2,213**	2,186	2,245
International			
Crude oil capacity**	**651**	428	437
Crude oil runs	**591**	424	396
Capacity utilization (percent)	**91 %**	99	91
Refinery production	**618**	439	405
Worldwide			
Crude oil capacity**	**2,859**	2,608	2,601
Crude oil runs	**2,616**	2,420	2,455
Capacity utilization (percent)	**92 %**	93	94
Refinery production	**2,831**	2,625	2,650
Petroleum products sales volumes			
United States			
Automotive gasoline	**1,336**	1,374	1,356
Distillates	**655**	675	553
Aviation fuels	**195**	201	191
Other products	**531**	519	564
	2,717	2,769	2,664
International	**759**	482	477
	3,476	3,251	3,141

**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 2006, 2005 and 2004 was 2,208,000, 2,182,000 and 2,160,000 barrels per day, respectively, in the United States. Actual international capacity was 693,000 barrels per day at year-end 2006 and 428,000 barrels per day at year-end 2005 and 2004.*

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.

2006 vs. 2005

Net income from the R&M segment increased 7 percent in 2006. The increase resulted primarily from:

- Higher U.S. refining and marketing margins, and higher U.S. refining volumes.
- The recognition of a net benefit related to business interruption insurance.
- The inclusion of an $83 million charge for the cumulative effect of adopting FIN 47 in the results for 2005.

The increase in net income was partially offset by impairments on assets held for sale recognized in 2006, as well as higher depreciation expense. See the Business Environment and Executive Overview section for our view of the factors supporting industry refining and marketing margins.

We expect our average worldwide refinery crude oil utilization rate for 2007 to average in the mid-nineties.

U.S. R&M

Net income from our U.S. R&M operations increased 18 percent in 2006, primarily due to:

- Higher refining and marketing margins, and higher refining volumes.
- The recognition of a net $111 million business interruption insurance benefit.
- A $78 million charge for the cumulative effect of adopting FIN 47 in 2005.

These items were partially offset by after-tax impairments of $227 million associated with certain assets held for sale, as well as higher depreciation expense.

Our U.S. refining capacity utilization rate was 92 percent in 2006, the same as in 2005, reflecting unplanned weather-related downtime in both years.

International R&M

Net income from our international R&M operations decreased 33 percent in 2006, due primarily to:

- The recognition of a $214 million after-tax impairment charge on certain assets held for sale.
- Lower refining margins.
- Preliminary engineering costs for certain refinery-related projects.

These decreases were partially offset by favorable foreign currency exchange impacts and higher refining and marketing sales volumes.

Our international refining capacity utilization rate was 91 percent in 2006, compared with 99 percent in 2005. The decrease reflects scheduled downtime at certain refineries and unscheduled downtime at the Humber refinery in the United Kingdom.

In February 2006, we acquired the Wilhelmshaven refinery in Germany. The purchase included the 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.

2005 vs. 2004

Net income from the R&M segment increased 52 percent in 2005, compared with 2004, primarily due to higher worldwide refining margins. 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 U.S. Gulf Coast refineries resulting from hurricanes Katrina and Rita.
- An $83 million charge for the cumulative effect of adopting FIN 47.

U.S. R&M

Net income from our U.S. R&M operations increased 57 percent in 2005, compared with 2004. 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 U.S. 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 lower 2005 rate was impacted by downtime related to hurricanes.

International R&M

Net income from our international R&M operations increased 37 percent in 2005, compared with 2004, 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.

LUKOIL Investment

	Millions of Dollars		
	2006	**2005**	**2004**
Net Income	**$ 1,425**	714	74
Operating Statistics*			
Net crude oil production (thousands of barrels daily)	**360**	235	38
Net natural gas production (millions of cubic feet daily)	**244**	67	13
Net refinery crude oil processed (thousands of barrels daily)	**179**	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. During 2005, we expended $2,160 million to purchase LUKOIL s ordinary shares, increasing our ownership interest to 16.1 percent. We expended another $2,715 million to increase our ownership interest in LUKOIL to 20 percent at December 31, 2006, based on 851 million shares authorized and issued. Our ownership interest based on estimated shares outstanding, used for equity-method accounting, was 20.6 percent at December 31, 2006.

2006 vs. 2005

Net income from the LUKOIL Investment segment increased 100 percent during 2006, primarily as a result of our increased equity ownership, higher estimated prices and volumes, and a net benefit from the alignment of our estimate of LUKOIL s fourth quarter 2005 net income to LUKOIL s reported results.

Because LUKOIL s accounting cycle close and preparation of U.S. generally accepted accounting principles (GAAP) financial statements occur subsequent to our reporting deadline, our equity earnings and statistics for our LUKOIL investment are estimated, based on current market indicators, historical production and cost trends of LUKOIL, and other objective data. Once the difference between actual and estimated results is known, an adjustment is recorded. This estimate-to-actual adjustment will be a recurring component of future period results. The adjustment to estimated results for the fourth quarter of 2005, recorded in 2006, increased net income $71 million, compared with a $10 million increase to net income recorded in 2005 to adjust the estimated results for the fourth quarter of 2004.

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 our employees seconded to LUKOIL.

2005 vs. 2004

In October 2004, we purchased 7.6 percent of LUKOIL s ordinary shares from the Russian government, and during the remainder of 2004, we increased our ownership interest to 10 percent. During 2005, we further increased our ownership interest to 16.1 percent. The 2005 results for the LUKOIL Investment segment reflect this increase in ownership, as well as favorable market conditions, including strong crude oil prices.

Chemicals

	Millions of Dollars		
	2006	**2005**	**2004**
Net Income	**$ 492**	323	249

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. These products are then marketed and sold, or used as feedstocks to produce plastics and commodity chemicals.

2006 vs. 2005

Net income from the Chemicals segment increased 52 percent during 2006. Results for 2006 reflected improved olefins and polyolefins margins and volumes. The results for 2006 also included a hurricane-related business interruption insurance benefit of $20 million after-tax, as well as lower utility costs due to decreased natural gas prices.

2005 vs. 2004

Net income from the Chemicals segment increased 30 percent in 2005, compared with 2004. The increase primarily was attributable to higher ethylene and polyethylene margins. Partially offsetting these margin improvements were higher utility costs, reflecting increased costs of natural gas, as well as hurricane-related impacts on 2005 production, and maintenance and repair costs.

Emerging Businesses

	Millions of Dollars		
	2006	**2005**	**2004**
Net Income (Loss)			
Power	**$ 82**	43	(31)
Technology solutions	**(23)**	(16)	(18)
Other	**(44)**	(48)	(53)
	$ 15	(21)	(102)

The Emerging Businesses segment represents our investment in new technologies or businesses outside our normal scope of operations. Activities within this segment are currently focused on power generation; carbon-to-liquids; technology solutions, such as sulfur removal technologies; and alternative energy programs, such as advanced hydrocarbon processes, energy conversion technologies, new petroleum-based products, and renewable fuels.

2006 vs. 2005

The Emerging Businesses segment had net income of $15 million in 2006, compared with a net loss of $21 million in 2005. The improved results reflect higher international power margins and volumes. The increase in net income was partially offset by a write-down of a damaged gas turbine at a domestic power plant, as well as lower domestic power margins and volumes.

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, which began commercial operations in the fourth quarter of 2004.

- Lower costs in the gas-to-liquids business due to the closing of a demonstration plant.

- Improved margins in the domestic power generation business.

Corporate and Other

	Millions of Dollars		
	2006	**2005***	**2004**
Net Income (Loss)			
Net interest	**$ (870)**	(467)	(514)
Corporate general and administrative expenses	**(133)**	(183)	(212)
Discontinued operations		(23)	22
Acquisition/merger-related costs	**(98)**		(14)
Other	**(86)**	(105)	(54)
	$ (1,187)	(778)	(772)

**Certain amounts have been reclassified to conform to current year presentation.*

2006 vs. 2005

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 increased 86 percent in 2006. The increase was primarily due to higher average debt levels as a result of the financing required to partially fund the acquisition of Burlington Resources. The increases were partially offset by higher amounts of interest being capitalized, as well as higher premiums incurred in 2005 on the early retirement of debt.

Corporate general and administrative expenses decreased 27 percent in 2006, primarily due to reduced benefit-related expenses.

Acquisition/merger-related costs in 2006 included seismic relicensing and other transition costs associated with the Burlington Resources acquisition. In 2007, we anticipate transition costs to be approximately $45 million after-tax.

The category Other includes certain foreign currency transaction gains and losses, and environmental costs associated with sites no longer in operation. Results from Other improved during 2006, primarily due to foreign currency transaction gains in 2006, versus losses in 2005, partially offset by certain tax items not directly attributable to the operating segments.

2005 vs. 2004

Net interest decreased 9 percent in 2005, compared with 2004, 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.

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.

Discontinued operations had a loss in 2005 compared with income in 2004, reflecting asset dispositions completed during 2004 and 2005.

Results from Other were lower in 2005, mainly due to certain unfavorable foreign currency transaction impacts.

CAPITAL RESOURCES AND LIQUIDITY

Financial Indicators

	Millions of Dollars Except as Indicated 2006		2005	2004
Net cash provided by operating activities	**$ 21,516**		17,628	11,959
Notes payable and long-term debt due within one year	**4,043**		1,758	632
Total debt	**27,134**		12,516	15,002
Minority interests	**1,202**		1,209	1,105
Common stockholders equity	**82,646**		52,731	42,723
Percent of total debt to capital*	**24**	%	19	26
Percent of floating-rate debt to total debt	**41**		9	19

**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 2006 we raised $545 million in funds from the sale of assets. During 2006, available cash was used to support our ongoing capital expenditures and investments program, provide loan financing to certain equity affiliates, repay debt, pay dividends, repurchase shares of our common stock and fund a portion of our acquisition of Burlington Resources Inc. Total dividends paid on our common stock in 2006 were $2.3 billion. During 2006, cash and cash equivalents declined $1,397 million to $817 million.

In addition to cash flows from operating activities and proceeds from asset sales, we also rely on our cash balance, commercial paper and credit facility programs, and our shelf registration statements, to support our short- and long-term liquidity requirements. We anticipate these sources of liquidity will be adequate to meet our funding requirements through 2008, including our capital spending program, our share repurchase programs, dividend payments, required debt payments and the funding requirements related to the business venture with EnCana Corporation (EnCana), which closed January 3, 2007. For additional information about the EnCana transaction, see Note 31 Joint Venture with EnCana Corporation, in the Notes to Consolidated Financial Statements.

Our cash flows from operating activities increased in each of the annual periods from 2004 through 2006. Favorable market conditions played a significant role in the upward trend of our cash flows from operating activities. In addition, cash flows in 2006 benefited from the inclusion of the operating activity of Burlington Resources beginning in the second quarter of 2006. Absent any unusual event during 2007, we expect market conditions will again be the most important factor affecting our 2007 operating cash flows.

Significant Sources of Capital

Operating Activities

During 2006, cash of $21,516 million was provided by operating activities, a 22 percent increase over cash from operations of $17,628 million in 2005. This increase reflects higher worldwide crude oil prices and U.S. refining margins, higher distributions from equity affiliates, and the impact of the Burlington Resources acquisition, partially offset by higher interest payments.

During 2005, cash flow from operations increased $5,669 million to $17,628 million. The improvement, compared with 2004, primarily resulted from higher crude oil, natural gas and natural gas liquids prices, as well as improved worldwide refining margins.

While the stability of our cash flows from operating activities benefits from geographic diversity and the effects of upstream and downstream integration, our short- and long-term operating cash flows are highly dependent upon prices for crude oil, natural gas and natural gas liquids, as well as refining and marketing margins. During 2005 and 2006, we benefited from favorable crude oil and natural gas prices, as well as refining margins. The sustainability of these prices and margins is driven by market conditions over which we have no control. Absent other mitigating factors, as these prices and margins fluctuate, we would expect a corresponding change in our operating cash flows.

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, weather conditions, the addition of proved reserves through exploratory success, and the timely and cost-effective development of those proved reserves. While we actively manage these factors that affect production, they cause certain variability in cash flows, although historically this variability has not been as significant as that experienced with commodity prices and refining margins.

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, driven primarily by acquisitions, including our increased ownership interest in LUKOIL over 2005 and 2006, and the acquisition of Burlington Resources in 2006. Going forward, based on our 2006 production level of 2.34 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 2011. These projections are tied to projects currently scheduled to begin production or ramp-up in those years, include our equity share of LUKOIL, and exclude our Canadian Syncrude mining operations.

To maintain or grow our production volumes, we must continue to add to our proved reserve base. Our reserve replacement over the three-year period ending December 31, 2006, was 254 percent. The purchase of reserves in place was a significant reason for our successful replacement of reserves over the past three years. These purchases included the acquisition of Burlington Resources in 2006 and the reentry into Libya in late 2005, as well as proved reserves added through our investments in LUKOIL.

We are developing and pursuing projects we anticipate will allow us to add to our reserve base going forward. However, access to additional resources has become increasingly difficult as direct investment is prohibited in some nations, while fiscal and other terms in other countries can make projects uneconomic or unattractive. In addition, political instability, competition from national oil companies, and lack of access to high-potential areas due to environmental or other regulation may negatively impact our ability to increase our reserve base. As such, the timing and level at which we add to our reserve base may, or may not, allow us to replace our production over subsequent years.

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 2006 and 2004, revisions decreased our reserves, while in 2005, revisions increased reserves. It is not possible to reliably predict how revisions will impact reserve quantities in the future. See the Capital Spending section for analysis of proved undeveloped reserves.

In addition, the level and quality of output from our refineries impacts our cash flows. The output at our refineries is impacted by such factors as operating efficiency, maintenance turnarounds, feedstock availability and weather conditions. We actively manage the operations of our refineries and typically any

72

variability in their operations has not been as significant to cash flows as that experienced with refining margins.

Asset Sales

Proceeds from asset sales in 2006 were $545 million, compared with $768 million in 2005. We announced in April 2006 an asset rationalization program to dispose of assets that no longer fit into our strategic plans or those that could bring more value by being monetized in the near term. We expect the program to result in proceeds from asset dispositions of $3 billion to $4 billion. Through January 31, 2007, proceeds from asset sales under this program were approximately $1.5 billion. In December 2006, we announced a program to dispose of our U.S. company-owned retail marketing outlets to new or existing wholesale marketers.

Commercial Paper and Credit Facilities

At December 31, 2006, we had two revolving credit facilities totaling $5 billion that expire in October 2011. Also, we have a $2.5 billion revolving credit facility that expires in April 2011, for which we recently requested an extension of one year in accordance with the terms of the facility. These facilities may be used as direct bank borrowings, as support for the ConocoPhillips $7.5 billion commercial paper program, as support for the ConocoPhillips Qatar Funding Ltd. $1.5 billion commercial paper program, or as support for 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 contain a cross-default provision relating to the failure to pay principal or interest on other debt obligations of $200 million or more by ourselves, or by any of our consolidated subsidiaries.

Our primary funding source for short-term working capital needs is the ConocoPhillips $7.5 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. The ConocoPhillips Qatar Funding Ltd. $1.5 billion commercial paper program is used to fund commitments relating to the Qatargas 3 project. At December 31, 2006 and 2005, we had no outstanding borrowings under the credit facilities, but $41 million and $62 million, respectively, in letters of credit had been issued. Under both commercial paper programs, there was $2,931 million of commercial paper outstanding at December 31, 2006, compared with $32 million at December 31, 2005. The commercial paper increase resulted from efforts to reduce the bridge facilities used for the acquisition of Burlington Resources discussed below.

Since we had $2,931 million of commercial paper outstanding and had issued $41 million of letters of credit, we had access to $4.5 billion in borrowing capacity under the three revolving credit facilities at December 31, 2006.

At December 31, 2006, 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 $7.5 billion revolving credit facilities.

Financing the Burlington Resources Inc. Acquisition

On March 31, 2006, we completed our acquisition of Burlington Resources Inc. by issuing approximately 270.4 million of our common shares, 32.1 million of which were issued from treasury shares, and paying approximately $17.5 billion in cash. We acquired $3.2 billion in cash and assumed $4.3 billion of debt from Burlington Resources in the acquisition. The cash payment was made through borrowings from two $7.5 billion bridge facilities, combined with $2.2 billion from cash balances and the issuance of

73

$300 million in commercial paper. The bridge facilities were both 364-day loan facilities with pricing and terms similar to our existing revolving credit facilities.

In April 2006, we entered into and funded a $5 billion five-year term loan, closed on the previously mentioned $2.5 billion five-year revolving credit facility, increased the ConocoPhillips commercial paper program to $7.5 billion, and issued $3 billion of debt securities. The term loan and new credit facility were broadly syndicated among financial institutions, with terms and pricing provisions similar to our two other existing revolving credit facilities. The proceeds from the term loan, debt securities and issuances of commercial paper, together with our cash balances and cash provided by operations, allowed us to repay the $15 billion bridge facilities during the second and third quarters of 2006.

The $3 billion of debt securities were issued under a new shelf registration statement filed with the U.S. Securities and Exchange Commission (SEC) in early April 2006 allowing for the issuance of various types of debt and equity securities. Of this issuance, $1 billion of Floating Rate Notes due April 11, 2007, were issued by ConocoPhillips, and $1.25 billion of Floating Rate Notes due April 9, 2009, and $750 million of 5.50% Notes due 2013 were issued by ConocoPhillips Australia Funding Company, a wholly owned subsidiary. ConocoPhillips and ConocoPhillips Company guarantee the obligations of ConocoPhillips Australia Funding Company. In October 2006, we filed a post-effective amendment to this registration statement to terminate the offering of securities under the registration statement.

Shelf Registrations

In mid-April 2006, we filed a universal shelf registration statement with the SEC, under which we, as a well-known seasoned issuer, have the ability to issue and sell an indeterminate amount of various types of debt and equity securities.

In October 2006, we filed a shelf registration statement with the SEC under which ConocoPhillips Canada Funding Company I and ConocoPhillips Canada Funding Company II, both wholly owned subsidiaries, could issue an indeterminate amount of senior debt securities, fully and unconditionally guaranteed by ConocoPhillips and ConocoPhillips Company. See the Capital Requirements section below for additional information on the issuance of debt securities under this registration statement.

Minority Interests

At December 31, 2006, we had outstanding $1,202 million of equity in less than wholly owned consolidated subsidiaries held by minority interest owners, including a minority interest of $508 million in Ashford Energy Capital S.A. The remaining minority interest amounts are primarily related to operating joint ventures we control. The largest of these, $672 million, was related to the Darwin LNG project located in northern Australia.

In December 2001, in order to raise funds for general corporate purposes, ConocoPhillips and Cold Spring Finance S.a.r.l. (Cold Spring) formed Ashford Energy Capital S.A. through the contribution of a $1 billion ConocoPhillips 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, 2006, was 6.69 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, 2006, 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, 2006, Ashford held $1.9 billion of ConocoPhillips subsidiary notes and $29 million in investments unrelated to ConocoPhillips. We report Cold Spring s investment as a minority interest

74

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

As part of our normal ongoing business operations and consistent with normal industry practice, we 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, 2006, we were liable for certain contingent obligations under the following contractual arrangements:

- *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, 2006, Qatargas 3 had $1.2 billion outstanding under all the loan facilities, of which ConocoPhillips provided $371 million, including accrued interest.

- *Rockies Express Pipeline LLC:* In June 2006, we issued a guarantee for 24 percent of the $2.0 billion in credit facilities of Rockies Express Pipeline LLC (Rockies Express), which will be used to construct a natural gas pipeline across a portion of the United States. The maximum potential amount of future payments to third-party lenders under the guarantee is estimated to be $480 million, which could become payable if the credit facility is fully utilized and Rockies Express fails to meet its obligations under the credit agreement. It is anticipated that construction completion will be achieved mid-2009, and refinancing will take place at that time, making the debt non-recourse. For additional information, see Note 7 Variable Interest Entities (VIEs), in the Notes to Consolidated Financial Statements.

- *Other:* At December 31, 2006, we had guarantees outstanding for our portion of joint-venture debt obligations, which have terms of up to 18 years. The maximum potential amount of future payments under the guarantees was approximately $140 million. Payment would be required if a joint venture defaults on its debt obligations.

For additional information about guarantees, see Note 17 Guarantees, in the Notes to Consolidated Financial Statements, which is incorporated herein by reference.

Capital Requirements

For information about the financing of the Burlington Resources acquisition or our capital expenditures and investments, see the Significant Sources of Capital section and the Capital Spending section, respectively.

75

Our debt balance at December 31, 2006, was $27.1 billion, an increase of approximately $14.6 billion during 2006. The increase reflects debt issuances of $15.3 billion during the first quarter of 2006 related to the acquisition of Burlington Resources. In addition, we assumed $4.3 billion of Burlington Resources debt, including the recognition of an increase of $406 million to record the debt at its fair value.

In May 2006, we redeemed our $240 million 7.625% Notes upon their maturity. We also redeemed our $129 million 6.60% Notes due in 2007 (part of the debt assumed in the Burlington Resources acquisition), at a premium of $4 million, plus accrued interest.

In October 2006, we redeemed our $1.25 billion 5.45% Notes upon their maturity. In addition, we redeemed our $500 million 5.60% Notes due December 2006, and our $350 million 5.70% Notes due March 2007 (both issues were a part of the debt assumed in the Burlington Resources acquisition), at a premium of $1 million, plus accrued interest. In order to finance the maturity and call of the above notes, ConocoPhillips Canada Funding Company I, a wholly owned subsidiary, issued $1.25 billion of 5.625% Notes due 2016, and ConocoPhillips Canada Funding Company II, a wholly owned subsidiary, issued $500 million of 5.95% Notes due 2036, and $350 million of 5.30% Notes due 2012. ConocoPhillips and ConocoPhillips Company guarantee the obligations of ConocoPhillips Canada Funding Company I and ConocoPhillips Canada Funding Company II.

In December 2006, we terminated the lease of certain refining assets, which we consolidated due to our designation as the primary beneficiary of the lease entity. As part of the termination, we exercised a purchase option of the assets totaling $111 million and retired the related debt obligations of $104 million 5.847% Notes due 2006. An associated interest swap was also liquidated.

During 2005, we announced three stock repurchase programs, which provided for the purchase of up to $3 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 2006, we purchased 15.1 million shares at a cost of $964 million under the programs, including 542,000 shares at a cost of $39 million from a consolidated Burlington Resources grantor trust. On January 12, 2007, we announced a fourth $1 billion stock repurchase program under like terms as the other three programs. Through January 31, 2007, under the four programs, we had purchased a total of 50.5 million shares, at a cost of $3.1 billion. On February 9, 2007, we announced plans to purchase $4 billion of our common stock in 2007, including the $1 billion announced on January 12, 2007. We expect to purchase $1 billion in the first quarter of 2007.

In December 2005, we entered into a credit agreement with Qatargas 3, whereby we will provide loan financing of approximately $1.2 billion for the construction of an LNG train in Qatar. This financing will represent 30 percent of the project s total debt financing. Through December 31, 2006, we had provided $371 million in loan financing, including accrued interest. See the Off-Balance Sheet Arrangements section for additional information on Qatargas 3.

In 2004, we finalized 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, 2006, we had provided $520 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 s oil-throughput capacity from 30,000 barrels per day to 240,000 barrels per day, 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. We estimate our total loan obligation for the terminal expansion to be approximately $460 million at current exchange rates, including interest to be accrued during construction. This amount will be adjusted as the project s cost estimate and schedule are updated and the ruble exchange rate fluctuates. Through December 31, 2006, we had provided $203 million in loan financing, including accrued interest.

Our loans to Qatargas 3, Freeport LNG and Varandey Terminal Company are included in the Loans and advances related parties line on the balance sheet.

On January 3, 2007, we closed on the previously announced business venture with EnCana. As part of this transaction, we expect to contribute $7.5 billion, plus accrued interest, over a ten-year period, beginning in 2007, to the upstream joint venture formed as a result of the transaction. An initial contribution of $188 million was made upon closing in January.

The remaining $7.3 billion contribution obligation will be reflected as a liability on our first quarter 2007 consolidated balance sheet. Principal and interest payments of $237 million will be made each quarter, beginning in the second quarter of 2007, and continuing until the balance is paid. The principal portion of these payments will be presented on our consolidated statement of cash flows as a financing activity. Interest accrues at a rate of 5.3 percent on the unpaid principal balance. For additional information about this business venture, see Note 31 Joint Venture with EnCana Corporation, in the Notes to Consolidated Financial Statements.

Effective January 15, 2007, we redeemed the 8% Junior Subordinated Deferrable Interest Debentures due 2037, at a premium of $14 million, plus accrued interest. This redemption resulted in the immediate redemption by Phillips 66 Capital II of $350 million of 8% Capital Securities. See Note 15 Debt, in the Notes to Consolidated Financial Statements, for additional information.

Also, in January 2007, we redeemed our $153 million 7.25% Notes upon their maturity, and in February 2007, we reduced our Floating Rate Five-Year Term Note due 2011 from $5 billion to $4 billion. Based on prevailing commodity price levels in early 2007, we anticipate reducing debt approximately $4 billion during 2007.

In February 2007, we announced a quarterly dividend of 41 cents per share, representing a 14 percent increase over the previous quarter s dividend of 36 cents per share. The dividend is payable March 1, 2007, to stockholders of record at the close of business February 20, 2007.

In 2007, we anticipate our cash from operations will fund our capital and dividend programs, with excess cash being used for share repurchases and debt reduction.

Contractual Obligations

The following table summarizes our aggregate contractual fixed and variable obligations as of December 31, 2006:

	Millions of Dollars Payments Due by Period Total	Up to 1 Year	Year 2-3	Year 4-5	After 5 Years
Debt obligations (a)	$ 27,090	1,598	1,685	12,640	11,167
Capital lease obligations	44	10	34		
Total debt	27,134	1,608	1,719	12,640	11,167
Interest on debt	16,692	1,594	3,043	2,704	9,351
Operating lease obligations	3,041	584	931	530	996
Purchase obligations (b)	93,025	35,494	7,701	5,260	44,570
Other long-term liabilities (c)					
Asset retirement obligations	5,402	576	404	390	4,032
Accrued environmental costs	1,062	270	262	119	411
Total	$ 146,356	40,126	14,060	21,643	70,527

(a) Includes $718 million of net unamortized premiums and discounts. See Note 15 Debt, in the Notes to Consolidated Financial Statements, for additional information.

(b) 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 $48,865 million, of which $17,611 million are primarily related to the supply of crude oil to our refineries and the optimization of the supply chain, $7,341 million primarily related to the supply of unfractionated natural gas liquids (NGL) to fractionators, optimization of NGL assets, and for resale to customers, $7,006 million primarily related to natural gas for resale customers, $6,166 million related to product purchase, $3,774 million related to transportation, $3,557 million on futures, $1,904 million related to the purchase side of exchange agreements and $1,506 million related to power trades; (2) $38,892 million of purchase commitments for products, mostly natural gas and NGL, from CPChem over the remaining term of 93 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-venturers 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; (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 13-year term if a variety of conditions are met; and (4) our contribution of $7.5 billion, plus accrued interest, over a ten-year period, beginning in 2007, to the upstream joint venture formed with EnCana on January 3, 2007.

(c) Does not include: Pensions for the 2007 through 2011 time period, we expect to contribute an average of $355 million per year to our qualified and non-qualified pension and postretirement medical plans in the United States and an average of $170 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 $435 million for the next two years and then approximately $305 million per year as our pension plans become better funded. Our required minimum funding in 2007 is expected to be $80 million in the United States and $115 million outside the United States.

Capital Spending

Capital Expenditures and Investments

	Millions of Dollars 2007 Budget	2006	2005	2004
E&P				
United States Alaska	$ 783	**820**	746	645
United States Lower 48	2,908	**2,008**	891	669
International	6,408	**6,685**	5,047	3,935
	10,099	**9,513**	6,684	5,249
Midstream	10	**4**	839	7
R&M				
United States	1,267	**1,597**	1,537	1,026
International	471	**1,419**	201	318
	1,738	**3,016**	1,738	1,344
LUKOIL Investment		**2,715**	2,160	2,649
Chemicals				
Emerging Businesses	237	**83**	5	75
Corporate and Other	185	**265**	194	172
	$ 12,269	**15,596**	11,620	9,496
United States	$ 5,153	**4,735**	4,207	2,520
International	7,116	**10,861**	7,413	6,976
	$ 12,269	**15,596**	11,620	9,496

Our capital spending for the three-year period ending December 31, 2006, totaled $36.7 billion, including a combined $7.5 billion in 2004 through 2006 related to our purchase of a 20 percent interest (based on shares authorized and issued) in LUKOIL. During the three-year period, 58 percent of total spending went to our E&P segment. In addition to our capital expenditures and investments spending during 2006, we also provided loans of approximately $800 million to certain affiliated companies.

Our capital expenditures and investments budget for 2007 is $12.3 billion. Included in this amount is approximately $500 million in capitalized interest. We plan to direct 82 percent of the capital expenditures and investments budget to E&P and 14 percent to R&M. With the addition of loans to certain affiliated companies; and contributions, including applicable accrued interest, related to funding our portion of the EnCana transaction; our total capital program for 2007 is approximately $13.5 billion. See the Capital Requirements section, as well as Note 10 Investments, Loans and Long-Term Receivables and Note 31 Joint Venture with EnCana Corporation, in the Notes to Consolidated Financial Statements, for additional information.

E&P

Capital spending for E&P during the three-year period ending December 31, 2006, totaled $21.4 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 satellite field prospects in Alaska.
- The 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.
- Development of the Corocoro field offshore Venezuela.
- The Ekofisk Area growth project and Alvheim project in the Norwegian North Sea.
- The Britannia satellite and Clair developments in the U.K. North Sea and Atlantic Margin, respectively.
- The Kashagan field and satellite prospects in the Caspian Sea, offshore Kazakhstan, including acquiring additional ownership interest.
- The acquisition of an interest in OOO Naryanmarneftegaz (NMNG), a joint venture with LUKOIL, and development of the Yuzhno Khylchuyu (YK) field.
- The Bayu-Undan gas recycle and liquefied natural gas development projects in the Timor Sea and northern Australia, respectively.
- The Belanak, Suban, Kerisi, Hiu, Pangkah and Belut projects in Indonesia.
- The Peng Lai 19-3 development in China s Bohai Bay and additional Bohai Bay appraisal and satellite field prospects.
- Expenditures related to the terms under which we returned to our former oil and natural gas production operations in the Waha concessions in Libya.

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

UNITED STATES

Alaska

During the three-year period ending December 31, 2006, we made capital expenditures for 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. The Nanuq and Fiord fields began production in 2006. Also during this three-year period, we completed both Phase I and Phase II of the Alpine Capacity Expansion project. In addition, we participated in exploratory drilling on the North Slope, including the Qannik discovery in 2006 the third Alpine satellite field, and acquired additional acreage.

We also made capital expenditures for construction of double-hulled Endeavour Class tankers for use in transporting Alaskan crude oil to the U.S. West Coast and Hawaii. The fifth and final Endeavour Class tanker began Alaska North Slope service in February 2007.

During 2004, we and our co-venturers in the Trans-Alaska Pipeline System began a project to upgrade the pipeline s pump stations. A phased startup of the project began in the first quarter of 2007.

Lower 48 States

In the Lower 48, we continued to develop our acreage positions in south Texas, the San Juan Basin, the Permian Basin, the Texas Panhandle, and in the deepwater Gulf of Mexico. Onshore we focused on natural gas developments in the San Juan Basin of New Mexico, the Lobo Trend of South Texas, the Bossier Trend of East Texas, the Barnett Shale Trend of North Texas, and the Permian Basin of West Texas.

Offshore, we expended funds for the development of the Magnolia, Ursa and K-2 fields in the deepwater of the Gulf of Mexico.

CANADA

In Canada, we continued with development of the Surmont heavy-oil project, where initial production is expected in the first half of 2007. Over the life of this 30-plus year project, we anticipate approximately 500 production and steam-injection well pairs will be drilled.

We also continued with development of the Syncrude Stage III expansion-mining project in the Canadian province of Alberta, where an upgrader expansion project was completed and became fully operational in 2006. In addition, capital expenditures were made on the development of our conventional crude oil and natural gas reserves in western Canada, as well as to progress the Parsons Lake/Mackenzie gas project.

SOUTH AMERICA

In the Gulf of Paria, off the coast of Venezuela, funds were expended to construct a floating storage and offloading (FSO) vessel and to construct and install a wellhead platform in the Corocoro field. Development drilling began on the Corocoro project in the second quarter of 2006. Arrival of the FSO and completion of pipelines and the FSO mooring is planned for the first quarter of 2007. Field production is expected to commence in the third quarter of 2008 upon installation of the central processing platform.

EUROPE

In the U.K. and Norwegian sectors of the North Sea, funds were invested during the three-year period ending December 31, 2006, 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 Britannia satellite fields, Callanish and Brodgar, where production is expected in 2008; and the Alvheim development project, where production is scheduled to begin in 2007.

In September 2006, we announced the Jasmine discovery, a new gas and condensate field in the U.K. sector of the North Sea. Results from the discovery are being evaluated to determine the plan for appraisal drilling and development.

AFRICA AND MIDDLE EAST

In late-December 2005, we announced, in conjunction with our co-venturers, an agreement with the Libyan National Oil Corporation on the terms under which we would return to our former crude oil and natural gas production operations in the Waha concessions in Libya. As a part of that agreement, we made a payment of $520 million in January 2006 for the acquisition of an ownership interest in, and extension of, the concessions. In December 2006, approximately $200 million was paid for unamortized investments made since 1986, agreed to be paid as part of the 1986 standstill agreement to hold assets in escrow for the U.S.-based co-venturers.

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 LNG project for the front-end engineering and design and related activities to move the project to a final investment decision.

RUSSIA AND CASPIAN

Russia

In June 2005, we acquired a 30 percent economic interest and a 50 percent governance 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, including development of the YK field.

Caspian

During the three-year period ending December 31, 2006, we invested funds to explore and develop the Kashagan field on the Kazakhstan shelf in the Caspian Sea. Construction activities to develop the field began in 2004. In 2005, we also expended funds to increase our ownership interest from 8.33 percent to 9.26 percent.

ASIA PACIFIC

Timor Sea and Australia

In the Timor Sea and Australia, we invested funds for development activities associated with Phase I and Phase II of the Bayu-Undan natural gas project, including the development of an onshore LNG facility near Darwin, Australia. Production of liquids began from Phase I in February of 2004, and development drilling concluded at the end of March 2005. In 2006, the LNG facility was completed and began full operation.

Indonesia

In Indonesia, funds were used for the completion of the Belanak and Hiu fields in the South Natuna Sea Block B, including construction of a floating production, storage and offloading (FPSO) vessel and associated gas plant facilities on the FPSO vessel. Oil production began from Belanak in late 2004 and first condensate production and gas exports began in June and October 2005, respectively. Natural gas production began from Hiu in late 2006. Also, in Block B funds were used to continue the development of the Kerisi and Belut fields. In South Sumatra, to prepare for the West Java gas sales agreement signed in August 2004, we continued the development of the Suban Phase II project, which is an expansion of the existing Suban gas plant.

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 vessel. Offshore installation work associated with the first new wellhead platform (WHP-C) was ongoing at year-end 2006.

Vietnam

In Vietnam, we began development of the Su Tu Vang field in Block 15-1 in late 2005, and continued appraisal work at the Su Tu Trang field. Preliminary engineering of the Su Tu Den Northeast development began in 2006.

On Block 15-2, we continued further development of our producing Rang Dong field, including developing the central part of the field, where two additional platforms were completed in 2005 and additional production and injection wells were completed in 2005 and 2006.

2007 CAPITAL EXPENDITURES AND INVESTMENTS BUDGET

E&P s 2007 capital expenditures and investments budget is $10.1 billion, 6 percent higher than actual expenditures in 2006. Thirty-seven percent of E&P s 2007 capital expenditures and investments budget is planned for the United States.

We plan to spend $783 million in 2007 for our Alaskan operations. A majority of the capital spending will fund Prudhoe Bay, Greater Kuparuk and Western North Slope operations including the Alpine satellite fields and the West Sak heavy-oil field, as well as exploration activities.

In the Lower 48, expenditures will focus primarily on developing natural gas reserves within core areas, including the San Juan Basin of New Mexico, the Lobo Trend of South Texas, the Bossier Trend of East Texas, the Barnett Shale Trend of North Texas, and the Permian Basin of West Texas; and new project developments such as the Piceance Basin in northwest Colorado. Offshore capital will be focused mainly on the Ursa development.

E&P is directing $6.4 billion of its 2007 capital expenditures and investments budget to international projects. Funds in 2007 will be directed to developing major long-term projects, including the Kashagan project in the Caspian Sea and the YK field in northern Russia, through the NMNG joint venture with LUKOIL; the Britannia satellites, the Ekofisk Area, and the Alvheim and Statfjord fields in the North Sea; the Bohai Bay project in China; heavy-oil and the Parsons Lake/Mackenzie gas projects in Canada, as well as western Canada natural gas projects; the Belanak, Kerisi, Hiu, Belut, Pangkah, and Suban Phase II projects in Indonesia; fields offshore Malaysia and Vietnam; the Corocoro project in Venezuela; and the Waha concessions in Libya.

PROVED UNDEVELOPED RESERVES

The net addition of proved undeveloped reserves accounted for 37 percent, 44 percent and 38 percent of our total net additions in 2006, 2005 and 2004, respectively. During these years, we converted, on average, 18 percent per year of our proved undeveloped reserves to proved developed reserves. Of our 2,976 million total BOE proved undeveloped reserves at December 31, 2006, we estimated that the average annual conversion rate for these reserves for the three-year period ending 2009 will be approximately 20 percent.

Costs incurred for the years ended December 31, 2006, 2005 and 2004, relating to the development of proved undeveloped oil and gas reserves were $6.4 billion, $3.4 billion, and $2.4 billion, respectively. Although it cannot be assured, estimated future development costs relating to the development of proved undeveloped reserves for the years 2007 through 2009 are projected to be $3.2 billion, $2.8 billion, and $2.4 billion, respectively.

Approximately 75 percent of our proved undeveloped reserves at year-end 2006 were associated with nine major development areas and our investment in LUKOIL. Seven of the major development areas 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 field in the North Sea.
- The Peng Lai 19-3 field in China.
- Fields in the United States and Canada associated with the Burlington Resources acquisition.

83

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 Midstream during the three-year period ending December 31, 2006, was primarily related to increasing our ownership interest in DCP Midstream in 2005 from 30.3 percent to 50 percent.

R&M

Capital spending for R&M during the three-year period ending December 31, 2006, was primarily for acquiring additional crude oil refining capacity, clean fuels projects to meet new environmental standards, refinery-upgrade projects to improve product yields, the operating integrity of key processing units, as well as for safety projects. During this three-year period, R&M capital spending was $6.1 billion, representing 17 percent of our total capital expenditures and investments.

Key projects during the three-year period included:

- Acquisition of the Wilhelmshaven refinery in Germany.
- A sulfur removal technology (S Zorb SRT) unit at the Lake Charles refinery.
- A fluid catalytic cracking gasoline hydrotreater at the Alliance refinery.
- Integration of a crude unit and coker adjacent to our Wood River refinery.
- A hydrotreater at the Rodeo facility of our San Francisco refinery.
- Expansion of existing hydrotreaters for both low-sulfur gasoline and ultra-low-sulfur diesel, with the addition of a new hydrogen plant at the Bayway refinery.
- A new ultra-low-sulfur diesel hydrotreater at the Sweeny refinery.
- A new ultra-low-sulfur diesel hydrotreater and hydrogen plant at the Billings refinery.
- Revamp of an existing hydrotreater for ultra-low-sulfur diesel and a new hydrogen plant at the Wood River refinery.
- A new hydrotreater for ultra-low-sulfur diesel and a hydrogen plant at the Ponca City refinery.
- Revamps of existing hydrotreaters for ultra-low-sulfur diesel at the Los Angeles, Trainer and Ferndale refineries.

Major construction activities in progress include:

- A new vacuum unit, coker and revamps of heavy oil and distillate hydrotreaters at the Borger refinery.
- A new S Zorb SRT unit at the Wood River refinery.
- Development of an additional coker at the Wood River refinery.
- U.S. programs aimed at air emission reductions.

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. The 2006 acquisition of the Wilhelmshaven refinery added 260,000 barrels per day to our crude oil refining capacity.

2007 CAPITAL EXPENDITURES AND INVESTMENTS BUDGET

R&M s 2007 capital budget is $1.7 billion, a 42 percent decrease from actual spending in 2006, reflecting the 2006 acquisition of the Wilhelmshaven refinery in Germany. Domestic spending in 2007 is expected to comprise 73 percent of the R&M budget.

We plan to direct about $1.1 billion of the R&M capital budget to domestic refining, primarily for projects

84

related to sustaining and improving the existing business with a focus on reliability, energy efficiency, capital maintenance and regulatory compliance. Work will continue on projects to increase crude oil capacity, expand conversion capability and increase clean product yield. Our U.S. marketing and transportation businesses are expected to spend about $150 million.

Internationally, we plan to spend $471 million, with a focus on projects related to reliability, safety and the environment, as well as the advancement of a full-conversion refinery project in Yanbu, Saudi Arabia. Other international refinery projects remain under study.

LUKOIL Investment

Capital spending in our LUKOIL Investment segment during the three-year period ending December 31, 2006, was for our initial purchase of an ownership interest in LUKOIL and continued purchases to increase our ownership interest. No additional purchases are expected in 2007.

Emerging Businesses

Capital spending for Emerging Businesses during the three-year period ending December 31, 2006, 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. Planned spending in 2007 is primarily for an expansion of the Immingham plant.

Contingencies

Legal and Tax Matters

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

Environmental

We are subject to numerous international, federal, state, and local environmental laws and regulations, as are other companies in the petroleum exploration and production, refining, and crude oil and refined product marketing and transportation 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 U.S. Environmental Protection Agency (EPA) regulation on sulfur content in highway diesel became effective in June 2006 with ConocoPhillips refineries producing ultra-low-sulfur diesel on schedule. The sulfur content regulation for non-road diesel, as promulgated in June 2004, further lowers the sulfur content of non-road diesel fuel beginning in June 2007. Capital strategy and market integration plans have incorporated this sulfur content step-down to ensure ongoing integrated compliance of our diesel fuel for the highway and non-road markets.

The Energy Policy Act of 2005 imposed obligations to provide increasing volumes on a percentage basis of renewable fuels in transportation motor fuels through 2012. Implementing regulations are currently being developed by the EPA to identify individual company utilization and compliance procedures needed to meet these obligations. We are in the process of establishing implementation, operating and capital strategies to meet the projected requirements. In addition, we are investigating innovative technologies for the production of biofuels that may facilitate compliance.

Since 1997 when 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, there have been a range of national, sub-national and international regulations proposed or implemented focusing on greenhouse gas reduction. These actual or proposed regulations do or will apply in countries where we have interests or may have interests in the future. Regulation in this field continues to evolve and while it is likely to be increasingly widespread and stringent, at this stage it is not possible to accurately estimate either a timetable for implementation or our future compliance costs. A recent example of such proposed regulation is California s Assembly Bill 32, which requires the California Air Resources Board (CARB) to develop regulations and market mechanisms that will ultimately reduce California s greenhouse gas emissions by 25 percent by 2020. The overall long-term fiscal impact from this type of regulation is uncertain.

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, 2005, we reported we had been notified of potential liability under CERCLA and comparable state laws at 66 sites around the United States. At December 31, 2006, we had resolved nine of these sites, had received six new notices of potential liability, and had reopened one site, leaving 64 unresolved sites where we have been notified of potential liability.

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

Expensed environmental costs were $912 million in 2006 and are expected to be about $967 million in 2007 and $984 million in 2008. Capitalized environmental costs were $1,118 million in 2006 and are expected to be about $945 million and $1,082 million in 2007 and 2008, respectively.

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, 2006.

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, 2006, our balance sheet included total accrued environmental costs of $1,062 million, compared with $989 million at December 31, 2005. 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 September 2006, the FASB issued Statement of Financial Accounting Standards (SFAS) No. 157, Fair Value Measurements. This Statement defines fair value, establishes a framework for its measurement and expands disclosures about fair value measurements. We use fair value measurements to measure, among other items, purchased assets and investments, leases, derivative contracts and financial guarantees. We also use them to assess impairment of properties, plants and equipment, intangible assets and goodwill. The Statement does not apply to share-based payment transactions and inventory pricing. This Statement is effective January 1, 2008. We are currently evaluating the impact on our financial statements.

In June 2006, the FASB issued FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109 (FIN 48). This Interpretation provides guidance on recognition, classification, and disclosure concerning uncertain tax liabilities. The evaluation of a tax position will require recognition of a tax benefit if it is more likely than not that it will be sustained upon examination. This Interpretation is effective beginning January 1, 2007. We have completed our analysis and concluded the adoption of FIN 48 will not have a material impact on our financial statements.

In September 2006, the FASB issued SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans an admendment of FASB Statements No. 87, 88, 106, and 132(R) (SFAS No. 158). We adopted the recognition and disclosure provisions of this new Statement as of December 31, 2006, and the impact from these changes is reflected in Note 23 Employee Benefit Plans, in the Notes to Consolidated Financial Statements. The requirement in SFAS No. 158 to measure plan assets and benefit obligations as of the date of the employer s fiscal year end is effective for fiscal years ending after December 15, 2008. The measurement date for our pension plan in the United Kingdom will be changed from September 30 to December 31 in time to comply with the Statement s 2008 required implementation date. All other plans are presently measured at December 31 of each year.

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 of the Board of Directors 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. At year-end 2006, 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 $1,313 million and the accumulated impairment reserve was $238 million. The weighted average judgmental percentage probability of ultimate failure was approximately 62 percent and the weighted average amortization period was approximately 3.5 years. If that judgmental percentage were to be raised by 5 percent across all calculations, pretax leasehold impairment expense in 2007 would increase by approximately $19 million. The remaining $3,615 million of capitalized unproved property costs at year-end 2006 consisted of individually significant leaseholds, mineral rights held in 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 $2 billion is concentrated in ten major assets. Management expects less than $100 million to move to proved properties in 2007. Most of the remaining value is associated with Parsons Lake/Mackenzie, Alaska North Slope and Australia natural gas projects, on which we continue to work with partners and regulatory agencies in order to develop.

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.

Once a determination is made 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. 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.

Management reviews suspended well balances quarterly, continuously monitors the results of the additional appraisal drilling and seismic work, and expenses the suspended well costs as a dry hole when it determines 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 2006, total suspended well costs were $537 million, compared with $339 million at year-end 2005. For additional information on suspended wells, including an aging analysis, see Note 11 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 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 2006 estimated reserves related to our LUKOIL Investment segment were based on LUKOIL s year-end 2005 oil and gas reserves. Because LUKOIL s accounting cycle close and preparation of U.S. GAAP financial statements occur subsequent to our accounting cycle close, our 20.6 percent equity-method share of LUKOIL s oil and gas proved reserves at year-end 2006 were estimated based on LUKOIL s prior-year report (adjusted for known additions, license extensions, dispositions, and other related information) and included adjustments to conform to our reserve policy and provided for estimated 2006 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 2006, 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 $63 billion and the depreciation, depletion and amortization recorded on these assets in 2006 was approximately $6.2 billion. The estimated proved developed oil and gas reserves on these fields were 5.2 billion BOE at the beginning of 2006 and were 6.4 billion BOE at the end of 2006. The estimated proved reserves on the Canadian Syncrude assets were 251 million barrels at the beginning of 2006 and were 243 million barrels at the end of 2006. 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 2006 would have been increased by an estimated $324 million. Impairments of producing oil and gas properties in 2006, 2005 and 2004 totaled $215 million, $4 million and $67 million, respectively. Of these write-downs, $131 million in 2006, $1 million in 2005 and $52 million in 2004 were due to downward revisions of proved reserves.

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 13 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 14 Asset Retirement Obligations and Accrued Environmental Costs, and Note 18 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

At December 31, 2006, we had $736 million of intangible assets determined to have indefinite useful lives, thus they 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 12 Goodwill and Intangibles, in the Notes to Consolidated Financial Statements, for additional information.

At December 31, 2006, we had $31.5 billion of goodwill recorded in conjunction with past business combinations. Under the accounting rules for goodwill, this intangible asset is not amortized. Instead, goodwill is subject to annual reviews for impairment at a reporting unit level. 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. 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.

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 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 estimated fair value of a reporting unit is less than the book value (including the goodwill), 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 2006, the estimated fair values of our Worldwide Exploration and Production, Worldwide Refining, and Worldwide Marketing reporting units ranged from between 25 percent to 69 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 an impairment.

Projected Benefit Obligations

Determination of the projected benefit obligations for our defined benefit pension and postretirement plans are important to the recorded amounts for such obligations on the balance sheet and to the amount of benefit expense in the income statement. This also impacts the required company contributions into the plans. The actuarial determination of projected benefit obligations and company contribution requirements involves judgment about uncertain future events, including estimated retirement dates, salary levels at retirement, mortality rates, lump-sum election rates, rates of return on plan assets, future health care cost-trend rates, and rates of utilization of health care services by retirees. Due to the specialized nature of these calculations, we engage outside actuarial firms to assist in the determination of these projected benefit obligations. For Employee Retirement Income Security Act-qualified pension plans, the actuary exercises fiduciary care on behalf of plan participants in the determination of the judgmental assumptions used in determining required company contributions into plan assets. Due to differing objectives and requirements between financial accounting rules and the pension plan funding regulations promulgated by governmental agencies, the actuarial methods and assumptions for the two purposes differ in certain important respects. Ultimately, we will be required to fund all promised benefits under pension and postretirement benefit plans not funded by plan assets or investment returns, but the judgmental assumptions used in the actuarial calculations significantly affect periodic financial statements and funding patterns over time. Benefit expense is particularly sensitive to the discount rate and return on plan assets assumptions. A 1 percent decrease in the discount rate would increase annual benefit expense by $110 million, while a 1 percent decrease in the return on plan assets assumption would increase annual benefit expense by $50 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

EnCana Joint Ventures

In October 2006, we announced a business venture with EnCana Corporation (EnCana), to create an integrated North American heavy-oil business. The transaction closed on January 3, 2007. The venture consists of two 50/50 operating joint ventures, a Canadian upstream general partnership, FCCL Oil Sands Partnership, and a U.S. downstream limited liability company, WRB Refining LLC. We plan to use the equity method of accounting for our investments in both joint ventures.

FCCL Oil Sands Partnership s operating assets consist of EnCana s Foster Creek and Christina Lake steam-assisted gravity drainage bitumen projects, both located in the eastern flank of the Athabasca oil sands in northeast Alberta. EnCana is the operator and managing partner of this joint venture. We expect to contribute $7.5 billion, plus accrued interest, to the joint venture over a 10-year period beginning in 2007. This interest-bearing cash contribution obligation will be recorded as a liability on our first quarter 2007 balance sheet.

WRB Refining LLC s operating assets consist of our Wood River and Borger refineries, located in Roxana, Illinois, and Borger, Texas, respectively. This joint venture plans to expand heavy-oil processing capacity at these facilities from 60,000 barrels per day to approximately 550,000 barrels per day by 2015. Total crude oil throughput at these two facilities is expected to increase from the current 452,000 barrels per day to approximately 600,000 barrels per day over the same time period. We are the operator and managing partner of this joint venture. EnCana is expected to contribute $7.5 billion, plus accrued interest to the joint venture over a 10-year period beginning in 2007. For the Wood River refinery, operating results will be shared 50/50 starting upon formation. For the Borger refinery, we are entitled to 85 percent of the operating results in 2007, 65 percent in 2008, and 50 percent in all years thereafter.

Alaska

We and our co-venturers continue to seek agreement with the state of Alaska on fiscal terms that would enable development of a pipeline to transport natural gas from Alaska s North Slope to markets in the U.S. Lower 48 states. Alaska s new governor has stated her administration will propose a new law in the Alaska legislature and seek new proposals for development of an Alaskan gas pipeline. We expect to be actively involved in this process throughout 2007.

In June 2006, the Federal Energy Regulatory Commission and the Regulatory Commission of Alaska ruled in a proceeding involving a method for compensating shippers according to the quality of crude oil they ship through the Trans-Alaska Pipeline System (quality bank). The rulings establish new valuation methodologies and require adjustments to quality bank payments retroactive to February 1, 2000. Based on our evaluations of the rulings, and taking into account contractual provisions with our crude oil customers regarding quality bank payments, our December 31, 2006, balance sheet contains a current liability for our required retroactive payments to the quality bank, and a current receivable for amounts due from our crude oil customers. There was no impact to our 2006 results of operations related to this matter.

In January 2007, we and our co-venturer jointly filed for a two-year extension of the Kenai LNG plant s export license with the U.S. Department of Energy. This application would extend the export license through March 31, 2011.

Venezuela

Our operations in Venezuela include two heavy-oil projects in the Orinoco Oil Belt (Petrozuata and Hamaca) and one conventional oil development (Corocoro). Over the past several years, our operating results have been negatively impacted by developments in Venezuela, including work disruptions, currency exchange controls, royalty rate increases, tax increases, and production quotas.

More recently, Venezuelan government officials have made public statements about increasing their ownership interests in heavy-oil projects required to give the national oil company of Venezuela, Petroleos de Venezuela S.A. (PDVSA), control and up to 60 percent ownership interests. On January 31, 2007, Venezuela s National Assembly passed an enabling law allowing the president to pass laws by decree on certain matters, including those associated with heavy-oil production from the Orinoco Oil Belt. PDVSA holds a 49.9 percent interest in the Petrozuata heavy-oil project and a 30 percent interest in the Hamaca heavy-oil project. We have a 50.1 percent interest and a 40 percent interest in the Petrozuata and Hamaca projects, respectively. The impact, if any, of these statements or other potential government actions, on our Petrozuata and Hamaca projects is not determinable at this time, but could include future reductions of our operating results, production and proved reserves.

The Petrozuata joint venture has received a preliminary audit report from the Venezuelan tax authorities, which if upheld, would result in additional income taxes of $245 million for 2002, plus interest and penalty. Petrozuata has also received an audit report claiming that it owes municipal sales tax and interest of $170 million for the period 2000 through 2005. Petrozuata believes, in both cases, these audit findings are not supported in law and it therefore does not owe these taxes. Accordingly, no provision has been established by Petrozuata. In addition, the Venezuelan tax authorities have announced their intention to accelerate the income tax audits of both Petrozuata and Hamaca for the years 2003 through 2006.

ConocoPhillips continues to preserve all of its rights under contracts, investment treaties, and international law and will continue to evaluate its options in realizing the value of its investments and operations in Venezuela. Our total assets invested in Venezuelan operations at December 31, 2006, was approximately $2.5 billion. At December 31, 2006, we had recorded 1,088 million BOE of proved reserves related to Hamaca and Petrozuata, and these joint ventures produced 101,000 net barrels per day of crude oil in 2006.

Other

The U.S. Pension Protection Act of 2006 (PPA) contained a variety of provisions designed to strengthen the funding rules for U.S. defined benefit pension plans including the imposition of certain benefit limitations on U.S. tax-qualified pensions that are less than 80 percent funded, based on the PPA s new funding liability. While the inputs to the PPA s new funding liability have not been completely specified at this time, we expect the PPA liability to be generally similar in concept to Current Liability as defined by section 412 (l) of the Internal Revenue Code, which is now used in pension funding calculations. On a Current Liability basis, on average our U.S. tax-qualified pensions were 95 percent funded for the plan year beginning January 1, 2006.

In December 2006, we and LUKOIL reached a definitive agreement for LUKOIL to purchase 376 of our fueling stations in six countries in Europe. The transaction is expected to close in the second quarter of 2007, following review by relevant authorities.

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, coulc intend, may, plan, potential, predict, should, will, expect, objective, projection, forecast, goal, guidance, outlook, 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.

- 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, refining, or transporting our products, including synthetic crude oil and chemicals products.

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

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

- Failure to complete definitive agreements and feasibility studies for, and to timely complete construction of, announced and future LNG and refinery projects and related facilities.

- Potential disruption or interruption of our operations due to accidents, extraordinary weather events, civil unrest, political events or terrorism.

- International monetary conditions and exchange controls.

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

- Liability resulting from litigation.

- General domestic and international economic and political developments, including armed hostilities, changes in governmental policies relating to crude oil, natural gas, natural gas liquids or refined product pricing and taxation, other political, economic or diplomatic developments, and international monetary fluctuations.

96

- Changes in tax and other laws, regulations (including alternative energy mandates), or royalty rules applicable to our business.

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

- Our ability to successfully integrate the operations of Burlington Resources into our own operations.

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 our 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 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.

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. 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 years ended December 31, 2006 and 2005, the gains or losses from this activity were not material to our cash flows or net income.

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, 2006, as derivative instruments in accordance with SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended (SFAS No. 133). 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, 2006 and 2005, was immaterial to our net income and cash flows. The VaR for instruments held for purposes other than trading at December 31, 2006 and 2005, 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 short-term U.S. 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 2006				
2007	**$ 557**	**7.43 %**	**$ 1,000**	**5.37 %**
2008	**32**	**6.96**		
2009	**307**	**6.43**	**1,250**	**5.47**
2010	**1,433**	**8.85**		
2011	**3,175**	**6.74**	**7,944**	**5.53**
Remaining years	**9,983**	**6.57**	**691**	**4.29**
Total	**$ 15,487**		**$ 10,885**	
Fair value	**$ 16,856**		**$ 10,885**	
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	

At the beginning of 2005, we held certain interest rate swaps that converted $1.5 billion of debt from fixed to floating rate. Under SFAS No. 133, 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, 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 remaining swaps continue to qualify for the shortcut method of hedge accounting, so we will not recognize any gain or loss due to ineffectiveness, if any, in the hedges.

	Millions of Dollars Except as Indicated		
	Interest Rate Derivatives		
Expected Maturity Date	Notional	Average Pay Rate	Average Receive Rate
Year-End 2006			
2007 variable to fixed	**$**	**%**	**%**
2008			
2009			
2010			
2011			
Remaining years fixed to variable	**350**	**5.57**	**4.75**
Total	**$ 350**		
Fair value position	**$ (10)**		
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)		

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, 2006 and 2005, 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, 2006 or 2005, exchange rates. The notional and fair market values of these positions at December 31, 2006 and 2005, were as follows:

Foreign Currency Swaps	**In Millions Notional***			**Fair Market Value****	
		2006	**2005**	**2006**	**2005**
Sell U.S. dollar, buy euro	USD	**242**	492	**$ 5**	(8)
Sell U.S. dollar, buy British pound	USD	**647**	463	**20**	(12)
Sell U.S. dollar, buy Canadian dollar	USD	**1,367**	517	**(19)**	
Sell U.S. dollar, buy Czech koruna	USD	**7**			
Sell U.S. dollar, buy Danish krone	USD	**17**	3		
Sell U.S. dollar, buy Norwegian kroner	USD	**1,145**	1,210	**15**	(15)
Sell U.S. dollar, buy Swedish krona	USD	**108**	107		1
Sell U.S. dollar, buy Slovakia koruna	USD	**2**			
Sell U.S. dollar, buy Hungary forint	USD	**4**			
Buy U.S. dollar, sell Polish zloty	USD		3		
Sell euro, buy Norwegian kroner	EUR	**10**			
Buy euro, sell Norwegian kroner	EUR		2		
Buy euro, sell Swedish krona	EUR		11		
Buy euro, sell British pound	EUR	**125**			

**Denominated in U.S. dollars (USD) and euro (EUR).*

***Denominated in U.S. dollars.*

For additional information about our use of derivative instruments, see Note 19 Financial Instruments and Derivative Contracts, in the Notes to Consolidated Financial Statements.

101

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, 2006. 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, 2006, 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, 2006.

/s/ James J. Mulva

James J. Mulva
Chairman, President and
Chief Executive Officer

/s/ John A. Carrig

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

February 22, 2007

103

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, 2006 and 2005, 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, 2006. 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, 2006 and 2005, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2006, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related condensed consolidating financial information and financial statement schedule, when considered in relation to the basic financial statements taken as a whole, present fairly in all material respects the information set forth therein.

As discussed in Note 2 to the consolidated financial statements, in 2006 ConocoPhillips adopted Emerging Issues Task Force Issue No. 04-13, Accounting for Purchases and Sales of Inventory with the Same Counterparty, and the recognition and disclosure provisions of Statement of Financial Accounting Standards No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans an amendment of FASB Statements No. 87, 88, 106, and 132(R), and in 2005 ConocoPhillips adopted Financial Accounting Standards Board Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations an interpretation of FASB Statement No. 143.

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, 2006, 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 22, 2007 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

ERNST & YOUNG LLP

Houston, Texas
February 22, 2007

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, 2006, 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, 2006, 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, 2006, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the 2006 consolidated financial statements of ConocoPhillips and our report dated February 22, 2007 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

ERNST & YOUNG LLP

Houston, Texas
February 22, 2007

Consolidated Income Statement	**ConocoPhillips**

Years Ended December 31	**Millions of Dollars**		
	2006	**2005**	**2004**
Revenues and Other Income			
Sales and other operating revenues*	**$ 183,650**	179,442	135,076
Equity in earnings of affiliates	**4,188**	3,457	1,535
Other income	**685**	465	305
Total Revenues and Other Income	**188,523**	183,364	136,916
Costs and Expenses			
Purchased crude oil, natural gas and products	**118,899**	124,925	90,182
Production and operating expenses	**10,413**	8,562	7,372
Selling, general and administrative expenses	**2,476**	2,247	2,128
Exploration expenses	**834**	661	703
Depreciation, depletion and amortization	**7,284**	4,253	3,798
Impairments	**683**	42	164
Taxes other than income taxes*	**18,187**	18,356	17,487
Accretion on discounted liabilities	**281**	193	171
Interest and debt expense	**1,087**	497	546
Foreign currency transaction (gains) losses	**(30)**	48	(36)
Minority interests	**76**	33	32
Total Costs and Expenses	**160,190**	159,817	122,547
Income from continuing operations before income taxes	**28,333**	23,547	14,369
Provision for income taxes	**12,783**	9,907	6,262
Income From Continuing Operations	**15,550**	13,640	8,107
Income (loss) from discontinued operations		(23)	22
Income before cumulative effect of changes in accounting principles	**15,550**	13,617	8,129
Cumulative effect of changes in accounting principles		(88)	
Net Income	**$ 15,550**	13,529	8,129
Income (Loss) Per Share of Common Stock *(dollars)*			
Basic			
Continuing operations	**$ 9.80**	9.79	5.87
Discontinued operations		(.02)	.01
Before cumulative effect of changes in accounting principles	**9.80**	9.77	5.88
Cumulative effect of changes in accounting principles		(.06)	
Net Income	**$ 9.80**	9.71	5.88
Diluted			
Continuing operations	**$ 9.66**	9.63	5.79
Discontinued operations		(.02)	.01
Before cumulative effect of changes in accounting principles	**9.66**	9.61	5.80
Cumulative effect of changes in accounting principles		(.06)	
Net Income	**$ 9.66**	9.55	5.80
Average Common Shares Outstanding *(in thousands)*			
Basic	**1,585,982**	1,393,371	1,381,568
Diluted	**1,609,530**	1,417,028	1,401,300
**Includes excise taxes on petroleum products sales:*	***$ 16,072***	*17,037*	*16,357*

See Notes to Consolidated Financial Statements.

107

Consolidated Balance Sheet	**ConocoPhillips**

At December 31	**Millions of Dollars**	
	2006	**2005**
Assets		
Cash and cash equivalents	**$ 817**	2,214
Accounts and notes receivable (net of allowance of $45 million in 2006 and $72 million in 2005)	**13,456**	11,168
Accounts and notes receivable related parties	**650**	772
Inventories	**5,153**	3,724
Prepaid expenses and other current assets	**4,990**	1,734
Total Current Assets	**25,066**	19,612
Investments and long-term receivables	**19,595**	15,406
Loans and advances related parties*	**1,118**	320
Net properties, plants and equipment	**86,201**	54,669
Goodwill	**31,488**	15,323
Intangibles	**951**	1,116
Other assets	**362**	553
Total Assets	**$ 164,781**	106,999
Liabilities		
Accounts payable	**$ 14,163**	11,732
Accounts payable related parties	**471**	535
Notes payable and long-term debt due within one year	**4,043**	1,758
Accrued income and other taxes	**4,407**	3,516
Employee benefit obligations	**895**	1,212
Other accruals	**2,452**	2,606
Total Current Liabilities	**26,431**	21,359
Long-term debt	**23,091**	10,758
Asset retirement obligations and accrued environmental costs	**5,619**	4,591
Deferred income taxes	**20,074**	11,439
Employee benefit obligations	**3,667**	2,463
Other liabilities and deferred credits	**2,051**	2,449
Total Liabilities	**80,933**	53,059
Minority Interests	**1,202**	1,209
Common Stockholders Equity		
Common stock (2,500,000,000 shares authorized at $.01 par value)		
Issued (2006 1,705,502,609 shares; 2005 1,455,861,340 shares)		
Par value	**17**	14
Capital in excess of par	**41,926**	26,754
Grantor trusts (at cost: 2006 44,358,585 shares; 2005 45,932,093 shares)	**(766)**	(778)
Treasury stock (at cost: 2006 15,061,613 shares; 2005 32,080,000 shares)	**(964)**	(1,924)
Accumulated other comprehensive income	**1,289**	814
Unearned employee compensation	**(148)**	(167)
Retained earnings	**41,292**	28,018
Total Common Stockholders Equity	**82,646**	52,731
Total	**$ 164,781**	106,999

**2005 amount reclassified from Investments and long-term receivables.*
See Notes to Consolidated Financial Statements.

108

Consolidated Statement of Cash Flows	**ConocoPhillips**

Years Ended December 31	**Millions of Dollars 2006**	**2005**	**2004**
Cash Flows From Operating Activities			
Net income	**$ 15,550**	13,529	8,129
Adjustments to reconcile net income to net cash provided by continuing operations			
Non-working capital adjustments			
Depreciation, depletion and amortization	**7,284**	4,253	3,798
Impairments	**683**	42	164
Dry hole costs and leasehold impairments	**351**	349	417
Accretion on discounted liabilities	**281**	193	171
Deferred income taxes	**263**	1,101	1,025
Undistributed equity earnings	**(945)**	(1,774)	(777)
Gain on asset dispositions	**(116)**	(278)	(116)
Loss (income) from discontinued operations		23	(22)
Cumulative effect of changes in accounting principles		88	
Other	**(201)**	(139)	(190)
Working capital adjustments*			
Decrease in aggregate balance of accounts receivable sold		(480)	(720)
Increase in other accounts and notes receivable	**(906)**	(2,665)	(2,685)
Decrease (increase) in inventories	**(829)**	(182)	360
Decrease (increase) in prepaid expenses and other current assets	**(372)**	(407)	15
Increase in accounts payable	**657**	3,156	2,103
Increase (decrease) in taxes and other accruals	**(184)**	824	326
Net cash provided by continuing operations	**21,516**	17,633	11,998
Net cash used in discontinued operations		(5)	(39)
Net Cash Provided by Operating Activities	**21,516**	17,628	11,959
Cash Flows From Investing Activities			
Acquisition of Burlington Resources Inc.**	**(14,285)**		
Capital expenditures and investments, including dry hole costs**	**(15,596)**	(11,620)	(9,496)
Proceeds from asset dispositions	**545**	768	1,591
Cash consolidated from adoption and application of FIN 46(R)			11
Long-term advances/loans to affiliates and other	**(780)**	(275)	(167)
Collection of advances/loans to affiliates and other	**123**	111	274
Net cash used in continuing operations	**(29,993)**	(11,016)	(7,787)
Net cash used in discontinued operations			(1)
Net Cash Used in Investing Activities	**(29,993)**	(11,016)	(7,788)
Cash Flows From Financing Activities			
Issuance of debt	**17,314**	452	
Repayment of debt	**(7,082)**	(3,002)	(2,775)
Repurchase of company common stock	**(925)**	(1,924)	
Issuance of company common stock	**220**	402	430
Dividends paid on company common stock	**(2,277)**	(1,639)	(1,232)
Other	**(185)**	27	178
Net cash provided by (used in) continuing operations	**7,065**	(5,684)	(3,399)
Net Cash Provided by (Used in) Financing Activities	**7,065**	(5,684)	(3,399)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**15**	(101)	125
Net Change in Cash and Cash Equivalents	**(1,397)**	827	897
Cash and cash equivalents at beginning of year	**2,214**	1,387	490
Cash and Cash Equivalents at End of Year	**$ 817**	2,214	1,387

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

109

Consolidated Statement of Changes in Common Stockholders Equity | ConocoPhillips

	Shares of Common Stock			Millions of Dollars							
	Issued	Held in Treasury	Held in Grantor Trusts	Common Stock Par Value	Common Stock Capital in Excess of Par	Treasury Stock	Grantor Trusts	Accumulated Other Comprehensive Income	Unearned Employee Compensation	Retained Earnings	Total
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 adjustments								777			777
Unrealized gain on securities								1			1
Hedging activities								(8)			(8)
Comprehensive income											8,900
Cash dividends paid on company 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 adjustments								(717)			(717)
Unrealized loss on securities								(6)			(6)
Hedging activities								1			1
Comprehensive income											12,751
Cash dividends paid on company 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
Net income										15,550	15,550
Other comprehensive income											
Minimum pension liability adjustment								33			33
Foreign currency translation adjustments								1,013			1,013
Hedging activities								4			4
Comprehensive income											16,600
Initial application of SFAS No. 158								(575)			(575)
Cash dividends paid on company common stock										(2,277)	(2,277)
Burlington Resources acquisition	239,733,571	(32,080,000)	890,180	3	14,475	1,924	(53)				16,349
Repurchase of company common stock		15,061,613	(542,000)			(964)	32				(932)
Distributed under incentive compensation and other benefit plans	9,907,698		(1,921,688)		697		33				730
Recognition of unearned compensation									19		19
Other										1	1
December 31, 2006	1,705,502,609	15,061,613	44,358,585	$ 17	41,926	(964)	(766)	1,289	(148)	41,292	82,646

See Notes to Consolidated Financial Statements.

110

Notes to Consolidated Financial Statements **ConocoPhillips**

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 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.

- **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.

Prior to April 1, 2006, revenues included the sales portion of transactions commonly called buy/sell contracts. Effective April 1, 2006, we implemented Emerging Issues Task Force (EITF) Issue No. 04-13, Accounting for Purchases and Sales of Inventory with the Same Counterparty. Issue No. 04-13 requires purchases and sales of inventory with the same counterparty and entered into in contemplation of one another to be combined and reported net (i.e., on the same income statement line). See Note 2 Changes in Accounting Principles, for additional information about our adoption of this Issue.

Revenues from the production of natural gas and crude oil 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 of three months or less from their date of purchase. They are carried at cost plus accrued interest, which approximates fair value.

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

Management reviews suspended well balances quarterly, 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 11 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 net book value. 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 impairments in the periods in which the determination of the 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 sold, the asset cost and related accumulated depreciation are eliminated, with any gain or loss reflected in other 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 14 Asset Retirement Obligations and Accrued Environmental Costs, 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. We reverse the fair-value liability only when there is no further exposure under the guarantee.

• **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 were accounted for under Accounting Principles Board (APB) Opinion No. 25, Accounting for Stock Issued to Employees, and related Interpretations; however, by the end of 2005, all of these awards had vested. Because the exercise price of our employee stock options equaled the market price of the underlying stock on the date of grant, generally no compensation expense was recognized under APB Opinion No. 25. The following table displays 2005 and 2004 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
Net income, as reported	$ 13,529	8,129
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects	142	93
Deduct: Total stock-based employee compensation expense determined under fair-value based method for all awards, net of related tax effects	(144)	(106)
Pro forma net income	$ 13,527	8,116
Earnings per share:		
Basic as reported	$ 9.71	5.88
Basic pro forma	9.71	5.87
Diluted as reported	9.55	5.80
Diluted pro forma	9.55	5.79

Generally, our stock-based compensation programs provided 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 recognized expense for these awards over the period of time during which the employee earned the award, accelerating the recognition of expense only when an employee actually retired (both the actual expense and the pro forma expense shown in the preceding table were calculated in this manner).

Effective January 1, 2006, we adopted SFAS No. 123 (revised 2004), Share-Based Payment (SFAS No. 123(R)), which requires 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 shortens 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 it has not had a material effect on our financial statements. For share-based awards granted after our adoption of SFAS No. 123(R), we have elected to recognize expense on a straight-line basis over the service period for the entire award, whether the award was granted with ratable or cliff vesting.

- **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.

- **Taxes Collected from Customers and Remitted to Governmental Authorities** Excise taxes are reported gross within sales and other operating revenues and taxes other than income taxes, while other sales and value-added taxes are recorded net in taxes other than 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. Also, this calculation includes fully vested stock and unit awards that have not been issued. 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 grantor trusts 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 Changes in Accounting Principles

Effective April 1, 2006, we implemented EITF Issue No. 04-13, Accounting for Purchases and Sales of Inventory with the Same Counterparty. Issue No. 04-13 requires purchases and sales of inventory with the same counterparty and entered into in contemplation of one another to be combined and reported net (i.e., on the same income statement line). Exceptions to this are exchanges of finished goods for raw materials or work-in-progress within the same line of business, which are only reported net if the transaction lacks economic substance. The implementation of Issue No. 04-13 did not have a material impact on net income.

The table below shows the pro forma sales and other operating revenues, and purchased crude oil, natural gas and products had Issue No. 04-13 been effective for all the periods prior to April 1, 2006.

	Millions of Dollars		
	2006	2005	2004
Pro Forma			
Sales and other operating revenues	**$ 176,993**	154,692	117,380
Purchased crude oil, natural gas and products	**112,242**	100,175	72,486

For information on our adoption of Financial Accounting Standards Board (FASB) Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations an interpretation of FASB Statement No. 143, and related disclosures, see Note 14 Asset Retirement Obligations and Accrued Environmental Costs.

117

In September 2006, the FASB issued SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans an amendment of FASB Statements No. 87, 88, 106, and 132(R). This Statement requires an employer that sponsors one or more single-employer defined benefit plans to:

- Recognize the funded status of the benefit in its statement of financial position.

- Recognize as a component of other comprehensive income, net of tax, the gains or losses and prior service costs or credits that arise during the period, but are not recognized as components of net periodic benefit cost.

- Measure defined benefit plan assets and obligations as of the date of the employer s fiscal year-end statement of financial position.

- Disclose in the notes to financial statements additional information about certain effects on net periodic benefit cost for the next fiscal year that arise from delayed recognition of the gains or losses, prior service costs or credits, and the transition asset or obligation.

The provisions of this Statement are effective December 31, 2006, except for the requirement to measure plan assets and benefit obligations as of the date of the employer s fiscal year end, which is effective December 31, 2008. For information on the impact of the adoption of this new Statement, see Note 23 Employee Benefit Plans.

In June 2006, the FASB ratified EITF Issue No. 06-3, How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That is, Gross versus Net Presentation). Issue No. 06-3 requires disclosure of either the gross or net method of presentation for taxes assessed by a governmental authority resulting from specific revenue-producing transactions between a customer and a seller. For any such taxes reported on a gross basis, the entity must also disclose the amount of the tax reported in revenue in the interim and annual financial statements. We adopted the Issue effective December 31, 2006. See Note 1 Accounting Policies, for additional information.

In December 2004, the FASB issued SFAS No. 123 (revised 2004), Share-Based Payment, (SFAS No. 123(R)), which superseded APB Opinion No. 25, Accounting for Stock Issued to Employees, and replaced SFAS No. 123, Accounting for Stock-Based Compensation, that we adopted effective January 1, 2003. SFAS No. 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. Our adoption of the provisions of this Statement on January 1, 2006, using the modified-prospective transition method, did not have a material impact on our financial statements. For more information on our adoption of SFAS No. 123(R) and its effect on net income, see Note 1 Accounting Policies and the section on stock-based compensation plans in Note 23 Employee Benefit Plans.

In November 2004, the FASB issued SFAS No. 151, Inventory Costs, an amendment of ARB No. 43, Chapter 4. This Statement clarifies how items, such as abnormal amounts of idle facility expense, freight, handling costs, and wasted material (spoilage) should be recognized as current-period charges. In addition, the Statement requires the allocation of fixed production overhead to the costs of conversion be based on the normal capacity of the production facilities. We adopted this Statement effective January 1, 2006. The adoption did not have a material impact on our financial statements.

In January 2004 and May 2004, the FASB issued FASB Staff Position (FSP) FAS 106-1, superseded by FSP FAS 106-2, regarding accounting and disclosure requirements related to the Medicare Prescription

Drug, Improvement and Modernization Act of 2003. We adopted this guidance effective July 1, 2004. See Note 23 Employee Benefit Plans, for additional information.

Note 3 Common Stock Split

On April 7, 2005, our Board of Directors declared a 2-for-1 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 this report are on an after-split basis for all periods presented.

Note 4 Discontinued Operations

During 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 29 Segment Disclosures and Related Information, these operations were included in Corporate and Other.

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**
Sales and other operating revenues from discontinued operations	$ 356	1,104
Income (loss) from discontinued operations before-tax	$ (26)	20
Income tax benefit	(3)	(2)
Income (loss) from discontinued operations	$ (23)	22

119

Note 5 Acquisition of Burlington Resources Inc.

On March 31, 2006, we completed the $33.9 billion acquisition of Burlington Resources Inc., an independent exploration and production company that held a substantial position in North American natural gas proved reserves, production and exploratory acreage. We issued approximately 270.4 million shares of our common stock and paid approximately $17.5 billion in cash. We acquired $3.2 billion in cash and assumed $4.3 billion of debt from Burlington Resources in the acquisition, including recognition of an increase of $406 million to record the debt at its fair value. Results of operations attributable to Burlington Resources were included in our consolidated income statement beginning in the second quarter of 2006.

The primary reasons for the acquisition and the principal factors contributing to a purchase price resulting in the recognition of goodwill were expanded growth opportunities in North American natural gas exploration and development, cost savings from the elimination of duplicate activities, and the sharing of best practices in the operations of both companies.

The $33.9 billion purchase price was based on Burlington Resources shareholders receiving $46.50 in cash and 0.7214 shares of ConocoPhillips common stock for each Burlington Resources share owned. ConocoPhillips issued approximately 270.4 million shares of common stock and approximately 3.6 million vested employee stock options in exchange for 374.8 million shares of Burlington Resources common stock and 2.5 million Burlington Resources vested stock options. The ConocoPhillips common stock was valued at $59.85 per share, which was the weighted-average price of ConocoPhillips common stock for a five-day period beginning two available trading days before the public announcement of the transaction on the evening of December 12, 2005. The Burlington Resources vested stock options, whose fair value was determined using the Black-Scholes-Merton option-pricing model, were exchanged for ConocoPhillips stock options valued at $146 million. Estimated transaction-related costs were $56 million.

Also included in the acquisition was the replacement of 0.9 million non-vested Burlington Resources stock options and 0.4 million shares of non-vested restricted stock with 1.3 million non-vested ConocoPhillips stock options and 0.5 million non-vested ConocoPhillips restricted stock. In addition, 1.2 million Burlington Resources shares of common stock held by a consolidated grantor trust, related to a deferred compensation plan, were converted into 0.9 million ConocoPhillips common shares and were recorded as a reduction of common stockholders equity.

The preliminary allocation of the purchase price to specific assets and liabilities was based, in part, upon a preliminary outside appraisal of the fair value of Burlington Resources assets. By March 31, 2007, we expect to receive the final outside appraisal of the long-lived assets and conclude the fair value determination of all other Burlington Resources assets and liabilities.

The following table summarizes, based on the preliminary purchase price allocation described above, the fair values of the assets acquired and liabilities assumed as of March 31, 2006:

	Millions of Dollars
Cash and cash equivalents	$ 3,238
Accounts and notes receivable	1,329
Inventories	234
Prepaid expenses and other current assets	108
Investments and long-term receivables	273
Properties, plants and equipment	28,377
Goodwill	16,615
Intangibles	107
Other assets	46
Total assets	$ 50,327
Accounts payable	$ 1,474
Notes payable and long-term debt due within one year	1,009
Accrued income and other taxes	716
Employee benefit obligations current	249
Other accruals	176
Long-term debt	3,330
Asset retirement obligations	732
Accrued environmental costs	117
Deferred income taxes	7,899
Employee benefit obligations	344
Other liabilities and deferred credits	417
Common stockholders equity	33,864
Total liabilities and equity	$ 50,327

We assigned all of the Burlington Resources goodwill to the Worldwide Exploration and Production reporting unit. Of the $16,615 million of goodwill, $8,003 million relates to net deferred tax liabilities arising from differences between the allocated financial bases and deductible tax bases of the acquired assets. None of the goodwill is deductible for tax purposes.

121

The following table presents pro forma information for 2006 and 2005, as if the acquisition had occurred at the beginning of each year presented.

	Millions of Dollars	
	2006	2005
Pro Forma		
Sales and other operating revenues*	**$ 185,555**	186,227
Income from continuing operations	**15,945**	14,780
Net income	**15,945**	14,669
Income from continuing operations per share of common stock		
Basic	**9.65**	8.88
Diluted	**9.51**	8.75
Net income per share of common stock		
Basic	**9.65**	8.82
Diluted	**9.51**	8.68

*See Note 2 Changes in Accounting Principles, for information affecting the comparability of 2006 with 2005 due to the adoption of EITF Issue No. 04-13.

The pro forma information is not intended to reflect the actual results that would have occurred if the companies had been combined during the periods presented, nor is it intended to be indicative of the results of operations that may be achieved by ConocoPhillips in the future.

Note 6 Restructuring

As a result of the acquisition of Burlington Resources, we implemented a restructuring program in March 2006 to capture the synergies of combining the two companies. Under this program, which is expected to be completed by the end of March 2008, we recorded accruals totaling $230 million for employee severance payments, site closings, incremental pension benefit costs associated with the workforce reductions, and employee relocations. Approximately 600 positions have been identified for elimination, most of which are in the United States. Of the total accrual, $224 million is reflected in the Burlington Resources purchase price allocation as an assumed liability, and $6 million ($4 million after-tax) related to ConocoPhillips is reflected in selling, general and administrative expenses. Included in the total accruals of $230 million is $12 million related to pension benefits to be paid in conjunction with other retirement benefits over a number of future years. The following table summarizes benefit payments made during 2006 related to the non-pension accrual.

	Millions of Dollars		
	2006 Accruals	Benefit Payments	Balance at December 31 2006 *
Burlington Resources	$ 212	(93)	119
ConocoPhillips	6	(5)	1
Total	$ 218	(98)	120

**Includes current liabilities of $72 million.*

122

Note 7 Variable Interest Entities (VIEs)

In June 2006, ConocoPhillips acquired a 24 percent interest in West2East Pipeline LLC (West2East), a company holding a 100 percent interest in Rockies Express Pipeline LLC (Rockies Express). Rockies Express plans to construct a 1,633-mile natural gas pipeline from Wyoming to Ohio. West2East is a VIE because a third party other than ConocoPhillips and our partners holds a significant voting interest in the company until project completion. We currently participate in the management committee of West2East as a non-voting member. We are not the primary beneficiary of West2East, and we use the equity method of accounting for our investment. We issued a guarantee for 24 percent of the $2 billion in credit facilities of Rockies Express. At December 31, 2006, we had made no capital investment in West2East. See Note 17 Guarantees, for additional information.

In June 2005, ConocoPhillips and OAO LUKOIL (LUKOIL) created the OOO Naryanmarneftegaz (NMNG) joint venture to develop resources in the Timan-Pechora province of Russia. The NMNG joint venture is 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 are not the primary beneficiary of the VIE and we use the equity method of accounting for this investment. At December 31, 2006, the book value of our investment in the venture was $984 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 oil-throughput capacity from 30,000 barrels per day to 240,000 barrels per day, with ConocoPhillips participating in the design and financing of the expansion. 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 are not the primary beneficiary and account for our loan to Varandey Terminal Company as a financial asset. We estimate our total loan obligation for the terminal expansion to be approximately $460 million at current exchange rates, including interest to be accrued during construction. This amount will be adjusted as the project s cost estimate and schedule are updated and the ruble exchange rate fluctuates. Through December 31, 2006, we had provided $203 million in loan financing, including accrued interest.

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, 2006, we had provided $520 million in financing, including accrued interest. Freeport LNG is a VIE, and we are not the primary beneficiary. We account for our loan to Freeport LNG as a financial asset.

In 2003, we entered into two 20-year agreements establishing separate guarantee facilities of $50 million each for two LNG ships 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. To the extent we receive any such payments, our actual gross payments over the 20 years could exceed $100 million. In September 2003, the first ship was delivered to its owner and in July 2005, the second ship was delivered to its owner. Both agreements represent a VIE, but we are not the primary beneficiary and, therefore, we do not consolidate these entities. The amount drawn under the guarantee facilities at December 31, 2006, was approximately $5 million for both ships. We currently account for these agreements as guarantees and contingent liabilities. See Note 17 Guarantees, for additional information.

In 1997, Phillips 66 Capital II (Trust II) was created for the sole purpose of issuing mandatorily redeemable preferred securities to third-party investors and investing the proceeds thereof in an approximate amount of subordinated debt securities of ConocoPhillips. At December 31, 2006, we reported debt of $361 million of 8% Junior Subordinated Deferrable Interest Debentures due 2037. Trust II is a VIE, but we do not consolidate it in our financial statements because we are not the primary beneficiary. Effective January 15, 2007, we redeemed the 8% Junior Subordinated Deferrable Interest Debentures due 2037 at a premium of $14 million, plus accrued interest. See Note 15 Debt, for additional information about Trust II.

In December 2006, we terminated the lease of certain refining assets which we consolidated due to our designation as the primary beneficiary of the lease entity. As part of the termination, we exercised a purchase option of the assets totaling $111 million and retired the related debt obligations of $104 million 5.847% Notes due 2006. An associated interest rate swap was also liquidated.

Ashford Energy Capital S.A. (Ashford) is consolidated in our financial statements because we are the primary beneficiary. In December 2001, in order to raise funds for general corporate purposes, ConocoPhillips and Cold Spring Finance S.a.r.l. (Cold Spring) formed Ashford through the contribution of a $1 billion ConocoPhillips 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, 2006, was 6.69 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, 2006, 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, 2006, Ashford held $1.9 billion of ConocoPhillips subsidiary notes and $29 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.

Note 8 Inventories

Inventories at December 31 were:

	Millions of Dollars 2006	2005
Crude oil and petroleum products	**$ 4,351**	3,183
Materials, supplies and other	**802**	541
	$ 5,153	3,724

Inventories valued on a LIFO basis totaled $4,043 million and $3,019 million at December 31, 2006 and 2005, 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 $4,178 million and $3,958 million at December 31, 2006 and 2005, respectively.

During 2006, certain inventory quantity reductions caused a liquidation of LIFO inventory values. This liquidation increased net income $39 million, of which $32 million was attributable to our Refining and Marketing (R&M) segment. In 2005, a liquidation of LIFO inventory values increased net income $16 million, of which $15 million was attributable to our R&M segment. Comparable amounts in 2004 increased net income $62 million, of which $54 million was attributable to our R&M segment.

Note 9 Assets Held for Sale

In 2006, we announced the commencement of certain asset rationalization efforts. During the third and fourth quarters of 2006, certain assets included in these efforts met the held-for-sale criteria of SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets. Accordingly, in the third and fourth quarters of 2006, on those assets required, we reduced the carrying value of the assets held for sale to estimated fair value less costs to sell, resulting in an impairment of properties, plants and equipment, goodwill and intangibles totaling $496 million before-tax ($464 million after-tax). Further, we ceased depreciation, depletion and amortization of the properties, plants and equipment associated with these assets in the month they were classified as held for sale. We expect this asset rationalization program to be completed in 2007.

At December 31, 2006, we reclassified $3,051 million from non-current assets into the Prepaid expenses and other current assets line of our consolidated balance sheet and we reclassified $604 million from non-current liabilities to current liabilities, consisting of $201 million into Accrued income and other taxes and $403 million into Other accruals.

The major classes of non-current assets and non-current liabilities held for sale at December 31, 2006, reclassified to current were:

	Millions of Dollars
Assets	
Investments and long-term receivables	$ 170
Net properties, plants and equipment	2,422
Goodwill	340
Intangibles	13
Other assets	106
Total assets reclassified	$ 3,051
Exploration and Production	$ 1,465
Refining and Marketing	1,586
	$ 3,051
Liabilities	
Asset retirement obligations and accrued environmental costs	$ 386
Deferred income taxes	201
Other liabilities and deferred credits	17
Total liabilities reclassified	$ 604
Exploration and Production	$ 392
Refining and Marketing	212
	$ 604

Note 10 Investments, Loans and Long-Term Receivables

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

	Millions of Dollars 2006	2005
Equity investments	**$ 18,544**	14,457
Loans and advances related parties	**1,118**	320
Long-term receivables	**442**	458
Other investments	**609**	491
	$ 20,713	15,726

Equity Investments

Affiliated companies in which we have a significant equity investment include:

- OAO LUKOIL (LUKOIL) 20 percent ownership interest at December 31, 2006 (16.1 percent at year-end 2005). 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.

- DCP Midstream, LLC (DCP Midstream) 50 percent ownership interest owns and operates gas plants, gathering systems, storage facilities and fractionation plants. Effective January 2, 2007,

126

Duke Energy Field Services, LLC (DEFS) formally changed its name to DCP Midstream.

- Chevron Phillips Chemical Co. LLC (CPChem) 50 percent owned joint venture with Chevron Corporation 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 extra heavy crude oil and upgrades it into medium grade crude oil at Jose on the northern coast of Venezuela.

- Petrozuata C.A. 50.1 percent non-controlling ownership interest accounted for under the equity method because the minority shareholder has 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 ownership interest and a 50 percent governance 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.

Summarized 100 percent financial information for equity-method investments in affiliated companies, combined, was as follows (information included for LUKOIL is based on estimates):

	Millions of Dollars 2006	2005	2004
Revenues	**$ 113,607**	96,367	45,053
Income before income taxes	**16,257**	15,059	5,549
Net income	**12,447**	11,743	4,478
Current assets	**24,820**	23,652	20,609
Noncurrent assets	**59,803**	48,181	43,844
Current liabilities	**15,884**	14,727	15,283
Noncurrent liabilities	**20,603**	15,833	14,481

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, 2006, retained earnings included $5,113 million related to the undistributed earnings of affiliated companies, and distributions received from affiliates were $3,294 million, $1,807 million and $1,035 million in 2006, 2005 and 2004, respectively.

LUKOIL

LUKOIL is an integrated energy company headquartered in Russia, with operations worldwide. 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 limits our ownership interest in LUKOIL to 20 percent of the shares authorized and issued and limits our ability to sell our LUKOIL shares for a period of four years from September 29, 2004, except in certain circumstances.

We increased our ownership interest in LUKOIL to 20 percent at December 31, 2006, based on 851 million shares authorized and issued. For financial reporting under U.S. generally accepted accounting principles, treasury shares held by LUKOIL are not considered outstanding for determining our equity-method ownership interest in LUKOIL. Our ownership interest, based on estimated shares outstanding, was 20.6 percent at December 31, 2006.

Because LUKOIL s accounting cycle close and preparation of U.S. generally accepted accounting principles (GAAP) financial statements occur subsequent to our reporting deadline, our equity earnings and statistics for our LUKOIL investment are estimated, based on current market indicators, historical production and cost trends of LUKOIL, and other objective data. Once the difference between actual and estimated results is known, an adjustment is recorded. This estimate-to-actual adjustment will be a recurring component of future period results. Any difference between our estimate of fourth-quarter 2006 and the actual LUKOIL U.S. GAAP net income will be reported in our 2007 equity earnings. At December 31, 2006, the book value of our ordinary share investment in LUKOIL was $9,564 million. Our 20 percent share of the net assets of LUKOIL was estimated to be $6,851 million. This basis difference of $2,713 million is primarily being amortized on a unit-of-production basis. Included in net income for 2006, 2005 and 2004 was after-tax expense of $41 million, $43 million and $14 million, respectively, representing the amortization of this basis difference.

On December 31, 2006, the closing price of LUKOIL shares on the London Stock Exchange was $86.70 per share, making the aggregate total market value of our LUKOIL investment $14,749 million.

DCP Midstream

DCP Midstream 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 DCP Midstream, which resulted in DCP Midstream becoming a jointly controlled venture, owned 50 percent by each company. This restructuring increased our ownership in DCP Midstream to 50 percent from 30.3 percent through a series of direct and indirect transfers of certain Canadian Midstream assets from DCP Midstream to Duke, a disproportionate cash distribution from DCP Midstream to Duke from the sale of DCP Midstream s interest in TEPPCO Partners, L.P., and a combined payment by ConocoPhillips to Duke and DCP Midstream 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 gain from DCP Midstream s sale of its interest in TEPPCO.

At December 31, 2006, the book value of our common investment in DCP Midstream was $1,150 million. Our 50 percent share of the net assets of DCP Midstream was $1,133 million. This difference of $17 million includes a profit-in-inventory elimination of $2 million and a basis difference of $19 million which is being amortized on a straight-line basis through 2014 consistent with the remaining estimated useful lives of DCP Midstream s properties, plants and equipment. Included in net income for 2006 was an after-tax expense of $2 million and in 2005 and 2004, an after-tax income of $17 million and $36 million, respectively, representing the amortization of the basis difference.

DCP Midstream 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.

CPChem

CPChem manufactures and markets petrochemicals and plastics. At December 31, 2006, the book value of our investment in CPChem was $2,252 million. Our 50 percent share of the total net assets of CPChem was $2,119 million. This basis difference of $133 million is being amortized through 2020, consistent with the remaining estimated useful lives of CPChem properties, plants and equipment.

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

Loans to Related Parties

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. Loans are recorded within Loans and advances related parties when cash is transferred to the affiliated company pursuant to a loan agreement. The loan balance will increase as interest is earned on the outstanding loan balance and will decrease as interest and principal payments are received. Interest is earned at the loan agreement s stated interest rate. Loans are assessed for impairment when events indicate the loan balance will not be fully recovered.

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, 2006, we had provided $520 million in loan financing, including accrued interest. See Note 7 Variable Interest Entities (VIEs), for additional information.

- We have an obligation to provide loan financing to Varandey Terminal Company for 30 percent of the costs of the terminal expansion. We estimate our total loan obligation for the terminal expansion to be approximately $460 million at current exchange rates, including interest to be accrued during construction. This amount will be adjusted as the project s cost estimate and schedule are updated and the ruble exchange rate fluctuates. Through December 31, 2006, we had provided $203 million in loan financing, including accrued interest. See Note 7 Variable Interest Entities (VIEs), 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, 2006, Qatargas 3 had $1.2 billion outstanding under all the loan facilities, of which ConocoPhillips provided $371 million, including accrued interest.

Note 11 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 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					
	2006			**2005**		
	Gross PP&E	**Accum. DD&A**	**Net PP&E**	**Gross PP&E**	**Accum. DD&A**	**Net PP&E**
E&P	**$ 88,592**	**21,102**	**67,490**	53,907	16,200	37,707
Midstream	**330**	**157**	**173**	322	128	194
R&M	**22,115**	**5,199**	**16,916**	20,046	4,777	15,269
LUKOIL Investment						
Chemicals						
Emerging Businesses	**1,006**	**98**	**908**	865	61	804
Corporate and Other	**1,229**	**515**	**714**	1,192	497	695
	$ 113,272	**27,071**	**86,201**	76,332	21,663	54,669

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. 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 2006, 2005 and 2004:

	Millions of Dollars		
	2006	**2005**	**2004**
Beginning balance at January 1	**$ 339**	347	403
Additions pending the determination of proved reserves	**225**	183	142
Reclassifications to proved properties	**(8)**	(81)	(112)
Charged to dry hole expense	**(19)**	(110)	(86)
Ending balance at December 31	**$ 537**	339	347

The following table provides an aging of suspended well balances at December 31, 2006, 2005 and 2004:

	Millions of Dollars		
	2006	**2005**	**2004**
Exploratory well costs capitalized for a period of one year or less	**$ 225**	183	142
Exploratory well costs capitalized for a period greater than one year	**312**	156	205
Ending balance	**$ 537**	339	347
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year	**22**	15	16

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, 2006:

	Millions of Dollars					
		Suspended Since				
Project	**Total**	**2005**	**2004**	**2003**	**2002**	**2001**
Alpine satellite Alaska *(2)*	$ 21				21	
Kashagan Kazakhstan *(1)*	18			9		9
Aktote Kazakhstan *(2)*	19		7	12		
Kairan Kazakhstan *(1)*	13		13			
Gumusut Malaysia *(2)*	30	6	12	12		
Malikai Malaysia *(2)*	29	19	10			
Plataforma Deltana Venezuela *(2)*	20	6	14			
Hejre Denmark *(1)*	22	14				8
Uge Nigeria *(1)*	16	16				
Su Tu Trang Vietnam *(2)*	16	8		8		
Caldita Australia *(1)*	33	33				
Eleven projects of less than $10 million each *(1)(2)*	75	54	1	11	9	
Total of 22 projects	$ 312	156	57	52	30	17

(1) Additional appraisal wells planned.

(2) Appraisal drilling complete; costs being incurred to assess development.

Note 12 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, 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
Acquired (Burlington Resources see below)	**16,615**		**16,615**
Acquired (Wilhelmshaven see below)		**229**	**229**
Goodwill allocated to assets held for sale	**(216)**	**(124)**	**(340)**
Impairment of goodwill associated with assets held for sale		**(230)**	**(230)**
Tax and other adjustments	**(110)**	**1**	**(109)**
Balance at December 31, 2006	**$ 27,712**	**3,776 ***	**31,488**

**Consists of two reporting units: Worldwide Refining ($2,222) and Worldwide Marketing ($1,554).*

On March 31, 2006, we acquired Burlington Resources Inc., an independent exploration and production company. As a result of this acquisition, we recorded goodwill of $16,615 million, all of which was assigned to the Worldwide E&P reporting unit. See Note −5 Acquisition of Burlington Resources Inc., for additional information.

On February 28, 2006, we acquired the Wilhelmshaven refinery, located in Wilhelmshaven, Germany. The purchase included the 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. As a result of this acquisition, we recorded goodwill of $229 million, all of which was aligned with our R&M segment. The allocation of the purchase price to specific assets and liabilities was based on a combination of an outside appraiser s valuation for fixed assets and an internal estimate of the fair values of the various other assets and liabilities acquired. This goodwill is not deductible for tax purposes.

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 making 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 $200 million (net to ConocoPhillips) that were agreed to be paid as part of the 1986 stand still agreement to hold the assets in escrow for the U.S.-based co-venturers. At December 31, 2006, $720 million had been paid or accrued. This transaction also resulted in the recording of $477 million of goodwill, which was reduced by $19 million in 2006, as the purchase price allocation was finalized. The $458 million remaining balance in goodwill 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 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, 2006			
Technology related	**$ 144**	**(51)**	**93**
Refinery air permits	**32**	**(12)**	**20**
Contract based	**139**	**(44)**	**95**
Other	**31**	**(24)**	**7**
	$ 346	**(131)**	**215**
Balance at December 31, 2005			
Technology related	$ 119	(36)	83
Refinery air permits	32	(6)	26
Contract based	32	(9)	23
Other	38	(23)	15
	$ 221	(74)	147
Indefinite-Lived Intangible Assets			
Balance at December 31, 2006			
Trade names and trademarks	**$ 494**		
Refinery air and operating permits	**242**		
	$ 736		
Balance at December 31, 2005			
Trade names and trademarks	$ 598		
Refinery air and operating permits	242		
Other*	129		
	$ 969		

**Primarily pension related. Due to the adoption of SFAS No. 158, we did not have pension-related intangibles at December 31, 2006.*

In addition to the above amounts, we have $13 million of intangibles classified as held for sale. See Note 9 Assets Held for Sale, for additional information.

During 2006, we reduced the carrying value of indefinite-lived intangible assets related to trademark intangibles. This impairment, recorded in the impairments line of the consolidated income statement, totaled $70 million before-tax and was associated with planned asset dispositions in our R&M segment.

Amortization expense related to the intangible assets above for the years ended December 31, 2006 and 2005, was $56 million and $21 million, respectively. The estimated amortization expense for 2007, 2008 and 2009 is approximately $50 million, $40 million and $30 million, respectively. It is expected to be approximately $20 million per year for 2010 and 2011.

Note 13 Impairments

During 2006, 2005 and 2004, we recognized the following before-tax impairment charges:

	Millions of Dollars		
	2006	**2005**	**2004**
E&P			
United States	**$ 55**	2	18
International	**160**	2	49
Midstream		30	38
R&M			
Goodwill and intangible assets	**300**		42
Other	**168**	8	17
	$ 683	42	164

During 2006, we recorded impairments of $496 million associated with planned asset dispositions in our E&P and R&M segments, comprised of properties, plants and equipment ($196 million), trademark intangibles ($70 million), and goodwill ($230 million). In the fourth quarter of 2006, we recorded an impairment of $131 million associated with assets in the Canadian Rockies Foothills area, as a result of declining well performance and drilling results. We recorded a property impairment of $40 million in 2006 as a result of our decision to withdraw an application for a license under the federal Deepwater Port Act, associated with a proposed LNG regasification terminal located offshore Alabama.

In 2005 and 2004, the E&P segment s impairments were the result of the write-down to market value of properties planned for disposition and properties failing to meet recoverability tests. 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. 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 14 Asset Retirement Obligations and Accrued Environmental Costs

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

	Millions of Dollars	
	2006	**2005**
Asset retirement obligations	**$ 5,402**	3,901
Accrued environmental costs	**1,062**	989
Total asset retirement obligations and accrued environmental costs	**6,464**	4,890
Asset retirement obligations and accrued environmental costs due within one year*	**(845)**	(299)
Long-term asset retirement obligations and accrued environmental costs	**$ 5,619**	4,591

**Classified as a current liability on the balance sheet, under the caption Other accruals. Included in 2006 was $386 million related to assets held for sale. See Note 9 Assets Held for Sale, for additional information.*

Asset Retirement Obligations

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.

In March 2005, the 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 2006 and 2005, our overall asset retirement obligation changed as follows:

	Millions of Dollars	
	2006	**2005***
Balance at January 1	**$ 3,901**	3,089
Accretion of discount	**248**	165
New obligations	**154**	144
Burlington Resources acquisition	**732**	
Changes in estimates of existing obligations	**299**	350
Spending on existing obligations	**(130)**	(75)
Property dispositions	**(20)**	
Foreign currency translation	**218**	(189)
Adoption of FIN 47		417
Balance at December 31	**$ 5,402**	3,901

**Certain amounts have been reclassified to conform to current year presentation.*

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**
Pro forma net income*	$ 13,600	8,113
Pro forma earnings per share		
Basic	9.76	5.87
Diluted	9.60	5.79
Pro forma asset retirement obligations at December 31	3,901	3,407

**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.

Accrued Environmental Costs

Total environmental accruals at December 31, 2006 and 2005, were $1,062 million and $989 million, respectively. The 2006 increase in total accrued environmental costs is due to new accruals and accretion, partially offset by payments on accrued environmental costs.

We had accrued environmental costs of $646 million and $552 million at December 31, 2006 and 2005, respectively, primarily related to cleanup at domestic refineries and underground storage tanks at U.S. service stations, and remediation activities required by Canada and the state of Alaska at exploration and production sites. We had also accrued in Corporate and Other $306 million and $320 million of environmental costs associated with non-operating sites at December 31, 2006 and 2005, respectively. In addition, $110 million and $117 million were included at December 31, 2006 and 2005, 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 the 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 $756 million at December 31, 2006. The expected future undiscounted payments related to the portion of the accrued environmental costs that have been discounted are: $157 million in 2007, $123 million in 2008, $82 million in 2009, $63 million in 2010, $49 million in 2011, and $372 million for all future years after 2011.

Note 15 Debt

Long-term debt at December 31 was:

	Millions of Dollars 2006	2005
9.875% Debentures due 2010	**$ 150**	
9.375% Notes due 2011	**328**	328
9.125% Debentures due 2021	**150**	
8.75% Notes due 2010	**1,264**	1,264
8.20% Debentures due 2025	**150**	
8.125% Notes due 2030	**600**	600
8% Junior Subordinated Deferrable Interest Debentures due 2037	**361**	361
7.9% Debentures due 2047	**100**	100
7.8% Debentures due 2027	**300**	300
7.68% Notes due 2012	**43**	49
7.65% Debentures due 2023	**88**	
7.625% Notes due 2006		240
7.625% Debentures due 2013	**100**	
7.40% Notes due 2031	**500**	
7.375% Debentures due 2029	**92**	
7.25% Notes due 2007	**153**	153
7.25% Notes due 2031	**500**	500
7.20% Notes due 2031	**575**	
7.125% Debentures due 2028	**300**	300
7% Debentures due 2029	**200**	200
6.95% Notes due 2029	**1,549**	1,549
6.875% Debentures due 2026	**67**	
6.68% Notes due 2011	**400**	
6.65% Debentures due 2018	**297**	297
6.50% Notes due 2011	**500**	
6.40% Notes due 2011	**178**	
6.375% Notes due 2009	**284**	284
6.35% Notes due 2011	**1,750**	1,750
5.95% Notes due 2036	**500**	
5.90% Notes due 2032	**505**	505
5.847% Notes due 2006		111
5.625% Notes due 2016	**1,250**	
Floating Rate Notes due 2009 at 5.47% at year-end 2006	**1,250**	
Floating Rate Notes due 2007 at 5.37% at year-end 2006	**1,000**	
5.50% Notes due 2013	**750**	
5.45% Notes due 2006		1,250
5.30% Notes due 2012	**350**	
4.75% Notes due 2012	**897**	897
Commercial paper and revolving debt due to banks and others through 2011 at 5.27% - 5.47% at year-end 2006 and 4.43% at year-end 2005	**2,931**	32
Floating Rate Five-Year Term Note due 2011 at 5.575% at year-end 2006	**5,000**	
Industrial Development Bonds due 2012 through 2038 at 3.60% - 4.05% at year-end 2006 and 2.98% - 3.85% at year-end 2005	**236**	236
Guarantee of savings plan bank loan payable due 2015 at 5.65% at year-end 2006 and 4.775% at year-end 2005	**203**	229
Note payable to Merey Sweeny, L.P. due 2020 at 7%	**180**	136
Marine Terminal Revenue Refunding Bonds due 2031 at 3.68% at year-end 2006 and 3.0% at year-end 2005	**265**	265
Other	**76**	151
Debt at face value	**26,372**	12,087
Capitalized leases	**44**	47
Net unamortized premiums and discounts	**718**	382
Total debt	**27,134**	12,516

Notes payable and long-term debt due within one year	**(4,043)**	(1,758)
Long-term debt	**$ 23,091**	10,758

138

Maturities of long-term borrowings, inclusive of net unamortized premiums and discounts, in 2007 through 2011 are: $1,608 million, $108 million, $1,611 million, $1,482 million and $8,223 million, respectively. At year-end 2006, notes payable and long-term debt due within one year was $4,043 million, which includes the maturities of $1,608 million in 2007, shown above, and $2,435 million reflecting our intent, based on prevailing commodity price levels, to further reduce debt during 2007.

The $14.6 billion increase in our debt balance from year-end 2005 reflects debt issuances of $15.3 billion related to the March 31, 2006, acquisition of Burlington Resources and the assumption of $4.3 billion of Burlington Resources debt, including the recognition of an increase of $406 million to record the debt at its fair value. These increases were partly offset by debt reductions during the year.

In March 2006, we closed on two $7.5 billion bridge facilities with a group of five banks to help fund the Burlington Resources acquisition. These bridge financings were both 364-day loan facilities with pricing and terms similar to our existing revolving credit facilities. These facilities were fully drawn in the funding of the acquisition.

In April 2006, we entered into and funded a $5 billion five-year term loan, closed on a $2.5 billion five-year revolving credit facility, increased the ConocoPhillips commercial paper program to $7.5 billion, and issued $3 billion of debt securities. The term loan and new credit facility were broadly syndicated among financial institutions with terms and pricing provisions similar to our other existing revolving credit facilities. The proceeds from the term loan, debt securities and issuances of commercial paper, together with our cash balances and cash provided from operations, were used to repay the $15 billion bridge facilities during the second and third quarters of 2006.

The $3 billion of debt securities were issued in early April 2006. Of this issuance, $1 billion of Floating Rate Notes due April 11, 2007, were issued by ConocoPhillips, and $1.25 billion of Floating Rate Notes due April 9, 2009, and $750 million of 5.50% Notes due 2013, were issued by ConocoPhillips Australia Funding Company, a wholly owned subsidiary. ConocoPhillips and ConocoPhillips Company guarantee the obligations of ConocoPhillips Australia Funding Company.

At December 31, 2006, we had two revolving credit facilities totaling $5 billion that expire in October 2011. Also, we have a $2.5 billion revolving credit facility that expires in April 2011, for which we recently requested an extension of one year in accordance with terms of the facility. These facilities may be used as direct bank borrowings, as support for the ConocoPhillips $7.5 billion commercial paper program, as support for the ConocoPhillips Qatar Funding Ltd. $1.5 billion commercial paper program, or as support for 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 covenants requiring maintenance of specified financial ratios or ratings. The credit facilities contain a cross-default provision relating to our, or any of our consolidated subsidiaries , failure to pay principal or interest on other debt obligations of $200 million or more. At December 31, 2006 and 2005, we had no outstanding borrowings under these credit facilities, but $41 million and $62 million, respectively, in letters of credit had been issued. Under both commercial paper programs there was $2,931 million of commercial paper outstanding at December 31, 2006, compared with $32 million at December 31, 2005. The increase in commercial paper resulted from using it to help repay the bridge facilities discussed above.

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.

In May 2006, we redeemed our $240 million 7.625% Notes upon their maturity. We also redeemed our $129 million 6.60% Notes due in 2007 (part of the debt assumed in the Burlington Resources acquisition), at a premium of $4 million, plus accrued interest.

In October 2006, we redeemed our $1.25 billion 5.45% Notes upon their maturity. In addition, we redeemed our $500 million 5.60% Notes due December 2006, and our $350 million 5.70% Notes due March 2007 (both issues were a part of the debt assumed in the Burlington Resources acquisition), at a premium of $1 million, plus accrued interest. In order to finance the maturity and call of the above notes, ConocoPhillips Canada Funding Company I, a wholly owned subsidiary, issued $1.25 billion of 5.625% Notes due 2016, and ConocoPhillips Canada Funding Company II, a wholly owned subsidiary, issued $500 million of 5.95% Notes due 2036, and $350 million of 5.30% Notes due 2012. ConocoPhillips and ConocoPhillips Company guarantee the obligations of ConocoPhillips Canada Funding Company I and ConocoPhillips Canada Funding Company II.

In December 2006, we terminated the lease of certain refining assets which we consolidated due to our designation as the primary beneficiary of the lease entity. As part of the termination, we exercised a purchase option of the assets totaling $111 million and retired the related debt obligations of $104 million 5.847% Notes due 2006. An associated interest rate swap was also liquidated.

At December 31, 2006, $203 million was outstanding under the ConocoPhillips Savings Plan term loan, which requires repayment in semi-annual installments beginning in 2011 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 of Directors, 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 23 Employee Benefit Plans, for additional discussion of the ConocoPhillips Savings Plan.

At December 31, 2006, Phillips 66 Capital II (Trust II) had outstanding $350 million of 8% Capital Securities (Capital Securities). The sole asset of Trust II was $361 million of the company s 8% Junior Subordinated Deferrable Interest Debentures due 2037 (Subordinated Debt Securities II). The Subordinated Debt Securities II were due January 15, 2037, and were 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 could be called at par, $1,000 per share, plus accrued and unpaid interest. Upon the redemption of the Subordinated Debt Securities II, Trust II is required to apply all redemption proceeds to the immediate redemption of the Capital Securities. Effective January 15, 2007, we redeemed the Subordinated Debt Securities II at a premium of $14 million, plus accrued interest, resulting in the immediate redemption of the Capital Securities.

Under the provisions of revised FASB Interpretation No. 46, Consolidation of Variable Interest Entities (FIN 46 (R)), Trust II, a variable interest entity, was not consolidated in our financial statements because we were not the primary beneficiary. However, the Subordinated Debt Securities II ($361 million) was included on our consolidated balance sheet in Notes payable and long-term debt due within one year at December 31, 2006, and in Long-term debt at December 31, 2005.

Also, in January 2007, we redeemed our $153 million 7.25% Notes upon their maturity, and in February 2007, we reduced our Floating Rate Five-Year Term Note due 2011 from $5 billion to $4 billion.

Note 16 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 were multi-seller conduits with access to the commercial paper market and purchased interests in similar receivables from numerous other companies unrelated to us. We held no ownership interests, nor any variable interests, in any of the bank-sponsored entities, which we did not consolidate.

Furthermore, except as discussed below, we did not consolidate the QSPE because it 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 met the isolation and other requirements of SFAS No. 140 to be accounted for as sales and were 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 were 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
Receivables sold at beginning of year	$ 480
New receivables sold	960
Cash collections remitted	(1,440)
Receivables sold at end of year	$
Discounts and other fees paid on revolving balances	$ 2

Note 17 Guarantees

At December 31, 2006, 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

- In June 2006, we issued a guarantee for 24 percent of the $2 billion in credit facilities of Rockies Express Pipeline LLC (Rockies Express), which will be used to construct a natural gas pipeline across a portion of the United States. The maximum potential amount of future payments to third-party lenders under the guarantee is estimated to be $480 million, which could become payable if the credit facility is fully utilized and Rockies Express fails to meet its obligations under the credit

141

agreement. It is anticipated that construction completion will be achieved mid-2009, and refinancing will take place at that time, making the debt non-recourse. At December 31, 2006, the carrying value of the guarantee to third-party lenders was $11 million. For additional information, see Note 7 Variable Interest Entities (VIEs).

- 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 has committed to provide $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. The project financing will be non-recourse upon certified completion, which is expected by December 31, 2009. At December 31, 2006, the carrying value of the guarantee to the third-party lenders was $11 million. For additional information, see Note 10 Investments, Loans and Long-Term Receivables.

Guarantees of Joint-Venture Debt

- At December 31, 2006, we had guarantees outstanding for our portion of joint-venture debt obligations, which have terms of up to 18 years. The maximum potential amount of future payments under the guarantees is approximately $140 million. Payment would be required if a joint venture defaults on its debt obligations.

Other Guarantees

- The Merey Sweeny, L.P. (MSLP) joint-venture project agreement requires the partners in the venture to pay cash calls to cover operating expenses in the event the venture does not have enough cash to cover operating expenses after setting aside the amount required for debt service over the next 18 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 $100 million in total. To the extent we receive any such payments, our actual gross payments over the 20 years could exceed that amount. 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 7 Variable Interest Entities (VIEs), for additional information.

- We have other guarantees with maximum future potential payment amounts totaling $370 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, three small construction completion guarantees, a guarantee associated with a pending lawsuit, guarantees of the lease payment obligations of a joint venture, and a guarantee of the residual value of leased aircraft. The carrying amount recorded for these other guarantees, at December 31, 2006, was $50 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 pending lawsuit.

Indemnifications

Over the years, we have entered into various agreements to sell ownership interests in certain corporations and joint ventures and have sold several assets, including 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 at December 31, 2006, was $426 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 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 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 $325 million of environmental accruals for known contamination that is included in asset retirement obligations and accrued environmental costs at December 31, 2006. For additional information about environmental liabilities, see Note 18 Contingencies and Commitments.

Note 18 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 14 Asset Retirement Obligations and Accrued Environmental Costs, for a summary of our accrued environmental liabilities.

Legal Proceedings

Our legal department applies its 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 those cases which have been scheduled for trial, as well as the pace of settlement discussions in individual matters. Based on professional judgment and experience in using these litigation management tools and available information about current developments in all our cases, our legal department believes 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, at December 31, 2006, we had performance obligations secured by letters of credit of $988 million (of which $41 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.

Venezuelan government officials have made public statements about increasing ownership interests in heavy-oil projects required to give the national oil company of Venezuela, Petroleos de Venezuela S.A. (PDVSA) control and up to 60 percent ownership interests. On January 31, 2007, Venezuela s National Assembly passed an enabling law allowing the president to pass laws by decree on certain matters, including those associated with heavy-oil production from the Orinoco Oil Belt. PDVSA holds a 49.9 percent interest in the Petrozuata heavy-oil project and a 30 percent interest in the Hamaca heavy-oil project. We have a 50.1 percent interest and a 40 percent interest in the Petrozuata and Hamaca projects, respectively. The impact, if any, of these statements or other potential government actions, on our Petrozuata and Hamaca projects is not determinable at this time.

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: 2007 $77 million; 2008 $69 million; 2009 $68 million; 2010 $68 million; 2011 $69 million; and 2012 and after $296 million. Total payments under the agreements were $66 million in 2006, $52 million in 2005 and $64 million in 2004.

Note 19 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	
	2006	**2005**
Derivative Assets		
Current	**$ 924**	674
Long-term	**82**	193
	$ 1,006	867
Derivative Liabilities		
Current	**$ 681**	1,002
Long-term	**126**	443
	$ 807	1,445

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 of 2005, we entered into additional commodity swaps to essentially offset any remaining exposure from the assumed swaps. At December 31, 2006 and 2005, the commodity swaps assumed in the acquisition had a negative fair value of $76 million and $316 million, respectively, and the commodity swaps entered into to offset the resulting exposure had a negative fair value of $6 million and a positive fair value of $109 million, respectively.

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 At the beginning of 2004, we held interest rate swaps that converted $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 remaining 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 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 years ended December 31, 2006, 2005 and 2004, the gains or losses from this activity were not material to our cash flows or net income.

We do not use 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 ICE Futures.

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 10 Investments, Loans 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 ICE Futures, 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	
	2006	2005	2006	2005
Financial assets				
Foreign currency derivatives	**$ 47**	5	**47**	5
Interest rate derivatives		1		1
Commodity derivatives	**959**	861	**959**	861
Financial liabilities				
Total debt, excluding capital leases	**27,090**	12,469	**27,731**	13,426
Foreign currency derivatives	**26**	39	**26**	39
Interest rate derivatives	**10**	10	**10**	10
Commodity derivatives	**771**	1,396	**771**	1,396

Note 20 Preferred Stock and Minority Interests

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, 2006 or 2005.

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, 2006 and 2005, was 6.69 percent and 5.37 percent, respectively. At December 31, 2006 and 2005, the minority interest was $508 million and $507 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 7 Variable Interest Entities (VIEs), for additional information.

148

The remaining minority interest amounts are primarily related to operating joint ventures we control. The largest amount, $672 million at December 31, 2006, and $682 million at December 31, 2005, relates to the Darwin LNG project in northern Australia.

Note 21 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 22 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, 2006, future minimum rental payments due under non-cancelable leases were:

	Millions of Dollars
2007	$ 584
2008	528
2009	403
2010	291
2011	239
Remaining years	996
Total	3,041
Less income from subleases	(176)*
Net minimum operating lease payments	$ 2,865

**Includes $103 million related to railroad cars subleased to CPChem, a related party.*

149

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

	Millions of Dollars 2006	2005	2004
Total rentals*	**$ 698**	564	521
Less sublease rentals	**(103)**	(66)	(42)
	$ 595	498	479

**Includes $29 million, $28 million and $27 million of contingent rentals in 2006, 2005 and 2004, respectively. Contingent rentals primarily are related to retail sites and refining equipment, and are based on volume of product sold or throughput.*

Note 23 Employee Benefit Plans

Pension and Postretirement Plans

On December 31, 2006, we adopted the recognition and disclosure provisions of SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans an amendment of FASB Statements No. 87, 88, 106, and 132(R) (SFAS No. 158). This new Statement requires employers to recognize the funded status (i.e., the difference between the fair value of plan assets and benefit obligations) of all defined benefit postretirement plans in the statement of financial position, with corresponding adjustments to accumulated other comprehensive income, net of tax, and intangible assets. The adjustment to accumulated other comprehensive income at adoption represents the net unrecognized actuarial losses/gains and unrecognized prior service costs, both of which were previously netted against the plan s funded status in the statement of financial position pursuant to the provisions of Statement Nos. 87 and 106. These amounts will be subsequently recognized as net periodic postretirement cost in accordance with our historical accounting policy for amortizing such amounts. Further, actuarial gains and losses that arise in subsequent periods and are not recognized as net periodic postretirement cost in the same periods will be recognized as a component of other comprehensive income. These amounts will be subsequently recognized as a component of net periodic postretirement cost on the same basis as the amounts recognized in accumulated other comprehensive income at adoption of SFAS No. 158. Additionally, the Statement provides guidance regarding the classification of plan assets and liabilities in the statement of financial position.

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	
	2006		2005		2006	2005
	U.S.	Int l.	U.S.	Int l.		
Change in Benefit Obligation						
Benefit obligation at January 1	**$ 3,703**	**2,495**	3,101	2,409	**815**	913
Service cost	**174**	**87**	151	69	**14**	19
Interest cost	**210**	**134**	174	122	**47**	48
Plan participant contributions		**9**		2	**31**	34
Medicare Part D subsidy					**6**	
Plan amendments	**1**		69		**(26)**	
Actuarial (gain) loss	**57**	**79**	378	232	**(59)**	(117)
Acquisitions	**275**	**42**			**36**	
Divestitures				(9)		
Benefits paid	**(307)**	**(77)**	(170)	(65)	**(86)**	(83)
Curtailment				(3)		
Recognition of termination benefits		**1**		3		
Foreign currency exchange rate change		**317**		(265)		1
Benefit obligation at December 31*	**$ 4,113**	**3,087**	3,703	2,495	**778**	815
**Accumulated benefit obligation portion of above at December 31*	***$ 3,493***	***2,585***	*3,037*	*2,099*		
Change in Fair Value of Plan Assets						
Fair value of plan assets at January 1	**$ 2,183**	**1,725**	1,701	1,627	**3**	4
Acquisitions	**214**	**44**				
Divestitures				(10)		
Actual return on plan assets	**356**	**142**	161	217		
Company contributions	**417**	**120**	491	144	**49**	48
Plan participant contributions		**9**		2	**31**	34
Medicare Part D subsidy					**6**	
Benefits paid	**(307)**	**(77)**	(170)	(65)	**(86)**	(83)
Foreign currency exchange rate change		**222**		(190)		
Fair value of plan assets at December 31	**$ 2,863**	**2,185**	2,183	1,725	**3**	3
Funded Status						
Excess obligation	**$ (1,250)**	**(902)**	(1,520)	(770)	**(775)**	(812)
Unrecognized net actuarial loss (gain)			812	398		(156)
Unrecognized prior service cost			88	46		73
Total recognized	**$ (1,250)**	**(902)**	(620)	(326)	**(775)**	(895)

151

	Millions of Dollars					
	Pension Benefits				Other Benefits	
	2006		2005		2006	2005
	U.S.	Int l.	U.S.	Int l.		
Amounts Recognized in the Consolidated Balance Sheet at December 31, 2006, under SFAS No. 158						
Noncurrent assets	**$**	**16**				
Current liabilities	**(3)**	**(11)**			**(48)**	
Noncurrent liabilities	**(1,247)**	**(907)**			**(727)**	
Total recognized	**$ (1,250)**	**(902)**			**(775)**	
Amounts Recognized in the Consolidated Balance Sheet at December 31, 2005, under Prior Accounting Rules						
Prepaid benefit cost	$			69		
Accrued benefit liability			(838)	(481)		(895)
Intangible asset			88	39		
Accumulated other comprehensive loss			130	47		
Total recognized	$		(620)	(326)		(895)
Weighted-Average Assumptions Used to Determine Benefit Obligations at December 31						
Discount rate	**5.75** %	**5.15**	5.50	5.05	**5.95**	5.70
Rate of compensation increase	**4.00**	**4.70**	4.00	4.35		
Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31						
Discount rate	**5.50** %	**5.05**	5.75	5.50	**5.70**	5.75
Expected return on plan assets	**7.00**	**6.50**	7.00	6.85	**7.00**	7.00
Rate of compensation increase	**4.00**	**4.35**	4.00	3.80		

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.

The adoption of SFAS No. 158 had no effect on the consolidated statement of income for the year ended December 31, 2006, or for any prior period presented, and it will not affect our reported operating results in future periods. Had we not been required to adopt SFAS No. 158, we would have recognized an additional minimum liability at December 31, 2006, pursuant to the provisions of Statement No. 87.

The effect of recognizing the additional minimum liability is included in the table below in the column labeled Prior to Adopting SFAS No. 158. The incremental effects of adopting the provisions of SFAS No. 158 on our consolidated balance sheet at December 31, 2006, are presented in the following table:

	Millions of Dollars		
	Prior to Adopting SFAS No. 158	Effect of Adopting SFAS No. 158	As Reported
Intangibles	$ 990	(39)	951
Other assets	430	(68)	362
Employee benefit obligations (short-term)	(1,394)	499	(895)
Employee benefit obligations (long-term)	(2,419)	(1,248)	(3,667)
Deferred income taxes	(20,375)	301	(20,074)
Accumulated other comprehensive income	(1,844)	555*	(1,289)

**Consistent with the presentation of other amounts within the Pension and Postretirement Plans section, this amount applies only to plans for which we are the primary obligor. An additional $20 million impact on Accumulated other comprehensive income in our consolidated balance sheet is related to plans for which we are not the primary obligor.*

Included in accumulated other comprehensive income at December 31, 2006, are the following before-tax amounts that have not yet been recognized in net periodic postretirement benefit cost:

	Millions of Dollars		
	Pension		Other Benefits
	U.S.	Int l.	
Unrecognized net actuarial loss (gain)	$ 577	460	(200)
Unrecognized prior service cost	79	44	28

Amounts included in accumulated other comprehensive income at December 31, 2006, that are expected to be amortized into net periodic postretirement cost during 2007 are provided below:

	Millions of Dollars		
	Pension		Other Benefits
	U.S.	Int l.	
Unrecognized net actuarial loss (gain)	$ 62	46	(20)
Unrecognized prior service cost	11	7	13

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).

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 $6,366 million, $5,400 million, and $4,543 million at December 31, 2006, respectively, and $5,896 million, $4,899 million, and $3,906 million at December 31, 2005, respectively.

For our unfunded non-qualified supplemental key employee pension plans, the projected benefit obligation and the accumulated benefit obligation were $345 million and $304 million, respectively, at December 31, 2006, and were $292 million and $227 million, respectively, at December 31, 2005.

The components of net periodic benefit cost of all defined benefit plans are presented in the following table:

	Millions of Dollars								
	Pension Benefits						**Other Benefits**		
	2006		**2005**		**2004**		**2006**	**2005**	**2004**
	U.S.	**Int l.**	**U.S.**	**Int l.**	**U.S.**	**Int l.**			
Components of Net Periodic Benefit Cost									
Service cost	**$ 174**	**87**	151	69	150	69	**14**	19	23
Interest cost	**210**	**134**	174	122	176	114	**47**	48	58
Expected return on plan assets	**(169)**	**(121)**	(126)	(105)	(105)	(92)			
Amortization of prior service cost	**9**	**7**	4	7	4	7	**19**	19	19
Recognized net actuarial loss (gain)	**89**	**41**	55	33	52	40	**(16)**	(6)	10
Net periodic benefit cost	**$ 313**	**148**	258	126	277	138	**64**	80	110

We recognized pension settlement losses of $11 million and $4 million and special termination benefits of $1 million and $3 million in 2006 and 2005, respectively.

In determining net pension and other postretirement benefit costs, we amortize prior service costs on a straight-line basis over the average remaining service period of employees expected to receive benefits under the plan. For net gains and losses, we amortize ten percent of the unamortized balance each year.

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 9.5 percent in 2007 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 2006 amounts:

	Millions of Dollars One-Percentage-Point Increase	Decrease
Effect on total of service and interest cost components	$ 3	(2)
Effect on the postretirement benefit obligation	36	(37)

Plan Assets We follow 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 2007, we expect to contribute approximately $430 million to our domestic qualified and non-qualified benefit plans and $165 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, 2006, the participating interest in the annuity contract was valued at $181 million and consisted of $412 million in debt securities and $53 million in equity securities, less $284 million for the accumulated benefit obligation covered by the contract. At December 31, 2005, the participating interest 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. 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, the weighted-average asset allocations are as follows:

	Pension U.S. 2006	2005	Target	International 2006	2005	Target
Asset Category						
Equity securities	**66** %	66	60	**50**	50	51
Debt securities	**33**	32	30	**40**	38	41
Real estate		1	5	**5**	3	6
Other	**1**	1	5	**5**	9	2
	100 %	100	100	**100**	100	100

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

155

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	
	2006	2005	2006	2005
Asset Category				
Equity securities	**72** %	72	**50**	50
Debt securities	**21**	18	**40**	38
Participating interest in annuity contract	**6**	8		
Real estate		1	**5**	3
Other	**1**	1	**5**	9
	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
2007	$ 280	99	51	7
2008	285	98	55	7
2009	281	106	57	8
2010	307	111	60	9
2011	345	124	62	8
2012-2016	2,311	687	331	40

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 deposits, up to 1.25 percent of eligible pay. Company contributions charged to expense for the CPSP and predecessor plans, excluding the stock savings feature (discussed below), were $19 million in 2006, $18 million in 2005, and $17 million in 2004. For the Burlington Resources Inc. Retirement Savings Plan (Burlington Savings Plan), ConocoPhillips matches deposits, up to 6 percent or 8 percent of the employee s eligible pay based upon years of service. During 2006, ConocoPhillips contributed $7 million to the Burlington Savings Plan, to match eligible contributions by employees.

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 2007 through 2010, 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 $126 million, $124 million and $85 million in 2006, 2005 and 2004, respectively, all of which was compensation expense. In 2006, 2005 and 2004, we made cash contributions to the CPSP stock savings feature of less than $1 million. In 2006, 2005 and 2004, we contributed 1,921,688 shares, 2,250,727 shares and 2,419,808 shares, respectively, of company common stock from the Compensation and Benefits Trust. The shares had a fair market value of $132 million, $130 million and $99 million, respectively. Dividends used to service debt were $37 million, $32 million, and $27 million in 2006, 2005 and 2004, respectively. These dividends reduced the amount of compensation expense recognized each period. Interest incurred on the CPSP debt in 2006, 2005 and 2004 was $12 million, $9 million and $5 million, respectively.

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

	2006	**2005**
Unallocated shares	**10,499,837**	11,843,383
Allocated shares	**18,501,772**	19,095,143
Total shares	**29,001,609**	30,938,526

The fair value of unallocated shares at December 31, 2006 and 2005, was $755 million and $689 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 including heritage Burlington Resources plans was approximately $31 million in 2006, $27 million in 2005 and $20 million in 2004.

Share-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, 40 million shares of common stock are available for incentive stock options, and no more than 40 million shares may be used for awards in stock.

Our share-based compensation programs generally 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. For share-based awards granted prior to our adoption of SFAS No. 123(R), we recognize expense over the period of time during which the employee earns the award, accelerating the recognition of expense only when an employee actually retires. For share-based awards granted after our adoption of SFAS No. 123(R) on January 1, 2006, we recognize share-based compensation expense 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, but not less than six months, as this is the minimum period of time required for an award to not be subject to forfeiture.

Some of our share-based awards vest ratably (i.e., portions of the award vest at different times) while some of our awards cliff vest (i.e., all of the award vests at the same time). For awards granted prior to our adoption of SFAS No. 123(R) that vest ratably, we recognize expense on a straight-line basis over the service period for each separate vesting portion of the award (i.e., as if the award was multiple awards with different requisite service periods). For share-based awards granted after our adoption of SFAS No. 123(R), we recognize expense on a straight-line basis over the service period for the entire award, whether the award was granted with ratable or cliff vesting.

Total share-based compensation expense recognized in income and the associated tax benefit for the three years ended December 31, 2006, was as follows:

	Millions of Dollars		
	2006	**2005**	**2004**
Compensation cost	**$ 140**	226	147
Tax benefit	**54**	84	54

Stock Options Stock options granted under the 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 generally vest ratably, with one-third of the options awarded vesting and becoming exercisable on each anniversary date following the date of grant. Options awarded to employees already eligible for retirement vest within six months of the grant date, but those options do not become exercisable until the end of the normal vesting period.

158

The following summarizes our stock option activity for the three years ended December 31, 2006:

	Options	Weighted-Average Exercise Price	Weighted-Average Grant-Date Fair Value	Millions of Dollars Aggregate Intrinsic Value
Outstanding at December 31, 2003	91,659,154	$ 24.54		
Granted	4,352,208	32.85	$ 7.13	
Exercised	(21,425,398)	21.22		$ 383
Forfeited/Expired	(322,042)	25.73		
Outstanding at December 31, 2004	74,263,922	$ 25.97		
Granted	2,567,000	47.87	$ 10.92	
Exercised	(19,265,175)	24.85		$ 615
Forfeited/Expired	(169,001)	34.83		
Outstanding at December 31, 2005	57,396,746	$ 27.31		
Burlington Resources acquisition at March 31, 2006	**4,927,116**	**33.95**		
Granted	**1,809,281**	**59.33**	**$ 16.16**	
Exercised	**(9,737,765)**	**24.32**		**$ 416**
Forfeited	**(341,759)**	**60.58**		
Expired	**(4,840)**	**50.16**		
Outstanding at December 31, 2006	**54,048,779**	**$ 29.31**		
Vested at December 31, 2006	**49,541,771**	**$ 27.64**		**$ 2,208**
Exercisable at December 31, 2006	**48,970,004**	**$ 27.15**		**$ 2,206**

The weighted-average remaining contractual term of vested options and exercisable options at December 31, 2006, was 4.79 years and 4.74 years, respectively.

During 2006, we received $231 million in cash and realized a tax benefit of $117 million from the exercise of options. At December 31, 2006, the remaining unrecognized compensation expense from unvested options was $18 million, which will be recognized over the next 31 months.

The significant assumptions used to calculate the fair market values of the options granted over the past three years, as calculated using the Black-Scholes-Merton option-pricing model, were as follows:

	2006	2005	2004
Assumptions used			
Risk-free interest rate	**4.63** %	3.92	3.48
Dividend yield	**2.50** %	2.50	2.50
Volatility factor	**26.10** %	22.50	24.16
Expected life (years)	**7.18**	7.18	5.95

The ranges in the assumptions used were as follows:

	2006		2005		2004	
	High	Low	High	Low	High	Low
Ranges used						
Risk-free interest rate	**5.15** %	**4.54**	4.45	3.33	3.50	1.08
Dividend yield	**2.50**	**2.50**	2.50	2.50	3.29	2.50
Volatility factor	**26.50**	**25.90**	25.70	22.30	30.10	18.50

We calculate volatility using all of the ConocoPhillips end-of-week closing stock prices available since the merger of Conoco and Phillips Petroleum on August 31, 2002, and will continue to do so until the span of data used equals the expected life of the options granted. We periodically calculate the average period of time lapsed between grant dates and exercise dates of past grants to estimate the expected life of new option grants. The change in expected life from six years in 2004 to slightly more than seven years in 2005 reflects a change in the population of employees receiving options.

Stock Unit Program Stock units granted under the provisions of the Plan vest ratably, with one-third of the units vesting in 36 months, one-third vesting in 48 months, and the final third vesting 60 months from the date of grant. Upon vesting, the units are settled by issuing one share of ConocoPhillips common stock per unit. Units awarded to employees already eligible for retirement vest within six months of the grant date, but those units are not issued as shares until the end of the normal vesting period. Until issued as stock, most recipients of the units receive a quarterly cash payment of a dividend equivalent that is charged to expense. The grant date fair value of these units is deemed equal to the average ConocoPhillips stock price on the date of grant. The grant date fair market value of units that do not receive a dividend equivalent while unvested is deemed equal to the average ConocoPhillips stock price on the grant date, less the net present value of the dividends that will not be received.

The following summarizes our stock unit activity for the three years ended December 31, 2006:

	Stock Units		Weighted-Average Grant-Date Fair Value		Millions of Dollars Total Fair Value
Outstanding at December 31, 2003		$			
Granted	2,367,542		32.10		
Forfeited	(43,764)		31.96		
Issued	(7,088)			$	
Outstanding at December 31, 2004	2,316,690	$	32.10		
Granted	1,668,192		46.95		
Forfeited	(57,262)		37.81		
Issued	(35,216)			$	2
Outstanding at December 31, 2005	3,892,404	$	38.34		
Granted	**1,480,294**		**57.77**		
Forfeited	**(118,461)**		**45.92**		
Issued	**(167,099)**			**$**	**11**
Outstanding at December 31, 2006	**5,087,138**	**$**	**43.75**		
Not Vested at December 31, 2006	**4,866,081**	**$**	**43.12**		

At December 31, 2006, the remaining unrecognized compensation cost from the unvested units was $105 million, which will be recognized over approximately the next four years.

Performance Share Program Under the Plan, we also annually grant to senior management stock units that do not vest until the employee becomes eligible for retirement, so we recognize compensation expense for these awards beginning on the date of grant and ending on the date the employee becomes eligible for retirement; however, since these awards are authorized three years prior to the grant date, for employees eligible for retirement by or shortly after the grant date, we recognize compensation expense over the period beginning on the date of authorization and ending on the date of grant. These units are settled by issuing one share of ConocoPhillips common stock per unit, generally when the employee retires from ConocoPhillips. Until issued as stock, recipients of the units receive a quarterly cash payment of a dividend equivalent that is charged to expense. In its current form, the first grant of units under this program was in 2006.

161

The following summarizes our Performance Share Program activity for the year ended December 31, 2006:

	Performance Share Stock Units	Grant-Date Fair Value	Millions of Dollars Total Fair Value
Outstanding at December 31, 2005		$	
Granted	**1,641,216**	**59.08**	
Forfeited			
Issued	**(184,975)**		**$ 12**
Outstanding at December 31, 2006	**1,456,241**	**$ 59.08**	
Not Vested at December 31, 2006	**868,241**	**$ 59.08**	

At December 31, 2006, the remaining unrecognized compensation cost from unvested Performance Share awards was $35 million, which will be recognized over the next 14 years.

Other In addition to the above active programs, we have outstanding shares of restricted stock and restricted stock units that were either issued to replace awards held by employees of companies we acquired or issued as part of a compensation program that has been discontinued. Generally, the recipients of the restricted shares or units receive a quarterly dividend or dividend equivalent.

The following summarizes the aggregate activity of these restricted shares and units for the three years ended December 31, 2006:

	Stock Units	Weighted-Average Grant-Date Fair Value	Millions of Dollars Total Fair Value
Outstanding at December 31, 2003	3,578,430	$ 26.25	
Granted	594,271	33.61	
Stock Swaps	327,712	44.16	
Issued	(550,379)		$ 22
Cancelled	(488,135)	32.06	
Outstanding at December 31, 2004	3,461,899	$ 28.44	
Granted	89,676	54.08	
Stock Swaps	9,116	43.97	
Issued	(135,168)		$ 7
Cancelled	(80,582)	28.93	
Outstanding at December 31, 2005	3,344,941	$ 29.16	
Granted	**248,421**	**64.48**	
Burlington Resources acquisition	**523,769**	**64.95**	
Issued	**(239,257)**		**$ 16**
Cancelled	**(275,499)**	**47.56**	
Outstanding at December 31, 2006	**3,602,375**	**$ 33.68**	
Not Vested at December 31, 2006	**462,021**	**$ 58.91**	

At December 31, 2006, the remaining unrecognized compensation cost from the unvested units was $15 million, which will be recognized over the next two years.

Compensation and Benefits Trust

The Compensation and Benefits Trust (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 2006 and 2005, shares transferred out of the CBT were 1,921,688 and 2,250,727, respectively. At December 31, 2006, the CBT had 44,010,405 shares remaining. All shares are required to be transferred out of the CBT by January 1, 2021. The CBT, together with a smaller grantor trust included in the Burlington Resources acquisition, comprise the Grantor trusts line in the equity section of the consolidated balance sheet.

Note 24 Income Taxes

Income taxes charged to income from continuing operations were:

	Millions of Dollars 2006	2005	2004
Income Taxes			
Federal			
Current	**$ 4,313**	3,434	1,616
Deferred	**(77)**	375	719
Foreign			
Current	**7,581**	5,093	3,468
Deferred	**392**	384	190
State and local			
Current	**622**	538	256
Deferred	**(48)**	83	13
	$ 12,783	9,907	6,262

163

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	
	2006	**2005**
Deferred Tax Liabilities		
Properties, plants and equipment, and intangibles	**$ 22,733**	12,737
Investment in joint ventures	**1,178**	1,146
Inventory	**339**	207
Partnership income deferral	**1,305**	612
Other	**438**	570
Total deferred tax liabilities	**25,993**	15,272
Deferred Tax Assets		
Benefit plan accruals	**1,730**	1,237
Asset retirement obligations and accrued environmental costs	**2,330**	1,793
Deferred state income tax	**408**	230
Other financial accruals and deferrals	**820**	724
Loss and credit carryforwards	**1,283**	936
Other	**230**	179
Total deferred tax assets	**6,801**	5,099
Less valuation allowance	**(822)**	(850)
Net deferred tax assets	**5,979**	4,249
Net deferred tax liabilities	**$ 20,014**	11,023

Current assets, long-term assets, current liabilities and long-term liabilities included deferred taxes of $173 million, $62 million, $175 million and $20,074 million, respectively, at December 31, 2006, and $363 million, $65 million, $12 million and $11,439 million, respectively, at December 31, 2005.

We have loss and credit carryovers in multiple taxing jurisdictions. These attributes generally expire between 2007 and 2026 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 2006, valuation allowances decreased $28 million. This reflects increases of $148 million primarily related to foreign tax loss carryforwards (including $45 million related to the acquisition of Burlington Resources), more than offset by decreases of $76 million primarily related to U.S. capital loss carryforward utilization and decreases of $100 million related to foreign loss carryforwards (i.e., expiration, relinquishment and currency translation). The balance includes valuation allowances for certain deferred tax assets of $298 million, for which subsequently recognized tax benefits, if any, will be allocated to goodwill. Based on our historical taxable income, 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.

At December 31, 2006 and 2005, income considered to be permanently reinvested in certain foreign subsidiaries and foreign corporate joint ventures totaled approximately $4,512 million and $2,202 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**		
	2006	**2005**	**2004**	**2006**	**2005**	**2004**
Income from continuing operations before income taxes						
United States	**$ 13,376**	12,486	7,587	**47.2 %**	53.0	52.8
Foreign	**14,957**	11,061	6,782	**52.8**	47.0	47.2
	$ 28,333	23,547	14,369	**100.0 %**	100.0	100.0
Federal statutory income tax	**$ 9,917**	8,241	5,029	**35.0 %**	35.0	35.0
Foreign taxes in excess of federal statutory rate	**2,697**	1,562	1,138	**9.5**	6.6	7.9
Domestic tax credits		(55)	(85)		(.2)	(.6)
Federal manufacturing deduction	**(119)**	(106)		**(.4)**	(.4)	
State income tax	**373**	404	175	**1.3**	1.7	1.2
Other	**(85)**	(139)	5	**(.3)**	(.6)	.1
	$ 12,783	9,907	6,262	**45.1 %**	42.1	43.6

Our 2006 tax expense was increased $470 million due to remeasurement of deferred tax liabilities and the current year impact of increases in the U.K. tax rate. This was mostly offset by a 2006 reduction in tax expense of $435 million due to the remeasurement of deferred tax liabilities from the 2006 Canadian graduated tax rate reduction and an Alberta provincial tax rate change. In 2005, our tax expense was reduced $38 million due to the remeasurement of deferred tax liabilities from the 2003 Canadian graduated tax rate reduction. Our 2004 tax expense was reduced $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 25 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
2006			
Minimum pension liability adjustment	**$ 53**	**20**	**33**
Foreign currency translation adjustments	**913**	**(100)**	**1,013**
Hedging activities	**4**		**4**
Other comprehensive income	**$ 970**	**(80)**	**1,050**
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

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	
	2006	2005
Defined benefit pension plans	**$ (665)**	
Minimum pension liability adjustment		(123)
Foreign currency translation adjustments	**1,958**	945
Deferred net hedging loss	**(4)**	(8)
Accumulated other comprehensive income	**$ 1,289**	814

Note 26 Cash Flow Information

	Millions of Dollars 2006	2005	2004
Non-Cash Investing and Financing Activities			
Issuance of stock and options for the acquisition of Burlington Resources	**$ 16,343**		
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	**129**	133	99
Investment in equity affiliate through exchange of non-cash assets and liabilities		109	
Increase in PP&E related to the increase in asset retirement obligations	**464**	511	150

**Payment obligations were included in the Other accruals line within the current liabilities section of the consolidated balance sheet.*

***See Note 19 Financial Instruments and Derivative Contracts, for additional information.*

	2006	2005	2004
Cash Payments			
Interest	**$ 958**	500	560
Income taxes	**13,050**	8,507	4,754

167

Note 27 Other Financial Information

	Millions of Dollars Except Per Share Amounts 2006	2005	2004
Interest			
Incurred			
Debt	**$ 1,409**	807	878
Other	**136**	85	98
	1,545	892	976
Capitalized	**(458)**	(395)	(430)
Expensed	**$ 1,087**	497	546
Research and Development Expenditures expensed	**$ 117**	125	126
Advertising Expenses	**$ 87**	84	101
Business Interruption Insurance Recoveries*	**$ 239**		

**Included in the Other income line of the consolidated income statement. Insurance recoveries in 2006 are primarily related to 2005 hurricanes in the Gulf of Mexico and southern United States.*

	2006	2005	2004
Shipping and Handling Costs*	**$ 1,415**	1,265	947

**Amounts included in E&P production and operating expenses.*

	2006	2005	2004
Cash Dividends paid per common share	**$ 1.44**	1.18	.895
Foreign Currency Transaction Gains (Losses) after-tax			
E&P	**$ (44)**	7	(13)
Midstream		7	(1)
R&M	**60**	(52)	12
LUKOIL Investment		(1)	
Chemicals			
Emerging Businesses	**1**	(1)	
Corporate and Other	**65**	(42)	44
	$ 82	(82)	42

Note 28 Related Party Transactions

Significant transactions with related parties were:

	Millions of Dollars		
	2006	**2005***	**2004***
Operating revenues (a)	**$ 8,724**	7,655	5,321
Purchases (b)	**6,707**	6,098	4,616
Operating expenses and selling, general and administrative expenses (c)	**391**	379	421
Net interest expense (d)	**94**	48	39

**Certain amounts reclassified to conform to current year presentation and adjusted to include other related party transactions.*

(a) We sell natural gas to DCP Midstream 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 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, Merey Sweeny L.P. (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 DCP Midstream 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 II trust. See Note 10 Investments, Loans and Long-Term Receivables, for additional information on loans to affiliated companies.

Elimination of our equity percentage share of profit or loss included in our inventory at December 31, 2006, 2005 and 2004, 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, 2006, 2005 and 2004, on the revenues from related parties described above was not material.

169

Note 29 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, 2006, our E&P operations were producing in the United States, Norway, the United Kingdom, the Netherlands, Canada, Nigeria, Venezuela, Ecuador, Argentina, offshore Timor Leste in the Timor Sea, Australia, China, Indonesia, Algeria, Libya, 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 This segment gathers, processes and markets natural gas produced by ConocoPhillips and others, and fractionates and markets natural gas liquids, primarily in the United States and Trinidad. The Midstream segment primarily consists of our 50 percent equity investment in DCP Midstream.

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, 2006, we owned 12 refineries in the United States, one in the United Kingdom, one in Ireland, one in Germany, 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. At December 31, 2006, our ownership interest was 20 percent, based on authorized and issued shares, and 20.6 percent, based on estimated shares outstanding. See Note 10 Investments, Loans and Long-Term Receivables, for additional information.

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 The Emerging Businesses segment represents our investment in new technologies or businesses outside our normal scope of operations. Activities within this segment are currently focused on power generation; carbon-to-liquids; technology solutions, such as sulfur removal technologies; and alternative energy and programs, such as advanced hydrocarbon processes, energy conversion technologies, new petroleum-based products, and renewable fuels.

Corporate and Other includes general corporate overhead, interest income and expense, discontinued operations, restructuring charges, 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.

Also, see Note 2 Changes in Accounting Principles, for information affecting the comparability of sales and other operating revenues presented in the following tables of our segment disclosures.

Analysis of Results by Operating Segment

	Millions of Dollars 2006	2005	2004
Sales and Other Operating Revenues			
E&P			
United States	**$ 35,335**	35,159	23,805
International	**28,111**	21,692	16,960
Intersegment eliminations U.S.	**(5,438)**	(4,075)	(2,841)
Intersegment eliminations international	**(7,842)**	(4,251)	(3,732)
E&P	**50,166**	48,525	34,192
Midstream			
Total sales	**4,461**	4,041	4,020
Intersegment eliminations	**(1,037)**	(955)	(987)
Midstream	**3,424**	3,086	3,033
R&M			
United States	**95,314**	97,251	72,962
International	**35,439**	30,633	25,141
Intersegment eliminations U.S.	**(855)**	(593)	(431)
Intersegment eliminations international	**(21)**	(11)	(26)
R&M	**129,877**	127,280	97,646
LUKOIL Investment			
Chemicals	**13**	14	14
Emerging Businesses*			
Total sales	**675**	618	246
Intersegment eliminations	**(515)**	(426)	(69)
Emerging Businesses	**160**	192	177
Corporate and Other	**10**	13	14
Other adjustments*		332	
Consolidated sales and other operating revenues	**$ 183,650**	179,442	135,076

**Sales and other operating revenues for 2005 in the Emerging Businesses segment have been restated to reflect intersegment eliminations on sales from the Immingham power plant (Emerging Businesses segment) to the Humber refinery (R&M segment). Since these amounts were not material to the consolidated income statement, the Other adjustments line above is required to reconcile the restated Emerging Businesses revenues to the consolidated income statement.*

Depreciation, Depletion, Amortization and Impairments

	2006	2005	2004
E&P			
United States	**$ 2,901**	1,402	1,126
International	**3,445**	1,914	1,859
Total E&P	**6,346**	3,316	2,985
Midstream	**29**	61	80
R&M			
United States	**1,014**	633	657
International	**458**	193	175
Total R&M	**1,472**	826	832
LUKOIL Investment			
Chemicals			
Emerging Businesses	**58**	32	8
Corporate and Other	**62**	60	57
Consolidated depreciation, depletion, amortization and impairments	**$ 7,967**	4,295	3,962

	Millions of Dollars		
	2006	**2005**	**2004**
Equity in Earnings of Affiliates			
E&P			
United States	**$ 20**	19	21
International	**782**	825	520
Total E&P	**802**	844	541
Midstream	**618**	829	265
R&M			
United States	**466**	388	245
International	**151**	227	110
Total R&M	**617**	615	355
LUKOIL Investment	**1,481**	756	74
Chemicals	**665**	413	307
Emerging Businesses	**5**		(7)
Corporate and Other			
Consolidated equity in earnings of affiliates	**$ 4,188**	3,457	1,535
Income Taxes			
E&P			
United States	**$ 2,545**	2,349	1,583
International	**7,584**	5,145	3,349
Total E&P	**10,129**	7,494	4,932
Midstream	**248**	214	137
R&M			
United States	**2,334**	2,124	1,234
International	**218**	212	197
Total R&M	**2,552**	2,336	1,431
LUKOIL Investment	**37**	25	
Chemicals	**171**	93	64
Emerging Businesses	**(2)**	(18)	(52)
Corporate and Other	**(352)**	(237)	(250)
Consolidated income taxes	**$ 12,783**	9,907	6,262
Net Income (Loss)			
E&P			
United States	**$ 4,348**	4,288	2,942
International	**5,500**	4,142	2,760
Total E&P	**9,848**	8,430	5,702
Midstream	**476**	688	235
R&M			
United States	**3,915**	3,329	2,126
International	**566**	844	617
Total R&M	**4,481**	4,173	2,743
LUKOIL Investment	**1,425**	714	74
Chemicals	**492**	323	249
Emerging Businesses	**15**	(21)	(102)
Corporate and Other	**(1,187)**	(778)	(772)
Consolidated net income	**$ 15,550**	13,529	8,129

	Millions of Dollars 2006	2005	2004
Investments In and Advances To Affiliates*			
E&P			
United States	**$ 690**	336	188
International	**4,346**	3,789	2,522
Total E&P	**5,036**	4,125	2,710
Midstream	**1,319**	1,446	413
R&M			
United States	**698**	662	752
International	**948**	819	667
Total R&M	**1,646**	1,481	1,419
LUKOIL Investment	**9,564**	5,549	2,723
Chemicals	**2,255**	2,158	2,179
Emerging Businesses			1
Corporate and Other		18	21
Consolidated investments in and advances to affiliates	**$ 19,820**	14,777	9,466
**Includes $158 million classified as assets held for sale.*			
Total Assets			
E&P			
United States	**$ 35,523**	18,434	16,105
International	**48,143**	31,662	26,481
Goodwill	**27,712**	11,423	11,090
Total E&P	**111,378**	61,519	53,676
Midstream	**2,045**	2,109	1,293
R&M			
United States	**22,936**	20,693	19,180
International	**9,135**	6,096	5,834
Goodwill	**3,776**	3,900	3,900
Total R&M	**35,847**	30,689	28,914
LUKOIL Investment	**9,564**	5,549	2,723
Chemicals	**2,379**	2,324	2,221
Emerging Businesses	**977**	858	972
Corporate and Other	**2,591**	3,951	3,062
Consolidated total assets	**$ 164,781**	106,999	92,861

Capital Expenditures and Investments*			
E&P			
United States	**$ 2,828**	1,637	1,314
International	**6,685**	5,047	3,935
Total E&P	**9,513**	6,684	5,249
Midstream	**4**	839	7
R&M			
United States	**1,597**	1,537	1,026
International	**1,419**	201	318
Total R&M	**3,016**	1,738	1,344
LUKOIL Investment	**2,715**	2,160	2,649
Chemicals			
Emerging Businesses	**83**	5	75
Corporate and Other	**265**	194	172
Consolidated capital expenditures and investments	**$ 15,596**	11,620	9,496

**Net of cash acquired.*

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

	Millions of Dollars		
	2006	**2005**	**2004**
Interest income*	**$ 106**	113	47
Interest and debt expense	**1,087**	497	546
**In addition, the E&P segment had interest income of:*	***$ 57***	*12*	*2*

Geographic Information

	Millions of Dollars						
	United States	**Norway**	**United Kingdom**	**Canada**	**Russia**	**Other Foreign Countries**	**Worldwide Consolidated**
2006							
Sales and Other Operating Revenues*	**$ 127,869**	**2,480**	**19,510**	**5,554**		**28,237**	**183,650**
Long-Lived Assets**	**$ 48,418**	**4,982**	**7,755**	**14,831**	**10,886**	**19,149**	**106,021**
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

**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 affiliated companies.*

Note 30 New Accounting Standards

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements. This Statement defines fair value, establishes a framework for its measurement and expands disclosures about fair value measurements. We use fair value measurements to measure, among other items, purchased assets and investments, leases, derivative contracts and financial guarantees. We also use them to assess impairment of properties, plants and equipment, intangible assets and goodwill. The Statement does not apply to share-based payment transactions and inventory pricing. This Statement is effective January 1, 2008. We are currently evaluating the impact on our financial statements.

In June 2006, the FASB issued FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109 (FIN 48). This Interpretation provides guidance on recognition, classification, and disclosure concerning uncertain tax liabilities. The evaluation of a tax

174

position will require recognition of a tax benefit if it is more likely than not that it will be sustained upon examination. This Interpretation is effective beginning January 1, 2007. We have completed our analysis and concluded the adoption of FIN 48 will not have a material impact on our financial statements.

In September 2006, the FASB issued SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans an admendment of FASB Statements No. 87, 88, 106, and 132(R) (SFAS No. 158). We adopted the recognition and disclosure provisions of this new Statement as of December 31, 2006, and the impact from these changes is reflected in Note 23 Employee Benefit Plans. The requirement in SFAS No. 158 to measure plan assets and benefit obligations as of the date of the employer s fiscal year end is effective for fiscal years ending after December 15, 2008. The measurement date for our pension plan in the United Kingdom will be changed from September 30 to December 31 in time to comply with the Statement s 2008 required implementation date. All other plans are presently measured at December 31 of each year.

Note 31 Joint Venture with EnCana Corporation

In October 2006, we announced a business venture with EnCana Corporation (EnCana), to create an integrated North American heavy-oil business. The transaction closed on January 3, 2007. The venture consists of two 50/50 operating joint ventures, a Canadian upstream general partnership, FCCL Oil Sands Partnership, and a U.S. downstream limited liability company, WRB Refining LLC.

FCCL Oil Sands Partnership s operating assets consist of EnCana s Foster Creek and Christina Lake steam-assisted gravity drainage bitumen projects, both located in the eastern flank of the Athabasca oil sands in northeast Alberta. EnCana is the operator and managing partner of this joint venture. We expect to contribute $7.5 billion, plus accrued interest, to the joint venture over a 10-year period beginning in 2007. This interest-bearing cash contribution obligation will be recorded as a liability on our first quarter 2007 balance sheet. Upon the closing in January, we made an initial contribution of $188 million to this joint venture.

WRB Refining LLC s operating assets consist of our Wood River and Borger refineries, located in Roxana, Illinois, and Borger, Texas, respectively. This joint venture plans to expand heavy-oil processing capacity at these facilities from 60,000 barrels per day to approximately 550,000 barrels per day by 2015. Total crude oil throughput at these two facilities is expected to increase from the current 452,000 barrels per day to approximately 600,000 barrels per day over the same time period. We are the operator and managing partner of this joint venture. EnCana is expected to contribute $7.5 billion, plus accrued interest to the joint venture over a 10-year period beginning in 2007. For the Wood River refinery, operating results will be shared 50/50 starting upon formation. For the Borger refinery, we are entitled to 85 percent of the operating results in 2007, 65 percent in 2008, and 50 percent in all years thereafter.

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 OAO LUKOIL s (LUKOIL) amounts. Because LUKOIL s accounting cycle close and preparation of U.S. GAAP financial statements occur subsequent to our reporting deadline, our equity share of financial information and statistics for our LUKOIL investment are estimated based on current market indicators, historical production and cost trends of LUKOIL, and other objective data. Once the difference between actual and estimated results is known, an adjustment is recorded. Our estimated year-end 2006 reserves related to our equity-method ownership interest in LUKOIL were based on LUKOIL s year-end 2005 reserves (adjusted for known additions, license extensions, dispositions, and other related information) and included adjustments to conform them to ConocoPhillips reserve policy and provided for estimated 2006 production. Other financial information and statistics were based on market indicators, historical production trends of LUKOIL, and other factors.

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 proved reserves include estimated quantities related to production sharing contracts (PSCs), which are reported under the economic interest method and are subject to fluctuations in prices of crude oil, natural gas and natural gas liquids; recoverable operating expenses; and capital costs. If costs remain stable, reserve quantities attributable to recovery of costs will change inversely to changes in commodity prices. For example, if prices go up then our applicable reserve quantities would decline. At December 31, 2006, approximately 14 percent of our total proved reserves (consolidated operations and our share of equity affiliates) were under PSCs, primarily in our Asia Pacific geographic reporting area.

Our disclosures by geographic area for our consolidated operations include the United States (U.S.), Canada, Europe (primarily Norway and the United Kingdom), Asia Pacific, Middle East and Africa, Russia and Caspian, and Other Areas (primarily South America). 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 Canada, Middle East and Africa, Russia and Caspian, and Other Areas. The Russia and Caspian area includes our share of Polar Lights Company, OOO Naryanmarneftegaz, and LUKOIL. Other Areas consists of our Petrozuata and Hamaca heavy-oil projects in Venezuela.

Venezuelan government officials have made public statements about increasing ownership interests in heavy-oil projects required to give the national oil company of Venezuela, Petroleos de Venezuela S.A. (PDVSA) control and up to 60 percent ownership interests. On January 31, 2007, Venezuela s National Assembly passed an enabling law allowing the president to pass laws by decree on certain matters, including those associated with heavy-oil production from the Orinoco Oil Belt. PDVSA holds a 49.9 percent interest in the Petrozuata heavy-oil project and a 30 percent interest in the Hamaca heavy-oil project. We have a 50.1 percent interest and a 40 percent interest in the Petrozuata and Hamaca projects, respectively. The impact, if any, of these statements or other potential government actions, on our Petrozuata and Hamaca projects is not determinable at this time.

Reserves Governance

The recording and reporting of proved reserves are governed by criteria established by regulations of the SEC. Those regulations define proved reserves as those estimated quantities of hydrocarbons that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved reserves are further classified as either developed or undeveloped. Proved developed reserves are the quantities expected to be recovered through existing wells with existing equipment and operating methods, while proved undeveloped reserves are the quantities expected to be recovered from new wells on undrilled acreage, or from an existing well where relatively major expenditures are required for recompletion.

We have a companywide, comprehensive internal policy that governs the determination and reporting of proved reserves. This policy is applied by the geologists, geophysicists and reservoir engineers in our E&P business units around the world. As part of our internal control process, each business unit s reserves are reviewed annually by an internal team composed of reservoir engineers, geologists, geophysicists and finance personnel for adherence to SEC guidelines and company policy through on-site visits and review of documentation. In addition to providing independent reviews of the business units recommended reserve changes, this internal team also ensures reserves are calculated using consistent and appropriate standards and procedures. This team is independent of business unit line management and is responsible for reporting their findings to senior management and internal audit. The team is responsible for maintaining and communicating our reserves policy and procedures and is available for internal peer reviews and consultation on major projects or technical issues throughout the year.

In addition, during 2006, approximately 80 percent of our year-end 2005 E&P proved reserves were reviewed by an outside independent petroleum engineering consulting firm. At the present time we plan to continue to have an outside firm review a pro rata portion of a similar percentage of our reserve base over the next three years.

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. See the Critical Accounting Policies section of Management s Discussion and Analysis of Financial Condition and Results of Operations for additional discussion of the sensitivities surrounding these estimates.

- **Proved Reserves Worldwide**

Years Ended December 31	Crude Oil Millions of Barrels Consolidated Operations										
	Alaska	**Lower 48**	**Total U.S.**	**Canada**	**Europe**	**Asia Pacific**	**Middle East and Africa**	**Russia and Caspian**	**Other Areas**	**Total**	**Equity Affiliates**
Developed and Undeveloped											
End of 2003	1,553	186	1,739	274	865	264	148			3,290	1,377
Revisions	31	(4)	27	(219)	28	8	(5)			(161)	(88)
Improved recovery	16	1	17		1	14				32	
Purchases											783
Extensions and discoveries	46	6	52	1	55	4	5	181		298	
Production	(110)	(19)	(129)	(9)	(98)	(35)	(21)			(292)	(54)
Sales											(36)
End of 2004	1,536	170	1,706	47	851	255	127	181		3,167	1,982
Revisions	31	6	37	4	34	7	(21)	(11)		50	6
Improved recovery	15	1	16							16	
Purchases		3	3				238	20		261	515
Extensions and discoveries	31	13	44	1	17	49	4		17	132	60
Production	(108)	(21)	(129)	(8)	(94)	(37)	(20)			(288)	(130)
Sales		(2)	(2)							(2)	(3)
End of 2005	1,505	170	1,675	44	808	274	328	190	17	3,336	2,430
Revisions	(118)	(11)	(129)	58	(65)	(12)	(18)	(74)	2	(238)	(35)
Improved recovery	13	1	14		5	63				82	
Purchases		181	181	16		13	42		17	269	393
Extensions and discoveries	53	9	62	4	6	8	3			83	74
Production	(97)	(37)	(134)	(9)	(90)	(39)	(39)		(3)	(314)	(171)
Sales		(18)	(18)							(18)	(1)
End of 2006	1,356	295	1,651	113	664	307	316	116	33	3,200	2,690
Equity affiliates											
End of 2003				37				45	1,295		1,377
End of 2004								800	1,182		1,982
End of 2005							46	1,295	1,089		2,430
End of 2006							60	1,607	1,023		2,690
Developed											
Consolidated operations											
End of 2003	1,365	163	1,528	51	454	95	137			2,265	
End of 2004	1,415	148	1,563	46	429	207	121			2,366	
End of 2005	1,359	158	1,517	42	409	202	326			2,496	
End of 2006	1,254	281	1,535	50	359	181	292		13	2,430	
Equity affiliates											
End of 2003				32				45	452		529
End of 2004								624	491		1,115
End of 2005								1,013	472		1,485
End of 2006								1,293	369		1,662

- Revisions in Alaska in 2006 were primarily a result of reservoir performance. Revisions in Canada in 2006 were primarily related to Phase I of the Surmont heavy-oil project. For Europe in 2006, revisions were primarily in Norway due to revised facility life expectations for the Eldfisk and Embla fields in the North Sea. In Russia and Caspian, the 2006 revisions were attributable to our Kashagan field in Kazakhstan, primarily reflecting a more limited area of proved reserves defined by the existing appraisal wells.

- Improved Recovery in 2006 in Asia Pacific was attributable to a waterflood project in China.

- Purchases in 2006 for our consolidated operations were primarily related to our acquisition of Burlington Resources. For our equity affiliate operations, purchases in 2006 were mainly related to acquiring additional interests in LUKOIL.

- 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 243 million barrels at the end of 2006. 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**										
	Alaska	**Lower 48**	**Total U.S.**	**Canada**	**Europe**	**Asia Pacific**	**Middle East and Africa**	**Russia and Caspian**	**Other Areas**	**Total**	**Equity Affiliates**
Developed and Undeveloped											
End of 2003	2,922	4,258	7,180	1,042	3,418	3,006	1,188			15,834	226
Revisions	551	141	692	29	(87)	804	(46)			1,392	
Improved recovery		1	1			5				6	
Purchases		4	4							4	666
Extensions and discoveries	23	298	321	66	382	79	3	119		970	
Production	(152)	(465)	(617)	(159)	(428)	(121)	(41)			(1,366)	(9)
Sales		(3)	(3)	(3)						(6)	(21)
End of 2004	3,344	4,234	7,578	975	3,285	3,773	1,104	119		16,834	862
Revisions	260	(43)	217	72	83	(20)		(3)		349	51
Improved recovery		1	1							1	
Purchases	7	163	170		1	8		13		192	453
Extensions and discoveries	5	270	275	78	79	85	2		5	524	1,212
Production	(144)	(449)	(593)	(155)	(386)	(146)	(45)			(1,325)	(30)
Sales		(62)	(62)							(62)	
End of 2005	3,472	4,114	7,586	970	3,062	3,700	1,061	129	5	16,513	2,548
Revisions	43	(87)	(44)	(123)	(293)	71	(64)	(31)	(39)	(523)	(310)
Improved recovery		4	4		1					5	
Purchases	6	5,258	5,264	2,466	432	25	94		129	8,410	325
Extensions and discoveries	23	551	574	353	64	6	58			1,055	925
Production	(130)	(770)	(900)	(356)	(414)	(233)	(62)		(6)	(1,971)	(99)
Sales		(43)	(43)							(43)	
End of 2006	3,414	9,027	12,441	3,310	2,852	3,569	1,087	98	89	23,446	3,389
Equity affiliates											
End of 2003				21					205		226
End of 2004								661	201		862
End of 2005							1,063	1,197	288		2,548
End of 2006							1,573	1,429	387		3,389
Developed											
Consolidated operations											
End of 2003	2,763	3,968	6,731	971	2,748	1,342	596			12,388	
End of 2004	3,194	3,989	7,183	934	2.467	1,520	522			12,626	
End of 2005	3,316	3,966	7,282	918	2,393	2,600	1,060			14,253	
End of 2006	3,336	7,484	10,820	2,672	2,314	3,105	1,029		24	19,964	
Equity affiliates											
End of 2003				20					103		123
End of 2004								207	118		325
End of 2005								581	155		736
End of 2006								655	173		828

- 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 plants or facilities.

- Revisions in Canada in 2006 were primarily related to well performance. In Europe in 2006, revisions were mainly in Norway due to revised facility life expectations for the Eldfisk and Embla fields in the North Sea. For our equity affiliate operations, positive revisions in Venezuela were more than offset by revisions for LUKOIL.

- Purchases in 2006 for our consolidated operations were primarily related to our acquisition of Burlington Resources. For our equity affiliate operations, purchases in 2006 were mainly related to the acquisition of additional interests in LUKOIL.

- Extensions and discoveries in the Lower 48 and Canada in 2006 consisted of reserves added from numerous fields. For our equity affiliate operations, extensions and discoveries were in Qatar, as well as for LUKOIL.

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

180

Years Ended December 31	**Natural Gas Liquids Millions of Barrels Consolidated Operations**										
	Alaska	**Lower 48**	**Total U.S.**	**Canada**	**Europe**	**Asia Pacific**	**Middle East and Africa**	**Russia and Caspian**	**Other Areas**	**Total**	**Equity Affiliates**
Developed and Undeveloped											
End of 2003	141	193	334	30	46	79	15			504	
Revisions	20	(98)	(78)	(1)	7	(5)	(10)			(87)	
Improved recovery											
Purchases											
Extensions and discoveries		1	1	1	1					3	
Production	(8)	(8)	(16)	(4)	(6)	(3)	(1)			(30)	
Sales											
End of 2004	153	88	241	26	48	71	4			390	
Revisions		17	17	1	6	4				28	
Improved recovery											
Purchases		8	8							8	
Extensions and discoveries		5	5		1	2				8	21
Production	(7)	(9)	(16)	(3)	(5)	(6)	(1)			(31)	
Sales		(1)	(1)							(1)	
End of 2005	146	108	254	24	50	71	3			402	21
Revisions	(1)	24	23	1	(4)	(1)	(1)			18	
Improved recovery											
Purchases		328	328	56						384	
Extensions and discoveries		14	14	7						21	11
Production	(6)	(22)	(28)	(9)	(5)	(7)				(49)	
Sales		(2)	(2)							(2)	
End of 2006	139	450	589	79	41	63	2			774	32
Equity affiliates											
End of 2003											
End of 2004											
End of 2005							21				21
End of 2006							32				32
Developed											
Consolidated operations											
End of 2003	141	188	329	27	26		15			397	
End of 2004	153	82	235	25	34	71	4			369	
End of 2005	146	106	252	23	31	64	2			372	
End of 2006	139	346	485	64	28	56	2			635	
Equity affiliates											
End of 2003											
End of 2004											
End of 2005											
End of 2006											

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

- Purchases in 2006 in our consolidated operations were related to our acquisition of Burlington Resources.

181

- **Results of Operations**

Year Ended December 31	Millions of Dollars Consolidated Operations										
	Alaska	**Lower 48**	**Total U.S.**	**Canada**	**Europe**	**Asia Pacific**	**Middle East and Africa**	**Russia and Caspian**	**Other Areas**	**Total**	**Equity Affiliates**
2006											
Sales	$ 6,304	3,408	9,712	2,951	5,950	3,755	1,965		140	24,473	5,161
Transfers	210	4,023	4,233		2,954	9	542			7,738	2,821
Other revenues	2	56	58	145	14	(8)	127		4	340	108
Total revenues	6,516	7,487	14,003	3,096	8,918	3,756	2,634		144	32,551	8,090
Production costs excluding taxes	708	893	1,601	706	814	324	215		27	3,687	739
Taxes other than income taxes	914	554	1,468	52	37	91	10	1	30	1,689	3,444
Exploration expenses	105	222	327	246	73	121	44	32	17	860	46
Depreciation, depletion and amortization	460	2,272	2,732	1,155	1,200	512	220	1	21	5,841	461
Property impairments		15	15	131		10			19	175	
Transportation costs	610	555	1,165	104	316	89	18		10	1,702	420
Other related expenses	11	44	55	15	87	18	38	43	28	284	52
Accretion	34	36	70	39	97	8	2			216	6
	3,674	2,896	6,570	648	6,294	2,583	2,087	(77)	(8)	18,097	2,922
Provision for income taxes	1,409	1,064	2,473	(193)	4,578	1,061	1,931	(13)	(7)	9,830	891
Results of operations for producing activities	2,265	1,832	4,097	841	1,716	1,522	156	(64)	(1)	8,267	2,031
Other earnings	68	183	251	191	335	62	32	(4)	(25)	842	133
Net income (loss)	$ 2,333	2,015	4,348	1,032	2,051	1,584	188	(68)	(26)	9,109	2,164
Results of operations for producing activities of equity affiliates	$						(6)	1,229	808		2,031

182

Year Ended December 31	Millions of Dollars Consolidated Operations										
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific	Middle East and Africa	Russia and Caspian	Other Areas *	Total *	Equity Affiliates *
2005											
Sales	$ 5,927	3,385	9,312	1,642	5,142	2,795	423			19,314	3,470
Transfers	172	1,206	1,378		2,207	26	640			4,251	1,458
Other revenues	2	168	170	40	(253)	11	4			(28)	38
Total revenues	6,101	4,759	10,860	1,682	7,096	2,832	1,067			23,537	4,966
Production costs excluding taxes	488	492	980	316	612	274	115			2,297	452
Taxes other than income taxes	537	311	848	33	41	26	18	1	1	968	1,635
Exploration expenses	120	66	186	147	87	139	69	33	8	669	56
Depreciation, depletion and amortization	443	848	1,291	399	1,074	329	53			3,146	288
Property impairments		1	1	13	(10)					4	
Transportation costs	665	350	1,015	53	296	64	5			1,433	255
Other related expenses	67	48	115	(12)	28	38	32	35	17	253	26
Accretion	29	19	48	16	84	7	2			157	1
	3,752	2,624	6,376	717	4,884	1,955	773	(69)	(26)	14,610	2,253
Provision for income taxes	1,342	900	2,242	228	3,311	747	759	(6)	(13)	7,268	673
Results of operations for producing activities	2,410	1,724	4,134	489	1,573	1,208	14	(63)	(13)	7,342	1,580
Other earnings	141	15	156	93	64	7	(28)	(2)	26	316	(90)
Cumulative effect of accounting change	1	(3)	(2)		(2)					(4)	
Net income (loss)	$ 2,552	1,736	4,288	582	1,635	1,215	(14)	(65)	13	7,654	1,490
Results of operations for producing activities of equity affiliates	$						(11)	773	818		1,580

**Certain amounts reclassified to conform to current year presentation.*

Year Ended December 31	Millions of Dollars Consolidated Operations										
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific	Middle East and Africa	Russia and Caspian*	Other Areas*	Total*	Equity Affiliates
2004											
Sales	$ 4,378	2,568	6,946	1,214	4,215	1,777	704			14,856	867
Transfers	121	832	953		1,255	71	75			2,354	481
Other revenues	4	(36)	(32)	116	9	10	5	5	9	122	33
Total revenues	4,503	3,364	7,867	1,330	5,479	1,858	784	5	9	17,332	1,381
Production costs excluding taxes	430	422	852	271	528	216	120			1,987	200
Taxes other than income taxes	373	267	640	35	38	17	12	1		743	206
Exploration expenses	82	101	183	112	86	106	67	86	57	697	5
Depreciation, depletion and amortization	426	586	1,012	349	1,095	275	43			2,774	137
Property impairments	6	12	18	47	2					67	
Transportation costs	598	241	839	43	296	48	2			1,228	65
Other related expenses	14	43	57	4	27	(2)	14	16	15	131	39
Accretion	21	21	42	14	72	6	2			136	1
	2,553	1,671	4,224	455	3,335	1,192	524	(98)	(63)	9,569	728
Provision for income taxes	888	584	1,472	127	2,232	477	514	(39)	(54)	4,729	108
Results of operations for producing activities	1,665	1,087	2,752	328	1,103	715	10	(59)	(9)	4,840	620
Other earnings	167	23	190	130	95	(2)	(35)	1	(4)	375	(59)
Net income (loss)	$ 1,832	1,110	2,942	458	1,198	713	(25)	(58)	(13)	5,215	561
Results of operations for producing activities of equity affiliates	$			9				121	490		620

**Certain amounts reclassified to conform to current year presentation.*

- Results of operations for producing activities consist of all the activities within the E&P organization and 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, 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.

- 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 29 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. Included in 2006 for Canada is a $353 million benefit (which excludes $48 million related to the Syncrude oil project reflected in other earnings) related to the remeasurement of deferred tax liabilities from the 2006 Canadian graduated tax rate reduction and an Alberta provincial tax rate change. Europe income tax expense for 2006 was increased $250 million due to remeasurement of deferred tax liabilities as a result of increases in the U.K. tax rate.

- **Statistics**

Net Production	**2006**	**2005**	**2004**
	Thousands of Barrels Daily		
Crude Oil			
Consolidated operations			
Alaska	**263**	294	298
Lower 48	**104**	59	51
United States	**367**	353	349
Canada	**25**	23	25
Europe	**245**	257	271
Asia Pacific	**106**	100	94
Middle East and Africa	**106**	53	58
Other areas	**7**		
Total consolidated	**856**	786	797
Equity affiliates			
Canada			2
Russia and Caspian	**375**	250	51
Other areas	**101**	106	93
Total equity affiliates	**476**	356	146
Natural Gas Liquids*			
Consolidated operations			
Alaska	**17**	20	23
Lower 48	**62**	30	26
United States	**79**	50	49
Canada	**25**	10	10
Europe	**13**	13	14
Asia Pacific	**18**	16	9
Middle East and Africa	**1**	2	2
Total consolidated	**136**	91	84

**Represents amounts extracted attributable to E&P operations (see natural gas liquids reserves for further discussion). Includes for 2006, 2005 and 2004, 11,000, 9,000, and 13,000 barrels daily in Alaska, respectively, that were sold from the Prudhoe Bay lease to the Kuparuk lease for re-injection to enhance crude oil production.*

	Millions of Cubic Feet Daily		
Natural Gas*			
Consolidated operations			
Alaska	**145**	169	165
Lower 48	**2,028**	1,212	1,223
United States	**2,173**	1,381	1,388
Canada	**983**	425	433
Europe	**1,065**	1,023	1,119
Asia Pacific	**582**	350	301
Middle East and Africa	**142**	84	71
Other areas	**16**		
Total consolidated	**4,961**	3,263	3,312
Equity affiliates			
Canada			1
Russia and Caspian	**244**	67	13
Other areas	**9**	7	4
Total equity affiliates	**253**	74	18

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

186

	2006	2005	2004
Average Sales Price			
Crude Oil Per Barrel			
Consolidated operations			
Alaska	**$ 62.66**	52.24	38.47
Lower 48	**57.04**	45.24	36.95
United States	**61.09**	51.09	38.25
Canada	**54.25**	44.70	32.92
Europe	**64.05**	53.16	37.42
Asia Pacific	**61.93**	51.34	38.33
Middle East and Africa	**66.59**	52.93	36.05
Other areas	**50.63**		
Total international	**63.38**	52.27	37.18
Total consolidated	**62.39**	51.74	37.65
Equity affiliates			
Canada			19.94
Russia and Caspian	**41.61**	37.39	27.72
Other areas	**46.40**	38.08	24.42
Total equity affiliates	**42.66**	37.60	25.52
Average Sales Price			
Natural Gas Liquids Per Barrel			
Consolidated operations			
Alaska	**$ 61.06**	51.30	38.64
Lower 48	**38.10**	36.43	28.14
United States	**40.35**	40.40	31.05
Canada	**45.62**	42.20	30.77
Europe	**38.78**	31.25	26.97
Asia Pacific	**43.95**	40.11	34.94
Middle East and Africa	**8.15**	7.39	7.24
Total international	**42.89**	36.25	28.96
Total consolidated	**41.50**	38.32	30.02
Average Sales Price			
Natural Gas Per Thousand Cubic Feet			
Consolidated operations			
Alaska	**$ 3.59**	2.75	2.35
Lower 48	**6.14**	7.28	5.46
United States	**6.11**	7.12	5.33
Canada	**5.67**	7.25	5.00
Europe	**7.78**	5.77	4.09
Asia Pacific	**5.91**	5.24	3.93
Middle East and Africa	**.70**	.67	.69
Other areas	**1.31**		
Total international	**6.27**	5.78	4.14
Total consolidated	**6.20**	6.32	4.62
Equity affiliates			
Canada			5.17
Russia and Caspian	**.57**	.48	.38
Other areas	**.30**	.26	.28
Total equity affiliates	**.57**	.46	.78

	2006	2005	2004
Average Production Costs Per Barrel of Oil Equivalent			
Consolidated operations			
Alaska	**$ 6.38**	3.91	3.37
Lower 48	**4.85**	4.63	4.11
United States	**5.43**	4.24	3.70
Canada	**9.05**	8.34	6.91
Europe	**5.12**	3.81	3.06
Asia Pacific	**4.02**	4.31	3.85
Middle East and Africa	**4.51**	4.57	4.56
Other areas	**7.65**		
Total international*	**5.65**	4.58	3.86
Total consolidated*	**5.55**	4.43	3.79
Equity affiliates			
Canada			8.83
Russia and Caspian	**3.53**	2.69	2.36
Other areas	**5.42**	5.01	4.29
Total equity affiliates	**3.91**	3.36	3.67

**Prior years restated to reflect reclassification of certain costs to conform to current year presentation.*

Taxes Other Than Income Taxes Per Barrel of Oil Equivalent			
Consolidated operations			
Alaska	**$ 8.23**	4.30	2.92
Lower 48	**3.01**	2.93	2.60
United States	**4.98**	3.67	2.78
Canada	**.67**	.87	.89
Europe	**.23**	.26	.22
Asia Pacific	**1.13**	.41	.30
Middle East and Africa	**.21**	.71	.46
Other areas	**8.50**		
Total international	**.60**	.42	.35
Total consolidated	**2.54**	1.87	1.42
Equity affiliates			
Russia and Caspian	**21.40**	17.12	10.59
Other areas	**5.28**	.06	
Total equity affiliates	**18.21**	12.16	3.78
Depreciation, Depletion and Amortization Per Barrel of Oil Equivalent			
Consolidated operations			
Alaska	**$ 4.14**	3.55	3.34
Lower 48	**12.35**	7.98	5.70
United States	**9.26**	5.59	4.39
Canada	**14.80**	10.53	8.90
Europe	**7.55**	6.68	6.35
Asia Pacific	**6.35**	5.17	4.91
Middle East and Africa	**4.61**	2.10	1.64
Other areas	**5.95**		
Total international	**8.43**	6.45	5.99
Total consolidated	**8.80**	6.07	5.29
Equity affiliates			
Canada			3.78
Russia and Caspian	**2.04**	1.55	2.19
Other areas	**4.04**	3.58	2.67
Total equity affiliates	**2.43**	2.14	2.52

188

Net Wells Completed ***(1)***	**Productive**			**Dry**		
	2006	**2005**	**2004**	**2006**	**2005**	**2004**
Exploratory (2)						
Consolidated operations						
Alaska			4	**1**	5	2
Lower 48	**27**	23	38	**9**	5	8
United States	**27**	23	42	**10**	10	10
Canada	**8**	26	52	**7**	7	26
Europe	**1**	1	2	**1**	*	*
Asia Pacific	**2**	7	*	**2**	3	6
Middle East and Africa	**1**		1	**1**	2	*
Russia and Caspian			*		*	*
Other areas	**1**	1		*****		2
Total consolidated	**40**	58	97	**21**	22	44
Equity affiliates						
Canada			2			1
Middle East and Africa	*****	*				
Russia and Caspian				**1**		
Other areas						
Total equity affiliates *(3)*	*****	*	2	**1**		1
Includes step-out wells of:	***37***	*42*	*89*	***11***	*7*	*34*

	Productive			**Dry**		
	2006	**2005**	**2004**	**2006**	**2005**	**2004**
Development						
Consolidated operations						
Alaska	**30**	31	37	**1**		
Lower 48	**659**	297	400	**3**	9	4
United States	**689**	328	437	**4**	9	4
Canada	**675**	425	323	**8**	2	4
Europe	**10**	19	11			
Asia Pacific	**15**	17	16			
Middle East and Africa	**7**	6	4			
Russia and Caspian	*****					
Other areas	**11**					
Total consolidated	**1,407**	795	791	**12**	11	8
Equity affiliates						
Canada			16			*
Middle East and Africa						
Russia and Caspian	**2**	1	1	**1**		
Other areas	**15**	28	33		1	
Total equity affiliates *(3)*	**17**	29	50	**1**	1	*

(1) Excludes farmout arrangements.

(2) Includes step-out wells, as well as other types of exploratory wells. Step-out exploratory wells are wells drilled in areas near or offsetting current production, for which we cannot demonstrate with certainty that there is continuity of production from an existing productive formation. These are classified as exploratory wells because we cannot attribute proved reserves to these locations.

(3) Excludes LUKOIL.

**Our total proportionate interest was less than one.*

189

Wells at Year-End 2006			**Productive *(2)***			
	In Progress *(1)*		**Oil**		**Gas**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Consolidated operations						
Alaska	14	8	1,620	727	27	18
Lower 48	155	116	11,702	4,249	24,389	15,406
United States	169	124	13,322	4,976	24,416	15,424
Canada	125 *(3)*	70 *(3)*	2,330	1,441	12,248	7,827
Europe	47	11	572	99	360	117
Asia Pacific	28	11	450	197	101	59
Middle East and Africa	45	11	1,183	247	1	1
Russia and Caspian	20	2				
Other areas	9	3	93	40	44	11
Total consolidated	443	232	17,950	7,000	37,170	23,439
Equity affiliates						
Canada					12	2
Russia and Caspian	14	5	75	27		
Other areas	38	16	555	250		
Total equity affiliates *(4)*	52	21	630	277	12	2

(1) Includes wells that have been temporarily suspended.

(2) Includes 4,142 gross and 2,623 net multiple completion wells.

(3) Includes 57 gross and 29 net stratigraphic test wells related to the Surmont heavy-oil project.

(4) Excludes LUKOIL.

Acreage at December 31, 2006	**Thousands of Acres**			
	Developed		**Undeveloped**	
	Gross	**Net**	**Gross**	**Net**
Consolidated operations				
Alaska	606	297	2,918	1,742
Lower 48	7,638	5,729	13,272	9,968
United States	8,244	6,026	16,190	11,710
Canada	7,827	4,722	15,142	9,729
Europe	1,383	344	4,319	1,073
Asia Pacific	4,743	2,092	26,204	17,849
Middle East and Africa	2,557	484	14,408	3,049
Russia and Caspian			1,379	128
Other areas	1,356	573	13,237	10,456
Total consolidated	26,110	14,241	90,879	53,994
Equity affiliates				
Middle East and Africa			76	11
Russia and Caspian	133	43	3,151	1,069
Other areas	198	85	25	9
Total equity affiliates*	331	128	3,252	1,089

Excludes LUKOIL.

190

- **Costs Incurred**

	Millions of Dollars											
	Consolidated Operations											
	Alaska	**Lower 48**	**Total U.S.**	**Canada**	**Europe**	**Asia Pacific**	**Middle East and Africa**	**Russia and Caspian**	**Other Areas**	**Total**	**Equity Affiliates**	
2006												
Unproved property acquisition	$ 4	860	864	554	113		30		39	1,600	143	
Proved property acquisition	13	15,784	15,797	8,296	1,169	525	856		252	26,895	2,647	
	17	16,644	16,661	8,850	1,282	525	886		291	28,495	2,790	
Exploration	131	332	463	182	172	231	57	47	27	1,179	58	
Development	629	1,733	2,362	1,926	1,653	919	249	371	141	7,621	1,326	
	$ 777	18,709	19,486	10,958	3,107	1,675	1,192	418	459	37,295	4,174	
Costs incurred of equity affiliates	$						183	3,854	137		4,174	
2005												
Unproved property acquisition	$ 1	14	15	68		26	85	83		277	796	*
Proved property acquisition	16	767	783			6	569	125		1,483	1,763	*
	17	781	798	68		32	654	208		1,760	2,559	*
Exploration	64	74	138	163	117	204	67	37	11	737	60	
Development	650	688	1,338	782	1,402	682	137	372	42	4,755	449	
	$ 731	1,543	2,274	1,013	1,519	918	858	617	53	7,252	3,068	*
Costs incurred of equity affiliates	$						54	2,903	111		3,068	*
2004												
Unproved property acquisition	$ 2	8	10	12		212	14			248	66	
Proved property acquisition	11	10	21	16	1					38	1,923	
	13	18	31	28	1	212	14			286	1,989	
Exploration	62	79	141	149	87	123	58	101	52	711	6	
Development	490	598	1,088	371	1,029	483	86	151	49	3,257	390	
	$ 565	695	1,260	548	1,117	818	158	252	101	4,254	2,385	
Costs incurred of equity affiliates	$			6				2,041	338		2,385	

**Restated to exclude goodwill considered to be a non-oil and gas producing activity.*

- Costs incurred include capitalized and expensed items.

- Acquisition costs include the costs of acquiring proved and unproved oil and gas properties. Costs in 2006 were significantly impacted by our acquisition of Burlington Resources. Equity affiliate acquisition costs were primarily related to LUKOIL. Some of the 2006 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 may be reclassified between proved and unproved property acquisition costs.

- 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.

- **Capitalized Costs**

At December 31	Millions of Dollars Consolidated Operations											
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific	Middle East and Africa	Russia and Caspian	Other Areas	Total	Equity Affiliates	
2006												
Proved properties	$ 9,567	26,227	35,794	14,455	17,773	6,870	2,577	1,669	633	79,771	11,550	
Unproved properties	840	1,045	1,885	1,425	365	743	321	117	72	4,928	944	
	10,407	27,272	37,679	15,880	18,138	7,613	2,898	1,786	705	84,699	12,494	
Accumulated depreciation, depletion and amortization	3,573	5,525	9,098	2,795	7,450	1,581	737	3	81	21,745	933	
	$ 6,834	21,747	28,581	13,085	10,688	6,032	2,161	1,783	624	62,954	11,561	
Capitalized costs of equity affiliates	$						180	8,310	3,071		11,561	
2005												
Proved properties	$ 8,934	9,327	18,261	4,151	13,324	5,411	1,587	1,293	222	44,249	7,673	*
Unproved properties	782	198	980	1,023	140	621	305	102	29	3,200	786	*
	9,716	9,525	19,241	5,174	13,464	6,032	1,892	1,395	251	47,449	8,459	*
Accumulated depreciation, depletion and amortization	3,083	3,665	6,748	1,533	5,583	1,053	625	2	36	15,580	537	
	$ 6,633	5,860	12,493	3,641	7,881	4,979	1,267	1,393	215	31,869	7,922	*
Capitalized costs of equity affiliates	$						43	4,810	3,069		7,922	

**Restated to exclude goodwill considered to be a non-oil and gas producing activity.*

- 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										
	Alaska	**Lower 48**	**Total U.S.**	**Canada**	**Europe**	**Asia Pacific**	**Middle East and Africa**	**Russia and Caspian**	**Other Areas**	**Total**	**Equity Affiliates**
2006											
Future cash inflows	$ 86,843	75,039	161,882	25,363	60,118	32,420	19,369	6,853	1,777	307,782	117,860
Less:											
Future production and transportation costs*	43,393	23,096	66,489	9,393	13,186	6,730	4,308	1,692	1,082	102,880	66,929
Future development costs	5,142	7,274	12,416	4,154	7,865	2,886	586	2,787	220	30,914	6,369
Future income tax provisions	14,138	14,357	28,495	2,313	25,627	9,204	12,029	590	101	78,359	16,085
Future net cash flows	24,170	30,312	54,482	9,503	13,440	13,600	2,446	1,784	374	95,629	28,477
10 percent annual discount	12,479	15,697	28,176	3,297	4,052	5,482	753	2,213	66	44,039	16,044
Discounted future net cash flows	$ 11,691	14,615	26,306	6,206	9,388	8,118	1,693	(429)	308	51,590	12,433
Discounted future net cash flows of equity affiliates	$						1,703	5,441	5,289		12,433
2005											
Future cash inflows	$ 96,574	48,560	145,134	11,907	74,790	31,310	19,337	11,069	787	294,334	111,825
Less:											
Future production and transportation costs*	34,586	10,425	45,011	2,892	12,055	5,343	3,442	2,410	488	71,641	47,634
Future development costs	4,569	1,686	6,255	965	7,517	2,920	474	1,917	149	20,197	4,760
Future income tax provisions	20,421	12,831	33,252	2,349	37,208	9,653	13,882	2,163	80	98,587	17,052
Future net cash flows	36,998	23,618	60,616	5,701	18,010	13,394	1,539	4,579	70	103,909	42,379
10 percent annual discount	19,414	11,934	31,348	2,184	6,006	5,639	560	4,168	56	49,961	25,720
Discounted future net cash flows	$ 17,584	11,684	29,268	3,517	12,004	7,755	979	411	14	53,948	16,659
Discounted future net cash flows of equity affiliates	$						1,865	5,024	9,770		16,659
2004											
Future cash inflows	$ 64,251	31,955	96,206	8,091	51,184	22,249	5,572	7,335		190,637	56,171
Less:											
Future production and transportation costs*	26,956	8,312	35,268	2,591	11,953	4,897	1,989	2,027		58,725	20,835
Future development costs	4,163	2,005	6,168	575	7,794	1,064	260	1,232		17,093	2,334
Future income tax provisions	11,698	7,233	18,931	1,139	19,850	5,683	2,675	1,379		49,657	10,711
Future net cash flows	21,434	14,405	35,839	3,786	11,587	10,605	648	2,697		65,162	22,291
10 percent annual discount	10,318	7,050	17,368	1,403	3,887	4,291	207	2,518		29,674	14,081
Discounted future net cash flows	$ 11,116	7,355	18,471	2,383	7,700	6,314	441	179		35,488	8,210
Discounted future net cash flows of equity affiliates	$							2,298	5,912		8,210

**Includes taxes other than income taxes.*

Excludes discounted future net cash flows from Canadian Syncrude of $2,220 million in 2006, $2,159 million in 2005 and $1,302 million in 2004.

Note 30 New Accounting Standards

194

Sources of Change in Discounted Future Net Cash Flows

	Millions of Dollars					
	Consolidated Operations			**Equity Affiliates**		
	2006	**2005***	**2004***	**2006**	**2005**	**2004**
Discounted future net cash flows at the beginning of the year	**$ 53,948**	35,488	30,195	**16,659**	8,210	6,179
Changes during the year						
Revenues less production and transportation costs for the year**	**(25,133)**	(18,867)	(13,252)	**(3,379)**	(2,586)	(877)
Net change in prices, and production and transportation costs**	**(18,928)**	46,332	14,133	**(5,582)**	6,555	1,415
Extensions, discoveries and improved recovery, less estimated future costs	**3,867**	3,942	3,724	**401**	2,201	
Development costs for the year	**7,020**	4,282	3,117	**1,327**	449	390
Changes in estimated future development costs	**(6,195)**	(3,261)	(2,402)	**(1,291)**	(142)	(81)
Purchases of reserves in place, less estimated future costs	**24,203**	6,610	8	**1,945**	2,361	3,208
Sales of reserves in place, less estimated future costs	**(506)**	(306)	(19)	**2**	(34)	(183)
Revisions of previous quantity estimates***	**(7,028)**	(175)	455	**107**	1,245	(1,301)
Accretion of discount	**9,759**	5,728	4,782	**2,215**	1,032	832
Net change in income taxes	**10,583**	(25,825)	(5,253)	**29**	(2,632)	(1,372)
Other						
Total changes	**(2,358)**	18,460	5,293	**(4,226)**	8,449	2,031
Discounted future net cash flows at year-end	**$ 51,590**	53,948	35,488	**12,433**	16,659	8,210

**Certain amounts reclassified to conform to 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			
	Sales and Other Operating Revenues**	Income from Continuing Operations Before Income Taxes	Income Before Cumulative Effect of Changes in Accounting Principles	Net Income	Income Before Cumulative Effect of Changes in Accounting Principles Basic	Diluted	Net Income Basic	Diluted
2006								
First	**$ 46,906**	**5,797**	**3,291**	**3,291**	**2.38**	**2.34**	**2.38**	**2.34**
Second	**47,149**	**8,682**	**5,186**	**5,186**	**3.13**	**3.09**	**3.13**	**3.09**
Third	**48,076**	**7,937**	**3,876**	**3,876**	**2.35**	**2.31**	**2.35**	**2.31**
Fourth	**41,519**	**5,917**	**3,197**	**3,197**	**1.94**	**1.91**	**1.94**	**1.91**
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

**Effective April 1, 2006, we adopted Emerging Issues Task Force Issue No. 04-13, Accounting for Purchases and Sales of Inventory with the Same Counterparty, and began including the impact of our acquisition of Burlington Resources in our results of operations. See Note 2 Changes in Accounting Principles and Note 5 Acquisition of Burlington Resources Inc., in the Notes to Consolidated Financial Statements; and Management s Discussion and Analysis of Financial Condition and Results of Operations, for information affecting the comparability of the data.*

***Includes excise taxes on petroleum products sales.*

Supplementary Information Condensed Consolidating Financial Information

We have various cross guarantees among ConocoPhillips, ConocoPhillips Company, ConocoPhillips Australia Funding Company, ConocoPhillips Canada Funding Company I, and ConocoPhillips Canada Funding Company II, with respect to publicly held debt securities. ConocoPhillips Company is wholly owned by ConocoPhillips. ConocoPhillips Australia Funding Company is an indirect, wholly owned subsidiary of ConocoPhillips Company. ConocoPhillips Canada Funding Company I and ConocoPhillips Canada Funding Company II are indirect, wholly owned subsidiaries of ConocoPhillips. ConocoPhillips and ConocoPhillips Company have fully and unconditionally guaranteed the payment obligations of ConocoPhillips Australia Funding Company, ConocoPhillips Canada Funding Company I, and ConocoPhillips Canada Funding Company II, with respect to their publicly held debt securities. Similarly, ConocoPhillips has fully and unconditionally guaranteed the payment obligations of ConocoPhillips Company with respect to its publicly held debt securities. In addition, 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, ConocoPhillips Company, ConocoPhillips Australia Funding Company, ConocoPhillips Canada Funding Company I, and ConocoPhillips Canada Funding Company II (in each case, reflecting investments in subsidiaries utilizing the equity method of accounting).

- All other non-guarantor subsidiaries of ConocoPhillips.

- 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.

197

Millions of Dollars
Year Ended December 31, 2006

Income Statement	ConocoPhillips	ConocoPhillips Company	ConocoPhillips Australia Funding Company	ConocoPhillips Canada Funding Company I	ConocoPhillips Canada Funding Company II	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Revenues and Other Income								
Sales and other operating revenues	$	117,063				66,587		183,650
Equity in earnings of affiliates	15,798	11,136				3,608	(26,354)	4,188
Other income		337				348		685
Intercompany revenues	173	2,599	94	17	10	15,740	(18,633)	
Total Revenues and Other Income	15,971	131,135	94	17	10	86,283	(44,987)	188,523
Costs and Expenses								
Purchased crude oil, natural gas and products		97,986				37,735	(16,822)	118,899
Production and operating expenses		4,720				5,782	(89)	10,413
Selling, general and administrative expenses	19	1,593				914	(50)	2,476
Exploration expenses		120				714		834
Depreciation, depletion and amortization		1,702				5,582		7,284
Impairments		410				273		683
Taxes other than income taxes		5,877				12,577	(267)	18,187
Accretion on discounted liabilities		58				223		281
Interest and debt expense	537	1,070	80	17	11	777	(1,405)	1,087
Foreign currency transaction (gains) losses		(2)		(39)	(37)	48		(30)
Minority interests						76		76
Total Costs and Expenses	556	113,534	80	(22)	(26)	64,701	(18,633)	160,190
Income from continuing operations before income taxes	15,415	17,601	14	39	36	21,582	(26,354)	28,333
Provision for income taxes	(135)	2,839	5	10	10	10,054		12,783
Income from continuing operations	15,550	14,762	9	29	26	11,528	(26,354)	15,550
Income (loss) from discontinued operations								
Income before cumulative effect of changes in accounting principles	15,550	14,762	9	29	26	11,528	(26,354)	15,550

Cumulative effect of changes in accounting principles								
Net Income	$ 15,550	14,762	9	29	26	11,528	(26,354)	15,550

198

Income Statement	Millions of Dollars Year Ended December 31, 2005 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
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	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

Income Statement	Millions of Dollars Year Ended December 31, 2004 ConocoPhillips	ConocoPhillips Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
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
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) losses		(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	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

200

Balance Sheet	Millions of Dollars At December 31, 2006 ConocoPhillips	ConocoPhillips Company	ConocoPhillips Australia Funding Company	ConocoPhillips Canada Funding Company I	ConocoPhillips Canada Funding Company II	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Assets								
Cash and cash equivalents	$	116			1	1,042	(342)	817
Accounts and notes receivable	65	13,233	22	10	2	17,224	(16,450)	14,106
Inventories		2,906				2,247		5,153
Prepaid expenses and other current assets	11	895		10	7	4,067		4,990
Total Current Assets	76	17,150	22	20	10	24,580	(16,792)	25,066
Investments and long-term receivables*	86,292	58,530	2,000	1,241	841	28,372	(156,563)	20,713
Net properties, plants and equipment		19,072				67,122	7	86,201
Goodwill		15,226				16,262		31,488
Intangibles		852				99		951
Other assets	10	141	5	35	24	195	(48)	362
Total Assets	$ 86,378	110,971	2,027	1,296	875	136,630	(173,396)	164,781
Liabilities and Stockholders Equity								
Accounts payable	$ 68	16,641		5	3	14,367	(16,450)	14,634
Notes payable and long-term debt due within one year	3,431	525				87		4,043
Accrued income and other taxes		732				3,577	98	4,407
Employee benefit obligations		464				431		895
Other accruals	50	804	24	16	10	1,565	(17)	2,452
Total Current Liabilities	3,549	19,166	24	21	13	20,027	(16,369)	26,431
Long-term debt	6,521	6,036	1,999	1,250	848	6,437		23,091
Asset retirement obligations and accrued environmental costs		1,095				4,524		5,619
Deferred income taxes	(8)	2,969		16	10	17,086	1	20,074
Employee benefit obligations		2,379				1,288		3,667
Other liabilities and deferred credits*	29	28,306				22,300	(48,584)	2,051
Total Liabilities	10,091	59,951	2,023	1,287	871	71,662	(64,952)	80,933

Minority interests		(19)				1,221		1,202
Retained earnings	34,756	22,939	4	29	26	28,029	(44,491)	41,292
Other stockholders equity	41,531	28,100		(20)	(22)	35,718	(63,953)	41,354
Total	$ 86,378	110,971	2,027	1,296	875	136,630	(173,396)	164,781

**Includes intercompany loans.*

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
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
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

**Includes intercompany loans.*

Statement of Cash Flows	Millions of Dollars Year Ended December 31, 2006 ConocoPhillips	ConocoPhillips Company	ConocoPhillips Australia Funding Company	ConocoPhillips Canada Funding Company I	ConocoPhillips Canada Funding Company II	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Cash Flows From Operating Activities								
Net cash provided by continuing operations	$ 29,520	6,723	4	6	8	7,659	(22,404)	21,516
Net cash used in discontinued operations								
Net Cash Provided by Operating Activities	29,520	6,723	4	6	8	7,659	(22,404)	21,516
Cash Flows From Investing Activities								
Acquisition of Burlington Resources Inc.						(14,285)		(14,285)
Capital expenditures and investments, including dry hole costs	(17,494)	(3,538)				(12,696)	18,132	(15,596)
Proceeds from asset dispositions		73				472		545
Long-term advances/loans to affiliates and other investments	(14,989)	(290)	(1,992)	(1,250)	(1,711)	(3,896)	23,348	(780)
Collection of advances/loans to affiliates		2,708			861	4,384	(7,830)	123
Net cash used in continuing operations	(32,483)	(1,047)	(1,992)	(1,250)	(850)	(26,021)	33,650	(29,993)
Net cash used in discontinued operations								
Net Cash Used in Investing Activities	(32,483)	(1,047)	(1,992)	(1,250)	(850)	(26,021)	33,650	(29,993)
Cash Flows From Financing Activities								
Issuance of debt	12,892	18,394	2,000	1,250	848	5,278	(23,348)	17,314
Repayment of debt	(6,936)	(4,536)				(3,440)	7,830	(7,082)
Repurchase of company common stock	(925)							(925)
Issuance of company common stock	220							220
Dividends paid on common stock	(2,277)	(20,000)	(5)			(2,056)	22,061	(2,277)
Other	(11)	(31)	(7)	(6)	(5)	18,006	(18,131)	(185)
Net Cash Provided by (Used in) Financing Activities	2,963	(6,173)	1,988	1,244	843	17,788	(11,588)	7,065
Effect of Exchange Rate Changes on Cash and Cash Equivalents						15		15
Net Change in Cash and Cash Equivalents		(497)			1	(559)	(342)	(1,397)
Cash and cash equivalents at beginning of year		613				1,601		2,214
Cash and Cash Equivalents at End of Year	$	116			1	1,042	(342)	817

203

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 hole costs		(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

204

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
Cash Flows From Investing Activities					
Capital expenditures and investments, including dry hole costs		(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

205

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

None.

Item 9A. CONTROLS AND PROCEDURES

As of December 31, 2006, 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, 2006.

There have been no changes in our internal control over financial reporting, as defined in Rule 13a-15(f) of the Securities Exchange Act, in the quarterly period ended December 31, 2006, 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 103 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 105 and 106 and is incorporated herein by reference.

Item 9B. OTHER INFORMATION

None.

PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information regarding our executive officers appears in Part I of this report on pages 44 and 45.

Code of Business Ethics and Conduct for Directors and Employees

We have a Code of Business Ethics and Conduct 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.

All other information required by Item 10 of Part III will be included in our Proxy Statement relating to our 2007 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2007, and is incorporated herein by reference.*

Item 11. EXECUTIVE COMPENSATION

Information required by Item 11 of Part III, including the new Compensation Discussion and Analysis, will be included in our Proxy Statement relating to our 2007 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2007, and is incorporated herein by reference.*

Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information required by Item 12 of Part III will be included in our Proxy Statement relating to our 2007 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2007, and is incorporated herein by reference.*

Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information required by Item 13 of Part III will be included in our Proxy Statement relating to our 2007 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2007, and is incorporated herein by reference.*

Item 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information required by Item 14 of Part III will be included in our Proxy Statement relating to our 2007 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2007, and 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 2007 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 102, are filed as part of this annual report.

2. Exhibits

The exhibits listed in the Index to Exhibits, which appears on pages 210 through 213, are filed as a part of this annual report.

CONOCOPHILLIPS

(Consolidated)

SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS

Millions of Dollars

Description	Balance At January 1	Additions Charged to Expense	Other(a)	Deductions	Balance At December 31
2006					
Deducted from asset accounts:					
Allowance for doubtful accounts and notes receivable	**$ 72**	**11**	**9**	**(47)(b)**	**45**
Deferred tax asset valuation allowance	**850**	**103**	**42**	**(173)**	**822**
Included in other liabilities:					
Restructuring accruals	**53**	**10**	**216**	**(115)(c)**	**164**
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:					
Restructuring accruals	89	(2)	(3)	(31)(c)	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:					
Restructuring accruals	247	29	13	(200)(c)	89

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

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

(c) *Benefit payments.*

209

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 9, 2007 (incorporated by reference to Exhibit 99.1 to the Current Report of ConocoPhillips on Form 8-K filed on February 12, 2007; 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).

Exhibit Number	Description
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).
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(incorporated by reference to Exhibit 10.7 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2005; File No. 001-32395).
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 (incorporated by reference to Exhibit 10.10 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2005; File No. 001-32395).
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 (incorporated by reference to Exhibit 10.12 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2005; File No. 001-32395).
10.13.1	Defined Contribution Make-Up Plan of ConocoPhillips Title I (incorporated by reference to Exhibit 10.13.1 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2005; File No. 001-32395).
10.13.2	Defined Contribution Make-Up Plan of ConocoPhillips Title II (incorporated by reference to Exhibit 10.13.2 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2005; File No. 001-32395).

Exhibit Number	Description
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 (incorporated by reference to Exhibit 10.17 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2005; File No. 001-32395).
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 (incorporated by reference to Exhibit 10.23.1 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2005; File No. 001-32395).
10.23.2	Key Employee Deferred Compensation Plan of ConocoPhillips Title II (incorporated by reference to Exhibit 10.23.2 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2005; File No. 001-32395).

Exhibit Number	Description
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 (incorporated by reference to Exhibit 10.25 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2005; File No. 001-32395).
10.26	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).
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.
99	Unaudited Pro Forma Combined Statement of Income for the year ended December 31, 2006.

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 22, 2007

/s/ James J. Mulva
James 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 22, 2007, on behalf of the registrant by the following officers in the capacity indicated and by a majority of directors.

Signature	**Title**
/s/ James J. Mulva *James 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 L. Armitage *Richard L. Armitage*	Director
/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/ 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/ Bobby S. Shackouls *Bobby S. Shackouls*	Director

/s/ Victoria J. Tschinkel *Victoria J. Tschinkel*	Director
/s/ Kathryn C. Turner *Kathryn C. Turner*	Director
/s/ William E. Wade, Jr. *William E. Wade, Jr.*	Director

216