

CONOCOPHILLIPS  
Form 10-K  
February 23, 2007

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

**Form 10-K**

(Mark One)

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

For the fiscal year ended December 31, 2006

**OR**

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

For the transition period from \_\_\_\_\_ to \_\_\_\_\_

Commission file number 001-32395

**ConocoPhillips**

*(Exact name of registrant as specified in its charter)*

**Delaware**

*(State or other jurisdiction of  
incorporation or organization)*

**01-0562944**

*(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

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7.125% Debentures due March 15, 2028  
9 3/8% Notes due 2011

New York Stock Exchange  
New York Stock Exchange

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.  Yes  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.  Yes  No

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer

Accelerated filer

Non-accelerated filer

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).  Yes  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)

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## PART I

Unless otherwise indicated, the company, we, our, us, and ConocoPhillips are used in this report to refer to the businesses of ConocoPhillips and its consolidated subsidiaries. Conoco and Phillips are used in this report to refer to the individual companies prior to the merger date of August 30, 2002. Items 1 and 2, Business and Properties, contain forward-looking statements including, without limitation, statements relating to the company's plans, strategies, objectives, expectations, and intentions, that are made pursuant to the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. The words forecasts, intends, believes, expects, plans, scheduled, should, goal, may, 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 (CPCChem).

- **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

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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.

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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**



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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.

### Cook Inlet Area

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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

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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

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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.

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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.

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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.

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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 Marañon 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**

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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

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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

## Edgar Filing: CONOCOPHILLIPS - Form 10-K

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.

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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 Khylychuy (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 Norsesea Pipeline Limited shareholders, progressed the application to obtain planning permission for an LNG regasification facility and combined heat and power plant at the existing Norsesea 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

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).

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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.

Refinery	Location	Region	Crude Throughput Capacity (MB/D)			
			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.

East Coast Region

**Bayway Refinery**

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

Gulf Coast Region

**Alliance Refinery**

The Alliance refinery is located on the Mississippi River in Belle Chasse, Louisiana. The refinery has a crude oil processing capacity of 247,000 barrels per day, and processes mainly light, low-sulfur crude oil. Alliance receives domestic crude oil from the Gulf of Mexico via pipeline, and foreign crude oil from the North Sea and West Africa via pipeline connected to the Louisiana Offshore Oil Port. The refinery produces a high percentage of transportation fuels, such as gasoline, diesel and jet fuel. 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 Mery 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 Mery, 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.

Refinery	Location		Ownership Interest	Crude Throughput Capacity (MB/D)	
				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 Česká 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 Zorb™ SRT), alkylation technologies (ReVAP™, IMP™, SOFT™), and

delayed coking (ThruPlus®) technologies. We also offer a gasification technology (E-Gas ) that uses petroleum coke, coal, and other low-value hydrocarbon as feedstock, resulting in high-value synthesis gas that can be used for a slate of products, including power, hydrogen and chemicals.

#### 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, CPCChem 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 CPCChem'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

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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.

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**Item 3. LEGAL PROCEEDINGS**

The following is a description of reportable legal proceedings, including those involving governmental authorities under federal, state and local laws regulating the discharge of materials into the environment for this reporting period. The following proceedings include those matters that arose during the fourth quarter of 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.

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## 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

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\*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.

**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
<b>2006</b>			
First	\$ 66.25	58.01	.36
Second	72.50	57.66	.36
Third	70.75	56.55	.36
Fourth	74.89	54.90	.36
<b>2005</b>			
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
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Closing Stock Price at January 31, 2007	\$ 66.41
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Number of Stockholders of Record at January 31, 2007*	66,202
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\*In determining the number of stockholders, we consider clearing agencies and security position listings as one stockholder for each agency or listing.

## Issuer Purchases of Equity Securities

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 billion 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.

**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.

## 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 company does not undertake to update, revise or correct any of the forward-looking information unless required to do so under the federal securities laws. Readers are cautioned that such forward-looking statements should be read in conjunction with the company's disclosures under the heading: CAUTIONARY STATEMENT FOR THE PURPOSES OF THE SAFE HARBOR PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995, beginning on page 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:

Years Ended December 31	Millions of Dollars		
	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.



*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, CPCChem, 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.

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## Segment Results

## E&amp;P

	2006	2005	2004
	Millions of Dollars		
<b>Net Income</b>			
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		
<b>Average Sales Prices</b>			
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

	Dollars Per Unit		
<b>Average Production Costs Per Barrel of Oil Equivalent</b>			
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		
<b>Worldwide Exploration Expenses</b>			
General administrative; geological and geophysical; and lease rentals	\$ 483	312	286
Leasehold impairment	157	116	175
Dry holes	194	233	242
	\$ 834	661	703

	2006	2005	2004
	Thousands of Barrels Daily		
<b>Operating Statistics</b>			
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.



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		
<b>Net Income*</b>	\$ 476	688	235
<i>*Includes DCP Midstream-related net income:</i>	\$ 385	591	143

	Dollars Per Barrel		
<b>Average Sales Prices</b>			
U.S. natural gas liquids*			
Consolidated	\$ 40.22	36.68	29.38
Equity	39.45	35.52	28.60
<i>*Based on index prices from the Mont Belvieu and Conway market hubs that are weighted by natural gas liquids component and location mix.</i>			

	Thousands of Barrels Daily		
<b>Operating Statistics</b>			
Natural gas liquids extracted*	209	195	194
Natural gas liquids fractionated**	144	168	205
<i>*Includes our share of equity affiliates, except LUKOIL, which is included in the LUKOIL Investment segment.</i>			

*\*\*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.

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**R&M**

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

	Dollars Per Gallon		
<b>U.S. Average Sales Prices*</b>			
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		
<b>Operating Statistics</b>			
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
<b>Net Income</b>	<b>\$ 1,425</b>	714	74
<b>Operating Statistics*</b>			
Net crude oil production (thousands of barrels daily)	<b>360</b>	235	38
Net natural gas production (millions of cubic feet daily)	<b>244</b>	67	13
Net refinery crude oil processed (thousands of barrels daily)	<b>179</b>	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
<b>Net Income</b>	<b>\$ 492</b>	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
<b>Net Income (Loss)</b>			
Power	\$ 82	43	(31 )
Technology solutions	(23 )	(16 )	(18 )
Other	(44 )	(48 )	(53 )
	<b>\$ 15</b>	(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
<b>Net Income (Loss)</b>			
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.

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**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
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

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

\$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

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.

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

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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

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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 Staffjord 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.



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**

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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



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 amendment 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**



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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,

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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*

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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*

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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.

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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**

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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

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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**

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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

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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**

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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

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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**

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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

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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 prelimi